TERASEN GAS INC. and TERASEN GAS (VANCOUVER ISLAND) INC.

Review of Price Risk Management Objectives and Hedging Strategy

~~CONFIDENTIAL~~

January 27, 2011

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1 EXECUTIVE SUMMARY

On an annual basis, Terasen Gas Inc. ("TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI"), (collectively the "Company" or "Terasen") file separate Price Risk Management Plans ("PRMP") which seek approval for gas commodity hedging plans for the next three years, or in TGVI's case, for the next five years.

On May 13, 2010 TGI and TGVI submitted their respective Price Risk Management Plans to the British Columbia Utilities Commission (the "Commission") for review and acceptance. On July 22, 2010 the Commission issued Order No. E-23-10 relating to the TGI 2010-2013 Price Risk Management Plan and Order No. E-24-10 relating to the TGVI 2010-2015 Price Risk Management Plan. The Orders denied the Price Risk Management Plans, directing TGI and TGVI to immediately suspend all related market activities. TGI and TGVI were directed to conduct a review of the Price Risk Management Plans' primary objectives in the context of the Clean Energy Act and increased domestic natural gas supply. As a result of discussions with Commission staff following the Orders, TGI and TGVI also agreed to examine the cost/benefit value of the hedging program for customers as part of the review.

The Clean Energy Act prescribes possible significant additions to British Columbia's electricity generation and transmission infrastructure and new renewable sources of supply which will increase the cost of electricity to British Columbians. In addition, the North American natural gas supply and demand market fundamentals have changed significantly in the near term such that there is greater North American natural gas supply certainty. As a result of these developments, all else being equal, the competitive position of natural gas has improved, in the near term. However, depressed natural gas prices (relative to recent historical values) do not necessarily mean reduced price volatility. Short term supply and demand imbalances can still cause market prices to fluctuate significantly. This can translate into significant commodity rate changes if effective hedging is not utilized.

Looking forward the Company believes that natural gas competiveness is less certain. While weakened natural gas demand and strong production from unconventional gas has created an abundant supply situation in North America in the near term, the return to a tighter supply and demand balance is expected beyond 2011 with the potential for higher natural gas prices and volatility. Furthermore, the risk of regional price disconnects due to infrastructure constraints in the Pacific Northwest region are also significant challenges that must be managed in order to reduce the impact to natural gas customers. In addition, the increases in carbon tax on natural gas, the unfavourable capital cost differential between natural gas and electric space and hot water heating equipment, and uncertainty regarding future electricity increases (in terms of both timing and amount) provide challenges for the Company in managing competitiveness. While the Clean Energy Act includes significant additions to the provincial electricity infrastructure, it is possible that some initiatives could be put delayed or even put on hold in order to manage the rate impacts on customers. As such, the Company believes that the objectives of the current

PRMP remain relevant and continue to be in the best interest of customers. This assertion will be emphasized with supporting evidence and analysis throughout this report.

Terasen hereby submits this report which reviews the objectives of the PRMP of TGI and TGVI and includes the recommended hedging strategy to achieve the objectives. Terasen continues to believe that hedging remains an important tool to help manage price volatility and gas costs for customers. Within the report, consideration of the use of storage and deferral account balances, which mitigate rate volatility to some degree, has also been included. The Company has focused on the importance of the value of price risk management for customers, balancing rate volatility mitigation and competitiveness with reducing the potential costs of hedging. In consultation with Commission staff, an external consultant with extensive experience with utility price risk management, was used for this review. The consultant's review and recommendations are included in this report.

1.1 Price Risk Management Objectives

Terasen strives to provide safe, reliable and cost effective service to energy customers within its service areas. The Price Risk Management Plan is one of the tools that that Terasen uses to support these goals. The primary objectives of the PRMP have been to:

- Improve the likelihood that natural gas remains competitive with other sources of energy, primarily electricity at this time;
- Moderate the volatility of market gas prices and their effect on rates for customers; and
- Reduce the risk of regional price disconnects.

There are indications that natural gas rate volatility is a concern for many Terasen customers. Evidence of this is provided in Section 4.5 of this report. While market prices are currently depressed and price volatility is low, there is the potential for price volatility to return to the marketplace in the future (as described in Section 3). The enhanced hedging program recommended within this report is the most effective way to mitigate market price volatility and its impacts on customers' rates.

An underlying objective has been to meet these primary objectives at a reasonable cost. The Company believes these objectives continue to be appropriate given the potential for future price volatility in the North American natural gas marketplace as well as the unique regional marketplace in which Terasen operates, as discussed within this report. These objectives are important in protecting customers from natural gas price volatility and also ensuring Terasen is able to continue to provide customers with a competitive energy product, in the near term, in a dynamic and evolving marketplace. Terasen believes that these objectives have been, and continue to be, in the best interest of customers. Terasen also believes that a review of the hedging program designed to meet these objectives is important to determine if the program should be enhanced to be more responsive to market conditions and improve value for customers.

1.2 Recommendations

Terasen recommends that the objectives of the Price Risk Management Plans continue to be relevant and appropriate. As in the wider non-regulated business world, Terasen must be successful at producing value for customers in order to maintain and grow its customer base. This includes providing cost effective, relatively stable (compared to the market) and competitive rates for customers in the near term. If Terasen is not successful in providing value, customer migration from natural gas could result in a smaller customer base and lower throughput volumes which increase per unit delivery costs for all customers. As such, a greater focus on cost effectiveness with respect to the hedging strategy is warranted.

The consultant RiskCentrix, LLC ("RiskCentrix") believes that these objectives are appropriate for Terasen and consistent with those of other utilities. Terasen recommends the hedging strategy as recommended by RiskCentrix for TGI. This hedging strategy provides an appropriate means to achieve these objectives while at the same time is expected to improve cost effectiveness. Rather than a largely programmatic implementation strategy as used by Terasen in the past, RiskCentrix suggests that a 'monitor and respond' approach will effectively mitigate rate volatility, manage competitiveness and also improve cost effectiveness. The RiskCentrix hedging strategy includes several key elements:

- Programmatic hedging for scheduled volatility reduction;
- Defensive hedging to respond to potential increases in prices above specific tolerances;
- Value hedging to capture favourable price opportunities; and
- Basis swaps for managing Sumas price exposure.

The strategy involves finding an appropriate balance between customer volatility tolerances, hedging cost (or out-of-market) tolerances and option expenditures. A greater use of options than in past hedging programs is recommended as these instruments provide effective upside cost mitigation while also reducing the potential out-of-the-money outcomes.

The detailed recommendations of RiskCentrix are provided in Section 7 of this report and the consultant's report is included as Appendix A. TGI is submitting a new Price Risk Management Plan based on the RiskCentrix strategy to the Commission concurrently with this report.

2 INTRODUCTION

On an annual basis, Terasen Gas Inc. ("TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI"), (collectively the "Company" or "Terasen") file separate Price Risk Management Plans ("PRMP") which seek approval for gas commodity hedging plans for the next three years, or in TGVI's case, for the next five years.

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The Clean Energy Act prescribes possible significant additions to British Columbia's electricity generation and transmission infrastructure and new renewable sources of supply which will increase the cost of electricity to British Columbians. In addition, the North American natural gas supply and demand market fundamentals have changed significantly in the near term such that there is greater North American natural gas supply certainty. As a result of these developments, all else being equal, the competitive position of natural gas has improved, in the near term. However, depressed natural gas prices (relative to recent historical values) do not necessarily mean reduced price volatility. Short term supply and demand imbalances can still cause market prices to fluctuate significantly. This can translate into significant commodity rate changes if effective hedging is not utilized.

Looking forward the Company believes that natural gas competiveness is less certain. While weakened natural gas demand and strong production from unconventional gas has created an abundant supply situation in North America in the near term, the return to a tighter supply and demand balance is expected beyond 2011 with the potential for higher natural gas prices and volatility. Furthermore, the risk of regional price disconnects due to infrastructure constraints in the Pacific Northwest region are also significant challenges that must be managed in order to reduce the impact to natural gas customers. In addition, the increases in carbon tax on natural gas, the unfavourable capital cost differential between natural gas and electric space and hot water heating equipment, and uncertainty regarding future electricity increases (in terms of both timing and amount) provide challenges for the Company in managing competitiveness. While the Clean Energy Act includes significant additions to the provincial electricity infrastructure, it is possible that some initiatives could be put delayed or even put on hold in order to manage the rate impacts on customers. As such, the Company believes that the objectives of the current

PRMP remain relevant and continue to be in the best interest of customers. This assertion will be emphasized with supporting evidence and analysis throughout this report.

Terasen hereby submits this report which reviews the objectives of the PRMP of TGI and TGVI and includes the recommended hedging strategy to achieve the objectives. Terasen continues to believe that hedging remains an important tool to help manage price volatility and gas costs for customers. Within the report, consideration of the use of storage and deferral account balances, which mitigate rate volatility to some degree, has also been included. The Company has focused on the importance of the value of price risk management for customers, balancing rate volatility mitigation and competitiveness with reducing the potential costs of hedging. In consultation with Commission staff, an external consultant with extensive experience with utility price risk management, was used for this review. The consultant's review and recommendations are included in this report.

2.1 Price Risk Management Objectives

Terasen strives to provide safe, reliable and cost effective service to energy customers within its service areas. The Price Risk Management Plan is one of the tools that that Terasen uses to support these goals. The primary objectives of the PRMP have been to:

- Improve the likelihood that natural gas remains competitive with other sources of energy, primarily electricity at this time;
- Moderate the volatility of market gas prices and their effect on rates for customers; and
- Reduce the risk of regional price disconnects.

It is important to note that an effective hedging program can help with the objective of competitiveness for the near term hedging horizon only. A narrowing of the gap between natural gas prices and electricity rates over the long run cannot be mitigated other than through a longer term hedging horizon. In other words, over the longer term it is the market that defines the competitive position of natural gas relative to electricity or other sources of energy.

There are indications that natural gas rate volatility is a concern for many Terasen customers. Evidence of this is provided in Section 4.5 of this report. While market prices are currently depressed and price volatility is low, there is the potential for price volatility to return to the marketplace in the future (as described in Section 3). The enhanced hedging program recommended within this report is the most effective way to mitigate market price volatility and its impacts on customers' rates.

An underlying objective has been to meet these primary objectives at a reasonable cost. The Company believes these objectives continue to be appropriate given the potential for future price volatility in the North American natural gas marketplace as well as the unique regional marketplace in which Terasen operates, as discussed within this report. These objectives are important in protecting customers from natural gas price volatility and also ensuring Terasen is able to continue to provide customers with a competitive energy product, in the near term, in a dynamic and evolving marketplace. Terasen believes that these objectives have been, and continue to be, in the best interest of customers. Terasen also believes that a review of the hedging program designed to meet these objectives is important to determine if the program should be enhanced to be more responsive to market conditions and improve value for customers.

While these objectives are appropriate for both TGI and TGVI, the recommended hedging strategy developed herein is applicable only for TGI. While TGVI does continue to have a significant competitive challenge going forward, TGVI does already have significant hedges in place out to October 2014, as implemented under the TGVI 2009-2014 Price Risk Management Plan. Within its upcoming Rate Design Application, to be filed with the Commission in the first quarter of 2012, TGI and TGVI will be proposing an amalgamated gas cost portfolio and harmonized rate setting mechanisms effective January 1, 2013. As such, TGVI is currently reviewing its hedging program and will submit its next Price Risk Management Plan based on these considerations.

2.2 Recommendations

Terasen recommends that the objectives of the Price Risk Management Plans continue to be relevant and appropriate. As in the wider non-regulated business world, Terasen must be successful at producing value for customers in order to maintain and grow its customer base. This includes providing cost effective, relatively stable (compared to the market) and competitive rates for customers in the near term. It is important to recognize that value for many customers, and potentially the determination of their energy choice, may also now include non economic factors, such as environmental considerations. If Terasen is not successful in providing value, customer migration from natural gas could result in a smaller customer base and lower throughput volumes which increase per unit delivery costs for all customers. As such, a greater focus on cost effectiveness with respect to the hedging strategy is warranted.

The consultant RiskCentrix, LLC ("RiskCentrix") believes that these objectives are appropriate for Terasen and consistent with those of other utilities. Terasen recommends the hedging strategy as recommended by RiskCentrix for TGI. This hedging strategy provides an appropriate means to achieve these objectives while at the same time is expected to improve cost effectiveness. Rather than a largely programmatic implementation strategy as used by Terasen in the past, RiskCentrix suggests that a 'monitor and respond' approach will effectively mitigate rate volatility, manage competitiveness and also improve cost effectiveness. The RiskCentrix hedging strategy includes several key elements:

- Programmatic hedging for scheduled volatility reduction;
- Defensive hedging to respond to potential increases in prices above specific tolerances;
- Value hedging to capture favourable price opportunities; and
- Basis swaps for managing Sumas price exposure.

The strategy involves finding an appropriate balance between customer volatility tolerances, hedging cost (or out-of-market) tolerances and option expenditures. A greater use of options than in past hedging programs is recommended as these instruments provide effective upside cost mitigation while also reducing the potential out-of-the-money outcomes.

The detailed recommendations of RiskCentrix are provided in Section 7 of this report and the consultant's report is included as Appendix A. TGI intends to submit a new Price Risk Management Plan based on the RiskCentrix strategy to the Commission separately in January 2011.

2.3 Price Risk Management and Natural Gas Utility Hedging

Price risk management is typically defined as taking appropriate measures to reduce exposure to uncertainty in future market prices. RiskCentrix describes price risk management as defending against intolerable outcomes and notes that the magnitude of risk in the natural gas marketplace is greater to the upside than the downside - prices are bounded by zero at the bottom but unlimited on the top[1]. In general, natural gas utilities use price risk management in order to reduce the uncertainty in future market prices which impacts gas costs that are passed onto customers through rates. It is important to distinguish this risk mitigation from attempting to "beat the market" or achieve the lowest possible pricing available in the marketplace. Given the myriad of supply and demand variables that affect market prices, it is very difficult for companies or utilities to implement hedges, as part of price risk management, that result in no hedging costs on a consistent basis. Furthermore, hedging should not be considered a profit-making endeavour. This would typically involve speculating on future price movements and potentially expose customers to even greater market price risk in the event that predictions are wrong. Effective hedging programs may result in unit commodity gas costs higher or lower than market prices, given the difficulty in "beating the market". The measure of success of a hedging program should not be whether hedging gains or costs were realized but rather whether the objectives, reflecting the interests of customers, were achieved. Terasen does recognize, however, that certain hedging instruments or strategies can result in a lower probability of hedging costs than other instruments or strategies, as will be described in Section 7.

1 RiskCentrix Findings and Recommendations Regarding Energy Risk Mitigation Program Prepared For Terasen Gas, December 27, 2010

Natural gas utility customers have indicated that they desire some level of stability in natural gas rates and implicit protection from the volatility in market prices. Customer complaints and media attention increases when natural gas rates increase as many customers on fixed incomes struggle to make bill payments. In February 2005, TGI engaged a research company to survey customers regarding their tolerance for volatility. The results of the Residential Customer Price Volatility Preferences Study, conducted in February 2005 by Western Opinion Research Inc., indicated that customers prefer price stability. The survey results confirmed that while customers will tolerate some volatility it is certainly less than the volatility that has occurred in the recent past, and could occur in the future, in the natural gas market. The results of a more recent focus group supported these survey findings. More discussion of this and other customer preferences evidence regarding volatility is provided in Section 4.

Furthermore, enrolment activity with alternate gas marketers offering fixed price contracts in the commodity unbundling environment provides evidence that customers desire rate stability. TGI had witnessed positive growth in enrolments with marketers when its commodity rate increased significantly during 2008. More discussion of this is also provided in Section 4.

Reducing market price volatility enables utilities and Terasen to offer a competitive product to customers over the near term. Customers are able to choose from a greater variety of energy sources in today's marketplace, including electricity, solar, and geothermal and so it is important for gas utilities to maintain competitive rates and a service that provides value to customers. Reducing natural gas rate variability helps gas utilities to maintain or grow their customer base. If natural gas rates are not competitive or too volatile for customers, declining throughput on the natural gas system places upward pressure on the per unit (or per customer) distribution and delivery costs, all else equal, for those customers that remain with natural gas service. Furthermore, in some jurisdictions, like British Columbia and Ontario, migration of natural gas customers to electricity can also place more pressure on electricity rates as well, given the necessity to replace aging infrastructure and secure more expensive sources of power to meet growing demand. This migration effect can also be adversely impacted by government legislation and the carbon tax and public policy regarding greenhouse gas emission targets, where natural gas is viewed as being less "green" than electricity. The impacts of migration from natural gas are discussed further in Section 4. In the end, managing rate volatility and ensuring competitive rates is in the best interests of energy customers.

2.4 TGI and TGVI Past Hedging

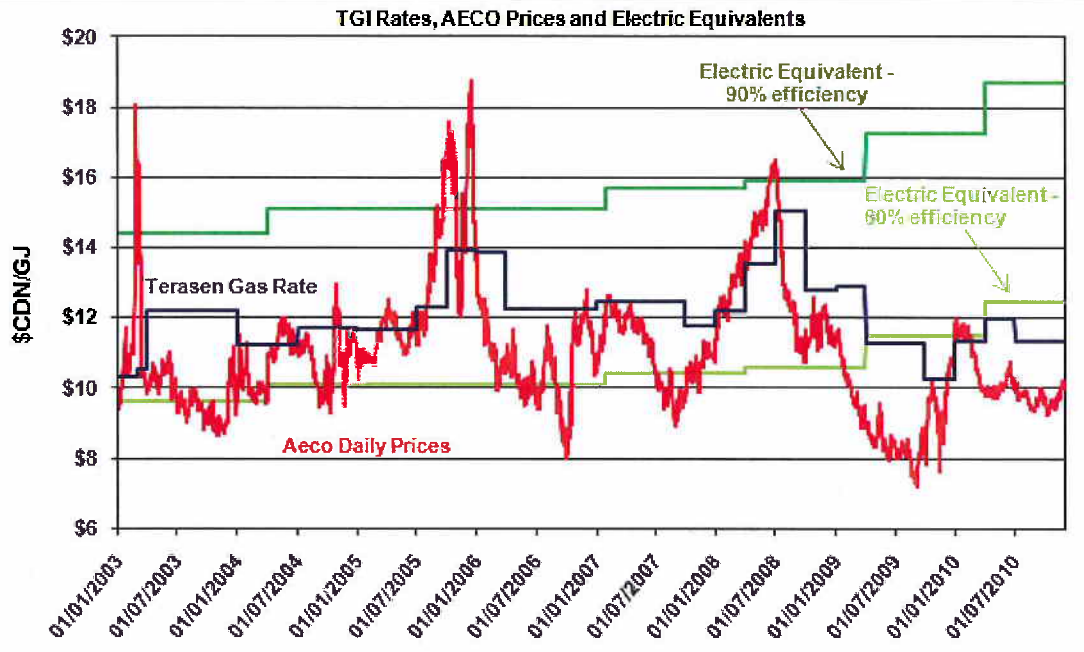
TGI and TGVI share the same price risk management objectives and have used hedging to manage rate volatility and competitiveness in the past. However, because of their different rate structures and cost recovery mechanisms, this hedging is reflected in the rates of TGI and TGVI in different ways.

2.4.1 TGI

The hedging program of TGI has played an important role in managing market price volatility for customers. Market prices have been highly volatile in the past, adversely impacting natural gas rates for customers and TGI's ability to compete with other sources of energy, primarily electricity. The Price Risk Management Plans have served to mitigate a significant amount of the market price volatility and helped to maintain competitive rates, at least on a variable cost basis. This has been particularly important in the past given the historically low electricity rates (as compared to other state and provincial jurisdictions) resulting from the preservation of BC Hydro Heritage Assets. Electricity rates in British Columbia have remained relatively flat for many years, unaffected by market power prices, while TGI rates have been impacted by the volatility in market natural gas prices. Furthermore, the hedging program has shielded customers from regional price disconnections where constrained infrastructure amid growing demand has resulted in Sumas price spikes which can adversely affect costs and rates for customers.

The following graph shows historical TGI residential rates compared to market prices (AECO/NIT daily spot prices) and the electric equivalent rates. In this case, the electric equivalent has been segmented, showing a 90% efficiency equivalent representative of new natural gas furnaces and a 60% efficiency equivalent representative of natural gas hot water heaters. The graph uses a blended electric equivalent after October 2008, when the two-step Conservation rate came into effect for all residential electricity customers. For simplicity, the blended electric equivalent was calculated by inflating April 2008 rates by the approved increases to the revenue requirement in the Commission decision on the BC Hydro F2009/2010 Revenue Requirements Application and the BC Hydro F2011 Revenue Requirement Application approved rate increases and rate rider. As discussed in Section 4, these space and hot water heating segments represent a significant portion of the TGI demand load. The market prices have been grossed up by the TGI fixed basic and delivery charges and Midstream rates in order to provide a direct comparison to the TGI rates and electricity equivalent rates. The graph does not include carbon tax, currently at about $1/GJ, applicable to natural gas and not electricity.

Figure 1: TGI Rate Compared to Market Gas Prices and Electric Equivalents



Note: - AECO prices adjusted up by Terasen Gas fixed, basic & delivery and midstream charges for comparison purposes
- Efficiency of gas furnace is 90% and hot water heater is 60% relative to 100% for electricity

As the graph illustrates, the TGI rate, including the use of hedging, serves to protect customers from a significant amount of the market price volatility and significantly reduces customers' exposure to the large price spikes that have occurred in the past. Without the hedges, the TGI rate increases during these price spike periods would have been significantly above customers' tolerances for bill increases, as detailed in Section 4. The TGI rate changes typically lag the AECO market price changes (up or down) mainly due to the quarterly rate setting mechanism, amortization of incurred deferral balances resulting from the difference between actual rate recoveries and actual gas costs and the impact of hedges. As will be discussed in Section 5, however, the quarterly rate setting mechanism and deferral balance amortization provide some degree of rate volatility mitigation but ultimately are not effective replacements for a hedging program.

While the hedging program protects customers from significant amounts of market price increases, customers have also benefited from market price declines as reflected in lower commodity rates. For example, the TGI commodity cost recovery rate ("CCRA rate") effective January 1, 2011 is at its lowest level ever since the inception of the CCRA rate in April 2004 with the introduction of commodity unbundling, at $4.568/GJ. While the decline in market prices since their peak in mid 2008 has resulted in hedging costs (i.e. out-of-the-market outcomes), a balanced portfolio approach, which includes hedging, storage and floating volumes, means that not all TGI market price exposure is hedged, enabling some downside market price participation. TGI recognizes that protecting customers from market volatility with minimal hedging costs would be a preferred outcome. However, it is also important to understand that the objective is not to beat the market and achieve zero hedging costs but rather protect customers at a reasonable cost. The recommended enhanced hedging strategy, as detailed in Section 7, will help in this regard.

The greater use of option instruments will also help reduce hedging costs while achieving the objectives. TGI has promoted greater use of options in past Price Risk Management Plans but has been limited by the Commission on the maximum percentage of options. Terasen believes this is due to the costs associated with options, either implicitly with costless collars (via a limited floor price) or explicitly with call options (via an upfront or deferred premium). However, it is important to recognize that there is an implicit cost associated with fixed price swap instruments when market prices decline. Options should be an important part of a hedging program that meets the objectives in different price environments. The use of options provide protection against unforeseen price spikes yet allow for downward market price participation if such adverse price movements do not materialize. Therefore, hedging costs are reduced compared to fixed price swaps and can be significantly less depending on the call premium or costless collar floor price.

Figure 1 also highlights the challenge TGI has had with electricity competitiveness. On a variable, or commodity, cost basis, while TGI has remained competitive with electricity for high efficiency natural gas furnaces (relative to electric baseboards for space heating), TGI rates have only recently been below the 60% efficiency electric equivalent for hot water heating. However, this is absent any consideration of the carbon tax applicable to natural gas or the higher capital costs associated with natural gas hot water and space heating equipment. Consideration of the capital costs is particularly important in attracting new customers or those considering retro-fitting because the upfront costs, as well as operational variable costs, will factor into customers' decision making when making energy choices. More discussion on appropriate electric equivalent benchmarks going forward, including consideration of capital costs and carbon tax, is provided in Section 4.

It is also important to note that rate volatility can also adversely influence consumer perceptions about natural gas. If natural gas rate volatility is significantly greater than that for electricity rates, consumers may choose electricity for rate stability even though, on a variable cost basis, natural gas may be competitive with electricity. This is discussed further in Section 4.

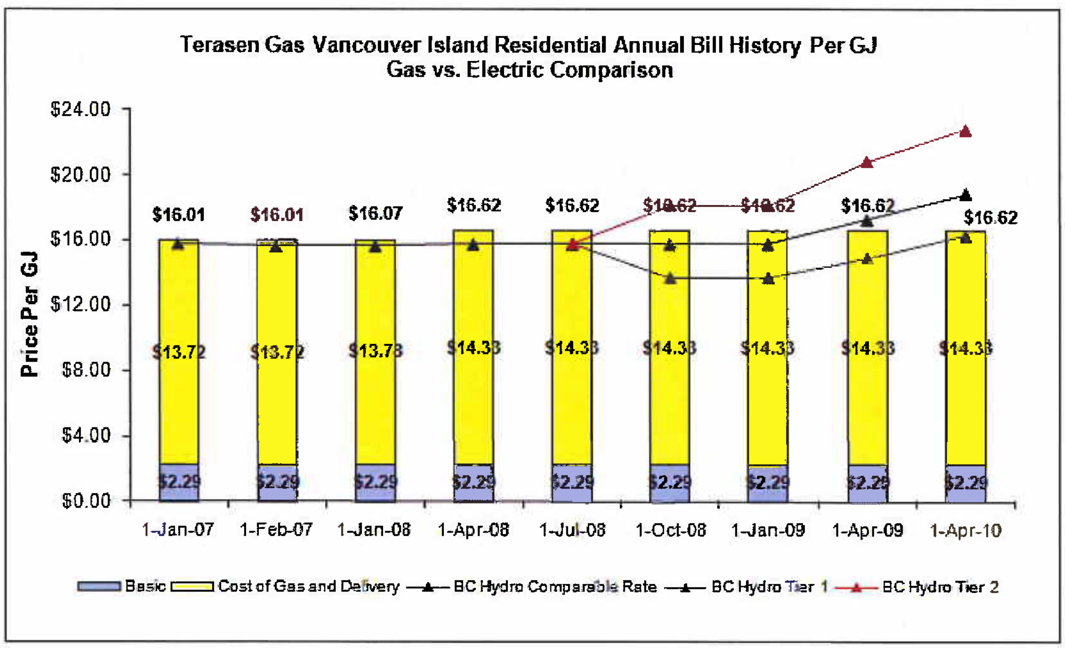
2.4.2 TGVI

TGVI's hedging program has also played an important role in managing gas cost volatility and competitiveness. However, because of TGVI's greater competitive challenge, TGVI has a rate structure that is different than that of TGI. TGVI has maintained residential rates at or near the average electric equivalent for a number of years through a "soft-cap" rate setting mechanism.

The hedging program has helped TGVI to manage gas costs and contributed to the elimination of the deficit balance collected in the Revenue Deficiency Deferral Account ("RDDA"), which eliminates one area of rate pressure in the near term. The following figure illustrates TGVI's historical competitiveness to electricity, on a variable or rate basis (excluding any capital cost differences or carbon tax), employing rates capped near the competing electricity prices to enable elimination of the RDDA deficit. TGVI received approval to maintain 2009 rates for 2010 and 2011 through the Negotiated Settlement Agreement for the TGVI 2010-2011 Revenue Requirements and Rate Design Application[2]. This enables TGVI to build a revenue surplus via the Revenue Surplus Deferral Account ("RSDA") as one tool to mitigate the impending loss of the royalty revenue arrangement at the end of 2011 to further support near term competiveness.

The graph (Figure 2) is based on average annual consumption for a TGVI residential customer of 55 GJ per year and the electricity rates based on 90% efficiency for natural gas relative to 100% for electricity. The BC Hydro comparable rate in the graph is essentially a blending of the RIB rates based on combined estimated usage at each of the Step 1 and Step 2 levels. The April 2010 BC Hydro rates presented in this graph are based on the BC Hydro proposed rate increases per the F2011 Revenue Requirements Application. The carbon tax on natural gas has not been included in the figure but it ranges from about $0.50 per GJ in July 2008 to about $1 per GJ by July 2010.

Figure 2: TGVI's Historical Competitiveness to Electricity



2 Per Commission Order No. G-140-09 dated November 26, 2009.

It is important to note that while TGVI's residential rates are currently competitive with electricity rates for space heating on a variable cost basis (based on 90% efficient natural gas furnace), the electric equivalent for hot water heating, as discussed in the previous section for TGI and in Section 4, is well below that for space heating. As such, TGVI is competitively challenged with respect to lower efficiency furnaces for space heating and hot water heating on a variable cost basis even without consideration of capital cost differences or carbon tax.

Because of TGVI's greater competitive challenge, its past hedging program has been more extensive that TGI's. TGVI's most recent PRMP included a hedging horizon of five years, compared to three years for TGI, and targeted a higher percentage of hedgeable volumes. While TGI targeted 60% and 45% of hedgeable volumes for winter and summer, respectively, TGVI targeted 100% of hedgeable volumes. This was based on consideration of the loss of the royalty revenue arrangement after 2011 and TGVI's greater competitive challenge. As such, based on the implementation of the TGVI 2009-2014 Price Risk Management Plan, TGVI has hedged 50% of the hedgeable volumes through October 2014. Had TGVI's recent hedging program not been denied and continued in the second half of 2010, the current low gas price environment would have resulted in TGVI completing hedging for 100% of the hedgeable volumes for most terms out to October 2014[redacted] This would have locked in good value for customers in terms of securing relatively low commodity gas costs (compared to recent historical averages) and reduced cost uncertainty when the royalty revenue arrangement expires after 2011. In light of the hedging already in place and the possibility of amalgamation between TGVI and TGI in the future, TGVI is currently evaluating its hedging strategy going forward and will submit a new PRMP to the Commission once this is complete. Therefore, the recommendations within this report regarding hedging strategy and implementation are applicable to TGI only. The review of the objectives continues to be applicable to both TGI and TGVI.

2.5 Future Competitiveness

Competitiveness will certainly continue to be a challenge for TGVI and TGI going forward. While projected increases in electricity rates and currently depressed natural gas prices have somewhat alleviated the immediate challenge on a variable cost basis, there is significant uncertainty regarding natural gas prices and volatility going forward, as discussed in Section 3. Higher capital costs for natural gas equipment and increasing carbon taxes until 2012, with uncertainty regarding the amount after that, add to the challenge. Furthermore, governmental legislation and public policy regarding the environmental perceptions of natural gas compared to electricity will also continue to impact natural gas in the future, as discussed in Section 4. Therefore, the Company believes price risk management and the hedging program are critically important in managing rate volatility and competitiveness over the hedge term horizon and providing reasonable rates and value for customers.

2.6 Value for Customers

Terasen creates value for customers by providing safe and reliable service at a reasonable cost. This includes managing costs that affect delivery rates as well as the cost of gas components. In terms of maintaining appropriate delivery costs, prudently managing expenditures and implementing programs and services that enhance value and ensure safety are keys to this endeavour. Managing the cost of gas is a significant part of maintaining reasonable commodity and midstream costs. Hedging is an important component of managing total gas costs. The end result is stability in rates (as compared to market prices) and maintaining near term competitiveness (on a variable costs basis) which provides value to customers.

The Annual Contracting Plans ("ACP"), Price Risk Management Plans and mitigation activity are the primary tools Terasen uses to provide security of supply at a reasonable cost. The ACP outlines the physical resource portfolio, comprised of commodity supply, storage and transportation resources which ensure diversity and reliable supply to meet both normal and peak day load requirements. Mitigation activity, which involves optimizing resources that are unused when normal loads do not occur, ensures that excess resources are sold off in the marketplace so costs are reduced and the most value is obtained from the physical portfolio. The development of the ACP involves balancing reliability, costs, diversity, and flexibility. Given these considerations and the lack of available incremental storage in the Pacific Northwest ("PNW") region, a significant portion of the physical portfolio is comprised of index priced gas, subject to market price movements.

To manage this exposure to market prices, Terasen engages in hedging activity as defined in the Price Risk Management Plans. This serves to dampen of the impacts of market price movements and mitigate any potential increases in gas costs.

For TGI, this is particularly important in the commodity unbundling environment wherein the Essential Services Model ("ESM") creates the separation of commodity costs from midstream costs on the customer bill. While the ESM is critical in ensuring the appropriate management of resources for core customers by the utility, it also increases the susceptibility of the commodity rate to market price movements when excluded from the midstream component. This is discussed further in Section 6.

2.7 Customer Value Proposition

The management of gas costs and utilization of price risk management activities can be looked at from a business case perspective in creating value for customers. While the costs of managing gas supply and delivery to customers are passed onto customers via rates, natural gas utilities, including Terasen, have the responsibility for managing these costs. If Terasen is able to provide cost effective rates then customer base will grow which helps to maintain or improve cost effectiveness for all customers; a virtuous circle. If Terasen does not effectively manage costs and rates and greater volatility and reduced competitiveness results, customer migration away from natural gas to other forms of energy is likely, increasing the cost base for remaining customers; the death spiral scenario. Providing value for customers is a fundamental objective of both regulated utilities and private enterprises.

This goal of managing overall costs extends to price risk management. The costs, and gains, associated with hedging outcomes are included in the cost of gas which is reflected in rates for customers. If hedging costs do become significant they could impact Terasen's ability to provide reasonable and competitive rates. However, this must be weighed against the use of hedging to mitigate rate volatility, which is also valued by customers. Therefore, it is important to find the appropriate balance of managing gas costs, including any potential hedging costs, with reducing adverse market price fluctuations. If Terasen is successful in this regard it reinforces the customer value proposition. As such, the Company continues to believe that the objectives of its price risk management are relevant and appropriate and that a reduction in the likelihood of significant hedging costs is important going forward. The hedging strategy, as recommended by RiskCentrix and detailed in Section 7, provides Terasen with the hedging program to meet the objectives including managing costs.

3 NATURAL GAS MARKET OVERVIEW

This section of the report will discuss the changes occurring within the North American natural gas marketplace. It will focus on factors that affect supply and demand balances which in turn influence market prices and volatility. These ultimately affect Terasen's commodity rates and competitiveness relative to other sources of energy. This section provides a summarized version of the detailed natural gas market overview, which is provided in Appendix D.

3.1 Introduction

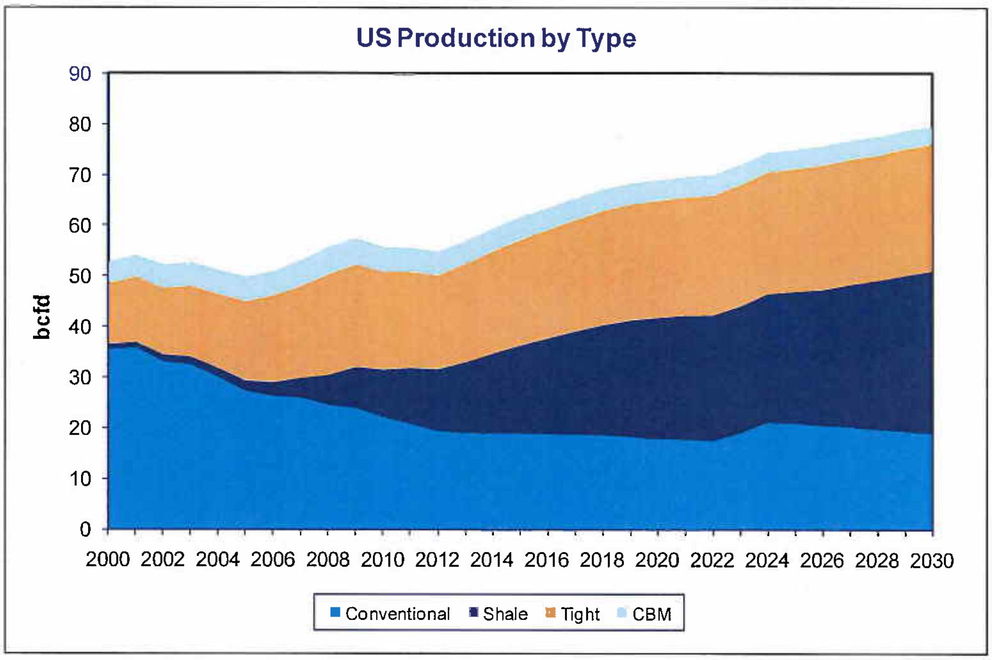
The natural gas market in North America has undergone some significant changes in the last number of years. Advances in drilling techniques and efficiencies have allowed exploration and production companies to discover and extract more natural gas than ever before. Furthermore, at the same time, demand for natural gas has reduced in direct response to the downturn in the global economy. The bulk of the reduction in demand is attributed to industrial customers, many of whom have either reduced output or shutdown operations altogether. The result has been record high natural gas storage levels and depressed natural gas prices. While spot prices have not fallen to the low levels seen in September 2009, forward prices are at the lowest level in many years.

However, natural gas prices in the future could be quite different than today. Reductions in natural gas drilling and decreased supply in response to low natural gas prices has already begun in some areas, as producers transition to drilling for oil and better returns on their investments. Increased industrial natural gas demand resulting from economic recovery is anticipated and there is evidence of this occurring already. Furthermore, natural gas demand for power generation is expected to rise significantly in the future as environmental legislation and aging coal plant retirements creates a shift from coal to gas fired generation. And, as always, weather events can significantly impact the short term supply and demand balance and cause prices to move adversely. So while prices are currently depressed relative to recent historical values, there is greater uncertainty in price levels and volatility going forward.

3.2 Natural Gas Supply

North American natural gas supply growth has recently undergone a dramatic shift from conventional supply to unconventional supply, which includes coal bed methane, tight gas and shale gas. In particular, advances in horizontal drilling technology have reduced production costs such that U.S. natural gas production reached its highest level ever in 2010. It is expected that most of the future growth in supply will continue to come from shale gas.

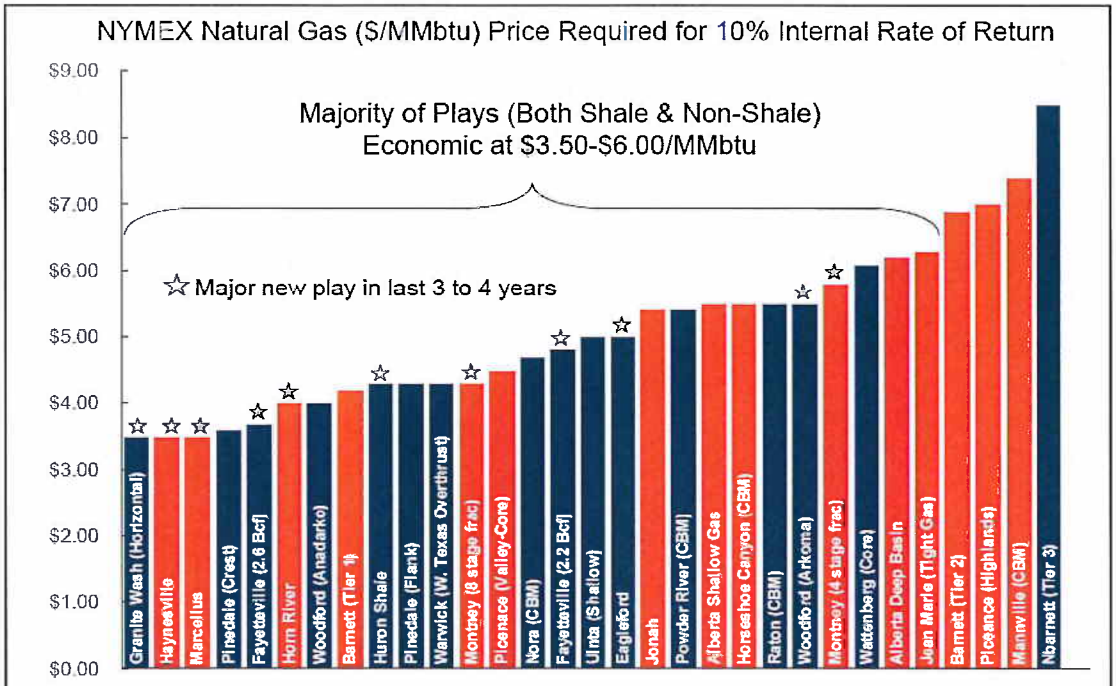
Figure 3: U.S. Natural Gas Production by Source [3]



However, this recent surge in unconventional production in 2010 has occurred despite depressed natural gas prices. In fact, many natural gas plays would be uneconomic to produce at current spot market prices of near $4.50 US/MMBtu.

[3] Wood MacKenzie North America Long Term View – September 2010

Figure 4: NYMEX Price Required for Various Gas Plays[4]



Source: Encana, Morgan Stanley May 2010

There are several factors which have contributed to this strong production despite depressed gas prices. One factor has been the lease hold conditions associated with land purchases. In order to maintain the right to drilling for gas, many companies have continued to drill even though it was less profitable, based on market prices, in the short term. These lease hold conditions require that producers drill for natural gas in order to maintain rights to the land. The majority of these land lease hold conditions expire in 2011. Another factor is related to producer hedging. Many producers had significant portions of their natural gas production volumes hedged in 2010 at price levels well above current market prices. It is estimated that some major producers had hedges in place near $6 US/MMBtu compared to market prices near $4 US/MMBtu in 2010. This has provided many producers with positive cash flows and favourable returns enabling them to fund these lease hold conditions and sustained drilling through 2010. However, the amount of hedging drops significantly for 2011 and 2012, leaving producers with greater exposure to market prices. Another factor helping boost recent production levels is related to the capital intensive nature of natural gas production. Many exploration companies who do own land use rights to desirable gas plays but do not have access to the capital required for production have entered into joint venture agreements with other interested companies so as to continue to explore and further develop their plays. However, with lease hold conditions

[4] Encana, Morgan Stanley, May 2010

expiring and less producer hedges in place for 2011 it is anticipated that this joint venture activity will slow down in the future. As these factors that have helped unconventional supply to reach record levels in 2010 become less influential in 2011, it is expected that production growth will subside and return to a more sustainable level for the future. This will provide support for higher natural gas prices in the future.

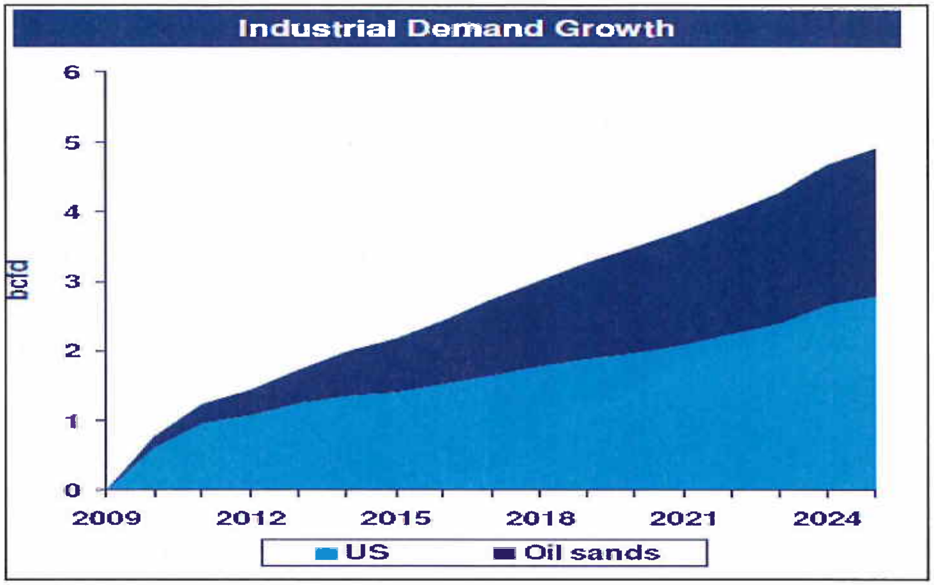
The market price differential between crude oil and natural gas is also beginning to affect natural gas production. With crude oil prices well above historical averages and near $90 US per barrel and gas prices below recent historical averages, many producers are shifting their capital dollars from natural gas production toward more liquid rich gas and oil plays where returns on investment are much higher. This will certainly temper the growth in natural gas production and increase costs and provide support for higher natural gas prices in the future.

3.3 Natural Gas Demand

Natural gas demand has also undergone dramatic changes in recent years. Commercial and, to a larger degree, industrial gas demand have been impacted and reduced due to the recent economic recession. However, economic growth in North America has returned in 2010 and continued growth is expected for the foreseeable future. With this economic growth, industrial demand is also expected to grow. Because industrial demand accounts for about a third of total natural gas consumption a recovery in this sector will provide support for natural gas prices in the future.

Another major component of natural gas demand is related to the extraction and production of oil in the oil sands region of Alberta. With the historically wide relative differential between crude oil and natural gas prices, this area of natural gas demand is expected to see significant growth in the future.

Figure 5: Projected Industrial Demand Growth[5]

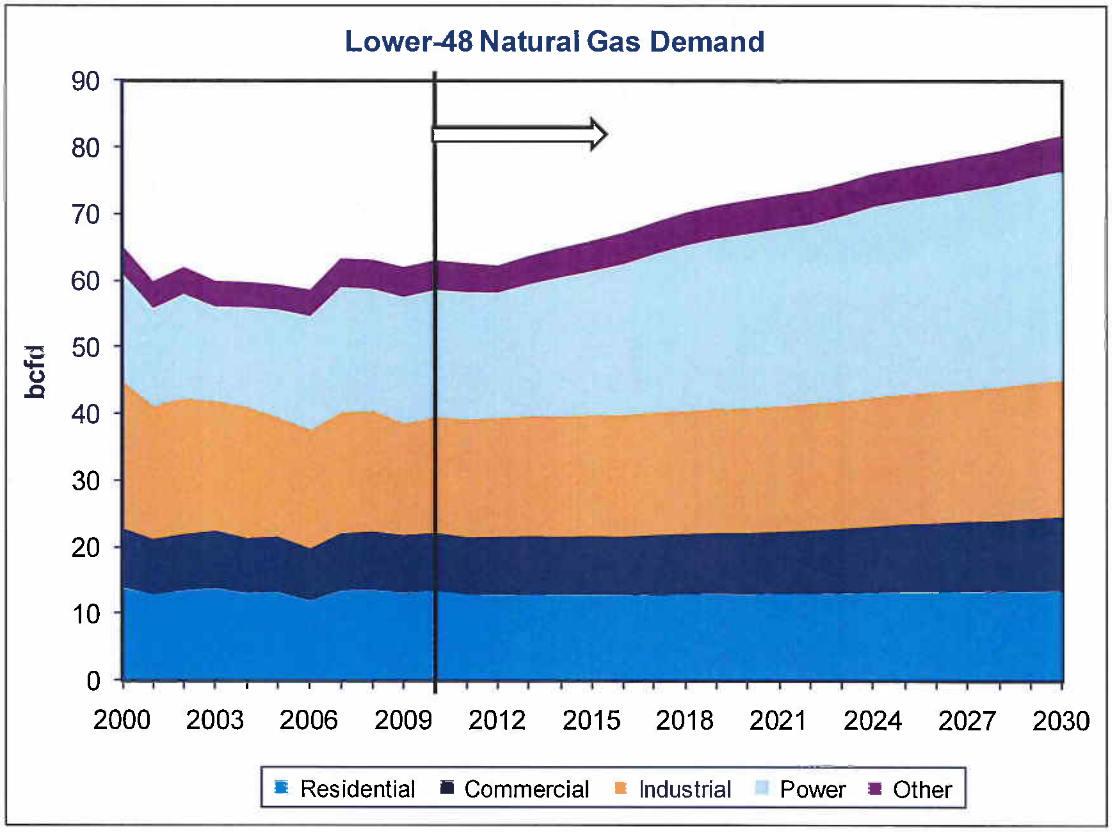


It is expected that significant natural gas demand growth in the future will also come from power generation demand. In fact, natural gas demand for power generation is expected to be the largest source of growth in total natural gas demand. The main reasons for the increase in use of natural gas for power generation are the gradual phasing out of coal fired power generation plants and increased demand for electricity in general. Increased awareness of the harmful effects of coal burning to the environment and government legislation related to reducing greenhouse gas emissions has lead to a gradual shift to natural gas for this same use. As a significant portion of the coal-fired power generation fleet is old enough that environmental retrofits are not generally economical, many coal plants will be retired in the coming years. In many cases, natural gas is the preferred source to replace coal for power generation due to its lower greenhouse gas emissions, lower capital investment requirements for power plants and more favourable plant efficiency.

The following figure shows historical and projected U.S. natural gas demand. Industrial and power generation demand represents the largest contributor to the growth.

[5] Wood MacKenzie North America Long Term View – September 2010

Figure 6: U.S. Natural Gas Demand[6]



The 'other' category in the figure includes natural gas demand for the transportation sector where natural gas provides a reduction in greenhouse gas emissions when compared to the conventional fuels such as gasoline and diesel.

It is anticipated that this increase in total natural gas demand in the future will help correct the current abundant supply situation which has resulted in depressed market prices. A discussion of natural gas prices and the forecasts for future prices is provided in the following section.

3.4 Natural Gas Pricing

Natural gas prices in North America are determined by numerous supply and demand factors, some of which have been discussed in the previous section. The factors that have been discussed thus far are generally longer term in nature, impacting natural gas prices over periods of years rather than months. With the recovery in industrial and commercial demand, growth in

6 Wood MacKenzie North America Long Term View – September 2010

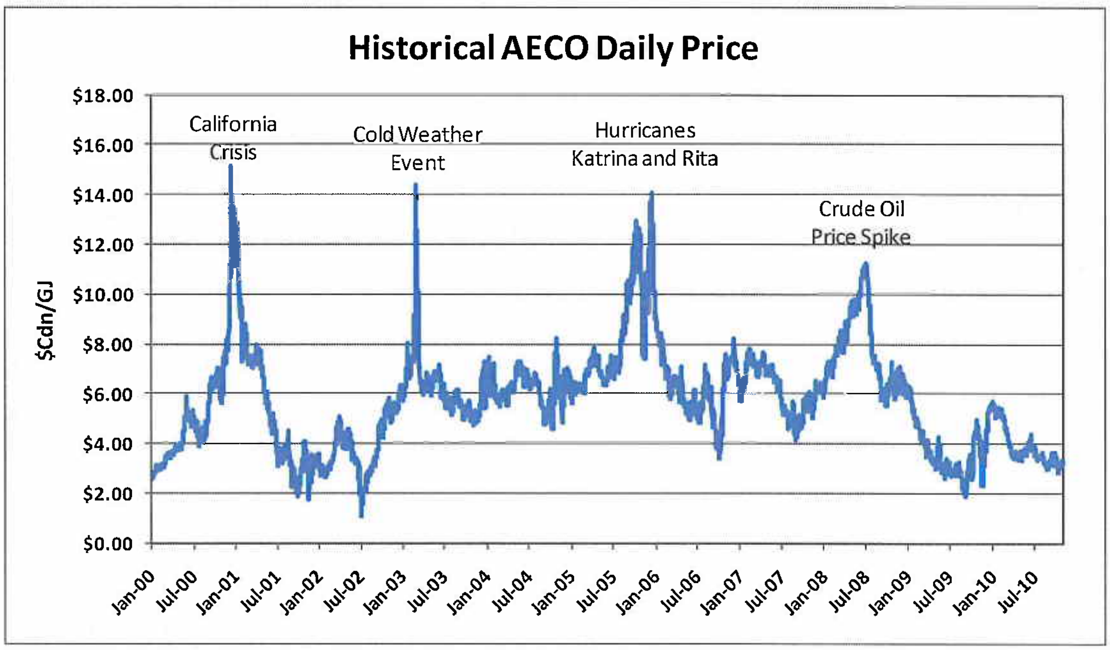
natural gas demand for power generation and a slowdown in natural gas production activity in the near term, natural gas prices are expected to increase in the future.

Furthermore, there are a multitude of factors that can adversely affect gas prices and volatility in the short term, for periods of several months or longer. Some of these factors include the following:

- Supply disruptions such as pipeline constraints during peak demand periods.
- Weather related supply disruptions such as hurricanes that disrupt production during the active hurricane season in the summer months.
- Unusually hot summer temperatures increase demand for natural gas for air conditioning loads.
- High demand for space heating in the winter months.
- Relative prices of competing fuels, such as crude oil or coal.

The following figure illustrates the influence of short term supply and demand imbalances that have caused natural gas prices to spike in the recent past.

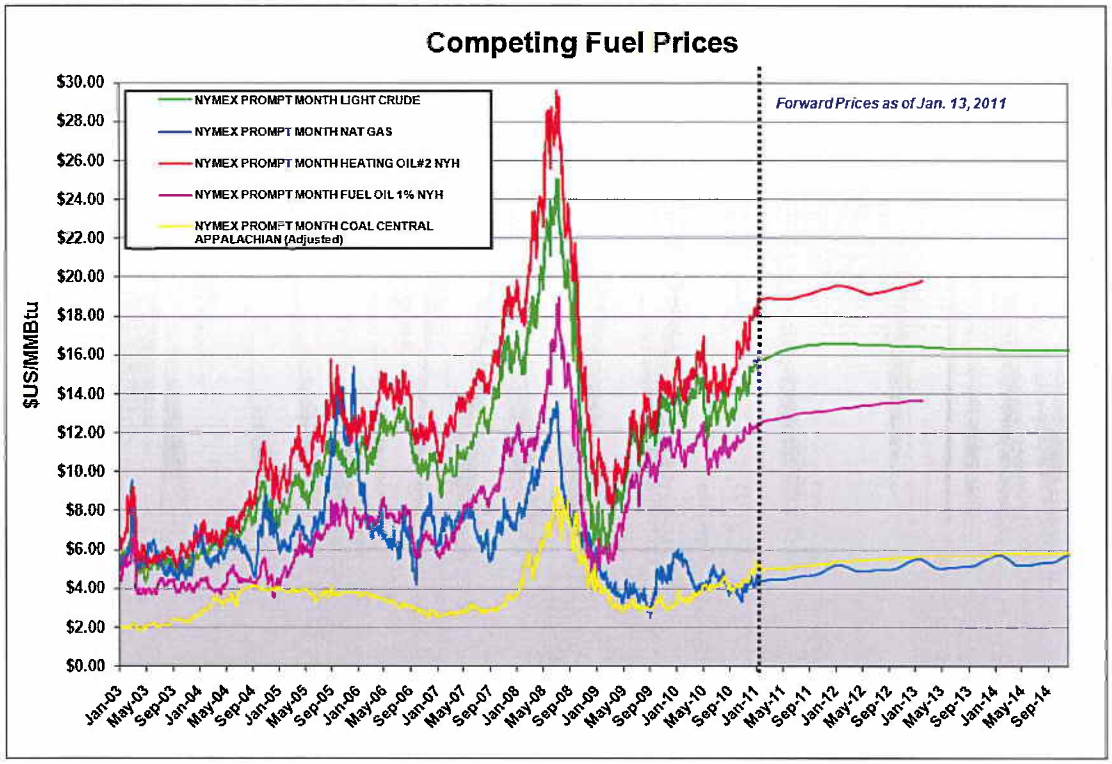
Figure 7: Historical AECO Prices



As the figure shows, price spikes are not limited to winter periods but can spike even in lower demand summer months as was the case in the summers of 2005 and 2008. The devastating hurricane season of 2005 severely disrupted natural gas production for many months while the run up in crude oil prices during mid 2008 dragged up prices for all other fuel sources, such as heating and fuel oil and natural gas. While it is difficult to predict if such circumstances could develop within the next few years, there is the potential for the reoccurrence of these factors which could adversely influence natural gas prices in the future. Weather events can have significant impacts and are difficult to predict. Crude oil prices continue to be volatile, influenced by a multitude of factors including global economic growth, China's demand for oil, the strength of the U.S. dollar relative to the Euro, OPEC production decisions, geo-political concerns such as Nigerian militant activity and Iran's nuclear program, speculative trading and hurricane activity.

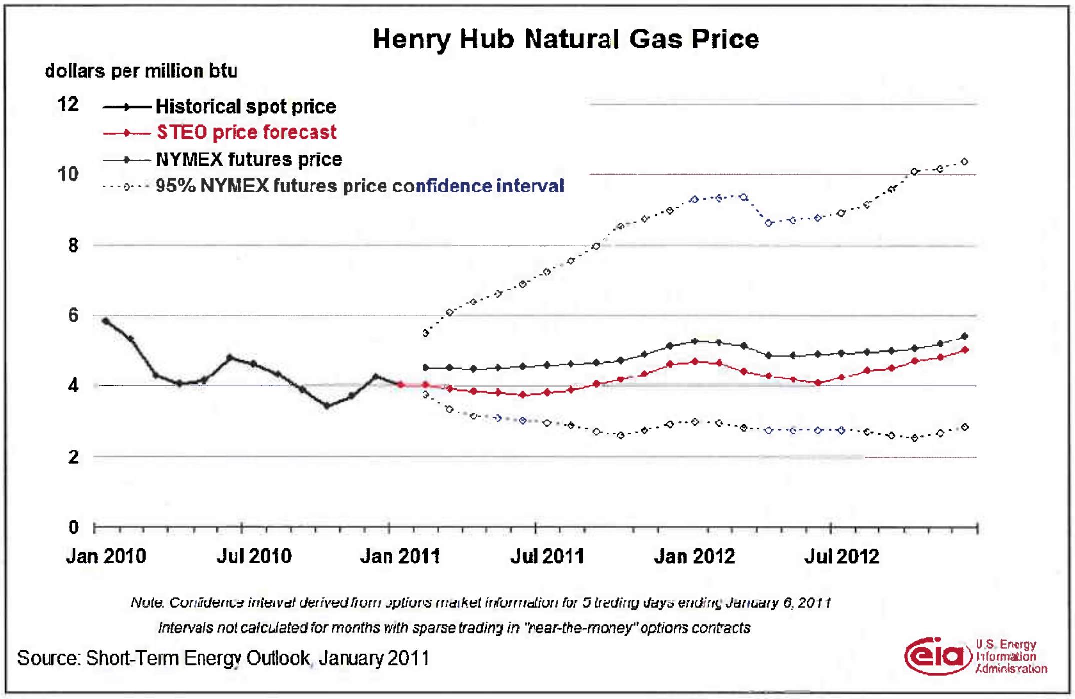
Recently, natural gas prices have also been influenced to a large degree by coal prices. As discussed, natural gas and coal are used by power generators to produce electricity. Some power generators have the ability to switch from coal to natural gas and vice versa depending on relative fuel prices. In the past, residual fuel oil prices provided the floor for natural gas prices as some power generators could switch between these fuels. However, the recent surge in crude oil prices and disconnection from natural gas prices has moved this residual fuel oil floor much higher than natural gas prices such that all the possible short term fuel switching has occurred. Now, coal prices are providing the next level of support for gas prices. This fuel switching ability in the U.S. is estimated to be in the order of up to about 4.5 Bcf/d depending on the differential between coal and gas prices. As a result in the recent low price environment resulting from abundant supply, this incremental demand for natural gas from coal substitution provides support, or a soft floor, for natural gas prices. This coal price support is reflected in the following figure, with recent historical and forward natural gas prices trading near coal prices.

Figure 8: Competing Fuels Prices



However, as the easing of natural gas supply growth and increased industrial and power generation demand occurs over the next few years, natural gas prices could move above this coal price support and be capped to the upside by heating oil. This provides a wide range of possible future natural gas prices. Figure following figure displays the U.S. Energy Information Administration ("EIA") Henry Hub natural gas price forecast as of November 2010. It also includes a 95% confidence interval forecast. This provides a range of possible natural gas prices in the future. In other words, the EIA expects the December 2012 gas price to settle in between a range between about $3 US/MMBtu and $10 US/MMBtu with a high degree of probability.

Figure 9: Henry Hub Natural Gas Price Forecast[7]



The wide range of forecast future prices helps to underscore the fact that while natural gas prices are currently depressed there is the potential for higher natural gas prices and volatility in the future.

This price uncertainty and volatility also exists within the Terasen regional marketplace as discussed in the following section.

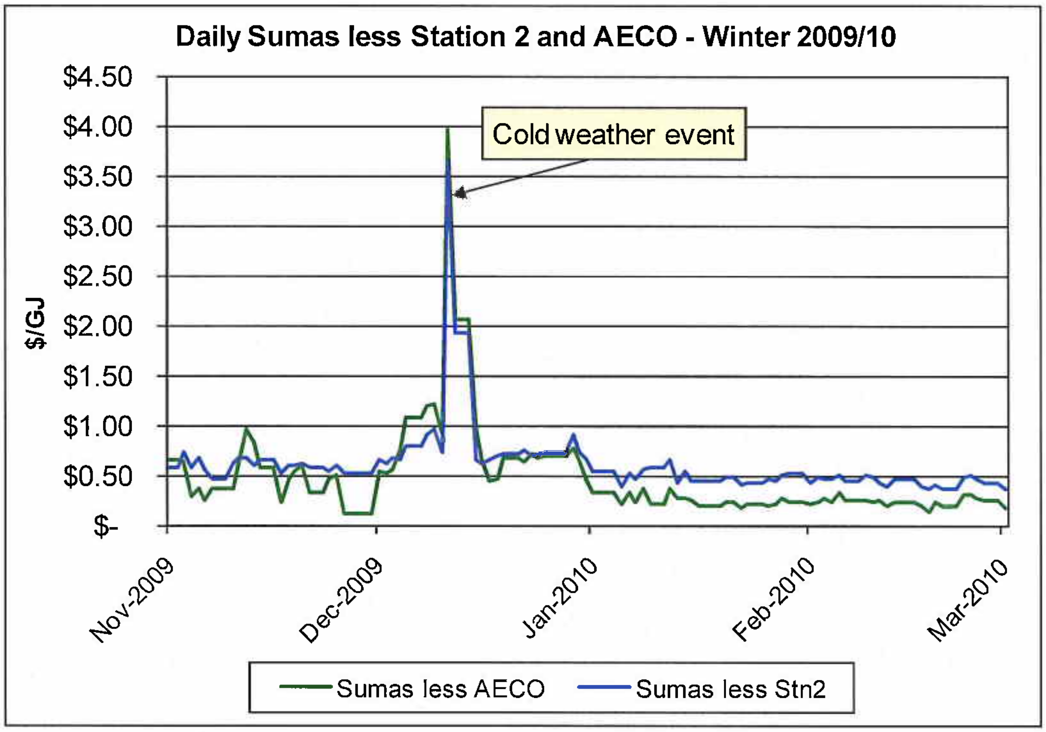
3.5 Regional Price Disconnections

Gas prices at the Sumas interconnect are more susceptible to price disconnects, typically in the colder winter months. A period of price disconnection occurs when demand in the Pacific Northwest, including B.C., creates a lack of gas deliverability at Sumas thus causing prices to increase significantly and disproportionately above Station 2 and AECO prices. Constrained regional infrastructure is the main reason for price disconnects during times of high demand. In other words, infrastructure developments, such as new pipeline or storage facilities, have not kept up with demand growth in the region. During winter 2009/10 Sumas prices disconnected from Station 2 and AECO prices during a weeklong cold spell in the region causing an increase in demand and maximum pipeline flows on Spectra Energy's system. During this past winter

[7] U.S. Energy Information Administration January 2011 Short-Term Energy Outlook

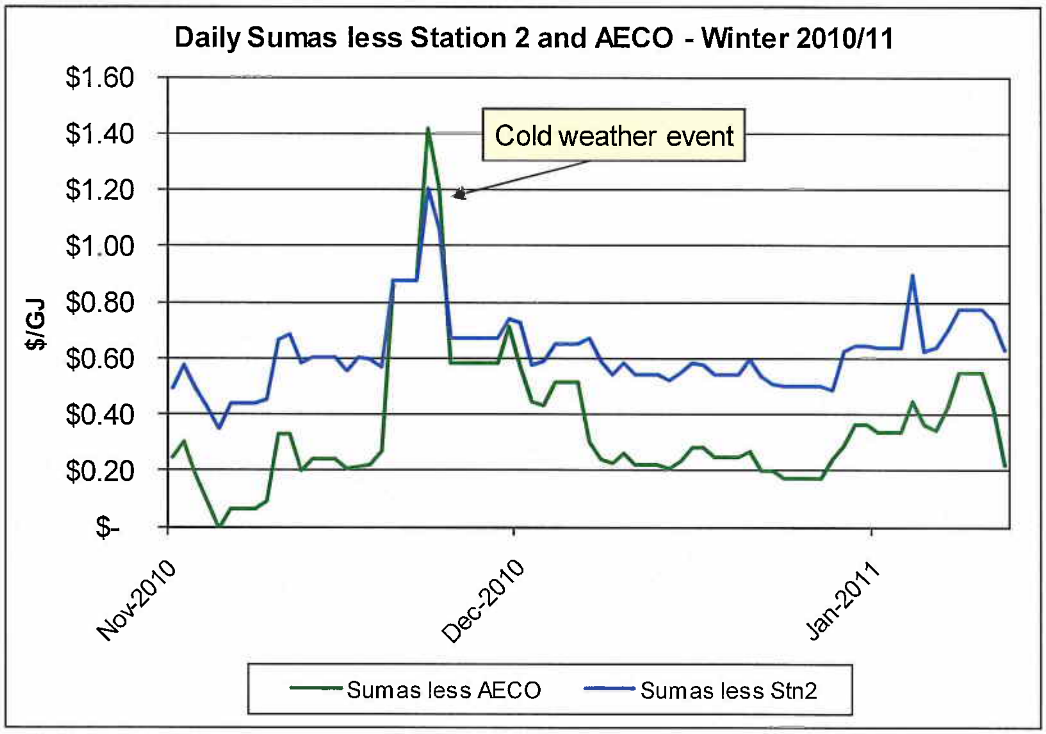
the price at Sumas increased by $4/GJ over prices at Station 2 and AECO. The price differentials between Sumas and Station 2 and AECO for this past winter period are shown below.

Figure 10: Sumas less Station 2 and AECO Prices - Winter 09/10



Similarly, during November 2010, a regional cold spell increased demand and prices at Sumas rose significantly. This occurred despite depressed gas prices and abundant natural gas supply for North America as a whole.

Figure 11: Sumas less Station 2 and AECO Prices - Winter 10/11



While the development of the prolific Horn River and Montney unconventional gas plays in northeast B.C. will significantly add to the region's supply of natural gas, the full potential of these plays will only be realized if the infrastructure is available to connect these supplies to markets outside of B.C. For example, the TransCanada Pipeline Limited ("TCPL") Horn River and Groundbirch pipeline projects will provide producers an avenue to transport Horn River and Montney supply on to TCPL's Alberta system, to offset declines in Alberta conventional supplies and feed the oil sands demand, and eastern markets. Up to 0.7 Bcf/d (initially) of north eastern B.C. supply could also flow to the Kitimat LNG facility to be processed and exported to Asia to meet growing demand. Therefore, the development of these unconventional plays in northeastern B.C. is not expected to reduce the risk of significant price disconnections within the region.

Therefore, when managing price risk, Terasen is concerned with North American natural gas supply and demand, and price volatility in general, as well as regional infrastructure constraints and price disconnections.

3.6 Conclusions

History has shown that natural gas prices are volatile and difficult to predict with any degree of accuracy. This is not expected to change going forward. Numerous supply and demand factors can influence natural gas factors over the long run, while weather, production disruptions and competing fuels prices can adversely impact prices in the short term. The natural gas supply picture has changed significantly in just a few years, with some of the largest developments taking place in B.C. The costs of producing and drilling have been reduced through technological advances such that near term natural gas prices look more favourable than they had just a couple of years ago. However, there is still a great deal of uncertainty with regard to future prices given the multitude of supply and demand factors that can impact prices. While prices are currently depressed due to weakened industrial demand and strong production, recovery in industrial demand, increased demand for natural gas from power generation and an easing in production growth will tighten future supply and demand balances and potentially lead to higher prices and volatility in the future. Furthermore, this abundant supply situation is largely the result of factors unaffected by low market price signals, such as producer hedges and drilling to hold land leases. As has been discussed, this will likely result in reduced supply growth once these hedges and lease hold conditions expire after 2011 and natural gas prices are not likely to be sustainable at current levels.

Ultimately, higher prices and volatility impacts Terasen's competitive position relative to other sources of energy and affects Terasen's ability to manage rate stability and ensure cost effective supply for customers. Therefore, Terasen believes it is prudent and appropriate to manage this price risk going forward in the best interests of its customers.

4 PRICE RISK MANAGEMENT OBJECTIVES

4.1 Utility Industry Practice

The hedging objectives of Terasen are consistent with those of other major natural gas utilities. The primary objective of most utilities is to reduce the market price volatility and its effects on natural gas rates. This is because the natural gas marketplace is inherently volatile, characterized by numerous supply and demand factors and a North America interconnected network of pipelines. This means that supply and demand imbalances and adverse price movements in one region can impact prices in other regions. Utilities also manage total gas costs in order to provide fair and reasonable rates to customers.

4.1.1 OTHER JURISDICTIONS

The hedging programs of the natural gas utilities in the other major Canadian jurisdictions are discussed in this section. For those utilities that do employ hedging, the objectives of their hedging programs are consistent with Terasen in terms of managing market price volatility and, for some, competitiveness. For those that do not employ hedging, they use other methods to manage price volatility and gas costs.

SaskEnergy Incorporated ("SaskEnergy") is a Canadian utility that hedges to manage price volatility for customers. The hedging program has enabled SaskEnergy to reduce market price volatility and its impacts on rates and it has allowed SaskEnergy to change commodity rates only twice a year for the past few years despite the price volatility in the marketplace.

Manitoba Hydro is another utility that manages rate volatility for customers. However, Manitoba Hydro does this primarily through fixed rate offerings for customers. Beginning in 2009, Manitoba Hydro began providing fixed price offerings to residential and commercial customers for one, three and five year terms. Therefore, those customers that desire stability in rates can choose to purchase their commodity supply from Manitoba Hydro or marketers. As such, Manitoba Hydro has been directed to wind down their hedging program related to the quarterly standard variable rate offerings only out to July 2011 and cease any hedging for periods beyond this month. Furthermore, the utility was ordered to accelerate the steps to assure customers of the ability to enter into fixed price contracts with Manitoba Hydro, should customers desire to do so. While TGI's residential and commercial customers do have the option to sign up for commodity supply from a Marketer under the Commodity Unbundling Program, TGI, as the default commodity provider, is prohibited from offering fixed rates under the Commodity Choice program in B.C. Furthermore, TGI was also denied continuation of the Stable Commodity Rate Residential Service offering program, which provided subscribers with a one year fixed rate offering by TGI, once the Residential Commodity Unbundling Program commenced. As such, TGI believes it is appropriate to continue to provide a default commodity rate offering to customers that includes prudent management of market price volatility. This provides value to customers and is what customers have come to expect from the utility variable default offering.

Gaz Metro Limited Partnership ("Gaz Metro") is another utility that uses hedges to mitigate market price risk. Gaz Metro, like Terasen, also faces the challenge of competing with electricity. Because of Quebec's abundant hydro-electric generating capacity, electricity rates in the province are amongst the lowest in the country. The hedging program of Gaz Metro helps in this regard.

The primary natural gas utilities in Ontario had hedging programs in the past but do not currently. Union Gas Limited ("Union Gas") and Enbridge Gas Distribution Inc. ("Enbridge") effectively had their hedging programs cancelled in 2008 and 2007, respectively. While these utilities maintained that their risk management activities had provided a material reduction in rate volatility for customers at a minimal cost, the Ontario Energy Board ("OEB") disagreed and argued that the quarterly rate adjustment mechanism process and the equal billing plan provided sufficient rate smoothing effects. Terasen strongly disagrees with this assertion and argues that the quarterly rate adjustment mechanism process and the equal billing plan do not provide the same degree of rate volatility mitigation as an effective hedging program, whether in Ontario or B.C. This is discussed in Sections 4.5.1 and 5.1. It is important to note that, with respect to available supply and storage resources, the Ontario utilities have access to the Dawn market trading hub, centrally located in southern Ontario. This hub includes the Dawn storage facility, owned by Union Gas, which is the largest underground storage facility in Canada, with 166 PJ of capacity, and the intersection of ten major pipelines, providing utilities with reliable and liquid supply options. This enables utilities, like Union Gas, to purchase less seasonal and peaking winter gas, use more storage gas and/or take advantage of favourably priced spot gas, than Terasen, at the Dawn hub as load requirements dictate. This effectively reduces the need to mitigate market price volatility risk like that which Terasen is exposed to at the Sumas hub.

4.2 Annual Contracting Plan ("ACP") Objectives

The objectives of the PRMP are consistent with those of the ACP. The ACP defines the physical resources, including commodity supply, storage and transportation, required to meet forecasted core customer loads. This commodity supply is based on index prices as determined in the natural gas market and which are set daily or monthly, depending on the index price. The PRMP defines the hedging strategy around mitigating this physical supply exposure to market prices. The primary objective for the ACP is to contract for resources which ensure an appropriate balance of cost minimization, security, diversity and reliability of gas supply in order to meet core customer design peak day and annual requirements. The cost minimization objective is balanced with achieving security of supply, diversity and reliability. However, the lowest possible cost, in a resource and infrastructure constrained environment, is not always achievable or appropriate in providing value to customers. The goal of cost minimization, or achieving cost effectiveness, underlies the importance of managing resource and gas costs and their effects on rates in terms of variability and competitiveness. If Terasen is able to effectively manage these costs then value is provided to customers through reasonable, relatively stable rates that are competitive with other sources of energy. This same principle applies to Terasen's price risk management and underlies its importance in maintaining and growing customer base to the benefit of all customers.

4.3 Price Risk Management Plan Objectives

The primary objectives of the PRMP have generally been as follows:

- Improve the likelihood that natural gas remains competitive with other sources of energy;
- Moderate the volatility of market gas prices and their effect on rates for customers; and
- Reduce the risk of regional price disconnects.

As discussed in Section 3 regarding the natural gas market overview, current supply and demand factors have resulted in depressed natural gas prices relative to recent historical averages. And with electricity rates in the province projected to increase, this has widened the gap between natural gas and electricity rates in the near term. However, as discussed in Section 3, there is uncertainty regarding natural gas prices and volatility going forward. Furthermore, uncertainty regarding the future electricity rates, capital cost considerations, increasing carbon taxes and public and environmental policy add to the competitive challenge for natural gas. Therefore, the Company believes that the objective of remaining competitive is still relevant and appropriate and competitiveness remains a challenge for Terasen into the future. However, it is the market conditions that can dictate the appropriate hedging strategy that should be employed to maintain competitiveness. This enhanced hedging strategy is discussed in Section 7.

As discussed in Section 4.5.1 regarding customer preferences, Terasen asserts that moderating market price volatility provides value to customers. Customers have indicated that they desire some degree of rate stability and are willing to accept that this may come at a reasonable cost.

As discussed in Section 4.6, Terasen's operating environment of constrained infrastructure requires mitigation of regional price disconnects. Regardless of what happens to overall natural gas price levels in North America, high demand in the Pacific Northwest region can result in independent and adverse price movements at the Sumas hub.

An underlying objective of the PRMP is to also provide this volatility protection and competitiveness at a reasonable cost to customers. Balancing these objectives may not necessarily result in the lowest cost portfolio given the volatility in the natural gas market and hedging at only the lowest points over time is an unreasonable expectation. However, Terasen recognizes that managing hedging costs is an important component of managing overall gas costs in the interests of providing reasonable and competitive rates for customers. The enhanced hedging strategy recommended within this report is critical in this regard.

Terasen believes that these objectives continue to be appropriate in meeting customers' preferences for volatility reduction and providing value for customers in terms of competitive rates. Maintaining competitiveness with electricity also serves to grow the natural gas customer base which enables Terasen to provide relatively stable delivery rates over time. It also prevents migration of natural gas customers to electricity, thereby preventing further pressure on electricity rates given BC Hydro's increasing infrastructure costs and more costly sources of new power. This is in the interests of all natural gas and electricity consumers in the province. This will be substantiated in the next section.

4.4 Maintaining Competitiveness

Maintaining competitiveness with other sources of energy enables Terasen to grow its customer base and continue to provide reasonable rates for customers. This will become increasing important in the future as energy consumers in B.C. have greater options for their energy sources. Ground source heat pumps and air source heat pumps are two examples of new energy sources that are growing in popularity. However, with these emerging energy alternatives being in their early stages of growth in B.C., Terasen's primary competitive challenge at this time continues to be electricity. As discussed in the next section, maintaining competitiveness with electricity is not only in the best interests of Terasen's customers, but it is also in the best interests of electricity consumers in the province.

4.4.1 COMPETITIVENESS BENEFITS ENERGY CONSUMERS

If natural gas in B.C. is viewed as being uncompetitive with electricity rates, customer and load migration from natural gas to electricity will lead to upward pressure on both natural gas delivery and electricity rates. Electricity rates would increase as BC Hydro would require new incremental sources of power, which will cost considerably more than the embedded cost of supply that is dominated by low cost supply from Heritage generation resources, as well as distribution system upgrades to serve the thermal load which occurs primarily in the winter. This is based on the fact that BC Hydro's embedded average residential rate is in the order of $0.065/kWh[8] while new electricity supply resources that must be acquired to meet demand

[8] The average for BC Hydro is identified in the BC Hydro F2011 Revenue Requirement Application, Appendix A, Schedule 15 as $0.0612/kWh before the interim increase of 6.11%. $0.0612/kWh x 1.0611 = $0.065/kWh (not including the interim rate rider of 4%). Fortis BC's average embedded rate is somewhat higher at $0.080/kWh ($0.0757/kWh from 2010 Revenue Requirements NSA Financial Schedules, page 18, Tables 2-A-1 and 2-A-2 plus the approved 6.0% rate increase (BCUC Orders No. G-162-09 and G-158-09)) but is still well below the marginal cost of new supply.

growth are in the range of $0.12/kWh[9] or more. It is public information that BC Hydro is already anticipating rate increases over the next five to ten years even without significant gas-to-electric load migration.

At the same time, Terasen delivery rates would increase as system throughput decreases. This is based on the fact that much of the utility cost of service is fixed in nature and therefore substantially the same level of costs must be recovered over a smaller throughput volume. The end result would be that customers of both natural gas and electric utilities would pay more for their energy costs. Terasen discussed this risk within the Terasen Utilities Return on Equity and Capital Structure Application dated May 15, 2009. The business risk was described on page 14:

> "Government policy that discourages consumers from using natural gas will have the effect of reducing throughput volumes on the TGI system and reducing the attachment of new customers. The recovery of fixed costs from a smaller customer base, and on lower throughput, leads to rate pressure for the remaining customers. Left unmitigated and unchecked, these effects can lead to loss of existing natural gas customers and a potential "downward spiral" in which the risk of non-recovery of invested capital increases and asset potentially become stranded. Policy changes and objectives, and changes in customers' perception arising from those policies and objectives, and from general concerns respecting GHGs, climate change and fossil fuel consumption are new factors that have increased TGI's business risks since the last ROE proceeding in 2005."

The potential impact on the TGI delivery margin can be illustrated through the use of an example. Currently, Terasen's greatest competitive challenge is with hot water heating due to the typically lower efficiency level for natural gas hot water heaters (about 60% efficiency compared to about 90% for electric hot water heaters) and the assumption that some customers' hot water consumption would incur the lower Step 1, rather than Step 2, residential electricity rate. If TGI were to experience loss of its entire current residential and commercial water heating load, which represents an estimated 19% of total TGI annual residential and commercial load, then TGI would see annual system throughput decline by approximately 22 PJ. If the load migration resulted in consumers no longer using natural gas, then the impact on TGI would be both a loss of customers and throughput. If these consumers continued to use

9 $0.12/kWh (or $120/MWh) was accepted as a proxy cost of new IPP electricity supply in the BC Hydro 2008 LTAP Proceeding (see for example BCUC LTAP Decision dated July 27, 2009, page 84). The marginal cost of new power supply is similar for Fortis BC since Fortis BC operates in the same jurisdiction as BC Hydro and must acquire incremental new supply in the same market conditions.

natural gas for space heating but switched to some other source for hot water heating, then the impact on TGI would be a loss of system throughput but not customers. The resulting impacts to residential and commercial customers of this migration could be significant and shown in the following table (based on approved TGI 2011 fixed basic and delivery rates). Based on the migration of Terasen's residential water heating load, the estimated residential and commercial delivery rate increases could be between 12% and 17% and the annual bill impacts between $55 and $1,398 depending on the scenario and rate class.

Table 1: Estimated Annual TGI Bill Impacts Resulting from Load Migration

TGI Delivery Rate Impact of Reduced Load by 22 PJs	Rate 1		Rate 2		Rate 3	
	Loss of Customers & Load	Loss of Load Only	Loss of Customers & Load	Loss of Load Only	Loss of Customers & Load	Loss of Load Only
Basic Charge & Delivery Rate Increase (%)	17%	12%	17%	12%	17%	12%
Approximate Annual Bill Impact ($)	$ 78	$ 55	$ 192	$ 135	$ 1,398	$ 983

The corresponding estimated potential impact on BC Hydro's residential rates can also be quantified. Assuming the same migration to electricity of 19% of TGI's residential and commercial load, or about 22 PJ per year, the following table illustrates the increase in electricity rates.

Table 2: Estimated Electricity Rate Impacts Resulting from Load Migration

Natural Gas Migration to Electricity		22	PJ
Assumed Natural Gas Efficiency (relative to electricity)		67%	
Increased Electric Load		15	PJ
Increased Electric Load (PJ x 277.78 = GWh)		4,094	GWh
12% Distribution and Transmission Line Losses		491	GWh
Total Incremental Electric Load		4,586	GWh
Cost of Incremental Electricity	$	0.12	KWh
Additional Cost	$	550	million
Portion of costs not covered by incremental revenue (25%)*	$	138	million
Electricity Rate Increase (based on $3 billion revenue reqt.)		5%	

*Based on assumption of Step 1 rate recovering about 50% of BC Hydro incremental costs and water heating load customers falling 50% into Step 1 rate and 50% into Step 2 rate

Based on these assumptions, the table indicates that the migration of Terasen's residential hot water heating load to electricity would result in electricity rates increasing by 5%. This increase would be incremental to those significant rate increases that BC Hydro has recently projected. If the load migration was related to higher efficiency appliances, such as furnaces, the electricity rate increase impact would likely be greater than the 5%. Furthermore, space heating load would result in higher supply and system costs because the demand occurs primarily in the winter months.

These results illustrate the importance of Terasen maintaining competitive rates with electricity. If Terasen is unsuccessful in this endeavour then load migration to electricity would increase both natural gas and electricity rates in the province. Clearly the objective of competitiveness is in the interests of natural gas and electricity consumers in B.C.

4.4.2 GOVERNMENT POLICY

Government policy can play a significant role in the competitiveness of natural gas relative to other sources of energy within B.C. The BC Clean Energy Act ("CEA") could determine the role of electricity and other sources of energy in the province in the future, influencing costs and rates for these forms of energy going forward. At this point in time, it is believed that the costs for electricity will be increasing in the future in response to the legislated requirement to achieve electricity self sufficiency for the province and to meet growing electricity demand in the province. On the other hand, the carbon tax, introduced in 2008, is applicable to natural gas and not electricity and increases each year until 2012 after which time there is uncertainty regarding the amount. Not only does this tax effectively add a cost to natural gas rates but also adversely influences public perception regarding the use of natural gas relative to other sources of energy. This serves to increase the challenge for natural gas competitiveness in the future. Furthermore, government policy aimed at curbing greenhouse gas emissions and reducing fossil fuel consumption in B.C. serves to adversely influence public perceptions about natural gas. This will also contribute to the competitive challenge for Terasen in the future.

4.4.2.1 The Clean Energy Act

The BC Clean Energy Act, released in June 2010, sets out the strategy for making the province self-sufficient in electricity while reducing greenhouse gas emissions. The strategy includes conservation to reduce pressure on energy supply as well as greater reliance on alternative energy sources such as bioenergy, geo-exchange, fuel cells, water-powered electricity, solar and wind. The CEA includes making B.C. electricity self-sufficient by 2016 and addresses the challenges of growing energy demand and environmental sustainability. BC Hydro estimates that B.C. is currently dependent on electricity imports for about 10% of the province's electricity supply and forecasts electricity demand to increase by up to 45% over the next 20 years[10]. To achieve these goals, investment in energy efficiency and conservation and significant additions to electricity generation and transmission infrastructure will be required over the coming years, increasing electricity rates going forward. The extent of these rate increases will depend on the magnitude, cost and timing of infrastructure additions, the cost of additional supply resources, the rate increases approved by the Commission and the rate structures utilized to encourage

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[10] The BC Energy Plan – A Vision for Clean Leadership, Feb.27, 2007, Page 9.

energy efficiency and conservation. It is important to note that large scale electricity generation and transmission infrastructure projects can take many years to build and can often be subject to hurdles or delays relating to environmental, regulatory or cost concerns or stakeholder consultations. It is also possible that some projects could be delayed or put on hold by BC Hydro or the Commission in order to manage the rate impacts on customers. Obviously there is uncertainty regarding the magnitude and timing of electricity rate increases in the future.

With respect to reducing greenhouse gas emissions for vehicular use, the CEA promotes a greater use of energy sources that are cleaner than gasoline or diesel. These include energy from hydrogen fuel cells, biofuels like ethanol and biodiesel, electricity and natural gas. The use of natural gas for vehicles is more cost effective for customers and better for the environment than conventional fuels. With recent declining natural gas usage on the TGI system, the development of the natural gas transportation market in B.C. would help to maintain loads on the TGI system and thereby help to maintain or reduce unit delivery costs for natural gas customers and deliver GHG emission reductions at the same time.

4.4.2.2 The Carbon Tax

The carbon tax has a significant impact on the competitiveness of natural gas relative to electricity or alternative sources of energy. The B.C. government implemented the carbon tax effective July 1, 2008, applicable to virtually all fossil fuels, including natural gas. The carbon tax reduces natural gas' competeviness relative to alternative energy sources that are not subject to the carbon tax, and the carbon tax will help to sensitize customers to the level of GHG emissions they generate by sending them price signals. The purpose of the tax is to encourage reduction in the use of fossil fuels and related emissions in the province. The base rate effective July 2008 was based on $10 per tonne of associated carbon dioxide emissions and rises by $5 per tonne each year until it reaches $30 per tonne on July 1, 2012. For natural gas, this equates to approximately $1 per gigajoule in 2010, increasing by about $0.25 per gigajoule per year until reaching $1.50 per gigajoule in 2012. At this point in time, the decision to continue to increase the carbon tax or implement another carbon-related cost after 2012 will rest with the government at that time.

However, some experts have suggested that if the government is committed to reducing greenhouse gas emissions, the carbon tax should continue to be increased after 2012. The National Round Table on the Environment and the Economy noted in its April 2009 report that carbon price increases would be necessary over the long run to meet the government's emission targets.[11] Also, in its report entitled "Meeting British Columbia's Targets: A report from the BC Climate Action Team", the Climate Action Team recommended the following: "After 2012, if required to achieve the emissions targets, increase the British Columbia carbon tax in a

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[11] Per Page 30 of National Round Table on the Environment and the Economy report entitled "Achieving 2050: A Carbon Pricing Policy for Canada".

manner that aligns with the policies of other jurisdictions and key economic facts."[12] Furthermore, in a recent study conducted by Simon Fraser University, the authors suggest that the carbon tax should continue to increase by at least $5 per tonne annually after 2012.[13]

Another such proponent of a higher carbon tax is the Pembina Institute, an organization which advances sustainable energy solutions through research, education, consultancy and advocacy. The Pembina Institute recently suggested that the carbon tax should reach $200 per tonne by 2020 if the government is serious about addressing climate change.[14] This would be the equivalent of about $10 per gigajoule added to the price of natural gas. As discussed in Section 4.4.5, the carbon tax adds to Terasen's competitive challenge.

In a separate recommendation, the government-formed Climate Action Team suggested the carbon tax should be increased after 2012 if the government wants to meet its aggressive greenhouse gas emission reduction targets by 2020.[15] Recently, the B.C. Finance Minister stated that the decisions made in California and other jurisdictions related to carbon reduction policies would factor into the decision regarding the carbon tax after 2012 and that a decision would likely be made by early 2011.[16]

Certainly there is uncertainty regarding the future of the carbon tax after 2012. If the carbon tax is maintained, or even increased, after 2012 this will continue to adversely affect Terasen's competitive position in the future.

4.4.3 ELECTRICITY RATES

Terasen believes that in order to retain customers and promote load growth it is important to ensure gas rates remain competitive with other forms of energy in British Columbia. While energy consumers have an increasing choice of energy source options, at this time, Terasen continues to use equivalent electricity rates as the best available measure of competitiveness. The ability of natural gas to compete with electricity is driven to a large degree by the electricity rates in the province of B.C. Historically, electricity rates in B.C. have been largely based on utility-owned supply and infrastructure costs, rather than being based on market-based prices. Past provincial policies and electricity development in B.C. have created low electricity rates and leave BC Hydro and residents of the province with a rich endowment of Heritage Assets and related benefits. As such, electricity rates have not been subject to market price volatility and significant increases over time. This has challenged natural gas rates from a competitive perspective as Terasen's rates have been subject, to a large degree, to market price volatility and significant increases. BC Hydro currently faces an era of increasing costs and higher rates in striving to achieve self-sufficiency and cleaner energy in terms of overall supply. These

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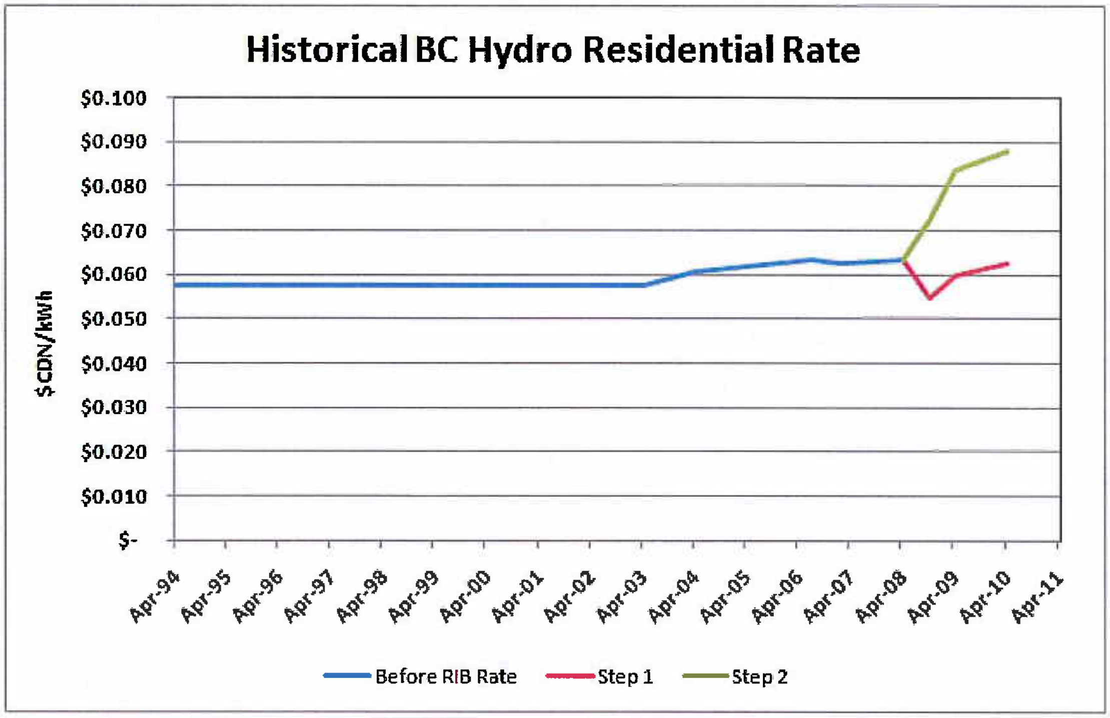
[12] Meeting British Columbia's Targets, A Report from the B.C. climate Action Team, July 28, 2008, page 3
[13] The Globe and Mail, December 9, 2010.
[14] Vancouver Sun, September 16, 2010.
[15] Vancouver Sun, August 7, 2008.
[16] Vancouver Sun, September 16, 2010.

expectations could improve Terasen's ability to manage the electric competitiveness objective all else being equal. However, uncertainty around the multiple supply and demand factors affecting future natural gas market prices (as discussed in Section 3) and the implementation of the phased-in carbon tax introduced in July 2008, increasing each year until 2012 (and uncertainty around this tax beyond 2012), will add to the Terasen challenge of maintaining competitiveness in the future. Furthermore, there is also uncertainty regarding the magnitude of future electricity rate changes or increases which will greatly affect the competitiveness of natural gas relative to electricity. The province's policy of keeping electricity rates in B.C. among the lowest in North America will begin to play more strongly in future directions for electricity if successive large rate increases begin to occur. The magnitude of expected future electricity rate increases is already being cited frequently in the media.

4.4.3.1 Residential Electricity Rate Structure

Residential electricity rates in B.C. have evolved from a single rate to a two-step rate typically adjusted on an annual basis. In the past, residential electricity rates in B.C. were based on a single rate that was adjusted infrequently. This rate reflected a high percentage of supply coming from the BC Hydro Heritage Assets based on historic electricity facilities which provided secure low cost electricity that was not representative of market electricity prices being experienced in other jurisdictions or the cost of incremental new supplies. As such, the rates were relatively stable compared to market electricity and natural gas prices. The following graph illustrates historical electricity rates.

Figure **12: Historical Residential Electricity Rates**



BC Hydro's two-step Conservation Rate (also known as Residential Inclining Block or "RIB" rate) came into effect for all residential customers on October 1, 2008. The RIB rate is a two-step rate structure designed to encourage residential customers to conserve electricity, given BC Hydro's mandate for self sufficiency. The RIB rate has a base rate for electricity consumption up to 1,350 kilowatts per hour (kWh) per two-month billing period (Step 1 rate) and a higher rate, notionally based on the marginal cost of new electricity supply, for all electricity consumed over that base amount (Step 2 rate). The 1,350 kWh threshold is about 90% of the median consumption of residential customers and the rate structure is designed to be revenue neutral to BC Hydro.

At this point in time, there is uncertainty regarding how the cost of new electricity supply will be reflected in the Step 1 and Step 2 rates. In BC Hydro's Residential Inclining Block (RIB) Rate Re-Pricing Application dated December 21, 2010, BC Hydro is seeking approval to apply the revenue requirement increases equally to both the Step 1 and Step 2 rates rather than adjusting the Step 2 rate from time to time to reflect new information regarding the cost of new electricity supply. BC Hydro has indicated that the cost of new electricity supply is significantly higher than that for existing supply. While BC Hydro's embedded average residential rate is in the order of

$0.065/kWh[17], new electricity supply resources that must be acquired to meet demand growth are in the range of $0.12/kWh[18] or more. It is public information that BC Hydro is already anticipating rate increases over the next five to ten years to meet the challenge of growing demand for power. The BC Hydro projected residential rate increases are discussed in the next section.

However, in addition to achieving energy self sufficiency and reducing green house gas emissions, the Clean Energy Act also includes the objective of ensuring electricity rates remain among the most competitive of public utilities in North America. Terasen believes that these aspects and others of the Clean Energy Act indicate a commitment by the Province to keep electricity rates as low as possible. Also, significant rate increases could be met with consumer backlash to rate shock, which may not be wise from a political perspective for the government of the day. So, at this point, there is uncertainty around how much of the cost of new sources of electricity will be reflected in future rates and therefore the competitiveness of natural gas relative to electricity.

In Ontario, for example, the provincial government recently passed the Ontario Clean Energy Benefit Act to help electricity customers manage rising electricity rates over the next five years. Ontario, like B.C., is facing significant cost increases in the coming years related to investment in infrastructure and clean power. Therefore, the government has implemented specific tax credit expansions, energy credits and the industrial conservation initiative to help mitigate some of the rate increases on certain customer segments.

4.4.3.2 Future Electricity Rates

Within its F2011 Revenue Requirements Application, BC Hydro had proposed increases of 6.11% on each of the Step 1 and Step 2 rates effective April 1, 2010 and also proposed increasing the Deferral Account Rate Rider from 1 percent to 4 percent, which the Commission had approved on an interim basis (per Order No. G-47-10 dated March 15, 2010).

BC Hydro has recently concluded a negotiated settlement process on its F2011 RRA which reduced the F2011 increase from the proposed 6.11% to 4.67% and the rate rider from the proposed 4% to 3.53%. The table below taken from paragraph xv of the F2011 RRA negotiated settlement (BCUC Order No. G-180-10) indicates the increases that are expected for the next

[17] The average for BC Hydro is identified in the BC Hydro F2011 Revenue Requirement Application, Appendix A, Schedule 15 as $0.0612/kWh before the interim increase of 6.11%. $0.0612/kWh x 1.0611 = $0.065/kWh (not including the interim rate rider of 4%). Fortis BC's average embedded rate is somewhat higher at $0.080/kWh ($0.0757/kWh from 2010 Revenue Requirements NSA Financial Schedules, page 18, Tables 2-A-1 and 2-A-2 plus the approved 6.0% rate increase (BCUC Orders No. G-162-09 and G-158-09)) but is still well below the marginal cost of new supply.

[18] $0.12/kWh (or $120/MWh) was accepted as a proxy cost of new IPP electricity supply in the BC Hydro 2008 LTAP Proceeding (see for example BCUC LTAP Decision dated July 27, 2009, page 84). The marginal cost of new power supply is similar for Fortis BC since Fortis BC operates in the same jurisdiction as BC Hydro and must acquire incremental new supply in the same market conditions.

four years after F2011. If these projections occur there will be a net rate increase of 55% over five years (including the 7% increase for F2011).

Table 3: **Projected Residential Electricity Rate Increases**

	F2011	F2012	F2013	F2014	F2015
Projected Rate Increase	4.67%	17.44%	5.42%	9.72%	8.37%
Projected Deferral Account Rate Rider	3.53%	2.50%	2.20%	2.00%	1.70%
Projected Net Bill Impact	7.29%	16.27%	5.11%	9.51%	8.05%
Projected Cumulative Net Bill Impact	7%	25%	31%	44%	55%

BC Hydro has also recently concluded the acquisition of new power supply through its Clean Power Call. The results of that call indicate an average acquisition cost of $0.1243/kWh[19]. This represents an increase of more than 40% in the cost of new supply relative to the 2006 Call for Power which had a comparable price of $0.0875/kWh[20]. While BC Hydro's Residential Inclining Block (RIB) Rate Re-Pricing Application recommends equal application of revenue requirement percentage increases to both Step 1 and Step 2 rates, there still remains uncertainty regarding approval of this methodology. Until there is further certainty on this matter, Terasen believes the approach of applying the general rate increase to both RIB steps on the same percentage basis is the most reasonable approach to projecting the Step 1 and Step 2 rates going forward.

Rate projections were made by BC Hydro in its 2008 LTAP going further out into the future but those have not been updated in relation to the five year projection presented in the table above. There has been significant media coverage recently of the projected large electricity rate increases. A response to these was contained in a recent press release dated December 2, 2010 by BC Hydro and the Province which indicates that action is being taken to keep Hydro rates among the lowest on the continent[21]. Terasen believes that this press release is indicative of efforts that will be made to curtail the cost and rate increases going forward. The regulatory process for BC Hydro's revenue requirement applications has been effective in the recent past in reducing rate increases below requested levels. Terasen believes that the influences of political pressure and the regulatory review process has significant potential to moderate future rate increases below those projected in the table above. For the purposes of this report, therefore, Terasen has provided analysis that sets the general rate increases (not the including the rate rider) at levels of 100% and 50% of the proposed increases which the Company believes provides a reasonable range of outcomes.

The following table provides some historical context regarding BC Hydro's recent requested electricity rate increases and the resulting approved rate increases.

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19 Clean Power Call Report dated Aug. 3, 2010, p.12

20 F2006 Open Call for Power Report, Aug. 31, 2006, p.26. The results of the F2006 Open Call for Power were used to establish the RIB Step 2 rate.

21 http://www.bchydro.com/news/articles/press_releases/2010/rates_reduction_strategies.html

Table 4: **Historical BC Hydro Requested vs. Approved Rate Increases**

Rate Application	Fiscal Year	BC Hydro Rate Increases		
		Applied For	Approved	Test Period Cumulative Difference
F05/F06 RRA	F2005	7.23%	4.85%	
	F2006	2.00%	0.00%	-4.5%
F07/F08 RRA	F2007*	4.65%	1.54%	
	F2008	2.71%	0.11%	-4.7%
F09/F10 RRA	F2009	6.56%	2.34%	
	F2010	8.21%	8.74%	-4.0%
F11 RRA	F2011**	9.26%	7.29%	-2.0%

*The F2007 increase occurred on July 1 and was therefore for a partial year
**F2011 increases include both the permanent rate increase and the rate rider change

The commodity component of the electric equivalent rate increases is presented in the following graphs. The commodity component represents the variable portion of the electric equivalent, net of the TGI delivery and midstream charges, carbon tax and the estimated capital cost differential between natural gas and electricity, that is used for establishing electric equivalent benchmarks. More discussion of these electric equivalents is provided in Section 4.4.5.

The first graph for each application includes BC Hydro's projected rate increases, including projected rate riders. The second graph includes only 50% of BC Hydro's projected rate increases but 100% of the projected rate riders given the significant deferral balance deficit to be recovered from customers. The AECO forward price curve and potential range (based on recent market volatility and 95% probability) as of December 2010 is presented within the graphs to provide a comparison to current and potential natural gas prices. The details of the derivation of these electric equivalents is provided in Section 4.4.5, which discusses the difference in electric equivalents for retaining existing natural gas customers versus attracting new customers for space and water heating applications.

Figure **13: TGI Electric Equivalent for Space Heating with BC Hydro Projected Rate Increases**

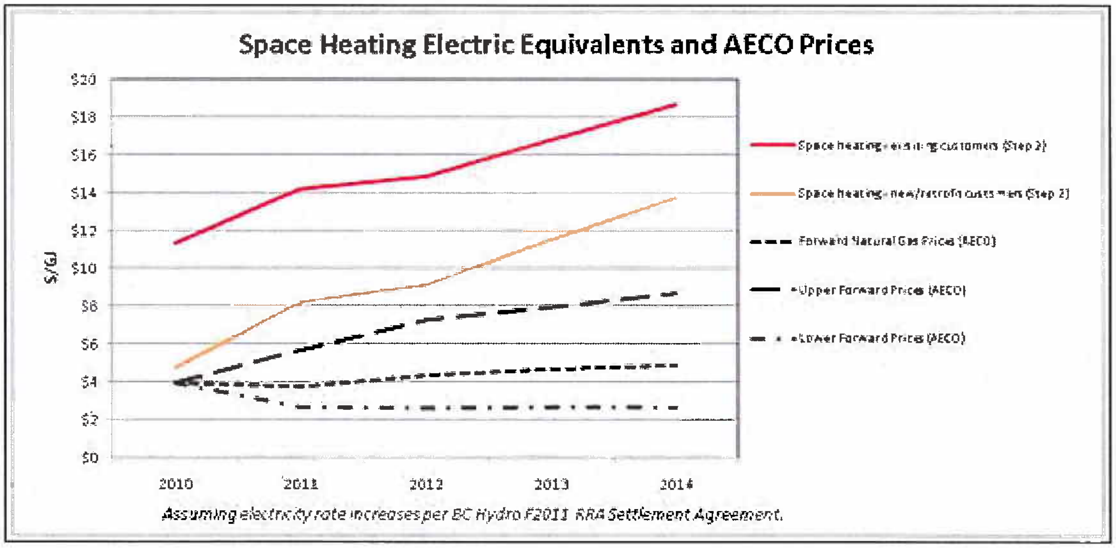


Figure **14: TGI Electric Equivalent for Space Heating with 50% of BC Hydro Projected Rate Increases**

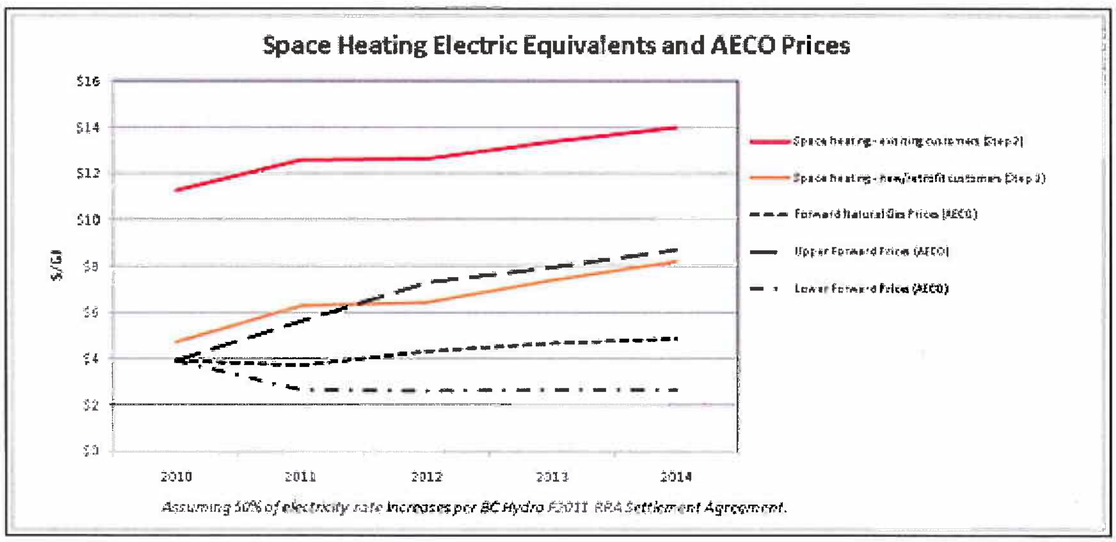


Figure **15: TGI Electric Equivalent for Hot Water Heating with BC Hydro Projected Rate Increases**

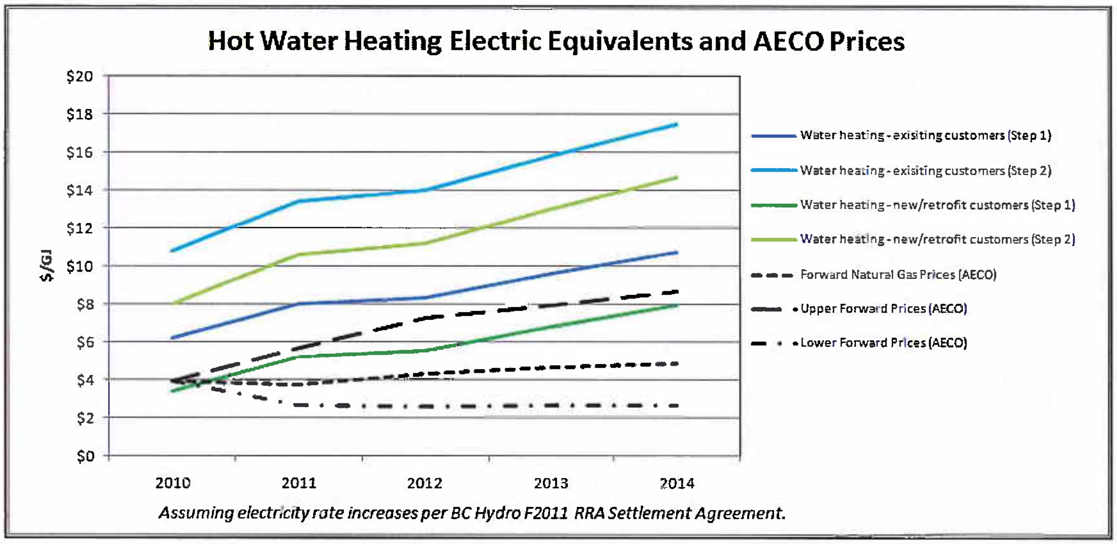
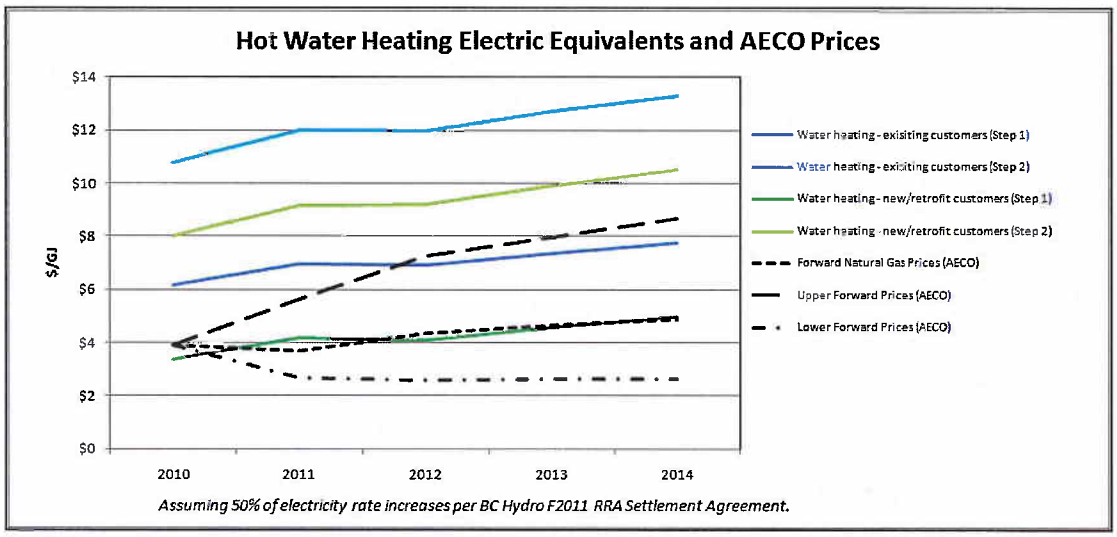


Figure **16: TGI Electric Equivalent for Hot Water Heating with 50% of BC Hydro Projected Rate Increases**



It is important to note that AECO prices, while currently depressed relative to historical values, have averaged near $6/GJ for the past five years (2006 through 2010) and settled above $10/GJ at times in the recent past (July 2008).

The above graphs relate to TGI only. With TGVI's higher delivery costs than those of TGI, the electric equivalents in the graphs would be significantly lower (by about $7/GJ) highlighting TGVI's significant competitive challenge going forward.

4.4.4 PUBLIC PERCEPTION OF NATURAL GAS

While differences in natural gas and electricity rates will drive consumer behavior with respect to energy use, so will public perception of natural gas relative to electricity in B.C. The Clean Energy Act has electricity as its primary focus. The heavy emphasis in the Clean Energy Act on promoting the electricity sector as the clean and green energy source in B.C. may only serve to increase public perceptions that natural gas by comparison is not a desirable source of energy to be used. More specifically, several factors have increased the challenge for natural gas in the Province:

- Government policy and legislation intended to reduce GHG emissions (which means generally less consumption of fossil fuels),
- Growing public sentiment ("green") against the use of fossil fuels and in support of reducing GHG emissions,
- Public perception regarding fossil fuel-based energy prices and future carbon taxes. Although natural gas commodity prices are low currently (relative to recent historical values), significantly higher prices and price volatility are in recent memory. Public discussion of climate change and the need to implement carbon taxes or cap and trade regimes to reduce GHG emissions is a matter of daily public discourse. This is further compounded by the public perception that electricity supply in BC is an "all green solution". Terasen believes that perceptions are often as much an influence in public behaviour with respect to energy use as economic indicators.

The provincial GHG reduction targets have the potential to adversely change public perception of natural gas over the long term. The targets will likely shift investment and consumption decisions of the consumer away from natural gas towards the consumption of electricity or other renewable energy alternatives (such as geo-exchange or solar). This focus on renewable energy may supersede historical decision criteria such as cost of product, ease of use, and reliability.

The 2008 Residential End Use Study ("REUS") provided support to the assertion that "customers change their consumption behaviour based on the real or perceived view that gas is uncompetitive with electricity or other sources of energy". In other words, more frequent rate changes or rate increases for natural gas than for electricity can create the perception that natural gas rates are uncompetitive on a variable cost basis with electricity while in fact the opposite may be true.

Contributing to this problem is the large component of market-based pricing of natural gas compared to electricity. Natural gas commodity rates are largely based on the market price of natural gas, subject to quarterly adjustments although some rate dampening is realized through the amortization of commodity deferral account balances and price risk management activities. Electricity rates, however, are set on an annual basis based on projected costs for existing and new supply as well as the electricity system cost of service. Therefore, natural gas rates are more volatile in B.C., particularly in TGI's service territory, than electricity rates. During periods of market instability, gas rates can change quarterly to reflect commodity market changes while electricity rate changes typically take place annually. Customers place value on rate stability so even if natural gas rates are lower on average on a variable costs basis over a period of time the ups and downs from volatility in natural gas rates has a negative influence on customers' perceptions of the product.

The end result of this negative public perception towards natural gas has consequences for Terasen's ability to compete and therefore the cost of energy to consumers in BC over the long run (as discussed in Section 4.4.1).

4.4.5 MAINTAINING EXISTING AND ATTRACTING NEW CUSTOMERS

Terasen's ability to offer reasonable and competitive rates is highly dependent on its ability to maintain existing customers and attract new customers. This is dependent on a number of factors which include:

- The difference in the variable component of natural gas and electricity rates
- The volatility of the variable component of rates
- The difference in upfront capital and maintenance costs of natural gas and electric space and hot water heating equipment
- Carbon tax on natural gas
- Public perception of natural gas relative to other energy sources

While the B.C. energy marketplace is evolving in terms of new energy sources available to customers, such as geo-exchange or solar, currently Terasen considers competing with electricity to be its primary focus to maintain and grow its customer base.

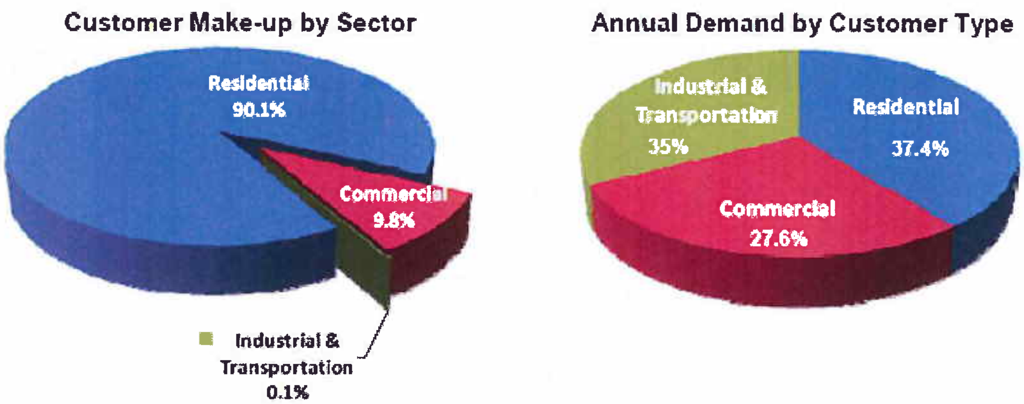
Natural gas may currently have a competitive advantage with electricity for some applications in terms of the variable (i.e. commodity) component of the rate, but other factors such as the carbon tax and public perception can reduce or negate this advantage. Furthermore, one of the most significant factors affecting long term competitiveness is the capital cost differential between natural gas and electricity.

4.4.5.1 Customer Profile

In order to properly assess Terasen's competitiveness with electricity, it is important first to profile the existing customer base. This will help determine the applications where Terasen has a competitive challenge (or advantage), quantify the risk of not maintaining the existing customers and establish electric equivalent benchmarks useful for hedging targets.

The Company's combined customer base consists of over 939,000 residential, commercial, industrial and transportation[22] customers. Recent annual system throughput for these customers exceeds 200 PJ. Terasen contracts for approximately 95 PJ of gas supply annually, based on a normal load forecast, for the residential and commercial segments (excluding marketer supply of approximately 19 PJ for fixed rate commodity offerings per the TGI Commodity Unbundling Program). Industrial and transportation customers typically make their own commodity supply arrangements and energy choices for their process load requirements. While the vast majority of customers are residential, the commercial, residential and combined industrial and transportation customers account for roughly equal shares of annual demand. The following chart shows the gas volumes used by customer group (based on the forecast for 2010).

Figure 17: Terasen Customer and Demand Overview[23]



Terasen believes maintaining existing and attracting new residential and commercial customers critically important in providing competitive and reasonable rates for all customers. Based on the 2008 Residential End Use Study ("REUS") it is estimated that, on average, TGI and TGVI residential customers use natural gas according to the following allocation: 72% for space heating, 19% for hot water heating and 9% for other applications (such as for cooking, decorative fireplaces, swimming pools and hot tubs). The majority of residential customers live in single family detached homes with the remaining living in townhouses, apartments or condominiums and mobile homes.[24]

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22 Transportation customers in this case refer to customers who purchase their own natural gas supply and contract with the Terasen Utilities to transport that supply across the Terasen Utilities' systems.

23 Terasen Gas Inc. 2010 Long Term Resource Plan, page 76.

24 Eighty-three percent (83%) of respondents to the 2008 REUS live in single family detached (SFD) dwellings, 13% in duplexes or townhouses, 1% in apartments or condominiums, and 3% in mobile homes or other dwelling type.

For commercial customers, the majority of their natural gas usage is for make-up air (ventilation), space and hot water heating. A study to determine the consumption estimates by end use and the energy use decision criteria for commercial customers is currently underway and so the percentage breakdown by application is not available at this time. However, it is recognized that the natural gas applications for many commercial customers will be similar to those for residential customers. While many commercial customers may use boilers for space heating rather than furnaces used by residential customers, the application is still the same and the range of possible efficiencies is similar. However, the natural gas delivery charge for commercial customers is less than that for residential customers, due to commercial customers' higher average use per account and load factors. Therefore, the competitive benchmarks for commercial customers, all else equal, would be higher or above those for residential customers. As such, Terasen has used residential customers as the proxy for all residential and commercial customers and achieving competitiveness for these customers would generally mean achieving competitiveness for commercial customers as well.

Therefore, at this time, Terasen believes that, in order to maintain existing customers and attract new customers, it should focus primarily on competing with electricity for space heating and hot water heating applications.

4.4.5.2 Capital Cost Differences

While achieving competitiveness on a variable cost basis is critical for maintaining and growing customer base, consideration of the capital and maintenance cost differences for natural gas versus electric appliances is also important in understanding competitiveness and developing appropriate benchmarks.

While based on current forward market gas prices, natural gas rates are currently competitive with electricity rates on a variable cost basis, this conclusion is absent consideration of any recovery of the upfront capital and ongoing maintenance cost differences between natural gas and electric space and hot water heating equipment. There are significant differences in capital costs associated with natural gas equipment for space and hot water heating and those based on electricity under consideration when building a new home or with energy appliance retrofits.

<u>Capital Cost Differences for Space Heating</u>

The upfront cost to install a high efficiency gas furnace (90% efficiency) and associated duct work in a home is estimated to be approximately $7,000 whereas the upfront estimated cost of installing baseboard electric heating is approximately $2,500, which equates to approximately $10.31/GJ[25]. Figure 18 shows the annual energy cost differential between a natural gas heated

[25] Page 64 of the Terasen Gas Inc. 2010-2011 Revenue Requirements and Delivery Rates Application, dated June 15, 2009

home and an electrically heated home must be more than $500 per year or $10.31/GJ over the life of the asset, in order to offset the capital cost differential for natural gas equipment versus electric baseboards.

Figure 18: Payback on Capital Costs Difference for a Natural Gas Heated Home[26]

Payback of Capital Costs (New Construction)	
Space Heating Requirement Only	
New Construction of home in Lower Mainland (2500 square feet in size)	
Capital Costs for High Efficent Furnace (90%) and ducting/installations	$7,000.00
Capital Cost for Electric Baseboards	($2,500.00)
Difference in up front capital costs	$4,500.00
Interest Rate	0.06
Measureable Life of Furnace (years)	18
Amount that has to be recovered in operating cost annually to payoff difference in capital cost	$415.60
Add in furnace maintence costs per year	$100.00
Total ($)	**$515.60**
Energy consumptions for natural gas space heating (GJ's)	50
Difference in cost that needs to exist between natural gas heated home and electricity heated home in $/GJ over 18 years	**$10.31**

Capital Cost Differences for Hot Water Heating

There is also a capital cost difference associated with hot water heating. The upfront cost to install a gas hot water heater in a home is estimated to be approximately $1,409 (including venting) whereas the upfront estimated cost of installing an electric hot water heater is approximately $973. Figure 19 shows the annual energy cost differential between a natural gas and electric hot water heater must be more than $55 per year or $2.79/GJ over the life of the asset, in order to offset the capital cost differential.

[26] The 50 GJ used in this calculation relates to a new residential home located in lower mainland (2500 square feet). This 50 GJ is for space heating only and does not include other uses of natural gas in the home such as water heating or natural gas stoves. This 50 GJ is lower than the average Rate Schedule 1 use rate of 93.4 GJ for 2009 because the 93.4 GJ is related to the total demand not just the space heating load. Also it reflects a decrease for the higher efficiencies of the new home and new furnace as compared to the existing stock of houses and furnaces.

Figure 19: Payback on Capital Costs Difference for Hot Water Heating

Payback of Capital Costs (Hot Water Heaters)	
Capital Costs for Natural Gas Hot Water Tanks and venting/installations	$1,409
Capital Cost for Electric Tanks	($973)
Difference in up front capital costs	$436
Interest Rate (%)	0.06
Measureable Life of Hot Water Tank (years)	11
Amount that has to be recovered in operating cost annually to payoff difference in capital cost	$55.28
Add in hot water tank maintence costs per year	$0.00
Total ($)	**$55.28**
Energy consumptions for hot water (GJ's)	20
Difference in cost that needs to exist between natural gas and electric hot water heater in $/GJ over 11 years	**$2.79**

Therefore, the capital cost differential adds a significant challenge in generating new customer growth in terms of the hot water heating segment.

4.4.5.3 Importance of Decision Makers

It is important to make the distinction between homeowners and builders or developers in making energy source decisions. Some homeowners may have direct influence on home heating decisions, directing the builder to install their preference for space heating based on economic and/or other values. In this case, the homeowner may consider both the capital costs and variable costs of natural gas versus other sources of energy. Therefore, in times of relatively high market natural gas prices or perceived increases in market prices in the future, these people may select electricity over natural gas. Or if the difference between natural gas and electricity is minimal, environmental considerations, such as greenhouse gas emissions, may tip the consumer's decision away from natural gas. Builders or developers not directed by homeowners regarding energy source may often select electricity over natural gas due to the incremental capital cost of installing natural gas equipment in building a typical home if they don't believe they can recover these cost differences in the selling price of the home. In either case, the capital cost differences between natural gas and electricity provide a challenge to the competitiveness of natural gas.

A comparison of the forecast natural gas rates compared to electricity rates, including carbon tax and capital cost differences, is examined following the determination of appropriate electric equivalent benchmarks.

4.4.5.4 Electric Equivalent Benchmarks – TGI

Establishing electric equivalent benchmarks based on segmented demand applications helps to illustrate the competitive challenges facing Terasen as well as providing appropriate targets for a natural gas hedging strategy.

In the past, TGI and TGVI developed electric equivalent targets for hedging purposes based solely on space heating applications. For simplicity, TGI has utilized a single electric equivalent within its Price Risk Management Plans. This was based on the efficiency for new furnaces, estimated to be 90% efficiency for natural gas relative to electricity. Similarly, the TGVI Price Risk Management Plan also focused on targets related to space heating, with benchmarks based on efficiencies for existing customers' furnaces as well as efficiencies for new furnaces. However, the Company believes it is more appropriate to further segment natural gas applications into space heating and hot water heating when developing electric equivalent targets to provide a more accurate picture of Terasen's competitive environment.

Space Heating

The electric equivalent benchmark for space heating differs for existing and new or retrofit customers. The difference is based on the relative efficiencies of natural gas compared to electricity and capital cost considerations. A new customer or one considering retrofitting with new equipment may consider the capital cost difference associated with natural gas versus electricity. This is because this type of customer is comparing a new furnace or new electric baseboard heating, both of which have associated capital costs. In this case the relative efficiency of a natural gas compared to electricity would be based on that for new furnaces, in the order of approximately 90% efficiency. For existing natural gas customers, in order to continue their space heating with natural gas rather than electricity, Terasen must maintain rates below the variable cost of electricity adjusted for the relative efficiency of their existing furnace. This efficiency could range from about 60% efficiency for older units to about 90% efficiency for new units. For both customer types, it is assumed that for the majority of customers who use natural gas for space heating, the appropriate electricity rate would be based on the Step 2 rate, rather than the Step 1 rate, of the RIB rate structure.

The commodity component of the electric equivalents will be determined next to enable a comparison to the natural gas market price and commodity rate and which could be used as hedging targets.

New or Retrofit Customers

The commodity component of the electric equivalent on a per unit basis includes adjustments for the TGI fixed basic, delivery and midstream charges as well as the carbon tax. The midstream rate has been inflated by 3% growth each year as an estimate of the increases in storage and transportation costs over time. The carbon tax has been increased to \$1.50/GJ in 2012 and left constant thereafter. However, it is recognized that carbon tax levels may increase beyond 2012 and Terasen will update the electric equivalent benchmarks when there is greater certainty regarding the future of the tax. The Step 2 rates are based on BC Hydro's projected net bill increases in the F2011 Revenue Requirement Application negotiated settlement dated November 18, 2010. Terasen has assumed that the increases are equally applied to the Step 1 and Step 2 rates per BC Hydro's recent Residential Inclining Block (RIB) Rate Re-Pricing Application, although there is still uncertainty at this time regarding the approval of this methodology. An average of 90% efficiency for new natural gas customers' furnaces has been used. When the capital cost differential is factored in, the result for new or retrofit customers is as follows.

Table 5: Commodity Component of the Electric Equivalent for New or Retrofit Customers assuming 100% of Projected Electricity Rate Increases

	Apr-10	Apr-11	Apr-12	Apr-13	Apr-14
Price Components	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**
Projected Rate Increase	4.67%	17.44%	5.42%	9.72%	8.37%
Projected Deferral Account Rate Rider	3.53%	2.50%	2.20%	2.00%	1.70%
Variable cost of electric (Step 2 + rate rider) (\$/kWh)	\$0.090	\$0.104	\$0.110	\$0.120	\$0.130
Variable cost of electric (Step 2 + rate rider) (\$/GJ)	\$24.89	\$28.94	\$30.42	\$33.32	\$36.00
Variable cost adjusted for gas efficiency (90%)	\$22.40	\$26.05	\$27.38	\$29.98	\$32.40
Less: Fixed Basic and Delivery Charge (\$/GJ)	(\$4.64)	(\$4.78)	(\$4.92)	(\$5.07)	(\$5.22)
Less: Midstream Rate (\$/GJ)	(\$1.73)	(\$1.50)	(\$1.55)	(\$1.59)	(\$1.64)
Less: Carbon Tax (\$/GJ)	(\$1.00)	(\$1.25)	(\$1.50)	(\$1.50)	(\$1.50)
Electric Equivalent Commodity Component (before capital) (\$/GJ)	**\$15.03**	**\$18.52**	**\$19.41**	**\$21.82**	**\$24.04**
Capital cost differential for natural gas vs. electric equipment (\$/GJ)	(\$10.31)	(\$10.31)	(\$10.31)	(\$10.31)	(\$10.31)
Electric Equivalent Commodity Component (\$/GJ)	**\$4.72**	**\$8.21**	**\$9.10**	**\$11.51**	**\$13.73**

Therefore, in order to attract new customers or those planning to retrofit with new equipment, TGI must maintain a commodity rate below \$8.21/GJ for 2011 and below \$13.73/GJ by 2014. The TGI commodity rate is \$4.568/GJ effective January 1, 2011 but has averaged about \$7/GJ since the inception of the commodity rate in 2004 with the Commodity Unbundling Program. The commodity rate has been as high as \$9.78 per gigajoule, in 2008. As discussed in Section 3 regarding market prices and volatility, natural gas prices have risen above or near these electric equivalents over the last few years and there is the potential for market prices to exceed this price level again in the future. Therefore, locking in a portion of gas costs through hedging at prices below these benchmark levels would certainly help Terasen in its ability to attract new or retrofit customers, grow its customer base and provide cost effective rates for all customers.

Terasen has also given consideration to the amount of the projected electric rate bill impact increases. As discussed in Section 4.4.3 regarding electricity rates, future rate increases may be somewhat tempered by stakeholder and ratepayer interests. The following table provides the commodity component electric equivalent benchmarks for residential customers assuming only 50% of the projected BC Hydro electricity rate increases are approved. The projected deferral account rate rider amounts have not been adjusted given the significant accumulated deferral balance deficit.

Table 6: Commodity Component of the Electric Equivalent for New or Retrofit Customers assuming 50% of Projected Electricity Rate Increases

	Apr-10	Apr-11	Apr-12	Apr-13	Apr-14
Price Components	Electric Equivalent	Electric Equivalent	Electric Equivalent	Electric Equivalent	Electric Equivalent
Projected Rate Increase	4.67%	8.72%	2.71%	4.86%	4.19%
Projected Deferral Account Rate Rider	3.53%	2.50%	2.20%	2.00%	1.70%
Variable cost of electric (Step 2 + rate rider) ($/kWh)	$0.090	$0.096	$0.099	$0.103	$0.107
Variable cost of electric (Step 2 + rate rider) ($/GJ)	$24.89	$26.80	$27.44	$28.72	$29.83
Variable cost adjusted for gas efficiency (90%)	$22.40	$24.12	$24.70	$25.85	$26.85
Less: Fixed Basic and Delivery Charge ($/GJ)	($4.64)	($4.78)	($4.92)	($5.07)	($5.22)
Less: Midstream Rate ($/GJ)	($1.73)	($1.50)	($1.55)	($1.59)	($1.64)
Less: Carbon Tax ($/GJ)	($1.00)	($1.25)	($1.50)	($1.50)	($1.50)
Electric Equivalent Commodity Component (before capital) ($/GJ)	**$15.03**	**$16.59**	**$16.73**	**$17.68**	**$18.49**
Capital cost differential for natural gas vs. electric equipment ($/GJ)	($10.31)	($10.31)	($10.31)	($10.31)	($10.31)
Electric Equivalent Commodity Component ($/GJ)	**$4.72**	**$6.28**	**$6.42**	**$7.37**	**$8.18**

While Terasen does not know with certainty what future electricity rate increases will be approved, this analysis does at least provide a possible range for the increases. Obviously, the 50% projected bill increases scenario places the electric equivalent benchmarks closer to historical market gas price averages and increases the competitive challenge for Terasen going forward should higher gas prices and volatility return.

Existing Customers

The electric equivalent commodity component for existing natural gas customers is higher, or more favourable for Terasen, than that for new or retrofit customers as these customers have already incurred the capital costs for their furnaces. The electric equivalent will depend on the relative efficiency of the home owners' furnaces. For simplicity, Terasen has used a 75% efficiency level for existing customers, recognizing that some customers will have furnaces with higher and lower efficiencies. The calculations based on 100% and 50% of the projected rate increases are provided.

Table 7: Commodity Component of the Electric Equivalent for Existing Customers assuming 100% of Projected Electricity Rate Increases

	Apr-10	Apr-11	Apr-12	Apr-13	Apr-14
Price Components	Electric Equivalent	Electric Equivalent	Electric Equivalent	Electric Equivalent	Electric Equivalent
Projected Rate Increase	4.67%	17.44%	5.42%	9.72%	8.37%
Projected Deferral Account Rate Rider	3.53%	2.50%	2.20%	2.00%	1.70%
Variable cost of electric (Step 2 + rate rider) ($/kWh)	$0.090	$0.104	$0.110	$0.120	$0.130
Variable cost of electric (Step 2 + rate rider) ($/GJ)	$24.89	$28.94	$30.42	$33.32	$36.00
Variable cost adjusted for gas efficiency (75%) ($/GJ)	$18.67	$21.71	$22.82	$24.99	$27.00
Less: Fixed Basic and Delivery Charge ($/GJ)	($4.64)	($4.78)	($4.92)	($5.07)	($5.22)
Less: Midstream Rate ($/GJ)	($1.73)	($1.50)	($1.55)	($1.59)	($1.64)
Less: Carbon Tax ($/GJ)	($1.00)	($1.25)	($1.50)	($1.50)	($1.50)
Electric Equivalent Commodity Component (variable portion) ($/GJ)	**$11.30**	**$14.18**	**$14.85**	**$16.83**	**$18.64**

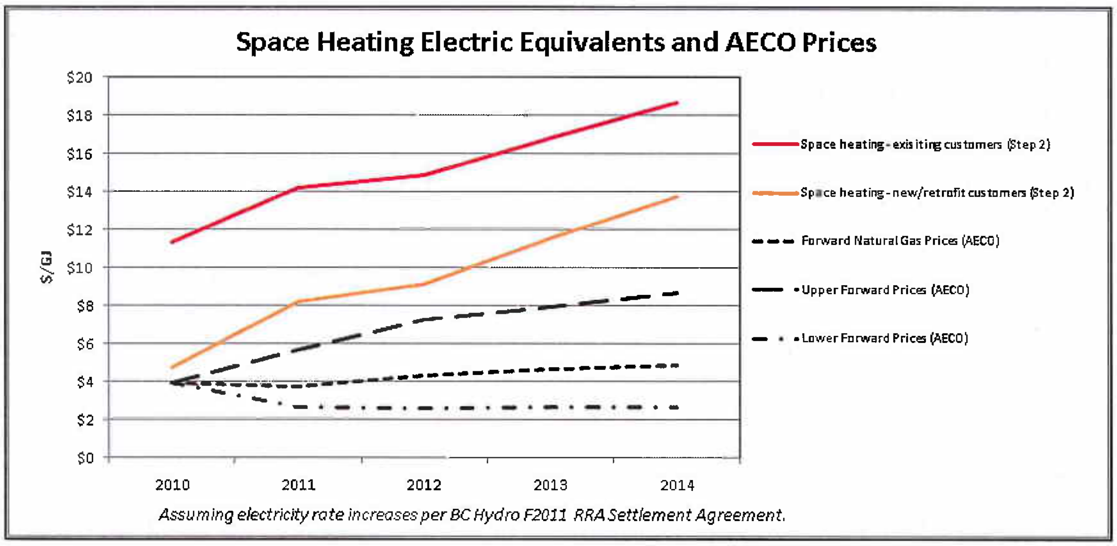
Table 8: Commodity Component of the Electric Equivalent for Existing Customers assuming 50% of Projected Electricity Rate Increases

	Apr-10	Apr-11	Apr-12	Apr-13	Apr-14
Price Components	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**
Projected Rate Increase	4.67%	8.72%	2.71%	4.86%	4.19%
Projected Deferral Account Rate Rider	3.53%	2.50%	2.20%	2.00%	1.70%
Variable cost of electric (Step 2 + rate rider) ($/kWh)	$0.090	$0.096	$0.099	$0.103	$0.107
Variable cost of electric (Step 2 + rate rider) ($/GJ)	$24.89	$26.80	$27.44	$28.72	$29.83
Variable cost adjusted for gas efficiency (75%) ($/GJ)	$18.67	$20.10	$20.58	$21.54	$22.37
Less: Fixed Basic and Delivery Charge ($/GJ)	($4.64)	($4.78)	($4.92)	($5.07)	($5.22)
Less: Midstream Rate ($/GJ)	($1.73)	($1.50)	($1.55)	($1.59)	($1.64)
Less: Carbon Tax ($/GJ)	($1.00)	($1.25)	($1.50)	($1.50)	($1.50)
Electric Equivalent Commodity Component (variable portion) ($/GJ)	**$11.30**	**$12.57**	**$12.61**	**$13.38**	**$14.01**

Space Heating Summary

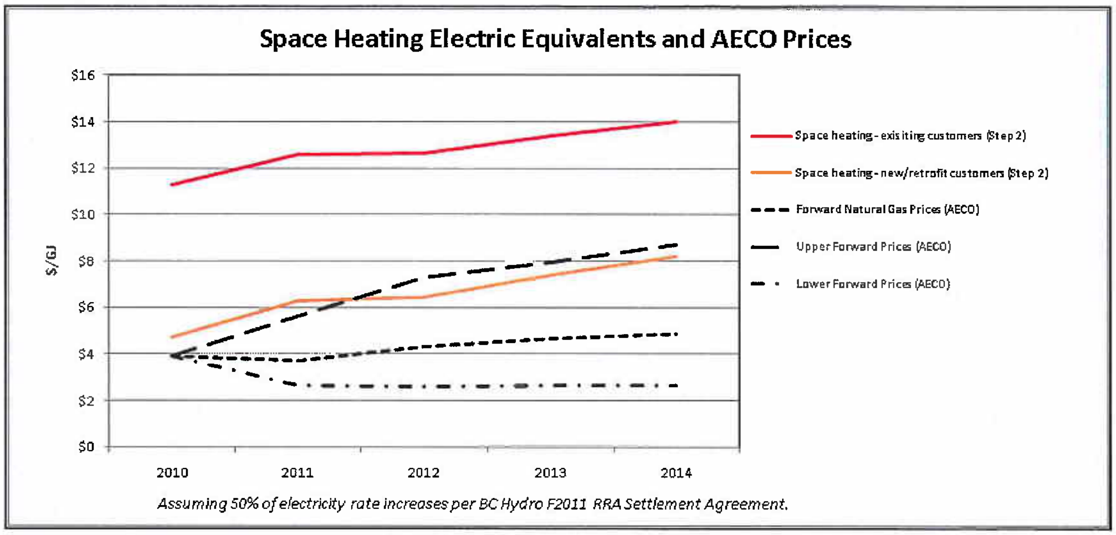
The following graph summarizes the electric equivalents for space heating, based on 100% of the BC Hydro rate projections, into one graph. Also included are recent AECO forward natural gas prices and the upper and lower AECO price bands based on the implied forward volatility subject to a 95% confidence level.

Figure 20: Space Heating Electric Equivalents and AECO Price Envelope



The following graph is based on the 50% BC Hydro rate projections scenario.

Figure 21: Space Heating Electric Equivalents and AECO Price Envelope



Based on these results alone, Terasen believes it must focus on attracting new customers or retrofit customers, given the competitive challenge that exists should market gas prices increase in the future. Furthermore, by targeting new or retrofit customers Terasen can add or maintain throughput on the system, which benefits all natural gas customers. This is important because of the declining throughput on the system from existing customers due to energy efficiency and conservation measures. Adding new customers would help offset this declining throughput. However, it is important to note that once existing customers' natural gas furnaces expire, they would then fall into the retrofit category, having to choose between a new natural gas furnace or electric baseboard heating or an alternate source of energy. The 2008 REUS showed that many customers' furnaces were of a lower efficiency level. This indicates that a large proportion of lower efficiency furnaces will be replaced with higher efficiency units within the coming years, particularly for TGI. At that point, their electric equivalent commodity component becomes significantly lower, increasing the competitive challenge for Terasen.

Water Heating

Natural gas is also disadvantaged in terms of competing with electricity with regard to attracting customers for hot water heating. While there is a capital cost differential related to hot water heating, the variable cost difference also challenges natural gas relative to electricity. This is because the relative efficiency of natural gas hot water heaters is typically only about 60% compared to about 90% efficiency for electric hot water heaters.

Similar to the calculations for space heating, the commodity component of the electric equivalent on a per unit basis includes adjustments for the TGI delivery and midstream charges as well as the carbon tax. An adjustment is not made for the TGI fixed basic charge because it is assumed that those customers with or considering using natural gas for water heating would, in most cases, have natural gas furnaces and therefore already incur the fixed basic charge. An average of 60% efficiency for existing natural gas customers' water heaters has been used, even though some customers will have units with efficiencies different than this percentage. Depending on the size of the home and number of electric appliances used, some consumers using electricity for water heating would likely incur electricity costs at the Step 2 rate level while others would likely incur the Step 1 rate level or a combination of both. Therefore, the commodity component electric equivalents have been calculated below based on Step 1 and Step 2 electricity rates separately.

New or Retrofit Customers

The following table shows the electric equivalent calculation assuming 100% of the BC Hydro projected rate increases applied to the Step 1 rate applicable for new or retrofit customers. This is the area where Terasen has the greatest competitive challenge because of the capital costs for new units and the lower Step 1 rate, typically associated with smaller homes such as apartments.

Table 9: Commodity Component of the Electric Equivalent for New or Retrofit Customers assuming 100% of Projected Electricity Rate Increases (Step 1)

	Apr-10	Apr-11	Apr-12	Apr-13	Apr-14
Price Components	Electric Equivalent	Electric Equivalent	Electric Equivalent	Electric Equivalent	Electric Equivalent
Projected Rate Increase	4.67%	17.44%	5.42%	9.72%	8.37%
Projected Deferral Account Rate Rider	3.53%	2.50%	2.20%	2.00%	1.70%
Variable cost of electric (Step 1 + rate rider) ($/kWh)	$0.065	$0.075	$0.079	$0.087	$0.094
Variable cost of electric (Step 1 + rate rider) ($/GJ)	$17.97	$20.89	$21.96	$24.05	$25.99
Variable cost adjusted for gas efficiency (67%) ($/GJ)	$12.04	$14.00	$14.72	$16.11	$17.41
Less: Delivery Charge ($/GJ)	($3.15)	($3.24)	($3.34)	($3.44)	($3.54)
Less: Midstream Rate ($/GJ)	($1.73)	($1.50)	($1.55)	($1.59)	($1.64)
Less: Carbon Tax ($/GJ)	($1.00)	($1.25)	($1.50)	($1.50)	($1.50)
Electric Equivalent Commodity Component (before capital) ($/GJ)	**$6.17**	**$8.01**	**$8.33**	**$9.59**	**$10.73**
Capital cost differential for natural gas vs. electric equipment ($/GJ)	($2.79)	($2.79)	($2.79)	($2.79)	($2.79)
Electric Equivalent Commodity Component ($/GJ)	**$3.38**	**$5.22**	**$5.54**	**$6.80**	**$7.94**

Based on this calculation, the electric equivalents, at least in the near term, are well within the range of possible market price movements. Any increases in market gas prices that go unmitigated could challenge natural gas, even assuming BC Hydro's rate projections materialize.

The benchmarks are lower and competitive challenge higher if BC Hydro rate increases are 50% lower than projected. In this scenario, the competitive benchmarks are right at the current forward price level of about $4/GJ.

Table 10: Commodity Component of the Electric Equivalent for New or Retrofit Customers assuming 50% of Projected Electricity Rate Increases (Step 1)

	Apr-10	Apr-11	Apr-12	Apr-13	Apr-14
Price Components	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**
Projected Rate Increase	4.67%	8.72%	2.71%	4.86%	4.19%
Projected Deferral Account Rate Rider	3.53%	2.50%	2.20%	2.00%	1.70%
Variable cost of electric (Step 1 + rate rider) ($/kWh)	6.47%	6.96%	7.13%	7.46%	7.75%
Variable cost of electric (Step 1 + rate rider) ($/GJ)	$17.97	$19.34	$19.81	$20.73	$21.54
Variable cost adjusted for gas efficiency (67%) ($/GJ)	$12.04	$12.96	$13.27	$13.89	$14.43
Less: Delivery Charge ($/GJ)	($3.15)	($3.24)	($3.34)	($3.44)	($3.54)
Less: Midstream Rate ($/GJ)	($1.73)	($1.50)	($1.55)	($1.59)	($1.64)
Less: Carbon Tax ($/GJ)	($1.00)	($1.25)	($1.50)	($1.50)	($1.50)
Electric Equivalent Commodity Component (before capital) ($/GJ)	**$6.17**	**$6.97**	**$6.89**	**$7.36**	**$7.75**
Capital cost differential for natural gas vs. electric equipment ($/GJ)	($2.79)	($2.79)	($2.79)	($2.79)	($2.79)
Electric Equivalent Commodity Component ($/GJ)	**$3.38**	**$4.18**	**$4.10**	**$4.57**	**$4.96**

For larger homes or those with more electricity usage, utilization of the Step 2 rate may be more appropriate for benchmarks. But, of course, some customers might incur a combination of the Step 1 and Step 2 rates and so the appropriate electric equivalent would likely lie somewhere in between. The following tables show the electric equivalents for the 100% and 50% of projected electricity rate scenarios. Because of the higher Step 2 rate, the competitive challenge is less than that of the Step 1 rate, all else equal.

Table 11: Commodity Component of the Electric Equivalent for New or Retrofit Customers assuming 100% of Projected Electricity Rate Increases (Step 2)

	Apr-10	Apr-11	Apr-12	Apr-13	Apr-14
Price Components	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**
Projected Rate Increase	4.67%	17.44%	5.42%	9.72%	8.37%
Projected Deferral Account Rate Rider	3.53%	2.50%	2.20%	2.00%	1.70%
Variable cost of electric (Step 2 + rate rider) ($/kWh)	$0.090	$0.104	$0.110	$0.120	$0.130
Variable cost of electric (Step 2 + rate rider) ($/GJ)	$24.89	$28.94	$30.42	$33.32	$36.00
Variable cost adjusted for gas efficiency (67%) ($/GJ)	$16.68	$19.39	$20.38	$22.32	$24.12
Less: Delivery Charge ($/GJ)	($3.15)	($3.24)	($3.34)	($3.44)	($3.54)
Less: Midstream Rate ($/GJ)	($1.73)	($1.50)	($1.55)	($1.59)	($1.64)
Less: Carbon Tax ($/GJ)	($1.00)	($1.25)	($1.50)	($1.50)	($1.50)
Electric Equivalent Commodity Component (before capital) ($/GJ)	**$10.80**	**$13.40**	**$14.00**	**$15.79**	**$17.44**
Capital cost differential for natural gas vs. electric equipment ($/GJ)	($2.79)	($2.79)	($2.79)	($2.79)	($2.79)
Electric Equivalent Commodity Component ($/GJ)	**$8.01**	**$10.61**	**$11.21**	**$13.00**	**$14.65**

Table 12: Commodity Component of the Electric Equivalent for New or Retrofit Customers assuming 50% of Projected Electricity Rate Increases (Step 2)

	Apr-10	Apr-11	Apr-12	Apr-13	Apr-14
Price Components	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**
Projected Rate Increase	4.67%	8.72%	2.71%	4.86%	4.19%
Projected Deferral Account Rate Rider	3.53%	2.50%	2.20%	2.00%	1.70%
Variable cost of electric (Step 2 + rate rider) ($/kWh)	$0.090	$0.096	$0.099	$0.103	$0.107
Variable cost of electric (Step 2 + rate rider) ($/GJ)	$24.89	$26.80	$27.44	$28.72	$29.83
Variable cost adjusted for gas efficiency (67%) ($/GJ)	$16.68	$17.95	$18.39	$19.24	$19.99
Less: Delivery Charge ($/GJ)	($3.15)	($3.24)	($3.34)	($3.44)	($3.54)
Less: Midstream Rate ($/GJ)	($1.73)	($1.50)	($1.55)	($1.59)	($1.64)
Less: Carbon Tax ($/GJ)	($1.00)	($1.25)	($1.50)	($1.50)	($1.50)
Electric Equivalent Commodity Component (before capital) ($/GJ)	**$10.80**	**$11.96**	**$12.00**	**$12.71**	**$13.31**
Capital cost differential for natural gas vs. electric equipment ($/GJ)	($2.79)	($2.79)	($2.79)	($2.79)	($2.79)
Electric Equivalent Commodity Component ($/GJ)	**$8.01**	**$9.17**	**$9.21**	**$9.92**	**$10.52**

Existing Customers

For existing customers, where capital cost considerations are not relevant, the electric equivalents are higher. However, it is important to note that once existing customers' hot water heaters expire, consideration of the capital costs becomes relevant and the competitive challenge for Terasen increases.

The following tables show the electric equivalents for existing natural gas water heater customers for both BC Hydro projected rate scenarios. Calculations using the Step 1 rate are shown first followed by those with Step 2.

Table 13: Commodity Component of the Electric Equivalent for Existing Customers assuming 100% of Projected Electricity Rate Increases (Step 1)

	Apr-10	Apr-11	Apr-12	Apr-13	Apr-14
Price Components	Electric Equivalent	Electric Equivalent	Electric Equivalent	Electric Equivalent	Electric Equivalent
Projected Rate Increase	4.67%	17.44%	5.42%	9.72%	8.37%
Projected Deferral Account Rate Rider	3.53%	2.50%	2.20%	2.00%	1.70%
Variable cost of electric (Step 1 + rate rider) ($/kWh)	$0.065	$0.075	$0.079	$0.087	$0.094
Variable cost of electric (Step 1 + rate rider) ($/GJ)	$17.97	$20.89	$21.96	$24.05	$25.99
Variable cost adjusted for gas efficiency (67%) ($/GJ)	$12.04	$14.00	$14.72	$16.11	$17.41
Less: Delivery Charge ($/GJ)	($3.15)	($3.24)	($3.34)	($3.44)	($3.54)
Less: Midstream Rate ($/GJ)	($1.73)	($1.50)	($1.55)	($1.59)	($1.64)
Less: Carbon Tax ($/GJ)	($1.00)	($1.25)	($1.50)	($1.50)	($1.50)
Electric Equivalent Commodity Component (variable portion) ($/GJ)	**$6.17**	**$8.01**	**$8.33**	**$9.59**	**$10.73**

Table 14: Commodity Component of the Electric Equivalent for Existing Customers assuming 50% of Projected Electricity Rate Increases (Step 1)

	Apr-10	Apr-11	Apr-12	Apr-13	Apr-14
Price Components	Electric Equivalent	Electric Equivalent	Electric Equivalent	Electric Equivalent	Electric Equivalent
Projected Rate Increase	4.67%	8.72%	2.71%	4.86%	4.19%
Projected Deferral Account Rate Rider	3.53%	2.50%	2.20%	2.00%	1.70%
Variable cost of electric (Step 1 + rate rider) ($/kWh)	$0.065	$0.070	$0.071	$0.075	$0.078
Variable cost of electric (Step 1 + rate rider) ($/GJ)	$17.97	$19.34	$19.81	$20.73	$21.54
Variable cost adjusted for gas efficiency (67%) ($/GJ)	$12.04	$12.96	$13.27	$13.89	$14.43
Less: Delivery Charge ($/GJ)	($3.15)	($3.24)	($3.34)	($3.44)	($3.54)
Less: Midstream Rate ($/GJ)	($1.73)	($1.50)	($1.55)	($1.59)	($1.64)
Less: Carbon Tax ($/GJ)	($1.00)	($1.25)	($1.50)	($1.50)	($1.50)
Electric Equivalent Commodity Component (variable portion) ($/GJ)	**$6.17**	**$6.97**	**$6.89**	**$7.36**	**$7.75**

Table 15: Commodity Component of the Electric Equivalent for Existing Customers assuming 100% of Projected Electricity Rate Increases (Step 2)

	Apr-10	Apr-11	Apr-12	Apr-13	Apr-14
Price Components	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**
Projected Rate Increase	4.67%	17.44%	5.42%	9.72%	8.37%
Projected Deferral Account Rate Rider	3.53%	2.50%	2.20%	2.00%	1.70%
Variable cost of electric (Step 2 + rate rider) ($/kWh)	$0.090	$0.104	$0.110	$0.120	$0.130
Variable cost of electric (Step 2 + rate rider) ($/GJ)	$24.89	$28.94	$30.42	$33.32	$36.00
Variable cost adjusted for gas efficiency (67%) ($/GJ)	$16.68	$19.39	$20.38	$22.32	$24.12
Less: Delivery Charge ($/GJ)	($3.15)	($3.24)	($3.34)	($3.44)	($3.54)
Less: Midstream Rate ($/GJ)	($1.73)	($1.50)	($1.55)	($1.59)	($1.64)
Less: Carbon Tax ($/GJ)	($1.00)	($1.25)	($1.50)	($1.50)	($1.50)
Electric Equivalent Commodity Component (variable portion) ($/GJ)	**$10.80**	**$13.40**	**$14.00**	**$15.79**	**$17.44**

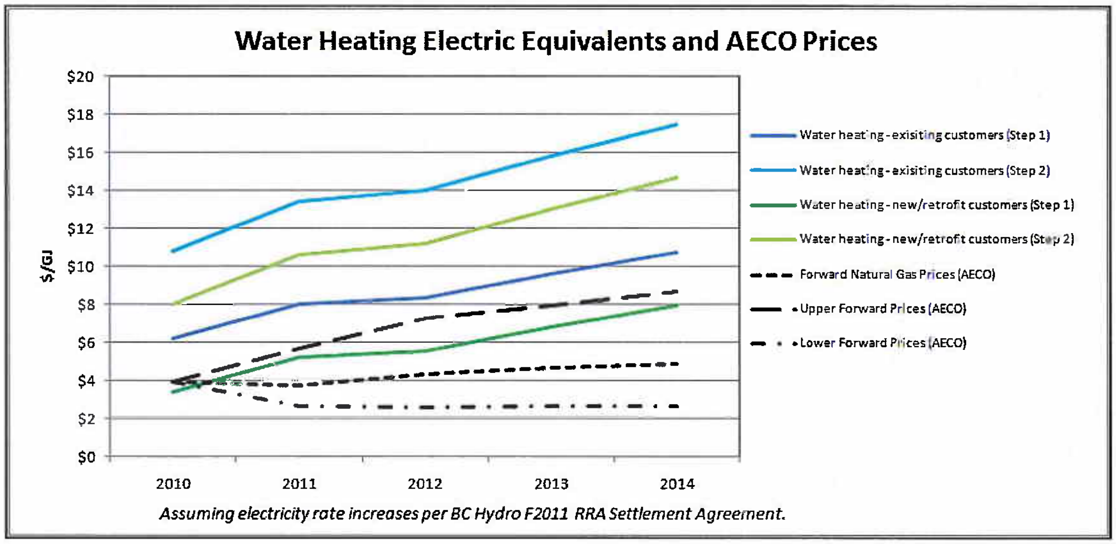
Table 16: Commodity Component of the Electric Equivalent for Existing Customers assuming 50% of Projected Electricity Rate Increases (Step 2)

	Apr-10	Apr-11	Apr-12	Apr-13	Apr-14
Price Components	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**	**Electric Equivalent**
Projected Rate Increase	4.67%	8.72%	2.71%	4.86%	4.19%
Projected Deferral Account Rate Rider	3.53%	2.50%	2.20%	2.00%	1.70%
Variable cost of electric (Step 2 + rate rider) ($/kWh)	$0.090	$0.096	$0.099	$0.103	$0.107
Variable cost of electric (Step 2 + rate rider) ($/GJ)	$24.89	$26.80	$27.44	$28.72	$29.83
Variable cost adjusted for gas efficiency (67%) ($/GJ)	$16.68	$17.95	$18.39	$19.24	$19.99
Less: Delivery Charge ($/GJ)	($3.15)	($3.24)	($3.34)	($3.44)	($3.54)
Less: Midstream Rate ($/GJ)	($1.73)	($1.50)	($1.55)	($1.59)	($1.64)
Less: Carbon Tax ($/GJ)	($1.00)	($1.25)	($1.50)	($1.50)	($1.50)
Electric Equivalent Commodity Component (variable portion) ($/GJ)	**$10.80**	**$11.96**	**$12.00**	**$12.71**	**$13.31**

Water Heating Summary

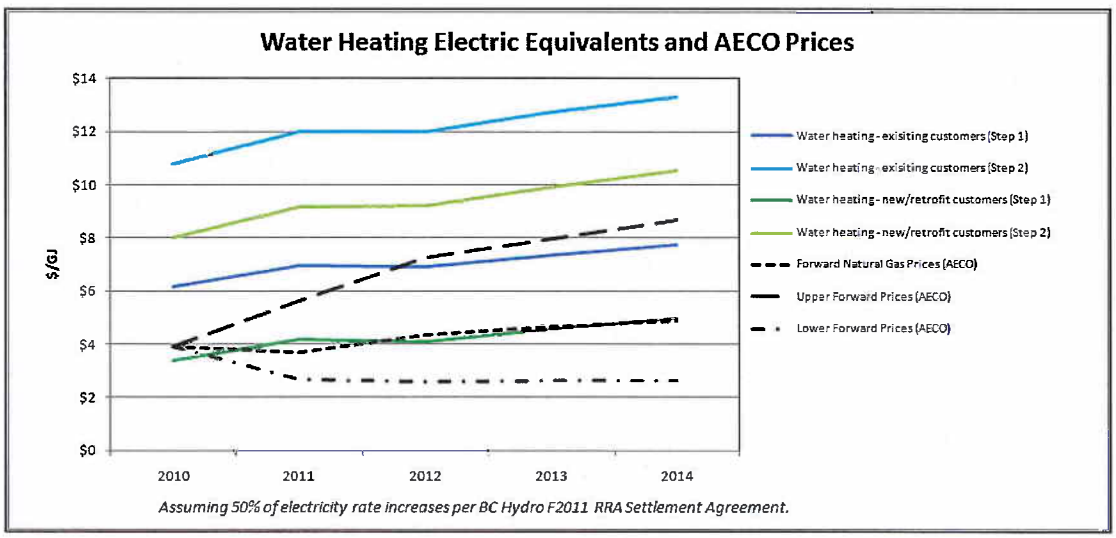
The following graph summarizes the electric equivalents for water heating, based on 100% of the BC Hydro rate projections, into one graph. Also included are recent AECO forward natural gas prices and the upper and lower AECO price bands based on the implied forward volatility subject to a 95% confidence level.

Figure 22: Water Heating Electric Equivalents and AECO Price Envelope



The following graph is based on the 50% electricity rate projection scenario.

Figure 23: Water Heating Electric Equivalents and AECO Price Envelope



Based on these results, Terasen is currently challenged in attracting new or retrofit customers for water heating based on the projected electricity rate increase scenarios in dwellings where the Step 1 rate comparison is appropriate. Furthermore, based on the recent AECO forward prices envelope (with 95% confidence level), Terasen may also be challenged with maintaining existing customers (other than those existing customers with higher electricity use where the Step 2 comparison is appropriate). As discussed in Section 4.4.1, by not maintaining existing water heating customers, migration of natural gas load to electricity load would increase rates for both natural gas and electricity customers. It is important to note that once existing customers' natural gas hot water heaters expire, they would then fall into the retrofit category. At that time, their electric equivalent commodity component becomes significantly lower, increasing the competitive challenge for Terasen.

Capturing natural gas prices, through hedging, at levels near current forward prices would help ensure that Terasen is able to improve its ability, at least on a variable cost basis, to maintain existing customers and attract new customers. However, without hedging, if market gas prices migrate towards the upper end of the forecast AECO price envelope, Terasen's competitive position is negatively impacted. If natural gas load migration occurs this would adversely affect both Terasen's and BC Hydro's rates as discussed in Section 4.4.1.

However, cost considerations are not the only ones which affect Terasen's ability to maintain existing and attract new customers. Consumer perceptions of natural gas, both economic and environmental, are also important in this regard.

4.4.6 RETAINING EXISTING CUSTOMERS

As discussed in the Information Request responses to the TGI 2010-2013 Price Risk Management Plan (in particular BCUC IR No. 1.2.1), retaining existing customers has been a challenge for Terasen in the past. Customer migration to other primary sources of energy in the recent past is likely due to economic reasons as well as perceptions regarding the green house gas emissions associated with fossil fuels.

4.4.6.1 Fuel Switching Evidence

TGI has experienced customer migration to other energy sources (fuel switching), some of which may be attributable to gas price volatility. Supporting statistics and information is found in the 2008 Residential End Use Study. The 2008 REUS concluded that, "the increase in the real price (nominal prices adjusted for inflation) of natural gas over the long-run is contributing to the decline in use rates"[27]. The authors conclude that long-term effects of such price increases can include fuel switching.

The authors noted that in the short-term, price spikes can influence customers to temporarily turn primary natural gas heating systems off in favour of readily available alternative secondary heating options. This is evidenced by the widespread use of multiple heating fuels (e.g., wood) and heating appliances (e.g., portable electric heaters and fireplaces) in B.C. homes. The 2008 REUS found that 56% of the TGI customers surveyed used supplementary heating fuels for space heating.

[27] 2008 Residential End Use Study, Sampson Research, November 30, 2009, page 3-13.

The 2008 REUS identifies trends in fuel switching away from natural gas. As participants in this research were required to be current TGI customers, estimates for fuel switching are likely underestimated. Former customers who switched to another primary fuel source, and did not retain any natural gas appliances are not reflected in the study. The 2008 REUS found on average, 3% of TGI customers changed their main space heating fuel in the last five years. On a regional basis, 11% of TGVI customers changed their fuel, significantly more than all other regions. Of those who switched their main or supplementary heating fuel in the last five years, there has been a net shift away from natural gas to electricity. Findings shows that 57% switched from natural gas as their space heating fuel, compared to 17% who switched from electricity. Another 19% switched from heating oil. Proportionately, three times as many people switched to their current fuel from natural gas than from electricity. Although the sample sizes are very small, the net shift away from natural gas appears most evident in the Lower Mainland, Interior and TGVI regions. The 2008 REUS marks the first time this has occurred, as the 2002 and 1993 surveys showed a positive gain for natural gas over electricity (42% to 29% in 2002 and 24% to 5% in 1993).[28]

For those who switched fuels in the last five years, of those who switched to electricity, 98% had previously used natural gas to heat their house, and a small percentage (2%) had used heating oil. Of those who switched to natural gas, 43% had used heating oil, 40% had used electricity, and 15% had used wood prior to the switch.

The authors of the 2008 Residential End Use Study state that in the long term, increases in natural gas prices can cause fuel switching. The results of the study, while potentially underestimated, demonstrate that approximately 3% of current TGI customers switched their primary fuel source in the last five years, and of the customers who switched from natural gas, 78% moved to electricity as their primary fuel source. Based on the 2008 REUS, it is believed that natural gas prices contribute to customer migration to other primary energy sources.

Based on these results, Terasen asserts that the continued use of natural gas hedging is critically important in mitigating market price volatility and the resultant affects on natural gas rates. Perceptions of natural gas price volatility, as well as actual volatility, impact consumer behaviour. An effective hedging strategy can reduce the frequency as well as the magnitude of commodity rate changes and help ensure cost effective and competitive rates for natural gas customers. Reducing the potential for customer migration to electricity also reduces the additional cost pressures on electricity rates, thus benefitting gas and electric consumers in B.C.

[28] 2008 Residential End Use Study, Sampson Research, November 30, 2009, pages 5-4 to 5-6.

4.5 Reducing Rate Volatility

Terasen believes that reducing rate volatility is critical in maintaining reasonable rates and creating value for energy customers. Reducing the effect of market price volatility on customer rates improves Terasen's ability to compete with other forms of energy. This enables Terasen to maintain existing customers and attract new customers and ensure reasonable rates for all customers.

Terasen recognizes that reducing rate volatility should be balanced with providing customers with appropriate price signals that are reflective of the natural gas marketplace. These signals help customers make informed decisions about their energy consumption. As discussed in Section 4.4.3, BC Hydro's lack of market based rates and annual rate setting challenges Terasen in this regard.

4.5.1 CUSTOMER PREFERENCES

Customers have indicated that they prefer some degree of rate stability. This has been expressed through customer surveys and focus groups, customer complaints and media attention.

4.5.1.1 Price Volatility Preferences Study

In February 2005, TGI engaged a research company to survey customers regarding their tolerance for rate volatility. The results of the Residential Customer Price Volatility Preferences Study, conducted in February 2005 by Western Opinion Research Inc. and submitted in the 2005-2008 Price Risk Management Plan, indicated that customers prefer rate stability. The study has been included in Appendix B of this report. The survey results confirmed that customers will tolerate some volatility in rates but that there were limits largely based on household budget constraints. The study revealed the following insights and preferences among residential customers:

- Natural gas bills are considered among the more significant monthly payments.
- Many customers cannot afford large increases in their natural gas bills.
- On average, the study respondents can tolerate annual natural gas billing changes of $169 (or 16% of average annual billing of $1033).
- For those respondents on tighter budgets with annual billings of less than $900, the average tolerable change was only $53 (or 11% of average annual billings of $482).
- For those respondents with higher budgets with annual billings of more than $900, the average tolerable change was $219 (or 17% of average annual billings of $1288).
- Seventy percent of respondents could tolerate annual bill changes of $100 or less.

This last point shows that the majority of customers could tolerate annual bill changes of a maximum of $100. Based on TGI's current average total residential annual billing of about $1,000 this tolerable increase represents approximately 10%.

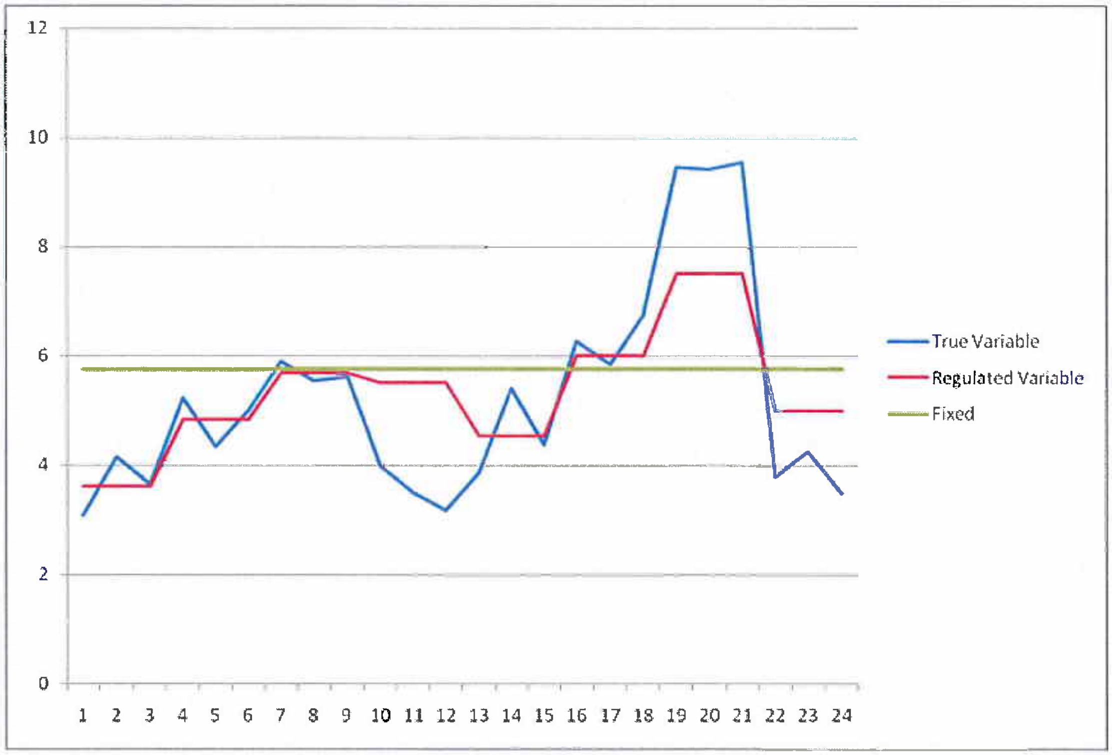
In the study, customers were also queried about their preferences for natural gas price hedging. The example of fixed versus variable rate mortgages was used to illustrate how hedging works. Participants were presented with three scenarios including a fixed rate bill scenario, a scenario where bills fluctuated with market prices (based on no hedging) and a scenario where bill changes were dampened from market price movements with some hedging. The majority of respondents were willing to accept less downside rate participation if upside rate increases were also limited. This is because many participants do not like or could not afford large bill increases and greater rate volatility made budgeting more difficult.

As discussed in the following section, Terasen recently conducted a customer focus group which revealed that customer preferences are still in line with the results of the 2005 study. Given that natural gas bills are still a significant household expense and many customers are on fixed budgets or affected by the impacts of the recent recession, Terasen believes that many customers still prefer rate stability and tolerances likely have not changed significantly.

4.5.1.2 Residential Customer Focus Group

Recently, in November 2010, Terasen enlisted Ideba, a research and consulting company, to conduct a focus group regarding residential customer preferences about evergreening, or automatic contract renewal, for customers enrolled with marketers under the Commodity Unbundling Program. During this session, customers were also queried about their preferences for rate stability. Participants were presented with three rate scenarios including a fixed rate, a variable (or market) rate and a controlled rate (one limited within a tighter range than the variable rate). The scenarios are not representative of historical natural gas prices or rates but are illustrative examples of rates to assess consumers' preferences. The scenarios are shown in the following graph.

Figure 24: Rate Scenarios



One participant preferred the fixed rate because he was on a fixed budget. However, he noted that this fixed rate must be reasonable or close to the average variable rate over the long run to be of any value. One participant preferred the variable rate based on her belief that rate increases would be matched with rate decreases. This participant did not have any concerns with significant fluctuations in monthly bills or budget constraints. However, the majority of respondents favoured a controlled rate and were willing to accept less downside rate participation than the variable rate if upside rate increases were also limited. The desire for some rate stability and less bill surprises (i.e. significant bill increases from one month to the next) were cited as reasons for selecting this controlled rate.

The results of this focus group help validate the findings of the Residential Customer Price Volatility Preferences Study conducted in 2005 and indicate that customers' preferences have not changed materially over time. Many customers prefer some degree of protection from market price volatility given that they have limited budgets for bills. These customers are willing to accept smaller rate decreases if rate increases are also limited.

4.5.1.3 Other Evidence of Price Volatility Preferences

In December 2004, Enbridge Gas Distribution ("Enbridge") commissioned Ipsos-Reid, a market research company, to conduct a study regarding customer threshold for natural gas rate volatility. The study is included in Appendix C. The study focused on residential and small commercial customers to assess their sensitivity to rate volatility and preferences for risk management strategies. The results of the study are as follows:

- In general, most customers believe it more important to maintain a steady rate than obtain the lowest possible rate.
- Most customers want Enbridge to manage the potential risk for large fluctuations in commodity prices.
- Customers are less willing to accept rate fluctuations as the amount of the bill adjustment increases. About one half of respondents expressed $100 as the tolerable annual fluctuation in their annual bill.
- Customers prefer rate stability for budget purposes and to avoid large bill surprises.

While this study was conducted in another jurisdiction, it is not inconsistent with Terasen's findings regarding customer preferences for volatility within its own jurisdiction. Generally speaking, it appears that many customers desire some degree of rate stability to manage their own budgets and avoid larger bill fluctuations that can occur without rate volatility mitigation strategies.

4.5.1.4 Risk Aversion

Many people are risk adverse and this is reflected, for example, in diversified retirement investment portfolios, purchasing of insurance for homes and cars, and entering into fixed rate mortgages. Consumers are willing to tolerate an acceptable amount of risk but generally prefer not to be subjected to the extremes, whether it is losses on retirement investments due to declines in stock prices or increases in natural gas bills. People are willing to give up some amount of potential gain in order to avoid the other extreme of higher-than-tolerable potential loss.

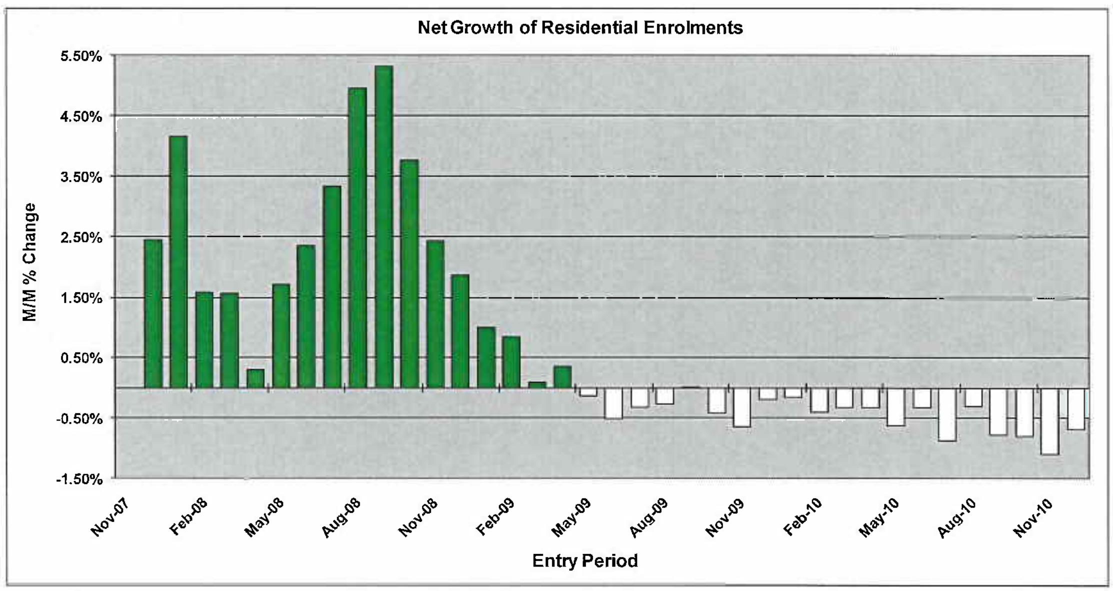
4.5.1.5 Equal Payment Plan

Customers' desire for stability is also reflected in enrolments for the Terasen Equal Payment Plan ("EPP"). The EPP provides customers with equal monthly bill payments for a twelve month period, based on their previous year's consumption volumes. Approximately 31% of customers are signed up for this billing option. While this acts to smooth customers' consumption via stable bill payments it does not affect underlying gas prices as per a price risk management program. In other words, under the EPP alone, consumers are artificially protected from market price volatility as they will ultimately have to pay the rate impacts of any market price fluctuations. Furthermore, under the EPP, the equal twelve month payment instalments are reviewed every three months and adjusted if necessary to reflect changes in weather, gas usage or gas rates. This is done to avoid significant billing adjustments at year end caused by large changes in weather related consumption or quarterly rates. So, during periods of extremely volatile market prices and subsequent quarterly rate changes, EPP customers may also be subject to quarterly, rather than annual, rate changes. As such, Terasen believes that the EPP is not a substitute for active price risk management but rather a way to smooth consumption and payments for customers.

4.5.1.6 Commodity Unbundling

Residential and commercial customer enrolment in the Commodity Unbundling Program since its introduction also illustrates that some customers desire rate stability. These customers have chosen to purchase their natural gas from marketers at a fixed rate for one to five year terms rather than purchase their commodity supply from TGI at its quarterly adjusted rate. Customers have indicated that the reasons for enrolling with marketers at a fixed rate includes rate stability for budget purposes and the perception that they would save money compared to the TGI commodity rate. Currently, approximately 16% of residential and commercial customers are enrolled with a marketer. The enrolment growth from the start of Residential Commodity Unbundling (November 1, 2007) is shown in the following graph.

Figure 25: Customer Choice Program Net Residential Enrolments



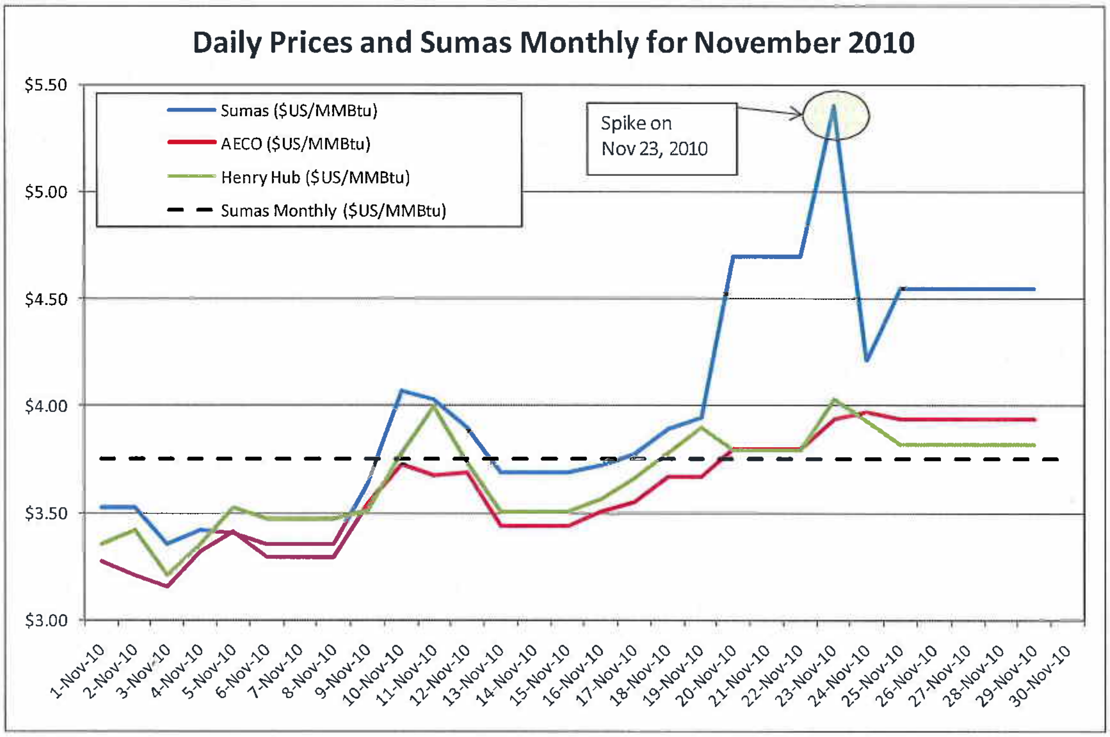
The graph shows that the migration of residential customers to marketers' fixed rate offerings has changed from positive growth since November 2007 to overall net negative growth in mid 2009. Some customers have returned to the TGI standard rate offering, which is subject to quarterly review and, at least historically, has been favourable relative to the average marketers' fixed rate products. The conclusion that can be drawn from this is that while many customers desire rate stability they are not willing to pay significant premiums over other alternatives for this rate certainty.

4.6 Regional Price Disconnects

Managing Sumas price exposure becomes critical, particularly during a period of price disconnection, and so it is considered an important objective of the hedging strategy. A period of disconnection occurs when increased demand in the Pacific Northwest including British Columbia creates a lack of gas delivery capacity at Huntingdon causing Sumas prices to increase significantly and disproportionately above other regional hub prices such as Station 2 and Alberta prices. This was particularly evident during the winter of 2000/01 when natural gas prices at Sumas increased to record-high levels (peaking at $60.96/GJ on December 11, 2000) and experienced unprecedented price volatility. While Southern Crossing Pipeline is an example of regional infrastructure required to meet growing regional demand and has helped to reduce the magnitude of these price disconnects, further infrastructure developments are needed to meet the pace of demand growth in the region.

A more recent example of the effects of constrained regional infrastructure occurred in November 2010. During November 20th to 25th a period of significantly cold weather occurred in the PNW and as a result the Sumas price disconnected from the AECO and Henry Hub spot price, as illustrated in Figure 26. Sumas and AECO spot prices traded below $4.00 US/MMBtu before the cold spell but then Sumas spot prices ran up to almost $5.50 US/MMBtu during the cold spell. This highlights the fact that the currently abundant North America supply and weakened demand balance does not insulate the Pacific Northwest regional market hubs from price increases and volatility when regional demand increases.

Figure 26: Daily and Monthly Sumas Prices for November 2010



Disconnects between Sumas and Station 2 and Alberta prices also occurred during the 2009/10 winter, when periods of cold weather and maximum flows on Spectra Energy's T-South pipeline segment raised Sumas daily prices above Station 2 and AECO prices by $4.00/GJ. A similar situation occurred during the middle of December 2008 when a week-long cold spell in the Pacific Northwest region increased the demand for Huntingdon gas and drove up Sumas prices. The price differentials for the past two winter periods are presented in the two figures below.

Figure 27: Sumas less Station 2 and AECO – Winter 2009/10

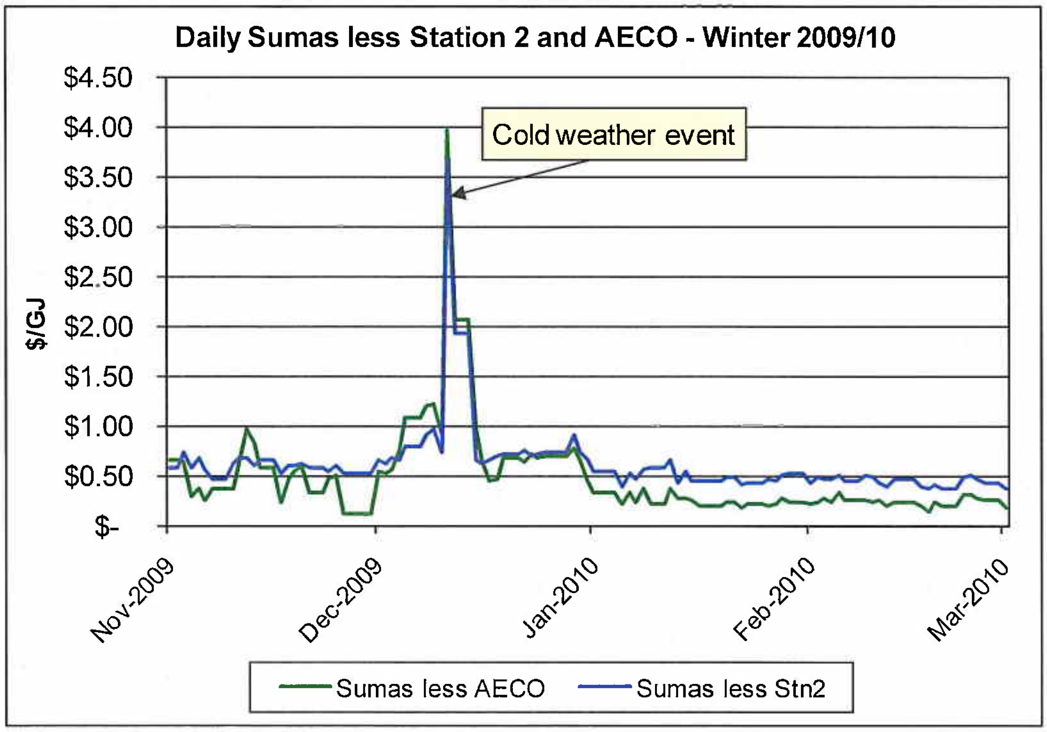
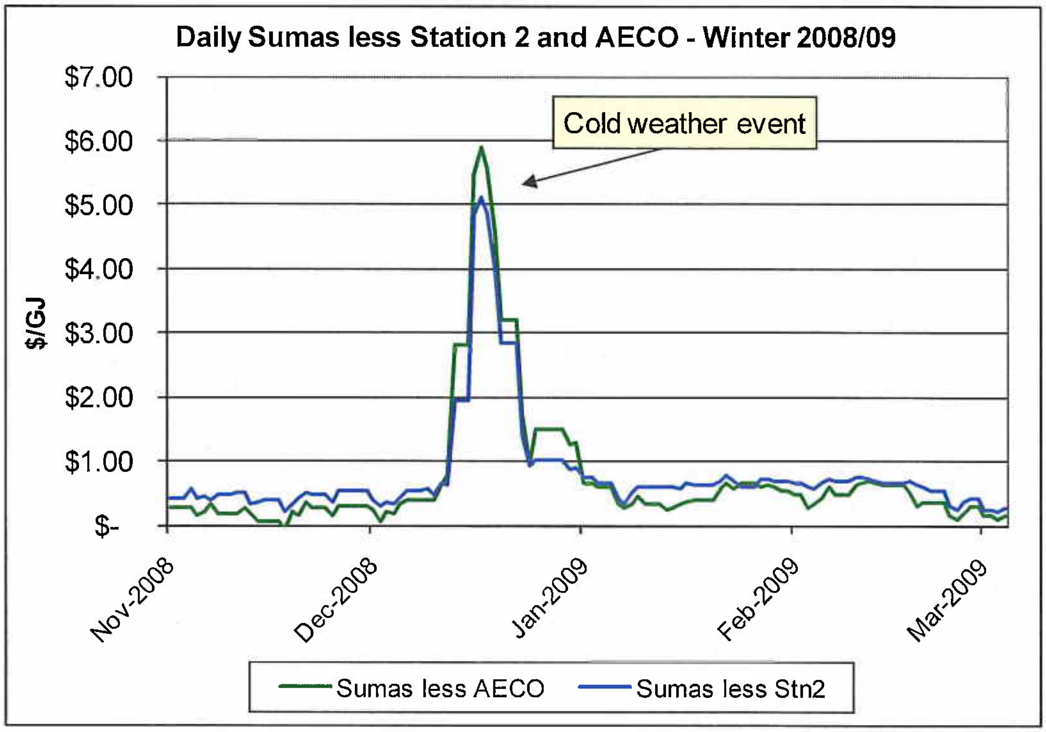


Figure 28: Sumas less Station 2 and AECO – Winter 2008/09



In managing Sumas price exposure, it is also important to understand how the monthly index is determined. The Sumas monthly index is established during the last five business days, or 'bid week', prior to the delivery month, compared to the AECO monthly index which is established during the entire month prior to the delivery month. As a result, cold weather spells and high demand periods in the Pacific Northwest region are more likely to adversely influence the Sumas monthly index and increase the probability of it separating from the AECO monthly index.

4.6.1 SUMAS-AECO BASIS SWAPS

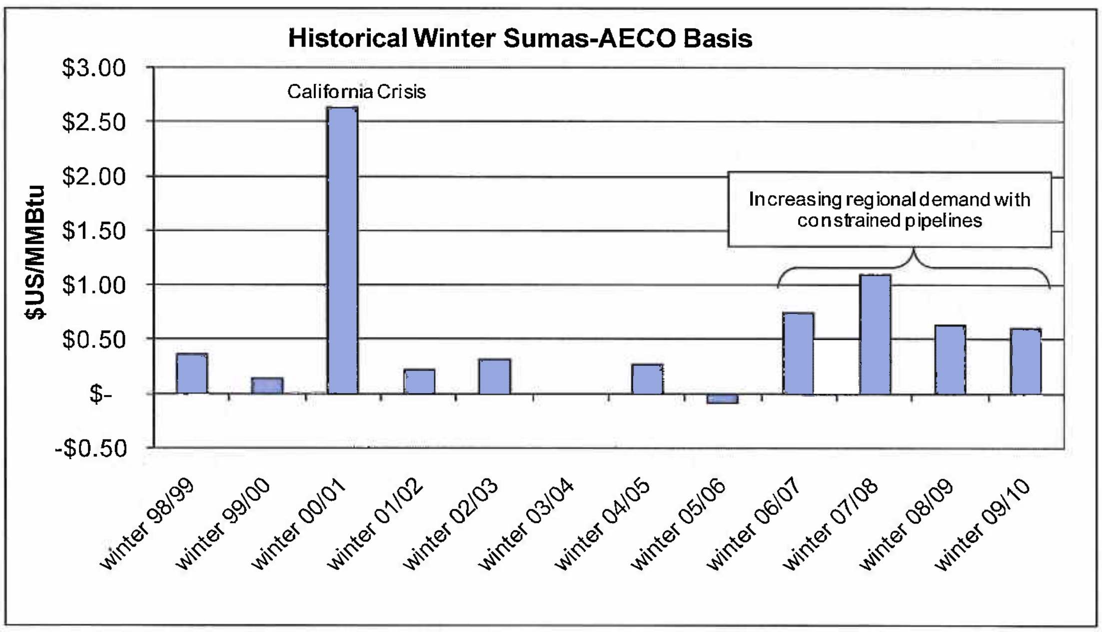
Terasen has historically used Sumas-AECO basis swaps to effectively manage this Sumas price exposure risk within the commodity and midstream portfolios. With a basis swap, the Sumas price exposure is converted to an AECO floating price plus a fixed Sumas-AECO price differential to remove the Sumas floating price risk. As shown in the following table, for the six seasons of winter 2000/01 and winter 2005/06 through winter 2009/10 in which TGI has used Sumas-AECO basis swaps, the net benefit to customers has been $8.8 million. Since regional pipeline capacity has not kept up with demand growth in recent years, Terasen believes there is greater potential than in the past for the Sumas basis to widen from AECO and Station 2 during high demand periods as the Sumas price increases to cover interruptible T-South transportation charges and draw gas away from Alberta. The basis hedging continues to provide protection against Sumas price disconnects from AECO in events of cold weather and high demand. Furthermore, basis hedging based off the AECO index also provides some price volatility reduction, as the AECO index is determined through the weighted average of trades during the entire month prior to the publication of the index as opposed to the Sumas index which is determined through the weighted average of trades occurring in only the five business days prior to the publication of the index.

Table 17: Value of TGI Sumas – AECO Basis Swaps

Term	Actual Basis ($US/MMBtu)	Terasen Gas Trades ($US/MMBtu)	Net Hedging Gain/(Cost) ($US/MMBtu)	Net Hedging Gain/(Cost) ($Cdn)
Winter 2000/01	$2.69	$0.27	$2.42	$11.2 million
Winter 2005/06	($0.10)	$0.31	($0.41)	($2.0) million
Winter 2006/07	$0.77	$0.46	$0.31	$2.7 million
Winter 2007/08	$1.13	$0.77	$0.36	$2.6 million
Winter 2008/09	$0.71	$1.28	($0.57)	($5.0) million
Winter 2009/10	$0.70	$0.80	($0.10)	($0.7) million
Weighted Average	**$0.71**	**$0.76**	**($0.04)**	**$8.8 million**

The following chart shows the recent increase in the Sumas-AECO basis for the winter period as regional pipeline capacity has not kept pace with growing demand in the Pacific Northwest region.

Figure 29: Historical Winter Sumas - AECO Basis



Since the Sumas price exposure in any given year can change based on contracted resources, including storage and other peaking supply, in the Annual Contracting Plan, the basis swaps for the Midstream account will be implemented within the twelve month window.

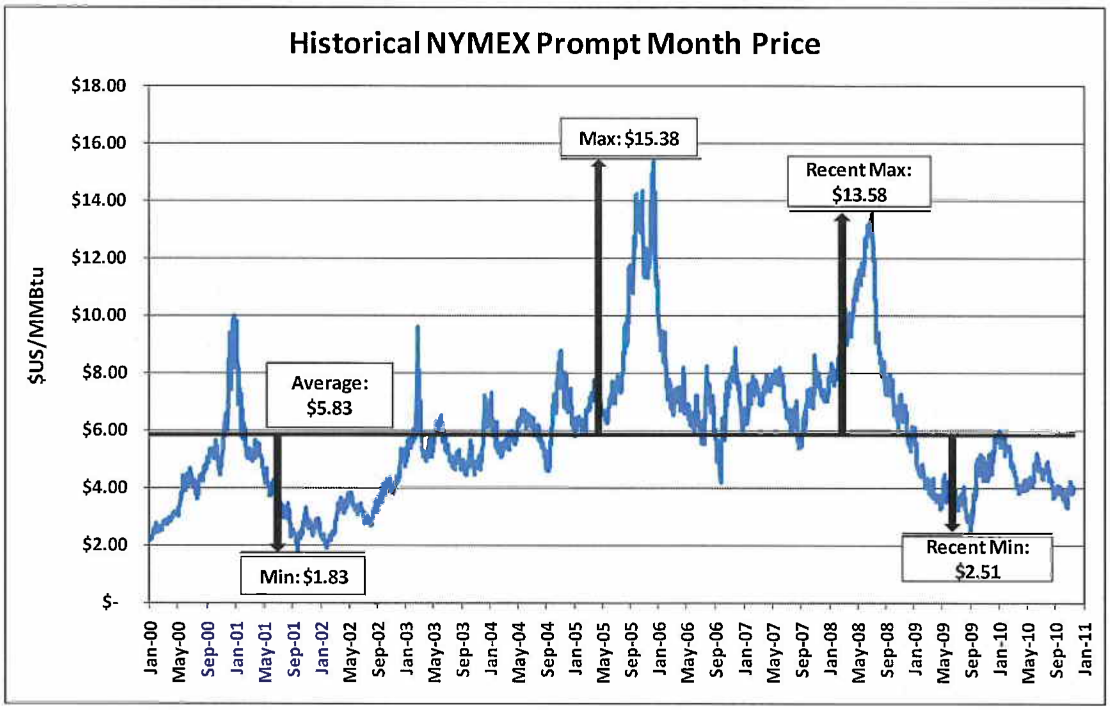
4.7 Reasonable Cost

Cost minimization is an important goal in maintaining cost effective and competitive rates for customers. For the ACP the primary objective is to contract for physical resources which ensure an appropriate balance of cost minimization, security, diversity and reliability of gas supply in order to meet core customer design peak day and annual requirements. Mitigation activity also helps in this regard, where the resale of excess gas, storage or transportation capacity lowers overall costs. As the ACP commodity supply is based on market index prices, an effective hedging program can fix a portion of this market based price in order to ensure reasonable, more stable and competitive natural gas commodity rates. Therefore, the ACP, physical mitigation activity and hedging program work together in managing security of supply at a reasonable cost for customers. However, it is important to recognize that achieving the lowest possible cost is not always possible when ensuring security and reliability of supply (as discussed within the 2010/11 ACP). For the PRMP, an underlying objective is to provide price risk management at a reasonable cost to customers. However, similar to the ACP, this objective must be balanced with maintaining competitive rates and reducing rate volatility for customers. It would be difficult for Terasen to incur no hedging costs each year while still managing competitiveness and volatility.

Hedging is frequently compared to the use of insurance to protect against uncertain events. For example, homeowners typically purchase home insurance to protect their home and belongings against unforeseen or uncertain events such as fires or earthquake. The insurance analogy is appropriate because it reflects the desire to protect against catastrophic events (or market price spikes) for a modest cost. Homeowners are willing to pay premiums each year for this protection and typically do not speculate regarding the timing of the adverse events and defer insurance protection to another year. Furthermore, homeowners are not likely to cancel insurance coverage if a catastrophic event has not occurred in the recent past – their concern is solely with the risk of exposure to future events. This insurance protection provides value to customers, giving them security and peace of mind. Ultimately, the hedging program should provide value for customers over the long run, yielding an appropriate balance of the benefit of risk mitigation with reasonable, acceptable cost for this protection.

With regard to the value of hedging, it is important to note that the variability of natural gas prices is not symmetric. Gas prices movements to the downside are typically limited at the extreme by zero but more likely somewhere near a level where production would be curtailed. Upside gas movements are less constrained (at least based on historical evidence) and price spikes above $10/GJ are not uncommon. In the past, price spikes have deviated further from the mean than price troughs, as illustrated in the following graph.

Figure 30: Historical NYMEX Prompt Month Price



While Terasen is not suggesting that prices will behave the same way in the future, the upside market price volatility in the past cannot be ignored. Terasen believes that it would be imprudent to leave customers exposed to these risks inherent in the natural gas marketplace without effective price risk management.

5 GAS COST DEFERRAL ACCOUNTS AND RECOVERY MECHANISMS

Gas cost deferral accounts and recovery mechanisms are commonly used by utilities to effectively manage the recovery of incurred gas costs from customers. While they do provide some degree of rate volatility reduction, as compared to market gas price movements, the mechanisms should not be considered a replacement for natural gas hedging in effectively managing market price risk. Gas cost deferral account mechanisms essentially collect the difference between forecast and incurred gas costs with the balances to be recovered from or refunded to customers at a later date through rates. In this way deferral accounts allow some rate stability by deferring the impact of commodity market volatility on gas costs. Hedging, on the other hand, mitigates the volatility in the incurred gas costs and therefore directly impacts the cost of gas rather than deferring some portion of over or under collected amounts. Therefore, hedging reduces market price risk as well as rate volatility. Given the price volatility inherent in the natural gas marketplace, this is an important distinction.

In its report, RiskCentrix makes similar observations regarding the effectiveness of deferral accounts to manage rate stability. RiskCentrix notes that a short duration deferral account adds modest stability when used in conjunction with an effective hedge program but it is inferior as a stand-alone approach in the mitigation of price risk. Furthermore, the risk of deferral accounting is that deferrals could accumulate to unsustainable levels resulting in the need to ultimately pass through more costs. RiskCentrix's findings and view regarding this matter are included on page 24 of its report, provided in Appendix A.

5.1 Gas Cost Deferral Account Balances

The gas cost deferral account recovery mechanism has evolved over time as the natural gas marketplace has changed. Prior to 1999, the gas cost recovery rates for TGI were established once per year, based on the forecast costs for the upcoming year and using a January 1st effective date. As a result of changing natural gas fundamentals, which increased market price volatility, TGI incurred much higher gas costs during 1999 and 2000 than forecast, and so mid-year increases to gas cost recovery rates were requested by TGI to reduce the significant under-recovery of gas costs. And, even with the mid-year gas cost recovery rate increases, the gas cost deferral account changed from a net surplus balance (gas cost recovery revenues exceeded gas costs incurred) to a net deficit balance (related costs exceeded gas cost recovery revenues) of approximately $180 million by the end of 2000.

Currently, TGI uses a quarterly rate adjustment review mechanism to effectively manage the deferral account balances from becoming too large, as well as providing appropriate price signals as the commodity rate charged to customers better reflects the current market price of natural gas. The TGI Commodity Cost Reconciliation Account ("CCRA") became effective April 1, 2004 and since that time deferral account balances, on a net of tax basis, have generally been within a ± $50 million range (with any exceptions noted to date being surplus balances). Significantly high balances above this level can impact TGI's financial borrowing capacity and ultimately its risk profile. The quarterly review and opportunity to adjust deferral account balances provides timely management of these balances to an appropriate amount. This is in the best interests of customers, in terms of rate volatility mitigation, price transparency and reduced intergenerational inequities and allows for prudent financial management by the Company.

5.2 TGI Current Rate Adjustment Mechanism

Currently, TGI reviews the CCRA rate on a quarterly basis and generally uses a CCRA rate adjustment mechanism with a 95% to 105% under/over recovery deadband on the rate change trigger ratio in determining whether or not a rate adjustment is required. TGI believes this mechanism has functioned appropriately to date and provides a balance of timely cost recovery, market price transparency for customers, intergenerational fairness, and deferral account balance management.

The Midstream Cost Reconciliation Account ("MCRA") contains the midstream costs which comprise a mixture of costs which are fixed in nature (related to storage and transportation demand charges) and those which are variable in nature (related to storage injections and withdrawals and seasonal commodity purchases and sales). Midstream cost recovery rates are also reviewed quarterly as part of the TGI quarterly gas cost reports filed with the Commission. However, under normal circumstances, the midstream rates (also referred to as the MCRA rates) are typically reset annually with a January 1st effective date.

5.3 CCRA & MCRA Deferral Accounts and Rate Setting Mechanisms Review

On June 15, 2010, the Commission issued Order No. G-106-10 with respect to the TGI 2010 Second Quarter Gas Cost Report and in its letter which accompanied that Order directed Commission staff to work with TGI to investigate the possibility of improving the MCRA forecasting capability, and to revalidate the methodology associated with the quarterly review of the CCRA costs and commodity rates. Following issuance of that directive, Commission staff and Terasen Gas held a number of discussions with respect to the CCRA and MCRA deferral accounts and rate setting mechanisms. As a result of those discussions, the following key areas were identified for Terasen Gas to conduct further analysis and review:

1. Commodity Price Forecasts – the forecast of natural gas commodity prices used in the determination of the gas cost forecasts for the quarterly review and resetting of rates.
2. CCRA Deferral Account and Rate Setting Mechanism – the effectiveness of the current 95% to 105% trigger ratio utilized to evaluate the appropriateness of the commodity cost recovery rate on a quarterly basis.
3. MCRA Deferral Account and Rate Setting Mechanism – the effectiveness of the current MCRA cost forecast and rate setting methodology, with a view to reducing rate volatility from year to year.

TGI anticipates submitting its Report on the CCRA and MCRA Deferral Accounts and Rate Setting Mechanisms (the "CCRA/MCRA Report") to the Commission in early 2011. TGI believes the results of its analysis and review will validate that the current CCRA and MCRA quarterly review and rate setting mechanisms, consistent with the Commission established Guidelines, have functioned appropriately up to now and continue to provide a strong base from which to build. TGI's CCRA/MCRA Report is expected to also propose minor changes to further improve the quarterly review and rate setting mechanisms, thereby benefiting customers through avoidance of unnecessary rate changes.

In conclusion, the quarterly rate review mechanism provides effective management of deferral balances and appropriate price signals for customers. While the deferral balances do offer some degree of rate volatility mitigation, this is limited and does not provide the same degree of price risk mitigation as an effective hedging program.

6 THE ROLE OF STORAGE

The effective use of storage is another tool used by natural gas utilities and Terasen to help manage price volatility and gas costs. Storage provides both operational and financial benefits and enables Terasen to achieve the Annual Contracting Plan objective of balancing supply reliability, portfolio diversity and cost minimization.

6.1 The Value of Storage

Storage, with associated transportation service, enables utilities to meet normal and peak winter demand and generally enables the use of lower priced summer gas for winter demand, effectively acting as a "natural hedge". Operational benefits can include imbalance protection (i.e. to meet third party pipeline daily or monthly volumetric balancing requirements), supply curtailment or disruption mitigation and balancing intra-day load variability. The primary financial benefit includes seasonal price protection (i.e. capturing the price differential between winter and the previous summer) which serves to protect customers from any adverse price movements in the winter period. The secondary financial benefit relates to taking advantage of shorter term price fluctuations. However, this seasonal price protection is somewhat limited due to the necessity to cycle most or all of the storage volumes on an annual basis to effectively meet load requirements and so does not provide the longer term (i.e. greater than single winter season) price protection like that of a hedging program. Furthermore, given importance of meeting customer load requirements during the winter and peak periods, capturing short term price fluctuations or price arbitrage opportunities are often secondary considerations. For example, selling storage volumes into the market at high prices during periods of low demand may be limited if a significant portion of the winter heating season still remains and storage inventory levels need to be maintained at specific levels for meeting potential future load requirements. Additionally, hedging enables Terasen to hedge summer period volumes, which can be subject to significant price volatility, due to hurricane disruptions (such as in 2005) or crude oil price spikes (such as in 2008), wherein storage enables capturing summer prices for winter demand but does not provide summer period price protection.

6.2 Storage and the Annual Contracting Plan

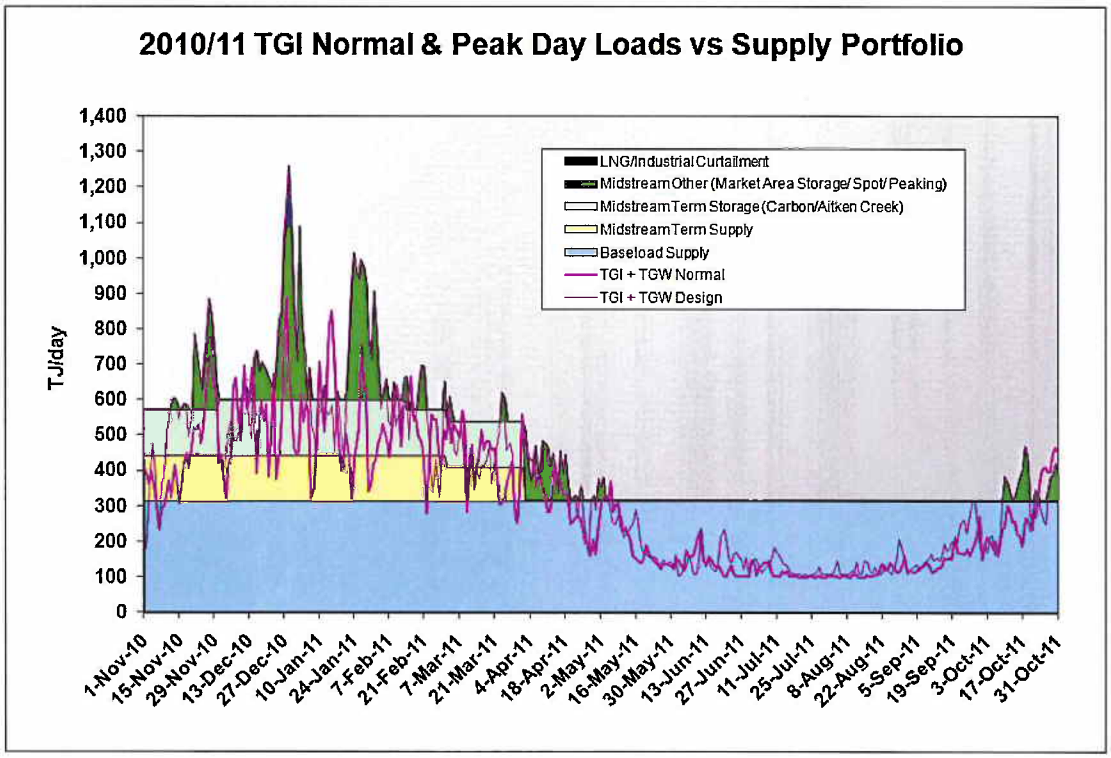
The Annual Contracting Plan ("ACP") for TGI and TGVI details the resources required to meet core customer loads. The objectives for the ACP are as follows:

1. To contract for resources which ensure an appropriate balance of cost minimization, security, diversity and reliability of gas supply in order to meet the core customer design peak day and annual requirements.

2. To develop a portfolio mix which incorporates flexibility in the contracting of resources based on short term and long term planning and evolving market dynamics.

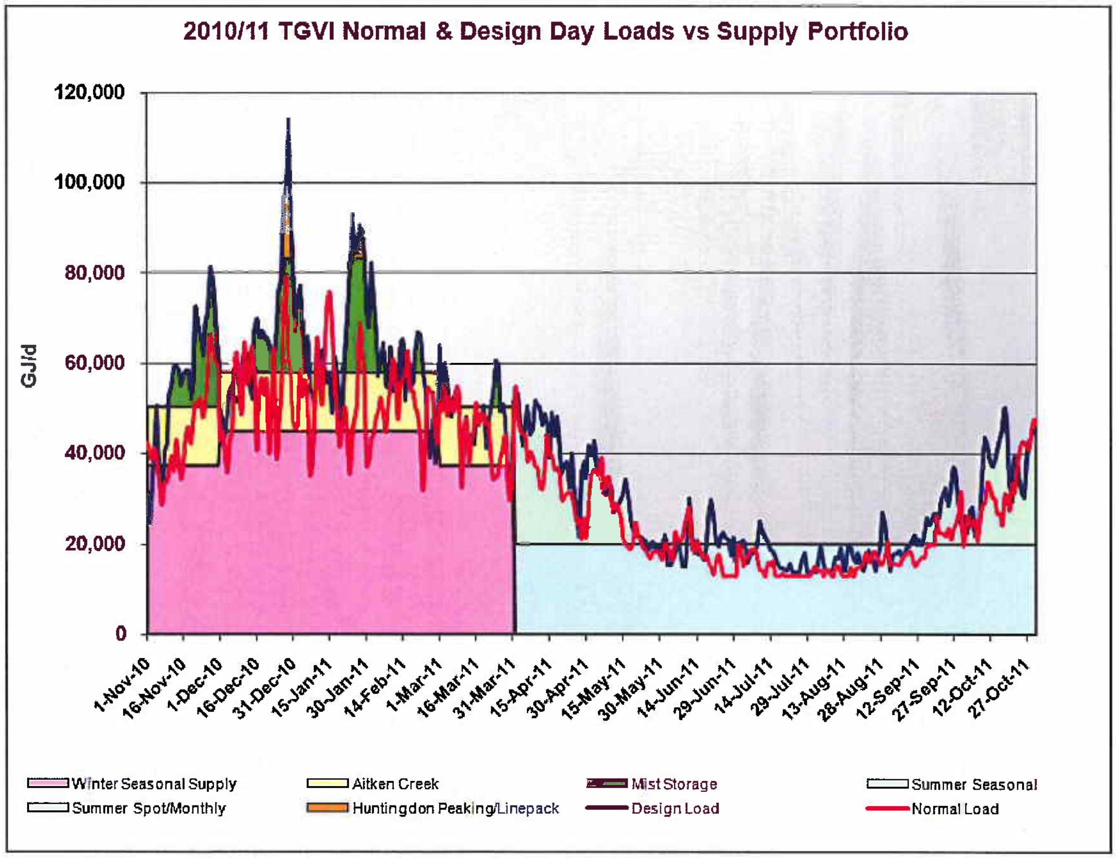
Storage plays an important role in meeting the objectives of the Annual Contracting Plan. As discussed, storage enables summer-priced supply to be withdrawn during the winter period and also provides Terasen with the ability to meet peak loads and the flexibility to manage load fluctuations. Rather than securing additional seasonal winter supply to meet above normal loads, Terasen will utilize storage resources to better shape resources to the load profile. This is more cost effective (by reducing the requirement to sell off excess supply at a possible loss and using summer priced gas) and also provides diversity in the portfolio. The following graph shows how the storage resources fit within the TGI portfolio, providing supply at the upper end of the load profile.

Figure 31: TGI Forecast Loads vs. Resource Portfolio



The following graph is for TGVI which uses Aitken Creek and MIST storage in a similar manner as TGI.

Figure 32: TGVI Forecast Loads vs. Resource Portfolio



By contracting for cost effective and reliable supply resources, including storage, Terasen also reduces the volatility of the midstream costs (including storage, transportation and commodity supply required for meeting winter demand) and improves its ability to compete with other sources of energy. The use of storage also reduces the portfolio exposure to regional price disconnections such as Sumas price spikes during periods of high regional demand.

6.3 TGI - Storage and the Essential Services Model

The Essential Services Model ("ESM") was established with the introduction of the TGI Commodity Unbundling Program in 2004 for commercial customers and extended to residential customers in 2007. Under commodity unbundling, residential and commercial customers can choose to purchase their commodity supply from TGI or at a fixed rate from a Marketer. Per the ESM, the Marketer delivers to TGI a quantity of gas based on a normalized forecast of the

Marketer's customers annual load requirements. This supply from the Marketers and the supply contracted directly by TGI constitute the commodity supply and related costs ("Commodity"). TGI is responsible for contracting and managing the midstream resources ("Midstream") for all customers which include transmission pipeline and storage capacity and provides balancing and peaking gas required to support annual load shaping. The costs for these resources are recovered from all customers regardless of whether they are supplied by a Marketer or TGI for their Commodity supply (other than those on industrial and large commercial transportation service). In the event of Marketer supply failure, TGI will act as the "Supplier of Last Resort", backstopping those customers with Commodity supply. TGI will also be responsible for longer term infrastructure planning and emergency response.

While the Annual Contracting Plan includes the planning and procurement of resources to meet normal and peak day load requirements, it is important to recognize that the Commodity and Midstream components are separate and distinct for rate purposes. As such, the use of storage serves to manage gas costs and rate volatility for the Midstream account only. Therefore, in the absence of storage, hedging market prices is the most effective way to manage quarterly rate volatility for the Commodity account for TGI.

6.4 TGVI - Storage and the Cost of Gas

TGVI operates under a different rate setting mechanism that TGI. In the past, TGVI customers have been largely protected from market price volatility through the Commission approved "soft-cap" rate design mechanism, which was designed to balance the objectives of long-term financial viability, revenue deficiency recovery (through reduction of the Revenue Deficiency Deferral Account ("RDDA") deficit balance), rate stability and continuity, adherence to cost of service principles, avoidance of undue customer rate impacts and observance of competitive forces. With the focus on maintaining competitive rates, this mechanism was designed to position TGVI residential rates near the electric equivalent rate on a variable basis. The continuation of the 2009 Core Market rates for 2010 and 2011 and the forecast surpluses to be captured in the Rate Stabilization Deferral Account ("RSDA") was agreed to in the TGVI 2010-2011 Revenue Requirements and Rate Design Application Negotiated Settlement and approved under Commission Order No. G-140-09, as a means of encouraging relative rate stability through the loss of the royalty revenues after 2011.

Without commodity unbundling and the separation of commodity and midstream costs like TGI, the cost of storage for TGVI is captured within the overall cost of gas account. While the continuation of the 2009 Core Market rates for 2010 and 2011 protect customers from market price volatility, it is critical that TGVI manage supply resource costs to maintain competitive rates and improve the ability to mitigate the potential for significant rate increases through the RSDA once the royalty revenue arrangement expires. The use of storage is critically important in this regard, providing operational flexibility and reducing exposure to winter prices.

TGVI anticipates filing its next Revenue Requirements Application for 2012-2013 in mid 2011. This will include a proposal to continue with the existing mechanism for 2012 in preparation for the proposed harmonization of rates for TGI and TGVI with amalgamation in 2013. Under this scenario in 2013, TGVI and TGI would have the same rate structure and rate setting mechanisms and include commodity unbundling for residential and commercial customers. Under this scenario, the benefits of storage in mitigating market price volatility would be limited to the Midstream account for both TGI and TGVI. Hedging would effectively mitigate market price risk and quarterly rate volatility for the Commodity account.

7 OVERVIEW OF RISKCENTRIX FINDINGS AND RECOMMENDATIONS

Through discussions with Commission staff regarding the review of the Terasen hedging program and objectives, it was determined that an external consultant with experience in natural gas hedging strategy could help in this regard. After reviewing the proposals of several consultants experienced with risk management, Terasen selected RiskCentrix as the most qualified candidate. RiskCentrix has extensive experience in designing and implementing commodity risk mitigation programs for natural gas and electric utilities. RiskCentrix also has strong analytical capabilities, promoting a focus on metrics-based hedging decision rules to constrain outcomes within certain specifications. RiskCentrix also believes that a hedging program should include appropriate objectives and take into consideration strategies that are responsive in different market price environments.

RiskCentrix reviewed both Terasen's price risk management objectives and existing hedging program. RiskCentrix determined that the objectives were appropriate and consistent with many other utilities and that the existing hedging program was consistent in many ways with the strategies used by other utilities to meet these objectives. RiskCentrix then looked at ways the hedging program could be improved in order to continue meeting the objectives and provide a greater focus on cost effectiveness. Their findings and recommendations are summarized in the next section and are consistent with the RiskCentrix discussions and presentation to Commission staff on November 17, 2010. The report prepared by RiskCentrix is included in Appendix A.

7.1 RiskCentrix Findings and Recommendations

The following provides a summary of RiskCentrix's findings and recommendations regarding Terasen's price risk management objectives and strategy. These form the basis for TGI's recommended hedging strategy going forward as discussed in Section 8.

7.1.1 PRICE RISK MANAGEMENT OBJECTIVES

RiskCentrix confirms that Terasen's objectives of mitigating market price volatility and maintaining competitiveness are appropriate given Terasen's competitive position and market price environment. While market prices are currently depressed, RiskCentrix believes that this does not eliminate price risk in the future and so appropriate strategies are important to quantify and mitigate this potential risk. RiskCentrix states that it is important to distinguish between "market view" and "risk view" when determining the appropriateness of hedging[29]. The market view relates to the perception of whether or not market prices are undervalued, overvalued or

[29] RiskCentrix Findings and Recommendations Regarding Energy Risk Mitigation Program Prepared For Terasen Gas, December 27, 2010, Page 9.

fairly valued. However, the risk view focuses on uncertainty, comparing price potentialities to objectives tolerances, and it is appropriate in the development of effective hedging strategies. Objectives, and success metrics, must balance three competing tolerances:

- Customer bill increase tolerance;
- Out-of-market tolerance; and
- Option expenditure tolerance.

Balancing these tolerances provides appropriate cost/benefit value for customers and ensures Terasen meets its objectives.

7.1.2 RECOMMENDED HEDGING STRATEGY

The RiskCentrix recommended hedging strategy includes several key elements to successfully meet the objectives. These include:

- Programmatic hedging for scheduled volatility reduction;
- Defensive hedging to respond to potential increases in prices above specific tolerances;
- Value hedging to capture favourable price opportunities; and
- Basis swaps for managing Sumas price exposure.

RiskCentrix recommends a monitor-and-respond mode of risk mitigation, rather than a primarily programmatic hedging implementation. This allows effective mitigation of rate increases for customers while also reducing the potential for intolerable hedging costs.

RiskCentrix tested its hedging strategy against some representative simulated market price paths in order to determine the effectiveness of the strategy. These price paths included both high and low market price movements and periods of high price volatility. This helps to ensure that the recommended strategy meets the objectives in various price environments with a high degree of probability.

The specific refinements to TGI's hedging strategy as recommended by RiskCentrix are summarized as follows:

a) Reduce Programmatic Accumulation - the proportion of hedges accumulated programmatically could be reduced from a target of about 50% of hedgeable volumes to 25%; this would constrain potential out-of-market settlements compared to current practice.

b) Add Defensive Hedge Rules - Begin monitoring the potential for price migration of TGI's natural gas portfolio and set interim tolerances for defensive hedge responses. By deploying Value at Risk ("VaR") metrics, Terasen could delay hedge decisions until necessary, avoiding some risk of loss in down markets.

c) Add Value-Screening Criteria – Terasen currently deploys price targets for accelerated or incremental hedge accumulation. Those targets are determined based on current CCRA rates but could also include consideration of competitive benchmarks. Some form of risk/reward measure can help mitigate the potential for unfavorable settlements. The recommended value-screening criteria measures the degree of contango shape of the forward price curve and then provides an assessment of the risk/reward tradeoff attributable to incremental hedge commitments.

d) Call options could be deployed to a greater extent to draw a better balance between bill increase mitigation and out-of-market settlement potential. Because investment in option premiums is intended to acquire upside cost mitigation without the hedge loss potential associated with fixed price instruments, they are recommended in conjunction with defensive hedge rules. Also, since premiums increase with tenor, options should be deployed in the last year or two prior to settlement.

Each of the recommended elements will now be discussed in further detail. The details regarding the hedging implementation schedule and specific defensive hedging targets are included in the TGI 2011-2014 Price Risk Management Plan.

7.1.2.1 Programmatic Hedging

RiskCentrix recommends some programmatic hedging, although less than Terasen has used in the past. Programmatic hedging is that which is implemented on a regular basis according to a predefined schedule. RiskCentrix recommends hedging 25% or less of the CCRA winter and summer hedgeable volumes programmatically. In the past, Terasen has hedged 60% and 45% of the winter and summer hedgeable volumes, respectively, according to a predefined schedule, subject to accelerated hedging increments of 5% of the hedgeable volumes if specific price targets were reached. Less programmatic hedging reduces the possibility of out-of-the-money outcomes while still providing some base amount of market price volatility reduction. Terasen believes that programmatic hedging of 25% is appropriate based in these considerations. The programmatic hedges would be implemented with fixed price swaps. The implementation schedule would extend out for three years and volumes would be accumulated in equal increments in each hedging window. This is consistent with TGI's past hedging horizon. The maximum volume that could be hedged, which includes any programmatic, defensive and value hedging, would be 60% of the hedgeable volumes for each of the summer and winter periods being hedged.

7.1.2.2 Defensive Hedging

Defensive hedges are used to respond to potential high prices by monitoring the VaR of the commodity portfolio. If potential price movements could increase costs above predefined tolerance levels related to the hedging objectives, then defensive hedges would be executed. If there is no risk of exceeding tolerances, then no defensive hedges would be necessary. This monitoring of potential forward price movements would occur on a weekly basis and the VaR evaluated for a forward looking ten day holding period. This holding period is reflective of the time window in which TGI would implement the defensive hedges or not. The potential price movements are based on a 95% probability (representative of two standard deviations), meant to capture the majority of potential price movements.

RiskCentrix uses a driving analogy to illustrate the monitor and respond approach to defensive hedging: "Better results can usually be attained by managing risk in smaller time increments – weekly for example - and making smaller hedge adjustments along the way. A crude but meaningful analogy would contrast the choice of fixing the steering wheel position of an automobile and watching where it goes for 52 seconds versus looking through the windshield every second, assessing the risk, and making small adjustments along the way."[30]

RiskCentrix explains that the monitor and respond approach provides the following advantages:

- A smaller volume of initial hedges is appropriate because the monitor and respond framework allows numerous adjustments;
- Sometimes the market will fall and fewer hedges will be a good thing;
- If properly monitored, there is almost always ample time to hedge defensively when market volatility rises;
- Diversity of commitments over time reduces the chances of a big mistake; and
- All other things equal, shorter tenor provides lower risk of losses.

The tolerance targets for this defensive hedging could be related to the objectives and predefined with several tiers. For example, the first defensive price target could be reflective of the maximum tolerable bill increase related to customers' preferences. The remaining two defensive price targets could be based on the electric equivalent benchmarks as determined in Section 4. Predefined hedgeable volume percentages would be assigned to each of the targets and the maximum hedged volume of 60% of the hedgeable volumes, which includes programmatic, defensive and value hedges, would not be exceeded.

The defensive hedging strategy uses more options than in past TGI hedging programs as these instruments provide effective upside cost mitigation while also reducing the potential out-of-the-money outcomes. The options would be limited to a maximum of 25% of the hedgeable volumes.

[30] RiskCentrix Findings and Recommendations Regarding Energy Risk Mitigation Program Prepared For Terasen Gas, December 27, 2010, Page 12.

7.1.2.3 Value Hedging

Value hedging is used to capture favourable pricing opportunities that help meet the objectives. This is similar to the accelerated or incremental hedging that TGI has used in the past. The targets for this hedging strategy would be based on consideration of current and past CCRA rates, forward market prices and competitive benchmarks. RiskCentrix recommends adding screening criteria based on the shape of the forward price curve. The value hedges should only be implemented if the forward price curve is in contango, or where forward prices increase as one looks further out in time. This is because backwardated prices, or those where future prices decrease as one looks further out in time, are consistent with near-term scarcity of supply, surplus demand, or speculative fervor whereas contango markets are the opposite, reflecting excess gas supply or weak demand. Value hedging should be executed in small increments rather than large lumps in order to avoid the risk that prices continue to decline. These hedges would be implanted with fixed price swaps.

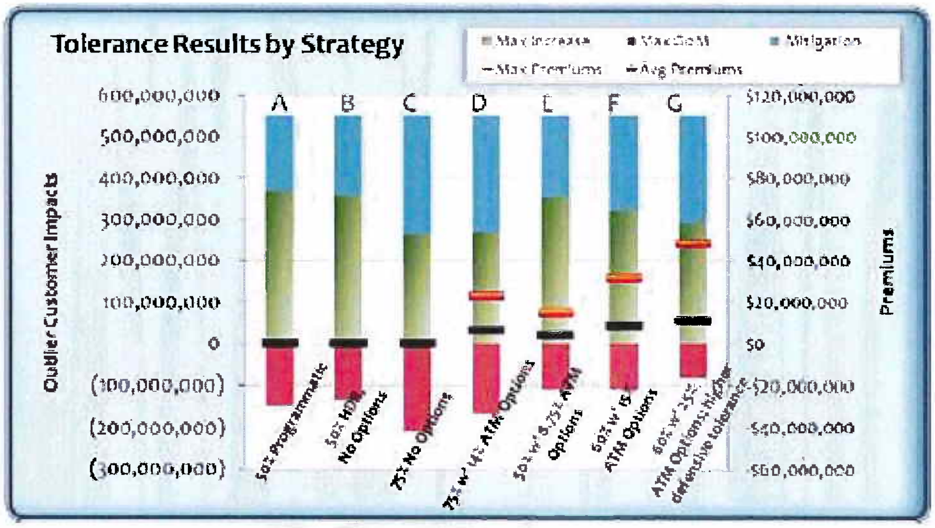
7.1.2.4 Basis Swaps

RiskCentrix recommends that TGI continue with implementing Sumas-AECO basis swaps to manage winter Sumas price exposure. With these instruments, the differential, or basis, between Sumas and AECO is fixed so that Sumas price disconnections from other market prices are mitigated. As discussed in Section 4.6, these price disconnections occur frequently when winter demand increases. These basis swaps would be implemented gradually within twelve months of the winter period being hedged. This allows for consideration of any changes in the physical resource portfolio as defined by the Annual Contracting Plan and the fact that the price disconnections only occur due to high winter demand conditions. While the basis swaps provide protection against Sumas price spikes, they also enable downward price participation in periods of overall declining prices as the AECO index portion of the instrument is not fixed. The basis swaps would be used for Sumas exposure within the commodity and midstream portfolios.

7.1.3 RISKCENTRIX ANALYSIS AND RESULTS

RiskCentrix performed analysis with respect to several different hedging strategies under several different representative market price scenarios (including high, low and mid level prices) to determine the overall effectiveness of each strategy in meeting the objectives. The results are discussed on page 21 of the RiskCentrix report in Appendix A. This analysis was necessary to validate the recommended strategy and derive the best value for customers. The results for each strategy are shown in the following figure. The table shows, for each strategy, the attainable tolerances against the unmitigated customer bill increases at the top of each bar in the graph. The price environments underlying this chart included rising prices up to $20/GJ in high cases and falling below $1.00/GJ in low ones. Strategy G, including 25% programmatic and 25% maximum defensive options hedging with a maximum overall target of 60% of hedgeable volumes, provides the most overall cost mitigation with the lowest potential amount of out-of-market outcomes. As such, TGI is recommending this strategy for its Price Risk Management Plan.

Table 18: Hedging Strategy Scenario Results



Note: "OoM" refers to out-of-market hedging costs; "ATM" refers to at-the-money call options (i.e. strike price of calls is equal to forward prices); "Mitigation" refers to reduction in bill increases due to hedging.

Terasen has incorporated these RiskCentrix findings and recommendations into the TGI recommended hedging strategy and implementation, which is discussed in the following section.

8 TGI – HEDGING STRATEGY AND IMPLEMENTATION

TGI has used RiskCentrix findings and recommendations within its proposed hedging strategy and implementation. An overview is provided here and the details are provided in the TGI 2011-2014 Price Risk Management Plan which has been filed concurrently with this review report.

8.1 Programmatic Hedging

The recommended implementation schedule for the programmatic hedging is presented below. The hedges are implemented equally in each monthly hedging window until 25% of the hedgeable volume target is reached. The schedule includes consideration of hedges that have already been implemented and so for some terms no further programmatic hedging is required. The hedges are implemented in equal increments in each hedging window to provide price diversity and reduce the risk of hedging a large or more significant volume when prices are high, relative to recent historical averages. The schedule extends out three years from the upcoming winter starting November 1, 2011.

[redacted]

The schedule takes into consideration volumes that have already been hedged under the previous Price Risk Management Plan, as noted for summer 2011, winter 2011/12 and summer 2012.

8.2 Defensive Hedging

The defensive hedging volumes for each price trigger for each term being hedged are presented in the following table (as a percentage of hedgeable volumes).

Table 19: Defensive Price Triggers and Volumes

	Price Trigger ($/GJ)	Cumulative Maximum
Programmatic	[redacted]	25%
Tier 1		35%
Tier 2		50%
Tier 3		60%

The defensive price targets are based on customers' tolerable bill preferences as well as electric equivalent commodity component benchmarks (as discussed in Section 4). The customer survey of 2005 indicated that, on average, residential customers could tolerate annual bill increases of 16%. [redacted] The remaining tier price targets are based on the electric equivalent benchmarks based on 100% and 50% of the projected BC Hydro rate increases. If 100% of the projected electricity rate increases are approved, TGI would be competitively challenged in hot water heating application for new or retrofit customers if market prices moved above the $5/GJ to $8/GJ range from 2011 to 2014. If only 50% of the projected electricity rate increases are approved, then TGI would be challenged with respect to space heating for new or retrofit customers if commodity prices moved above about $6/GJ to $8/GJ from 2011 to 2014. Furthermore, for existing hot water customers, TGI is challenged for those customers where the Step 1 comparison is applicable if market prices move above $7/GJ to $8/GJ from 2011 to 2014. Therefore, TGI has based the tier 2 and tier 3 defensive price targets on consideration of these benchmarks.

These defensive hedges would be implemented with options and fixed price swaps. The maximum options percentage would be 25% of the hedgeable volumes. It is recommended that call options with deferred premiums be used as they provide greater downside price participation than costless collars. The defensive hedges would be implemented within two years of the term being hedged allowing for a gradual ramping into defensive posture.

8.3 Value Hedging

The value hedging would be implemented if a specific predefined price target was reached. TGI believes that this target should take into consideration historical commodity rates as well as competitive benchmarks. TGI's lowest commodity rate since the inception of the CCRA rate in 2004 is the $4.568/GJ rate effective January 1, 2011. Since 2004, the TGI CCRA rate has average about $7.00/GJ and been as high as $9.78/GJ set in July 2008. As such, TGI believes that a value hedging target below the $4.50/GJ level would help maintain historically low commodity rates and provide good value for customers. Furthermore, TGI is competitively challenged for new or retrofit hot water heating customers where the Step 1 rate is applicable. If 50% of the BC Hydro projected rate increases are approved, this benchmark target is near $4.00/GJ to $4.50/GJ from 2011 to 2014. [redacted] By layering in the value hedges in small increments, TGI captures more downside market price movement if prices continue to decline thus avoiding greater accumulation of out-of-market costs.

8.4 Sumas Basis Swaps

As discussed, the Sumas price exposure within both the commodity and midstream portfolios would be hedged with Sumas-AECO basis swaps within the twelve month window, consistent with past practice.

8.5 Summary

RiskCentrix recommends that the Terasen objectives of mitigating market price volatility and ensuring competitiveness at a reasonable cost continue to be relevant and appropriate. Refinements to the past hedging strategy including less programmatic hedging with a monitor and respond approach will help ensure the objectives continue to be met and the most value is provided for customers.

Terasen supports Riskcentrix's findings and recommendations and believes the enhanced strategy will meet the objectives and reduce the risk of out-of-the-money hedging costs.

9 CREDIT RISK MANAGEMENT

Terasen does not expect its effective management of counterparty credit risk to change with this recommended hedging strategy. Terasen continues to be conservative in its approach to managing credit and will continue to act prudently regardless of the hedging implementation or strategy in order to limit credit risk and manage costs on behalf of its customers.

9.1 Counterparty Credit Risk

An important component of a price risk management program is to prudently and effectively manage counterparty credit exposure. Reducing future price uncertainty risk can also increase other risks, such as credit exposure to counterparties. In order to manage this credit exposure, Terasen has numerous policies, procedures and controls in place, while approval procedures and signing authority levels for gas price hedging reduce the potential for imprudent trades. These policies and procedures are also subject to annual internal and quarterly external audits to confirm they are updated and approved. Hedge accounting documentation, mark-to-market data, and invoice settlements are also audited to ensure prudent reporting of financial information.

Terasen's current list of counterparties includes entities that are A-rated or better. In order to manage the risk of credit default related to longer term hedging, Terasen is continuing to limit transactions beyond eighteen months out to AA-rated counterparties and "A Schedule 1" rated banks only. Terasen's current number of counterparties totals ten with a total credit limit of about $0.8 billion.

Consistent with the recommended hedging strategy, an increased use of options would allow Terasen to reduce counterparty credit exposure, all else being equal. This is because of the premium associated with call options. If market prices exceed the call option strike price, then the counterparty owes Terasen this difference less the premium that Terasen owes. If market prices stay below the strike price, then there is no counterparty credit exposure.

9.2 Reporting

TGI proposes to continue to submit, on a monthly and quarterly basis, reports regarding hedging transactions in order to inform the Commission of financial transactions in a timely fashion and to confirm that the Price Risk Management Plan is being implemented within the guidelines presented and approved by the Commission. These reports include the monthly Credit Exposure, Hedging Position and Detailed Hedge Transactions reports and the quarterly report regarding mark-to-market position, showing hedging gains and costs by month and instruments for the past two years.

In addition to this reporting, Terasen anticipates enhancing the reporting to better convey the hedging results in terms of achieving the objectives of maintaining competiveness, managing price volatility and mitigating price disconnects. .

10 SUMMARY AND RECOMMENDATIONS

Terasen recognizes that the natural gas marketplace has undergone some significant changes in recent years. At the current time, the rapid development of unconventional gas production and weakened demand has resulted in an abundance of natural gas supply and depressed prices relative to recent historical values. However, changes in supply and demand factors going forward can significantly alter the supply and demand balance in the future and higher prices and volatility may occur. Recovery of gas demand following the recession, decreased gas production growth due to lower prices and increased demand for power generation are examples of near term driving factors. Weather events or supply infrastructure disruptions are examples of more immediate factors. The risk of prices and volatility increasing in the future cannot be ignored and it is Terasen's belief that prudent management of this price risk is in the best interests of customers.

Therefore, Terasen continues to believe that its price risk management objectives are appropriate. Improving the ability to maintain competitiveness with other sources of energy in the near term and reducing the impacts of market price volatility is in the best interests of all energy consumers within B.C.

The enhanced hedging strategy as recommended by RiskCentrix will help Terasen meet these objectives. The monitor and respond approach effectively manages rate volatility and competitiveness while value hedging and less programmatic hedging reduces the potential for significant hedging costs.

Based on these conclusions, TGI is concurrently submitting a new 2011-2014 Price Risk Management Plan that includes the recommended hedging strategy of RiskCentrix. Approval of this plan will ensure that TGI provides the best value for natural gas customers in terms of cost effective, relatively stable and competitive rates.

Appendix A

RISKCENTRIX FINDINGS AND RECOMMENDATIONS REPORT

RiskCentrix, LLC

Clarity in a World of Uncertainty

~~CONFIDENTIAL~~

Findings and Recommendations Regarding
Energy Risk Mitigation Program

Prepared for Terasen Gas

December 27, 2010

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Introduction

This report and the studies underlying it were commissioned by Terasen Gas ("Terasen") and conducted by RiskCentrix for the purpose of reviewing and then recommending refinements to Terasen's natural gas risk mitigation program. It is consistent with RiskCentrix presentation materials discussed on November 17, 2010 with representatives of the British Columbia Utilities Commission; Terasen and RiskCentrix representatives attended those discussions.

Executive Summary, Findings and Recommendations

Studies were undertaken to assess objectives and strategies; recommend refinements; and provide tools for implementation in accordance with the following framework:

1. Assess Terasen's Risk Mitigation Objectives
    a) Quantify risk;
    b) View objectives in light of quantified risk;
    c) View regulatory feedback in light of quantified risk;
    d) Recommend refinements to objectives consistent with item 2-c below.
2. Recommend Strategies Commensurate with Refined Objectives
    a) Postulate strategies in the form of Hedging Decision Rules ("HDR");
    b) Test HDR results against simulated future price scenarios;
    c) Recommend viable hedging decision rules consistent with item 1-d above
3. Provide Excel-based tools for implementation

Note that *quantified* objectives could only be validated in light of feasible strategies, and viable strategies could only be validated in light of acceptable objectives, so items 1-d and 2-c represented an iterative process.

The review and studies were performed only with respect to Terasen's portfolio under the Commodity Cost Reconciliation Account ("CCRA") , excluding supply provided by Marketers under the commodity unbundling program. RiskCentrix did not assess Terasen's midstream portfolio or costs related to physical storage, transportation and seasonal or peaking resources. While the Midstream charge is subject to some degree of market price volatility, it is significantly less than that related to the Commodity rate.

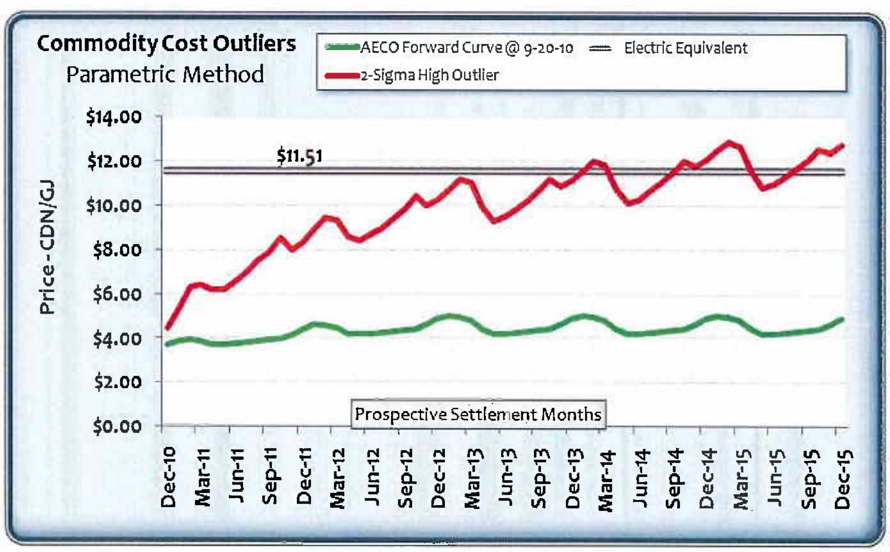
The numerous findings and recommendations contained here are complex, and nuances are critical to their understanding. Each finding and recommendation will be discussed in some detail later, but for the purpose of organizing a roadmap for the reader, they are listed here in outline form.

Key findings include the following:

As to Objectives

1) Qualitatively, objectives appear appropriate in light of Terasen's position and market realities. The net reduction of volatility is typical of utility risk programs, and more specifically, the competitiveness objective appears appropriate in light of Terasen's filed variable electricity proxy price. Terasen is currently reviewing its electric equivalent benchmark targets to provide segmentation with respect to energy applications and consideration of capital cost differentials as well. Results of that review were not available to RiskCentrix at the time of these studies, but inclusion of capital cost differentials and a broader sampling of applications could extend the competitive benchmark to lower prices. Details will be provided in a Terasen report regarding its price risk management objectives for the next Price Risk Management Plan.

   RiskCentrix worked with the electricity benchmark filed in the original PRMP. Beginning with current gas prices and measured AECO volatility, RiskCentrix constructed a price risk envelope at 95% confidence. The electricity proxy price, as filed in the original PRMP, fell within that envelope about three years into the hedge horizon as shown below.



2) Objectives could be stated with greater specificity, and thereby drive hedge decisions more directly. Specifying objectives quantitatively, at a 95% confidence level, [1] would impose discipline as to the choices that are necessarily implicit in balancing three competing tolerances - cost increases, out of market outcomes, and options expenditures.

   The studies conducted here sought to quantify attainable objectives by assessing simulated results of hedge strategies against postulated price environments, including stress conditions where unmitigated average bills could rise by 42% year over year. The various price environments used for assessments encompassed AECO hub market prices at $20/GJ highs and $1/GJ lows. Results indicate that one set of quantified objectives could consist of the following market-compatible tolerances under those stress conditions:

A.	Outlier average bill increase, exceeding 2 sigma: [2]		23% over prior year bill
B.	Outlier out-of-market outcome, exceeding 2 sigma:		10% of unhedged bill
C.	Options expenditures	Average year:	$ 11 million
		Outlier, >2-sigma:	$ 48 million

As to Strategy

3) Terasen's current strategy includes programmatic and accelerated/incremental hedge rules, as well as contingent rules dealing with the avoidance of noncompetitive hedge accumulation. This structure, with certain refinements and the addition of defensive hedge rules, is consistent with the ultimate recommendations contained here.

4) Basis hedging is conducted in a way that mitigates exposure to seasonal spot volatilities at Sumas. This is consistent with practices adopted by most robust hedge programs and should be continued.

5) Terasen's strategy could be refined by limiting programmatic accumulation, adding defensive hedge rules, and adding value-screening criteria to accelerated/incremental hedges. The framework of multi-part Hedging Decision Rules is a proven one, while the specific design metrics (programmatic maximum, defensive tolerances and hedge levels, value criteria, etc.)

[1] Because risk mitigation programs are primarily focused on the mitigation of intolerable outcomes ("outliers"), we will discuss outliers extensively. Throughout this document the phrase "95% confidence" or "2-sigma" will be used to delineate outlier probabilities. For clarity, the term 2-sigma defines a condition where 95% of the probability distribution is contained within the 2-sigma envelope, and 5% falls outside of it - half to the top and half to the bottom of the probability distribution. We are often concerned with only one side of the probability distribution, like high prices and not low prices; in those cases 2-sigma outliers describe a 2.5% probability (one out of forty outcomes). See the graphic labeled A2, Figure 2 in Appendix 2.

[2] Stress conditions were generated via Monte Carlo simulation and then price paths exceeding 2-sigma conditions were selected for the testing of hedge decision rules and the assessment of tolerances.

have been tested here and are proposed as a starting point, subject to refinement as management completes its own assessments. Design metrics would be subject to management's judgment from time to time; it is envisioned that Terasen's Price Risk Management Committee would review such design choices annually or more frequently as conditions may dictate. RiskCentrix has tested the following:

a) Reduce Programmatic Accumulation - the proportion of hedges accumulated programmatically could be reduced from 50% of hedgeable volumes to 25%; this would constrain potential out-of-market settlements compared to current practice;

b) Add Defensive Hedge Rules - Begin monitoring the potential for price migration of Terasen's natural gas portfolio and set cascading tolerances for defensive hedge responses. By deploying Value at Risk ("VaR") metrics, described in detail later, Terasen could delay hedge decisions until necessary, avoiding some risk of loss in down markets.

c) Add Value-Screening Criteria – Terasen currently deploys price targets for accelerated or incremental hedge accumulation. Those targets are determined based on fundamental inputs including competitive benchmarks. Constrained "Value Hedging" is appropriate to utility hedge programs; yet some form of risk/reward measure can help mitigate the potential for unfavorable settlements. The problem is that perceptions of value tend to be distorted by the most recent market activity. For example, following a $12/GJ price spike (2005 or 2008), $8/GJ prices may have appeared attractive; hedges executed under such circumstances can often produce large out-of-market settlements. The recommended value-screening criteria will be discussed in some detail; it measures the degree of contango shape[3] of the forward price curve and then provides an assessment of the risk/reward tradeoff attributable to incremental hedge commitments.

6) Call options could be deployed to a greater extent to draw a better balance between bill increase mitigation and out-of-market settlement potential. Because investment in option premiums is intended to acquire upside cost mitigation without the hedge loss potential associated with fixed-price instruments, they are recommended in conjunction with defensive hedge rules. Also, since premiums increase with tenor,[4] options should be deployed in the last year or two prior to settlement. The strategy recommendations discussed later include the

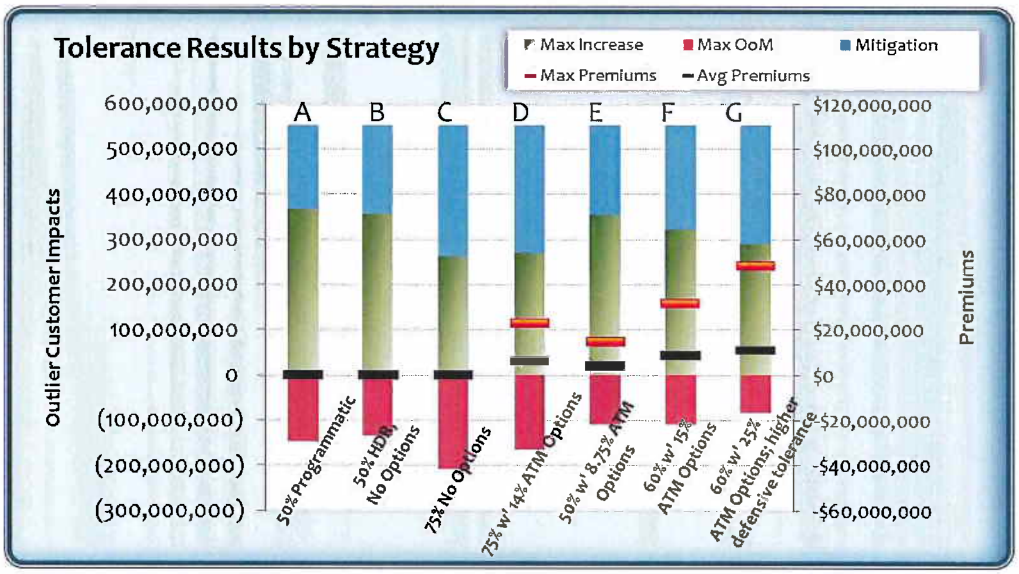
[3] Contango price curves are characterized by lower near-term prices compared to longer-term prices. Gas price curves typically cycle from contango to backwardated (higher near-term prices), and hedge commitments in backwardated markets carry greater risk as hedges may settle in dramatically lower (contango) markets later.

[4] The word "tenor" means the time horizon or term of the hedge contract

use of at-the-money call options as part of the defensive hedge strategy up to 25% of hedgeable volumes, although higher proportions could be deployed depending on the appetite for premium expenditures.

Strategy evaluations were conducted and their associated attainable tolerances assessed. The discussion entitled "Analytical Results" includes a more detailed description of the strategies and the stress conditions used for the assessment, but Figure 11, excerpted from that discussion presents a summary.

Figure 11, Strategy Assessment Results



It shows, for each strategy, the attainable tolerances against the unmitigated customer bill increase at the top of each bar in the graph. Price environments underlying this chart included rising prices up to $20/GJ in high cases and falling below $1.00/GJ in low ones.

Note that all options premiums are also included in the cost and out of market metrics, so there is no need to add them separately.

Looking at the results beginning from the left, unmitigated customer bills[5] would rise by $552 million in the unmitigated high price case, while a 50% programmatic program would mitigate that to about a $366 million increase; out of market outcomes could grow to $147 million in a severe market collapse akin to the collapse beginning in the later half of 2008. Column B indicates that adding defensive hedges would reduce the mitigated outcome to $355 million, a $10 million

[5] In all cases where bill changes are shown, non-commodity costs related to TGI fixed basic, delivery and midstream charges were assumed to be $6.37/GJ (based on rates effective October 1, 2010).

improvement; stress case out of market outcomes also improve by $12 million to $135 million. As expected, Column C indicates that a greater maximum hedge ratio improves mitigation but also risks greater out of market outcomes.

Call options produce the expected results. Column D shows that out of market settlements can be mitigated while retaining the mitigation benefits of the 75% hedge ratio. Column E may be attractive; it shows better mitigation and smaller loss potential than A or B. Finally Column F draws a balance, seeking a small loss potential with better than average mitigation effects, while Column G takes the concept a step further with greater options expenditures and looser defensive boundaries to further constrain out of market outcomes. If options expenditures are acceptable, these strategies (F & G) provide a good balance of customer bill mitigation and out of market mitigation, potentially yielding the best value for customers.

RiskCentrix would recommend strategies toward the right of the graph for their greater mitigation and lower risk of out-of-market settlements, but customized preference should dictate the decision.

Finally, deferral mechanisms were investigated. Generally deferrals do not serve as an alternative to an effective hedging program. A short-duration deferral adds modest additional stability when used in conjunction with a robust hedge program; it is inferior as a stand-alone approach in the absence of a hedge program. Any deferrals of greater than one year duration may exacerbate customer bill instability as balances grow; multi-year deferrals add financial risk in the form of large balances that strain liquidity with no benefit in short-term stability.

Background and Scope

Regulatory Background

Terasen filed its Price Risk Management Plans ("PRMPs") with the British Columbia Utilities Commission ("Commission") on May 13, 2010; the PRMPs (one for TGI and one for TGVI) were intended to cover multi-year periods beginning November 2010. In an order dated July 22, 2010, the Commission denied the request for approval of the PRMPs. The Commission ordered Terasen to suspend all market related activities associated with the PRMPs; conduct a review of the primary objectives in the context of the Clean Energy Act and increased domestic natural gas supply; and generally to consult with Commission staff regarding the subsequent regulatory process.

In discussions that followed between the Commission and Terasen, views were shared regarding the appropriateness of the competitiveness objective in light of current gas-to-electric price differentials, abundant gas supplies driven by shale resource development, and the implications of the BC Clean Energy Act. The Commission suggested a cost-benefit analysis be conducted for the program, and Terasen suggested that a monitor-and-respond strategy be evaluated in that context as well.

Scope

On October 8, 2010 RiskCentrix was engaged by Terasen to conduct studies and make recommendations regarding the risk mitigation program including quantification of risk, the appropriateness of objectives, and prospective strategy refinements in light of those objectives. RiskCentrix was also charged with providing analytical tools for the ongoing conduct of a monitor-and-respond element if management chose to add one to Terasen's risk mitigation program.

Methodology and Approach

Certain tenets form the foundation of RiskCentrix' approach, so this section will be prefaced with a discussion of perspective to be followed by details of specific work efforts.

Perspective

There are four foundational issues that must be discussed in order to present the results of these studies with conviction; they are:

- Market View v. Risk View
- The Nature of Price Risk
- Defining Success in Risk Mitigation

Market View v. Risk View

Hedge decisions may be driven by a conviction that market prices are undervalued, overvalued, or fairly valued; such a motivation would constitute a "market view." It is a red-blooded mindset that is appropriate to investment or trading activities, but it should not be the primary driver in risk mitigation activities. In investment or trading activities a "risk view" is supplemental to a market view; it assumes a white-blood-cell posture that embraces neutrality as to valuations and guards against intolerable outcomes. In effect, the risk view focuses on the broad spectrum of uncertainty, comparing potentialities to tolerances.

Risk mitigation activities should be driven primarily by the risk view, relegating market view to a supplemental role. The primary objective of a risk program is to produce *tolerable* results on behalf of customers. Hedge accumulation and timing must be sufficient to produce high confidence in tolerable outcomes. Only within that framework should specific hedge decisions be supplemented by a market view – e.g., which deliveries to hedge in what months.

This distinction does not always come naturally to red-blooded business people because a cause-effect narrative, steeped in fundamentals, is so naturally appealing. Yet a sober reflection on the history of forecasting makes it clear that if we are to produce tolerable results, we must recognize that any market view is fraught with uncertainty and prone to error; we will embrace neutrality as to risk valuations.

So how would we incorporate fundamental factors, like the BC Clean Energy Act or the abundance of shale gas development, into our risk view without introducing bias? Unless we possess some insider knowledge, which we do not, we will accept the reality that the market price reflects a consensus assessment of those fundamental impacts. Perhaps more importantly, the observed volatility in market prices reflects collective uncertainty with respect to the confidence of that market consensus. So by measuring the price and volatility we can reach an unbiased assessment of the risk.

One final point on this - any risk assessment will be imperfect; there will always be new events that surprise us and the entire marketplace. Yet, the discipline of measuring risk and acting on its implications produces insights, management rigor, and ultimately more robust performance.

Price Risk

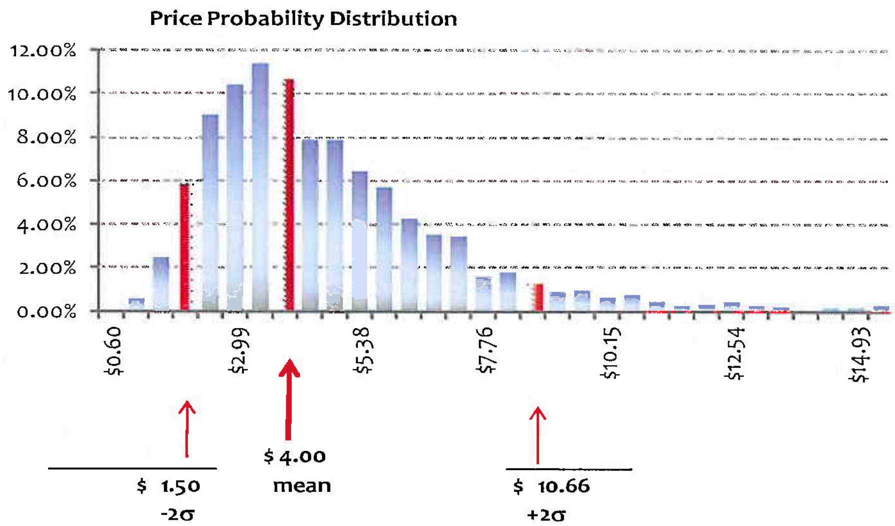
If we are to maintain neutrality in risk assessments, what methodologies produce unbiased views? The quantitative finance methodology utilized here has been deployed in the energy industry since the 1990's when futures contracts evolved as a means of managing volatile deregulated markets. The deregulation of natural gas, the emergence of NYMEX futures contracts, and later the deregulation of electricity placed a burden on energy companies and energy users; they needed to manage volatility. To do so, they turned to the principles of the finance industry. [6]

Appendix 2 presents a supplemental discussion of volatility, value at risk, and Monte Carlo simulations, but a few observations are offered here.

The following graphic shows the risk distribution of AECO prices considering a one year potential price migration, with an illustrative starting futures price of $ 4.00/GJ and using the 50% volatility as observed.

[6] RiskMetrics, a JP Morgan subsidiary, published risk methodologies in 1992 that had been developed and deployed earlier within JP Morgan. That work became a finance industry standard, and in the 1990's the same methods were adapted to the energy industry. Others have built on that work.

Figure 1, One-Year-Later Uncertain Price Distribution [7]



A few things are worth noting. Notice that the shape of the distribution is skewed to the right side. Gas prices follow this distribution (lognormal); prices are bounded by zero at the bottom, but unbounded at the top. The implication is that the magnitude of risk is greater to the high side than the low side while the more frequent outcomes are skewed to the downside. So generally hedge programs are likely to experience small losses more often than the larger, but less frequent, gains. This effect is consistent with the intent of hedging which usually involves accepting the prospect of relatively smaller pain to mitigate the potential for intolerable outcomes. The final observation is that "outliers" to the right of the 2σ band, while unlikely, can extend well beyond the range that might be considered normal in colloquial terms.

Using actual numbers for AECO, in September 2010 the prompt month of October was trading at $3.37/GJ and volatility was measured as 50%.[8] See Appendix 2 for a discussion of how volatility is measured. Considering the lognormal skew and measured volatility, the 2-sigma prompt-month risk bands for various horizons would be as follows:

[7] Figure 1 shows mean expectation and +/- 2σ outcomes for one-year-later uncertain prices. For those less familiar with statistical terminology, 95% of uncertain outcomes fall within the 2σ band; 2.5% above and 2.5% below. Outcomes outside of the 2σ band will be referred to as "outliers."

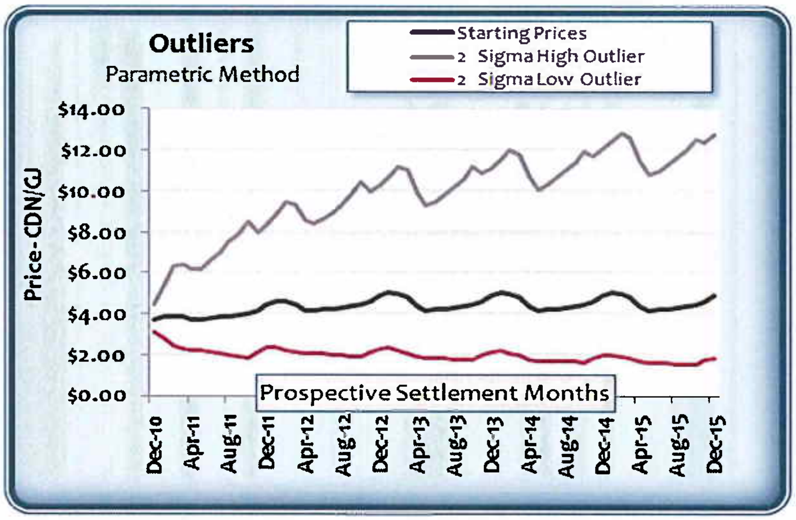
[8] Obviously the October contract will not be exposed to a full year's risk, but the prompt month will roll from October to November, etc.

Figure 2, AECO Risk Bands

	2 σ Risk Bands			Risk
	1 day	252 day	10 day	10 day
Mean	$ 3.37	$ 3.37	$ 3.37	
High	$ 3.58	$ 8.99	$ 4.10	$0.73
Low	$ 3.17	$ 1.26	$ 2.77	-$0.60

This methodology could be applied to the entire forward curve and the risk envelope could be extended years into the future. Figure 3 shows the results of such an analysis for AECO.

Figure 3, Long-Term Uncertain Price Envelope



While the risk portrayed in Figure 3 is interesting as a long-term view of risk, it does little to help manage week-to-week hedge decisions; Value at Risk or VaR is a tool for that purpose.

Value at Risk ("VaR")

Viewing risk in a longer term framework (Figure 3) tends to drive managers into unnecessarily lumpy one-time decisions. For example, fixing the price for 50% of one year's gas requirements will mitigate 50% of the potential upward price migration and eliminate 50% of downside participation; whether executed immediately or programmatically it is a big commitment. Better results can usually be attained by managing risk in smaller time increments – weekly for example - and making smaller hedge adjustments along the way. A crude but meaningful analogy would contrast the choice of fixing the steering wheel position of an automobile and watching where it goes for 52 seconds versus looking through the windshield every second, assessing the risk, and making small adjustments along the way.

Assessing risk and then making hedge decisions in weekly increments provides numerous advantages:

- A smaller volume of initial hedges is appropriate because the monitor-and-respond framework allows numerous adjustments;
- Sometimes the market will fall and fewer hedges will be a good thing;
- If properly monitored, there is *"almost always"* ample time to hedge defensively when market volatility rises;
- Diversity of commitments over time reduces the chances of a big mistake;
- All other things equal, shorter tenor provides lower risk of losses.

In a monitor-and-respond mode of risk mitigation, rather than making decisions based on long-term price potential, it is more helpful to assess the potential for migration of prices over a short "holding period." In effect, we assess the near-term risk of hedge opportunities (futures prices) migrating to an unacceptable level; the tool to do this is VaR or Value at Risk. Rekindling the automobile analogy, when making small steering adjustments, the driver does not focus on where the car might wander in the long term, the near-term directional variance is more important.

Value at Risk quantifies the risk for a "holding period" that is appropriate to the hedge manager's response time in making and executing hedge decisions. If the hedge program is designed to monitor and respond to risk on a weekly basis, a ten-day risk assessment would provide an appropriate cushion in the determination of how the decision to *forego* today's hedge opportunities might be tolerated. The ten day time span is called the "holding period" because it indicates the hedge manager's risk of holding positions unchanged for that period.

Defining Success in Risk Mitigation

Risk mitigation involves managing economics to produce tolerable results in terms of potential customer bill increases and potential out of market settlements, thereby providing value to customers. Since intolerable results occur at the outer bands of the probability distribution, success must be defined in terms of how well a strategy performs under stressful conditions. Averages are not particularly meaningful because in liquid markets hedge instruments are fairly valued, so over the long run hedged costs equal unhedged costs except for the small costs embedded in each transaction. Swaps carry very small bid-asked spreads, and even options premiums, which constitute a front-end cost, are expected to payout on average at settlement except for small volatility increments.[9]

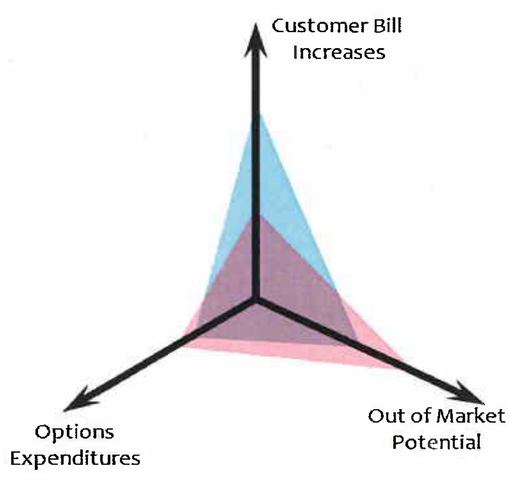
So success is defined in terms of boundary results; we will focus on the 2.5% probability outliers (2 sigma single-tail potential outcomes). At those boundaries any hedge program must balance three competing factors. For utilities the primary objective is typically constraining customers' upside price exposure. But every hedge carries the risk of loss, so pursuit of aggressive hedge accumulation runs the risk of large out-of-market settlements. Options provide a means of securing "insurance" against both, but premiums can be expensive.

So objectives, and success metrics, must balance 3 competing tolerances:

- Customer bill increase tolerance
- Out of market tolerance
- Option expenditure tolerance

In Figure 4 the blue and red triangles are alternative sets of tolerances for an assumed underlying volatility level. The blue triangle tolerates higher cost increases at the 2-sigma level in exchange for modest out-of-market results and modest premium expenditures. The red triangle substantially tightens the 2-sigma cost increases at the expense of accepting somewhat greater out-of-market outcomes and greater premium expenditures at the 2-sigma boundary. The shapes of these triangles may be modified ad infinitum, but their size will be dictated by the underlying volatility.

Figure 4, Tolerance Sets



[9] Options values are substantially determined by the volatility assumption embedded in the premium; greater volatility in the underlying contract raises the option premium. Typically options trade with a higher implied volatility than that which can be observed in the underlying commodity contract, and that produces a cost increment, but typically options premiums constitute a minor element in the utility portfolio and the incremental cost is a small fraction of that. All studies conducted here accounted for such increments.

Precisely articulated objectives, when well-founded, produce fewer disappointments, so an explicit balance as to tolerances - and the related strategy which is inextricably linked - is superior to vague intent. The approach in this work, to be described next, utilized Monte Carlo simulations to assure that both strategy and objectives are well-founded.

Approach

RiskCentrix scope of work included the following efforts:

1) Reviewing filings and other information from management
2) Quantifying observed price volatility at AECO
3) Propagating random future price paths, consistent with observed volatility, and
4) Choosing four price paths representing stress conditions for strategy testing
5) Postulating alternative hedge decision rules, and then
6) Simulating hedge decisions against stressed price conditions
7) Presenting strategy-tolerance pairings to facilitate management's selection of market-compatible objectives and a commensurate strategy.

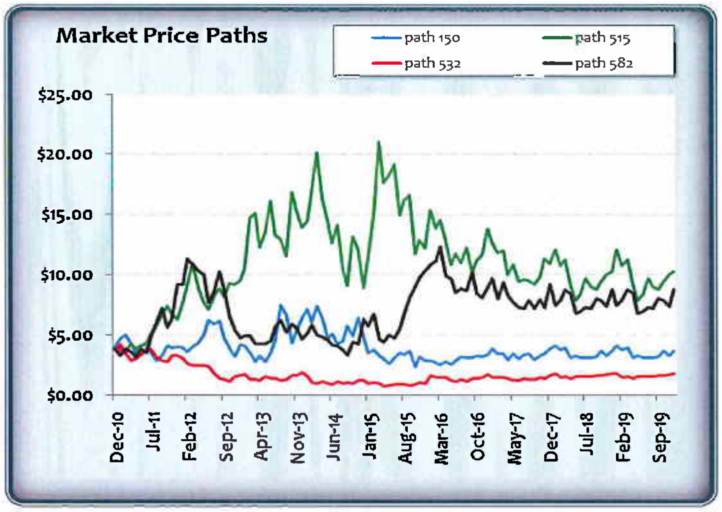
Some of these are self-explanatory or treated in the appendices, and Item 7 is covered in the results. The price paths selected and the simulation of hedge decision rules will be described here.

Price Paths for Testing Strategies

Using a Monte Carlo methodology that propagated daily random price walks, RiskCentrix generated 660 future price environments for the purpose of identifying stress cases and testing hedge decision strategies.[10] From those price paths, three paths outside of the 2-sigma envelope and one representative "normal" path were randomly selected. The price paths selected are represented in Figure 5 below.

[10] Generating price paths for the purpose of hedge strategy assessment is a computationally intensive effort because each randomly propagated path must contain a daily representation of the full forward curve consistent with volatility and correlation observations. So one sample price path, representing a ten-year random walk with 60 monthly forward contracts requires 151,00 price points, i.e., 10 years x 252 days/yr x 60 forward months.

Figure 5, Price Paths Used for Testing Hedge Strategy



Paths were numbered and characterized as follows:

Path 515 (Green):	Radical High, Extreme Case
Path 532 (Red):	Radical Low
Path 582 (Black):	High Cycle
Path 150 (Blue):	Mid-Low Cycling (within the 2-sigma envelope)

The graphic shows the settlement values for each monthly contract on each price path, but in each case and for each day simulated, the 60-month forward curves were generated along the entire price path.

Customizing Hedge Decision Rules

For the purpose of building a disciplined framework regarding ongoing risk mitigation, RiskCentrix uses a four-part segmentation for hedge decision rules. Hedge decisions have been divided into these categories:

Programmatic	scheduled net volatility reduction
Defensive	respond to *potential* high price by monitoring volatility, VaR, and related price holding period outliers
Value	respond to favorable price opportunities
Contingent	addressing other concerns, e.g. - loss potential or fixing unattractive hedges

TGI's PRMP strategy is primarily programmatic, accumulating about 50% hedge (i.e. 60% winter and 45% summer) coverage in accordance with a predetermined schedule; there are also "Value" elements[11] and "Contingent" elements. Value hedges are accumulated when prices reach a predefined price target, and the contingent element mandates limited hedge accumulation when prices rise to a noncompetitive level.

The categorization of hedge decisions described above facilitates a comparison of different hedge strategies against the price environments described earlier. Computer models can measure prices, VaR and other metrics and then simulate hedge decisions in accordance with prescribed rules. Programmatic hedges are simply "executed" on a time schedule in equal increments to diversify hedge accumulation; Defensive and Value hedges require some explanation and they are described below. Contingent strategies were not dealt with in the simulations; they are left to management's responses in the real world. Contingent responses are typically driven by ad hoc conditions like the extraordinary market collapse in 2008, unusual collateral requirements, or the 2008 financial crisis.

Defensive Hedges

Defensive hedges are the most important monitor-and-respond element in the risk toolkit. Appendix 2 provides an illustration of how VaR is calculated, and VaR is the principle concept underlying Defensive hedges. Figures 6 and 7 will serve to illustrate the mechanism deployed for defensive hedges, both in the simulations and in the actual conduct of the recommended strategy.

Figure 6, VaR in Defensive Hedges

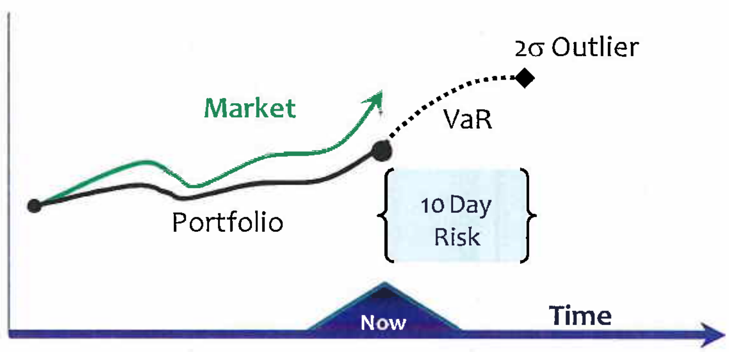
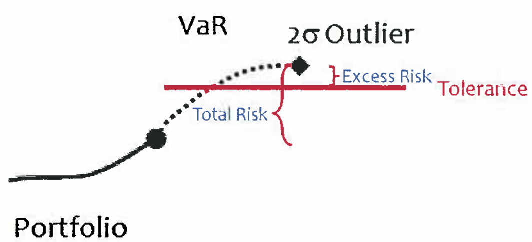


Figure 6 shows a gas supply portfolio (solid black) that happens to be tracking below rising market prices (green). The same principles apply regardless of the relationship of the portfolio to market values. The dotted line is a representation of the 10-day VaR as described in Appendix 2.

[11] Terasen uses the terms "accelerated" or "incremental."

Figure 7 expands the VaR illustration and compares the resulting 2-sigma outlier to a management-imposed tolerance that has been illustrated in red. Note that the risk outlier encroaches on the tolerance – an "encroachment." The defensive tolerance should be based on fundamental objectives such as customer rate tolerance and competitive benchmarks.

Figure 7, VaR Outlier v. Tolerance



The total risk reflects price exposure associated with the unhedged or open portion of the portfolio, so if the hedge manager desired to eliminate the encroachment, adding hedges in a volume equal to a portion of the open positions defined by the ratio "Excess Risk/Total Risk" would bring the post-hedge 2-sigma outlier down to the red tolerance. This would be a Defensive hedge; the cycle of monitoring and responding was simulated weekly as it would be performed in reality by way of routine measurement of AECO volatility.

In the strategy assessments Defensive hedges have been deployed for two forward calendar years. Empirically, futures contracts grow in volatility as they approach the prompt month. Typically the greatest prices spikes are experienced within a year of contract settlement; less so two years out. By monitoring and defending tolerances for two years forward price escalation can be mitigated effectively and the prior year, the third forward, is used as a year of programmatic accumulation.

One more design element is worthy of discussion in defensive hedge rules. If rules were designed with a single tolerance, hedges could be accumulated precipitously. So a better design would set multiple tolerances as cascading defenses, hedging up to incremental maximum hedge ratio with each cascading tolerance. So in three tiers, defensive hedge rules could be specified on top of Programmatic hedges as illustrated here:

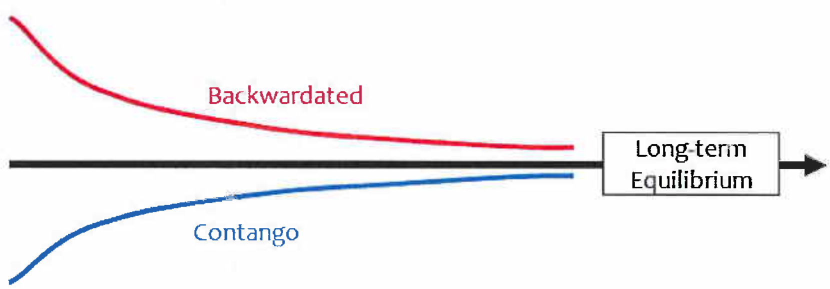
Rules	Tolerance	Max Hedge Ratio
Programmatic		25%
Defense 1	[redacted]	35%
Defense 2	[redacted]	50%
Defense 3	[redacted]	60%

Value Hedges

Capturing value opportunities can have a beneficial effect if prices are attractive relative to budget objectives, particularly if risk characteristics are observed.[12] The risk of making Value hedges is most pronounced following market peaks when budgets as well as transient perceptions of value are distorted by recently elevated prices. To avoid this perceptual trap, RiskCentrix recommends applying an objective screening criterion to such hedge decisions – a criterion that is risk oriented and not solely tied to price perception.

The recommended screening criterion makes use of the shape of the forward curve and how it relates to the future risk of loss versus "neutral" pricing. Figure 8 shows the difference between backwardated and contango forward curves.

Figure 8, Backwardated & Contango Curves



Backwardated prices are consistent with near-term scarcity of supply, surplus demand, or speculative fervor; hurricanes in the Gulf of Mexico provide one example of how such conditions arise. In such environments near-term prices tend to bid up radically while longer-dated contracts reflect an expected gradual return to equilibrium conditions. Contango markets are opposite, reflecting gas gluts or slack demand, but similarly the long-term expectations and prices gravitate toward equilibrium levels. Notice the enigma. In a contango market, while year-forward prices are higher than current prompt prices, they still reflect a potential bargain when compared to equilibrium prices. The (usually wrong) superficial response to a contango price curve could be "why would I hedge next year at $5.00 when current spot prices are at $4.00?"

It may be instructive to consider how the shape of the forward curve changes as price levels decline. Figure 9 shows a typical progression from an exuberant price spike to a price trough.

[12] Recall it has been recommended that risk mitigation decisions be dominated by the risk view, not market view. Simply timing the market can look quasi-speculative, but hedging in small increments at desirable values also tends to provide assurance that ultimate outcomes will fall into a tolerable range, particularly if hedge loss potential is mitigated as an intrinsic part of the decision process.

Note that near the peak prices are backwardated, but as prices decline the degree of backwardation moderates, becomes contango, and ultimately reaches a steep contango shape as illustrated in the heavy green forward price curve.

Figure 9, Shape Progression in a Declining Market

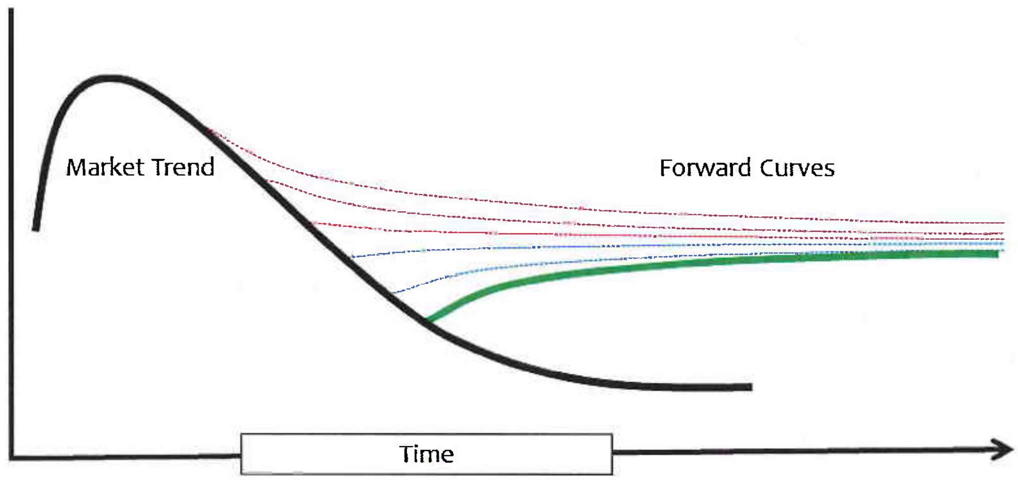
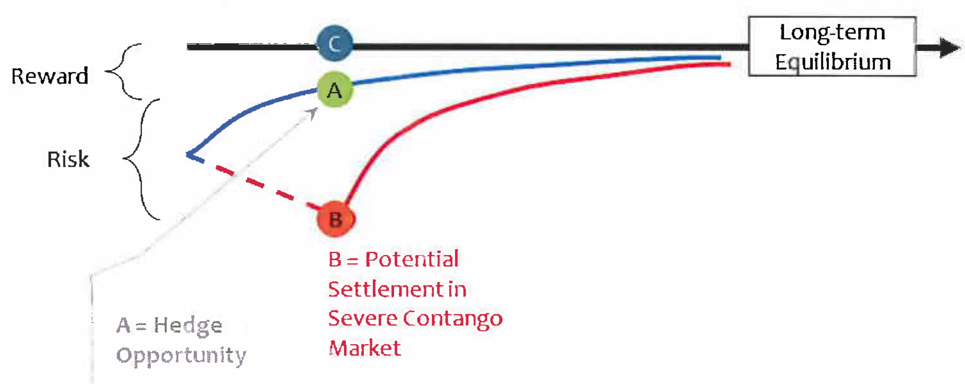


Figure 10 shows a simple screening metric that can be used to judge the risk of capturing price opportunities without relying on transient misleading perceptions.

Figure 10, Value Criterion in Contango Markets



By comparing the potential for hedge settlements at equilibrium prices to the hedge settlements in a severely contango market, a screening ratio can be determined and a standardized criterion can be formulated for the simulation process. In Figure 10 the screening criterion would be calculated as the ratio of "reward" to risk, expressed as (C-A)/(A-B). In the hedge decision simulations, that criterion was specified at a fairly selective provision so that Value hedges contributed to the portfolio without dominating it.

Analytical Results

Studies conducted included too many simulations to summarize here, so this report will focus on seven strategies, each of which was simulated against the four price paths described earlier. Our focus was on the following indications:

- Unmitigated customer bill increase, worst year
- Mitigation effectiveness, worst year and mitigated bill increase
- Out of market settlements, worst year
- Option premium expenditures, average year
- Option premium expenditures, worst year

Note that the "worst year" for any given metric would often be a different year than another metric. High bill increases occur at different times than unfavorable settlements. For each strategy, results were tabulated against each price path and then the worst results across all years for all paths were taken as the outliers. This constitutes a stringent test because the price paths, which included $20/GJ highs and less than $1.00/GJ lows, represented greater than 2 sigma outliers, so worst case metrics reflect severe stress conditions.

The strategies of focus are summarized below.

Strategies Tested

Hedge Rule		50% Programmatic	50% HDR, No Options	75% HDR No Options
Overall	Max Hedge	50%	50%	75%
Programmatic	Horizon	36 mos.	36 mos.	36 mos.
	Max	50%	15%	20%
Defensive	Top Boundary Year 1, % of starting yr. portfolio value	NA	116%	116%
	Top Boundary Year 2, % of starting yr. portfolio value	NA	121%	121%
	Options as % of Defensive Hedges	NA	0%	0%
Value	Target, % of starting year price	95%	95%	95%
	Increment	5%	1%	1%
	Screening Criterion	None	120%	120%

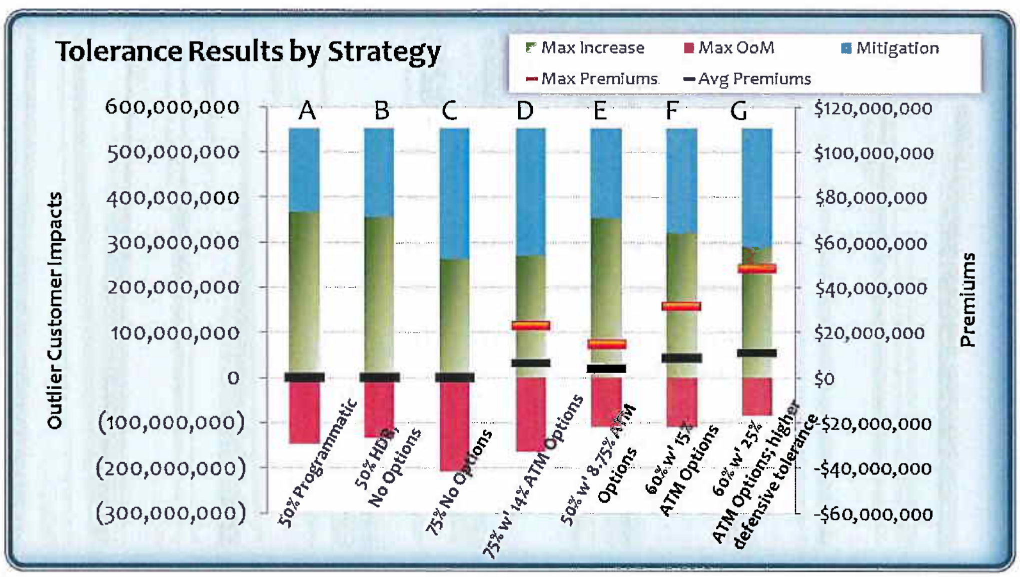
HDR indicates more than programmatic Hedge Decision Rules

		75% with Call Options	50% with Call Options	60% with Call Options	60% w/ 25% ATM Options; high defensive tolerance
Overall	Max Hedge	75%	50%	60%	60%
Programmatic	Horizon	36 mos.	36 mos.	36 mos.	36 mos.
	Max	20%	15%	15%	25%
Defensive	Top Boundary Year 1, % of starting yr. portfolio value	116%	116%	116%	135%
	Top Boundary Year 2, % of starting yr. portfolio value	121%	121%	121%	135%
	Options as % of Defensive Hedges	25%	25%	43%	71%
Value	Target, % of starting year price	95%	95%	95%	95%
	Increment	1%	1%	1%	1%
	Screening Criterion	120%	120%	120%	150%

Options when deployed were at-the-money calls

The results of the hedge decision simulations are most easily displayed in graphic form as shown in Figure 11. That figure shows, for each strategy, the attainable tolerances against the unmitigated customer bill increase at the top of each bar in the graph. Recall that the price environments evaluated were dramatic ones with prices rising to $20/GJ in high cases and falling below $1.00/GJ in low ones; so expect dramatic worst case results. An expansive blue area indicates substantial mitigation of the unmitigated price peak, while a large red area shows heavy out of market settlements in the case of collapsing prices. Option premiums needs are shown by hash marks read on the right axis. Black hash marks show the average year and orange shows the worst year. Note that all options premiums are also included in the cost and out of market metrics, so there is no need to add them separately.

Figure 11, Strategy Assessment Results



Looking at the results beginning from the left, unmitigated customer bills[13] would rise by $552 million in the unmitigated high price case, while a 50% programmatic program would mitigate that to about a $366 million increase; out of market outcomes could grow to $147 million in a severe market collapse. Column B indicates that adding defensive hedges would reduce the mitigated outcome to $355 million, a $10 million improvement; stress case out of market outcomes also improve by $12 million to $135 million. As expected, Column C indicates that a greater maximum hedge ratio improves mitigation but also risks greater out of market outcomes.

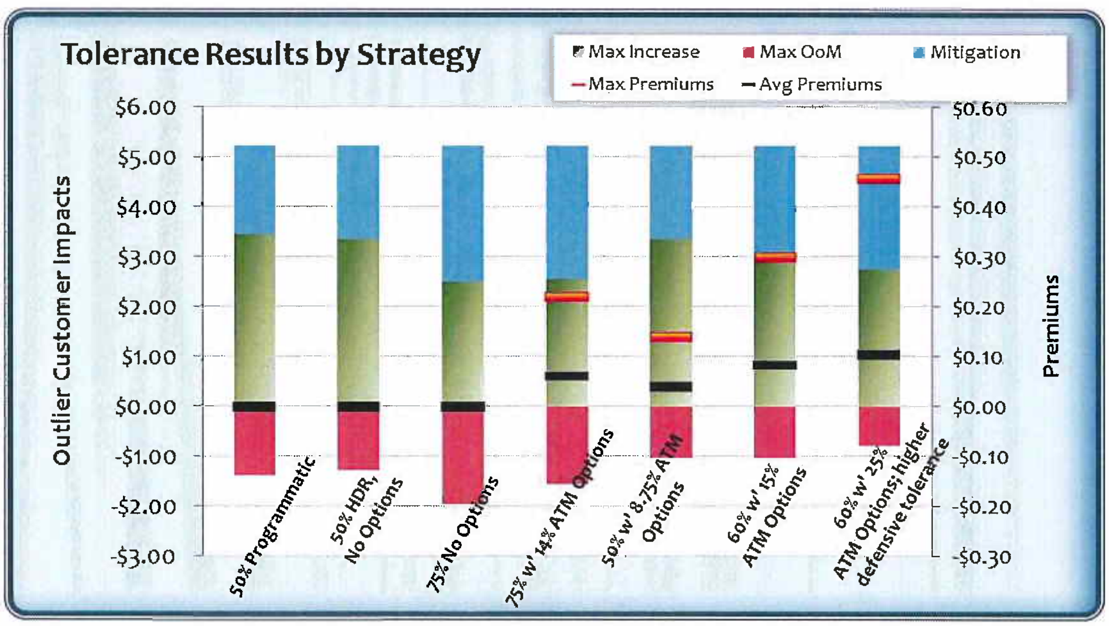
[13] In all cases where bill changes are shown, non-commodity costs were assumed to be $6.37/GJ.

Call options produce the expected results. Column D shows that out of market settlements can be mitigated while retaining the mitigation benefits of the 75% hedge ratio. Column E may be attractive; it shows better mitigation and smaller loss potential than A or B. Finally Column F draws a balance, seeking a small loss potential with better than average mitigation effects, while Column G takes the concept a step further with greater options expenditures and looser defensive boundaries to further constrain out of market outcomes. If options expenditures are acceptable, these strategies (F & G) provide a good balance of customer bill mitigation and out of market mitigation, potentially yielding the best value for customers.

Figure 11A below shows the results in $/GJ, and numerical results underlying the graphics are tallied in Appendix 1, with more detail as to particular strategy assessments provided in Appendix 3.

Figure 11A, Strategy Results in $/GJ

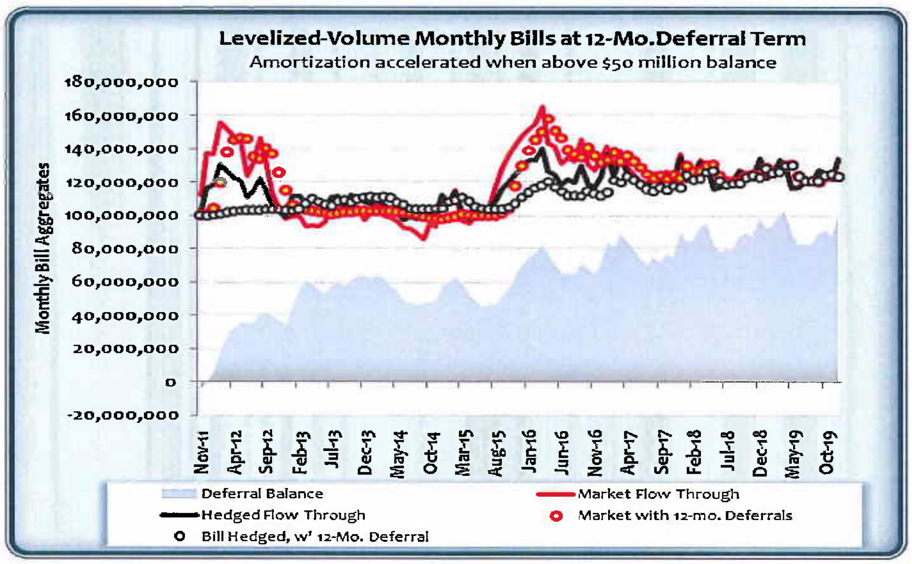
(All metrics reflect the full requirements, hedged & unhedged, as denominator)



Deferral Accounting

RiskCentrix also performed simulations of deferral accounting mechanisms of various time frames. Generally deferrals do not serve as an alternative to an effective hedging program. A short-duration deferral mechanism adds modest additional stability when used in conjunction with a robust hedge program; it is inferior as a stand-alone approach in the absence of a hedge program. Figure 13 shows the high-cycling price path with market values in red and a 12-month deferral in the lagging red circles. The black line shows the results of hedge decision rules with a 60% maximum hedge ratio. Note that the hedged line is more stable than the simple deferral. The black circles indicate that a short duration deferral of costs as hedged, provides superior stability.

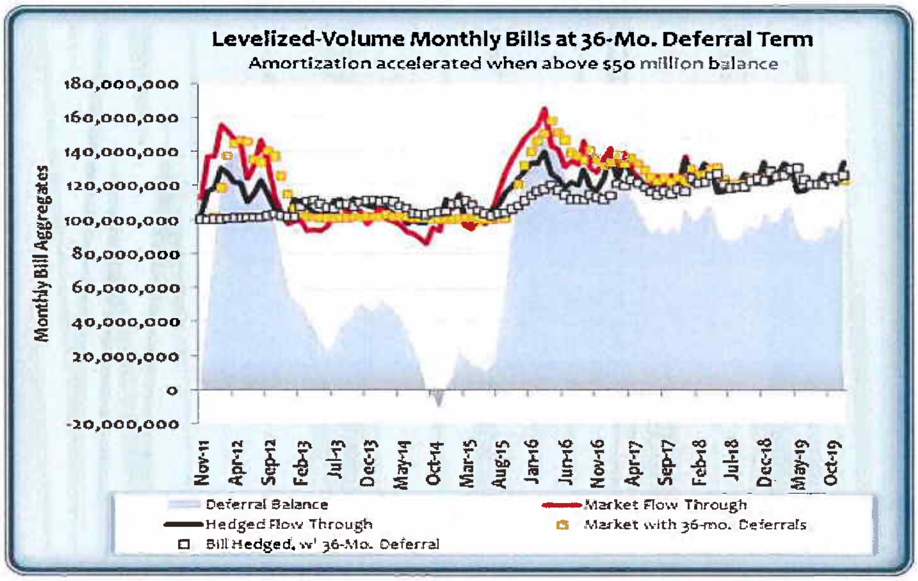
Figure 13, Comparison of 12-Month Deferrals with and Without Hedges



The risk of deferral accounting is that deferrals could accumulate to unsustainable levels resulting in the need to ultimately pass through more radical costs. To avoid a dramatically unfavorable outcome in this regard, each of the deferral simulations here assumed accelerated pass through when balances reached $50 million. The blue shaded area in Figure 13 shows how deferrals accumulate to less than $100 million over the near-decade horizon; this is probably manageable.

Figure 14 pushes the envelope to a 36-month deferral and the results indicate that deferred balances become unstable and potentially unsustainable with no material improvement in customer bill stability.

Figure 14, 36 Month Deferral



In summary, RiskCentrix views short-duration deferrals, in conjunction with a robust risk mitigation program, to be an appropriate means of further smoothing customers' bills. Yet, deferrals are not a substitute for a risk program, and any deferrals of greater than one year duration may exacerbate customer bill instability as balances grow; multi-year deferrals also add financial risk in the form of large balances that strain liquidity with no benefit in short-term stability.

Other Deliverables

As an adjunct to this report RiskCentrix has delivered to Terasen the following tools:

- The Price Propagation Tool used to perform Monte Carlo simulations
- The Hedge Decision Simulator
- A production VaR Assessment Tool for the purpose of ongoing volatility assessment and defensive hedge support

Appendices

Appendix 1: Hedge Strategy Assessment Summaries

Hedge Simulations Master Summary

A

Overall	Max Hedge	50%
Program.	Horizon	36 mos.
	Max	50%
Defensive	Top Boundary Year 1	NA
	Top Boundary Year 2	NA
	Options, % of Defense	NA
Value	Target	95%
	Increment	5%

Metric	High Cycle Path 582 $ 12.33 High $ 3.14 Low	Very High Path 515 $ 20.99 High $ 3.55 Low	Very Low Path 532 $ 4.18 High $ 0.66 Low	Mid-Cycle Path 150 $ 7.44 High $ 2.37 Low	"Worst of Worst"
	Price Paths & Results				
	41.8%	34.0%	6.7%	19.8%	41.8%
Max Hedged Bill Change	31.9%	23.9%	2.4%	9.6%	31.9%
Mitigation	9.9%	10.1%	4.3%	10.2%	9.9%
Max Increase at Market	498,212,802	551,904,876	51,617,061	215,064,247	551,904,876
Max Increase, Hedged	365,599,539	282,319,234	19,745,425	107,544,083	365,599,539
Mitigation	132,613,263	269,585,643	31,871,636	107,520,164	186,305,337
Max Out of Market	79,950,796	0	147,121,621	119,996,744	147,121,621
OOM / vg. Annual Bill @ Mkt.	5.7%	0.0%	17.4%	11.1%	17.4%
Avg. Option Premiums	0.0%	0.0%	0.0%	0.0%	0 Avg
Max-Yr. Option Premiums	0	0	0	0	0
Mitigation (%) per OOM (%)	1.75	NA	0.25	0.92	0.57
Mitigation ($) per OOM ($)					1.27

B

Overall	Max Hedge	50%
Program.	Horizon	36 mos.
	Max	15%
Defensive	Top Boundary Year 1	116%
	Top Boundary Year 2	121%
	Options, % of Defense	0%
Value	Target	95%
	Increment	1%

Metric	High Cycle Path 582	Very High Path 515	Very Low Path 532	Mid-Cycle Path 150	"Worst of Worst"
Max Market Bill Change	41.8%	34.0%	6.7%	19.8%	41.8%
Max Hedged Bill Change	24.7%	25.2%	2.6%	8.9%	25.2%
Mitigation	17.1%	8.9%	4.1%	10.9%	16.6%
Max Increase at Market	498,212,802	551,904,876	51,617,061	215,064,247	551,904,876
Max Increase, Hedged	278,807,359	355,233,552	21,572,342	100,652,257	355,233,552
Mitigation	219,405,443	196,671,325	30,044,719	114,411,990	196,671,325
Max Out of Market	98,311,613	0	135,471,013	120,218,346	135,471,013
OOM / Avg. Annual Bill @ Mkt.	7.0%	0.0%	16.0%	11.1%	16.0%
Avg. Option Premiums	0	0	0	0	0 Avg
Max-Yr. Option Premiums	0	0	0	0	0
Mitigation (%) per OOM (%)	2.46	NA	0.26	0.98	1.04
Mitigation ($) per OOM ($)					1.45

C

Overall	Max Hedge	75%
Program.	Horizon	36 mos.
	Max	20%
Defensive	Top Boundary Year 1	116%
	Top Boundary Year 2	121%
	Options, % of Defense	0%
Value	Target	95%
	Increment	1%

Metric	High Cycle Path 582	Very High Path 515	Very Low Path 532	Mid-Cycle Path 150	"Worst of Worst"
Max Market Bill Change	41.8%	34.0%	6.7%	19.8%	41.8%
Max Hedged Bill Change	17.5%	20.2%	2.6%	5.3%	20.2%
Mitigation	24.3%	13.9%	4.1%	14.6%	21.6%
Max Increase at Market	498,212,802	551,904,876	51,617,061	215,064,247	551,904,876
Max Increase, Hedged	194,564,335	263,491,437	21,311,354	58,663,648	263,491,437
Mitigation	303,648,467	288,413,440	30,305,707	156,400,599	288,413,440
Max Out of Market	153,330,106	0	208,036,482	186,808,591	208,036,482
OOM / Avg. Annual Bill @ Mkt.	10.8%	0.0%	24.5%	17.2%	24.5%
Avg. Option Premiums	0	0	0	0	0 Avg
Max-Yr. Option Premiums	0	0	0	0	0
Mitigation (%) per OOM (%)	2.24	NA	0.17	0.85	0.88
Mitigation ($) per OOM ($)					1.39

Hedge Simulations
Master Summary

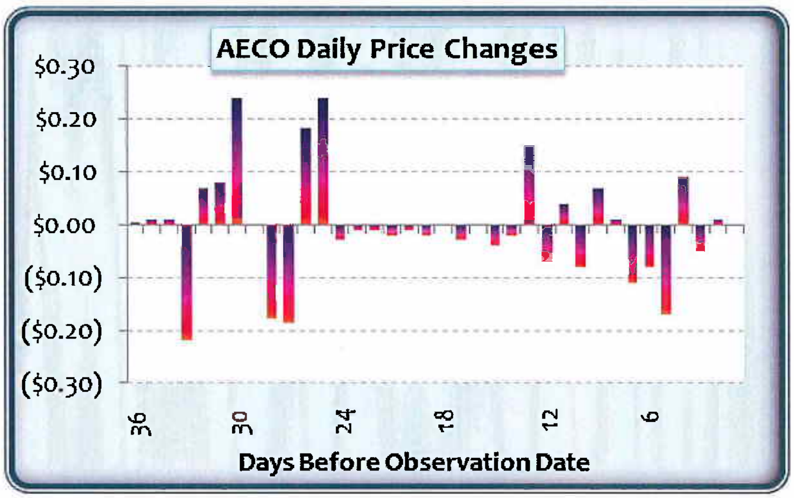
			Metric	Price Paths & Results				"Worst of Worst"
				High Cycle Path 582 $ 12.33 High $ 3.14 Low	Very High Path 515 $ 20.99 High $ 3.55 Low	Very Low Path 532 $ 4.18 High $ 0.66 Low	Mid Cycle Path 150 $ 7.44 High $ 2.37 Low	
D			Max Market Bill Change	41.8%	34.0%	6.7%	19.8%	41.8%
Overall	Max Hedge	75%	Max Hedged Bill Change	18.1%	20.4%	2.6%	5.7%	20.4%
Program.	Horizon	36 mos.	Mitigation	23.7%	13.7%	4.2%	14.2%	21.4%
	Max	20%	Max Increase at Market	498,212,802	551,904,876	51,617,061	215,064,247	551,904,876
Defensive	Top Boundary Year 1	116%	Max Increase, Hedged	201,767,764	268,731,105	21,053,778	64,603,108	268,731,105
	Top Boundary Year 2	121%	Mitigation	296,445,038	283,173,772	30,563,283	150,455,139	283,173,772
	Options, % of Defense	25%	Max Out of Market	128,560,197	0	165,611,115	154,457,398	165,611,115
Value	Target	95%	OOM / Average Annual Bill @ Market	9.1%	0.0%	19.5%	14.2%	19.5%
	Increment	1%	Avg. Option Premiums	7,060,000	10,620,000	2,420,000	5,460,000	6,390,000 Avg
			Max-Yr. Option Premiums	13,816,138	23,205,143	11,514,450	11,300,458	23,205,143
			Mitigation (%) per OOM (%)	2.61	NA	0.21	1.00	1.10
			Mitigation ($) per OOM ($)					1.71
E			Max Market Bill Change	41.8%	34.0%	6.7%	19.8%	41.8%
Overall	Max Hedge	50%	Max Hedged Bill Change	25.1%	25.2%	2.6%	9.8%	25.2%
Program.	Horizon	36 mos.	Mitigation	16.7%	8.8%	4.1%	10.0%	16.5%
	Max	15%	Max Increase at Market	498,212,802	551,904,876	51,617,061	215,064,247	551,904,876
Defensive	Top Boundary Year 1	116%	Max Increase, Hedged	284,101,259	352,918,934	21,118,960	109,839,476	352,918,934
	Top Boundary Year 2	121%	Mitigation	214,111,543	198,985,942	30,498,101	105,224,771	198,985,942
	Options, % of Defense	25%	Max Out of Market	80,205,222	0	108,921,240	101,505,093	108,921,240
Value	Target	95%	OOM / Avg. Annual Bill @ Mkt.	5.7%	0.0%	12.8%	9.4%	12.8%
	Increment	1%	Avg. Option Premiums	4,740,000	6,860,000	1,570,000	3,570,000	4,185,000 Avg
			Max-Yr. Option Premiums	9,012,358	14,632,070	7,335,580	7,412,149	14,632,070
			Mitigation (%) per OOM (%)	2.94	NA	0.32	1.07	1.29
			Mitigation ($) per OOM ($)					1.83
F			Max Market Bill Change	41.8%	34.0%	6.7%	19.8%	41.8%
Overall	Max Hedge	60%	Max Hedged Bill Change	22.7%	23.5%	2.7%	8.9%	23.5%
Program.	Horizon	36 mos.	Mitigation	19.1%	10.5%	4.0%	11.0%	18.3%
	Max	15%	Max Increase at Market	498,212,802	551,904,876	51,617,061	215,064,247	551,904,876
Defensive	Top Boundary Year 1	116%	Max Increase, Hedged	255,367,146	320,942,869	21,815,257	99,996,264	320,942,869
	Top Boundary Year 2	121%	Mitigation	242,845,656	230,962,007	29,801,804	115,067,983	230,962,007
	Options, % of Defense	43%	Max Out of Market	88,171,002	0	108,573,155	105,365,177	108,573,155
Value	Target	95%	OOM / Avg. Annual Bill @ Mkt.	6.2%	0.0%	12.8%	9.7%	12.8%
	Increment	1%	Avg. Option Premiums	9,980,387	14,639,862	3,207,076	7,479,430	8,826,689 Avg
			Max-Yr. Option Premiums	19,107,169	31,814,205	15,434,785	15,324,749	31,814,205
			Mitigation (%) per OOM (%)	3.07	NA	0.31	1.13	1.43
			Mitigation ($) per OOM ($)					2.13
G			Max Market Bill Change	41.8%	34.0%	6.7%	19.8%	41.8%
Overall	Max Hedge	60%	Max Hedged Bill Change	23.6%	20.4%	2.5%	10.4%	23.6%
Program.	Horizon	36 mos.	Mitigation	18.2%	13.7%	4.2%	9.5%	18.2%
	Max	25%	Max Increase at Market	498,212,802	551,904,876	51,617,061	215,064,247	551,904,876
Defensive	Top Boundary Year 1	135%	Max Increase, Hedged	269,790,669	290,850,406	20,390,439	116,965,010	290,850,406
	Top Boundary Year 2	135%	Mitigation	228,422,134	261,054,470	31,226,622	98,099,237	261,054,470
	Options, % of Defense	71%	Max Out of Market	78,790,410	0	82,650,343	60,665,019	82,650,343
Value	Target	95%	OOM / Avg. Annual Bill @ Mkt.	5.6%	0.0%	9.8%	5.6%	9.8%
	Increment	1%	Avg. Option Premiums	13,128,457	22,029,340	1,226,118	7,780,230	11,041,036 Avg
			Max Yr. Option Premiums	37,870,476	48,343,979	9,405,451	19,729,282	48,343,979
			Mitigation (%) per OOM (%)	3.26	NA	0.43	1.69	1.86
			Mitigation ($) per OOM ($)					3.16

Appendix 2: Volatility, Monte Carlo Price Models, and VaR

Volatility

Observed volatility is typically measured by monitoring price movements over some recent, but statistically significant period. The graphic below shows AECO price changes for 36 days leading up to late September 2010. By measuring appropriate confidence bands for these price changes, daily volatility may be quantified.[14] For the September 2010 assessment, one-sigma daily volatility was estimated at 3.15%.

A-2, Figure 1

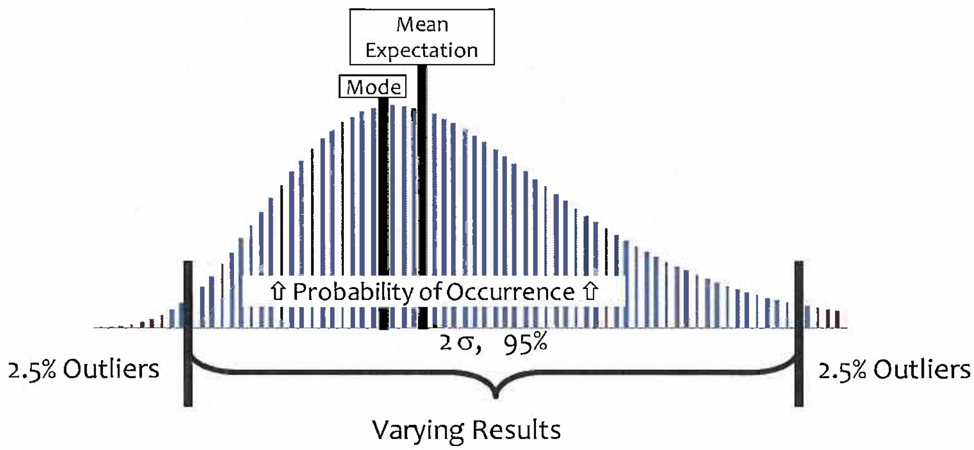


But by convention volatility would be expressed as the one-sigma variation in prices over one year. Price risk grows with the square root of time, so with 252 trading days per year (excluding weekend and holidays), annual volatility was quantified as 3.15% x SQRT(252) or 50%.

[14] Gas prices are generally considered to be lognormally distributed, meaning that they are constrained by zero on the low side but unconstrained on the high side resulting in a skewed risk distribution.

Viewed in a traditional histogram, the price risk at 2-sigma would appear as follows, where 2.5% of probable outcomes would fall outside the 2-sigma band to each side.

A-2, Figure 2

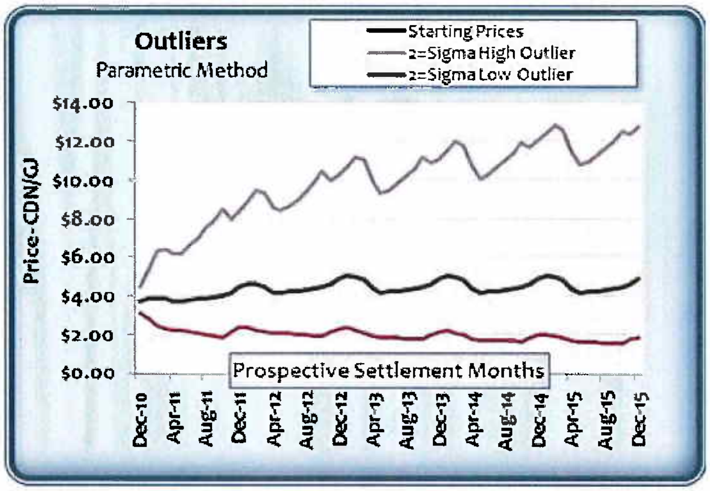


AECO volatility, as measured, would indicate the prompt month price of $3.37/GJ could migrate upward to $3.58 or downward to $3.17 over one day; as 2-sigma risk estimates these numbers would encompass all but 2.5% of the outcomes that might still fall above plus 2.5% that might fall below.

Prompt month daily volatility was measured as 3.15% and for a given futures contract, price risk is proportionate to the square root of time. So the Oct-10 contract could migrate three times as much over nine days as one day. Similarly, volatilities of further-forward futures contracts decline with distance from the prompt, so measured in December 2010, Jan-11 will be more volatile than Feb-11 which is more volatile than Mar-11, etc. When quantifying risk for any multi-month period the volatility must reflect a composite of the futures contracts for that period.

Generating risk assessments for each monthly futures contract, beginning with the forward curve as the mean expectation, the risk envelope could be extended; it would appear as follows:

A-2, Figure 3



This graphic shows a very orderly view of the 2-sigma boundaries associated with current prices and volatility. But real markets do not behave in such an orderly manner; prices may be confined to these boundaries 95% of the time, but the path by which they get there will be chaotic. Monte Carlo simulations may be used to generate random price paths to be used in the assessment of risk strategies.

Value at Risk (VaR)

A hedge program is primarily aimed at producing high confidence in tolerable outcomes. VaR provides a tool that can be deployed in hedge decisions to provide that confidence.

Value at Risk quantifies the risk for a "holding period" that is appropriate to the hedge manager's hedging decisions. If the hedge program is designed to monitor and respond to risk on a weekly basis, a ten-day risk assessment would provide an appropriate cushion in the determination of how the decision to *forego* today's hedge opportunities might be tolerated. The ten day time span is called the "holding period" because it indicates the hedge manager's risk of holding positions unchanged for that period.

So to calculate an illustrative value at risk, assume that the 2011 AECO strip exhibits a 2-sigma upward market risk over the next ten days equal to $.60 per GJ. Note that VaR relates to the market values only inasmuch as the portfolio is unhedged; our real concern is the portfolio of customer gas requirements. If those requirements were hedged in a 40% ratio, the portfolio would be exposed to 60% of the market risk, so it would be exposed to a $.36/GJ move upward. If that portfolio represented 100 million GJ to serve customers, the VaR related to customer bill risk would be $36 million. Further, if the current portfolio price were $4.00/GJ the expected value of customer gas requirements would be $400 million and the 2-sigma outlier for hedge opportunities that might be presented 10 days from now would be $436 million. The hedge manager could make use of that outlier to determine if it is tolerable to hold current hedge positions until the next review.

Monte Carlo Models

Having quantified volatility, a Monte Carlo simulation was run to propagate random price paths (day 2 values migrate randomly from day 1 values, and so on). The day-to-day random walk was generated assuming a lognormal distribution and using standard Brownian motion techniques, including a random walk of the volatility parameter. Inter-month correlations were assumed at 99%. For each price path, daily 60-month forward curves were generated through 2019. For the hedge decision simulations week-ending values were recorded from the Monte Carlo model and strategy assessments were conducted based on weekly hedge decisions in accordance with the various rules specified.

Appendix 3: Hedge Strategy Assessments, Metrics and Graphics

Each Strategy is presented as to performance on each of four price paths.

Strategy A

Summary of Path Results — path 582

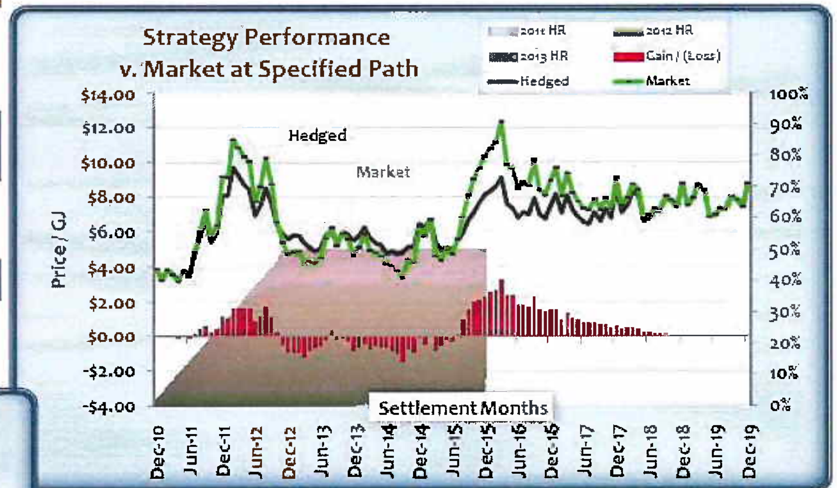
Strategy		Max Overall Hedge Ratio/Horizon	50%	36 months
path 582		Premiums Expended, ($ Mil.)	$0.00 Avg Yr	$0.00 Max Yr

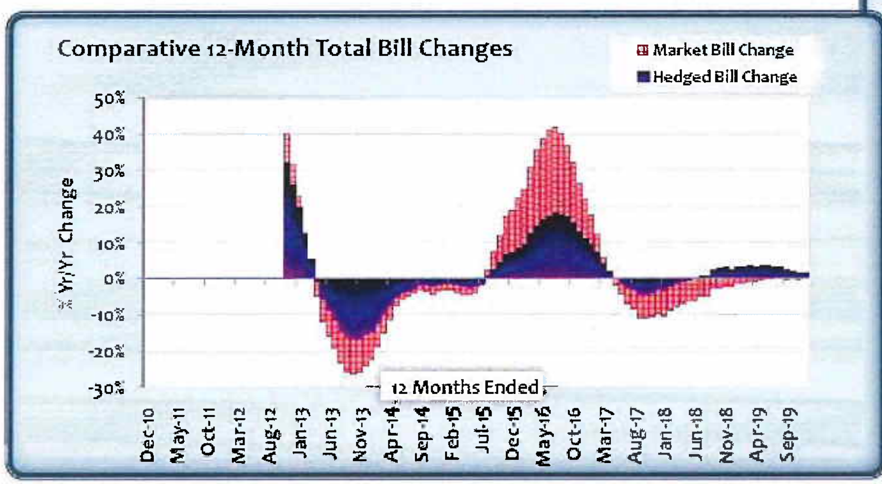
Max Programmatic 50% | Boundary 3 112% | Value Target Yr 1 95%

Programmatic Rules	1 (1=On)	Horizon	Increment	Hedge Ratio
Increment		36 Months	2.0%	
Max Programmatic				50%
Min @ Month 12				50%

Defensive Rules	0 (1=On)	1st Calendar Year		2nd Calendar Year	
Percentage Options:	25%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
~~Boundary 1~~		[illegible]	[illegible]	[illegible]	[illegible]
~~Boundary 2~~		[illegible]	[illegible]	[illegible]	[illegible]
~~Boundary 3~~		[illegible]	[illegible]	[illegible]	[illegible]

Value Rules	1 (1=On)	Price	Risk/Reward Criteria	Increment	Cumulative Max
~~Value Target Yr 1~~		95%	None	5%	50%
~~Value Target Yr 2~~		95%		3%	50%
~~Value Target Yr 3~~		0%		3%	50%





Average Commodity Market Value		$ 6.99
Average Annual Bills at Market		$ 1,414,316,104
Worst 12-Month Total Bill Increase		
At Market	498,212,802	41.8% Max
As Hedged	365,599,539	31.9% Max
Mitigation	$ 132,613,263	9.9%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 79,950,796
% of Average Annual Bill @ Market		5.7% Max
Mitigation Ratio		
Mitigation / Out of Market		**1.75**

Summary of Path Results

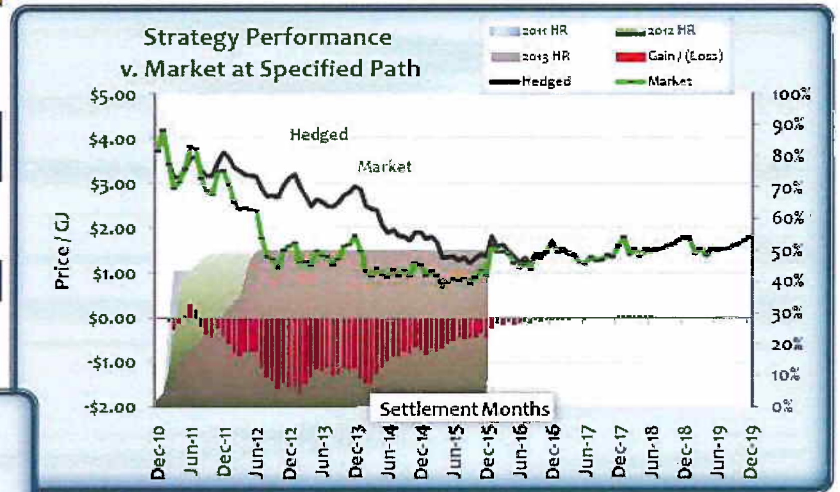
path 532

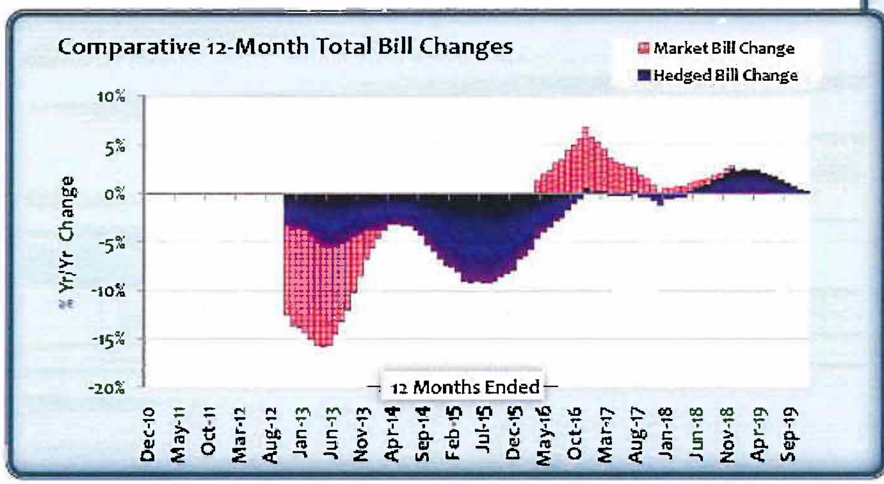
Strategy		Max Overall Hedge Ratio/Horizon		50%	36 months	Max Programmatic 50%	Boundary 3 112%	Value Target Yr 1 95%
path 532		Premiums Expended, ($ Mil.)		$0.00 Avg Yr	$0.00 Max Yr			

Programmatic Rules	1 (1=On)	Horizon	Increment	Hedge Ratio	
Increment		36 Months	2.0%		
Max Programmatic				50%	
Min @ Month 12				50%	

Defensive Rules	0 (1=On)	1st Calendar Year		2nd Calendar Year	
Percentage Options:	25%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
~~Boundary 1~~		[illegible]	[illegible]	[illegible]	[illegible]
~~Boundary 2~~		[illegible]	[illegible]	[illegible]	[illegible]
~~Boundary 3~~		[illegible]	[illegible]	[illegible]	[illegible]

Value Rules	1 (1=On)	Price	Risk/Reward Criteria	Increment	Cumulative Max
~~Value Target Yr 1~~		95%	None	5%	50%
~~Value Target Yr 2~~		95%		3%	50%
~~Value Target Yr 3~~		0%	....	3%	50%





Average Commodity Market Value		$ 1.64
Average Annual Bills at Market		$ 847,680,622
Worst 12-Month Total Bill Increase		
At Market	51,617,061	6.7% Max
As Hedged	19,745,425	2.4% Max
Mitigation	$ 31,871,636	4.3%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 147,121,621
% of Average Annual Bill @ Market		17.4% Max
Mitigation Ratio		
Mitigation / Out of Market		**0.25**

Summary of Path Results

path 515

Strategy: path 515

Max Overall Hedge Ratio/Horizon	50% / 36 months
Premiums Expended, ($ Mil.)	$0.00 Avg Yr / $0.00 Max Yr
Max Programmatic	50%
Boundary 3	112%
Value Target Yr 1	95%

Programmatic Rules 1 {1=On}

	Horizon	Increment	Hedge Ratio
Increment	36 Months	2.0%	
Max Programmatic			50%
Min @ Month 12			50%

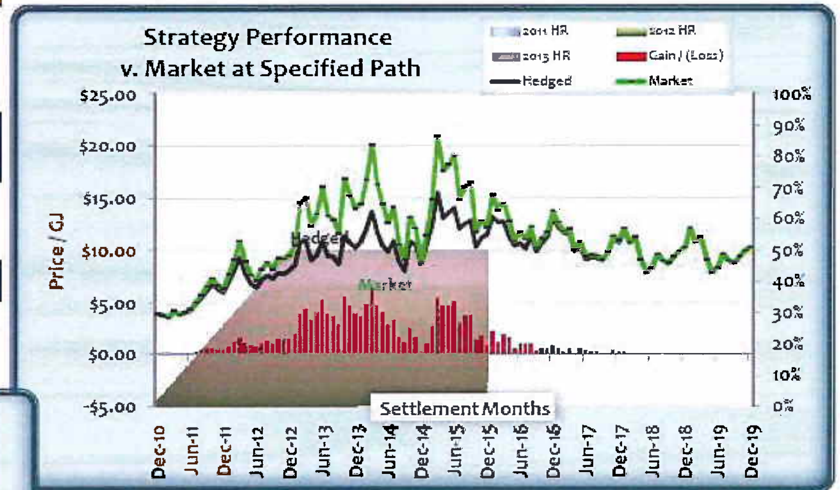
Defensive Rules 0 {1=On}

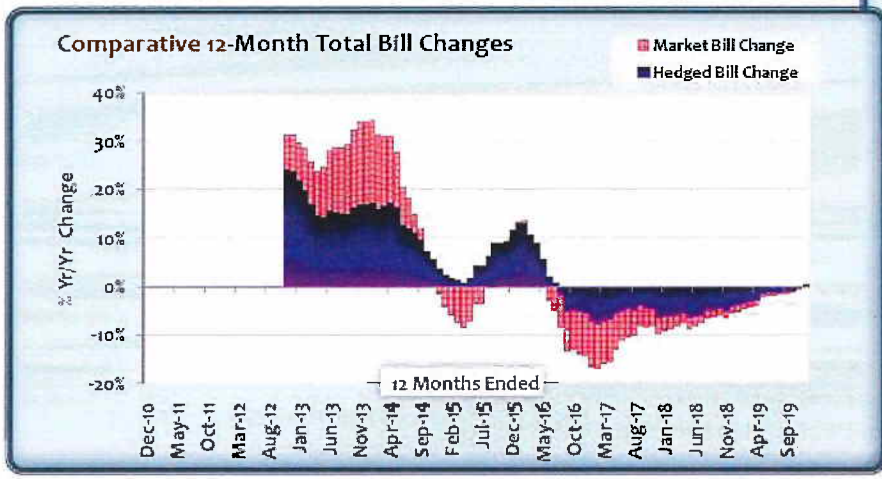
Percentage Options: 25%

	1st Calendar Year Price Tolerance	1st Calendar Year Max Ratio	2nd Calendar Year Price Tolerance	2nd Calendar Year Max Ratio
~~Boundary 1~~	[illegible]	[illegible]	[illegible]	[illegible]
~~Boundary 2~~	[illegible]	[illegible]	[illegible]	[illegible]
~~Boundary 3~~	[illegible]	[illegible]	[illegible]	[illegible]

Value Rules 1 {1=On}

	Price	Risk/Reward Criteria	Increment	Cumulative Max
~~Value Target Yr 1~~	95%	None	5%	50%
~~Value Target Yr 2~~	95%		3%	50%
~~Value Target Yr 3~~	0%		3%	50%





Average Commodity Market Value		$ 10.96
Average Annual Bills at Market		$ 1,834,066,556
Worst 12-Month Total Bill Increase		
At Market	551,904,876	34.0% Max
As Hedged	282,319,234	23.9% Max
Mitigation	$ 269,585,643	10.1%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 0
% of Average Annual Bill @ Market		0.0% Max
Mitigation Ratio		
Mitigation / Out of Market		**NA**

Summary of Path Results

path 150

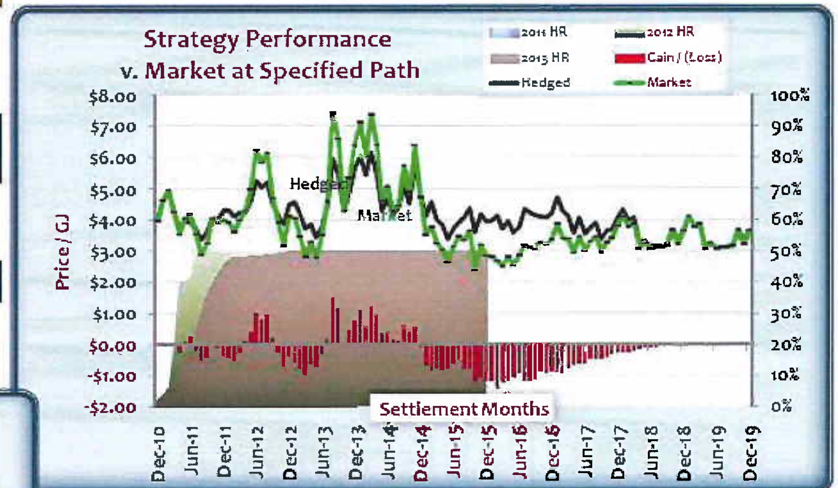
Strategy		Max Overall Hedge Ratio/Horizon	50%	36 months	
path 150		Premiums Expended, ($ Mil.)	$0.00 Avg Yr	$0.00 Max Yr	

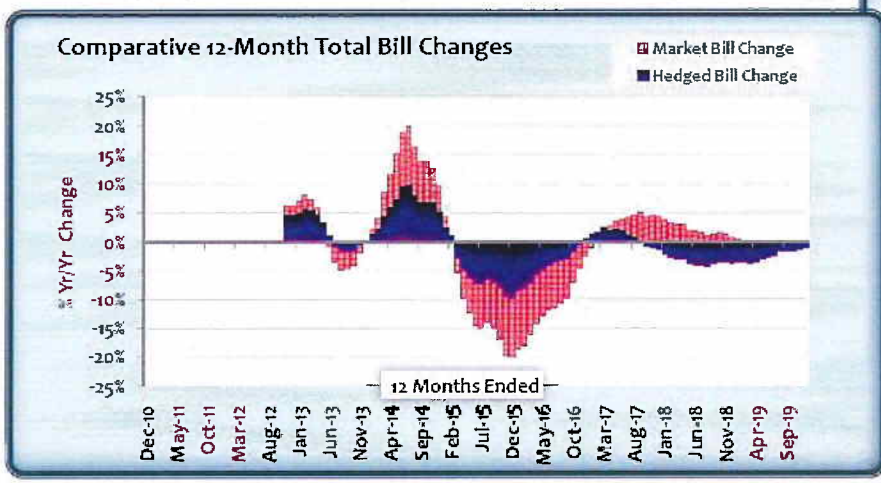
Max Programmatic	50%	Boundary 3	112%	Value Target Yr 1	95%

Programmatic Rules	1 {1=On}	Horizon	Increment	Hedge Ratio
Increment		36 Months	2.0%	
Max Programmatic				50%
Min @ Month 12				50%

Defensive Rules	0 {1=On}	1st Calendar Year		2nd Calendar Year	
Percentage Options:	25%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
~~Boundary 1~~		[illegible]	[illegible]	[illegible]	[illegible]
~~Boundary 2~~		[illegible]	[illegible]	[illegible]	[illegible]
~~Boundary 3~~		[illegible]	[illegible]	[illegible]	[illegible]

Value Rules	1 {1=On}	Price	Risk/Reward Criteria	Increment	Cumulative Max
~~Value Target Yr 1~~		95%	None	5%	50%
~~Value Target Yr 2~~		95%		3%	50%
~~Value Target Yr 3~~		0%		3%	50%





Average Commodity Market Value		$ 3.88
Average Annual Bills at Market		$ 1,085,466,256
Worst 12-Month Total Bill Increase		
At Market	215,064,247	19.8% Max
As Hedged	107,544,083	9.6% Max
Mitigation	$ 107,520,164	10.2%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 119,996,744
% of Average Annual Bill @ Market		11.1% Max
Mitigation Ratio		
Mitigation / Out of Market		0.92

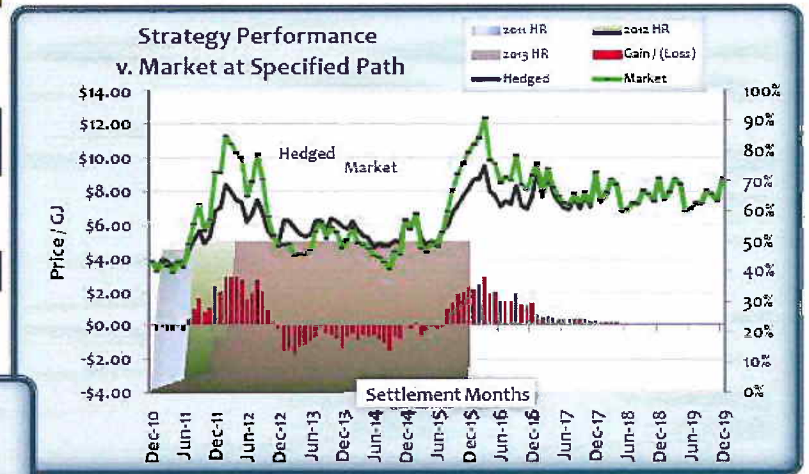
Strategy B

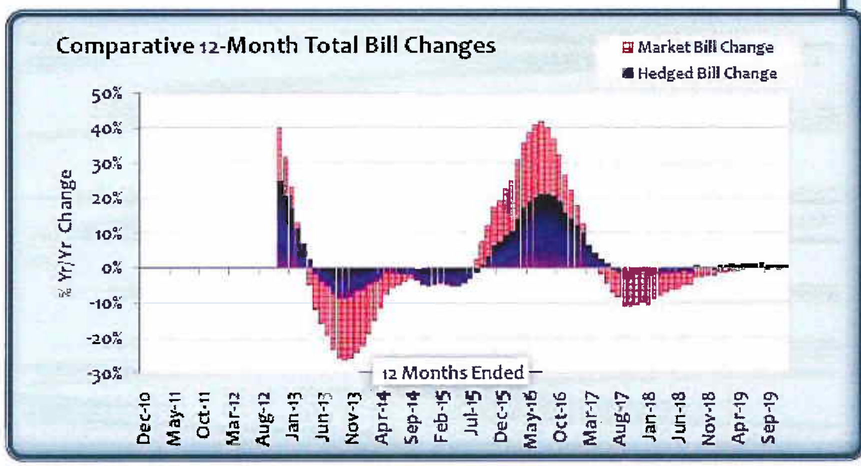
Summary of Path Results

path 582

Strategy		Max Overall Hedge Ratio/Horizon		50%	36 months
path 582		Premiums Expended, ($ Mil.)		$0.00 Avg Yr	$0.00 Max Yr
Programmatic Rules	1 (1=On)	Horizon	Increment	Hedge Ratio	
Increment		36 Months	0.6%		
Max Programmatic				15%	
Min @ Month 12				15%	
Defensive Rules	1 (1=On)	1st Calendar Year		2nd Calendar Year	
Percentage Options:	0%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		110%	30%	115%	20%
Boundary 2		114%	40%	119%	30%
Boundary 3		116%	50%	121%	40%
Value Rules	1 (1=On)	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	120%	1%	50%
Value Target Yr 2		95%	120%	1%	50%
Value Target Yr 3		0%	120%	1%	50%

Max Programmatic 15% **Boundary 3** 116% **Value Target Yr 1** 95%





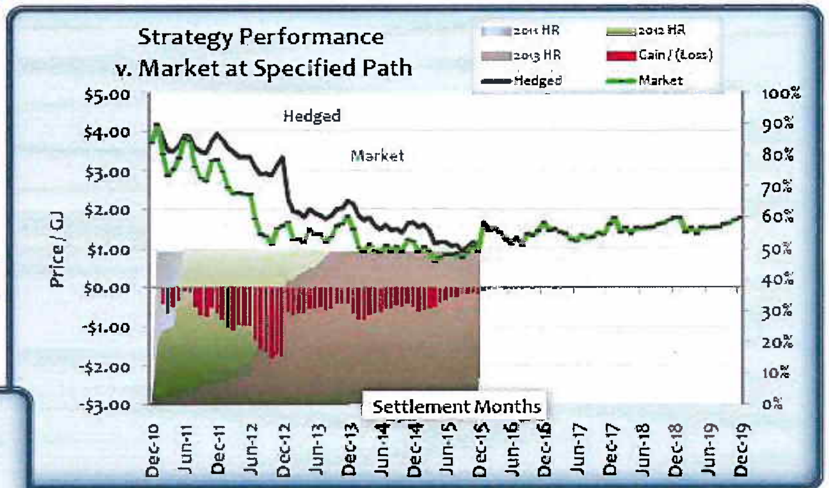
Average Commodity Market Value		$ 6.99
Average Annual Bills at Market		$ 1,414,316,104
Worst 12-Month Total Bill Increase		
At Market	498,212,802	41.8% Max
As Hedged	278,807,359	24.7% Max
Mitigation	$ 219,405,443	17.1%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 98,311,613
% of Average Annual Bill @ Market		7.0% Max
Mitigation Ratio		
Mitigation / Out of Market		2.46

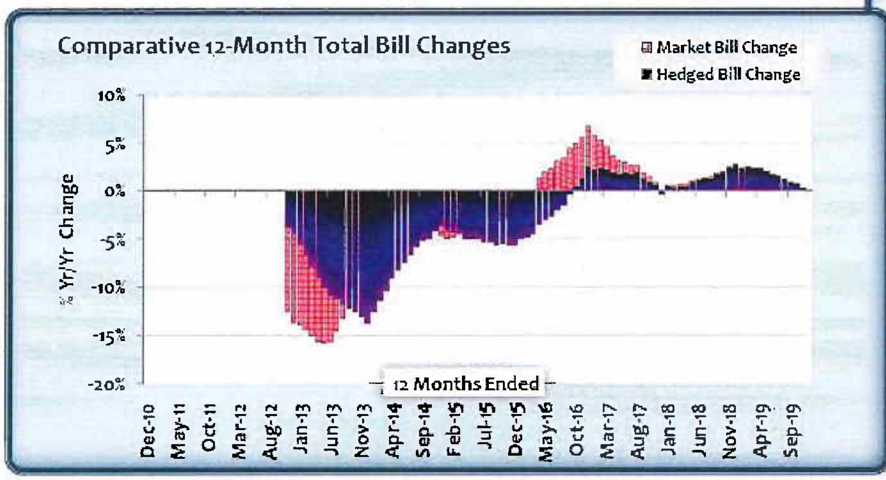
Summary of Path Results

path 532

Strategy		Max Overall Hedge Ratio/Horizon		50%	36 months
path 532		Premiums Expended, ($ Mil.)		$0.00 Avg Yr	$0.00 Max Yr
Programmatic Rules	1 {1=On}	Horizon	Increment	Hedge Ratio	
Increment		36 Months	0.6%		
Max Programmatic				15%	
Min @ Month 12				15%	
Defensive Rules	1 {1=On}	1st Calendar Year		2nd Calendar Year	
Percentage Options:	0%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		110%	30%	115%	20%
Boundary 2		114%	40%	119%	30%
Boundary 3		116%	50%	121%	40%
Value Rules	1 {1=On}	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	120%	1%	50%
Value Target Yr 2		95%	120%	1%	50%
Value Target Yr 3		0%	120%	1%	50%

Max Programmatic	15%	Boundary 3	116%	Value Target Yr 1	95%





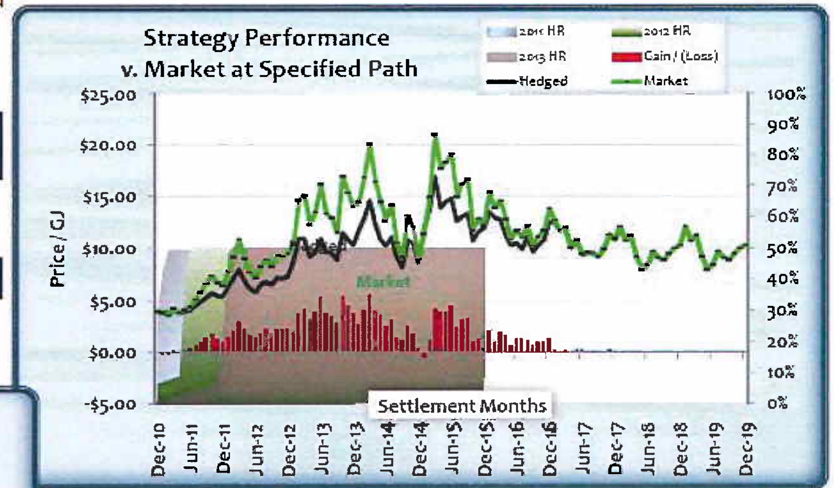
Average Commodity Market Value		$ 1.64
Average Annual Bills at Market		$ 847,680,622
Worst 12-Month Total Bill Increase		
At Market	51,617,061	6.7% Max
As Hedged	21,572,342	2.6% Max
Mitigation	$ 30,044,719	4.1%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 135,471,013
% of Average Annual Bill @ Market		16.0% Max
Mitigation Ratio		
Mitigation / Out of Market		**0.26**

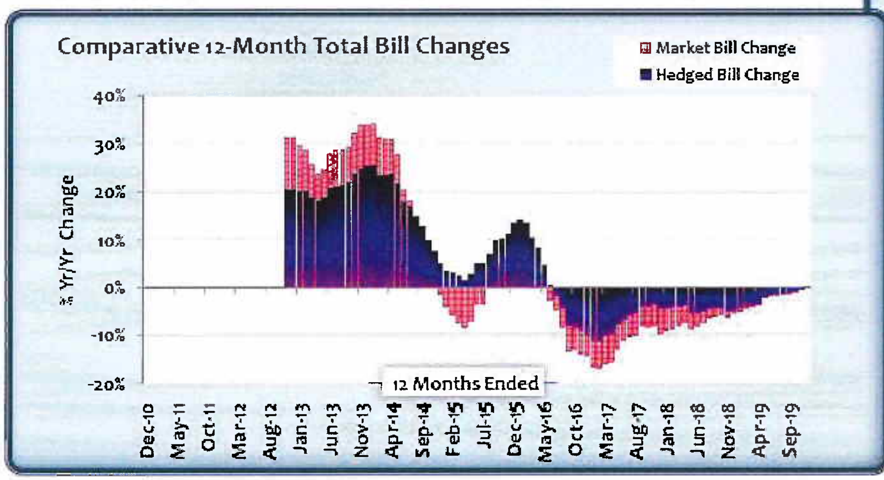
Summary of Path Results

path 515

Strategy		Max Overall Hedge Ratio/Horizon	50%	36 months	Max Programmatic 15%	Boundary 3 116%	Value Target Yr 1 95%
path 515		Premiums Expended, ($ Mil.)	$0.00 Avg Yr	$0.00 Max Yr			

Programmatic Rules	1 (1=On)	Horizon	Increment	Hedge Ratio	
Increment		36 Months	0.6%		
Max Programmatic				15%	
Min @ Month 12				15%	
Defensive Rules	1 (1=On)	1st Calendar Year		2nd Calendar Year	
Percentage Options:	0%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		110%	30%	115%	20%
Boundary 2		114%	40%	119%	30%
Boundary 3		116%	50%	121%	40%
Value Rules	1 (1=On)	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	120%	1%	50%
Value Target Yr 2		95%	120%	1%	50%
Value Target Yr 3		0%	120%	1%	50%





Average Commodity Market Value		$ 10.96
Average Annual Bills at Market		$ 1,834,066,556
Worst 12-Month Total Bill Increase		
At Market	551,904,876	34.0% Max
As Hedged	355,233,552	25.2% Max
Mitigation	$ 196,671,325	8.9%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 0
% of Average Annual Bill @ Market		0.0% Max
Mitigation Ratio		
Mitigation / Out of Market		NA

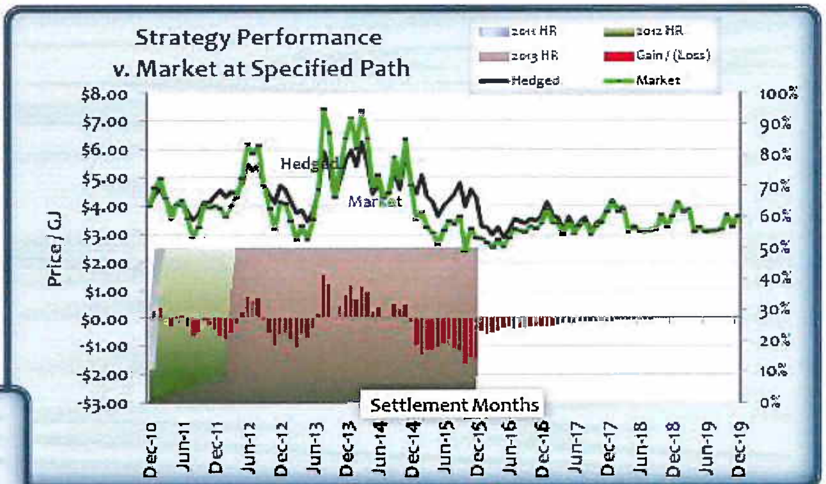
Summary of Path Results

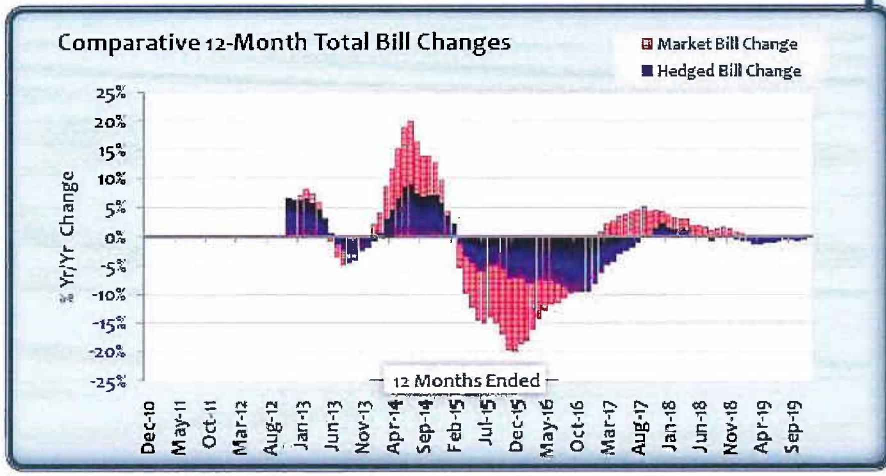
path 150

Strategy		**Max Overall Hedge Ratio/Horizon**	50%	36 months	
path 150		**Premiums Expended, ($ Mil.)**	$0.00 Avg Yr	$0.00 Max Yr	

Max Programmatic 15% | **Boundary 3** 116% | **Value Target Yr 1** 95%

Programmatic Rules	1 {1=On}	Horizon	Increment	Hedge Ratio	
Increment		36 Months	0.6%		
Max Programmatic				15%	
Min @ Month 12				15%	
Defensive Rules	1 {1=On}	1st Calendar Year		2nd Calendar Year	
Percentage Options	0%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		110%	30%	115%	20%
Boundary 2		114%	40%	119%	30%
Boundary 3		116%	50%	121%	40%
Value Rules	1 {1=On}	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	120%	1%	50%
Value Target Yr 2		95%	120%	1%	50%
Value Target Yr 3		0%	120%	1%	50%





Average Commodity Market Value		$ 3.88
Average Annual Bills at Market		$ 1,085,466,256

Worst 12-Month Total Bill Increase

At Market	215,064,247	19.8% Max
As Hedged	100,652,257	8.9% Max
Mitigation	$ 114,411,990	10.9%

Max 12-Month Out-of-Market Variance

$CDN Million	$ 120,218,346
% of Average Annual Bill @ Market	11.1% Max

Mitigation Ratio

Mitigation / Out of Market	0.98

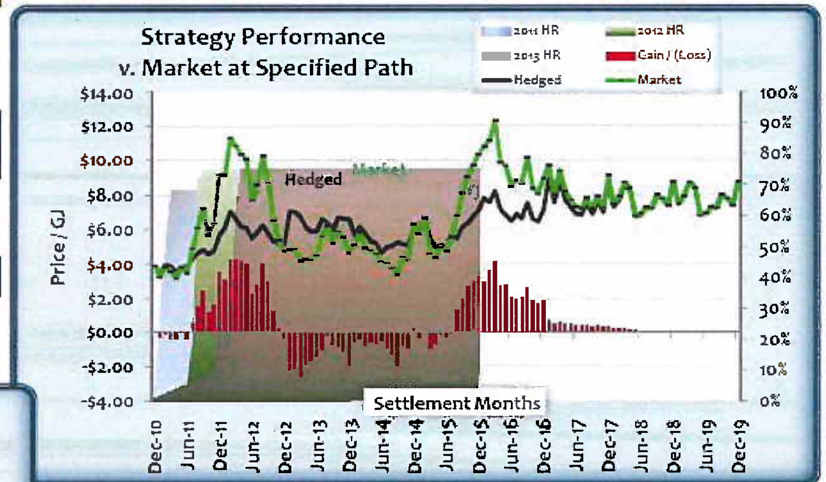
Strategy C

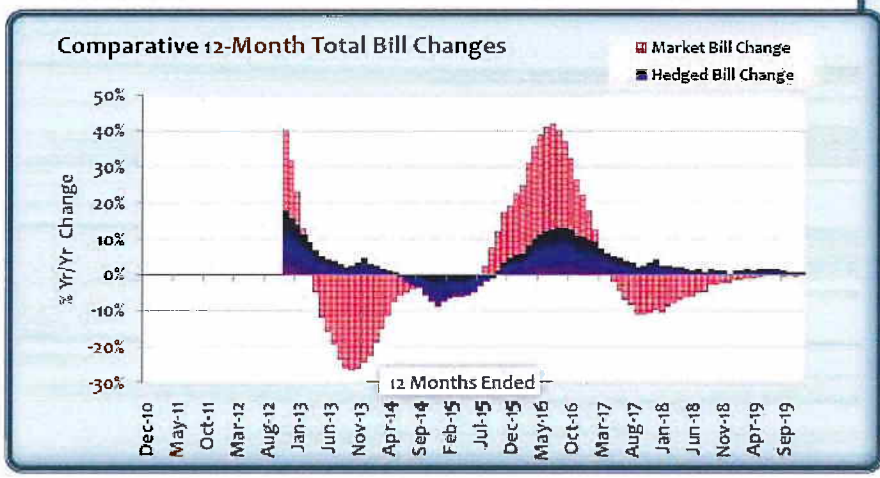
Summary of Path Results

path 582

Strategy	Max Overall Hedge Ratio/Horizon	75%	36 months	Max Programmatic 20%	Boundary 3 116%	Value Target Yr 1 95%
path 582	Premiums Expended, ($ Mil.)	$0.00 Avg Yr	$0.00 Max Yr			

Programmatic Rules	1 {1=On}	Horizon	Increment	Hedge Ratio	
Increment		36 Months	0.8%		
Max Programmatic				20%	
Min @ Month 12				20%	
Defensive Rules	1 {1=On}	1st Calendar Year		2nd Calendar Year	
Percentage Options:	0%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		110%	45%	115%	35%
Boundary 2		114%	60%	119%	50%
Boundary 3		116%	75%	121%	60%
Value Rules	1 {1=On}	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	120%	1%	50%
Value Target Yr 2		95%	120%	1%	50%
Value Target Yr 3		0%	120%	1%	50%





Average Commodity Market Value		$ 6.99
Average Annual Bills at Market		$ 1,414,316,104
Worst 12-Month Total Bill Increase		
At Market	498,212,802	41.8% Max
As Hedged	194,564,335	17.5% Max
Mitigation	$ 303,648,467	24.3%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 153,330,106
% of Average Annual Bill @ Market		10.8% Max
Mitigation Ratio		
Mitigation / Out of Market		2.24

RiskCentrix, LLC
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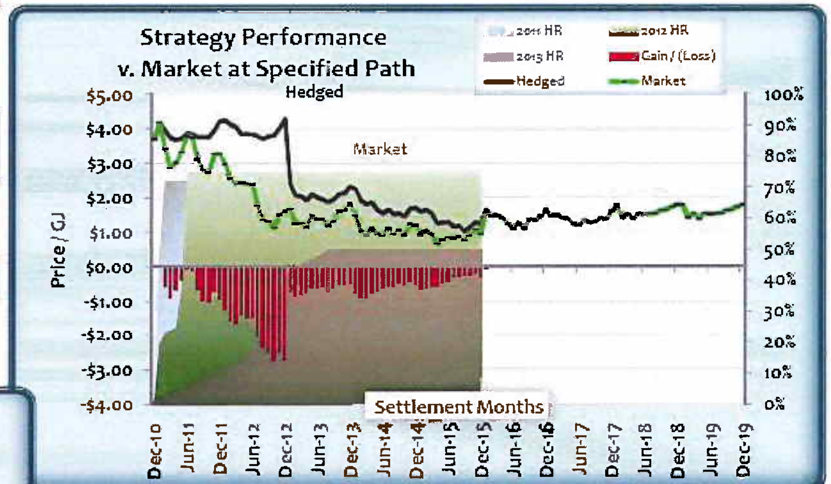
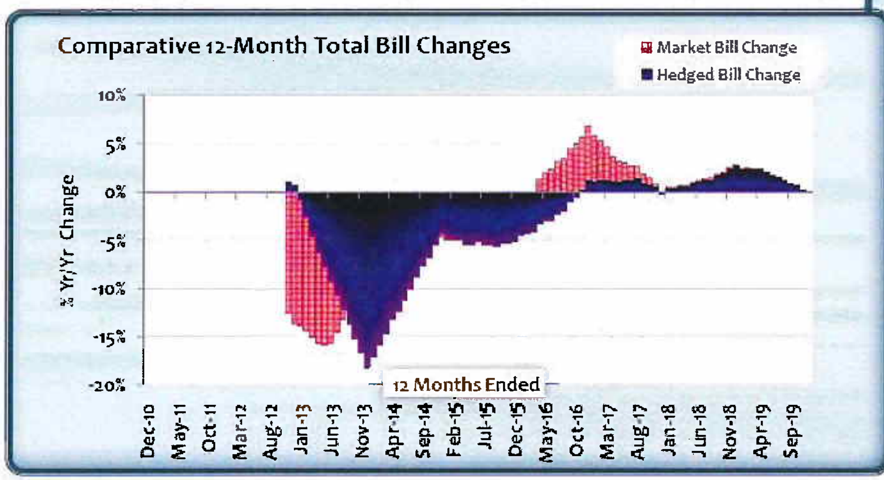
Summary of Path Results

path 532

Strategy		Max Overall Hedge Ratio/Horizon	75%	36 months	
path 532		Premiums Expended, ($ Mil.)	$0.00 Avg Yr	$0.00 Max Yr	
Programmatic Rules	1 {1=On}	Horizon	Increment	Hedge Ratio	
Increment		36 Months	0.8%		
Max Programmatic				20%	
Min @ Month 12				20%	
Defensive Rules	1 {1=On}	1st Calendar Year		2nd Calendar Year	
Percentage Options:	0%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		110%	45%	115%	35%
Boundary 2		114%	60%	119%	50%
Boundary 3		116%	75%	121%	60%
Value Rules	1 {1=On}	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	120%	1%	50%
Value Target Yr 2		95%	120%	1%	50%
Value Target Yr 3		0%	120%	1%	50%

Max Programmatic	20%	Boundary 3	116%	Value Target Yr 1	95%





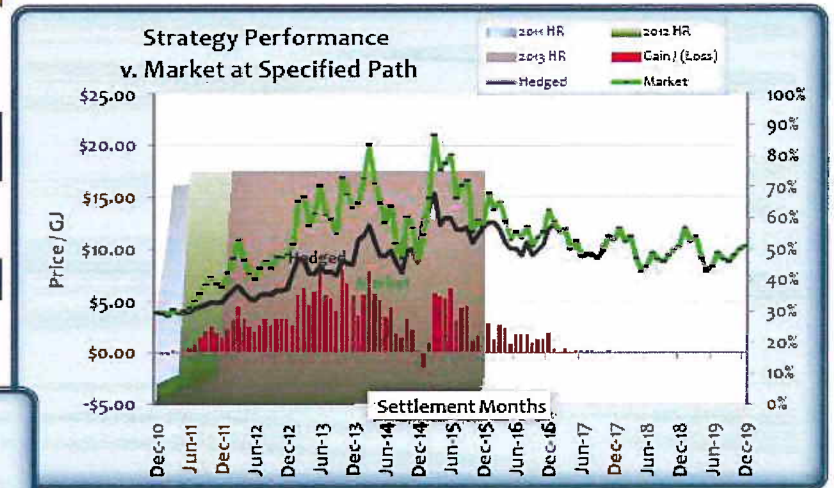
Average Commodity Market Value		$ 1.64
Average Annual Bills at Market		$ 847,680,622
Worst 12-Month Total Bill Increase		
At Market	51,617,061	6.7% Max
As Hedged	21,311,354	2.6% Max
Mitigation	$ 30,305,707	4.1%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 208,036,482
% of Average Annual Bill @ Market		24.5% Max
Mitigation Ratio		
Mitigation / Out of Market		0.17

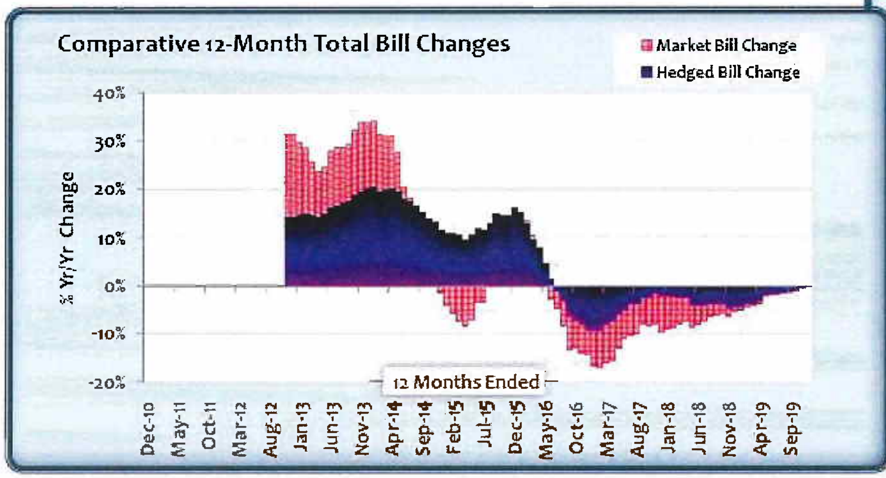
Summary of Path Results

path 515

Strategy		Max Overall Hedge Ratio/Horizon		75%	36 months
path 515		Premiums Expended, ($ Mil.)		$0.00 Avg Yr	$0.00 Max Yr
Programmatic Rules	1 {1=On}	Horizon	Increment	Hedge Ratio	
Increment		36 Months	0.8%		
Max Programmatic				20%	
Min @ Month 12				20%	
Defensive Rules	1 {1=On}	1st Calendar Year		2nd Calendar Year	
Percentage Options:	0%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		110%	45%	115%	35%
Boundary 2		114%	60%	119%	50%
Boundary 3		116%	75%	121%	60%
Value Rules	1 {1=On}	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	120%	1%	50%
Value Target Yr 2		95%	120%	1%	50%
Value Target Yr 3		0%	120%	1%	50%

Max Programmatic	20%	Boundary 3	116%	Value Target Yr 1	95%





Average Commodity Market Value		$ 10.96
Average Annual Bills at Market		$ 1,834,066,556
Worst 12-Month Total Bill Increase		
At Market	551,904,876	34.0% Max
As Hedged	263,491,437	20.2% Max
Mitigation	$ 288,413,440	13.9%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 0
% of Average Annual Bill @ Market		0.0% Max
Mitigation Ratio		
Mitigation / Out of Market		**NA**

Summary of Path Results

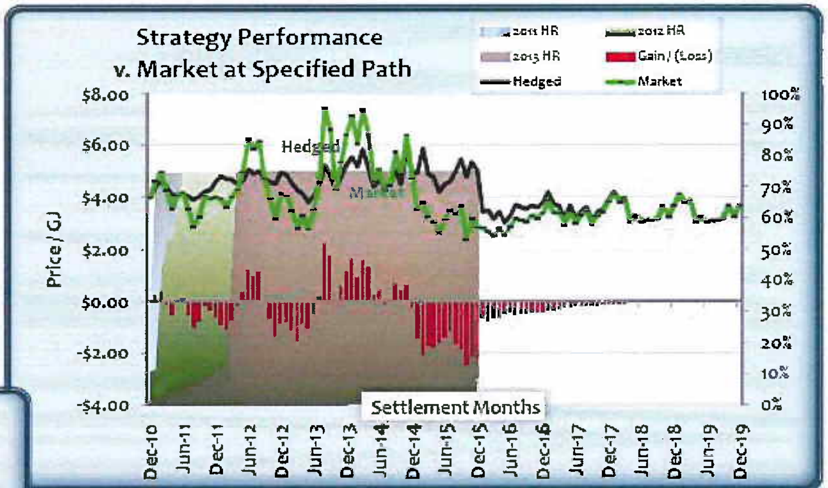
path 150

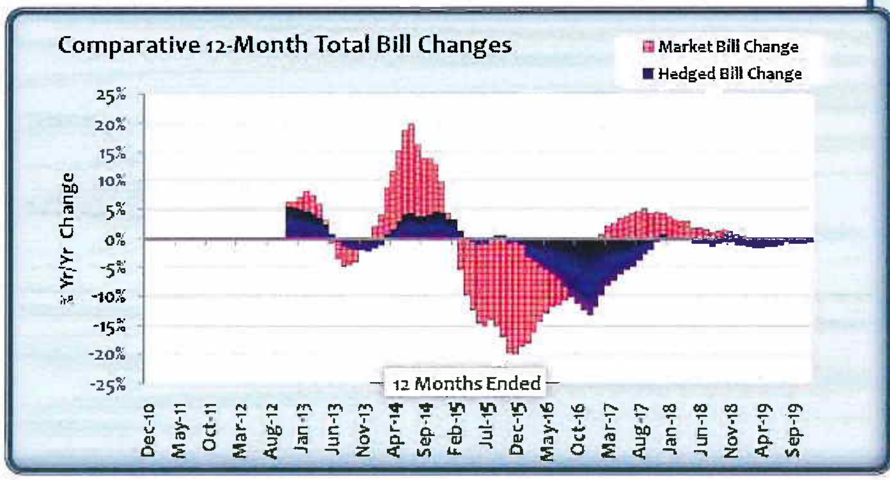
Max Overall Hedge Ratio/Horizon	75%	36 months	Max Programmatic 20%	Boundary 3 116%	Value Target Yr 1 95%
Premiums Expended, ($ Mil.)	$0.00 Avg Yr	$0.00 Max Yr			

Strategy

path 150

Programmatic Rules	1 (1=On)	Horizon	Increment	Hedge Ratio	
Increment		36 Months	0.8%		
Max Programmatic				20%	
Min @ Month 12				20%	
Defensive Rules	1 (1=On)	1st Calendar Year		2nd Calendar Year	
Percentage Options:	0%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		110%	45%	115%	35%
Boundary 2		114%	60%	119%	50%
Boundary 3		116%	75%	121%	60%
Value Rules	1 (1=On)	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	120%	1%	50%
Value Target Yr 2		95%	120%	1%	50%
Value Target Yr 3		0%	120%	1%	50%





Average Commodity Market Value		$ 3.88
Average Annual Bills at Market		$ 1,085,466,256

Worst 12-Month Total Bill Increase

At Market	215,064,247	19.8% Max
As Hedged	58,663,648	5.3% Max
Mitigation	$ 156,400,599	14.6%

Max 12-Month Out-of-Market Variance

$CDN Million	$ 186,808,591
% of Average Annual Bill @ Market	17.2% Max

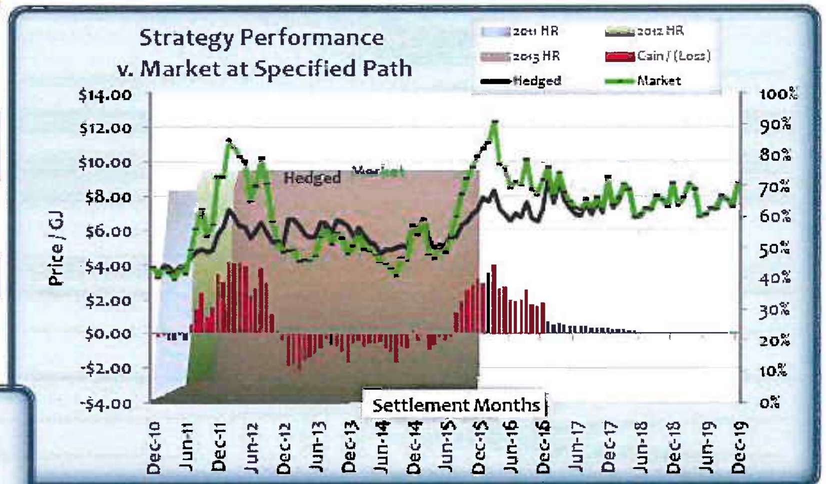
Mitigation Ratio

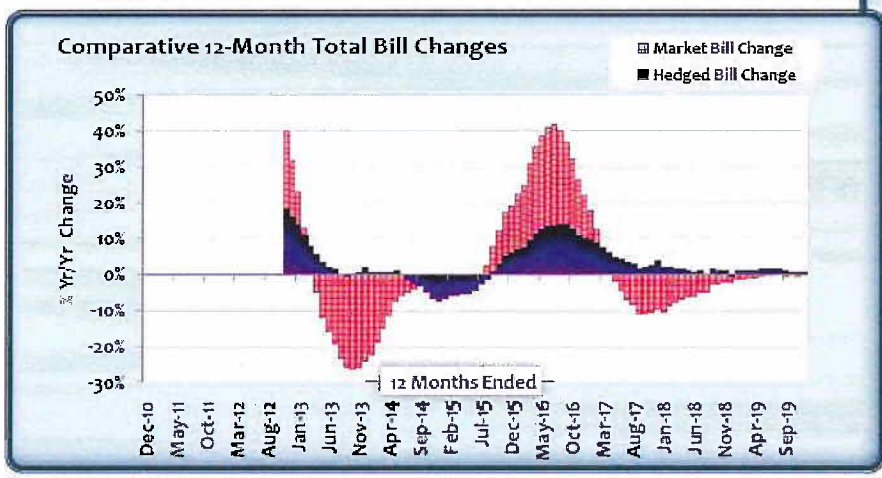
Mitigation / Out of Market	0.85

Strategy D

Summary of Path Results path 582

Strategy		Max Overall Hedge Ratio/Horizon		75%	36 months	Max Programmatic 20% Boundary 3 116% Value Target Yr 1 95%
path 582		Premiums Expended, ($ Mil.)		$7.06 Avg Yr	$13.82 Max Yr	
Programmatic Rules	1 (1=On)	Horizon	Increment	Hedge Ratio		
Increment		36 Months	0.8%			
Max Programmatic				20%		
Min @ Month 12				20%		
Defensive Rules	1 (1=On)	1st Calendar Year		2nd Calendar Year		
Percentage Options:	25%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio	
Boundary 1		110%	45%	115%	35%	
Boundary 2		114%	60%	119%	50%	
Boundary 3		116%	75%	121%	60%	
Value Rules	1 (1=On)	Price	Risk/Reward Criteria	Increment	Cumulative Max	
Value Target Yr 1		95%	120%	1%	50%	
Value Target Yr 2		95%	120%	1%	50%	
Value Target Yr 3		0%	120%	1%	50%	



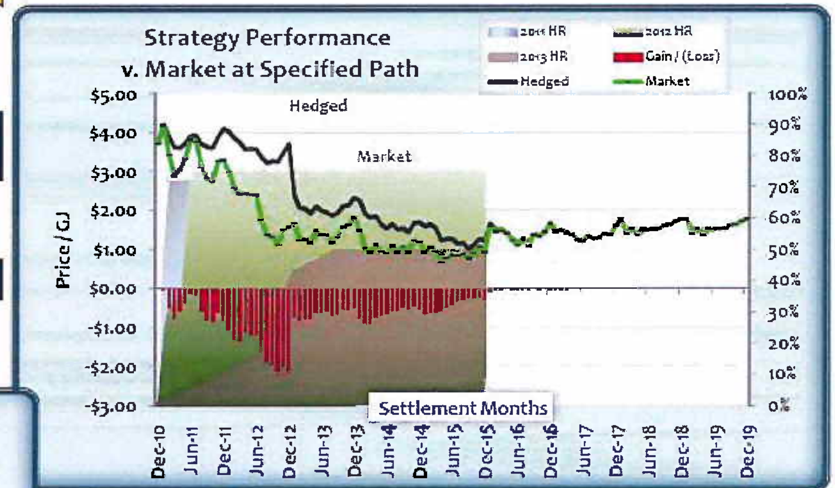


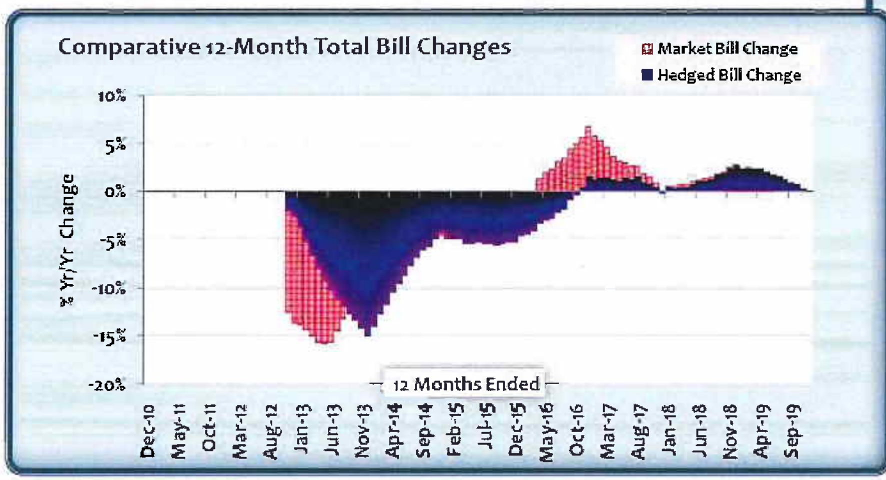
Average Commodity Market Value		$ 6.99
Average Annual Bills at Market		$ 1,414,316,104
Worst 12-Month Total Bill Increase		
At Market	498,212,802	41.8% Max
As Hedged	201,767,764	18.1% Max
Mitigation	$ 296,445,038	23.7%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 128,560,197
% of Average Annual Bill @ Market		9.1% Max
Mitigation Ratio		
Mitigation / Out of Market		**2.61**

Summary of Path Results — path 532

Strategy		Max Overall Hedge Ratio/Horizon		75%	36 months
path 532		Premiums Expended, ($ Mil.)		$2.42 Avg Yr	$11.51 Max Yr
Programmatic Rules	1 {1=On}	Horizon	Increment	Hedge Ratio	
Increment		36 Months	0.8%		
Max Programmatic				20%	
Min @ Month 12				20%	
Defensive Rules	1 {1=On}	1st Calendar Year		2nd Calendar Year	
Percentage Options:	25%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		110%	45%	115%	35%
Boundary 2		114%	60%	119%	50%
Boundary 3		116%	75%	121%	60%
Value Rules	1 {1=On}	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	120%	1%	50%
Value Target Yr 2		95%	120%	1%	50%
Value Target Yr 3		0%	120%	1%	50%

Max Programmatic 20% | Boundary 3 116% | Value Target Yr 1 95%





Average Commodity Market Value		$ 1.64
Average Annual Bills at Market		$ 847,680,622
Worst 12-Month Total Bill Increase		
At Market	51,617,061	6.7% Max
As Hedged	21,053,778	2.6% Max
Mitigation	$ 30,563,283	4.2%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 165,611,115
% of Average Annual Bill @ Market		19.5% Max
Mitigation Ratio		
Mitigation / Out of Market		0.21

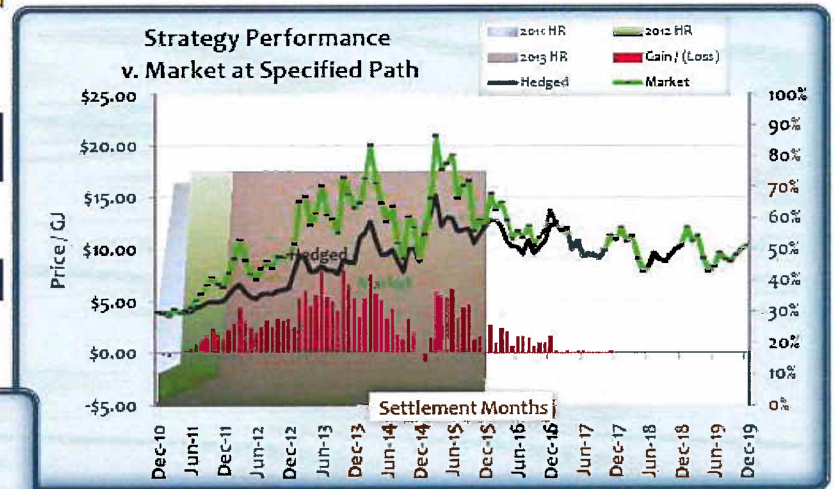
Summary of Path Results

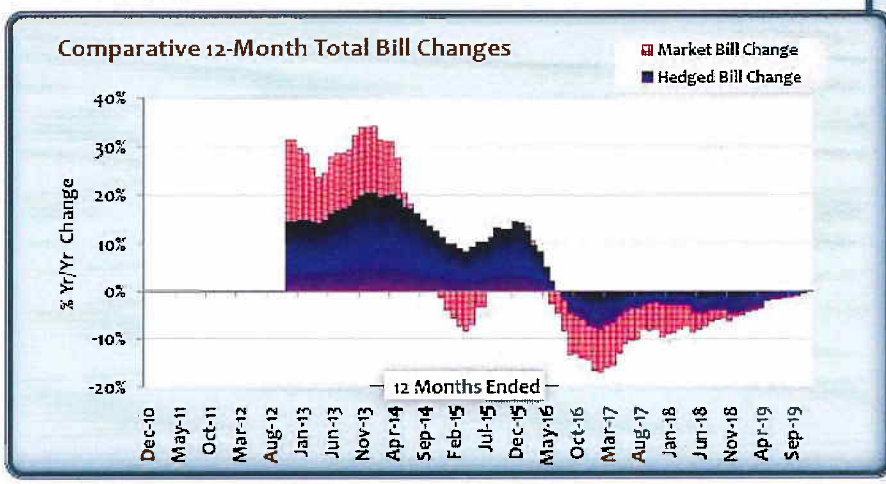
path 515

Strategy		Max Overall Hedge Ratio/Horizon	75%	36 months
path 515		Premiums Expended, ($ Mil.)	$10.62 Avg Yr	$23.21 Max Yr

Max Programmatic 20% | Boundary 3 116% | Value Target Yr 1 95%

Programmatic Rules	1 {1=On}	Horizon	Increment	Hedge Ratio	
Increment		36 Months	0.8%		
Max Programmatic				20%	
Min @ Month 12				20%	
Defensive Rules	1 {1=On}	1st Calendar Year		2nd Calendar Year	
Percentage Options:	25%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		110%	45%	115%	35%
Boundary 2		114%	60%	119%	50%
Boundary 3		116%	75%	121%	60%
Value Rules	1 {1=On}	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	120%	1%	50%
Value Target Yr 2		95%	120%	1%	50%
Value Target Yr 3		0%	120%	1%	50%





Average Commodity Market Value		$ 10.96
Average Annual Bills at Market		$ 1,834,066,556
Worst 12-Month Total Bill Increase		
At Market	551,904,876	34.0% Max
As Hedged	268,731,105	20.4% Max
Mitigation	$ 283,173,772	13.7%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 0
% of Average Annual Bill @ Market		0.0% Max
Mitigation Ratio		
Mitigation / Out of Market		NA

Summary of Path Results

path 150

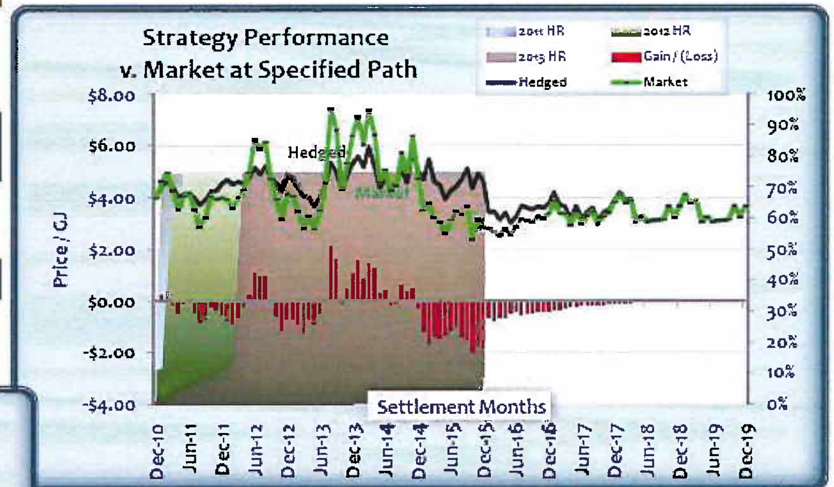
Strategy		Max Overall Hedge Ratio/Horizon	75%	36 months	
path 150		Premiums Expended, ($ Mil.)	$5.46 Avg Yr	$11.30 Max Yr	

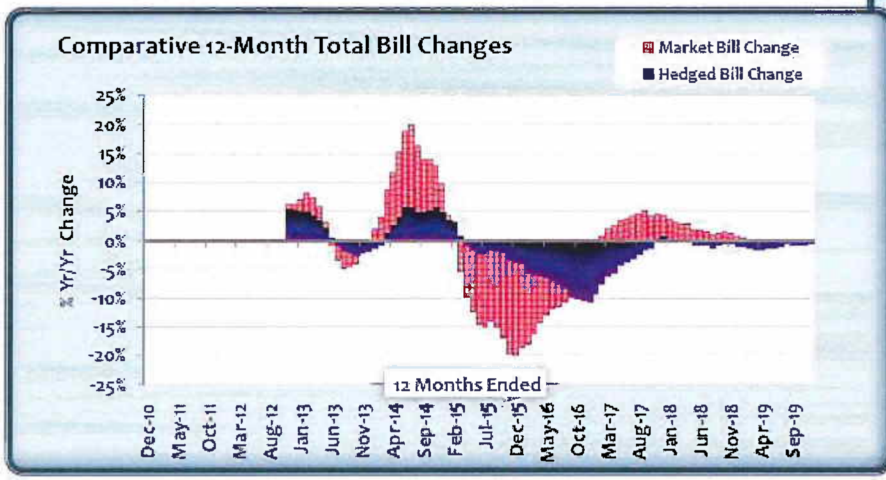
Max Programmatic 20% | Boundary 3 116% | Value Target Yr 1 95%

Programmatic Rules	1 {1=On}	Horizon	Increment	Hedge Ratio
Increment		36 Months	0.8%	
Max Programmatic				20%
Min @ Month 12				20%

Defensive Rules	1 {1=On}	1st Calendar Year		2nd Calendar Year	
Percentage Options:	25%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		110%	45%	115%	35%
Boundary 2		114%	60%	119%	50%
Boundary 3		116%	75%	121%	60%

Value Rules	1 {1=On}	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	120%	1%	50%
Value Target Yr 2		95%	120%	1%	50%
Value Target Yr 3		0%	120%	1%	50%





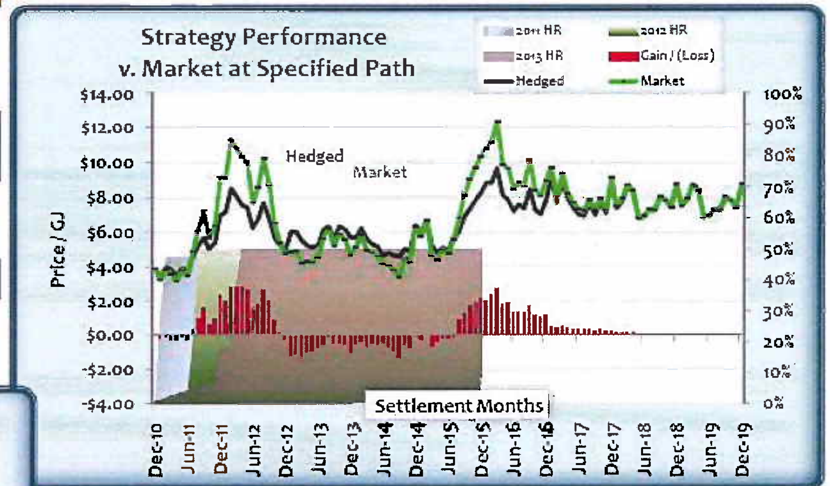
Average Commodity Market Value		$ 3.88
Average Annual Bills at Market		$ 1,085,466,256
Worst 12-Month Total Bill Increase		
At Market	215,064,247	19.8% Max
As Hedged	64,609,108	5.7% Max
Mitigation	$ 150,455,139	14.2%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 154,457,398
% of Average Annual Bill @ Market		14.2% Max
Mitigation Ratio		
Mitigation / Out of Market		1.00

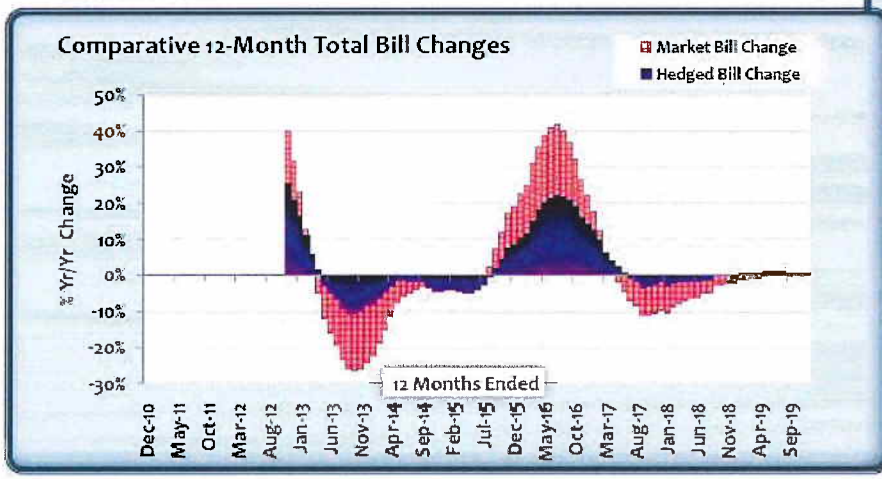
Strategy E

Summary of Path Results

path 582

Strategy		Max Overall Hedge Ratio/Horizon		50%	36 months	Max Programmatic 15% · Boundary 3 116% · Value Target Yr 1 95%
path 582		Premiums Expended, ($ Mil.)		$4.74 Avg Yr	$9.01 Max Yr	
Programmatic Rules	1 {1=On}	Horizon	Increment	Hedge Ratio		
Increment		36 Months	0.6%			
Max Programmatic				15%		
Min @ Month 12				15%		
Defensive Rules	1 {1=On}	1st Calendar Year		2nd Calendar Year		
Percentage Options:	25%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio	
Boundary 1		110%	30%	115%	20%	
Boundary 2		114%	40%	119%	30%	
Boundary 3		116%	50%	121%	40%	
Value Rules	1 {1=On}	Price	Risk/Reward Criteria	Increment	Cumulative Max	
Value Target Yr 1		95%	120%	1%	50%	
Value Target Yr 2		95%	120%	1%	50%	
Value Target Yr 3		0%	120%	1%	50%	





Average Commodity Market Value		$ 6.99
Average Annual Bills at Market		$ 1,414,316,104
Worst 12-Month Total Bill Increase		
At Market	498,212,802	41.8% Max
As Hedged	284,101,259	25.1% Max
Mitigation	$ 214,111,543	16.7%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 80,205,222
% of Average Annual Bill @ Market		5.7% Max
Mitigation Ratio		
Mitigation / Out of Market		2.94

RiskCentrix, LLC

Clarity in a World of Uncertainty

Summary of Path Results

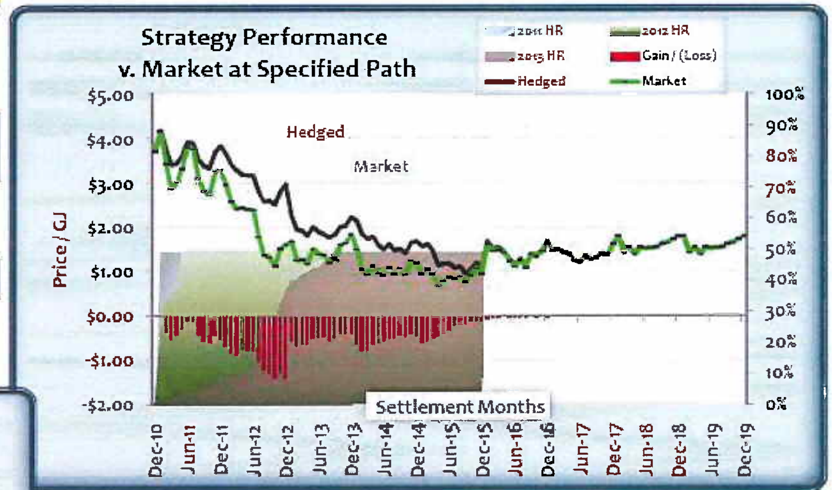
path 532

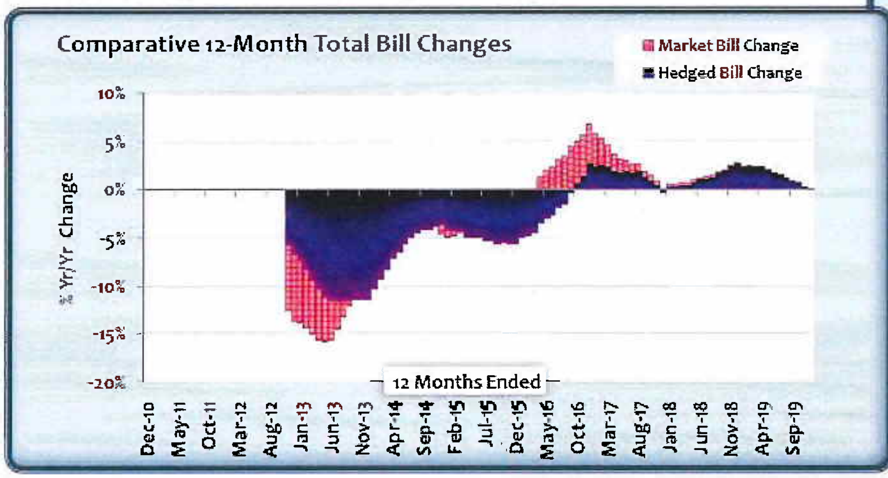
Strategy		Max Overall Hedge Ratio/Horizon	50%	36 months	Max Programmatic 15%	Boundary 3 116%	Value Target Yr 1 95%
path 532		Premiums Expended, ($ Mil.)	$1.57 Avg Yr	$7.34 Max Yr			

Programmatic Rules	1 {1=On}	Horizon	Increment	Hedge Ratio
Increment		36 Months	0.6%	
Max Programmatic				15%
Min @ Month 12				15%

Defensive Rules	1 {1=On}	1st Calendar Year		2nd Calendar Year	
Percentage Options:	25%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		110%	30%	115%	20%
Boundary 2		114%	40%	119%	30%
Boundary 3		116%	50%	121%	40%

Value Rules	1 {1=On}	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	120%	1%	50%
Value Target Yr 2		95%	120%	1%	50%
Value Target Yr 3		0%	120%	1%	50%





Average Commodity Market Value		$ 1.64
Average Annual Bills at Market		$ 847,680,622
Worst 12-Month Total Bill Increase		
At Market	51,617,061	6.7% Max
As Hedged	21,118,960	2.6% Max
Mitigation	$ 30,498,101	4.1%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 108,921,240
% of Average Annual Bill @ Market		12.8% Max
Mitigation Ratio		
Mitigation / Out of Market		0.32

RiskCentrix, LLC

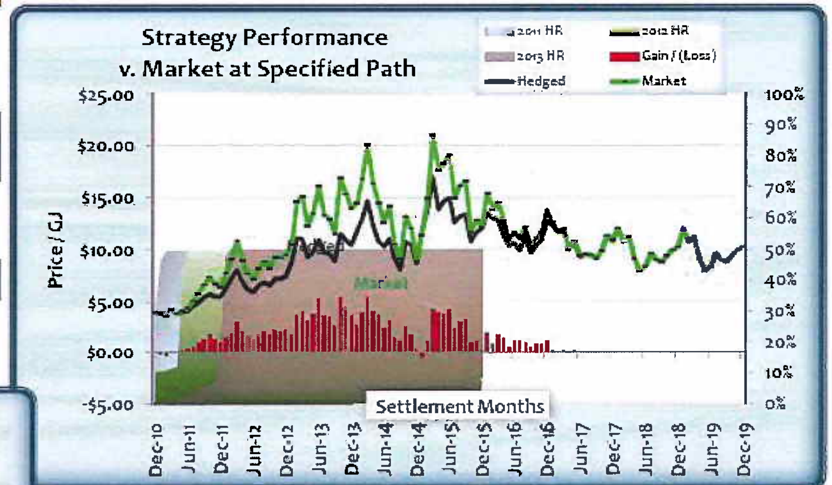
Clarity in a World of Uncertainty

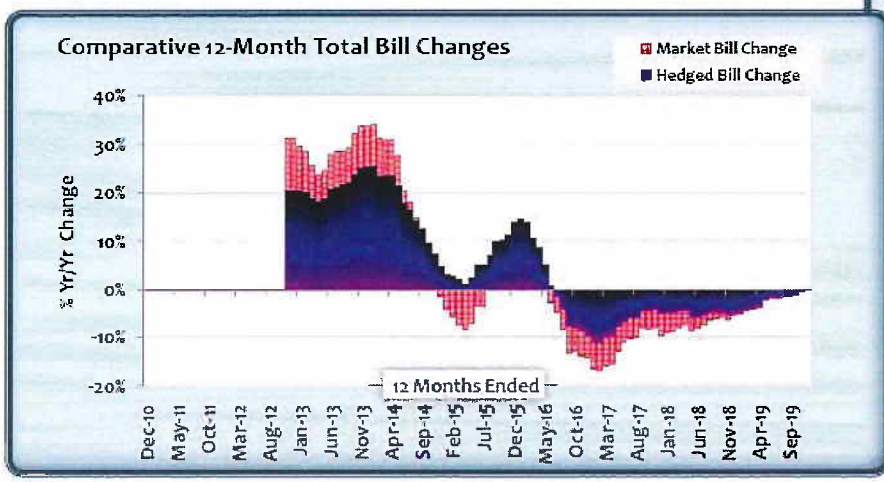
Summary of Path Results

path 515

Strategy		Max Overall Hedge Ratio/Horizon	50%	36 months	Max Programmatic 15%	Boundary 3 116%	Value Target Yr 1 95%
path 515		Premiums Expended, ($ Mil.)	$6.86 Avg Yr	$14.63 Max Yr			

Programmatic Rules	1 {1=On}	Horizon	Increment	Hedge Ratio	
Increment		36 Months	0.6%		
Max Programmatic				15%	
Min @ Month 12				15%	
Defensive Rules	1 {1=On}	1st Calendar Year		2nd Calendar Year	
Percentage Options:	25%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		110%	30%	115%	20%
Boundary 2		114%	40%	119%	30%
Boundary 3		116%	50%	121%	40%
Value Rules	1 {1=On}	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	120%	1%	50%
Value Target Yr 2		95%	120%	1%	50%
Value Target Yr 3		0%	120%	1%	50%





Average Commodity Market Value		$ 10.96
Average Annual Bills at Market		$ 1,834,066,556
Worst 12-Month Total Bill Increase		
At Market	551,904,876	34.0% Max
As Hedged	352,918,934	25.2% Max
Mitigation	$ 198,985,942	8.8%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 0
% of Average Annual Bill @ Market		0.0% Max
Mitigation Ratio		
Mitigation / Out of Market		NA

RiskCentrix, LLC

Clarity in a World of Uncertainty

Summary of Path Results

path 150

Max Overall Hedge Ratio/Horizon	50%	36 months		
Premiums Expended, ($ Mil.)	$3.57 Avg Yr	$7.41 Max Yr		
Max Programmatic 15%	Boundary 3 116%	Value Target Yr 1 95%		

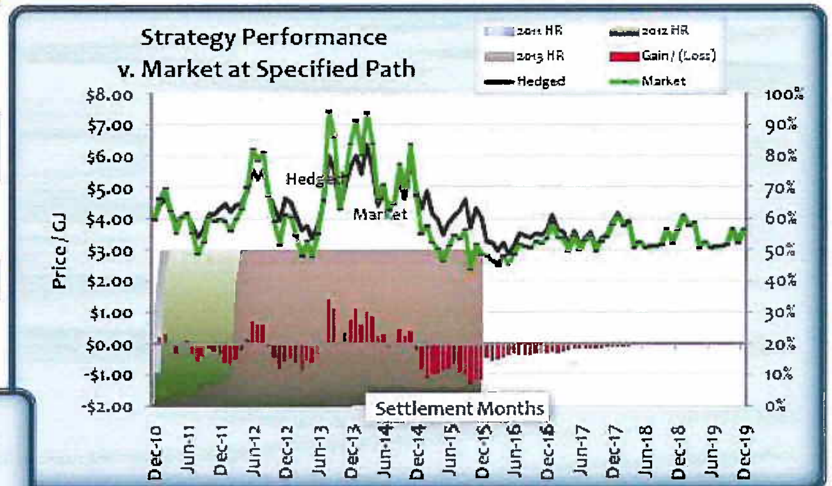
Strategy

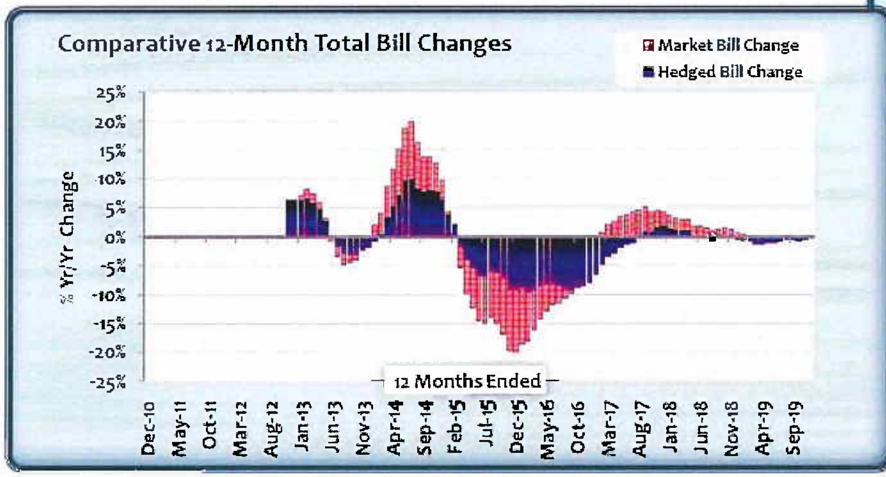
path 150

Programmatic Rules	1 (1=On)	Horizon	Increment	Hedge Ratio	
Increment		36 Months	0.6%		
Max Programmatic				15%	
Min @ Month 12				15%	

Defensive Rules	1 (1=On)	1st Calendar Year		2nd Calendar Year	
Percentage Options:	25%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		110%	30%	115%	20%
Boundary 2		114%	40%	119%	30%
Boundary 3		116%	50%	121%	40%

Value Rules	1 (1=On)	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	120%	1%	50%
Value Target Yr 2		95%	120%	1%	50%
Value Target Yr 3		0%	120%	1%	50%





Average Commodity Market Value		$ 3.88
Average Annual Bills at Market		$ 1,085,466,256
Worst 12-Month Total Bill Increase		
At Market	215,064,247	19.8% Max
As Hedged	109,839,476	9.8% Max
Mitigation	$ 105,224,771	10.0%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 101,505,093
% of Average Annual Bill @ Market		9.4% Max
Mitigation Ratio		
Mitigation / Out of Market		1.07

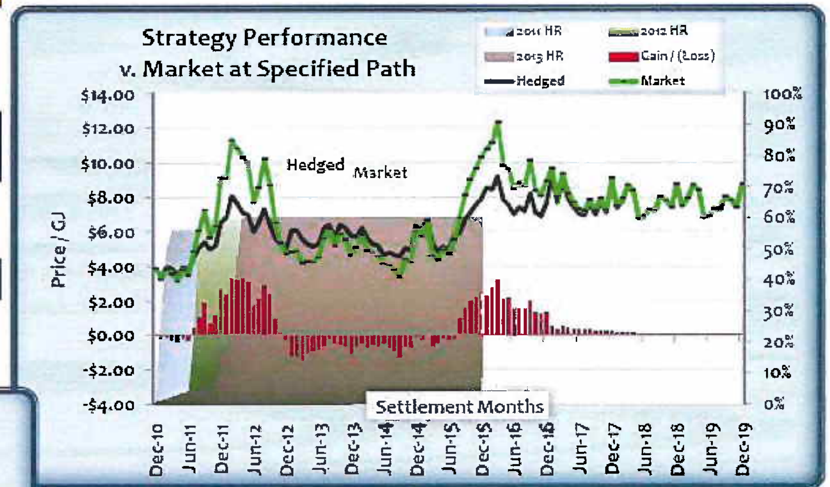
Strategy F

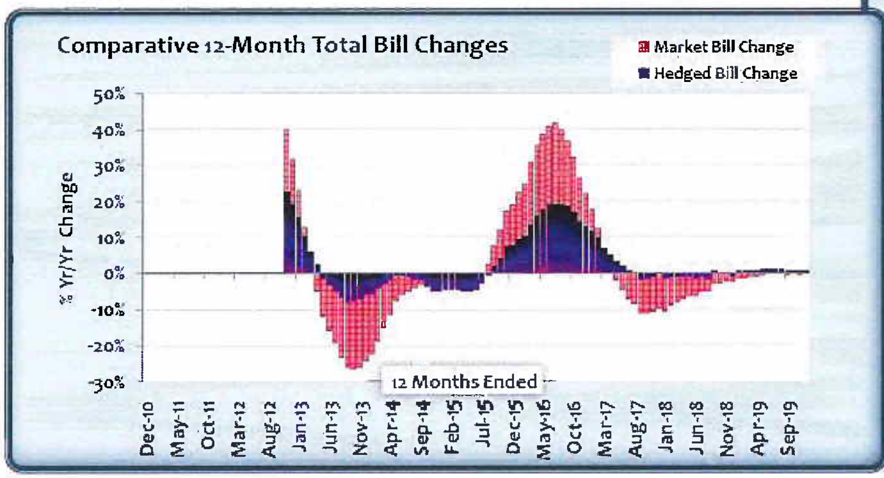
Summary of Path Results

path 582

Strategy		Max Overall Hedge Ratio/Horizon		60%	36 months
path 582		Premiums Expended, ($ Mil.)		$9.98 Avg Yr	$19.11 Max Yr
Programmatic Rules	1 (1=On)	Horizon	Increment	Hedge Ratio	
Increment		36 Months	0.6%		
Max Programmatic				15%	
Min @ Month 12				15%	
Defensive Rules	1 (1=On)	1st Calendar Year		2nd Calendar Year	
Percentage Options:	43%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		110%	30%	115%	25%
Boundary 2		114%	50%	119%	35%
Boundary 3		116%	60%	121%	45%
Value Rules	1 (1=On)	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	120%	1%	50%
Value Target Yr 2		95%	120%	1%	50%
Value Target Yr 3		0%	120%	1%	50%

Max Programmatic	15%	Boundary 3	116%	Value Target Yr 1	95%





Average Commodity Market Value		$ 6.99
Average Annual Bills at Market		$ 1,414,316,104
Worst 12-Month Total Bill Increase		
At Market	498,212,802	41.8% Max
As Hedged	255,367,146	22.7% Max
Mitigation	$ 242,845,656	19.1%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 88,171,002
% of Average Annual Bill @ Market		6.2% Max
Mitigation Ratio		
Mitigation / Out of Market		3.07

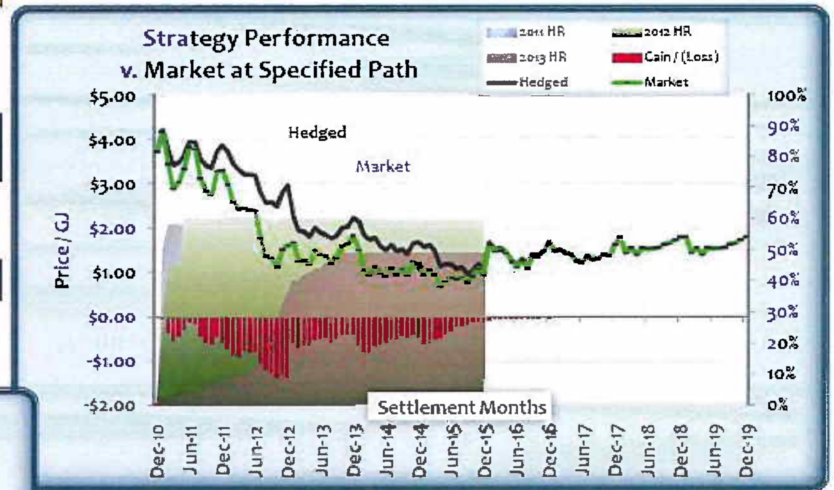
RiskCentrix, LLC

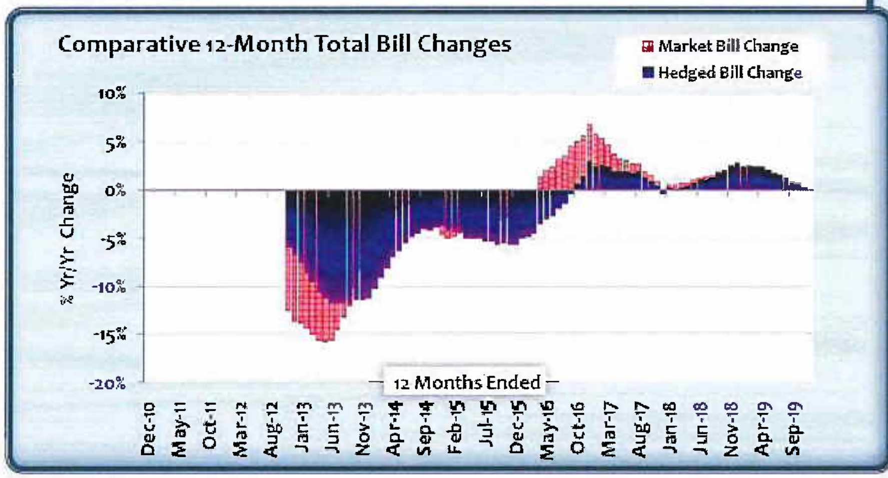
Clarity in a World of Uncertainty

Summary of Path Results — path 532

Strategy		Max Overall Hedge Ratio/Horizon		60%	36 months
path 532		Premiums Expended, ($ Mil.)		$3.21 Avg Yr	$15.43 Max Yr
Programmatic Rules	1 (1-On)	Horizon	Increment	Hedge Ratio	
Increment		36 Months	0.6%		
Max Programmatic				15%	
Min @ Month 12				15%	
Defensive Rules	1 (1-On)	1st Calendar Year		2nd Calendar Year	
Percentage Options:	43%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		110%	30%	115%	25%
Boundary 2		114%	50%	119%	35%
Boundary 3		116%	60%	121%	45%
Value Rules	1 (1-On)	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	120%	1%	50%
Value Target Yr 2		95%	120%	1%	50%
Value Target Yr 3		0%	120%	1%	50%

Max Programmatic 15% | Boundary 3 116% | Value Target Yr 1 95%





Average Commodity Market Value		$ 1.64
Average Annual Bills at Market		$ 847,680,622
Worst 12-Month Total Bill Increase		
At Market	51,617,061	6.7% Max
As Hedged	21,815,257	2.7% Max
Mitigation	$ 29,801,804	4.0%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 108,573,155
% of Average Annual Bill @ Market		12.8% Max
Mitigation Ratio		
Mitigation / Out of Market		**0.31**

Summary of Path Results

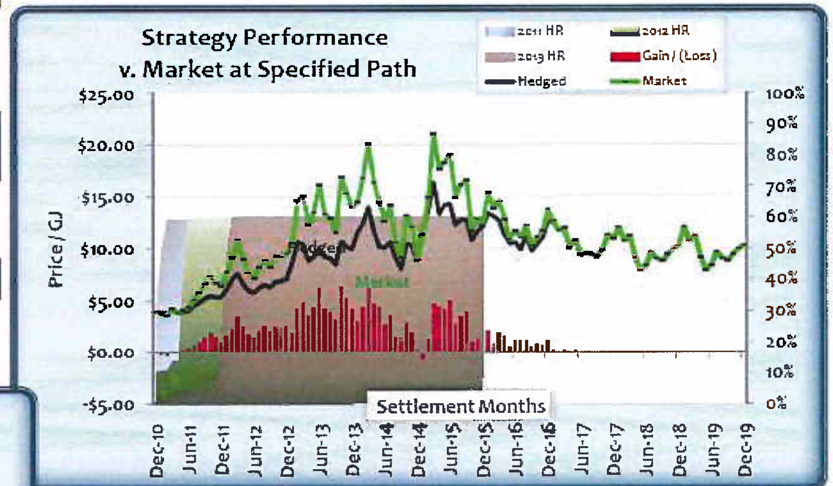
path 515

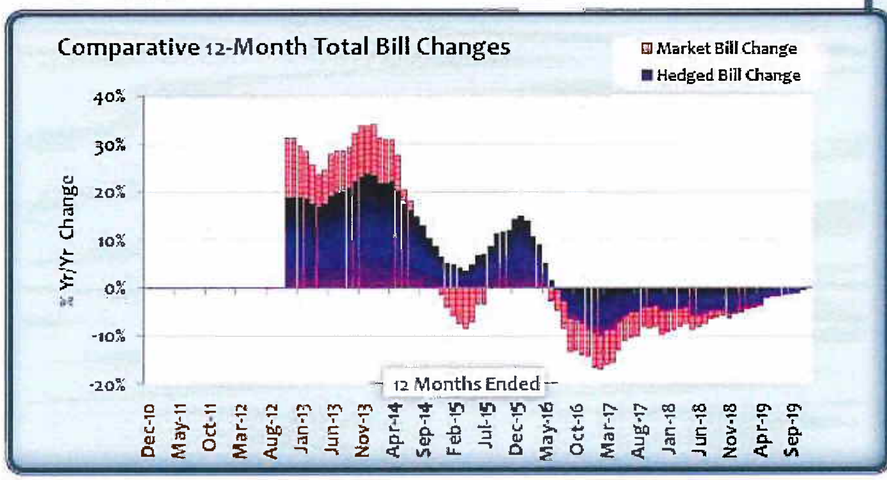
Strategy	Max Overall Hedge Ratio/Horizon	60%	36 months	Max Programmatic 15%	Boundary 3 116%	Value Target Yr 1 95%
path 515	Premiums Expended, ($ Mil.)	$14.64 Avg Yr	$31.81 Max Yr			

Programmatic Rules	1 (1=On)	Horizon	Increment	Hedge Ratio	
Increment		36 Months	0.6%		
Max Programmatic				15%	
Min @ Month 12				15%	

Defensive Rules	1 (1=On)	1st Calendar Year		2nd Calendar Year	
Percentage Options	43%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		110%	30%	115%	25%
Boundary 2		114%	50%	119%	35%
Boundary 3		116%	60%	121%	45%

Value Rules	1 (1=On)	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	120%	1%	50%
Value Target Yr 2		95%	120%	1%	50%
Value Target Yr 3		0%	120%	1%	50%





Average Commodity Market Value		$ 10.96
Average Annual Bills at Market		$ 1,834,066,556
Worst 12-Month Total Bill Increase		
At Market	551,904,876	34.0% Max
As Hedged	320,942,869	23.5% Max
Mitigation	$ 230,962,007	10.5%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 0
% of Average Annual Bill @ Market		0.0% Max
Mitigation Ratio		
Mitigation / Out of Market		**NA**

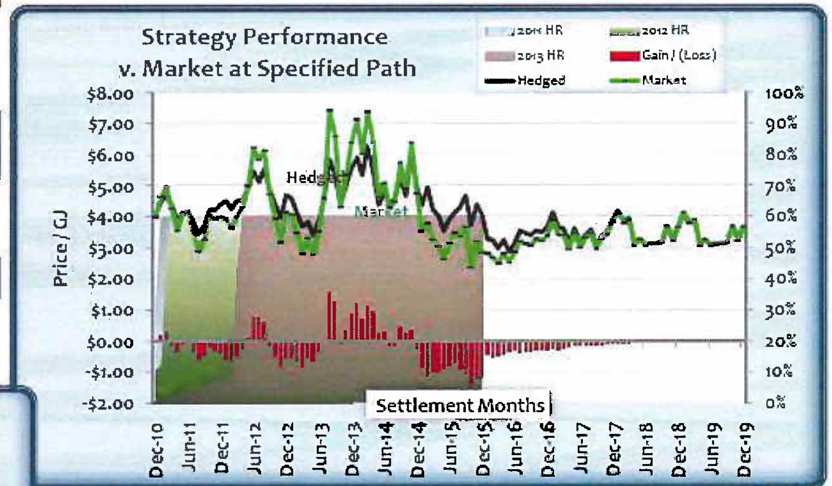
Summary of Path Results

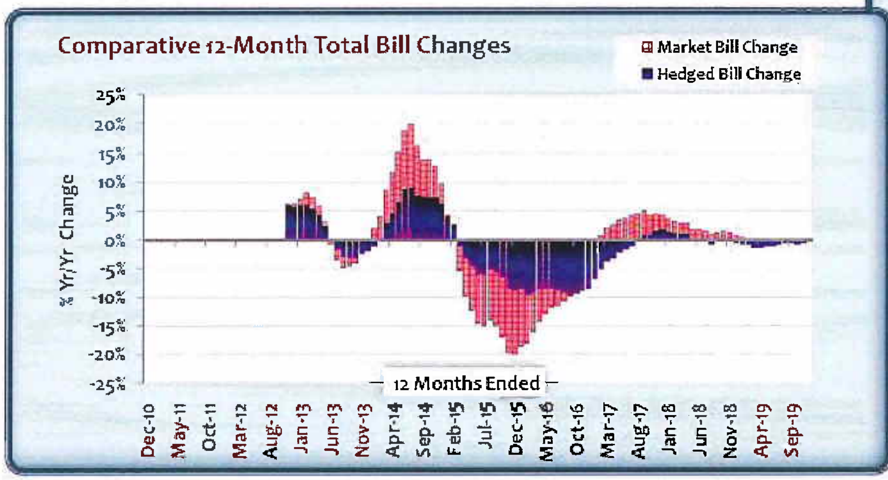
path 150

Strategy		Max Overall Hedge Ratio/Horizon		60%	36 months
path 150		Premiums Expended, ($ Mil.)		$7.48 Avg Yr	$15.32 Max Yr

Max Programmatic 15% | Boundary 3 116% | Value Target Yr 1 95%

Programmatic Rules	1 (1=On)	Horizon	Increment	Hedge Ratio	
Increment		36 Months	0.6%		
Max Programmatic				15%	
Min @ Month 12				15%	
Defensive Rules	1 (1=On)	1st Calendar Year		2nd Calendar Year	
Percentage Options:	43%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		110%	30%	115%	25%
Boundary 2		114%	50%	119%	35%
Boundary 3		116%	60%	121%	45%
Value Rules	1 (1=On)	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	120%	1%	50%
Value Target Yr 2		95%	120%	1%	50%
Value Target Yr 3		0%	120%	1%	50%





Average Commodity Market Value		$ 3.88
Average Annual Bills at Market		$ 1,085,466,256
Worst 12-Month Total Bill Increase		
At Market	215,064,247	19.8% Max
As Hedged	99,996,264	8.9% Max
Mitigation	$ 115,067,983	11.0%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 105,365,177
% of Average Annual Bill @ Market		9.7% Max
Mitigation Ratio		
Mitigation / Out of Market		1.13

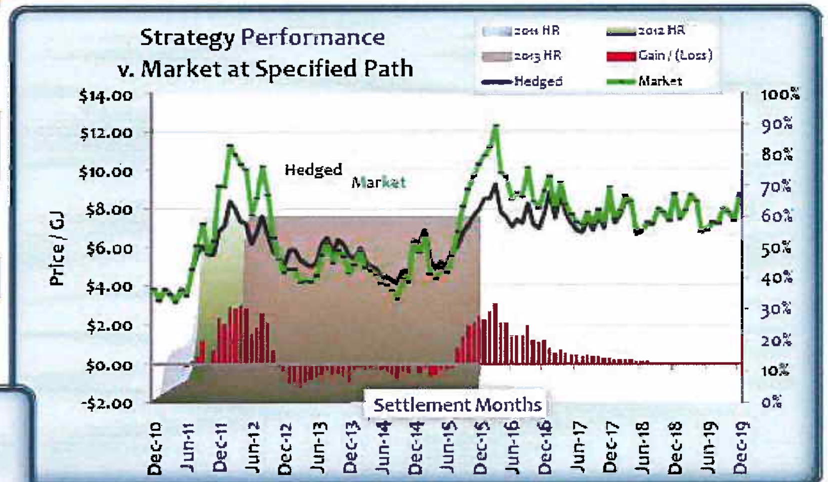
Strategy G

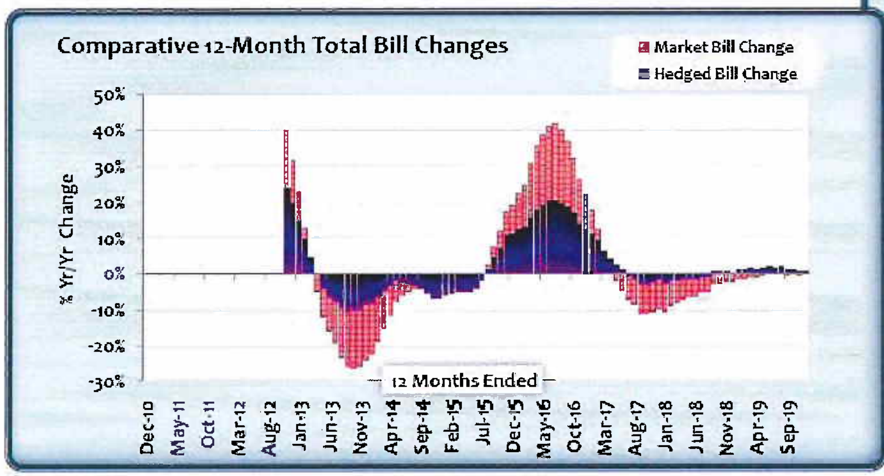
Summary of Path Results path 582

Strategy		Max Overall Hedge Ratio/Horizon	60%	36 months	
path 582		Premiums Expended, ($ Mil.)	$13.13 Avg Yr	$37.87 Max Yr	

Max Programmatic 25% | Boundary 3 135% | Value Target Yr 1 95%

Programmatic Rules	1 (1=On)	Horizon	Increment	Hedge Ratio	
Increment		36 Months	1.0%		
Max Programmatic				25%	
Min @ Month 12				25%	
Defensive Rules	1 (1=On)	1st Calendar Year		2nd Calendar Year	
Percentage Options	71%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		120%	35%	120%	33%
Boundary 2		130%	50%	130%	40%
Boundary 3		135%	60%	135%	45%
Value Rules	1 (1=On)	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	150%	1%	50%
Value Target Yr 2		95%	150%	1%	50%
Value Target Yr 3		0%	150%	1%	50%





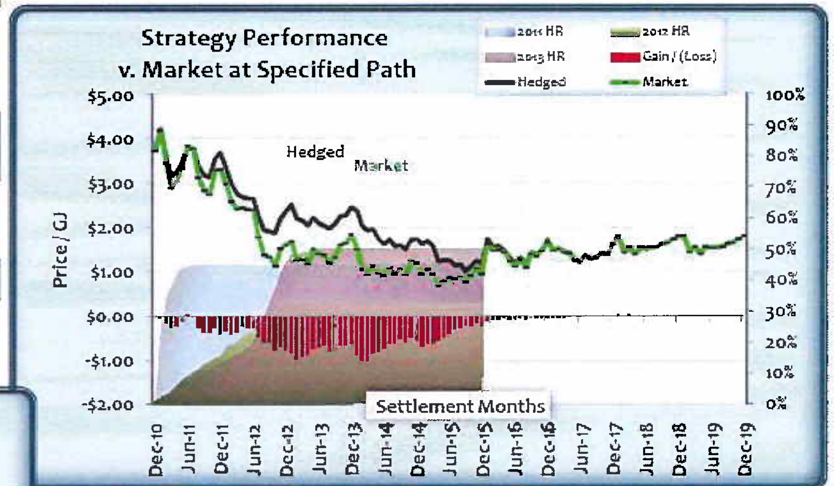
Average Commodity Market Value		$ 6.99
Average Annual Bills at Market		$ 1,414,316,104
Worst 12-Month Total Bill Increase		
At Market	498,212,802	41.8% Max
As Hedged	269,790,669	23.6% Max
Mitigation	$ 228,422,134	18.2%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 78,790,410
% of Average Annual Bill @ Market		5.6% Max
Mitigation Ratio		
Mitigation / Out of Market		3.26

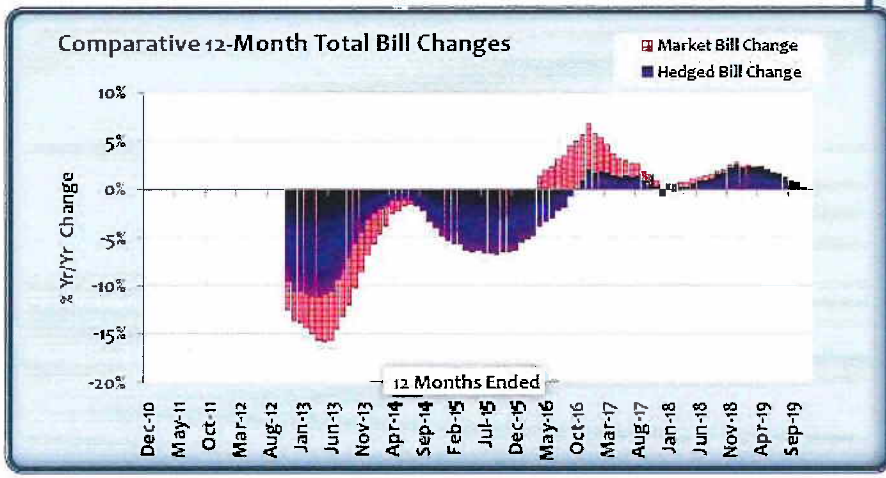
Summary of Path Results

path 532

Strategy		Max Overall Hedge Ratio/Horizon		60%	36 months
path 532		Premiums Expended, ($ Mil.)		$1.23 Avg Yr	$9.41 Max Yr
Programmatic Rules	1 {1-On}	Horizon	Increment	Hedge Ratio	
Increment		36 Months	1.0%		
Max Programmatic				25%	
Min @ Month 12				25%	
Defensive Rules	1 {1-On}	1st Calendar Year		2nd Calendar Year	
Percentage Options:	71%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		120%	35%	120%	33%
Boundary 2		130%	50%	130%	40%
Boundary 3		135%	60%	135%	45%
Value Rules	1 {1-On}	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	150%	1%	50%
Value Target Yr 2		95%	150%	1%	50%
Value Target Yr 3		0%	150%	1%	50%

Max Programmatic	25%	Boundary 3	135%	Value Target Yr 1	95%





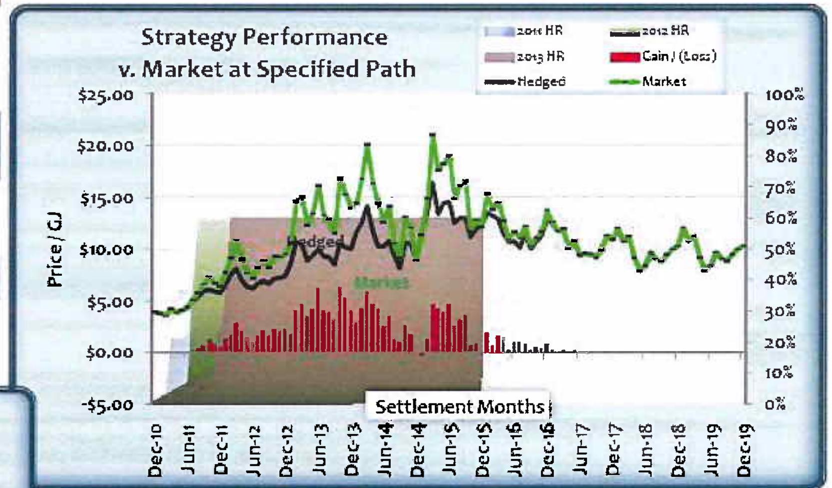
Average Commodity Market Value		$ 1.64
Average Annual Bills at Market		$ 847,680,622
Worst 12-Month Total Bill Increase		
At Market	51,617,061	6.7% Max
As Hedged	20,390,439	2.5% Max
Mitigation	$ 31,226,622	4.2%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 82,650,343
% of Average Annual Bill @ Market		9.8% Max
Mitigation Ratio		
Mitigation / Out of Market		0.43

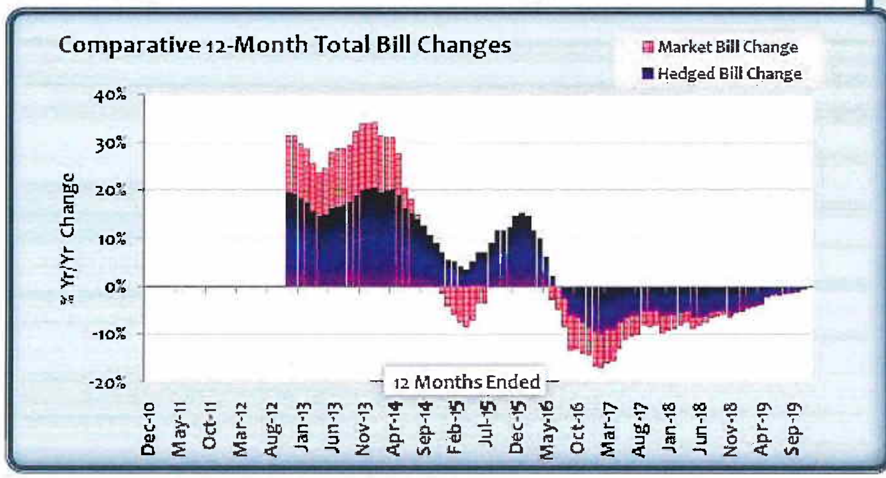
Summary of Path Results

path 515

Strategy					
path 515		Max Overall Hedge Ratio/Horizon	60%	36 months	
		Premiums Expended, ($ Mil.)	$22.03 Avg Yr	$48.34 Max Yr	
Programmatic Rules	1 (1=On)	Horizon	Increment	Hedge Ratio	
Increment		36 Months	1.0%		
Max Programmatic				25%	
Min @ Month 12				25%	
Defensive Rules	1 (1=On)	1st Calendar Year		2nd Calendar Year	
Percentage Options:	71%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		120%	35%	120%	33%
Boundary 2		130%	50%	130%	40%
Boundary 3		135%	60%	135%	45%
Value Rules	1 (1=On)	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	150%	1%	50%
Value Target Yr 2		95%	150%	1%	50%
Value Target Yr 3		0%	150%	1%	50%

Max Programmatic 25% **Boundary 3** 135% **Value Target Yr 1** 95%





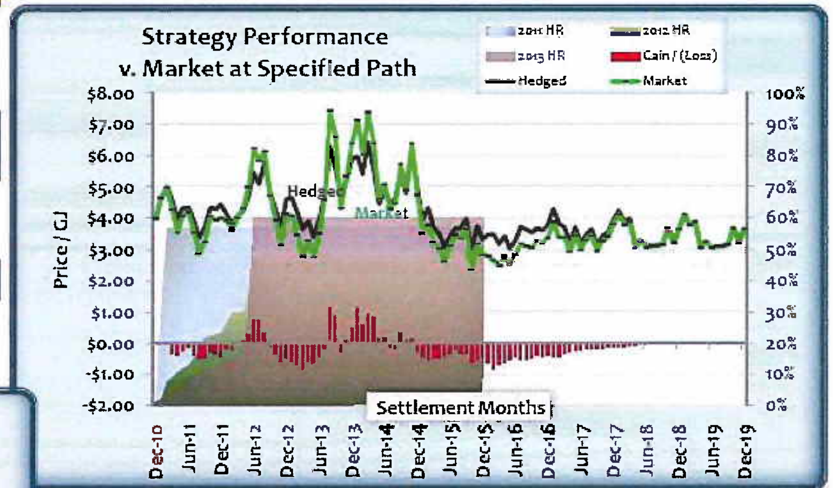
Average Commodity Market Value		$ 10.96
Average Annual Bills at Market		$ 1,834,066,556
Worst 12-Month Total Bill Increase		
At Market	551,904,876	34.0% Max
As Hedged	290,850,406	20.4% Max
Mitigation	$ 261,054,470	13.7%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 0
% of Average Annual Bill @ Market		0.0% Max
Mitigation Ratio		
Mitigation / Out of Market		**NA**

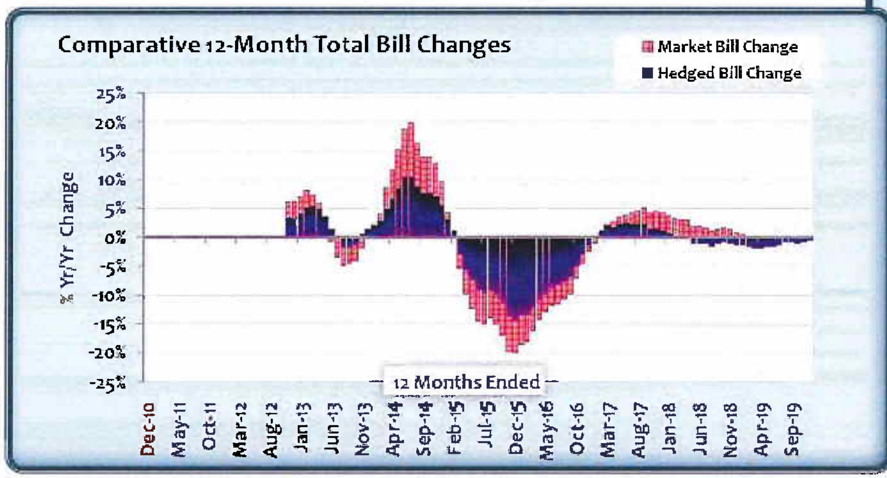
Summary of Path Results

path 150

Strategy		Max Overall Hedge Ratio/Horizon	60%	36 months	Max Programmatic 25%	Boundary 3 135%	Value Target Yr 1 95%
path 150		Premiums Expended, ($ Mil.)	$7.78 Avg Yr	$19.73 Max Yr			

Programmatic Rules	1 (1=On)	Horizon	Increment	Hedge Ratio	
Increment		36 Months	1.0%		
Max Programmatic				25%	
Min @ Month 12				25%	
Defensive Rules	1 (1=On)	1st Calendar Year		2nd Calendar Year	
Percentage Options:	71%	Price Tolerance	Max Ratio	Price Tolerance	Max Ratio
Boundary 1		120%	35%	120%	33%
Boundary 2		130%	50%	130%	40%
Boundary 3		135%	60%	135%	45%
Value Rules	1 (1=On)	Price	Risk/Reward Criteria	Increment	Cumulative Max
Value Target Yr 1		95%	150%	1%	50%
Value Target Yr 2		95%	150%	1%	50%
Value Target Yr 3		0%	150%	1%	50%





Average Commodity Market Value		$ 3.88
Average Annual Bills at Market		$ 1,085,466,256
Worst 12-Month Total Bill Increase		
At Market	215,064,247	19.8% Max
As Hedged	116,965,010	10.4% Max
Mitigation	$ 98,099,237	9.5%
Max 12-Month Out-of-Market Variance		
$CDN Million		$ 60,665,019
% of Average Annual Bill @ Market		5.6% Max
Mitigation Ratio		
Mitigation / Out of Market		1.69

End of Report

Appendix B

RESIDENTIAL CUSTOMER PRICE VOLATILITY PREFERENCES STUDY

TERASEN GAS

RESIDENTIAL CUSTOMER
NATURAL GAS PRICE VOLATILITY PREFERENCES
QUALITATIVE RESEARCH STUDY
FEBRUARY 2005

Detailed Report

March 14, 2005

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Executive Overview

Introduction

In February 2005, Terasen Gas engaged Western Opinion Research Inc. to conduct a two-phased study with residential customers of Terasen Gas to assess and measure the perceptions and preferences of customers as they relate to natural gas price volatility.

Phase 1 consisted of four focus groups with residential natural gas customers as follows:

- 2 Groups with GVRD[1] residents (one group on the EPP[2], one Group not on the EPP)
- 2 Groups with CRD residents[3] (one group on the EPP, one Group not on the EPP)

Phase 2 of the project, will consist of a telephone survey of 1000 Terasen Gas residential customers as follows:

- 400 interviews with Mainland customers on the EPP;
- 400 interviews with Mainland customers not on the EPP
- 100 interviews with Vancouver Island customers on the EPP
- 100 interviews with Vancouver Island customers not on the EPP

This report summarizes the results of Phase 1 of the research, which will be used to identify the range of opinions on the subject and aid in the development of a questionnaire in Phase 2. The objective of Phase 2 will be to quantify the findings from the qualitative phase, and to examine important differences in sub-groups.

[1] Greater Vancouver Regional District
[2] Equal Payment Plan
[3] Capital Regional District (Vancouver Island)

Key Findings

1. Concerns about the price or price volatility of natural gas were not top-of-mind among most participants.
   - In the questionnaire administered to participants just prior to the discussion, natural gas prices were considered to have increased slightly over the past year, which was about the same as for electricity, and fruits and vegetables. Results show that of the five product and service categories, gasoline prices were considered to have increased the most over the past year; to have had the greatest price volatility; and to be the greatest concern to participants (68%). In contrast, natural gas price increases were cited as being the main concern by only 13 percent of participants, which was the same as for electricity (13%).
   - During the opening discussion about their natural gas bill and their household natural gas service, relatively few commented or complained about natural gas pricing or price volatility.
   - While there was some awareness of a longer term increase in the price of natural gas, few commented about price fluctuations in natural gas.
   - Vancouver Island participants were more attuned to the price of natural gas as compared to electricity. This is not unexpected as many said they had recently converted some of their appliances or heating over to gas from electricity with the expectation of saving money.
   - Largely, participants said they did not automatically assume that changes in their bill were due to price fluctuations.
2. The natural gas bill is a significant monthly expense and while it is not closely reviewed every month, participants do periodically review it to examine their consumption and assess their energy conservation efforts.
   - The natural gas bill was typically not viewed as being the largest bill for participants, but was considered among the more "significant" monthly payments, particularly among those with fixed incomes or no mortgage payments.
   - Periodically people said they reviewed their consumption, often utilizing the graph provided on the bill to compare usage over the past year and the average temperature. In this regard a number of participants said they reviewed their bills to determine if their energy conservation efforts were effective or not.
3. Awareness of the components of monthly billing charges was relatively low.
4. There was some awareness of what caused fluctuations in natural gas prices, but there were misconceptions as well.
   - When asked what caused fluctuations in natural gas prices, participants correctly identified supply and demand, weather / seasonal factors, and the costs of exploration, among other factors.
   - A number of misconceptions emerged as well, with a few participants citing profits or inflated executive salaries by Terasen Gas, or the belief that British Columbians should pay less for natural gas because natural gas is extracted in BC.

5. Awareness of activities or programs by Terasen Gas to control natural gas price fluctuations was very low, though some "assumed" this was the case.
   - There was a low awareness of measures by Terasen Gas to control fluctuations in the price of natural gas. Few participants actually knew that Terasen Gas did this but several assumed or guessed that Terasen followed this practice with the view that "a responsible company has to manage the price of gas".

6. Most participants were supportive of Terasen Gas' current approach to hedging, and preferred this approach over the "more" or "less" hedging alternatives.
   - Feedback from participants was that they were largely supportive of the current Terasen Gas hedging practice, though a few wondered if this practice was regulated.
   - When given the choice among three hedging scenarios, most (29 of 34) participants said they preferred the current approach because they didn't like or could not afford big price increases on their gas bill; that it was helpful for budgeting; that the current practice could benefit from price decreases; and that they thought it might provide lower average pricing than the 100% fixed scenario.
   - Four participants preferred the "100% hedging" approach mainly because it eliminated fluctuations in their gas bill which was helpful in budgeting.
   - One participant preferred the "Almost No Hedging Strategy" because this approach would allow them to "know what they bought" and they would not have to "rely on" or need to "trust" the hedging strategy. When probed further by the moderator this individual's pricing volatility tolerance was actually closer to the current hedging program.

7. On average, participants said they could "live with" a $169 change in their annual natural gas billings which represents 16% of participants' annual natural gas billings. As might be expected, the maximum change in annual gas billings that participants say they can live with tends to vary based on their total annual natural gas billings.
   - The average (estimated) annual natural gas billings for group participants was $1033, and the maximum amount of change in their annual natural gas billings they were willing to live with was $169.
   - As might be expected, the maximum change in annual gas billings that participants say they can live with tends to increase as their annual gas billings increase. Results show that for total annual natural gas billings of less than $900, the average amount of change participants could live with in their annual gas billings was $53 (or 11% of total annual billings under $900). For total annual natural gas billings of $900 or more, the average amount of change per year participants could live with was $219 (or 17% of total annual billings of $900 and over).
   - As expected, the average estimated annual natural gas billings for the Vancouver Island participants was lower than for the GVRD participants ($689 vs. $1287). Accordingly, the average amount of annual change in natural gas billings Vancouver Island participants were willing to accept was also lower ($90 versus $227).
   - Those preferring the 100% Hedging Scenario were less tolerant to price fluctuations. As a percentage of their total annual gas bill, those choosing the 100% Hedging Scenario would only accept a maximum change of 4% over the year,

which is lower than those choosing the Current Program who would tolerate (on average) a maximum change of 19%.

8. The Equal Payment Plan was perceived as having both benefits and drawbacks. Those who favoured the EPP mentioned that it kept monthly household natural gas costs stable (i.e., no surprises on the monthly bill), which is helpful for budgeting purposes.

   Drawbacks of the EPP were that no interest is given on the pre-paid money (although another commented that Terasen Gas does not charge interest for EPP funds owing either).

   - Reasons for not going on the EPP were that participants wanted to see and monitor their actual gas consumption; they liked having lower payments in summer to better match to their income flow; or they wanted to monitor their efforts to conserve energy.

Foreword

Background and Research Objectives

In February 2005, Terasen Gas engaged Western Opinion Research Inc. to conduct a two-phased study with residential customers of Terasen Gas to assess and measure the perceptions and preferences of customers as they relate to natural gas price volatility.

The objectives of the research were to:

- Define customers' level of understanding regarding natural gas rates – including their components and how rates are set.
- Understand customer risk preferences regarding rates and determine if price points exist where customers are willing to accept more risk in the form of rate variability and where they desire less risk through rate stability.
- Use the results to revise Terasen Gas's price-risk management hedging strategy as appropriate.

Phase 1 consisted of four focus groups with residential natural gas customers as follows:

- 2 Groups with GVRD[4] residents (one group on the EPP[5], one Group not on the EPP)
- 2 Groups with CRD residents[6] (one group on the EPP, one Group not on the EPP)

Phase 2 of the project, will consist of a telephone survey of 1000 Terasen Gas residential customers as follows:

- 400 interviews with Mainland customers on the EPP;
- 400 interviews with Mainland customers not on the EPP
- 100 interviews with Vancouver Island customers on the EPP
- 100 interviews with Vancouver Island customers not on the EPP

This report summarizes the results of Phase 1 of the research, which will be used to identify the range of opinions on the subject and aid in the development of a questionnaire in Phase 2.

Phase 2 of the research will quantify the findings from the qualitative phase, and examine importance differences in sub-groups.

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[4] Greater Vancouver Regional District
[5] Equal Payment Plan
[6] Capital Regional District (Vancouver Island)

Methodology

Phase 1: Focus Groups with Residential Gas Customers

Four focus groups were held with residential gas customers of Terasen Gas on February 7th (GVRD) and 8th (CRD) 2005, as follows:

- 2 Groups with GVRD residents (one group on the EPP, one Group not on the EPP)
- 2 Groups with CRD residents (one group on the EPP, one Group not on the EPP)

Both groups were held in focus group facilities equipped with one-way mirrors for observers, boardroom-style meeting room and audio-visual recording equipment.

Participants were recruited from customer lists provided by Terasen Gas. Individuals in the household who were most familiar with buying and paying for the household's natural gas were targeted. To encourage participation, a $60 cash incentive was provided. Ten customers were recruited for each group for eight to participate (though up to ten were allowed to participate if they arrived. To be eligible to participate in the groups participants must have met the following criteria:

- Individuals and the members of their household could not be employed by Terasen Gas or subsidiary of Terasen Incorporated, a natural gas distributor, producer or natural gas marketer, the media, advertising, or a market research firm;
- They must live within the boundaries of the GVRD/CRD;
- They could not have attended a focus group within the past 12 months; and
- They could not have attended more than five focus groups in the past five years.

To ensure a broad representation of Terasen Gas residential customers, efforts were made to recruit a mix of:

- Males and females;
- Owners and Renters (though the sample was heavily weighted to Owners);
- Those residing in single family as well as multi-family dwellings;
- Residents from a range of communities within the GVRD/CRD; and
- Customers representing a range of age, education, household income and occupational categories.

<u>A Note Regarding the Context of Qualitative Research</u>

The primary benefit of focus group discussions is that they allow for in-depth probing with qualifying participants on behavior, habits, usage patterns, perceptions and attitudes that relate to the subject matter. The group discussion allows for flexibility in exploring other areas that may be pertinent to the investigation.

The focus group technique is used in marketing research as a means of gaining insight and direction, rather than collecting quantitatively precise data or absolute measures. Although numbers are sometimes presented as illustrative of the opinions of the participants in this study, these are offered for insight and should not be considered statistically reliable.

Detailed Findings

1.0 Pre-Exercise: General Concern about Natural Gas Price Volatility

As part of the focus groups, participants were asked to complete two questionnaires. The first questionnaire was completed by participants just prior to the start of the groups. The purpose of this first exercise was to gauge participants' level of concern about price volatility in each of five product/service categories. It also prepared participants for the upcoming discussion about natural gas price volatility.

Results show that of all the product and service categories, gasoline prices were considered to have increased the most over the past year, to have had the greatest price volatility; and to be the greatest concern to participants (68%). In contrast, natural gas price increases were cited as being the main concern by only 13 percent of participants, which was the same as electricity (13%).

Results were virtually the same with respect to perceptions about the coming year.

The following bullet-points summarize the findings.

Perceptions of price volatility in the past year

With respect to the price volatility of the five product service categories over the past year, most participants thought:

- That the price of gasoline had increased *significantly*
- The price of electricity had increased *slightly*
- That the price of natural gas had increased *slightly*
- That the price of fruits and vegetables had increased *slightly*
- That phone charges had *stayed the same* or increased *slightly*

- Increases in the "price of gasoline" was most frequently cited as concerning participants the most (by two-thirds). Only 13% cited increases in the price of natural gas as being a concern, while another 12% cited being concerned about increases in the price of electricity.
- Gasoline was most frequently cited as having the greatest price volatility (88%). Natural gas was cited by 3% as having had the highest price volatility.
- Phone services (45%) and fruits and veggies (32%) were more frequently cited as having the lowest price volatility. Natural gas was cited by 6% as having the lowest price volatility.

Perceptions of price volatility in the coming year

With respect to the price volatility of the five product service categories over the next year, most participants thought:

- That the price of gasoline will increase *significantly or slightly*
- The price of electricity will increase *slightly*

- That the price of natural gas will increase *slightly*
- That the price of fruits and vegetables will increase *slightly*
- That phone charges will *stay the same* or increase *slightly*

- Increases in the "price of gasoline" over the next year was most frequently cited as concerning participants the most (by two-thirds). Only 13% cited increases in the price of natural gas as being a concern, while another 13% cited being concerned about increases in the price of electricity.
- Gasoline was most frequently cited as having the greatest potential price volatility (88%). Only 6 percent think natural gas will have the greatest price volatility.
- Phone services (56%) was most frequently cited as having the lowest price volatility.

2.0 General Natural Gas Customer Observations

Following the opening statements by the moderator and the round-table introductions, participants were asked to give their general views about their natural gas bill (examples of which were circulated), as well as their top-of-mind impressions about their household natural gas service. Relatively few commented or complained about natural gas pricing or price volatility. The following bullet-points summarize participants' comments.

- Frequently people pay their natural gas bill without closely reviewing their usage or price fluctuations other than checking the amount to be paid and the due date. Periodically people do review their consumption, often utilizing the graph provided on the bill to compare usage over the past year and the average temperature. Several participants commented that they would like the graph to cover a longer time period than currently provided. In this regard, a number of participants said they reviewed their bills to determine if their energy conservation efforts were effective or not.
- A few commented that sometimes they had difficulty reconciling their gas bill charges with their usage, or wondered why the charges were so high during the summer. One participant said it would be helpful to see information about how their gas consumption compared to other similar size houses.
- A few complained about not being able to pay their bill with their credit card or having to pay a service charge to do so.
- Awareness of the various components of the natural gas bill charges was relatively low.
- There were some misconceptions that Terasen Gas made a profit by marking up the natural gas commodity.
- Positive comments were that Terasen Gas has provided good, responsive service, and that people liked the graph on the bills showing past consumption.
- Less positive comments were that Terasen Gas was a "monopoly" or that some services offered by BC Gas were no longer offered by Terasen Gas.
- Some participants were confused about the name change and what its purpose was except that it was costly and served no benefit to the customer.
- Relatively few commented or complained about natural gas pricing or price volatility. When prompted about pricing, participants were mixed with some saying the cost of natural gas was reasonable, while a few said that it was too expensive. When asked if gas prices changed, the general response was that they changed only a little bit.

3.0 Price Fluctuations

Next, the discussion moved to natural gas price fluctuations. There was awareness of longer-term increases in natural gas, but less awareness of quarterly natural gas pricing adjustments. In this respect, there was some confusion between the timing of price adjustments and periodic adjustments to the monthly EPP amount. Typically, however, changes in monthly billing amounts were attributed to changes in consumption rather than the price of natural gas.

When asked what caused fluctuations in natural gas prices, participants correctly identified supply and demand, weather / seasonal factors, and the costs of exploration, among other factors. A number of misconceptions emerged as well, with a few participants citing profits or inflated executive salaries by Terasen Gas, or the belief that British Columbians should pay less for natural gas because natural gas is extracted in BC.

Awareness of activities or programs by Terasen Gas to control natural gas price fluctuations was very low; only those with related occupational knowledge were aware of this. A few other participants assumed that Terasen did this, but didn't know for sure.

The following bullet-points summarize the findings.

Awareness of Price Fluctuations and their Cause

- A number of participants said that over the longer-term, there had been a trend of increasing natural gas prices.
- In one group, there was a misconception that Terasen Gas had recently applied for a rate increase, when in fact this was BC Hydro.
- On Vancouver Island, participants were more attuned to the price of natural gas as compared to electricity.
- Few participants were aware of quarterly Equal Billing Payment Plan (EPP) bill adjustments for rate changes or changes in consumption.
- A few were aware that Terasen Gas periodically assessed natural gas pricing to customers and commented that this ranged from once a year to every few months to quarterly. However, there was some confusion between the periodic EPP adjustments and periodic natural gas rate adjustments by Terasen Gas.
- Participants said they found out about changes to natural gas rates on their bill from the business section of newspapers or from Terasen Gas.
- Largely, participants said they did not automatically assume that changes in their bill were due to price fluctuations.
- Fluctuations in natural gas prices were attributed to supply and demand; cost of exploration; weather and seasonal factors; profit of suppliers/shareholders; executive salaries; and the cost of electricity.
- There were a number of misconceptions about what influenced natural gas prices. A few participants commented that British Columbians should pay less for natural gas given that it is produced in BC. Others mentioned that Terasen Gas paid its executives too much. In this respect, some didn't know that the cost of the natural gas on their bills could fluctuate based on the price of natural gas on the open market.

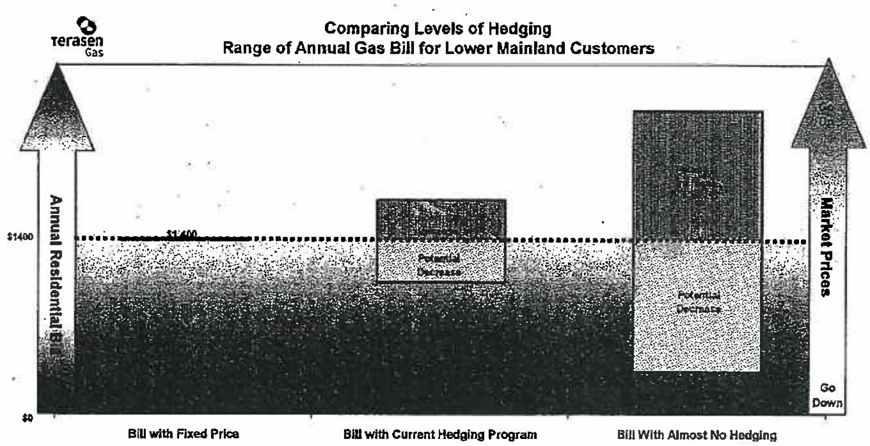
Awareness of Measures to Control Price Fluctuations

- There was a low awareness of measures by Terasen Gas to control fluctuations in the price of natural gas. Few participants actually *knew* that Terasen Gas did this but several *assumed* or guessed that Terasen followed this practice with the view that "a responsible company has to manage the price of gas".
- Only two or three participants were aware specifically of "hedging" practices by Terasen Gas to control price fluctuations, and these were people with backgrounds in banking/finance or who (had) worked in an industry with natural gas involvement (e.g. green house grower).

4.0 Hedging Preferences

Next, the moderator described the current Terasen Gas hedging program to participants in simple terms. To help convey the hedging concept, the example of fixed and variable mortgage rate plans was used. Feedback from participants was that they were largely supportive of the current hedging practice though a few wondered if this practice was regulated.

After this, two alternative hedging practices were presented (an "almost no hedging" scenario and a "100% hedging" scenario) along with the current approach. To help explain the three approaches, a graphical portrayal of the scenarios was circulated to participants. The following figure shows the example used for the two Lower Mainland focus groups. A similar chart was used for the Vancouver Island groups with the yearly average (dotted line) being $1000. Prior to discussing their preferences in the group, participants recorded their preferred hedging approach on answer sheets.



All but 5 of the 34 participants said they preferred the current approach because they didn't like or could not afford surprises (big price increases) on their gas bill; that it was helpful for budgeting; that the current practice could benefit from price decreases; and that they thought it might provide lower average pricing than the 100% fixed scenario. Virtually no participants preferred the "almost no hedging" approach, while four participants preferred the "100%

hedging" approach mainly because it eliminated fluctuations in their gas bill which was helpful for budgeting.

In a follow-up exercise, when asked the maximum dollar amount of change per year they could "live with" or "tolerate" in their natural gas billings, the most frequently cited amount was $100, while the average amount was $169. Seventy percent of participants expressed amounts of $100 or less.

The following bullet-points summarize the discussion.

Preferred Hedging Program

- Participants were largely supportive of efforts to control price fluctuations through hedging practices though a few were suspicious / wary of this practice either because they didn't fully understand it or weren't sure if this practice was regulated.
- The large majority of participants (29 of 34) preferred the existing hedging strategy employed by Terasen Gas and typically leaned more towards more hedging (100% hedging scenario) than less hedging (almost no hedging scenario).
- Reasons for preferring the existing hedging strategy were that they didn't like or could not afford surprises (big price increases) on their gas bill; it was helpful for budgeting; the current practice could benefit from price decreases, and it might provide lower average pricing than the 100% fixed scenario.
- Four participants preferred the 100 percent hedging scenario because it was helpful for budgeting, they preferred fixed pricing, or because it was viewed as less risky than the scenarios with less hedging. A couple of the participants mentioned that they could not foresee prices coming down in the next few years since natural gas is a non-renewable resource, and therefore, they would rather fix the price.
- One participant chose the "Almost No Hedging" scenario. Interestingly, this choice was not so much a preference for the pricing variability, but that it would allow them to "know what they bought" and they would not have to "rely on" or need to "trust" the hedging strategy. This person had a relatively small annual natural gas billing. When probed further by the moderator, this individual's pricing volatility tolerance was actually closer to the current hedging program.
- When asked what maximum dollar amount of change in their gas billings they could live with in a year, the most frequently mentioned amount was $100, while the average amount was $169. Seventy percent of participants expressed amounts of $100 or less. (see analysis of hedging preference questionnaire below for more details).
- The natural gas bill was typically not viewed as being the largest bill for participants, but was considered among the more "significant" monthly payments, particularly among those with fixed incomes or no mortgage payments.

Analysis of Hedging Preference Questionnaire

As mentioned earlier, participants completed a questionnaire during the group which asked them to choose which hedging strategy they preferred and why. It also asked participants to record their annual household gas bill charges along with the maximum potential change in their annual gas bill they could live with or tolerate. These results are summarized in detail here.

Participants Preferred Hedging Scenario

- Virtually all (29), but five of the 34 participants chose the "Current Hedging" program used by Terasen Gas.
- Four participants chose the "100% Hedging" scenario.
- One participant chose the "Almost No Hedging" scenario.

Reasons for Preferring the Current Terasen Gas Hedging Scenario

Avoids Large Price Increases
- The current hedging strategy helps with budgeting
- Some people cannot afford large increases
- Natural gas is viewed as a "necessity" and so should not cause financial hardship
- Fewer surprises in gas bill

Current Program a "Middle Ground" Between the Scenarios
- The current program is working well
- The current program limits price variability but leaves room to take advantage of price decreases
- The "almost no hedging" scenario is too much of a gamble
- The "100% hedging" strategy might increase the average price of natural gas.
- The perception that the "100% hedging" strategy would have fewer, but potentially larger price adjustments. The concern here was that with 100% hedging, the price would remain fixed for a given period, but at the end of this period if natural gas prices had changed drastically, their bill would also increase dramatically (as opposed to potentially more frequent but less severe price adjustments with the Current Hedging program).

Other
- The perception that the current strategy helps people to distinguish their attempts to conserve energy. We hypothesize that this comment stems from the view that holding the price of gas more constant allows people to more easily track changes in consumption.

Reasons for Preferring the 100% Hedging Scenario

- Stable natural gas pricing
- Helps with budgeting
- Less risky than other scenarios
- Fixed pricing acts almost like the Equal Payment Plan ("Prices go up in winter and down in summer, so I might as well have fixed prices")
- Natural gas is a non-renewable resource; therefore, prices are anticipated to keep rising in the near future

Reasons for Preferring the Almost No Hedging Scenario

- This participant said this approach would allow her to "know what she bought" and would not have to "rely on" or need to "trust" the hedging strategy. When probed further by the moderator, this individual's pricing volatility tolerance was actually closer to the current hedging program.

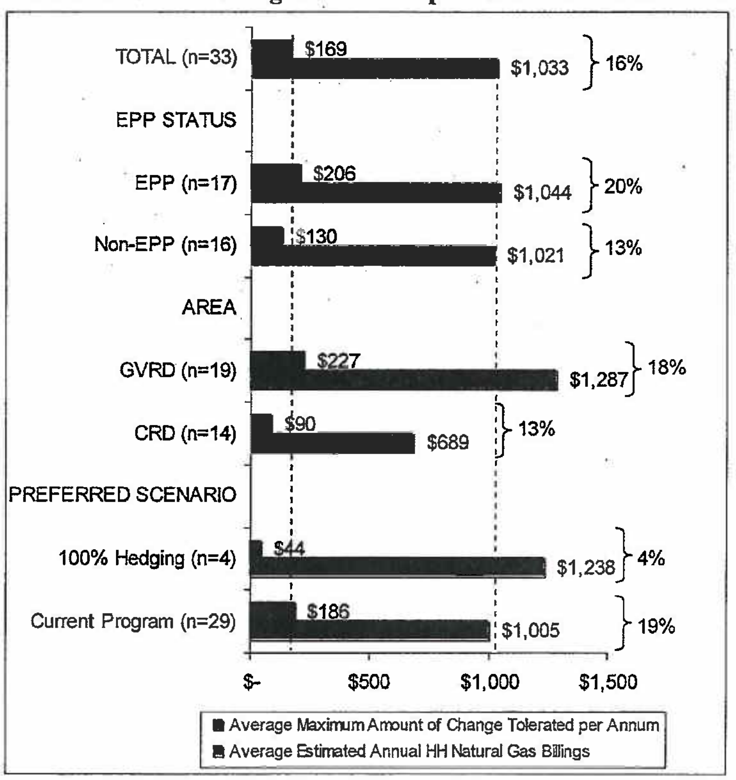
Tolerance for Natural Gas Price Volatility

Next, participants estimated their household's total annual natural gas billings, and with this in mind, recorded the maximum amount of change in their annual gas billings that they could live with or tolerate. The following chart summarizes the *average* results along with the maximum acceptable change as a percentage of total annual gas billings.

Q2A. Please write down your household's total annual $ gas billings [an estimate is fine]
Q2B. What is the maximum $ dollar amount of change in your family's annual natural gas bill that you can tolerate due to fluctuations in natural gas prices? Write down an approximate dollar amount that, within this amount as a rate payer, you can live with and expect, given that natural gas is a product bought and sold on the open market.

CAUTION: SMALL SAMPLE SIZE
RESULTS ARE INTENDED TO BE "DIRECTIONAL" ONLY

Average Estimated Household Natural Gas Billings & the Average Maximum Amount of Change in Annual Natural Gas Billings that Participants Could Live With

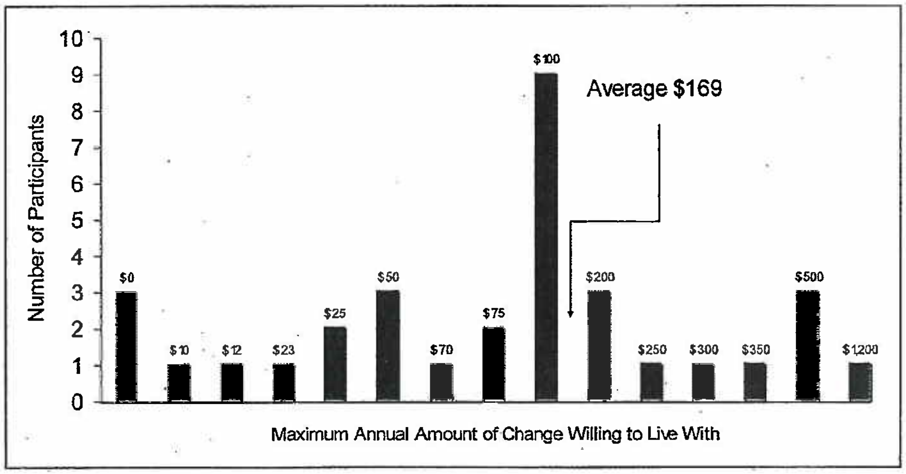


- Overall, the average (estimated) annual natural gas billings for group participants was \$1033, and the maximum amount of change in their annual natural gas billings they were willing to live with was \$169 (which represents 16% of participants' annual natural gas billings).
- As expected, the average estimated annual natural gas billings for the Vancouver Island participants was lower than for the GVRD participants (\$689 vs. \$1287). Accordingly, the average amount of annual change in natural gas billings that Vancouver Island participants were willing to accept was also lower (\$90 versus \$227).
- There was no significant difference in the estimated annual natural gas billings between EPP and Non-EPP participants. Those not on the EPP did not appear to be more tolerant to fluctuations in annual natural gas billings than those on the EPP. Results appear to be the reverse, but this is partly due to the three non-EPP participants who said they wouldn't tolerate any price fluctuations (excluding these three participants the mean increases from \$130 to \$160).
- As expected, those choosing the 100% Hedging Scenario appear to have larger estimated annual natural gas bills than those choosing the Current Hedging Scenario (\$1238 vs. \$1005). Those choosing the 100% Hedging Scenario also appear to have a lower willingness to tolerate volatility in the annual natural gas billings than those choosing the Current Hedging Scenario (\$44 vs. \$186).
- As a percentage of their total annual gas bill, those choosing the 100% Hedging Scenario would only accept a maximum change of 4% over the year, which is lower than those choosing the Current Program who would tolerate (on average) a maximum change of 19%.

The following chart shows the *distribution* of participants' answers for the maximum dollar amount of change they could live with per year.

> Q2B. What is the maximum $ dollar amount of change in your family's annual natural gas bill that you can tolerate due to fluctuations in natural gas prices? Write down an approximate dollar amount that, within this amount as a rate payer, you can live with and expect, given that natural gas is a product bought and sold on the open market.
>
> **CAUTION**: SMALL SAMPLE SIZE
> RESULTS ARE INTENDED TO BE "DIRECTIONAL" ONLY

Maximum $ Dollar Amount of Change in Annual Natural Gas Billings that Participants Could Live With [Distribution of Responses]

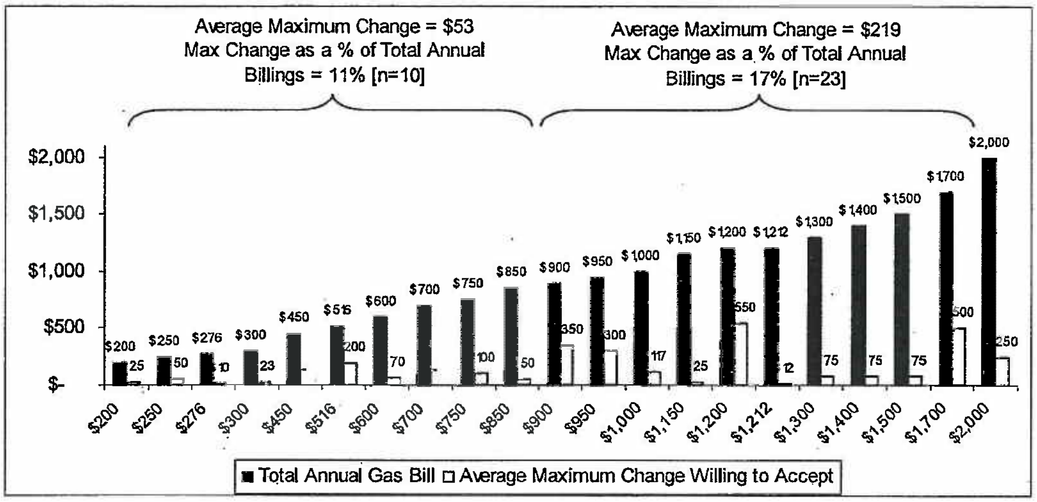


With respect to the maximum change in the annual natural gas billings that participants were willing to live with, results show that:

- The minimum amount was $0 and the maximum was $1200
- The average amount was $169
- The most frequently given response was $100 (nine participants)
- Just under one-quarter of participants expressed amounts of $25 or less;
- 70% of participants expressed amounts of $100 or less

The maximum dollar amount change in annual natural gas billings that participants are willing to live with tends to increase as the total annual billings for the household increases. This is demonstrated in the following chart.

Estimated Annual Household Natural Gas Billings & the Maximum Amount of Change in Annual Natural Gas Billings that Participants Could Live With



The above chart shows participants' total estimated annual natural gas billings along with the maximum change in their annual gas billings they could live with.

- Results show that for total annual natural gas billings of less than $900, the average amount of change participants could live with in their annual gas billings was $53 (or 11% of total annual billings under $900).
- For total annual natural gas billings of $900 or more, the average amount of change per year participants could live with was $219 (or 17% of total annual billings of $900 and over)

5.0 Equal Payment Plan

- The benefits of the EPP were that it was helpful for budgeting purposes and that there were no monthly surprises on the natural gas bill.
- Drawbacks of the EPP were that there was no interest paid on the pre-paid money (though another commented that Terasen Gas didn't charge interest either so that it all balanced out).
- Reasons for not going on the EPP were that participants wanted to see and monitor their actual gas consumption; that they liked having lower payments in summer to better match their income flow; or they wanted to monitor their efforts to conserve energy.

Appendices

A. Moderator Discussion Guide (GVRD Version)
B. Pre-Group Handout Questionnaire

Appendix A: Focus Group Discussion Guide

Natural Gas Price Volatility Focus Groups
February 7th & 8th, 2005 - Draft 6

Introduction

- Who is Western Opinion Research
- Importance of group / Feedback from all participants
- Don't all talk at once
- The moderator does not have any answers, just questions
- There are only right answers
- Have fun
- Video/audio taping -And we have observers
- Let's start by going around the room with brief intros

General Natural Gas Observations - Warm-up

1. The discussion this evening will be about different aspects and issues regarding residential natural gas services. I would like to start off by discussing briefly the natural gas bill you receive each month. What are your general thoughts? [HAND OUT EXAMPLE NATURAL GAS BILLS]

2. What are some top-of-mind impressions about your household natural gas service----likes and dislikes? IF NECESSARY PROMPT WITH... What about pricing?

   Are people aware that the bill charges can be broken down into separate charges?
   Is it clear to you what the various items on the bill are?
   [TRY TO ISOLATE THE GAS COMMODITY PORTION ALONG WITH OTHER ELEMENTS AS NOTED BELOW]
   LOOK FOR HOW CUSTOMERS DESCRIBE THE VARIOUS PARTS OF THE BILL - WHAT LINGO DOES CUSTOMER USE?
   SHOW PARTS OF THE BILL ON FLIPCHART

   - Commodity (Cost of the Gas)
   - Delivery Charge (Charge from Terasen Gas for delivering Gas to customers)
   - Taxes

Price Fluctuations

3. One of the concerns expressed about natural gas services was price fluctuations or price volatility (that is, the ups and downs of prices). What do you think is behind or is causing price fluctuations in your natural gas bill? [FLIPCHART - BUILD LIST AS NOTED BELOW]
   - Weather
   - Economy
   - International Events
   - Production and Transportation Costs

4. Is there a part of your natural gas bill you think is most responsible for the price changes you experience throughout the year? [REFER TO EARLIER BILL COMPONENT DISCUSSION IF NECESSARY]

5. How do you determine that a change in your monthly bill is as a result of an increase or a decrease in the price of natural gas as opposed to a change in your own usage or consumption of natural gas? (e.g. Seasonal/cold weather)?
   [LISTEN FOR MEDIA MENTIONED]

   Do you automatically assume any change in billing amount is related to price and not to usage?

   In the past, have you reviewed your bill to determine in which part of the bill the increase is occurring? Was this recently? What did you determine?

6. In your view, how often does your natural gas bill fluctuate as a result of natural gas price changes?
   WHERE APPROPRIATE MENTION COST OF GAS IS A FLOW THROUGH CHARGE. IN OTHER WORDS, TERASEN GAS CHARGES CUSTOMERS <u>AT COST</u> FOR GAS (NO PROFIT)
   TERASEN GAS DOES MAKE A PROFIT FROM THE DELIVERY PORTION OF THE BILL, BUT THIS IS REGULATED BY THE BC UTILITIES COMMISSION

Awareness of Measures to Control Price variations

7. Is Terasen Gas doing anything to try to control these price fluctuations? What steps is Terasen Gas taking? [PROBE]

Quarterly Price Adjustments

CLARIFICATION FOR PARTICIPANTS: So we are all clear on this, in the remainder of the group when I want to refer to the <u>cost of the gas</u> but <u>not any other charges</u> that may appear on your bill, I will call this "**Gas Commodity**" charges.

8. Currently Terasen Gas reviews the natural gas commodity charge (that is the price for the natural gas) every 3 months. How many of you were aware of this?

READ If Terasen Gas has paid more or less for the natural gas than it has collected from customers, this review may lead to an increase or decrease in the commodity charge.

Do you think that making a price adjustment every three months is a good approach to take?
IF PARTICIPANT ASKS WHAT OTHER FREQUENCY OF PRICE CHANGE, CAN USE 'EVERY YEAR/ANNUALLY'.

Hedging Program

Like many products and services, the price that Terasen Gas pays for natural gas can go up or down, and this can increase or decrease the Gas Commodity Charges that customers pay on their Natural Gas Bill.

Terasen Gas operates a "Hedging Program" on behalf of its natural gas customers to moderate or smooth out the degree of natural gas price volatility or price fluctuations. The result of this works almost like different mortgage rate plans: Variable Rate and Fixed Rate Mortgages.

For example, the interest rate you pay on a variable rate mortgage can go up or down, depending on the market. For people who are tolerant to changes in interest rates, this can save them money in the long run.

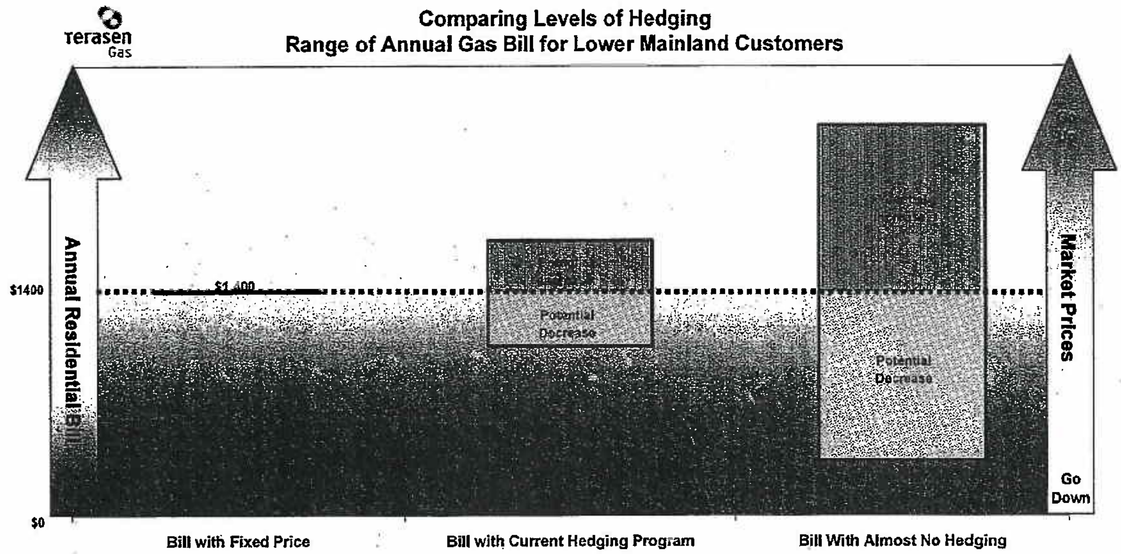
For people who are less tolerant to changes in interest rates or who want to pay the same amount for their mortgage payment each month, they can choose to have a fixed rate mortgage, where the interest rate remains fixed for a period of time. If the market interest rate goes up, they benefit from a fixed interest rate. However, if the market interest rate goes down, they are tied to the fixed interest rate.

- Fixed Rate works better if prices go up
- Variable Rate works better if prices go down

Fixed rate mortgages eliminate price fluctuations. In a similar way, Terasen Gas strategy is to manage price fluctuation to reduce, but not completely eliminate, gas price fluctuations

Let me describe this in more detail.

HANDOUT 1


Terasen Gas
Comparing Levels of Hedging
Range of Annual Gas Bill for Lower Mainland Customers
Annual Residential Bill
$1400
$0
$1,400
Potential Decrease
Potential Decrease
Market Prices
Go Down
Bill with Fixed Price
Bill with Current Hedging Program
Bill With Almost No Hedging

SCENARIO 2: Current program

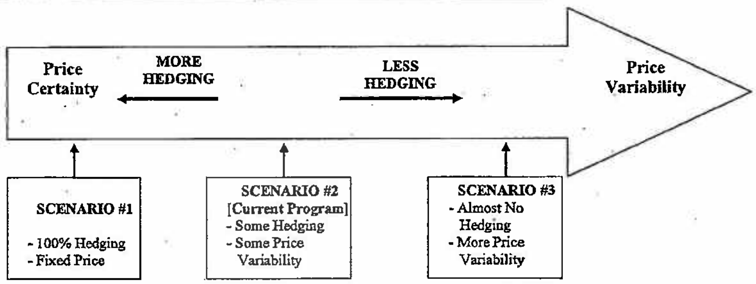
9. What is your understanding of the current program to manage price fluctuations as I have just described it? What are the positive aspects? What are the trade-offs?

Is this a worthwhile program for Terasen Gas to have on behalf of its natural gas customers?

Now I would like to discuss with you two possible modifications to the current hedging program that I just described.

SCENARIOS 1 AND 3 - DESCRIBE ALTERNATIVE PROGRAMS

CIRCULATE HANDOUT #2 – ARROW DIAGRAM



Q1A. Please check which one of the three hedging program approaches you *personally* would prefer:
CHOOSE ONE
☐ Scenario 1 (fixed price),
☐ Scenario 2 (current)
☐ Scenario 3 (more variable price).

Q1B. Please write down the main reasons why you would prefer that Terasen Gas utilize the approach you selected above.

____

____

Q2A. Please write down your household's total annual $ gas billings [an estimate is fine] RECORD ANSWER HERE → $

Q2B. What is the maximum $ dollar amount of change in your family's annual natural gas bill that you can tolerate due to fluctuations in natural gas prices? Write down an approximate dollar amount that, within this amount as a rate payer, you can live with and expect, given that natural gas is a product bought and sold on the open market.

RECORD ANSWER HERE → $

10. **Before I hear your views,** I would like you to write down for me on the sheet of paper which of the three hedging program approaches you personally would prefer: **scenario 1** (fixed price), **scenario 2 (current),** or **scenario 3 (more variable price).** In addition, please write down the primary reason (s) why you would prefer that Terasen Gas utilize the approach you selected.

11. Then indicate a) your HH's current total annual natural gas billings and b) what the maximum amount of change in your family's annual natural gas bill that you could live with due to fluctuations in natural gas prices? Write down for me a dollar amount that, within this amount as a rate payer, you can live with and expect, given that natural gas is a product bought and sold on the open market.

Start with your current ANNUAL bill amount (approximately). What then would be an acceptable change to this annual amount that you can tolerate?
IF NECESSARY: CHANGE IS INCREASE OR DECREASE

[DISCUSS ITEMS #10 AND #11 IN GROUP]

Do you consider your gas cost to be a significant % percent of your total household expenditure?

Do you know what % of your total household expenditures that your gas bill represents?

EPP

12. [*NON-EPP GROUPS*] What do you know about the Equal Billing Payment Plan? How does it work? [FLIPCHART] In your opinion what are the benefits?
13. Drawbacks? [FLIPCHART]
14. Why aren't you on the Equal Billing Payment Plan?
15. [*EPP GROUP*] All of you are on the EPP. What in your opinion are the main benefits of this plan? [FLIPCHART] What would you say is the primary reason for your choosing this plan? What about the drawbacks?
16. How does the EPP manage changes in the price of natural gas? When are the adjustments made to the cost of the plan?
17. Do you think that EPP is a good program for households to use to manage natural gas price fluctuations? (for helping to manage your monthly household budget expenses?)

Wrap-up

Any last thoughts
Thank you for your help this evening
Good-bye

Appendix B: Pre-Group Handout Questionnaire

First Name: ___________

While waiting for the research discussion group to commence, please complete the following brief questionnaire. The hostess will pickup the completed questionnaires before the discussion begins.

FIRST, PLEASE ANSWER THESE QUESTIONS ABOUT THE LAST YEAR.

1. As you think back over the Last year, how would you describe the price changes that have occurred for each of the products and services listed below?

   Please √ the appropriate box.

	Increased significantly	Increased slightly	Stayed the same	Decreased slightly	Decreased significantly	*Don't know*
Electricity						
Phone						
Gasoline						
Natural Gas						
Fruits & Vegetables						

2. Of the above-listed products and services that have increased in price over the last year, which one of the increases concerns you the most? ____________________

3. Sometimes there are a number of ups and downs in the prices of products and services within any given year. We will call these ups and downs **price fluctuations** or **price volatility.**

   a) Over the last year, which one of the products and services listed above has shown the greatest price fluctuation or greatest price volatility? __________

   b) And over the last year, which one has shown the least price fluctuation or least price volatility? ______________

Continue on page 2

NOW, PLEASE ANSWER THE FOLLOWING QUESTIONS ABOUT NEXT YEAR.

4. As you look ahead over the next year, how would you describe the price changes that you expect will occur for each of the products and services listed below?

Please √ the appropriate box.

	Will increase significantly	Will increase slightly	Will stay the same	Will decrease slightly	Will decrease significantly	*Don't know*
Electricity						
Phone						
Gasoline						
Natural Gas						
Fruits & Vegetables						

5. Of the above-listed products and services that you expect will increase in price over the next year, which one of the expected increases concerns you the most?

____

6. As noted earlier, sometimes there are a number of ups and downs in the prices of products and services within any given year. Here we will call these ups and downs **price fluctuations** or **price volatility.**

   a) Now, looking ahead over the next year, which one of the products and services listed above do you think will show the greatest price fluctuation or greatest price volatility? ______________________

   b) And, over the next year, which one do you think will show the least price fluctuation or least price volatility? ______________________

Thank you. The hostess will collect your completed questionnaire.

TERASEN GAS INC.

RESIDENTIAL CUSTOMER
PRICE VOLATILITY
PREFERENCE SURVEY

FEBRUARY 2005

Final Report

April 15, 2005

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Executive Overview

Introduction

In February 2005, Terasen Gas engaged Western Opinion Research Inc. to conduct a two-phased study with residential customers of Terasen Gas to assess and measure the perceptions and preferences of customers as they relate to natural gas price volatility.

Phase 1 consisted of four focus groups with residential natural gas customers as follows:

- 2 Groups with GVRD[1] residents (one group on the EPP[2], one group not on the EPP)
- 2 Groups with CRD[3] residents (one group on the EPP, one group not on the EPP)

The groups were held on February 7th and 8th, 2005. Both groups were moderated by Brian Owen.

Phase 2 of the project consisted of a telephone survey of 1000 Terasen Gas residential customers as follows:

- 400 interviews with Mainland customers on the EPP;
- 400 interviews with Mainland customers not on the EPP
- 100 interviews with Vancouver Island customers on the EPP
- 100 interviews with Vancouver Island customers not on the EPP

Data collection for the telephone survey occurred from February 18 to March 7, 2005. This report summarizes the results of Phase 2 of the research. Phase 1 of the research was used to identify the range of opinions on the subject and aid in the development of a questionnaire. The objective of Phase 2 was to quantify the findings from the qualitative phase, and to examine important differences in sub-groups.

Key Findings

1. **A sizeable proportion (71%) of respondents expressed concern about future fluctuations in the price of natural gas. Respondents tended to be more concerned about future price fluctuations in the price of gasoline and natural gas, than they were about price fluctuations in the cost of telephone or electricity.**

    - On a scale of one to ten, with ten being the highest level of concern, 71% of respondents expressed a higher level of concern about future increases in the price of natural gas (rated 7 or more out of ten).
    - While this was not as high as expressed for gasoline (75% rated 7 or higher), it was markedly higher than for electricity (58%) or telephone (40%).

[1] Greater Vancouver Regional District
[2] Equal Payment Plan
[3] Capital Regional District (Victoria)

2. Frequent reasons for concern about future natural gas price fluctuations were that it made *budgeting more difficult*, that respondents *didn't like having to pay more for natural gas*, that *natural gas is a necessity* or concern that *world market forces affected prices*.

   - Most frequently, 34% of respondents said that changing prices would make it more difficult to budget for natural gas expenses, particularly for those on fixed incomes.
   - Other reasons primarily related to concerns over having to pay more for natural gas. This included responses such as: "concerns over rising natural gas prices" (21%), that respondents "didn't like having to pay more for natural gas" (11%), or that "natural gas prices were considered too high already" (10%).
   - The fact that natural gas was viewed as a "necessity" (14%) was another theme that emerged. Participants said they used natural gas to heat their houses, water heaters and appliances. Because of the importance of natural gas in these daily aspects of life, respondents expressed concern over the potential for future price increases.
   - A few (8%) expressed concern over the world market being the driving force behind natural gas price fluctuations. Concerns in this respect related to external factors influencing an important commodity. A related theme was that Canadians should not have to pay market prices for natural gas because natural gas is extracted in Canada.
   - Finally a small percentage (5%) attributed rising natural gas prices to a perceived "monopoly status" of Terasen Gas. The perception was that in the absence of competition, Terasen Gas could charge whatever it wanted for natural gas.

3. Just under half (45%) of residential customers said they were aware that Terasen Gas passes on the cost of natural gas it buys at cost to customers. While a sizeable minority of residential customers says they are aware of this fact, it would appear that there is room to increase awareness on this measure.

4. Customers are generally aware that supply and demand for natural gas are the key drivers of natural gas pricing.

   - Generally, there was a fairly high level of knowledge among residential customers that supply (30%) and demand (42%) and world market (14%) forces are key drivers of natural gas pricing. Other factors cited by respondents included political factors (9%), the weather (7%), the economy (6%) and corporate profits /greed (8%) or oil producer profits (4%).

5. Typically, customers attribute month-to-month changes in their natural gas bill to changes in *consumption* rather than changes in the *price* of natural gas.

   - Largely, respondents were of the perception that month-to-month changes in their natural gas bill are due to changes in their consumption (52%) rather than price (28%), though a small proportion insisted it was due to both (8%). A similar result was found in the Phase 1 Focus Groups, in which customers did not automatically attribute changes in their gas bill to rate changes, but rather to changes in consumption.

6. Awareness of hedging activities by Terasen Gas to manage natural gas price fluctuations is very low among residential customers.

   - A third (33%) of residential gas customers said they were aware of measures or programs operated by Terasen Gas to smooth out natural gas price fluctuations. However, when asked to *describe* measures or programs that Terasen Gas operates to manage natural gas price fluctuations, very few customers were able to provide accurate answers.
   - Only 1% of all respondents could accurately cite activities by Terasen Gas to manage price fluctuations.

7. When informed about hedging activities undertaken by Terasen Gas to manage fluctuations in natural gas prices, most residential customers (66%) were in support of this activity. Reasons for not supporting hedging activities generally revolved around the following: a) a lack of knowledge about how the Hedging Program works; b) general cynicism about how natural gas rates are established or the belief that natural gas rates are already too high; and c) mistrust of the Program or of Terasen Gas.

   - While 66% were in support of the current Hedging Program, this support tended to be fairly soft with a higher proportion of respondents being "somewhat" supportive (41%) than "strongly" (25%) supportive. Another 9% of respondents said they were "neutral" towards the program while 11% said they "didn't know" or "refused" (1%). Relatively few respondents (13%) said they were opposed to the program.
   - A number of reasons were cited for opposing the current Hedging Program, including the lack of knowledge about how the Program works (23% didn't know & 5% said they needed more information), general cynicism about how natural gas rates are established (13%), that natural gas rates are already too high (12%), mistrust of the Program (10%) or mistrust of Terasen Gas (8%).
   - Other less frequent reasons for opposing the Program included: a) preference for a fixed rate for natural gas (9%), b) concerns that natural gas prices increase with hedging (8%), and c) the belief that natural gas should only be purchased as needed (7%).
   - As might be expected, the primary reasons for neither supporting nor opposing the Program (i.e. neutral or don't know responses) were: a) respondents didn't know enough to respond (41%), b) they needed more information (23%), or c) they didn't fully understand the Program (5%).

8. The general "stated" preference by residential customers for natural gas hedging activities is towards the *current hedging program* and leaning slightly towards *more hedging* activities rather than less hedging.

   - Results show that 44% of respondents preferred the Current Hedging Program while 28% said they preferred more hedging and 20% less hedging. This would indicate that the general preference towards hedging activities is towards the current hedging program and leaning towards more hedging activities than less hedging. Similar results were received in the phase 1 focus groups with residential customers.

9. The maximum change in annual natural gas billings that customers could live with in a year *averaged* $340. Excluding amounts over $1500 the average was $234; and excluding amounts over $1000 the average was $144.

   The median[4] amount of change in annual natural gas billings that customers could live with in a year was $100 for all responses. Excluding amounts over $1500 the median remained unchanged at $100 while excluding amounts over $1000 reduced the median amount to $74.

   As a percentage of respondents' estimated annual natural gas billings, the maximum amount of increase that respondents could live with averaged 27% for the total sample. Noteworthy is that this proportion tended to decrease as respondents' annual billings increased.

   - The *minimum* amount was $0 (16%), while the *maximum* was $4000.
   - Among participants who provided dollar amounts (including $0), one-quarter said $0/no increase; just over one-half said amounts of $100 or less, and 70% said amounts of $240 or less.
   - Customers' annual estimated natural gas billings typically fell between $500 and $1800 and averaged $1262 per year. As expected, costs were higher in the Interior ($1281) and Lower Mainland regions ($1299) than for Vancouver Island ($956).
   - Although the maximum amount of increase that respondents could live with averaged 27% of their total annual natural gas billings for the total sample, this proportion tended to decrease as respondents' annual billings increased. Respondents having somewhat smaller annual gas billings (eg $900 or less) tended to be willing to accept higher proportions (eg 38% - 48%) while those with higher annual gas billings (eg >$1300) tended to be willing to live with somewhat lower proportions (eg 15% to 27%).
   - Those who preferred the Current Hedging Program gave significantly lower annual average amounts of change that they could live with ($302) than those preferring more hedging ($378) or less hedging ($405). As a percentage of total annual estimated natural gas billings, respondents preferring the Current Program also cited lower percentages (24% vs. 30-33%). On the basis of these results it would appear that respondents preferring the Current Hedging Program are less willing to accept change in natural gas costs than those preferring less hedging or more hedging.

10. As the potential for savings increases or decreases, respondents were not willing to increase or decrease the maximum amount of increase in annual natural gas billings they were willing to tolerate. While customers could articulate a maximum increase in their natural gas billings they were willing to live with, it was difficult for many to consider or understand changing that amount to receive the "potential" benefit of lower prices.

    - Results show that to a large extent, respondents' answers remained constant, regardless of the amount of potential decrease in their annual billings. In other words,

[4] the middle value in a distribution, above and below which lie an equal number of values.

respondents' answers remained the same given four different potential savings scenarios: $600, $400, $200 and $100.

- Perhaps this is because residential consumers of natural gas do not think in terms of the potential for savings on their natural gas bill, but rather the maximum amount of change they are willing to live with.

Conclusions and Recommendations

Based on the results of the focus groups and survey of residential customers, the following conclusions and recommendations emerge.

1. A sizeable proportion (71%) of residential customers expressed a higher level of concern over future natural gas price fluctuations (7 or higher out of a possible 10). This stems from potentially having to pay more for a household "staple", which is a concern for people on fixed incomes, and those who don't want to pay more for natural gas.

2. A sizeable minority of customers are aware that Terasen Gas passes on the cost of natural gas that it buys to customers at cost, that is, with no added markup or charges (45%); however, most are not aware of this fact. In the event of increased volatility in the price of natural gas, it would be advantageous for Terasen Gas to increase awareness of this fact among residential customers.

3. The fact that most respondents attribute changes in their natural gas bill to changes in consumption (52%) rather than natural gas rates (28%) indicates that at present, natural gas volatility is not a big issue with customers. This is supported by focus groups with customers who raised few concerns about current natural gas rates, or natural gas price volatility. However, based on customers' stated level of concern over the possibility of future natural gas price fluctuations, Terasen Gas should continue with hedging practices to buffer against such possible volatility.

4. Awareness of hedging activities by Terasen Gas to manage natural gas price fluctuations is very low among residential customers but when explained to them, two-thirds are supportive of this practice. We hypothesize that the reason why support for current hedging practices was not higher is mainly because respondents required more information than could be provided in the short telephone interview.

5. The general "stated" preference by residential customers for natural gas hedging activities is towards the current hedging program (44%), and leaning slightly towards more hedging activities (28%) than less hedging (20%). This would indicate that if any changes were made to Terasen Gas' overall hedging strategy, it would be towards more rather than less hedging.

6. The maximum change in annual natural gas billings that customers could live with in a year *averaged* $340; though it should be noted that this figure was inflated by a relatively small number of large dollar amounts. Excluding amounts over $1500 the average decreases to $234; and excluding amounts over $1000 the average decreases to $144. Noteworthy is that 70% of customers (citing dollar amounts) gave amounts of $240 or less. On the basis of these findings the overall average of $340 overstates the preferred price volatility of a substantial proportion of customers. If a figure must be chosen to

reflect the diverse preferences of all customers we suggest using the median for the entire sample ($100) or perhaps the mean excluding amounts over $1000 ($144).

7. The maximum amount of increase that respondents could live with averaged 27% of their total annual natural gas billings for the total sample. Noteworthy, is that this proportion tended to *decrease* as respondents' annual billings *increased.* That is, respondents having somewhat smaller annual gas costs tended to be willing to accept higher "proportional amounts" (e.g. 38%-48%) while those with higher annual gas billings tended to be willing to live with somewhat lower proportions (15%-27%). A hypothesis to explain this finding is that those with lower annual natural gas billings may be willing to accept a proportionately higher amount of price volatility because the dollar amount of change at stake is smaller, and so poses less of a potential disruption to household budgets.

8. Based on this research, the potential for receiving greater savings on natural gas costs does not affect customers' willingness to accept more or less fluctuation in their annual natural gas bill.

Foreword

Background and Research Objectives

In February 2005, Terasen Gas engaged the services of Western Opinion Research Inc. to conduct a two-phased study with residential customers of Terasen Gas. The purpose of the research is to assess and measure the perceptions and preferences of customers as they relate to natural gas price volatility.

More specifically, the objectives of the research are to:

- Define customers' level of understanding regarding natural gas rates – including their components and how rates are set.
- Understand customers' natural gas price volatility preferences and determine if price points exist where customers are willing to accept more volatility in the form of rate variability and where they desire less volatility through rate stability.
- Use the results to revise Terasen Gas' price-risk management hedging strategy as appropriate.

Phase 1 consisted of four focus groups with residential natural gas customers as follows:

- 2 Groups with GVRD[5] residents (one group on the EPP[6], one Group not on the EPP)
- 2 Groups with CRD[7] residents (one group on the EPP, one Group not on the EPP)

Phase 2 of the project, consisted of telephone survey of 1000 Terasen Gas residential customers as follows:

- 400 interviews with Mainland customers on the EPP;
- 400 interviews with Mainland customers not on the EPP
- 100 interviews with Vancouver Island customers on the EPP
- 100 interviews with Vancouver Island customers not on the EPP

This report summarizes the results of Phase 2 of the research. Phase 1 of the research was used to identify the range of opinions on the subject and aid in the development of a questionnaire. The objective of Phase 2 was to quantify the findings from the qualitative phase, and to examine importance differences in sub-groups.

[5] Greater Vancouver Regional District
[6] Equal Payment Plan
[7] Capital Regional District (Victoria)

Methodology

Phase 1: Focus Groups with Residential Gas Customers

Four focus groups were held with residential gas customers of Terasen Gas on February 7th (GVRD) and 8th (CRD) 2005, as follows:

- 2 Groups with GVRD residents (one group on the EPP, one group not on the EPP)
- 2 Groups with CRD residents (one group on the EPP, one group not on the EPP)

All groups were held in focus group facilities equipped with one-way mirrors for observers, boardroom-style meeting room, and audio-visual recording equipment.

Participants were recruited from customer lists provided by Terasen Gas. Individuals in the household who were most familiar with buying and paying for the household's natural gas were targeted. To encourage participation, a $60 cash incentive was provided. Ten customers were recruited for each group for eight to participate (though up to ten were allowed to participate if they arrived. To be eligible to participate in the groups, participants must have met the following criteria:

- Individuals and the members of their household could not be employed by Terasen Gas or a subsidiary of Terasen Incorporated, a natural gas distributor, producer or natural gas marketer, the media, advertising, or a market research firm;
- They must live within the boundaries of the GVRD/CRD;
- They could not have attended a focus group within the past 12 months; and
- They could not have attended more than five focus groups in the past five years.

To ensure a broad representation of Terasen Gas residential customers, efforts were made to recruit a mix of:

- Males and females;
- Owners and Renters (though the sample was heavily weighted to Owners);
- Those residing in single family as well as multi-family dwellings;
- Residents from a range of communities within the GVRD/CRD; and
- Customers representing a range of age, education, household income and occupational categories.

Phase 2: Telephone Survey of Residential Gas Customers

Phase 2 of the project consisted of a telephone survey of 1000 Terasen Gas residential customers as follows:

Sampling Quota	Sampling Error
400 interviews with Mainland customers on the EPP	+/ - 5.0%
400 interviews with Mainland customers not on the EPP	+/ - 5.0%
100 interviews with Vancouver Island customers on the EPP	+/ - 10%
100 interviews with Vancouver Island customers not on the EPP	+/ - 10%
Total 1000 Residential Terasen Gas Customers	+/ - 3.2%

Results for the total sample of 1000 completed interviews were weighted to be representative of the total population of residential customers in the Vancouver Island, Lower Mainland and Interior regions of BC. The following table shows the weights used.

Region	Weight
Lower Mainland	1.1354
Interior	1.1255
Vancouver Island	0.4705

Throughout the report, survey results are reported in the form of weighted percentages; that is the weighted number of responses as a percentage of the total weighted number of people responding to each question. For significance testing purposes, the *unweighted* base is shown for each chart or table.

The list of customers for the telephone survey was provided by Terasen Gas.

The status of whether or not customers were on the Equal Payment Plan (EPP) was supplied along with the call sample to Western Opinion Research for sample records in the Lower Mainland and Interior regions. On Vancouver Island, customer's EPP status was not readily available, so respondents were asked whether they were on the EPP in the questionnaire.

Interviews were conducted with the person in the household who was responsible or partly responsible for reviewing and paying for the household's natural gas bills. Data collection occurred from February 18 to March 7, 2005.

A number of survey questions were open-ended; these answers were recorded verbatim by interviewing staff. During data processing, response categories were developed, and the verbatim results numerically coded and tabulated.

Telephone Survey: Detailed Findings

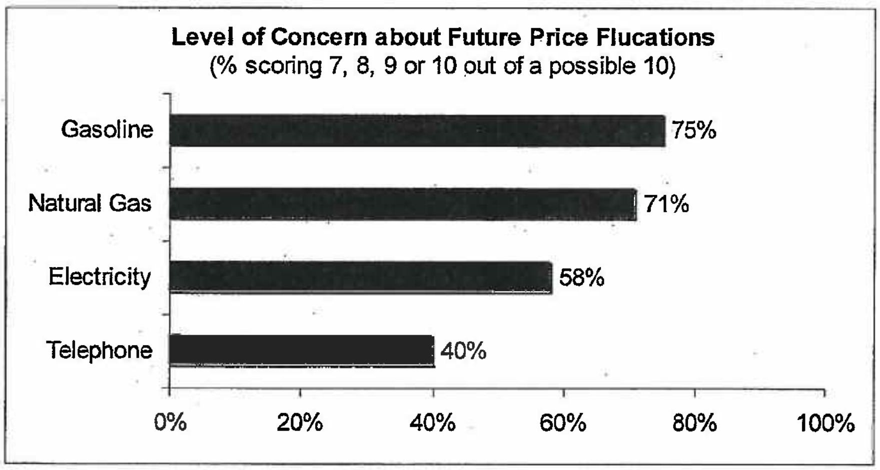
This section presents the results for each question asked of respondents. An interpretive summary of the results follows each chart or table. Sub-group differences in the results are also noted below in bullet form, where they are statistically significant and meaningful.

We begin by examining respondents' level of concern over future price fluctuations among four product or service categories.

1.0 Level of Concern over Price Fluctuations

Concern over Future Price Fluctuations

Q1a. (a-d)	Please tell me how concerned you are about future price fluctuations using a scale from 1 to 10 where 1 is not at all concerned and 10 is extremely concerned?
***Base*:**	Total Unweighted Sample (n=1000)



Results show that respondents tended to be more concerned about future price fluctuations in the price of gasoline and natural gas, than they were about price fluctuations in the cost of telephone or electricity.

On a scale of one to ten, with ten being the highest level of concern, 71% of respondents expressed a higher level of concern about future increases in the price of natural gas (7 or more out of ten). While this was not quite as high as expressed for gasoline (75% 7 or higher), it was markedly higher than for electricity (58%) or telephone (40%).

Sub-Group Differences:

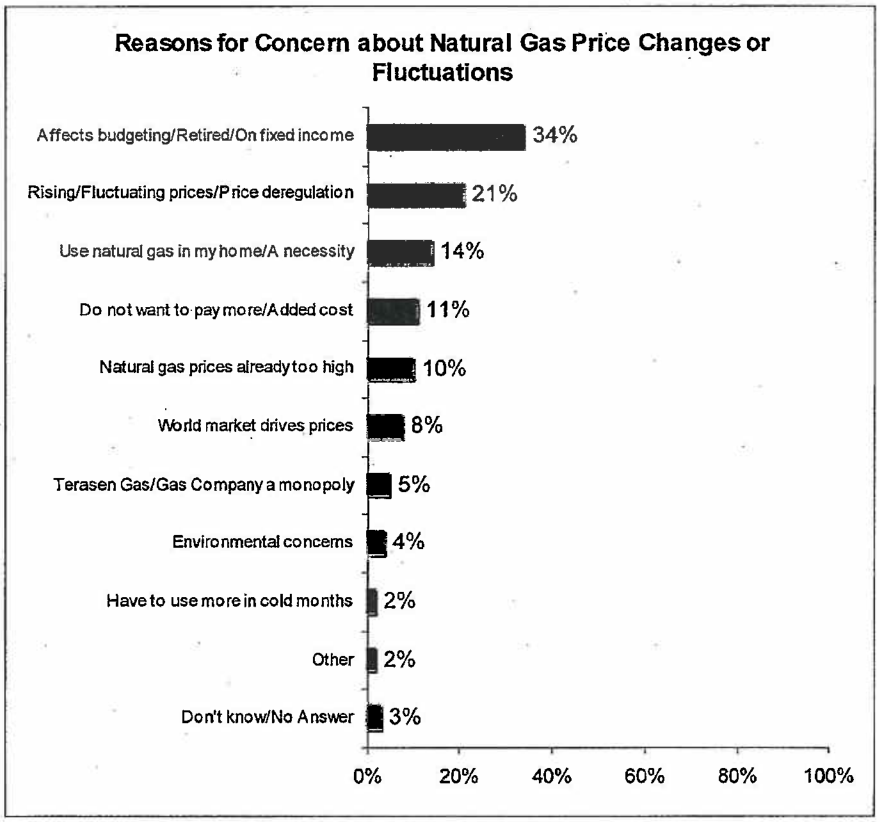
- Respondents with a high level of concern about future price fluctuations for natural gas (defined here as 8 or higher out of a possible 10) also tended to be more concerned about future price fluctuations for electricity (mean 8.0), telephone (mean 6.7) and gasoline (mean 8.8) than other respondents.

- Respondents who attributed changes in their monthly gas bill to *price* rather than consumption had tended to have a higher level of concern about future natural gas price fluctuations than other respondents (mean rating of 8.1 vs. 7.3 out of a possible 10).
- Respondents with higher levels of annual natural gas consumption tended to be more concerned about future natural gas price fluctuations (e.g. Mean rating of 8.0 for those with >$1800 in estimated annual gas consumption vs. a mean rating of 6.9 for those with $500 or less in annual gas consumption).
- Respondents under age 35 tended to be less concerned about future natural gas price fluctuations (mean rating of 6.5) than older respondents (e.g. age 55+ mean rating of 7.7).
- Respondents with some post secondary education or less, tended to be more concerned about future natural gas price fluctuations than those who have completed university (mean rating 7.8 vs. 7.2).
- Respondents with an annual household income of less than $40,000 tended to be more concerned about future natural gas price fluctuations than those with incomes of $100,000 or more.

Reason for Concern about Natural Gas Price Fluctuations

Those who expressed some level of concern about future natural gas price fluctuations (7 or higher out of 10) were asked to explain why they were concerned.

Q1b.	Why are you concerned about natural gas price changes or fluctuations? MULTIPLE RESPONSES
Base:	Unweighted Base IF 7-10 TO Q1a. (n=700)



Most frequently, customers said that changing prices would make it more difficult to budget for natural gas expenses; particularly for those on fixed incomes (34%).

Other reasons were primarily related to concerns over having to pay more for natural gas. This included concerns over rising natural gas prices (21%), that respondents didn't like having to pay more for natural gas (11%), or that natural gas prices were considered too high already (10%).

The fact that natural gas was viewed as a "necessity" (14%) was another theme that emerged. Participants said they used natural gas to heat their houses, water heaters and appliances. Because of the importance of natural gas in these daily aspects of life, respondents expressed concern over the potential for future price increases.

A few (8%) expressed concern over the world market being the driving force behind natural gas price fluctuations. Concerns in this respect related to external factors influencing an important commodity. A related theme was that Canadians should not have to pay market prices for natural gas because natural gas is extracted in Canada.

Finally, a small percentage (5%) attributed rising natural gas prices to a perceived "monopoly status" of Terasen Gas. The perception was that in the absence of competition, Terasen Gas could charge whatever it wanted for natural gas.

Sub-Group Differences:

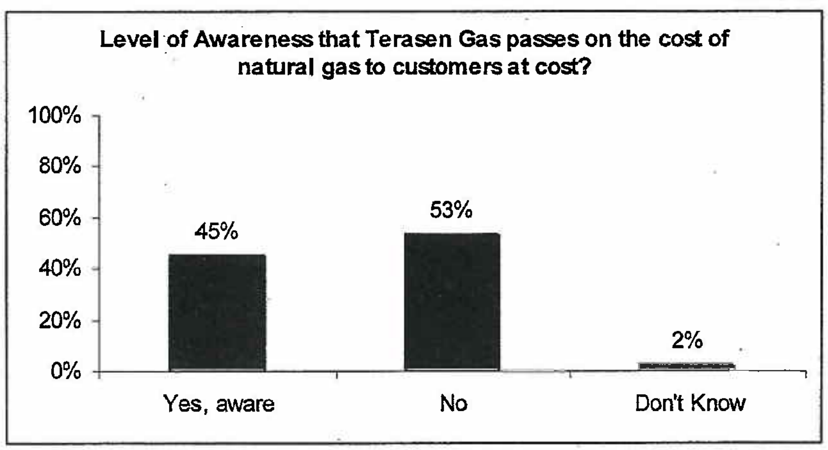
- Respondents aged 55+ were more likely to say that natural gas price fluctuations affected their budgeting than those under 55 (38% vs. 23%)
- More recent natural gas customers (5 years or less) were more likely to say that natural gas price fluctuations are a concern than longer term customers (21-30 years) (22% vs. 10%) because natural gas is viewed as a household "necessity/use gas appliance in home".

2.0 Awareness of Factors Related to Natural Gas Price Fluctations

Earlier, results showed that a substantial proportion of customers were concerned about the possibility of future fluctuating natural gas prices. Given that fluctuating prices could occur, it would be advantageous for Terasen Gas to inform customers that Terasen Gas buys its natural gas on the open market, and passes on the cost of gas to customers with no markup. The following chart shows respondents' level of awareness of this fact.

Awareness that Terasen Gas Passes on the Cost of Natural Gas to Customers at Cost

Q2.	Terasen Gas buys natural gas on the open market and passes on the cost of this natural gas to its customers at cost, that is, with no markup or added charges. Were you aware of this?
***Base*:**	Total Unweighted Sample (n=1000)



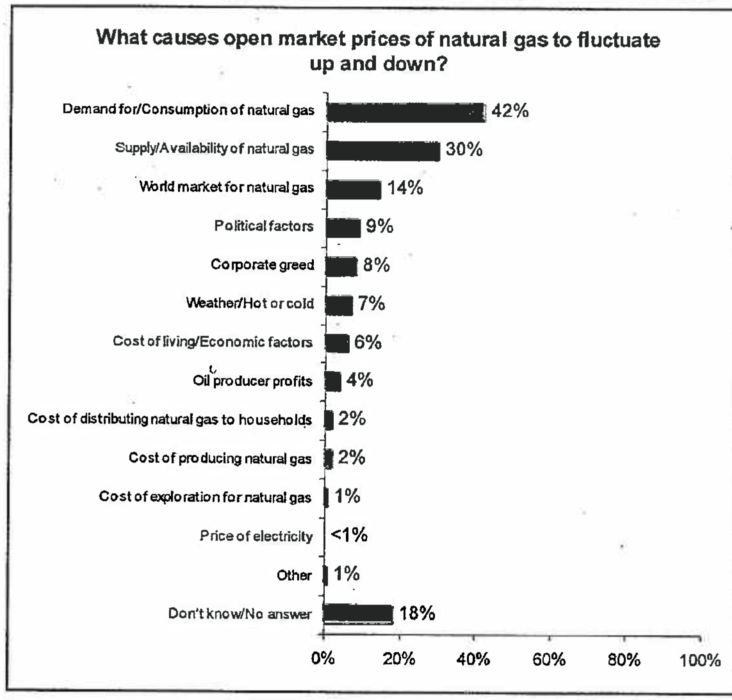
Results show that just under half of residential customers (45%) were aware that Terasen Gas passes on the cost of natural gas at cost to customers. While a sizeable minority of residential customers *said* they were aware of this fact, it would appear that there is room to increase awareness on this measure.

Sub-Group Differences:

- Those under age 34 were more likely to be aware that Terasen Gas passes on the cost of natural gas at cost to customers (71% aware) than those age 55+ (51% aware)
- Those with lower annual household incomes (<$20,000) were more likely to be aware that Terasen Gas passes on the cost of natural gas at cost to customers (67%) than other customers (50%).
- More recent natural gas customers (5 years or less) were more likely to be aware that Terasen Gas passes on the cost of natural gas at cost to customers (72%) than longer term customers (11+ years) (47%)
- Males were more likely to be aware that Terasen Gas passes on the cost of natural gas at cost to customers (58%) than females (34%)
- Those on Vancouver Island were less likely to be aware that Terasen Gas passes on the cost of natural gas at cost to customers (20%) than respondents in other regions (47%)

Awareness of Factors Causing Natural Gas Price Fluctuations

Q3.	What do you think causes the open market price of natural gas to fluctuate up and down? MULTIPLE RESPONSES
Base:	Total Unweighted Sample (n=1000)



Generally, there was a fairly high level of knowledge among residential customers that supply (30%) and demand (42%) and world market (14%) forces are key drivers of natural gas pricing.

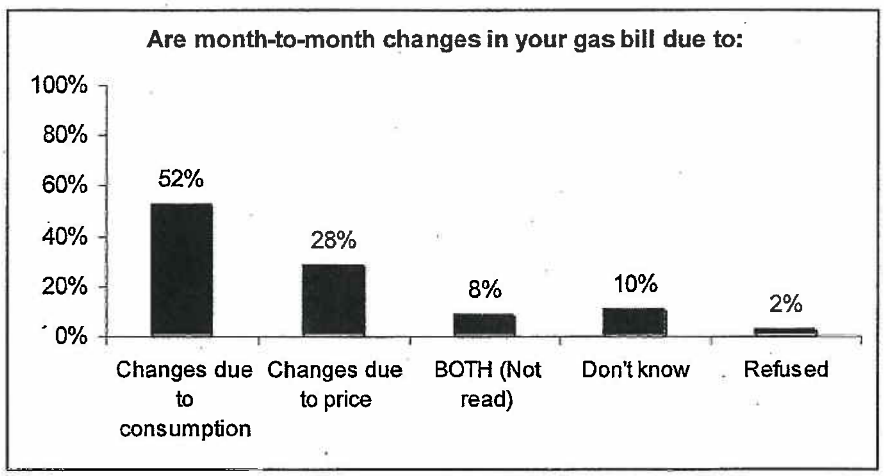
Other factors cited by respondents included political factors (9%), corporate profits /greed (8%), the weather (7%), the economy (6%) and or oil producer profits (4%).

Sub-Group Differences:

- Those with a high school education or less were more likely to say they "didn't know" what causes the open market price of natural gas to fluctuate (26%) than other respondents (13%)
- Those with income levels of less than $20,000 were more likely to say they "didn't know" what causes the open market price of natural gas to fluctuate (41%) than respondents with higher income levels (16%)

Are Changes in Monthly Natural Gas Bill Automatically Attributed to Changes in Rates?

Q4.	Are month-to-month changes in the amount of your household's natural gas bill typically due to changes in the price of natural gas, or due to changes in your household's consumption of natural gas?
Base:	Total Unweighted Sample (n=1000)



Largely, respondents were of the perception that month-to-month changes in their natural gas bill were due to changes in their consumption (52%) rather than due to price (28%) though a small proportion insisted it was due to both (8%). A similar result was found in the Phase 1 Focus Groups, in which customers did not automatically attribute changes in their gas bill to rate changes, but rather to changes in consumption.

Sub-Group Differences:

The following groups were more likely to attribute changes in their monthly gas bill to price:

- Respondents with a higher level of concern (defined here as 8 or higher out of a possible 10) about future natural gas price fluctuations (33%) as compared to those with lower levels of concern (22%).
- Respondents with a high school graduation or less (34%) as compared to others (24%)
- Those aged 65 or older (36%) versus younger respondents (19%)

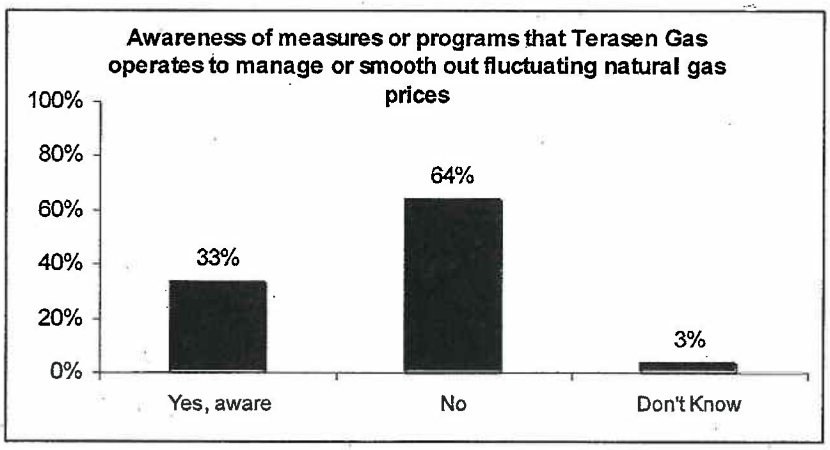
- Those with annual household incomes of less than $20,000 (38%) versus those with incomes of $40,000 or higher (23%)
- Natural gas customers for more than 30 years (34%) versus shorter term customers (22%)
- Respondents living in the Lower Mainland (28%) or Interior (31%) versus those living on Vancouver Island (18%)

3.0 Terasen Gas Natural Gas Hedging Program

Having now defined the level of residential customer awareness of a number of natural gas price fluctuation related issues, questions were posed about Terasen Gas' Natural Gas Hedging Program. The following graph shows respondents awareness of this Program, unaided.

Awareness of Terasen Gas Programs to Manage Fluctuating Natural Gas Prices

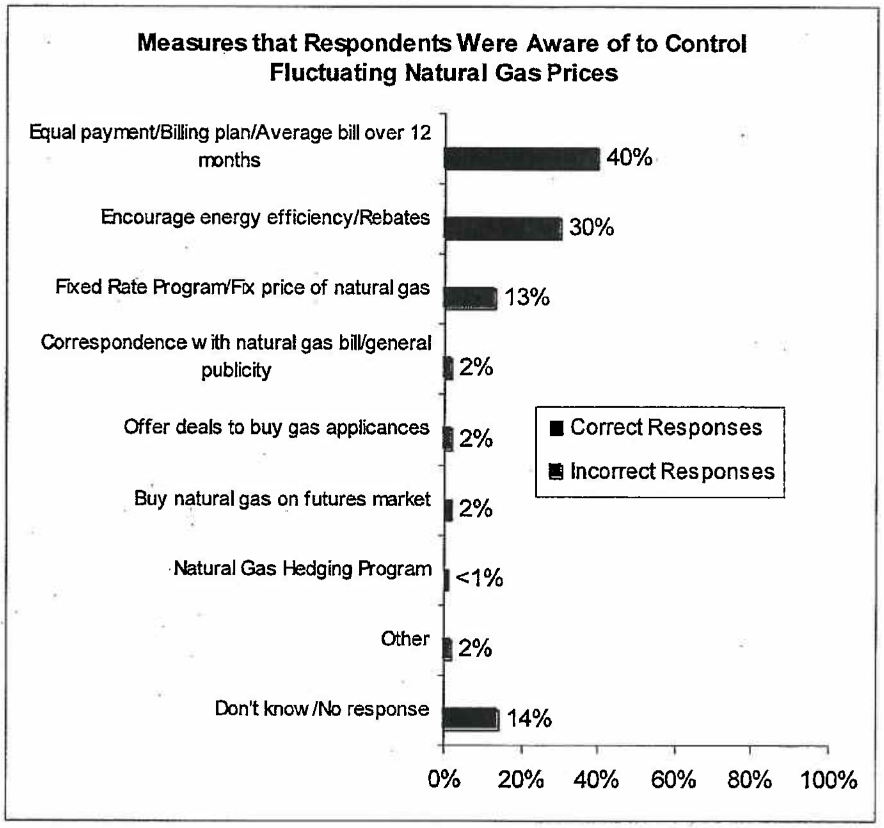
Q6.	Are you aware of any measures or programs that Terasen Gas operates, or that it may operate on behalf of its customers to manage or smooth out fluctuating natural gas prices?
Base:	Total Unweighted Sample (n=1000)



A third (33%) of residential gas customers said they were aware of measures or programs operated by Terasen Gas to smooth out natural gas price fluctuations.

In fact, the results to the following question will demonstrate that awareness is much lower.

Q6.	What measures are you aware of? MULTIPLE RESPONSES
Base:	Unweighted Base IF YES TO Q5 (n=308)



When asked to describe measures or programs that Terasen Gas operates to manage natural gas price fluctuations, very few customers were able to provide accurate answers.

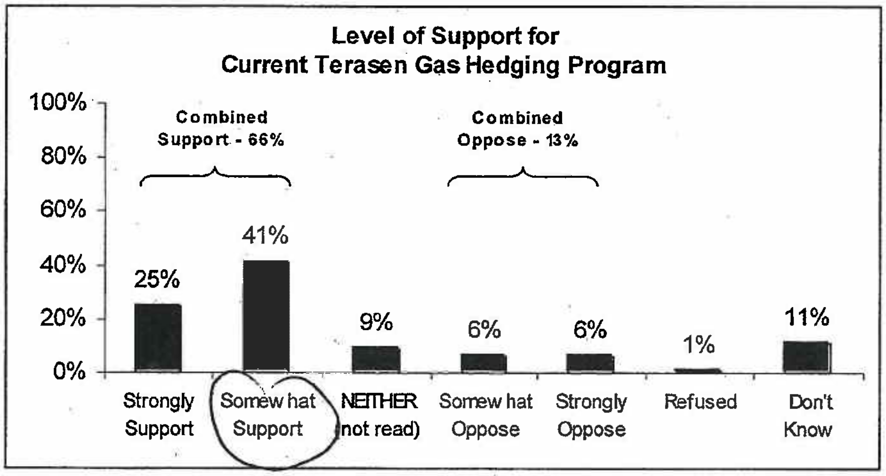
Among the third of respondents who *said* they were aware of such measures, only two percent could give correct answers; which included "buying gas on the futures market" (2%), or "natural gas hedging activities" (<1%). As a percent of *all respondents* in the total sample, only 1% could accurately cite activities by Terasen Gas to manage price fluctuations.

More frequently, participants who *said* they were aware of such measures incorrectly cited the Equal Payment Plan (40%), energy efficiency programs or rebates (30%) or the Fixed Rate Program. Some confusion between aspects of the Equal Payment Plan and changes to natural gas rates was also noted in the Phase 1 focus groups.

Level of Support for Current Terasen Gas Hedging Program

Having now gauged customers' awareness of activities to manage natural gas price fluctuations, respondents were asked if they supported or opposed these activities by Terasen Gas.

> PREAMBLE READ TO RESPONDENTS:
>
> Currently, Terasen Gas does operate a hedging program on behalf of its customers to moderate or smooth out price fluctuations of natural gas purchased on the open market.
>
> It works much like different mortgage rate plans such as Variable Rate and Fixed Rate mortgages. Fixed Rate mortgages eliminate interest rate changes, while Variable Rate mortgages can change with the market. Having a fixed rate is better if interest rates go up because you don't pay more than your fixed mortgage rate. Having a variable rate is better if interest rates go down because you can benefit from declining rates.
>
> In a similar way, Terasen Gas' hedging strategy is used to reduce but not completely eliminate market price fluctuations. In other words, the current hedging program has some variable and some fixed pricing.
>
> Q7a Do you support or oppose Terasen Gas' program to hedge natural gas prices? Would that be strongly or just somewhat?
>
> *Base*: Total Unweighted Sample (n=1000)



Results indicate that most residential customers (66%) are in support of the current Hedging Program, but this support tends to be fairly soft with a higher proportion of respondents being "somewhat" in support (41%) than "strongly" (25%) in support. Another 9% of respondents said they were "neutral" towards the program while 11% said they "didn't know".

Relatively few respondents (13%) said they were opposed to the program[8].

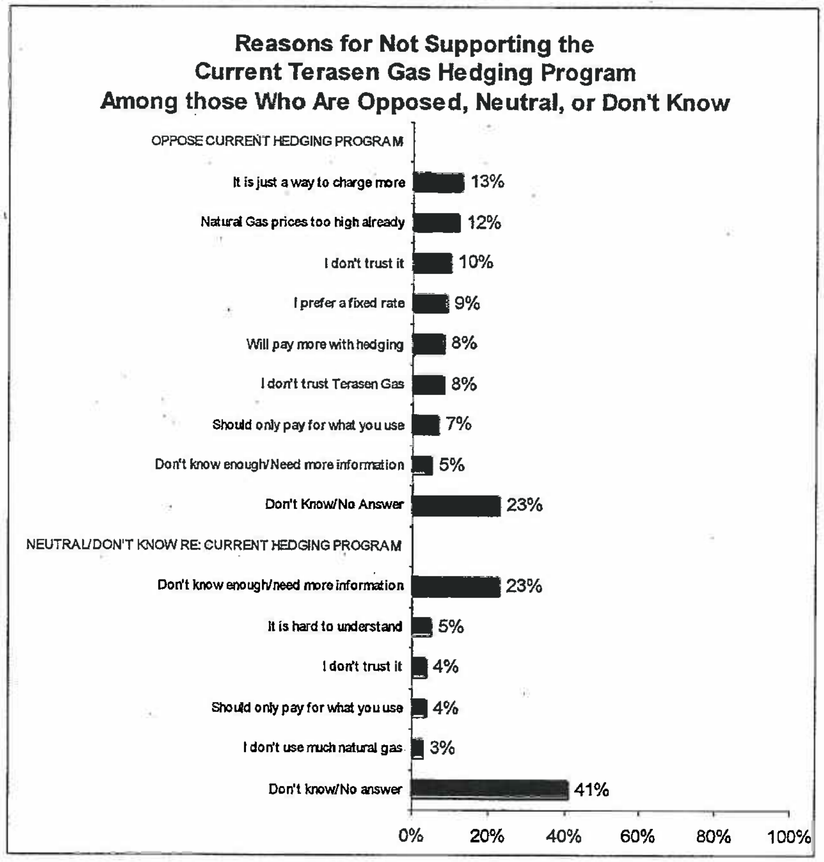
Sub-Group Differences:

The following groups were identified as being more likely to oppose the Current Terasen Gas Hedging Program:

[8] Note: the total percent "opposed" rounds to 13% when combined.

- Respondents with high (defined here as 8 or higher out of a possible 10) levels of concern about future natural gas price fluctuations (16% opposed) versus other respondents (8% opposed)
- Respondents who attributed changes in their monthly gas bill to changes in price (11% strongly opposed) vs. those attributing change to consumption (3% strongly opposed)
- Respondents aged 65+ (15% opposed) versus respondents under age 65 (10% opposed)
- Natural gas customers for more than 20 years (8% strongly opposed) versus customers for 20 years or less (3% strongly opposed).
- Those residing in the Interior (8% strongly oppose) or Lower Mainland (6% strongly opposed) versus those on Vancouver Island (2% strongly opposed)

Q7b.	Why do you say that? MULTIPLE RESPONSES
Base:	Unweighted Base IF OPPOSED, NEUTRAL, DON'T KNOW TO Q7A (n=324) [Most frequent responses shown]



Earlier, about two thirds of respondents said they supported efforts by Terasen Gas to manage price fluctuations while the balance was neutral, didn't know, or were opposed. In a follow up question, respondents not in favour of hedging (i.e. opposed, neutral or didn't know) were asked *why* they answered this way.

A number of reasons were cited for opposing the current Hedging Program but these responses can be grouped into three main categories, including a) the *lack of knowledge about how the Program works to be able to respond* (23% don't know & 5% need more information; b) *general cynicism about how natural gas rates are established* (13%) *or that natural gas rates are already too high* (12%); and c) *mistrust of the Program* (10%) *or of Terasen Gas* (8%).

Other less frequent reasons for opposing the Program included those having a *preference for a fixed rate for natural gas* (9%), those concerned that *natural gas costs more with hedging* (8%) or the belief that *natural gas should only be purchased as needed* (7%).

As might be expected, the primary reasons for neither supporting nor opposing the Program (i.e. neutral or don't know responses) were that respondents *didn't know enough to respond* (41%), that they *needed more information* (23%), or that they *didn't fully understand the Program* (5%).

Sub-Group Differences:

- Those who had completed university were more likely to say they needed more information about the Hedging Program (21%) than those with a high school education or less (10%).

Preferred Natural Gas Hedging Strategy

Next, respondents were read a description of three possible hedging strategies to manage fluctuations in natural gas pricing and then, asked which of the three scenarios they preferred.

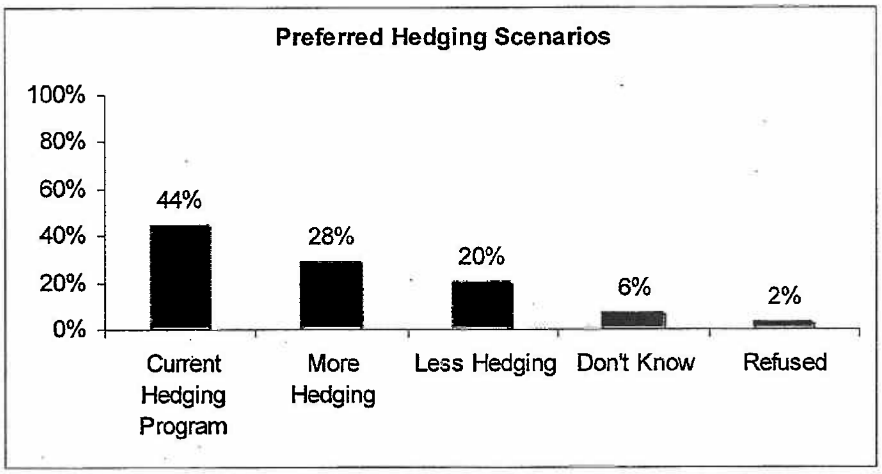
Q8. I am going to read you three different points of view about Terasen Gas' Program to reduce price fluctuations. After I read all three statements, I would like you to tell me which one of the statements is closest to your own view. RANDOMIZE ORDER a-c

a. Terasen Gas should continue its present hedging program to smooth out natural gas price fluctuations.

b. Terasen Gas should hedge less and not smooth out price fluctuations as much as it does. Instead, it should pass on more of the actual ups and downs of market prices to its customers. This would allow customers to benefit more from any drop in natural gas prices, but they may also have to pay more if market prices increase.

c. Terasen Gas should hedge more to further smooth out natural gas price fluctuations. This would provide a fixed price for natural gas which would protect customers from potential increases in the price of natural gas but on the other hand would not allow them to benefit from potential decreases in price.

***Base*:** Total Unweighted Sample (n=1000)



Results show that 44% of respondents preferred the *Current Hedging Program* while 28% said they preferred *more hedging* and 20% said *less hedging.* This would indicate that the general preference for hedging activities is towards the current hedging program, and leaning towards more hedging activities than less hedging. Similar results were received in the phase 1 focus groups with residential customers.

Sub-Group Differences:

The following were more likely to prefer the Current Terasen Gas Hedging Strategy:

- Those with a lower level of concern over future natural gas price fluctuations (defined here as 7 or less out of a possible 10) (55% versus 37% among those with higher levels of concern (8 or higher).
- Those who attribute monthly changes in their natural gas bill to consumption (50% vs. 38% among those who attribute monthly changes in their gas bill to price).
- Respondents on the EPP (49% vs 40% among those not on the EPP).
- Those completing technical/vocational/university (50% versus 38% among those with a high school education or less.
- Those who own their home with a floating rate mortgage (58% versus 42% among those who own their home with no mortgage.
- Those aged 45 – 54 (60% versus 30% among those aged 55+).
- Those with household incomes of $20,000 or more (49% versus 29% among those with less than a $20,000 household income).
- Natural gas customers for 5 years or less (59% versus 40% among customers for 31 or more years).

The following were more likely to prefer More Hedging:

- Those with a higher level of concern over future natural gas price fluctuations (8 or higher out of a possible 10) (32% versus 21% among those with lower levels of concern).
- Those who attribute monthly changes in their natural gas bill to price (33% versus 25% among those who attribute monthly changes in their bill to consumption).
- Those aged 65+ (33% versus 22% among those under 65).
- Those with household incomes of less than $20,000 (42% versus 26% among those with higher household incomes).

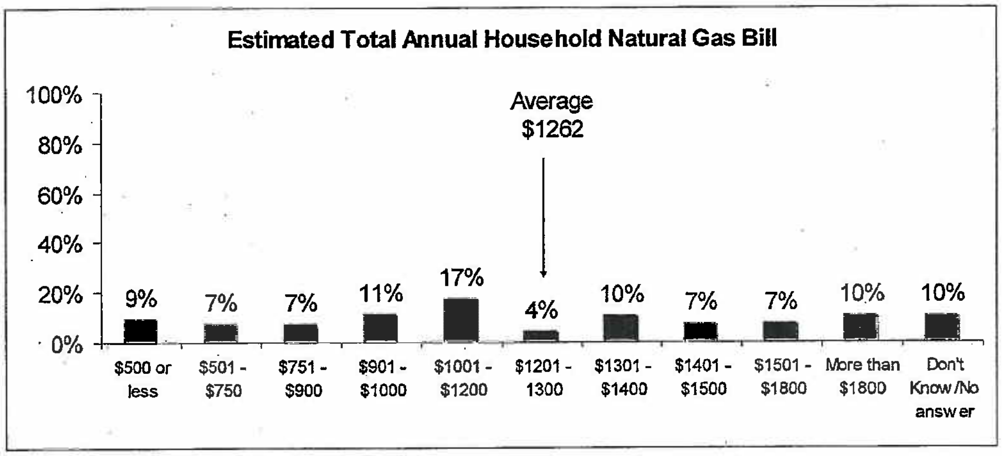
- Those who own their home with no mortgage (30% vs. 17% among those who own their home with a floating rate mortgage).

The following were more likely to prefer <u>Less Hedging:</u>
- Those aged 35 – 44 (26% versus 14% among those aged 45 – 54)
- Natural gas customers for 31+ years (23% versus 13% among customers for 5 years or less)

Estimated Total Annual Household Natural Gas Billings

Next, respondents were asked to estimate their total annual household natural gas billings. The purpose of the question was to help put into context the relative value (%) for how much change in natural gas costs respondents could live with in a given year.

Q9.	Approximately how much is your total annual natural gas bill including all charges and taxes?
Base:	Total Unweighted Sample (n=1000)



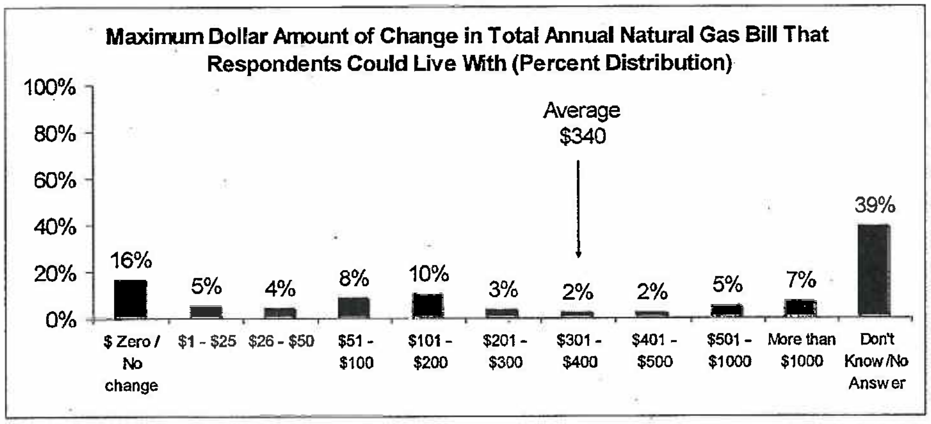
The above chart shows customers' annual natural gas billings which were typically between $500 and $1800, and averaged $1262 per year.

<u>Sub-Group Differences:</u>
- As expected, annual natural gas costs were higher in the Interior ($1281) and Lower Mainland regions ($1299) than for Vancouver Island ($956).
- Those with higher levels of concern about future natural gas price fluctuations (8 or higher out of a possible 10) tended to have higher annual natural gas costs ($1316) than those with lower levels of concern (5 or less out of 10) ($1118)
- Those with higher levels of household income tended to report higher annual natural gas costs (e.g., those with incomes of $100,000 or more reported annual natural gas costs of $1629)

Maximum Annual Change in Natural Gas Billings Respondents Could Live With

Next, respondents were asked to provide the maximum dollar amount of change in their annual natural gas billings that they could live with. The percent distribution of responses is shown below with the overall average amount ($340).

Q10.	Recognizing that market prices for natural gas will continue to fluctuate up and down, what is the maximum dollar amount of change in your family's total annual natural gas bill that you could live with?
Base:	Total Unweighted Sample (n=1000)



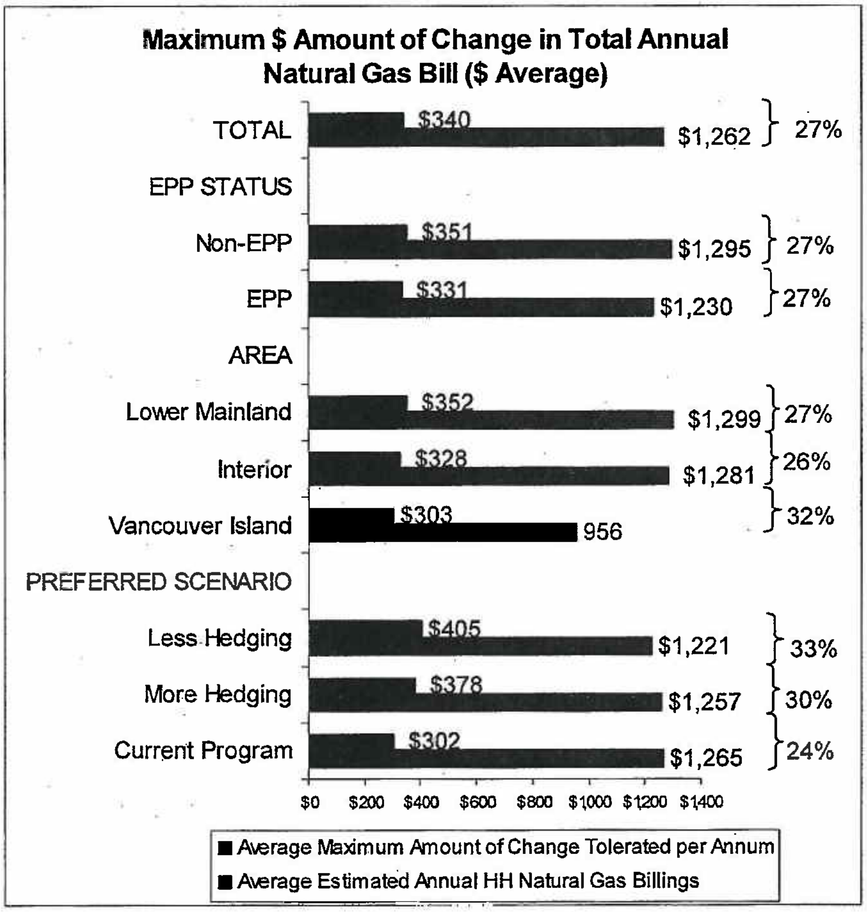
Results show that:

- The minimum amount was $0 (16%), while the maximum was $4000.
- The average amount was $340 (including $0 dollar amounts). Excluding amounts over $1500 the average was $234; and excluding amounts over $1000 the average was $144.
- The median[9] amount of change in annual natural gas billings that customers could live with in a year was $100 for all responses. Excluding amounts over $1500 the median remained unchanged at $100 while excluding amounts over $1000 reduced the median amount to $74.
- The most frequent response categories were $0 (16%), $101-200 (10%) and $51 - $100 (8%).
- Excluding "don't know" responses from the base (not shown in chart), one-quarter of participants providing an answer expressed amounts of $0; just over one-half cited amounts of $100 or less, and 70% said amounts of $240 or less.

[9] the middle value in a distribution, above and below which lie an equal number of values.

The following chart compares respondents' maximum $ amount of change with their (estimated) total annual natural gas billings. Results are shown for the total sample as well as for certain cohorts of interest.

Maximum Average $ Amount of Change in Annual Billings Respondents Could Live With As Compared to their Total Annual Natural Gas Billings



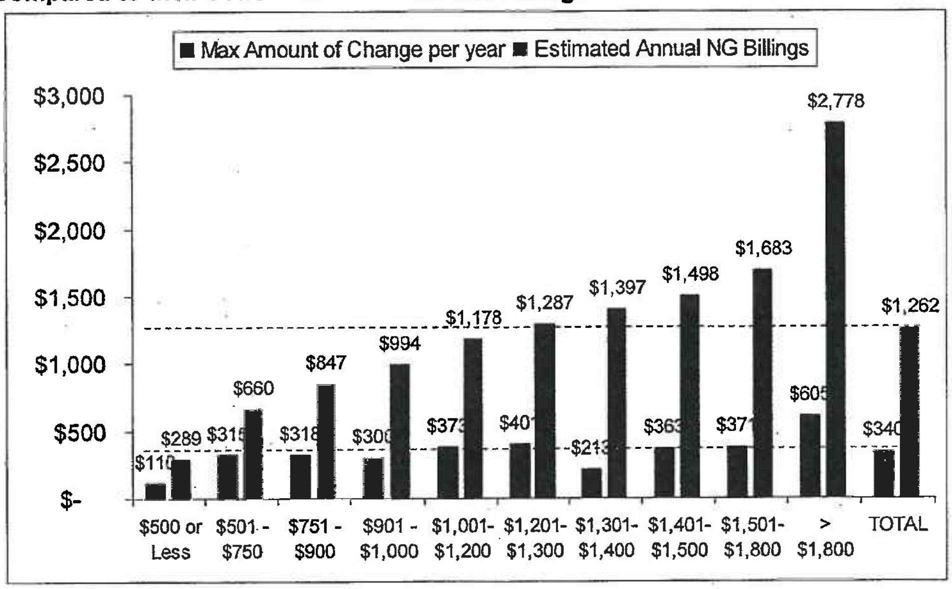
As previously mentioned, respondents' average maximum dollar change in their annual natural gas billings they could live with was $340; this represents 27% of respondents total average estimated natural gas billings ($1262).

Results for key segments of interest are shown in the above chart, but only one statistically significant difference is noted: respondents who preferred the Current Hedging Program gave significantly lower annual average amounts of change that they could live with ($302) than those preferring more hedging ($378) or less hedging ($405). Similarly, as a percentage of total annual estimated natural gas billings, respondents preferring the Current Program also cited lower percentages (24% vs. 30-33%). On the basis of these results, it would appear that respondents preferring the Current Hedging Program are less willing to accept change in natural gas costs than those preferring less hedging or more hedging.

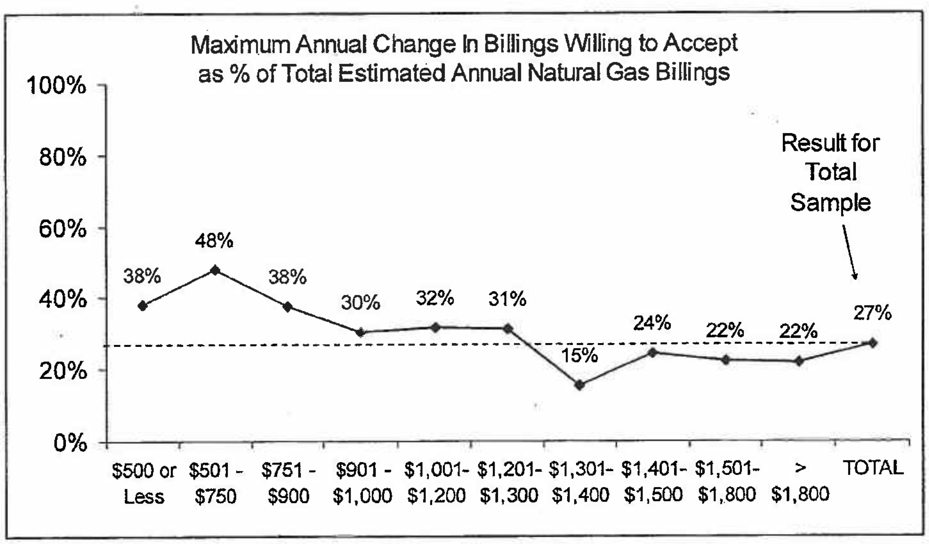
Noteworthy is that there was virtually no difference between customers on the Equal Payment Plan (EPP) versus those not on the EPP. One might have expected those on the EPP to be less tolerant of natural gas price volatility, however, few significant differences were found.

The chart below shows a) the *average annual natural gas billings* for each of eleven dollar amount categories along with b) the *corresponding average maximum annual increase in billings* that respondents in each category could live with (the dotted line shows results for the total sample). The subsequent chart shows b) as a percent of a) for each of the eleven categories.

Maximum Average $ Amount of Change in Annual Billings Respondents Could Live With As Compared to their Total Annual Natural Gas Billings



Maximum Average $ Amount of Change in Annual Billings Respondents Could Live With as a Percentage of their Total Annual Natural Gas Billings



Results show that for the total sample, the maximum amount of increase that respondents could live with averaged 27% of their total annual natural gas billings (see dotted line on lower chart). Comparing this proportion across each of eleven categories, we see that respondents having smaller annual gas billings (e.g. $900 or less) tended to be willing to accept higher proportions (e.g. 38% - 48%) while those with higher annual gas billings (e.g. >$1300) tended to accept somewhat lower proportions (e.g. 15% to 27%). A hypothesis to explain this finding is that those with lower annual natural gas billings may be willing to accept a proportionately higher amount of price volatility because the dollar amount of change at stake is smaller and so may pose less of a potential disruption to household budgets.

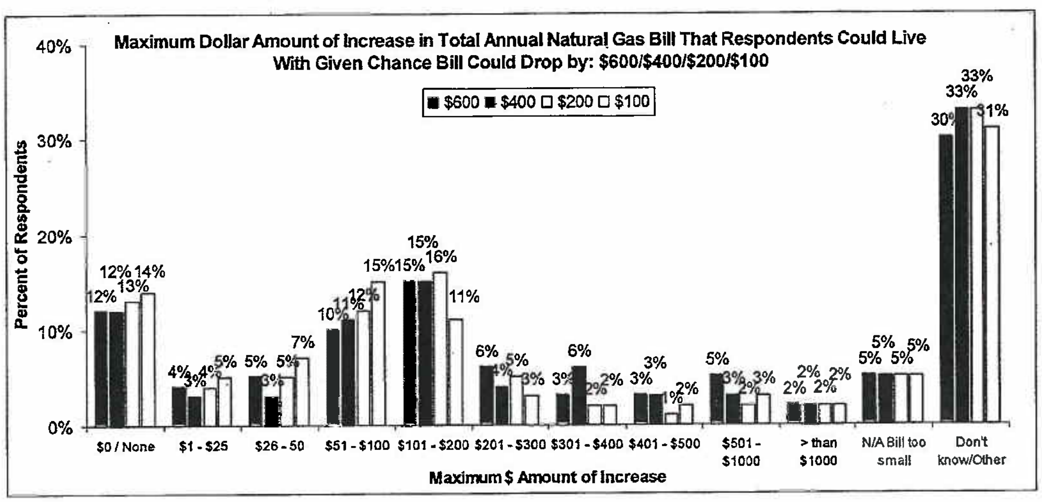
Sub-Group Differences:

- Those who preferred the Current Hedging Program tended to report a lower average maximum amount of change in their annual natural gas bill that they could live with ($302) than those who preferred More Hedging ($378) or Less Hedging ($405).
- Those with annual natural gas expenses of $500 or less gave a lower average amount of fluctuation in natural gas costs that they could live with ($110) than those with annual expenses of $1800 or higher ($605).
- Those with a higher level of concern about future natural gas price fluctuations (defined here as 8 or higher out of a possible 10) tended to report a lower average amount of change that they could live with ($301) than those with a lower level of concern (7 or less) ($393)

Maximum Annual Increase in Natural Gas Billings Given Four Levels of Possible Savings

The following question was asked to determine if different dollar amounts of potential *savings* in annual natural gas billings changed the amount of *increase* in annual billings that respondents could live with.

Q11a-e If an expert told you that your gas bill could *decrease* by: [a. $600 b. $400 c. $200 d. $100] or that it might increase but they couldn't tell you by how much, what is the maximum increase in your annual bill that you could live with in this case?
Base: Total Unweighted Sample (n=1000)



Results show that to a large extent, respondents' answers remained constant regardless of the amount of potential decrease in their annual billings. In other words, the distribution of respondents' answers remained the same given four different potential savings scenarios: $600, $400, $200 and $100. For example, 12% of respondents said they would not accept any ($0) increase in their total annual household billings given the chance their billings could drop by $600. This finding is not significantly different than the 14% who said they would not accept any increase in their billings given the chance their billings could drop by $100.

This would indicate that as the potential for savings increases or decreases, respondents are not willing to increase or decrease the maximum amount of increase they are willing to tolerate. Rather, respondents have a maximum tolerance for natural gas price fluctuations which remains constant. Perhaps this is because residential consumers of natural gas do not think in terms of the potential for savings on their natural gas bill, but rather the maximum amount of change they are willing to live with.

4.0 Sample Demographics

The following tables provide details on the demographic composition of the sample of slot machine players interviewed in the survey.

Sample Demographics	Weighted Percent (Unweighted Base n=1000)
Equal Payment Plan	
Household on EPP	50%
Household not on EPP	50%
Gender	
Female	55%
Male	45%
Education	
Less than High School	12%
High School Graduate	25%
Some Post Secondary	17%
Completed college/Technical/Vocational/Trade	15%
University Degree	29%
Refused	2%
Respondent Age Category	
18 – 24	<1%
25 – 34	3%
35 – 44	9%
45 – 54	15%
55 – 64	20%
65 and over	52%
Refused	1%
Own or Rent?	
Rent	3%
Own Home with Fixed Rate Mortgage	18%
Own Home with Floating Rate Mortgage	7%
Own Home No Mortgage	69%
Don't know/Refused	3%
Total Annual Household Income for 2004	
< $20,000	8%
$20,000 to < $40,000	20%
$40,000 to < $60,000	19%
$60,000 to < $80,000	13%
$80,000 to < $100,000	5%
$100,000 or more	10%
Don't know/Refused	27%
Length of Time a Natural Gas Customer in BC	
5 years or less	7%
6 – 10 years	9%
11 – 20 years	15%
21 – 30 years	22%
31+ years	45%

Sample Demographics	Unweighted Percent (Unweighted Base n=1000)	Weighted Percent (Unweighted Base n=1000)
Region		
Vancouver Island	20%	9%
Interior	28%	27%
Lower Mainland	56%	63%

Appendices

A. Questionnaire

Appendix A: Telephone Survey Questionnaire

NATURAL GAS PRICE VOLATILITY SURVEY – RESIDENTIAL
Draft 7 – February 22, 2005

A. My name is ________. I am calling on behalf of Western Opinion Research a professional market research firm. This evening we are calling to conduct a short survey with natural gas customers in BC. The study is being sponsored by Terasen Gas and will take about 10 minutes.

May I please speak with the person in the household who is responsible or partly responsible for reviewing and paying for the household's natural gas bills?

IF SPEAKING: [CONTINUE]
IF RESPONDENT COMES TO PHONE: [REPEAT INTRODUCTION AT A]
IF RESPONDENT UNAVAILABLE: [ARRANGE CONVENIENT TIME TO CALL BACK]

I can assure you that your answers will be anonymous because they will only be grouped with the responses of others, and no one's identity will be revealed.

S2. Please tell me if you or any members of your immediate family hold jobs with any of the following:

a Any Media including Radio, TV or print media [THANK AND TERMINATE]
b Advertising [THANK AND TERMINATE]
c Market Research [THANK AND TERMINATE]
d Terasen Gas or subsidiary of Terasen Incorporated [THANK AND TERMINATE]
e A Natural Gas Distributor, Producer or Natural Gas Marketer [THANK AND TERMINATE]

IF NECESSARY:

- The purpose of this call is to conduct a survey; we are not selling anything at all.
- IF ASKED HOW WE GOT THEIR NAME: Your name and phone number were randomly selected from a customer list provided by Terasen Gas.
- IF CUSTOMER WANTS TO BE TAKEN OFF LIST FOR FUTURE RESEARCH AND IS A LOWER MAINLAND OR INTERIOR CUSTOMER Please call the Terasen Gas Customer Care Centre at 1-888-224-2710 and tell them you don't want to be contacted by Terasen Gas to participate in market research.
- IF CUSTOMER WANTS TO OPT OUT OF FUTURE STUDIES AND IS A VANCOUVER ISLAND CUSTOMER Please call the Terasen Gas Customer Care Centre at 1-800-667-6064 and tell them you don't want to be contacted by Terasen Gas to participate in market research.
- IF CUSTOMER SAYS THEY HAVE OPTED OUT OF TERASEN GAS STUDIES "Please accept our apologies. The customer list used for this study may have been generated before you advised Terasen Gas that you did not want to participate in any research studies." Then thank and hang up.
- IF CUSTOMER WANTS TO VERIFY THE LEGITIMACY OF THE RESEARCH Please call Terasen Gas at 604-576-7000 and say they you would like to verify the legitimacy of this research that is being conducted by Western Opinion Research.

IF VANCOUVER ISLAND:
S3. To begin, are you on the Terasen Gas Equal Billing Payment Plan? [AS NECESSARY: With the Equal Billing Payment Plan, those who participate in the plan pay the same amount for gas each month, instead of paying higher bills in the winter when gas use increases.]

[IF ASKED HOW IT WORKS: Terasen Gas estimates your gas use for the next year based on your past 12 months of gas consumption, and divides your total charges into 12 equal installments.]

Yes- WATCH QUOTAS!
No WATCH QUOTAS!
DON'T KNOW = NO FOR QUOTA TRACKING PURPOSES
REFUSED – TERMINATE WITH THANKS "Thank you, those are all my questions"

Q1a. Sometimes there are a number of ups or downs in the prices of products and services within a given year. These ups and downs in prices can be called <u>price changes</u> or <u>price fluctuations</u>. For each of the following product or service categories, please tell me how concerned you are about <u>future price fluctuations</u> using a scale from 1 to 10 where 1 is not at all concerned and 10 is extremely concerned. IF NEED TO REPEAT SCALE: please tell me how concerned you are about <u>future price fluctuations</u> for PRODUCT/SERVICE using a scale from 1 to 10 where 1 is not at all concerned and 10 is extremely concerned.

RANDOM
a Electricity
b Telephone
c Gasoline
d Natural Gas
END RANDOM

ASK Q1B RIGHT AFTER D
Q1b .IF 7, 8, 9 OR 10 TO NATURAL GAS IN Q1a Why are you concerned about natural gas price changes or fluctuations?

READ Your gas bill is comprised of the amount paid for the natural gas itself, plus charges for delivering the natural gas to your home, and taxes.

Q2. Terasen Gas buys natural gas on the open market and passes on the cost of this natural gas to its customers at cost, that is, with no markup or added charges? Were you aware of this?

Yes
No
Don't Know [That is, is not aware]
Refused

Q3. What do you think causes the open market price of natural gas to fluctuate up and down?
[DO NOT READ] PROBE FOR CLARIFICATION AND COMPLETENESS OF RESPONSE
RECORD VERBATIM AND CODE RESPONSE

Hot or Cold Weather
Natural Gas Production Costs
Costs of Distributing Natural Gas to Households
Profit taking by natural gas producers
OTHER SPECIFY ______________
DON'T KNOW
REFUSED

Q4. Are month-to-month changes in the amount of <u>your</u> household's natural gas bill typically due to changes in the <u>price</u> of natural gas, or due to changes in your household's <u>consumption</u> of natural gas? IF BOTH, SAY Which one, price changes or consumption changes, causes more of a change in your household's natural gas bill.

Changes due to Price
Changes due to Consumption
BOTH PRICE AND CONSUMPTION [ACCEPT BUT DO NOT READ IF THEY CAN'T CHOOSE]
DON'T KNOW
REFUSED

Q5. Are you aware of any measures or programs that Terasen Gas operates or that it may operate on behalf of its customers to manage or "smooth-out" fluctuating natural gas prices? [IF NECESSARY: This does <u>not</u> include the [IF MAINLAND: Equal Payment Plan IF VANCOUVER ISLAND: Equal Billing Payment Plan] where customers, if they choose, can spread their annual energy costs evenly across the twelve months of the year.]

Yes
No
Don't Know [That is, is not aware]
Refused

Q6. [IF YES] What measures are you aware of? [IF NECESSARY: This does <u>not</u> include the [IF MAINLAND: Equal Payment Plan IF VANCOUVER ISLAND: Equal Billing Payment Plan] where customers, if they choose, can spread their annual energy costs evenly across the twelve months of the year.] [DO NOT READ]
RECORD BOTH VERBATIM AND CODED RESPONSE

NATURAL GAS HEDGING PROGRAM
OTHER SPECIFY ______________
DON'T KNOW
REFUSED

HEDGING PROGRAM

READ
Currently, Terasen Gas does operate a hedging program on behalf of its customers to moderate or smooth out price fluctuations of natural gas purchased on the open market.

It works much like different mortgage rate plans such as Variable Rate and Fixed Rate mortgages. Fixed Rate mortgages eliminate interest rate changes, while Variable Rate mortgages can change with the market. Having a fixed rate is better if interest rates go up because you don't pay more than your fixed mortgage rate. Having a variable rate is better if interest rates go down because you can benefit from declining rates.

In a similar way, Terasen Gas' hedging strategy is used to reduce but not completely eliminate market price fluctuations. In other words, the current hedging program has some variable and some fixed pricing.

Q7a Do you support or oppose Terasen Gas' program to hedge natural gas prices? Would that be strongly or just somewhat?

Strongly support
Somewhat support
NEITHER [VOLUNTEERED]
Somewhat oppose
Strongly oppose
DK/Refuse

IF NEITHER, DON'T KNOW OR OPPOSE Q7a ASK
Q7b. Why do you say that? PROBE FOR CLARIFICATION AND COMPLETENESS OF RESPONSE
RECORD VERBATIM RESPONSE

Q8 I am now going to read you three different points of view about Terasen Gas's hedging program to reduce **natural gas** price fluctuations. After I read all three statements, I would like you to tell me which one of the statements is closest to your own view.

Here are the three statements. First, some people say…

[RANDOMIZE ORDER B AND C]

a. Terasen Gas should continue its present hedging program to smooth out natural gas price fluctuations.

Second, some other people say…

b. Terasen Gas should hedge less and not smooth out price fluctuations as much as it does. Instead, it should pass on more of the actual ups and downs of market prices to its customers. This would allow customers to benefit more from any drop in natural gas prices, but they may also have to pay more if market prices increase.

Third, some other people say…

c. Terasen Gas should hedge more to further smooth out natural gas price fluctuations. This would provide a fixed price for natural gas which would protect customers from potential increases in the price of natural gas but on the other hand would not allow them to benefit from potential decreases in price.

Which of these three points of view best represents your view on this matter? The current hedging program; [ROTATE ORDER]: the program with more hedging to even further smooth out price fluctuations; or the program with less hedging which would allow more price fluctuations

Q9 Approximately how much is your total annual natural gas bill including all charges and taxes? An estimate is fine.

INTERVIEWER: READ AVERAGE IF RESPONDENT IS UNABLE TO ESTIMATE THEIR ANNUAL GAS BILL. AS NECESSARY HELP RESPONDENT "DO THE MATH" TO CALCULATE ANNUAL COSTS.
PROGRAMMER: REVEAL APPROPRIATE AVERAGE BASED ON SAMPLE AREA

[IF DK VANCOUVER ISLAND READ: The average annual residential natural gas bill for your area is about $1000. Is yours around this amount or would it be higher or lower? About what might it be? An estimate is fine.]
[IF DK MAINLAND READ: The average annual residential natural gas bill for your area is about $1400 Is yours around this amount or would it be higher or lower? About what might it be? An estimate is fine.]

RECORD ANNUAL DOLLAR AMOUNT OF NATURAL GAS BILL
DON'T KNOW
REFUSED

Q10 Recognizing that market prices for natural gas will continue to fluctuate up and down, what is the maximum dollar amount of change in your family's total annual natural gas bill that you could live with?

RECORD ANNUAL DOLLAR AMOUNT OF CHANGE
DON'T KNOW
REFUSED

For each of the following questions, please tell me how much of an increase in your annual gas bill you could live with, knowing that your bill could decrease by a given amount.

Q11a. First, if an expert told you that your gas bill could decrease by **$600** in a year, or that it might increase but they couldn't tell you by how much, what is the maximum increase in your annual bill that you could live in this case? ADD IF R SAYS DECREASE UNREALISTIC SAY "Assuming this could occur, what is the maximum increase in your annual bill that you could live with?"

RECORD MAXIMUM ANNUAL PRICE INCREASE
NOT APPLICABLE/ANNUAL GAS BILL TOO SMALL
DON'T KNOW
REFUSED

Q11b. If an expert told you that your gas bill could decrease by **$400** in a year, or that it might increase but they couldn't tell you by how much, what is the maximum increase in your annual bill that you could live with in this case?

RECORD MAXIMUM ANNUAL PRICE INCREASE
NOT APPLICABLE/ANNUAL GAS BILL TOO SMALL
DON'T KNOW
REFUSED

Q11c. . If an expert told you that your gas bill could decrease by **$200** in a year, or that it might increase but they couldn't tell you by how much, what is the maximum increase in your annual bill that you could live with in this case?

RECORD MAXIMUM ANNUAL PRICE INCREASE
NOT APPLICABLE/ANNUAL GAS BILL TOO SMALL
DON'T KNOW
REFUSED

Q11d . If an expert told you that your gas bill could decrease by **$100** in a year, or that it might increase but they couldn't tell you by how much, what is the maximum increase in your annual bill that you could live with in this case?

RECORD MAXIMUM ANNUAL PRICE INCREASE
NOT APPLICABLE/ANNUAL GAS BILL TOO SMALL –
DON'T KNOW
REFUSED

DEMOGRAPHICS

Finally, I have some questions that will enable us to make sure that we have talked to a good cross-section of households. All responses will be held in strict confidence and will not be attributed to any individual.

Q12. What is the highest level of schooling you have completed?
1. Some high school or less
2. High school graduate
3. Some post secondary (university/college/technical school)
4. Diploma, certificate, or degree from community college, trade, technical or vocational school or business college
5. University degree
6. DON'T KNOW
7. REFUSED

Q13. Which of the following categories contains your age, is it: [READ]
1. 18-24
2. 25-34
3. 35-44
4. 45-54
5. 55-64
6. 65 or older
7. REFUSED

Q14. Which of the following best describes the home you are currently living in? Do you …
1. Rent your home
2. Own your home and have a fixed-rate mortgage
3. Own your home and have a floating-rate mortgage
4. Own your home outright with no mortgage.
5. Other

Q15. For statistical purposes only, we need information about your income. All individual responses will be kept confidential. Which broad income category best describes your total household income before taxes in 2004.
1. Under $20,000
2. $20,000 to under $40,000
3. $40,000 to under $60,000
4. $60,000 to under $80,000
5. $80,000 to under $100,000
6. $100,000 and over

Q16. How long have you been a natural gas customer in BC? AS NECESSARY "The number of years"

RECORD NUMBER OF YEARS_____
DON'T KNOW
REFUSED

18. Record Gender *(Record from voice DO NOT READ)*
1. male
2. female

What are the first three digits of your postal code? _________

18. IMPORT REGION FROM SAMPLE

Thank you for participating in the survey. Thank you very much!

Appendix C

ENBRIDGE RESIDENTIAL CUSTOMER RATE VOLATILITY PREFERENCES STUDY

Ipsos Reid

Enbridge Gas Distribution

Customer Threshold for Gas Supply Volatility Study

December 2004

ENBRIDGE

CR-374

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Ipsos Reid

Study Background

Overview of Objectives

- Ipsos-Reid was commissioned by Enbridge Gas Distribution ("EGD") to conduct quantitative survey research for residential (rate 1) and small commercial[1] (rate 6) customers to understand their sensitivity to price volatility and related issues. The specific objectives of the research were to:
  - Assess customers' level of knowledge, understanding and expectations about gas pricing and EGD's role in the process
  - Determine customers' expectations about gas prices and their sensitivity to price volatility
  - Understand customers' preferences for risk management strategies in general and under different market conditions
  - Determine customers' preferences for the frequency of administering bill adjustments

[1] "Small Commercial" includes commercial, industrial, institutional and multi-residential customers with an annual natural gas consumption of <= 75,000 m^3.

Methodology

- A total of 1200 telephone interviews (computer assisted telephone interviewing) were conducted among 800 residential (rate 1) customers and 400 small commercial (rate 6) customers.
  - With a sample size of 800, results are considered accurate to within +/- 3.5%, at a 95% confidence level.
  - With a sample size of 400, results are considered accurate to within +/- 4.9%, at a 95% confidence level.
- Interviews were conducted between November 22nd and December 7th, 2004.
- Respondents were screened to ensure the interview was conducted with the person in the household or business that was responsible for making decisions regarding energy-related products and services and paying the monthly natural gas bill.
- Based on Enbridge Gas Distribution's records,
  - Of the 800 residential customers interviewed, 382 were system gas customers and 418 were direct purchase customers,
  - Of the 400 commercial customer interviewed, 193 were system gas customers and 207 were direct purchase small commercial customers.

Methodology Cont'd...

- The reporting of the results focuses on:
  - All customers (combined residential and small commercial responses)
  - Residential versus small commercial
- Some results are also presented based on customers' awareness of their natural gas commodity supplier:
  - System Gas ("SG") Actual: System Gas customers who are aware that they purchase their natural gas commodity from Enbridge
  - Direct Purchase ("DP") Actual: Direct Purchase customers who are aware that they purchase their natural gas commodity from a broker
  - Direct Purchase ("DP") – System Gas Perceived: Direct Purchase customers who believe they purchase their natural gas commodity from Enbridge
  - System Gas – Direct Purchase ("DP") Perceived: System Gas customers who believe they purchase their natural gas commodity from a broker

Note: The sums of the individual response categories may not add to 100% due the effect of rounding.

Ipsos Reid

Executive Summary

Executive Summary

Understanding and Perceptions of Natural Gas Pricing

- While the majority of system gas customers are aware that they purchase their natural gas commodity from Enbridge Gas Distribution (90%), nearly three-in-five direct purchase customers (58%) continue to believe they purchase their natural gas commodity from Enbridge.
- Three-quarters of customers (75%) expect the market price for the natural gas commodity will increase over the next year.
- Sixteen percent of all customers (13% of residential and 22% of small commercial customers) believe that utilities like Enbridge have the most responsibility when dealing with issues related to natural gas pricing.
- More than four-in-five of all customers (83%) believe that Enbridge makes a profit from the price charged for the supply of the natural gas commodity.
- More than one-third of all customers (35%) think that the market price that Enbridge pays for the natural gas commodity it buys remains stable over the year.
- According to just over one-half of all respondents (54%), Enbridge should purchase the natural gas commodity at a fixed price instead of a floating rate.
  - Direct Purchase customers (56%) are somewhat more likely than System Gas customers (47%) to say that the company should purchase natural gas at a fixed rate.

Executive Summary Cont'd...

Sensitivity to Price Volatility

- 57% of all customers think it is more important to maintain a steady price than to obtain the lowest price.
  - Somewhat more small commercial than residential customers believe it is more important to maintain a steady price than to obtain the lowest price (62% vs. 55%).
  - Direct purchase customers are more likely than system gas customers to find a steady price to be most important (63% DP Actual versus 51% SG Actual).
- Customer expectations about the future of natural gas prices seem to affect their sensitivity to price volatility. Customers that expect the market price for natural gas to increase over the next year are more likely to:
  - prefer that Enbridge purchase natural gas at a fixed rate (56% versus 41% for customers who expect a price decrease)
  - believe that maintaining a steady price is more important than obtaining the lowest price (58% versus 35% for customers who expect a price decrease).
- Only one-half (50%) of customers report noticing a bill adjustment made to their bill in the past year.
  - More small commercial than residential customers have noticed the adjustments (54% versus 48%).

Executive Summary Cont'd…

Sensitivity to Price Volatility Cont'd

- For all customers, as the amount of the bill adjustment increases, there is a reduced willingness to accept price fluctuations.
  - However, even at the highest level tested ($100), nearly one-half of customers (48%) reported they would be very or somewhat willing to have the commodity portion of their bill fluctuate by this amount in any one year (period of time).
    - Small commercial customers are somewhat more willing to accept a fluctuation of $100 than are residential customers (52% versus 46% very/somewhat willing).
  - At the $75 level, almost three-in-five of all customers are willing to have the commodity portion of their bill fluctuate by this amount (56% very/somewhat willing).
  - At the lowest levels tested, the majority of all customers are willing to accept the fluctuation on their bill (78% very/somewhat willing at $25; 68% very/somewhat willing at $50).
  - There is little variation in customers' willingness to accept bill fluctuations at the levels tested among type of customer (DP or SG) or supplier awareness..

Executive Summary Cont'd...

Adjustment Frequency Preferences

- In general, about six-in-ten of all customers (58%) would prefer that Enbridge make smaller, more frequent adjustments to their bill, and four-in-ten of all customers (40%) would prefer a one-time, year-end adjustment.
  - More small commercial than residential customers prefer smaller, more frequent adjustments (63% versus 55%).
- While the proportion of all customers who prefer frequent adjustments increases as the amount of the debit/credit increases, more of all customers prefer frequent adjustments under the refund scenario than the payment scenario at all adjustment levels.
  - Under the payment scenario, small commercial customers are significantly more likely to prefer a one-time adjustment than residential customers at each level tested.

Risk Management Strategy Preferences

- When no price point is attached to the question, the risk management strategy preferences of all customers rank as follows:
  - creating a high and low limit around the current price (33%)
  - purchase insurance (26%),
  - fixing prices at current levels (25%).
  - do not manage the price risk in any way (15%)

Executive Summary Cont'd...

Affect of Price Decrease on Strategy Preference

- When presented with a scenario of a 50% price decrease, nearly two-thirds of all respondents (64%) who originally stated a preference for Enbridge to fix prices at current levels indicated the scenario would change their response.
- Almost one-half (45%) of these chose a new strategy that allowed them some benefit from falling prices (7% of all respondents; 29% of those who originally selected the strategy).
- Seven percent of those who originally chose an approach that afforded some protection from increasing prices now opted for Enbridge to NOT manage the price risk in any way.

Affect of Price Decrease on Strategy Preference

- When presented with a scenario of a 50% price *increase*, less than one-third (32%) of all customers who initially preferred that Enbridge not manage the price risk indicated the scenario would change their response.
- Six-in-ten (60%) of these chose a new approach that afforded some protection from increasing prices (3% of all respondents; 19% of those who originally selected the strategy).

Recommendations

- Any issue related to "price" represents a very special challenge to Enbridge:
  - Residential and small business consumers think that the price they pay for the commodity will continue to rise
  - Consumers ultimately associate pricing issues with the utility and government
  - And consumers are generally confused on related issues such as who is profiting, what the regulatory environment is, etc.
- In this environment opinion is more divided than polarized one way or the other on options/ideas for preferences and actions on price-related issues:,
  - Fixed and steady tend to win out over floating and lowest in defining consumer preferences, although opinion is divided
  - One-time wins out over more frequent in terms of general adjustment frequency preferences when the potential refund or payment are at lower levels, while more frequent wins out over one-time as the payment/refund levels increase (especially in the case of a payment)
  - The vast majority of consumers want Enbridge to execute some kind of strategy to help manage the potential risk for large fluctuations in commodity prices; however preference is split between fixing prices at current levels, purchasing insurance or creating a high/low price band around the current price

Recommendations Cont'd...

- This suggests that there is a consumer environment:
  - With potential for skepticism about any changes that Enbridge might introduce on "pricing issues"
  - Regardless of any changes made, there is a sizeable proportion of consumers who will be more receptive and a sizeable proportion of consumers who will be less receptive to any change
    - With this in mind, if the basic principle used by Enbridge in making some of its strategic decisions is that "the majority rules," then the study results suggest that:
      - $75 represents the cut-off in terms of acceptable fluctuation in the commodity portion of consumers' bills among residential customers, and
      - $100 is the level among commercial customers.

Ipsos Reid

Prices and Regulation

Natural Gas Supplier Awareness

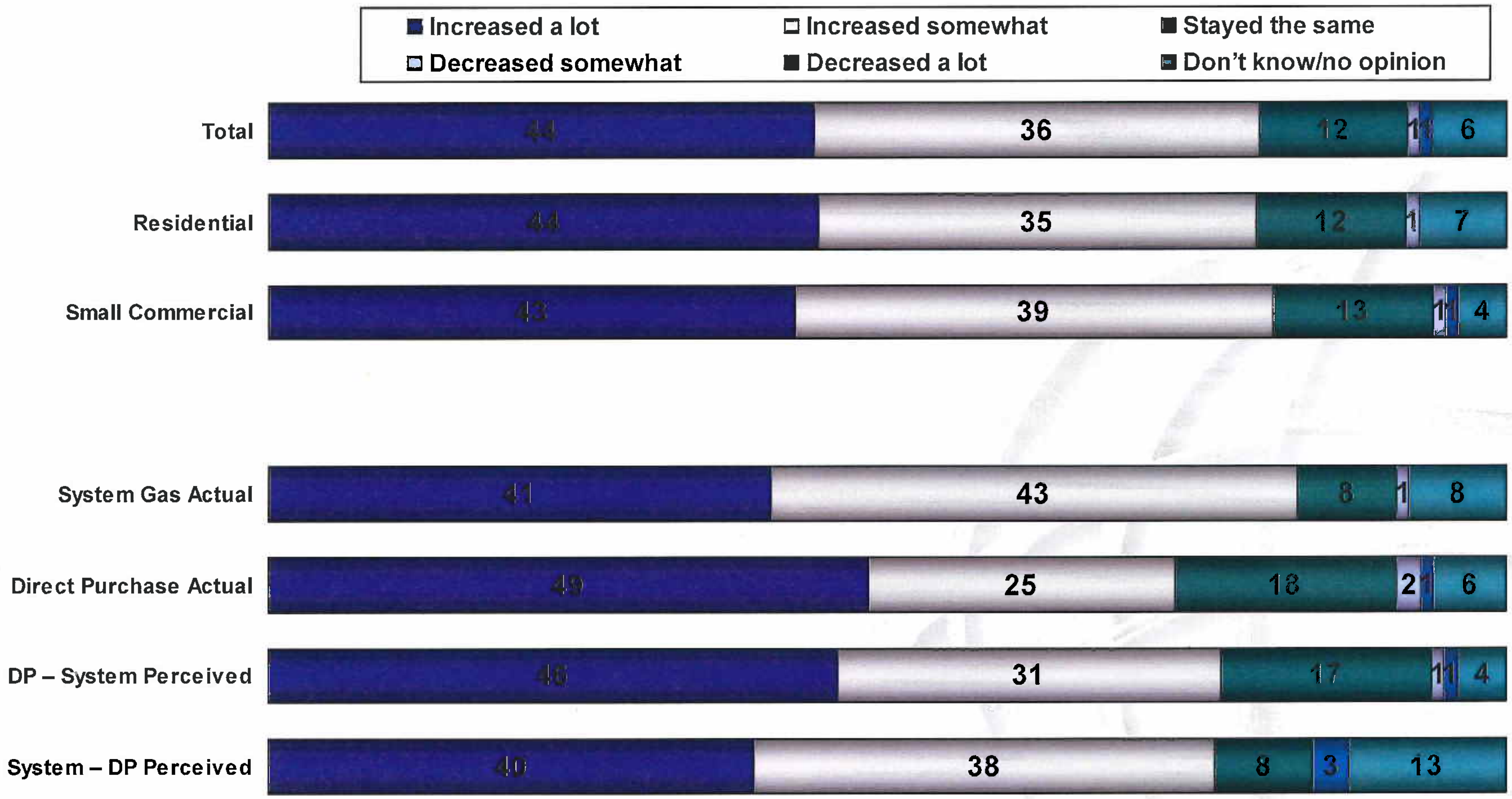
- Nearly six-in-ten (58%) direct purchase customers continue to believe that they purchase their natural gas commodity from Enbridge Gas Distribution. Less than a third (32%) are aware that they are direct purchase customers.
- Comparatively, the majority (90%) of system gas customers identified Enbridge as their supplier.
- Residential and Small Commercial customers are equally as likely to be able to identify if they are system or direct purchase gas customers.

	System Gas Customers	Direct Purchase Customers
N=	574	625
Enbridge (System Gas)	*90*	*58*
Direct Purchase Net	*7*	*32*
Direct Energy	5	23
Ontario Energy Savings Corporation	1	5
Gas Marketer (unknown)	1	3
Superior	-	1
Other	1	3
Don't know	2	7

Q1. Who do you purchase your natural gas commodity from?

Perceptions of the Market Price of Natural Gas

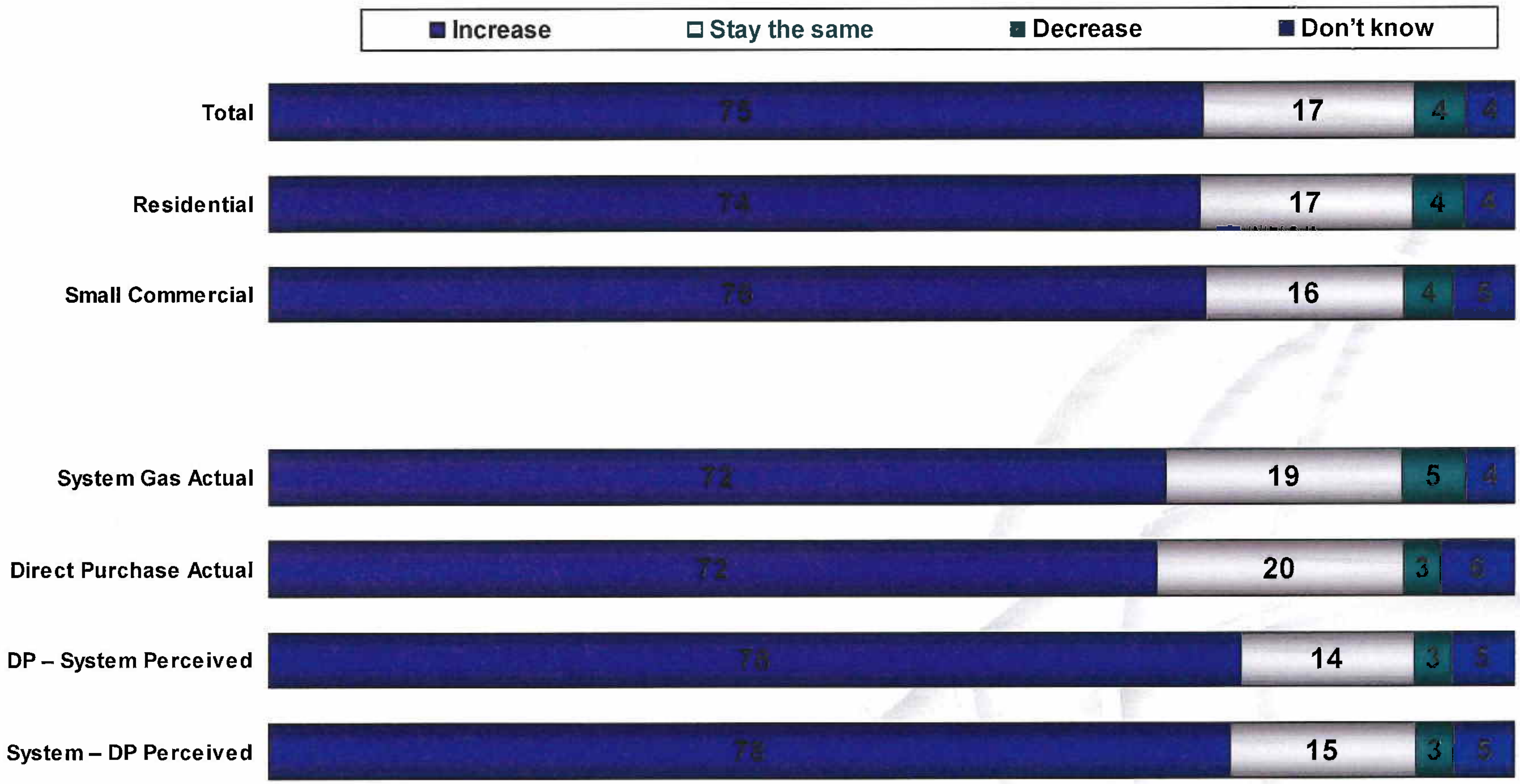
Four-in-five customers believe that the market price for the natural gas commodity has increased over the past two years (80% increased a lot/somewhat) and one-in-ten believe it has stayed the same (12%). These results are consistent for both residential and small commercial customers. However, System Gas customers (84%) are somewhat more likely to believe the price has increased than are Direct Purchase customers (74%).



Q2. Thinking specifically about the market price for the natural gas commodity, over the past two years, would you say the price has increased a lot, increased somewhat, stayed the same, decreased somewhat, or decreased a lot?

Perceptions of the Future of Natural Gas Prices

In addition, three-quarters of customers (75%) expect the market price for the natural gas commodity will increase over the next year and another one-in-five (17%) think it will stay the same.



Q3. And, over the next year, do you think the market price for the natural gas commodity will increase, decrease or stay the same?

Natural Gas Market Price Influencers

According to customers, the greatest impacts influencing the price for natural gas commodity are: world energy prices (18%), supply and demand (18%), availability (11%) and world events (10%).

	Total	Residential	Small Commercial
N=	1200	800	400
World energy prices	18	19	18
Supply and demand	18	17	19
Availability (supply) of natural gas	11	12	10
World events	10	8	12
High profits (greed, etc.)	7	8	6
Production/ distribution/ labour cost	7	6	8
More government control/ intervention/ regulation	6	7	5
Economy	4	3	5
Variations in climate	4	3	4
Don't know	19	18	21

Q4. What do you think would have the greatest impact on influencing the price that you pay for the natural gas commodity, that is the supply of natural gas that you use?

Responsibility for Natural Gas Price Issues

- Enbridge customers think that officials from the federal (22%) and provincial (20%) government have the most responsibility for dealing with issues associated with natural gas prices, followed by utilities (16%).
- Proportionately more small commercial customers than residential believe that utilities have the most responsibility when dealing with these issues (22% versus 13%).

	Total	Residential	Small Commercial
N=	1200	800	400
Officials from the federal government	22	22	24
Officials from the provincial government	20	22	17
Utilities like Enbridge Gas Distribution	16	13	22
Natural Gas marketers	7	8	5
Ontario Energy Board	5	5	4
Government / politicians (unspecified)	3	3	3
Customers/me/myself	3	3	2
Don't know	15	15	15

Q7. Who do you think has the most responsibility for dealing with issues associated with natural gas prices?

Regulatory Process for Distribution Rates

- Nearly six-in-ten customers (58%) agree that the Ontario government's regulatory process for setting approving distribution rates ensures fair and reasonable prices for natural gas.
- Residential customers are less likely to agree with this than are small commercial customers (56% versus 63%).

	Total	Residential	Small Commercial	System Gas Actual	Direct Purchase Actual	DP – System Perceived	System – DP Perceived
N=	1200	800	400	518	199	363	40
Top 2 Box %	*58*	*56*	*63*	*58*	*53*	*58*	*78*
Strongly agree	10	10	11	10	11	10	13
Somewhat agree	48	45	53	48	42	48	65
Somewhat disagree	17	17	18	17	18	18	13
Strongly disagree	19	20	16	19	22	19	10
Don't know	6	7	3	6	8	5	-

Q8. Do you agree or disagree that the Ontario government's regulatory process for setting and approving distribution rates ensures fair and reasonable prices for natural gas?

Understanding of Natural Gas Pricing

- More than four-in-five customers (83%) believe that Enbridge makes a profit from the price charged for the supply of the natural gas commodity.
- Only about three-in-five (59%) think that the prices that Enbridge charges for delivering natural gas are regulated.

	Total	Residential	Small Commercial	System Gas Actual	Direct Purchase Actual	DP – System Perceived	System – DP Perceived
N=	1200	800	400	518	199	363	40
Does Enbridge make a profit from supply?							
Yes	83	82	86	83	81	87	73
No	11	11	10	12	11	8	23
Don't know	6	6	5	5	8	5	5
Are natural gas delivery prices regulated?							
Yes	59	59	59	57	57	63	55
No	21	18	27	20	21	22	30
Don't know	20	23	14	22	22	16	15

Q5. And, as far as you know, does Enbridge make a profit from the price they charge for the supply of the natural gas commodity, that is the actual gas you use?
Q6. Are the prices that Enbridge charges for delivering natural gas to your home regulated?

Understanding of Natural Gas Pricing Cont'd...

- More than one-half of both residential and small commercial customers think that the market price that Enbridge pays for the natural gas commodity it buys changes frequently over the year (57% and 53% respectively).
- System Gas customers are somewhat more likely to think that the price changes as compared to Direct Purchase customers (59% versus 55%).

	Total	Residential	Small Commercial	System Gas Actual	Direct Purchase Actual	DP – System Perceived	System – DP Perceived
N=	1200	800	400	518	199	363	40
Does the price Enbridge pays for natural gas change?							
Changes	56	57	53	59	55	49	73
Stable	35	32	41	32	35	41	28
Don't know	9	11	7	9	11	10	-
How frequently does Enbridge set rates customers pay for natural gas?							
Every month	17	19	15	18	16	18	18
Every 3-4 months	31	31	32	33	26	30	33
Twice a year	22	21	25	25	24	18	20
Once a year	20	19	21	17	20	23	23
Don't know	10	11	8	7	15	12	8

Q9. Do you think the market price that Enbridge Gas Distribution pays to the companies from which it buys the natural gas commodity changes frequently over the year, or do they pay a stable price over the year?
Q10. Based on what you know or think is the case, how frequently does Enbridge review and set the rates that customers pay for the natural gas commodity on the bill

Ipsos Reid

Sensitivity to Price Volatility

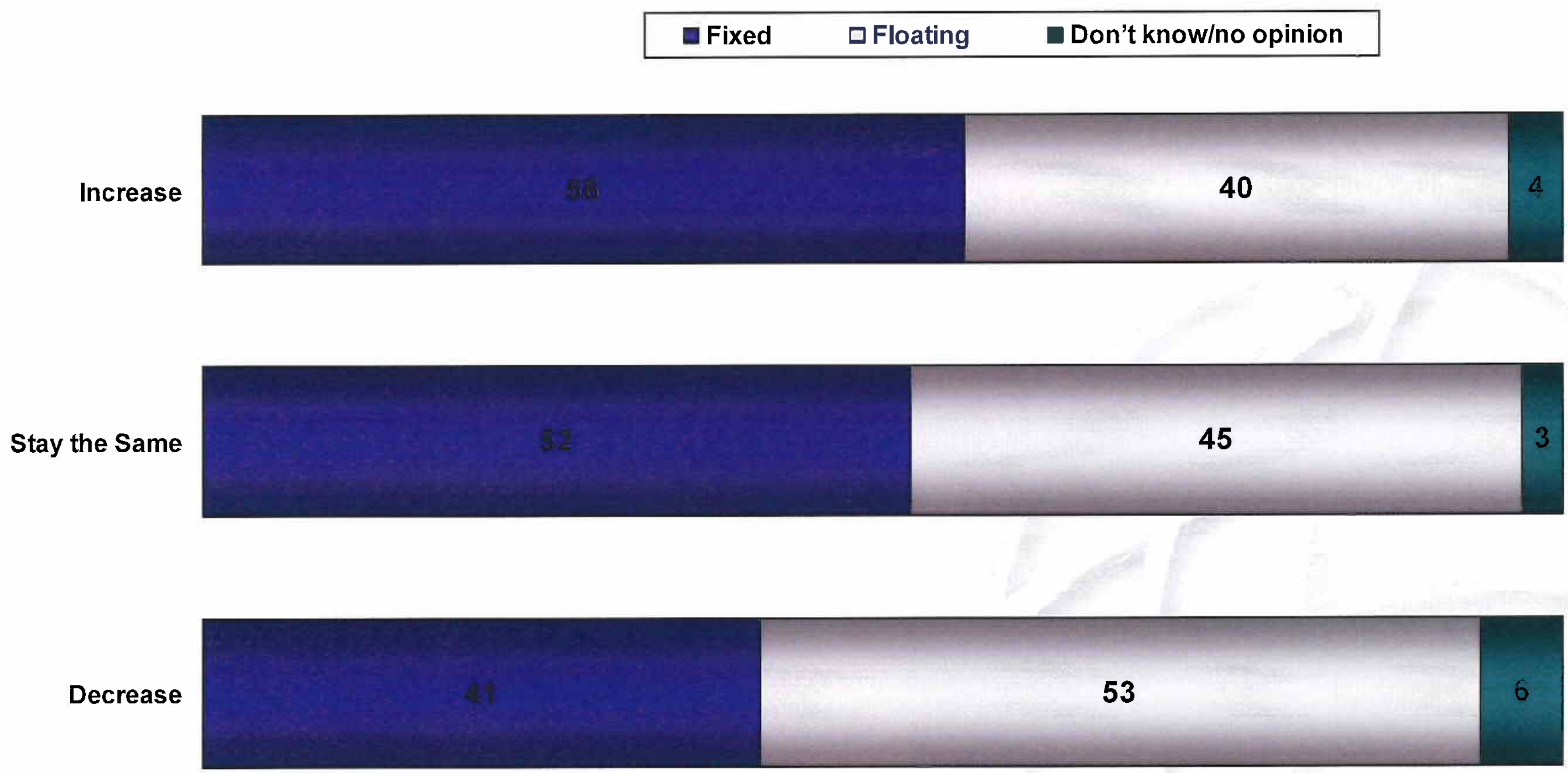
Fixed Price Versus Floating Rate

When asked whether Enbridge should purchase the natural gas commodity at a fixed price or at a floating rate, just over one-half of respondents (54%) said a fixed rate. Direct Purchase customers (56%) are somewhat more likely than System Gas customers (47%) to say that the company should purchase natural gas at a fixed rate.

Q11. Do you think the company should purchase the natural gas commodity at a fixed price with stable pricing but not necessarily the lowest price or do you think they should purchase the natural gas commodity at a floating rate which can lead to a lower price but also runs the risk of having to pay higher prices?

Fixed Price Versus Floating Rate And Perceptions of the Future of Natural Gas Prices

Customers that indicated they expect the market price for the natural gas commodity to increase over the next year are more likely to prefer that Enbridge purchase natural gas at a fixed rate than are customers who expect the price to decrease.



Q11. Do you think the company should purchase the natural gas commodity at a fixed price with stable pricing but not necessarily the lowest price or do you think they should purchase the natural gas commodity at a floating rate which can lead to a lower price but also runs the risk of having to pay higher prices?

Reasons for a Fixed Rate

More small commercial than residential customers state that the main reason for wanting Enbridge to purchase natural gas at a fixed rate is for stable prices with no fluctuations (57% small commercial customers and 47% residential) and for the ability to budget (24% versus 14%).

Base: Respondents who said fixed rate at Q11	Total	Residential	Small Commercial
N=	644	417	227
Stability of pricing/ no fluctuations/ no changes in prices	50	47	57
Customers know what they are paying	24	23	25
Ability to budget	18	14	24
Protects you from increasing prices	9	10	7
Able to take advantage of lower prices/ benefit from lower prices/ best price advantage	8	8	8
Consistency in our bill	6	7	4
More fair	4	3	5
Don't know	3	3	2

Q12. And, why do you think they should purchase the natural gas commodity at a fixed rate?

Reasons for a Floating Rate

The main reason provided for wanting Enbridge to purchase natural gas at a floating rate is to take advantage of lower prices (28%).

Base: Respondents who said floating rate at Q11	Total	Residential	Small Commercial
N=	497	340	157
To take advantage/ benefit from lower prices	28	28	30
Supply and Demand	17	16	20
Gas prices might go down	13	13	13
The prices are always changing	11	13	9
Stability of pricing/ no fluctuations	7	8	6
The consumer might miss out on cheaper prices	7	8	6
Long term benefit	7	5	10
More fair	6	6	6
Reflects actual cost	5	4	6
Protects you from increasing prices	4	5	3
Can make alternative decision/ option	4	4	4

Q12. And, why do you think they should purchase the natural gas commodity at a floating rate?

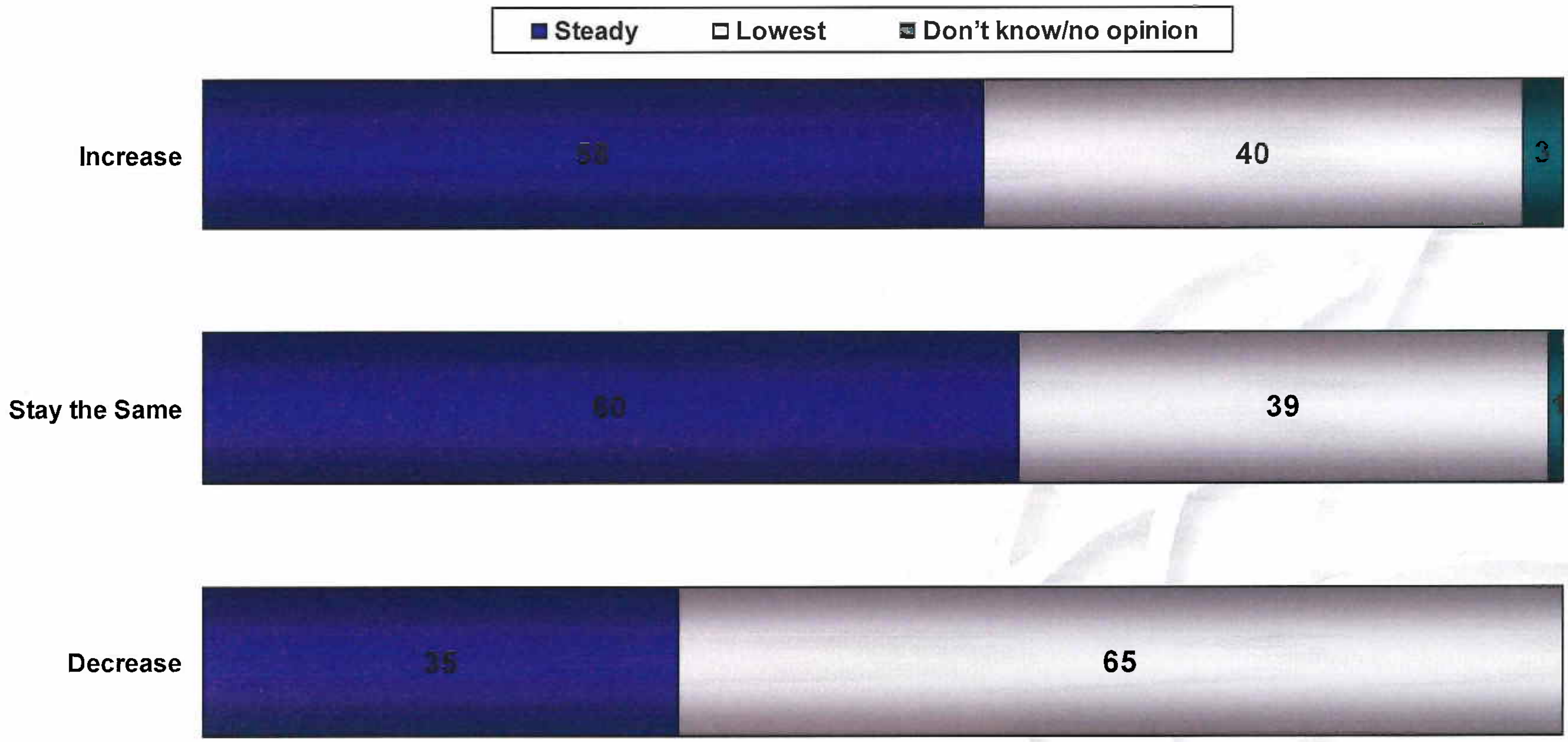
Steady Price Versus Lowest Price

It is more important to maintain a steady price than to try to obtain the lowest price for more than six-in-ten (62%) small commercial customers, somewhat more than residential customers (55%).

Q13. What is more important to you, maintaining a steady price for the natural gas commodity, which may or may not be higher than the market rate or trying to find the lowest price for natural gas commodity even if its means the price will fluctuate more frequently and could result in higher prices?

Steady Price Versus Lowest Price And Perceptions of the Future of Natural Gas Prices

Maintaining a steady price is more important than obtaining the lowest price for significantly more customers who expect the market price of natural gas to increase in the next year than those who expect it to decrease (58% versus 35%).



Q13. What is more important to you, maintaining a steady price for the natural gas commodity, which may or may not be higher than the market rate or trying to find the lowest price for natural gas commodity even if its means the price will fluctuate more frequently and could result in higher prices?

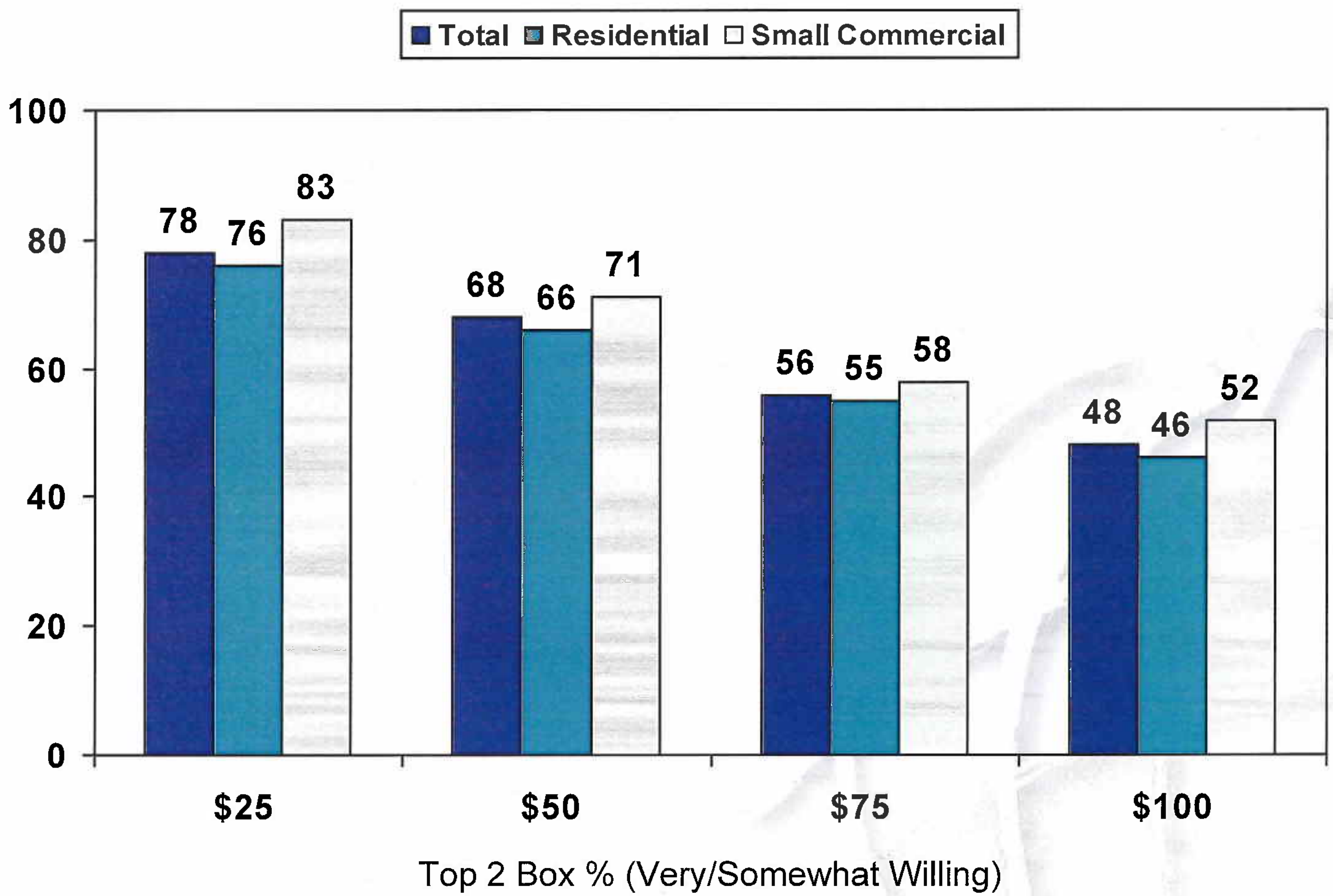
Willingness for Bill Fluctuation

Customers are less willing to accept price fluctuations as the amount of the bill adjustment increases. This is true of both residential and small commercial customers. At the highest level tested ($100), nearly one-half of all customers (48%) reported they would be very or somewhat willing to have the commodity portion of their annual natural gas bill fluctuate by this amount. Small commercial customers are somewhat more willing to accept a fluctuation of $100 than are residential customers (52% versus 46% very/somewhat willing).

	Total				Residential				Small Commercial			
	$25	$50	$75	$100	$25	$50	$75	$100	$25	$50	$75	$100
Net Willing (Top 2 Box %)	78	68	56	48	76	66	55	46	83	71	58	52
Very willing	37	27	18	14	34	24	15	12	42	31	23	17
Somewhat willing	42	41	38	34	42	42	40	33	41	40	36	35
Not very willing	8	14	17	18	9	14	16	18	7	16	19	17
Not at all willing	11	16	25	32	12	18	26	34	8	11	23	30
Don't know	3	2	2	2	3	2	3	3	2	2	1	1

Q19. Would you be very willing, somewhat willing, not very willing, or not at all willing to have the commodity portion of your annual natural gas bill fluctuate by a maximum of [INSERT ITEM]?

Willingness for Bill Fluctuation



Q19. Would you be very willing, somewhat willing, not very willing, or not at all willing to have the commodity portion of your annual natural gas bill fluctuate by a maximum of [INSERT ITEM]?

Original
EB-2005-0001
Exhibit A3
Tab 3
Schedule 1
Attachment

Willingness for Bill Fluctuation – System vs. Direct Purchase

Willingness to accept the various bill fluctuations does not vary by customer type (system or direct purchase) or customers' awareness of their supplier.

	System Gas Actual				Direct Purchase Actual				DP - System Perceived				System - DP Perceived			
	$25	$50	$75	$100	$25	$50	$75	$100	$25	$50	$75	$100	$25	$50	$75	$100
Net Willing (Top 2 Box %)	*77*	*67*	*56*	*48*	*77*	*69*	*55*	*46*	*79*	*69*	*56*	*47*	*90*	*73*	*63*	*50*
Very willing	34	26	17	14	35	23	15	14	38	28	19	13	53	38	28	15
Somewhat willing	43	41	39	34	42	46	40	33	41	41	37	34	38	35	35	35
Not very willing	9	15	16	18	11	14	18	19	7	12	18	19	8	15	15	18
Not at all willing	11	15	25	32	11	17	26	33	12	17	25	33	3	13	23	33
Don't know	4	3	3	3	2	1	1	2	2	1	1	1	-	-	-	-

Q19. Would you be very willing, somewhat willing, not very willing, or not at all willing to have the commodity portion of your annual natural gas bill fluctuate by a maximum of [INSERT ITEM]?

Original
EB-2005-0001
Exhibit A3
Tab 3
Schedule 1
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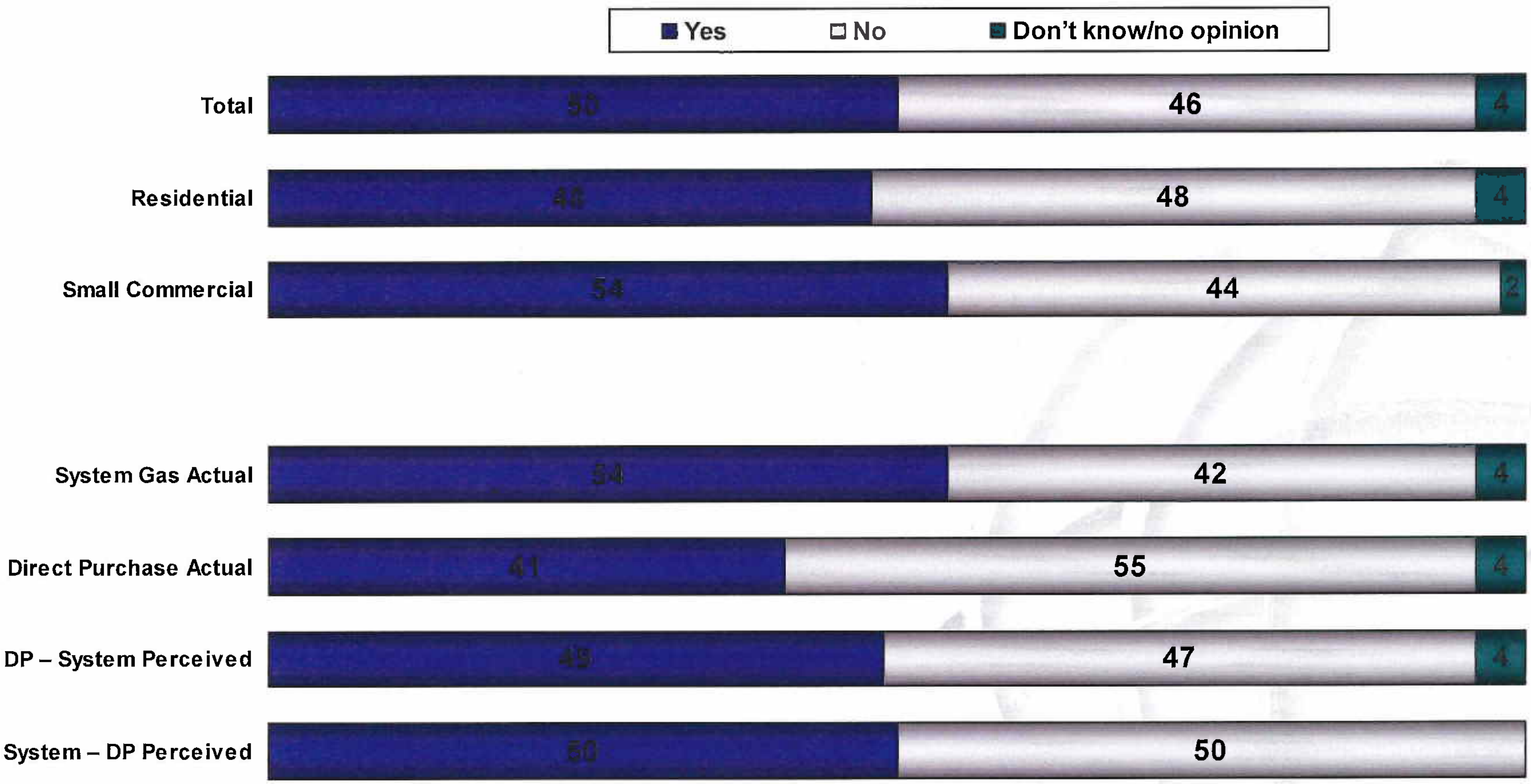
Bill Adjustment Preferences

Awareness of Bill Adjustments

- One-half (50%) of customers report noticing a bill adjustment made to their bill in the past year, with somewhat more small commercial than residential customers noticing the adjustments (54% vs. 48%).
- System gas customers are more likely to report noticing the adjustments than direct purchase customers (54% vs. 41%).

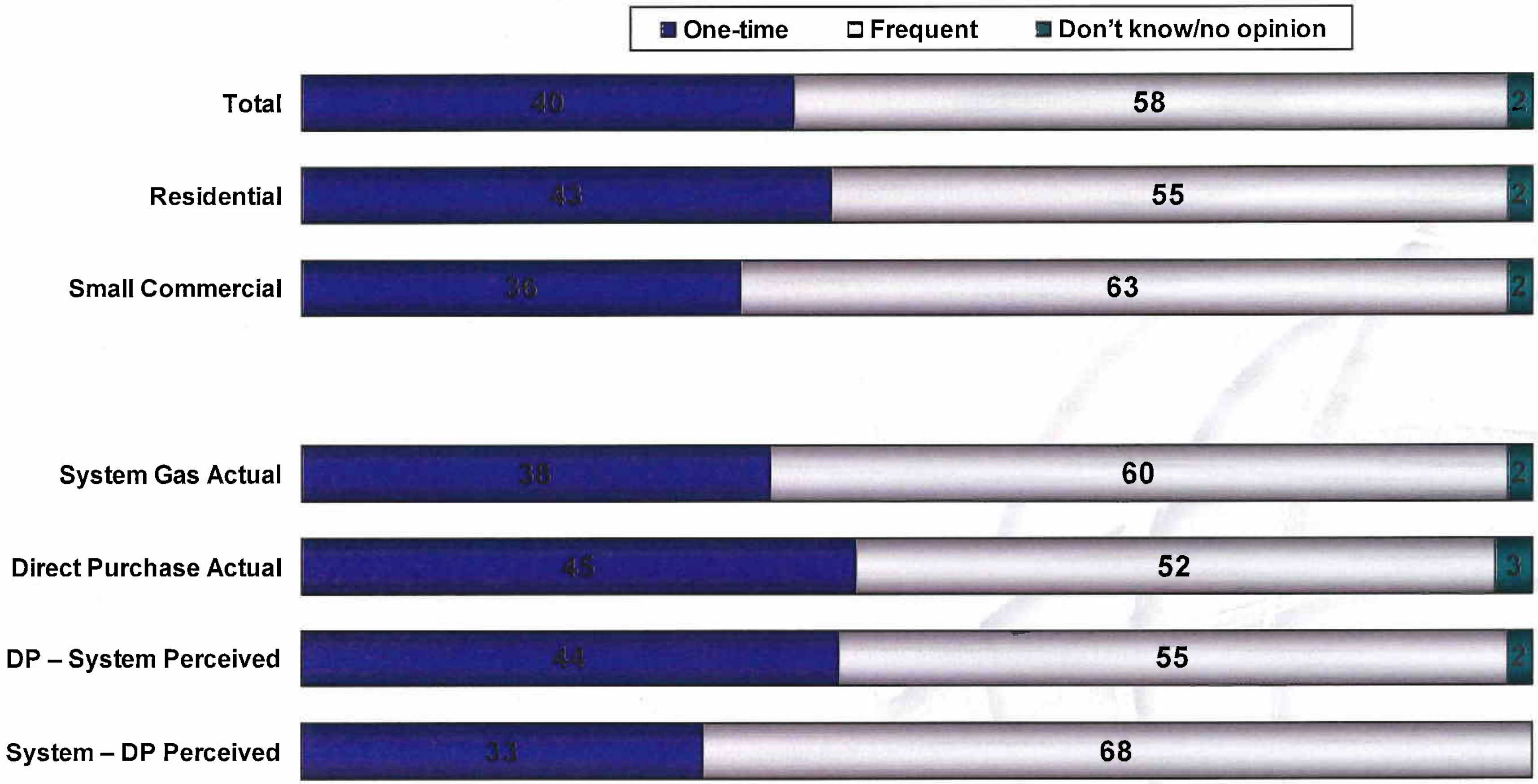


Q20. Have you noticed such an adjustment being made to your bill in the past year?

Original
EB-2005-0001
Exhibit A3
Tab 3
Schedule 1
Attachment

General Preference for Frequency of Bill Adjustments

In general, about six-in-ten customers (58%) would prefer that Enbridge make smaller, more frequent adjustments to their bill, and four-in-ten (40%) would prefer a one-time, year-end adjustment. More small commercial than residential customers prefer smaller, more frequent adjustment (63% versus 55%).



Q21. Generally speaking, would you prefer that Enbridge make a one-time, year-end adjustment to your bill, or make smaller, more frequent adjustments to your bill?

Frequency of Bill Adjustments

Among customers who would prefer smaller and more frequent adjustments to their bill, most think that the adjustments should be made four times per year (61%).

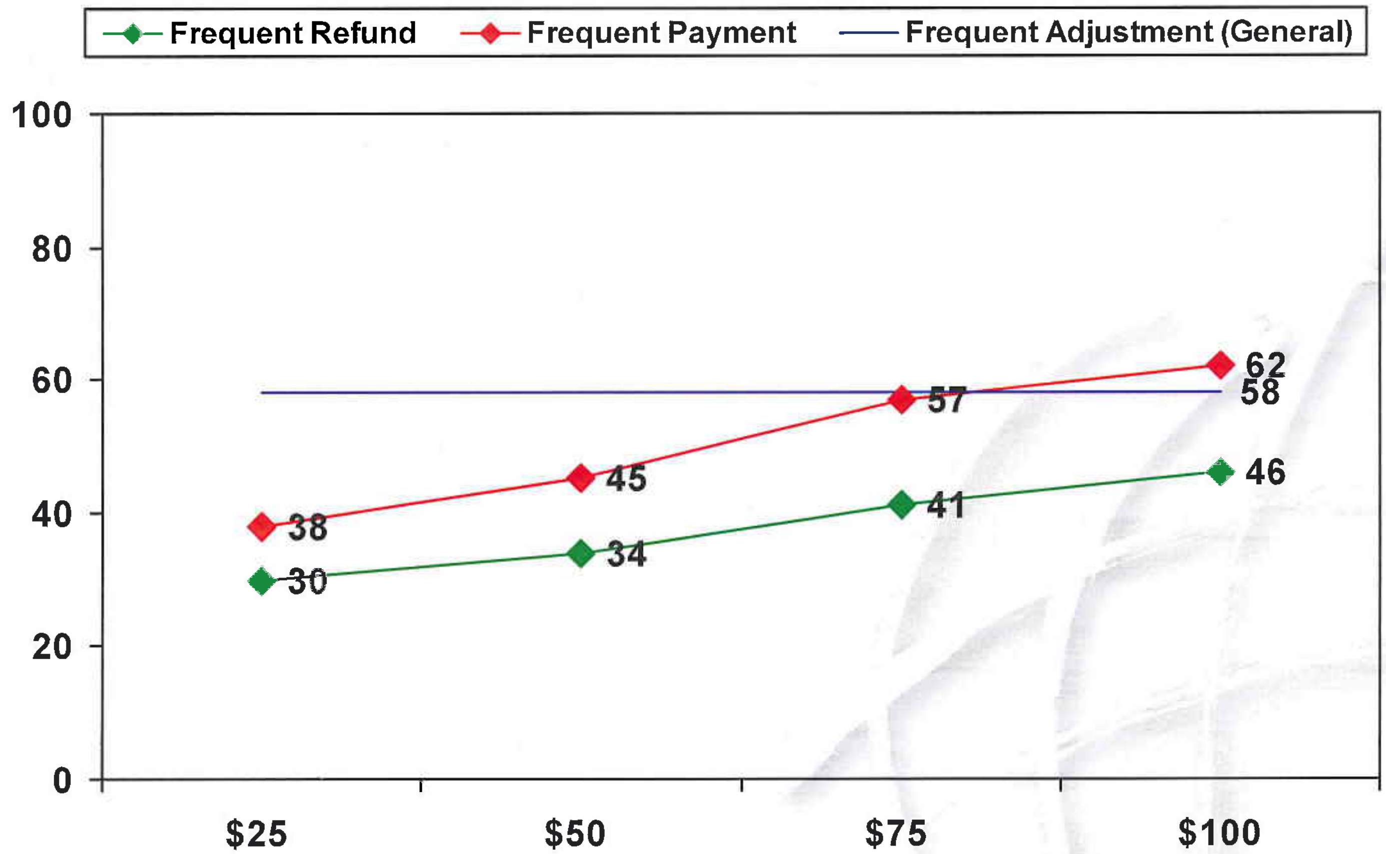
Base: Respondents who wanted smaller, more frequent adjustments to their bill	Total	Residential	Small Commercial	System Gas Actual	Direct Purchase Actual	DP – System Perceived	System – DP Perceived
N=	691	440	251	313	104	198	27
Twice per year	12	12	11	9	14	17	11
Four times per year	61	60	62	65	59	55	52
Once per month	27	27	27	26	27	28	37
Don't know	-	1	-	-	1	1	-

Q22. And, generally speaking, how frequently do you think Enbridge should make these adjustments to your bill?
Base: Respondents who said they wanted 'smaller, more frequent adjustments' to their bill at Q21.

Original
EB-2005-0001
Exhibit A3
Tab 3
Schedule 1
Attachment

Frequency of Bill Adjustments Based on Refund/Payment Scenarios

Under both the refund and payment scenarios, the proportion of customers who prefer frequent adjustments increases as the amount of the debit/credit increases. However, proportionately more customers prefer frequent adjustments under the refund scenario than the payment scenario at all adjustment levels.



Q23. If Enbridge were to make a total adjustment for the year, in the amount of [INSERT ITEM] which would be a refund to be paid to you, do you think they should adjust your bill for this amount at the end of the year or should they make smaller adjustments throughout the year?
Q24. And, if Enbridge were to make a total adjustment for the year, in the amount of [INSERT ITEM] which would be a payment to be collected from you, should they adjust your bill for this amount at the end of the year or should they make smaller adjustments throughout the year?

Frequency of Bill Adjustments Based on Refund/Payment Scenarios

- Under the refund scenario, there is little difference between residential and small commercial customers in their preference for one-time or frequent adjustments.
- Under the payment scenario, small commercial customers are significantly more likely to prefer a one-time adjustment than residential customers at each adjustment level tested.

	Total				Residential				Small Commercial			
	$25	$50	$75	$100	$25	$50	$75	$100	$25	$50	$75	$100
Refund												
One-time adjustment	68	65	57	53	67	64	57	53	71	67	58	53
More frequent adjustments	30	34	41	46	31	35	42	45	28	32	41	46
Don't know	1	1	1	1	2	1	2	1	1	1	1	1
Payment												
One-time adjustment	60	54	42	36	57	50	38	34	66	61	48	40
More frequent adjustments	38	45	57	62	41	48	60	64	33	38	51	59
Don't know	2	2	2	2	2	2	2	2	1	1	2	1

Q23. If Enbridge were to make a total adjustment for the year, in the amount of [INSERT ITEM] which would be a refund to be paid to you, do you think they should adjust your bill for this amount at the end of the year or should they make smaller adjustments throughout the year?
Q24. And, if Enbridge were to make a total adjustment for the year, in the amount of [INSERT ITEM] which would be a payment to be collected from you, should they adjust your bill for this amount at the end of the year or should they make smaller adjustments throughout the year?

Frequency of Bill Adjustments Based on Refund/Payment Scenarios

There is little variation in preference for one-time or frequent adjustments based on customer type (system or direct purchase) or awareness of supplier.

	System Gas Actual				Direct Purchase Actual				DP – System Perceived				System – DP Perceived			
	$25	$50	$75	$100	$25	$50	$75	$100	$25	$50	$75	$100	$25	$50	$75	$100
Refund																
One-time adjustment	68	64	56	51	71	65	57	55	68	66	59	56	78	75	65	63
More frequent adjustments	31	34	42	48	27	34	41	43	32	34	41	44	23	25	33	38
Don't know	2	2	2	2	2	2	2	2	1	1	1	-	-	-	3	-
Payment																
One-time adjustment	61	55	40	34	60	52	45	38	61	56	44	39	58	58	38	35
More frequent adjustments	37	43	57	64	37	45	52	59	38	44	52	60	43	43	63	65
Don't know	2	2	3	2	3	3	3	3	1	-	3	1	-	-	-	-

Q23. If Enbridge were to make a total adjustment for the year, in the amount of [INSERT ITEM] which would be a refund to be paid to you, do you think they should adjust your bill for this amount at the end of the year or should they make smaller adjustments throughout the year?
Q24. And, if Enbridge were to make a total adjustment for the year, in the amount of [INSERT ITEM] which would be a payment to be collected from you, should they adjust your bill for this amount at the end of the year or should they make smaller adjustments throughout the year?

Risk Management Strategy Preferences

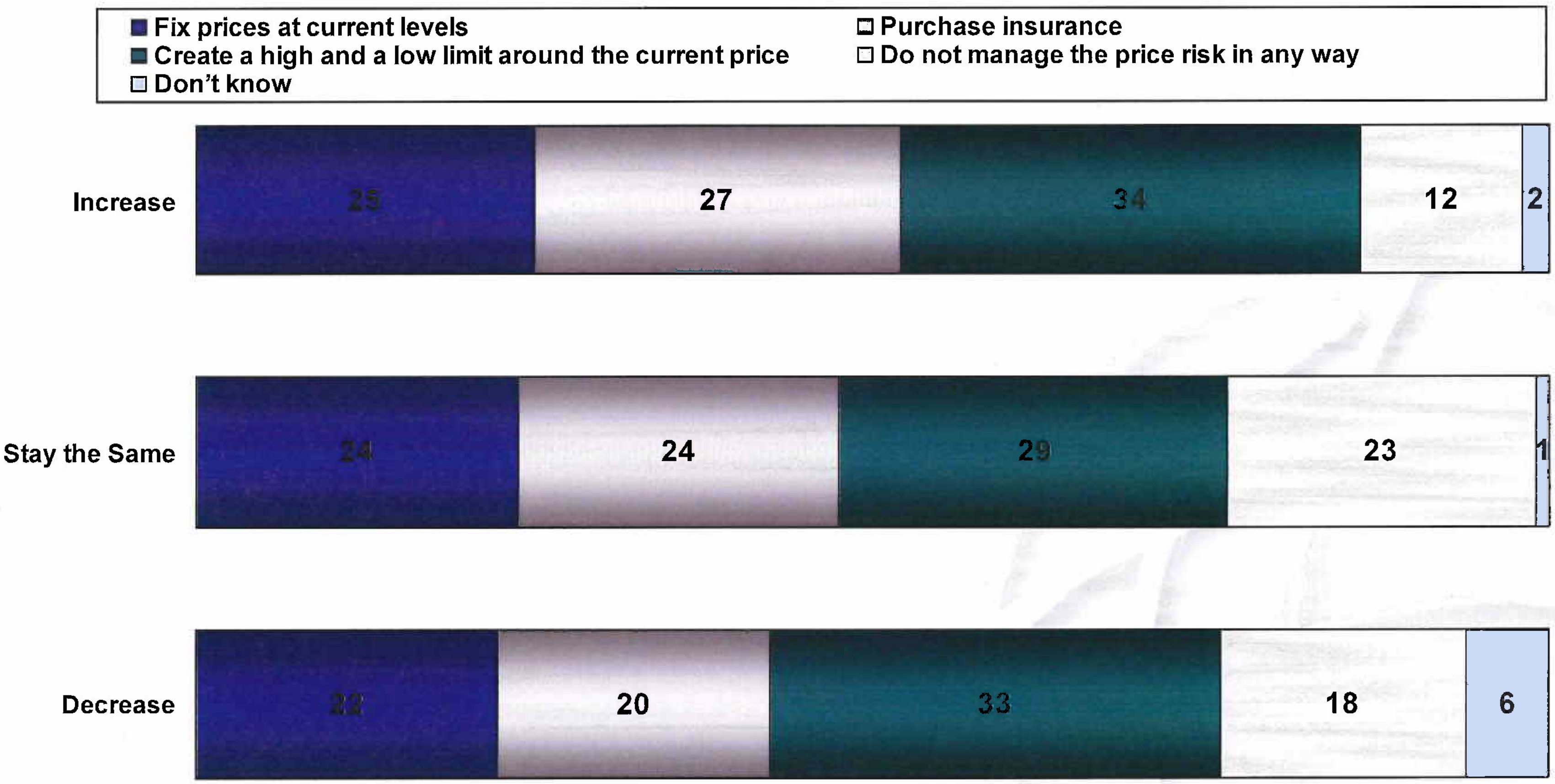
Risk Management Strategy Preference

In general, creating a high and low limit around the current price is the preferred strategy of one-third of customers (33%). The next most preferred approaches, purchase insurance (26%) and fixing prices at current levels (25%) are evenly matched at about one-quarter each. Only about one-in-seven (15%) would not like Enbridge to manage the price risk in any way. These results are consistent for both residential and small commercial customers and across customer types.

Q14. Which of these four approaches would you like to see Enbridge use on behalf of its customers?

Risk Management Strategy Preference And Perceptions of the Future of Natural Gas Prices

Customers that expect the market price for natural gas to stay the same over the next year are more likely to prefer that Enbridge not manage the price risk than are those who expect the price to increase (23% versus 12%).



Q14. Which of these four approaches would you like to see Enbridge use on behalf of its customers?

Strategy Preference Change – Price Decrease

Nearly two-thirds of respondents (64%) who originally stated a preference for Enbridge to fix prices at current levels indicated that a price decrease of 50% would change their response. When provided with the options again, almost one-half (45%) of these chose a strategy that allowed them some benefit from falling prices. Seven percent of those who originally chose an approach that afforded some protection from increasing prices now opted for Enbridge to NOT manage the price risk in any way.

	Fix Prices at Current Levels	Purchase Insurance	Create a High and Low Limit	Do Not Manage the Price Risk
Would a Price Decrease of 50% Change your Preference?				
N=	294	308	396	174
Yes	64	57	50	43
No	33	40	48	53
Don't know	3	3	2	3
What Pricing Approach Would You Like Enbridge to Use if the Price Decreased by 50%?				
Base: Respondents who said a price decrease of 50% would change their response	188	176	196	75
Fix Prices at Current Levels	54	15	17	16
Purchase Insurance	13	51	14	16
Create a High and Low Limit	24	18	49	19
Do Not Manage the Price Risk	8	13	17	44
Don't know	2	3	3	5

Q14. Which of these four approaches would you like to see Enbridge use on behalf of its customers?
Q15. If this price decreased 50% to $300, would this change your answer with respect to how you would like to see Enbridge manage the cost of the natural gas commodity on behalf of its customers?
Q16. And, what pricing approach would you like to see Enbridge use on behalf of its customers if the current market price of gas commodity decreased by 50%?

Strategy Preference Change – Price Increase

Interestingly, less than one-third (32%) of customers who preferred that Enbridge not manage the price risk indicated that a price increase of 50% would change their response. Six-in-ten (60%) of these chose a new approach that afforded some protection from increasing prices. More than one-half of those who chose one of the risk management strategies reported that a price increase of 50% would not change their response. In addition, about half of those who stated that a price increase would change their response selected the same pricing approach when provided with the options.

	Fix Prices at Current Levels	**Purchase Insurance**	**Create a High and Low Limit**	**Do Not Manage the Price Risk**
Would a Price Increase of 50% Change your Preference?				
N=	294	308	396	174
Yes	45	42	39	32
No	53	58	59	64
Don't know	3	1	2	4
What Pricing Approach Would You Like Enbridge to Use if the Price Increased by 50%?				
Base: Respondents who said a price increase of 50% would change their response	131	128	154	55
Fix Prices at Current Levels	54	24	25	20
Purchase Insurance	18	46	20	26
Create a High and Low Limit	20	22	46	15
Do Not Manage the Price Risk	5	4	8	35
Don't know	3	4	2	6

Q17. Which of these four approaches would you like to see Enbridge use on behalf of its customers?
Q18. If the current market price of natural gas commodity for the next year increased 50% to approximately $900, would this change your answer with respect to how you would like to see Enbridge manage the cost of the natural gas commodity on behalf of its customers?
Q19. And, what pricing approach would you like to see Enbridge use on behalf of its customers if the current market price of the natural gas commodity increased by 50%?

Ipsos Reid

Enbridge Gas Distribution

Customer Threshold for Gas Supply Volatility Study

December 2004

ENBRIDGE

CR-374

Appendix D
NATURAL GAS MARKET OVERVIEW

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1 NATURAL GAS MARKET OVERVIEW

The natural gas market in North America has undergone some significant changes in the last number of years. Advances in drilling techniques and efficiencies have allowed exploration and production companies to discover and extract more natural gas than ever before. Furthermore, at the same time, demand for natural gas has declined in direct response to the downturn in the global economy. The bulk of the reduction in demand is attributed to industrial customers, many of whom have either had to reduce output or shutdown operations altogether. The result has been record high natural gas storage levels and depressed natural gas prices. While spot prices have not fallen to the low levels seen in September 2009, forward prices are at the lowest level in many years.

However, natural gas prices in the future could be quite different than today. Reductions in natural gas drilling and decreased supply in response to low natural gas prices has already begun in some areas, as producers transition to drilling for oil and better returns on their investments. Increased industrial natural gas demand resulting from economic recovery is anticipated in the future and there is evidence of this occurring already. Furthermore, natural gas demand for power generation is expected to rise significantly in a few years as environmental legislation and aging coal plant retirements creates a shift from coal to gas fired generation. And, as always, weather can significantly impact the short term supply and demand balance and cause prices to move adversely.

Appendix D will examine both the supply and demand side of the natural gas market. It will discuss the current price environment as well as the numerous factors that can influence gas prices and volatility in the future. It will demonstrate that while prices are currently depressed relative to recent historical values, there is greater uncertainty in price levels going forward. This section will also examine the unique characteristics and challenges of the B.C. marketplace with respect to supply, demand and natural gas pricing. Therefore, while abundant natural gas supply and recent increases in electricity rates have improved the current competitive position of natural gas relative to electricity, all else being equal, there is less certainty regarding this competitiveness in the future.

2 NATURAL GAS SUPPLY

Natural gas supply in North America is extracted primarily from conventional and unconventional natural gas basins. Conventional production is mainly sourced from vertically drilled wells which are drilled directly down into known natural gas reserves. Conventional production has historically made up the majority of the supply, but been declining in recent years due to the success of unconventional production.

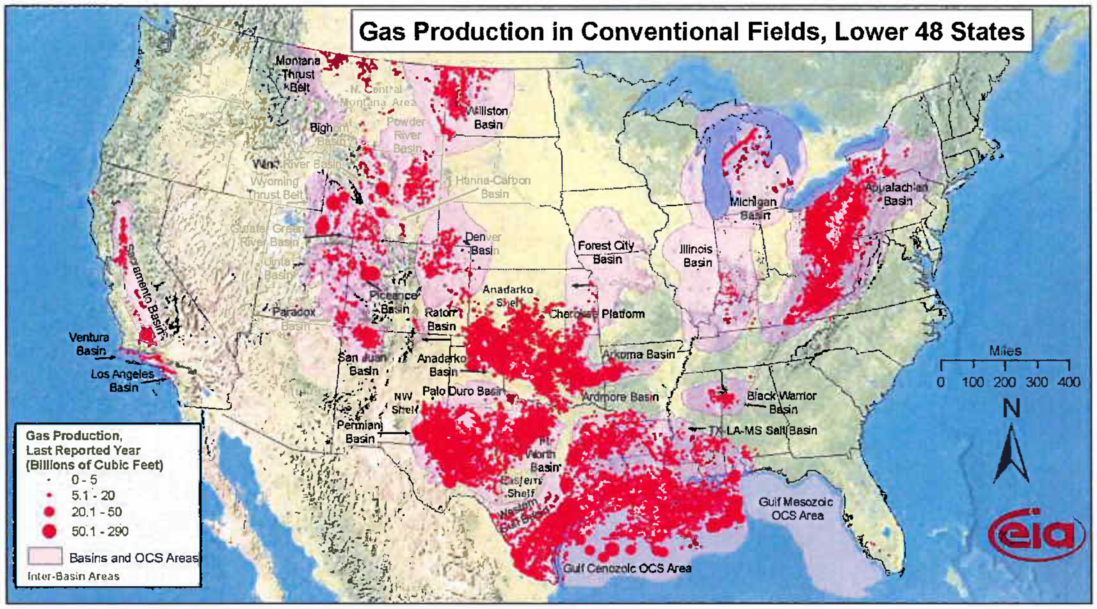
Unconventional production comes from natural gas reserves locked in tight shale rock formations, coalbed methane and tight sands formations. Shale gas has contributed significantly to the growth in unconventional supply, where gas trapped in shale rock formations is extracted by first drilling vertically and then horizontally into the shale rock. A mixture of sand, water and chemical mixtures are then pumped at very high pressures into the shale rock to fracture the shale rock to allow the trapped natural gas to escape to the surface. This procedure is often referred to as hydraulic fracturing or 'fracking'. Technological advancements in recent years have led to significant cost reductions and enabled unconventional gas supply to surge and make up an increasing percentage of total gas supply in North America.

2.1 U.S. Conventional Supply

Conventional natural gas supply is extracted using traditional and vertical drilling methods. Gas wells are typically drilled straight and vertically down into the earth into known natural gas supply basins. Figure shows graphically all current and active conventional natural gas fields in the Lower 48 U.S. states.[1] Currently conventional supply represents about 25 Bcf/d out of total U.S. supply of about 59 Bcf/d.

[1] U.S. Energy Information Administration

Figure 1: U.S. Conventional Natural Gas Fields - Lower 48 States



Source: Energy Information Administration based on data from HPDI, IN Geological Survey, USGS
Updated: April 8, 2009

Conventional production is expected to continue to decline gradually and eventually contribute about 20 Bcf/d out of total production of about 80 Bcf/d by 2030. Conventional production is expected to decline in the future for a number of reasons. These include producers shifting their exploration and production focus towards crude oil production resulting from the increasing oil-to-natural gas price spread, improved efficiencies and costs associated with unconventional drilling and general exhaustion of conventional gas reserves that were once easily accessible and produced.

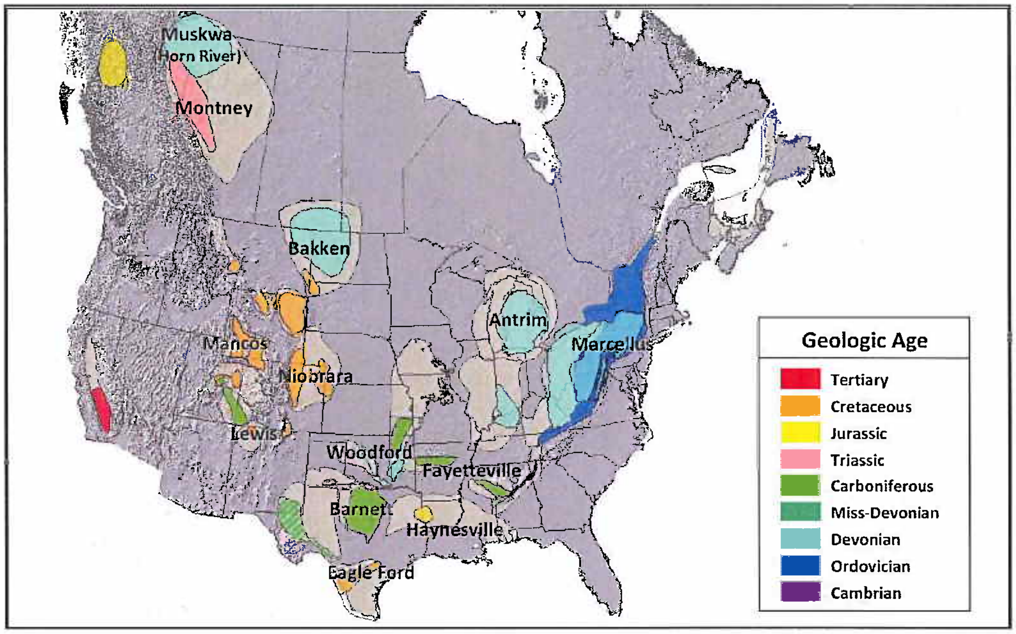
2.2 U.S. Unconventional Supply

After 2012 overall production in the U.S. is forecast to increase with the majority of the increase in total production from unconventional sources. According the National Energy Board of Canada ("NEB") shale gas production in Canada and the U.S. will represent at least a third of total North American production by 2020.[2] Apart from shale gas contributing to the growth in overall production, production from tight sands and coalbed methane deposits will remain relatively stable from 2008 to 2035. Advances in horizontal drilling and hydraulic fracturing techniques — as well as improved drill bits, steering systems, and instrumentation monitoring

[2] Canada's Energy Future – Infrastructure Changes and Challenges to 2020, An Energy Market Assessment October 2009, page 17

equipment — have contributed to higher success and recovery rates, reduced cycle times, lower costs, and shorter times required to bring new shale gas production to market.[3] Presently, production from unconventional sources contributes about 34 Bcf/d out of total production of about 59 Bcf/d. By 2030, 60 Bcf/d is expected to come from unconventional sources out of total expected production of about 80 Bcf/d. The figure below shows the active shale gas plays in the Canada and the US.

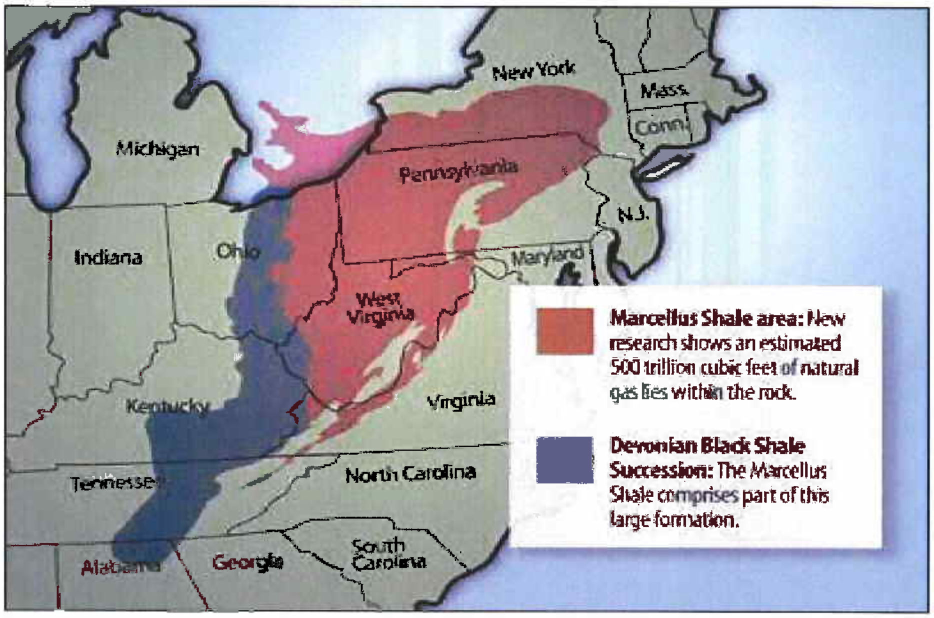
Figure 2: North American Shale Gas Regions[4]



There are several natural gas shale deposits in the United States with the most significant being the Barnett, Haynesville and Marcellus shale deposits. The Marcellus is one of the newest sources of shale gas supply in North America. The area extends from southern New York, across Pennsylvania, and into western Maryland, West Virginia, and eastern Ohio. Reserve estimates range from 45 to 50 Tcf, which makes it one of the biggest gas fields in North America. The location near eastern U.S. urban areas makes the Marcellus a desirable supply source for the key consuming eastern region of the U.S. This has implications for traditional gas supply coming from the WCSB (discussed in Section 1.3.3 on pricing). The map below shows the location of the Marcellus shale gas area and its proximity to major demand areas.

3 U.S. Energy Information Administration – Annual Energy Outlook 2010, April 2010
4 Conoco Philips: Operating in a New Natural Gas Bubble, Dr. Jim Duncan, November 2010

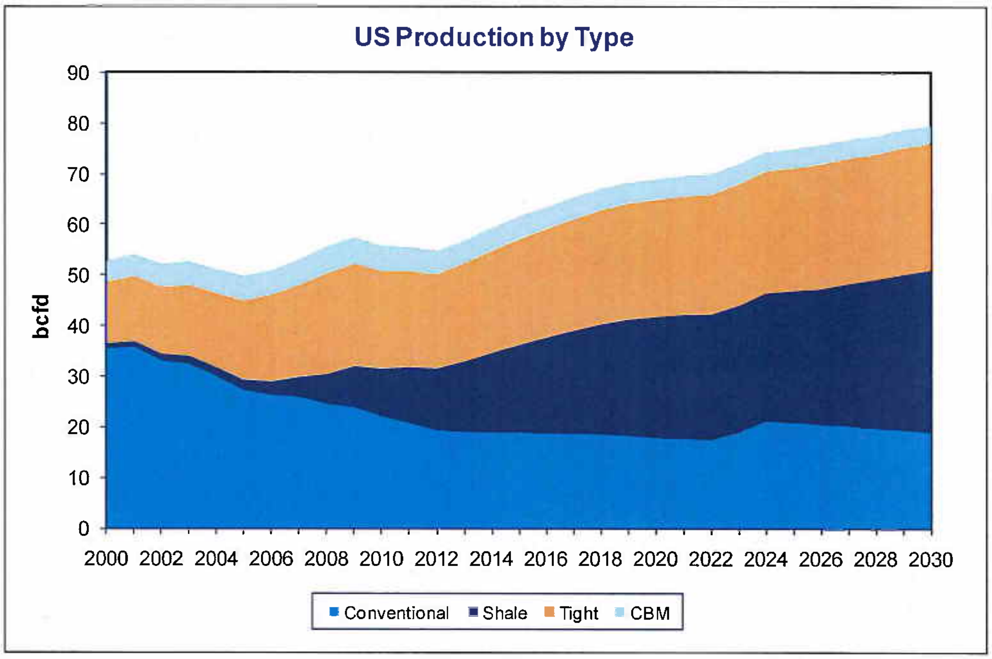
Figure 3: Marcellus Shale Gas Region



2.3 Total US Supply

The figure below displays a recent forecast for U.S. natural gas production out to 2030. Total production is expected to decline slightly until about 2012 then begin to increase thereafter. Of particular note is the gradual decline from conventional natural gas sources and a larger offsetting quantity of supply from unconventional supply sources, particularly from shale gas production.

Figure 4: Natural Gas Production by Source [5]



2.4 Canadian Supply

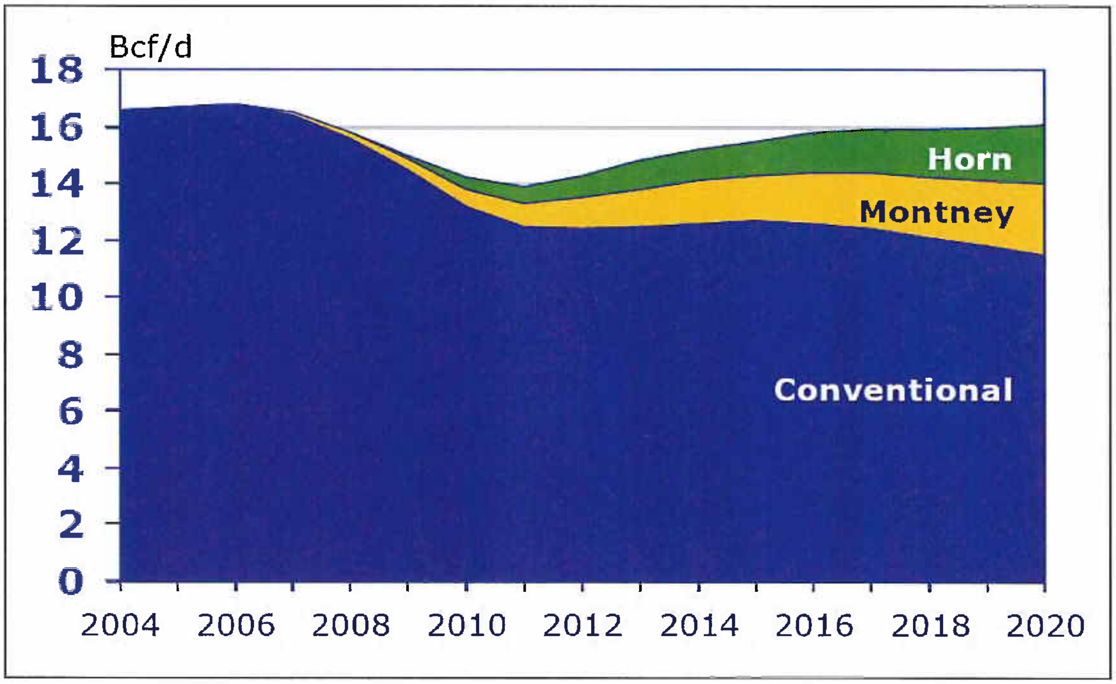
In Canada, the majority of natural gas supply originates from the Western Canadian Sedimentary Basin ("WCSB") with smaller quantities of supply originating from eastern Canada, particularly off the coast of Nova Scotia from offshore, underwater wells. The WCSB spans southwest Manitoba, southern Saskatchewan, Alberta, northeast British Columbia, and the southwest corner of the Northwest Territories. The WCSB contains one of the world's largest reserves of petroleum and natural gas reserves and supplies much of the demand in North America. Canada is the third largest producer and second largest exporter of natural gas in the world, with a majority of it coming from the WCSB. The WCSB is estimated to have 143 Tcf of marketable gas remaining (discovered and undiscovered), which represents about two thirds of Canadian gas reserves. Current WCSB production is almost 12 Bcf/d.

Over half of the gas produced from the WCSB is exported to the United States.[6] The remainder is mainly used for meeting Canadian demand and the extraction of crude oil from the oil sands region in Alberta. However, WCSB flows to the U.S. are expected to decline slightly by about 2

5 Wood Mackenzie North America Long Term View – September 2010
6 http://en.wikipedia.org/wiki/Western_Canadian_Sedimentary_Basin

Bcf/d between 2010 and 2012. After 2012, a little less than half of all WCSB production will be exported to the U.S. out to 2022.

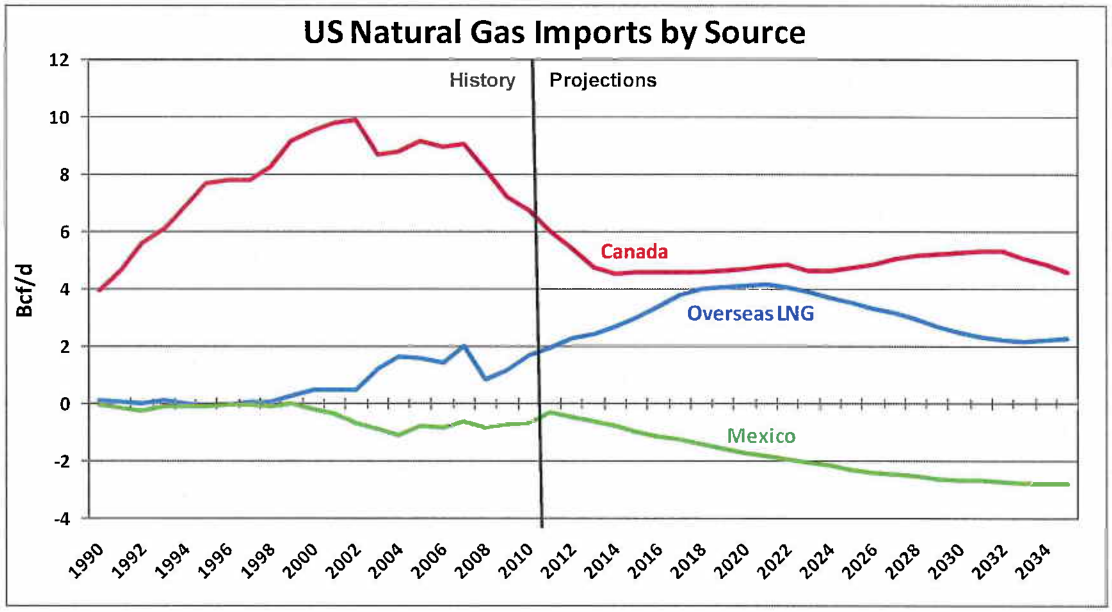
Figure 5: WCSB Natural Gas Production Forecast[7]



The following figure below shows a decline in U.S. imports of Canadian WCSB supply of about 2 Bcf/d to 2012 before levelling out and remaining constant to 2034. The decreased reliance on Canadian imports is a direct reflection of the surge in the quantity of shale gas supply in the U.S. market as well as increased demand for Canadian WCSB supply for oil sands extraction.

7 TransCanada – North America Natural Gas Presentation, Bill Langford, September 28, 2010.

Figure 6: U.S. Natural Gas Imports by Source[8]



2.4.1 CONVENTIONAL CANADIAN SUPPLY

Gas production from the WCSB has historically been focused on supply from conventional gas plays. But it is currently undergoing a drastic and rapid shift away from conventional sources to unconventional gas sources. This shift is happening amid falling conventional gas production and new shale discoveries in northeast B.C. Production in the WCSB peaked between 2004 and 2006 and declined since mid-2007 by over 8 per cent.[9] The downward trend has continued into early 2009 mainly due to relatively low natural gas commodity prices, limited conventional drilling targets and the depressed economic climate which has reduced industrial demand for natural gas. Overall production is expected to decline further in 2010 due to a slowdown in conventional natural gas drilling activity and only gradual increase in unconventional gas drilling. Overall Canadian production is expected to partially recover after 2010 but not to the levels achieved in 2006 in the near future.

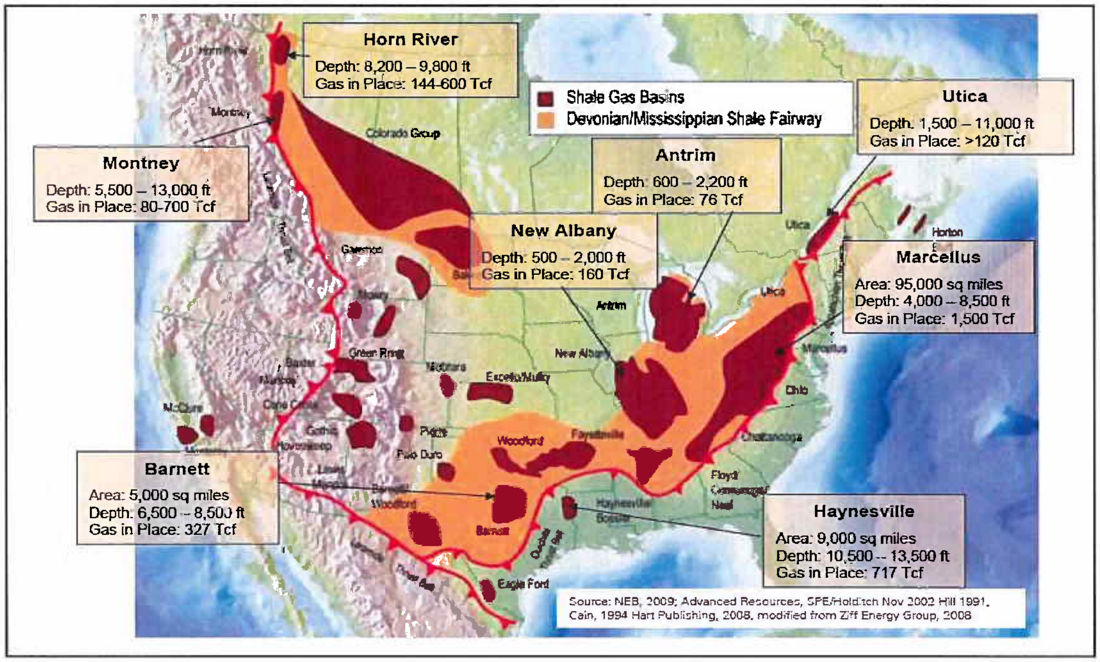
2.4.2 UNCONVENTIONAL CANADIAN SUPPLY

The two most significant unconventional natural gas plays in Canada are the Montney and Horn River supply basins in northeast B.C. and northwest Alberta. Major industry players have showed their long-term commitment to these shale plays by spending billions of dollars in B.C.

8 U.S. Energy Information Administration – Natural Gas Annual Energy Outlook; April 2010.
9 Canadian Gas Association - North American Natural Gas Supply: Increasingly Unconventional

land sales to lock up drilling rights. Estimates of total reserves in the Montney and Horn River areas would place this region among the most prolific shale plays in all of North America. Figure graphically shows the Horn River and Montney located in northeast B.C. and northwest Alberta and estimated reserves of various shale gas plays across North America. The Montney and Horn River shale plays are also discussed in Section 1.4 regarding the B.C. marketplace.

Figure 7: Major Shale Gas Basins (including Horn River and Montney)[10]



This North American natural gas production growth in recent years has occurred despite depressed market prices. The next section addresses some of the reasons for this.

2.5 Strong Production Despite Depressed Prices

Despite the recent and current global economic slowdown that has adversely affected industrial and commercial natural gas demand, an associated decrease in natural gas production has not materialized in 2010. Production has remained strong relative to historical values and US production has reached record high levels in the latter part of 2010, as shown in the figure below.

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10 National Energy Board, 2009, Advanced Resources

Figure 8: Historical US Production

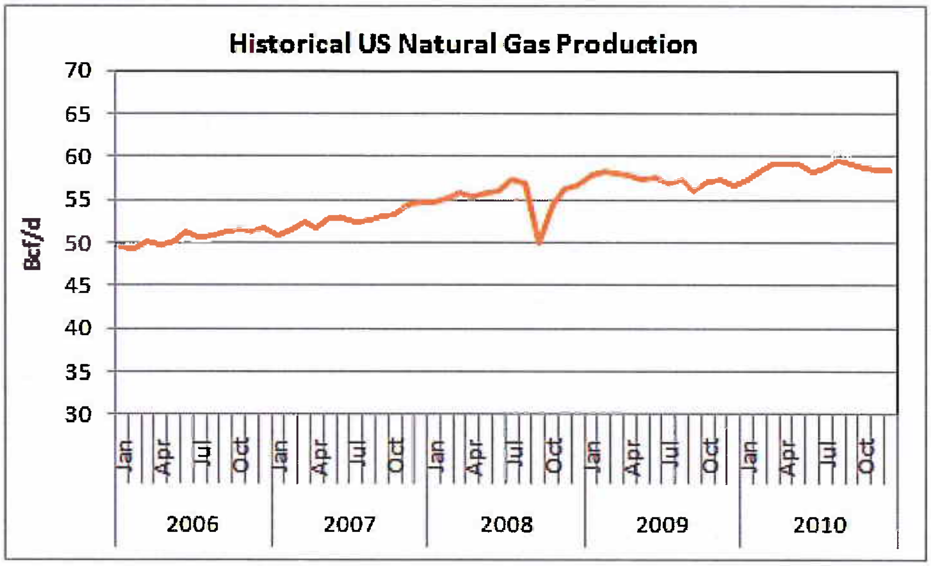
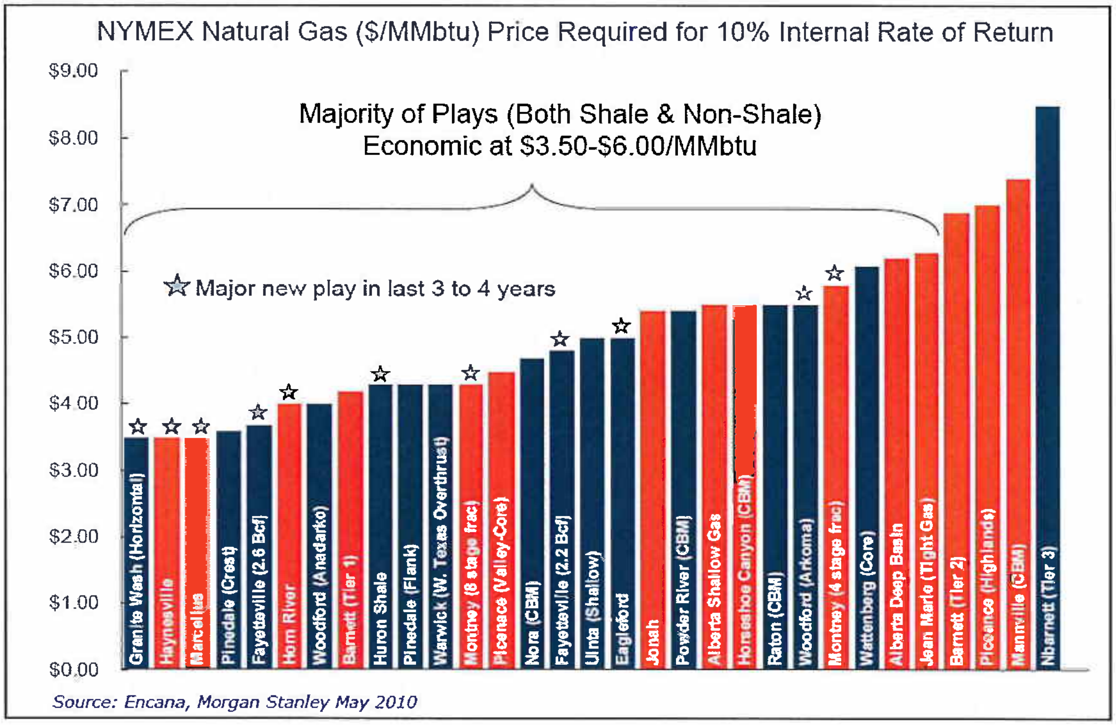


Figure 9 summarizes the NYMEX gas price required for various unconventional natural gas plays in North America that would allow the producer an internal rate of return of 10% based on current costs. It should be noted that the NYMEX forward price average for 2011 is currently about $4.50 US/MMBtu. As shown in the graph, this is below the average cost of production for many unconventional plays, which range from a $3.50 US/MMBtu to $6.00 US/MMBtu break even cost based on a ten percent rate of return.

Figure 9: NYMEX Price Required for Various Gas Plays[11]



There are a number of reasons why production has remained strong despite lower demand and depressed prices for natural gas:

- Drilling and hold-by-production leases to maintain land rights

Many producers are continuing to explore and drill for natural gas despite reduced demand and low gas prices in order to maintain land drilling rights. For example, during the natural gas price run up in 2008, many production companies purchased land rights that included lease hold conditions, primarily in the Haynesville play. The majority of land rights were for three years and so expire in mid 2011. Therefore, in order to maintain the right to drilling for gas, many companies have continued to drill even though it was less profitable, based on market prices, in the short term.

- Joint venture transactions between companies

Many companies who have access to land and acreage to explore and drill may be unable to further develop their gas plays due to tighter access to credit and lending in response to the

[11] Encana, Morgan Stanley, May 2010

economic downturn, given the capital intensive nature of natural gas production. Therefore, in order to overcome this, companies who do own land use rights to desirable gas plays have entered into joint venture agreements with other interested companies so as to continue to explore and further develop their plays. For example, Chesapeake and Statoil, two very large E&P companies, entered into a joint venture agreement in the Marcellus region in 2010 to ensure further development of Chesapeake's gas plays in the region.

- Producer Hedging

A significant number of producers have secured hedges at price levels significantly above production costs and current price levels. Since many producers are hedged at a price significantly greater than market prices today, many are able and willing to continue producing despite the drastic decline in natural gas prices.

It is estimated that, on average, 53% of North American natural gas production is hedged at a floor of $6.25 US/MMBtu for 2010. For 2011, the amount of hedging drops to 31% at a floor of about $6.04 US/MMBtu. For 2012, the percentage declines to only 14% with a floor of about $5.95 US/MMBtu.[12]

For example, Encana, the largest natural gas producer in Canada and second largest in North America behind Chesapeake Energy, reported that it has over 45% of its natural gas production hedged for 2010, 38% for 2011, and 31% for 2012, all at NYMEX price levels above $6 US/Mcf.[13] Another large natural gas producer, Anadarko, also recently announced that their 2010 production is about 78% hedged, 26% hedged in 2011, and 23% in 2012. Additionally, Petrohawk, an unconventional natural gas producer in the U.S. regions of Haynesville, Eagle Ford, and Fayetteville, recently announced that their 2010 production is about 75% hedged, 62% hedged for 2011, and 25% hedged for 2012, all at NYMEX prices at or over $5 US/MMBtu.

As a result of previous hedging activity, many large producers are currently realising prices that are generally above current market prices, which allows companies to continue producing in the face of depressed prices. However, there exists limited appetite for future hedging out beyond 2011 at currently depressed forward price levels amid rising production costs resulting in reduced rates of return.

In August 2010 an analyst with Macquarie Capital noted: "The need to drill to keep shorter leases and the ability to keep producing because of strong forward contracts, or hedging, will eventually peter out. I think by the middle of next year when a lot of retention leases have

[12] Credit Suisse Equity Research October 27, 2010.
[13] Encana 3rd Quarter Financial Results News Release, October 20, 2010, page 5

expired, my sense is producers will go to a more level-loaded, sustainable drilling pace and with it a rebalancing in prices for 2011".[14]

➢ Strong productive capacity of horizontal gas wells

Horizontal gas wells have been increasing in popularity in the past few years because of the relative strong marginal productive capacity of horizontal wells relative to vertical, conventional wells. Accordingly, horizontal wells require a lower gas price relative to vertical wells to maintain the same rate of return.

To illustrate the strong productive capacity of horizontal wells, according to the EIA, Figure shows that despite a large drop off in the number of natural gas rigs, dry gas production has remained relatively unchanged. The large drop off in the rig count is mainly due to less vertical wells being utilized and displaced by more productive horizontal wells, which explains the fall in the overall rig count but the relative stability of dry gas production.

Figure 10: US Dry Gas Production vs. Rig Count

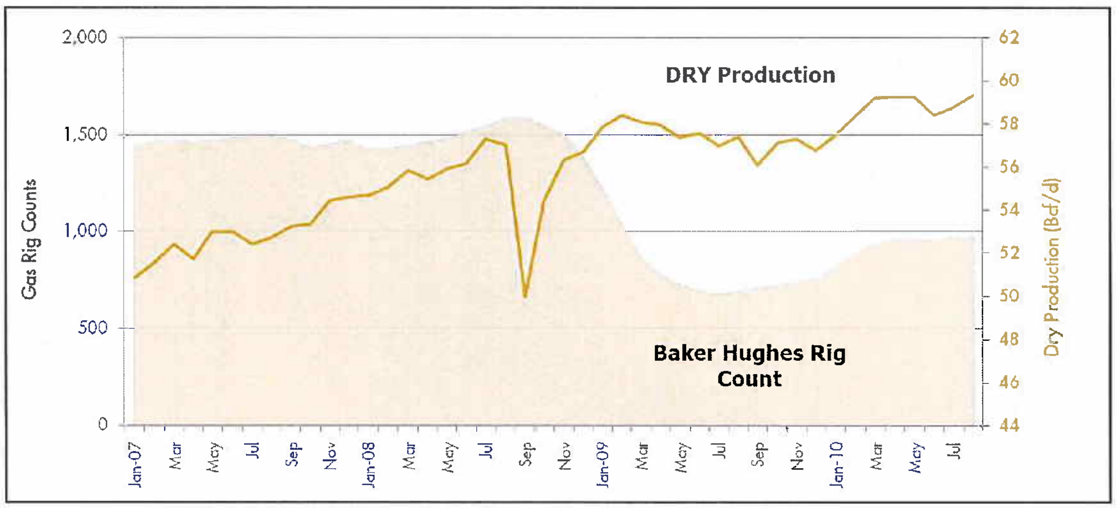
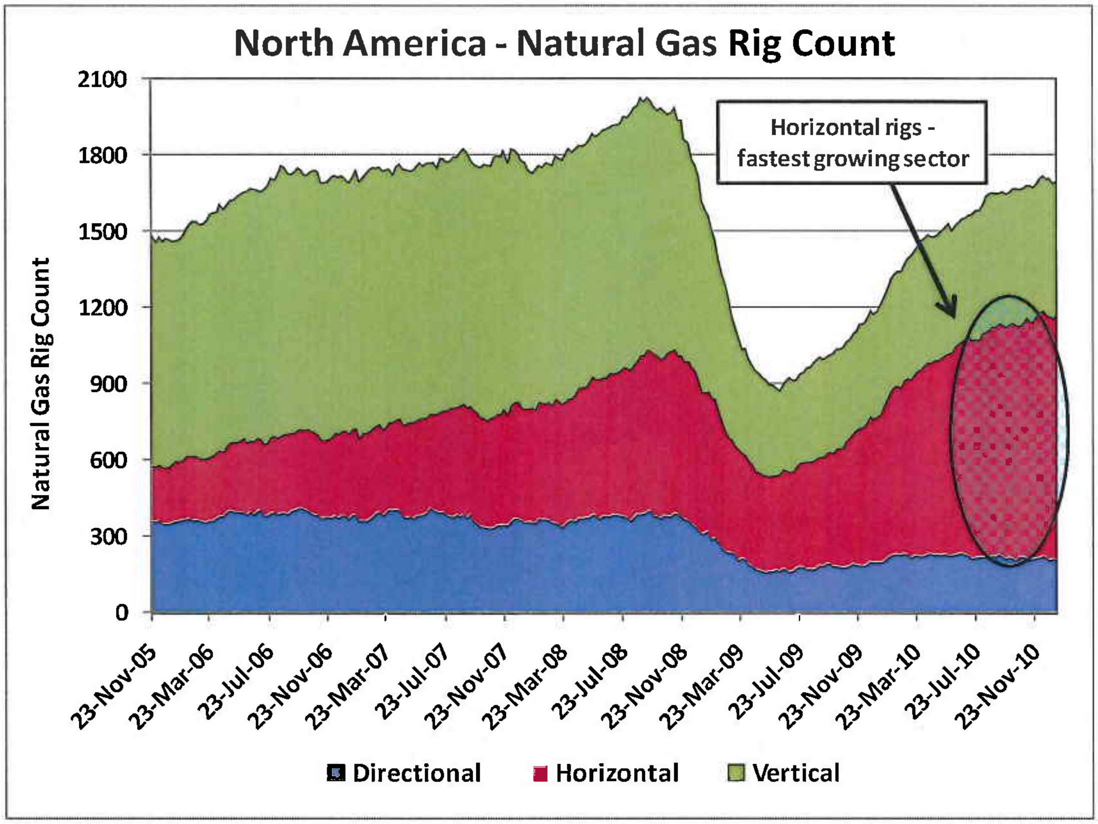


Figure 11 below breaks down the rig count numbers presented in Figure to show the total U.S. natural gas rig count by category; horizontal, directional, and vertical natural gas rigs. The fastest growing type of natural gas rig is horizontal rigs, which are associated with unconventional gas production.

[14] Calgary Herald, August 18, 2010

Figure 11: U.S. Natural Gas Rig Count[15]



In addition to horizontal wells being more productive than vertical wells, technological advances in drilling and improved efficiencies in completion techniques have all contributed to increases in natural gas production despite a reduction in the number of natural gas rigs.

In summary, natural gas production levels in the near term are not reflective of the current price environment. Lease hold drilling conditions, joint venture arrangements, producer hedging and the increased productivity of unconventional production have served to produce near record high production levels despite depressed demand and prices. However, a high degree of uncertainty exists with respect to natural gas prices once these producer hedges and land leases expire and production growth subsides after 2011. According to Encana, the largest unconventional natural gas producer in Canada and the second largest in North America, "North America's ongoing oversupply of natural gas production has driven prices for the near term to levels that we believe are unsustainably low".

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[15] Baker Hughes Incorporated: U.S. Natural Gas Rig Counts as of January 1, 2011.

2.6 Concerns and Issues with Unconventional Production

A number of issues and concerns relating to unconventional production may have an adverse effect on natural gas production. This may result in less unconventional supply being developed in the future than originally anticipated. However the degree of the effect on supply will be know with greater certainty as these issues and concerns are addressed by the stakeholders involved. The majority of these concerns revolve around the impacts of unconventional production on the environment. However, other issues may also affect overall natural gas production such as demand for liquids extraction (primarily ethane), operating expenses relating to land leases, royalties, and labour costs.

2.6.1 ENVIRONMENTAL AND SAFETY CONCERNS

Shale gas production requires large amounts of water, sand, and chemical additives be pumped down through the drilled pipe at enormous pressures to create small fissures and cracks in the shale rock. This process releases the trapped natural gas in the shale rock which is then pumped back up to the surface to the drill rig.

As a result, a number of environmental concerns have surfaced regarding impacts of shale gas production such as quality of groundwater, disposal and processing of used water, wildlife impacts, and a variety of other issues relating to environmental sustainability and safety. This has led to greater governmental investigations and regulations in many jurisdictions, drilling moratoriums and, in some cases, legal action against producers.

For example, Southwest Energy, a Marcellus shale gas drilling company which owns leases to about 150,000 acres in the Marcellus, has been named in a lawsuit filed collectively by thirteen families. The suit alleges that the energy company's drilling activities in the Marcellus shale region contaminated their drinking water. The suit also claims that the Pennsylvania Department of Environmental Protection found high levels of barium, magnesium and strontium in area water wells after drilling began in the region causing local residents to fall ill and damage property as a result of the drilling activity.

Similar water contamination issues have begun to emerge out of the Barnett shale area which is located in Texas. The Texas Commission on Environmental Quality found elevated levels of benzene near several Barnett shale gas wells. Additionally, many shale gas wells have experienced some sort of water disposal issue however; increased oversight by local, state and federal regulatory bodies should lead to changes to industry practices regarding waste water treatment and disposal.

Furthermore, the U.S. Environmental Protection Agency ("EPA") has commenced an extensive study into the impacts of hydraulic fracturing that will conclude in 2012.[16] The EPA has proposed a "life-cycle" analysis of fracturing which will review the risks to the environment, water quality, and general overall impacts of fracking. The EPA is also requesting that leading drilling companies disclose information on operating procedures and the composition of fluids used in fracking. If the EPA determines that fracking is environmentally unsafe, it may ask U.S. Congress to implement more stringent regulations on drilling companies regarding hydraulic fracturing. This may potentially lead to tighter monitoring and regulation resulting in higher operating costs for drilling companies.

There are examples of greater regulatory oversight and legislation at both the state and federal levels. These may have consequences for the costs of producing natural gas and/or the future growth of unconventional supply.

- Moratoriums

There have been examples of regulation aimed at natural gas drilling practices at the state level in the U.S. For example, the New York Senate currently has a nine-month moratorium on natural gas drilling over concerns of the adverse impacts to the State's groundwater resources resulting from horizontal drilling in the Marcellus shale region. The moratorium will remain in place until further studies can be conducted to explore the effects of fracking on the quality of groundwater in New York, which is used for drinking and consumption.[17] One possible consequence that may result from this review is more stringent reporting requirements relating to horizontal drilling, or fracking. This may lead to higher costs associated with unconventional drilling for companies who wish to continue to drill this type of natural gas well. With the Marcellus shale being one of the most prolific shale gas regions in North America, this will adversely impact production companies abilities to drill for natural gas in this region until the moratorium is lifted and may affect amounts drilled in the future once the moratorium is lifted.

Similarly, water contamination issues have begun to emerge out of the Barnett shale area which is located in Texas. The Texas Commission on Environmental Quality found elevated levels of benzene near several Barnett shale gas wells. Increased oversight by local, state and federal regulatory bodies should lead to changes to industry practices regarding waste water treatment and disposal and likely increase costs for producers.

[16] Energy Intelligence – Natural Gas Week, September 20, 2010, page 15
[17] http://www.reuters.com/article/idU.S.TRE67358R20100804

- FRAC Act

The Fracking Responsibility and Awareness of Chemical Act ("FRAC Act") was introduced in 2009, but has not been passed into law yet. The FRAC Act aims to amend the Energy Policy Act of 2005 to include the hydraulic fracturing process to the Safe Drinking Water Act. If the FRAC Act is approved it will move legislation of the fracking process to the federal level and would require full disclosure by operators of any chemicals used in the fracking process.

- CLEAR Act

The Consolidated Land, Energy, and Aquatic Resources Act ("CLEAR Act"), which only applies to federal lands in the U.S. was passed into law on July 30, 2010. The CLEAR Act will require any companies that drill on federal lands to utilize those practices that will minimize impacts and threats to health and environment, and will also include requirements to disclose chemicals used in the fracking and extraction process.

- Clean Energy Jobs and Oil Accountability Act

This Act requires companies to fully and publicly disclose any chemicals used in the fracking process to state governments. The federal government will have the right and obligation to disclose this data to the public.

Increased legislative and regulatory oversight, for both the oil and natural gas industries, by local, state and/or federal governmental bodies will likely contribute to increases in costs as in the future.

Consequently, all of the above issues revolving around impacts to health, environment, and safety standards and the resultant increase in legislative and governmental oversight may negatively impact overall natural gas production in the Marcellus and other gas regions. All of these measures could result in higher prices in the future if prohibitive regulations and legislations are implemented by federal and state governments on oil and gas drilling companies.

2.6.2 OTHER CONCERNS AND ISSUES

Other factors that may impact companies' abilities to drill for unconventional natural gas in the future are uncertainties regarding operating expenses, labour costs, accessibility to equipment, such as rigs, casings, pressure pumping equipment, etc., and other factors that may make drilling unfeasible or uneconomical.

2.6.2.1 Pumping Cost Increases

In the Haynesville shale, located in northeast Texas and northwest Louisiana, there are constraints around pressure pumping equipment, which is equipment required to complete natural gas wells.[18] This equipment shortage is creating a backlog in production of over 300 drilled but uncompleted wells out of a total of 650 to 700 completed wells in the area. Typically, there are about 50 uncompleted wells. The backlog is expected to contribute to strong production into 2011 but increased operating costs out of the Haynesville shale until this shortage in equipment is resolved. A similar backlog in production situation is occurring in the Marcellus and Eagle Ford shale areas as well. Service costs are not expected to drop due to increased demand to drill in the Marcellus, Haynesville, and Eagle Ford areas.

2.6.2.2 Ethane Extraction

Another concern regarding natural gas production occurring in the Marcellus shale region is the inability to process natural gas containing ethane. Gas extracted from the Marcellus shale region has high ethane content is normally used as feedstock in the petrochemical industry. Pricing for ethane is typically higher than natural gas and helps improve profitability for producers who are able to extract and market this ethane by-product. However, in the Marcellus shale region, ethane extraction (and more generally natural gas liquids ("NGLs")) is becoming an issue. The infrastructure required to process and market the ethane is not sufficient currently due to the rapid increase in shale gas production. To help address the issue of ethane oversupply a number of new gas processing plants are proposed and being built in the Marcellus region.

Oversupply of NGLs resulting from production in the Marcellus region may negatively impact producers' willingness to continue to produce if producers are unable to market ethane into the marketplace. This reduced willingness may also adversely and indirectly impact shale gas production, thus affecting natural gas prices.

2.7 Implications of Macondo Oil Spill

The Macondo oil spill that occurred on April 20, 2010 in the Gulf of Mexico was the single largest accidental marine oil spill in the history of the petroleum industry. The physical flow of oil from the sea floor was stopped on July 15, 2010 and the exploded well was officially capped on September 19, 2010. The effects of the oil spill caused extensive damage to surrounding marine and wildlife habitats.

[18] Wood Mackenzie North America Long Term View – September 2010

After the explosion of the Deepwater Horizon well, on May 30, 2010 the U.S. Department of the Interior instituted a six-month moratorium on offshore drilling and ordered immediate inspections of all deep-water drilling rigs in the Gulf of Mexico. This moratorium suspended operations of about thirty three rigs. There are plans to introduce energy reform legislation for consideration by the U.S. House of Representatives that would take into consideration a company's past safety record when determining to grant drilling leases. Similarly, on April 28, 2010, the National Energy Board ("NEB"), which regulates drilling in Canada and the Canadian Arctic, called for more stringent safety and environmental measures for companies engaging in deep-water drilling.

While this unfortunate isolated incident was related to oil drilling, the negative public perception regarding drilling in general may have longer term effects on natural gas and oil drilling in terms of greater regulatory scrutiny and reporting and operating costs.

2.8 Summary of Natural Gas Supply

North American natural gas supply has been altered drastically by the emergence of unconventional supply resources such as shale gas, coalbed methane and tight gas. Current North American production is near the highest level it has ever been. However, this abundant supply situation is largely the result of weakened demand and factors unaffected by low market price signals, such as producer hedges and drilling to hold land leases. As has been discussed, market prices will play a more significant role in producers' production decisions once these hedges and lease hold conditions expire after 2011. Environmental and safety concerns and increased scrutiny around natural gas drilling will likely impact the amount and costs of production in the future. The result is likely to be a subsiding of natural gas production growth and higher prices going forward.

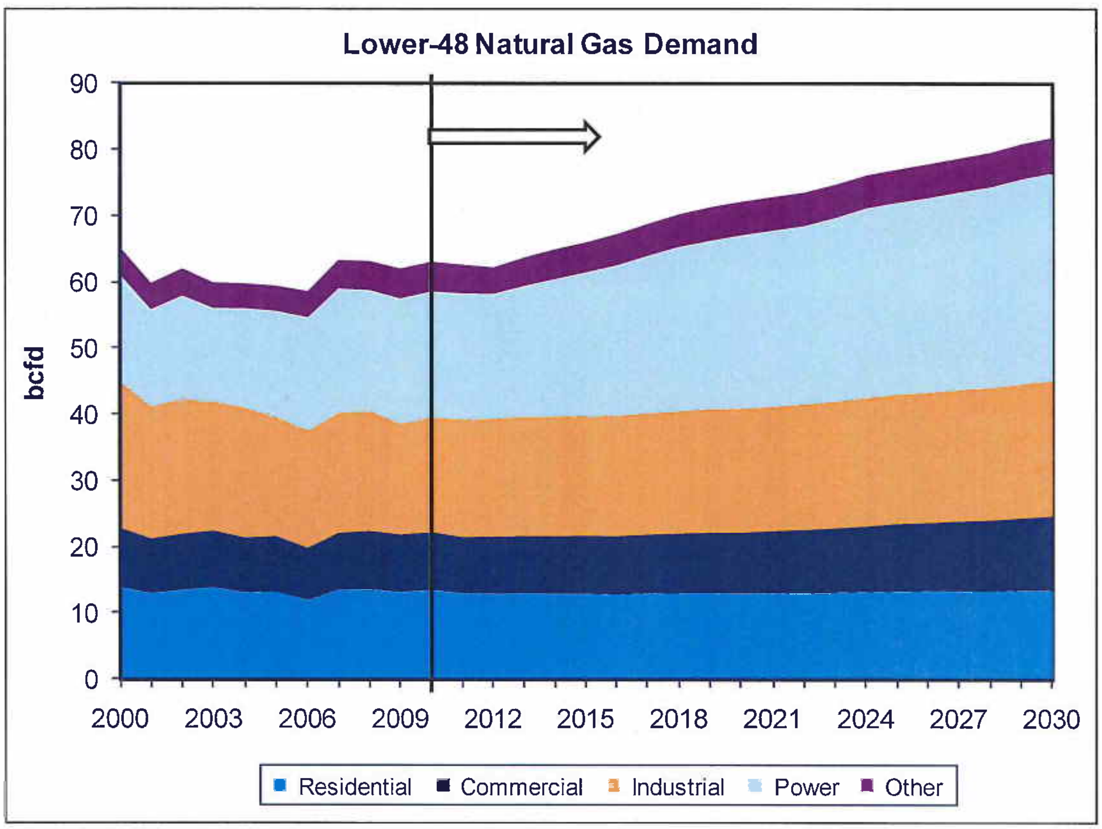
Demand related factors will also have a significant impact on the supply and demand balance, natural gas prices and volatility in the future. The next section will discuss North American natural gas demand.

3 NATURAL GAS DEMAND

Like supply factors, there are also numerous factors that influence demand which impact the supply and demand balance in the natural gas marketplace and determines market prices. While demand in Canada and the U.S. is currently depressed relative to pre-2008 levels, demand for natural gas is expected to grow in the future and will be driven by a number of factors.

Demand of natural gas in North America primarily consists of demand from residential, commercial, industrial, transportation and power generation sectors. Due to the recent economic slowdown, which began in the second half of 2008, demand for natural gas, primarily in the industrial sector, eroded in response to this reduced level of economic activity. The forecast is for a recovery in overall gas consumption after 2010 with steady growth to 2030, led by the industrial and electric power generation sectors, as depicted in the figure below.

Figure 12: U.S. Natural Gas Demand[19]



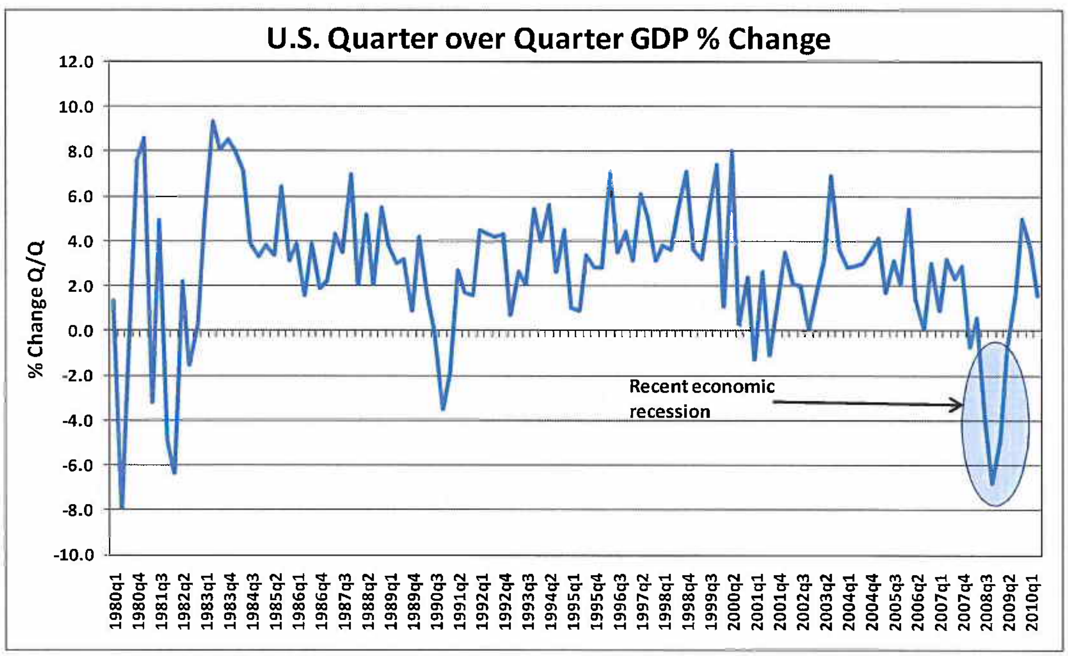
[19] Wood Mackenzie – North America Natural Gas Long Term View, September 2010

This section will explore the different components of current and future natural gas demand, with particular focus on demand in the industrial and power generation sectors. These two sectors make up a significant portion of overall North America gas demand currently and are expected to represent a growing proportion of total demand in the future. The recent economic slowdown has affected these two sectors more adversely than the residential and commercial sectors. Generally, residential, and to a lesser degree commercial, demand for natural gas is not as closely correlated to overall economic activity as is demand in the industrial and power generation sectors. Generally it is expected that any growth in residential and commercial demand in terms of population growth and fuel switching from heating and fuel oil may be partially offset due to improvements to natural gas appliance efficiencies and energy conservation initiatives over the long run.

3.1 The Economy and Recession

The recent economic slowdown experienced in 2008 and into 2009 is shown in Figure below. The data is presented in terms of quarter-over-quarter percentage changes.

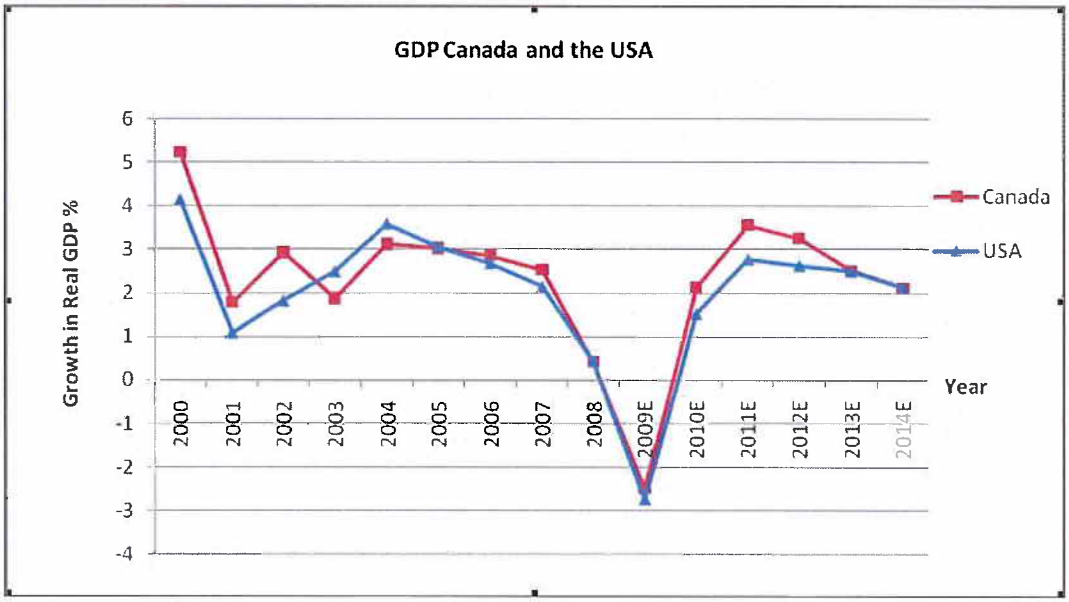
Figure 13: U.S. Quarter over Quarter GDP % Change[20]



[20] U.S. Bureau of Economic Analysis

Figure 14 shows a projection for future GDP growth for Canada and the U.S. going out to 2014. Growth, after declining in 2008 for reasons discussed earlier, has recovered somewhat in 2010 and is expected to remain above 2% per year by 2014. As expected, there is some uncertainty regarding these GDP projections which depend on a number of factors such as employment, exchange rates, and overall general recovery of consumer demand.

Figure 14: Projected GDP Growth (Canada and U.S.)[21]



Source: IMF website

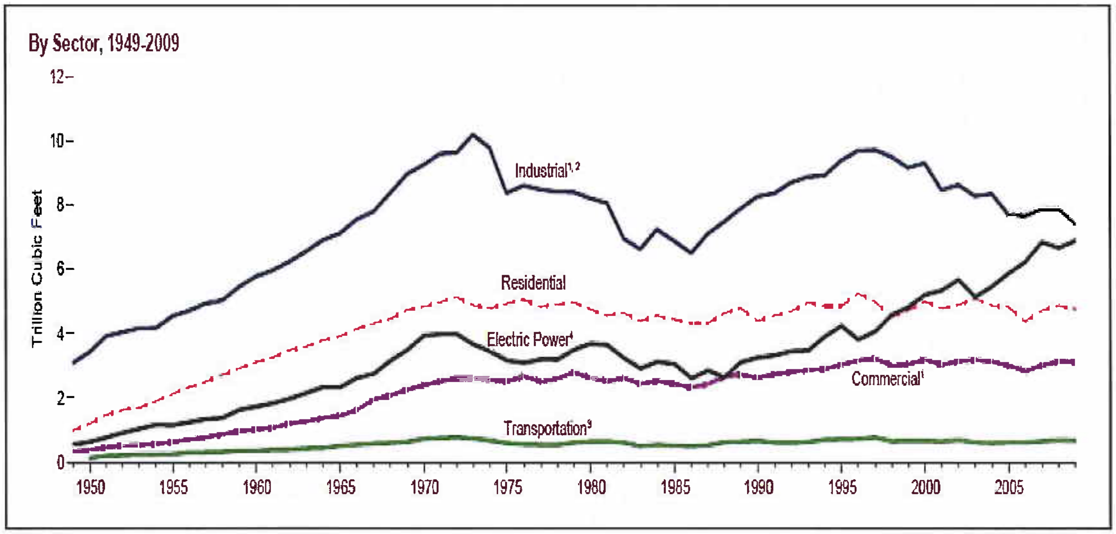
This economic growth will impact industrial demand going forward.

3.2 Industrial Demand

Industrial demand related to manufacturing and processing closely reflects current economic market conditions. When the economy is growing industrial demand for natural gas also expands and conversely when the economy is stagnant, or contracting, industrial demand typically reduces as well. Figure shows total U.S. natural gas demand by sector from 1949 to 2009. In 2009, industrial demand accounted for about 32% of total natural gas consumption.[22]

[21] International Monetary Fund – World Economic Outlook, April 2010.
[22] U.S. Energy Information Administration – Annual Energy Review 2009, August 19, 2010.

Figure 15: U.S. Natural Gas Consumption (Tcf/year)[23]



According to the EIA, industrial demand for gas in the U.S. increased by about 7% in 2010 over 2009 levels from 16.8 Bcf/d to about 18.0 Bcf/d. For 2011 and beyond industrial demand growth continues but at a slower rate. Because industrial demand accounts for about a third of total natural gas consumption a recovery in this sector will provide support for natural gas prices in the future.

Natural gas used for extraction and production in the oil sands region of Alberta is another major component of industrial demand. The main driver of the growth in Canadian natural gas demand comes from expanding requirements from the oil sands concentrated in north central and northeast Alberta. As seen in Figure, demand for natural gas for the oil sands more than doubled from 1999 to 2008 according to the Alberta Energy Resource and Conservation Board ("ERCB"). The ERCB forecasts that oil sands gas demand in Canada will double again in the next decade, increasing from slightly more than 1 Bcf/d in 2009 to roughly 2.3 Bcf/d in 2018.

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[23] U.S. Energy Information Administration – Annual Energy Review 2010 – August, 2010.

Figure 16: Alberta Oil Sands Gas Demand[24]

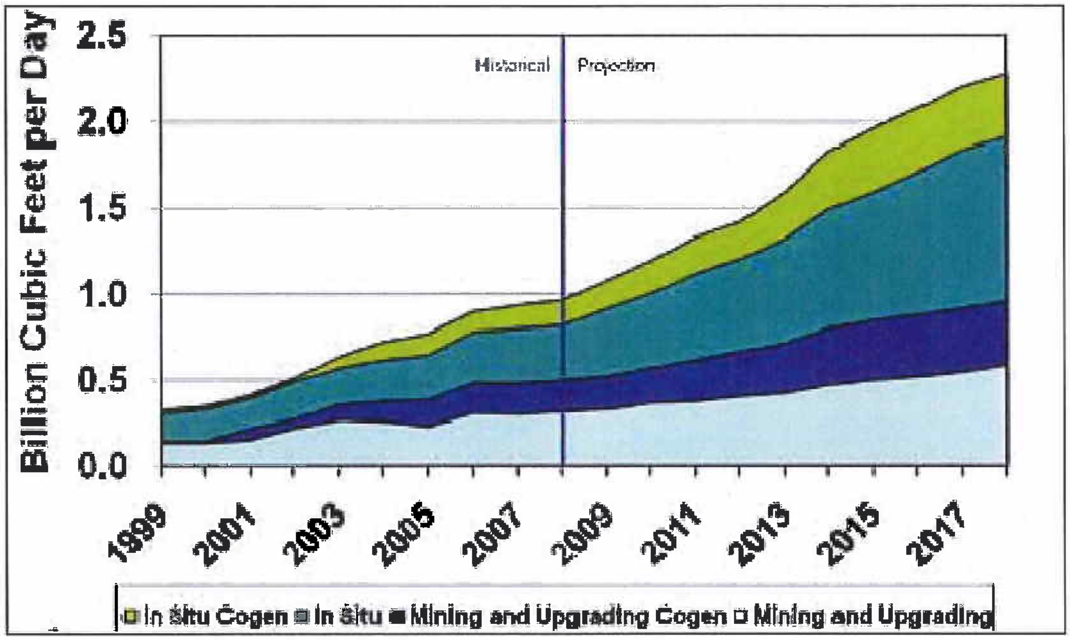
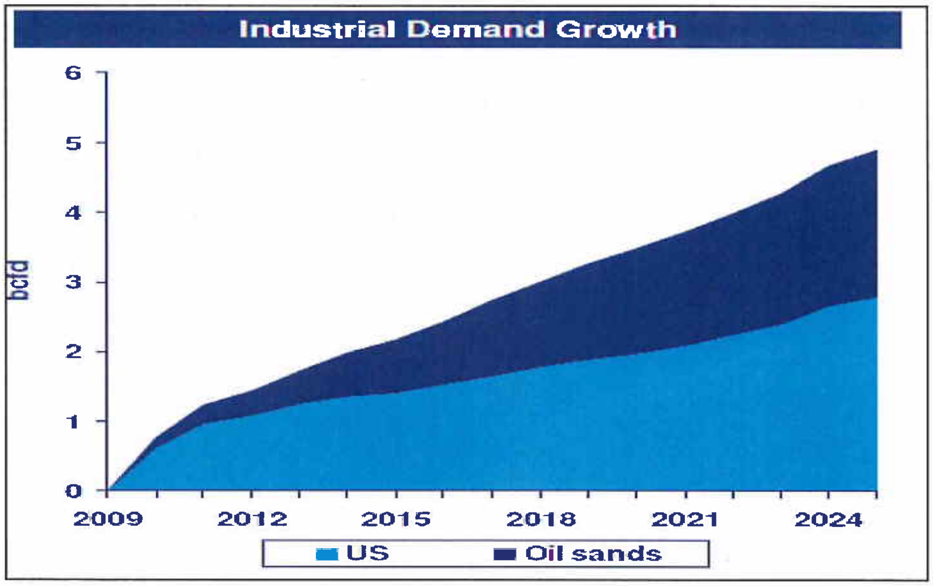


Figure 17 provides a forecast of industrial demand in the U.S. and the oil sands region of Alberta going out to 2024. Using 2009 as the base year, the growth figures are presented in terms of increases over 2009 in year-over-year Bcf/d.

[24] Alberta Energy Resource and Conservation Board

Figure 17: Projected Industrial Demand Growth[25]



One particular example of industrial demand recovery is Methanex, a Vancouver-based and publicly traded company and the largest supplier of methanol in the world to international markets. Methanex is planning to restart its methanol plant in Medicine Hat, Alberta in April 2011 in response to global economic growth and low natural gas feedstock prices. Methanex intends to purchase up to 50 TJ/d of natural gas in the Alberta market to produce methanol from this plant.

In summary, industrial demand for natural gas has shown signs of recovery and this is likely to continue if economic growth continues in the future. Oil sands demand is likely to remain strong given the outlook for the continued disconnection between crude oil and natural gas prices (see Section 1.3 regarding prices). These developments will continue to provide support for natural gas demand, contributing to a tightening in the overall supply/demand balance and potentially increasing natural gas prices and volatility in the future.

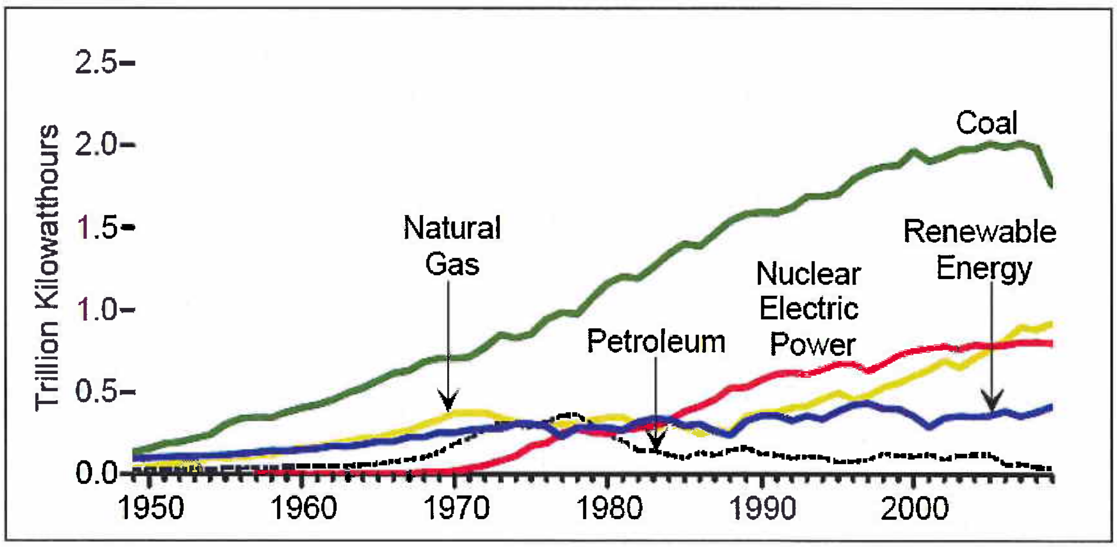
3.3 Power Generation Demand

Similar to industrial demand, natural gas use for power generation is projected to continue increasing in the future. In fact, natural gas demand for power generation is expected to be the largest source of growth in total natural gas demand. As illustrated in Figure, up until about 1998 natural gas consumption for power generation was the third largest sector behind

[25] Wood Mackenzie North America Long Term View – September 2010

industrial and residential demand. However, gas demand for the power generation sector is now the second largest sector of demand behind only industrial demand. One of the main reasons for the increase in use of natural gas for power generation is the gradual phasing out of coal fired power generation plants. Increased awareness of the harmful effects of coal burning to the environment has lead to a gradual shift to natural gas for this same use. GHG emissions targets, as set forth by government initiatives, have helped the shift towards natural gas as a cleaner burning fossil fuel. Figure illustrates the energy source mix that is used for power generation in the U.S. Historically coal has been the most common energy source for power generation. However, there has been a slow and gradual decline in the popularity of coal over the last few years and natural gas usage has increased steadily since 1950 such that it is now the second most popular fuel used for power generation.

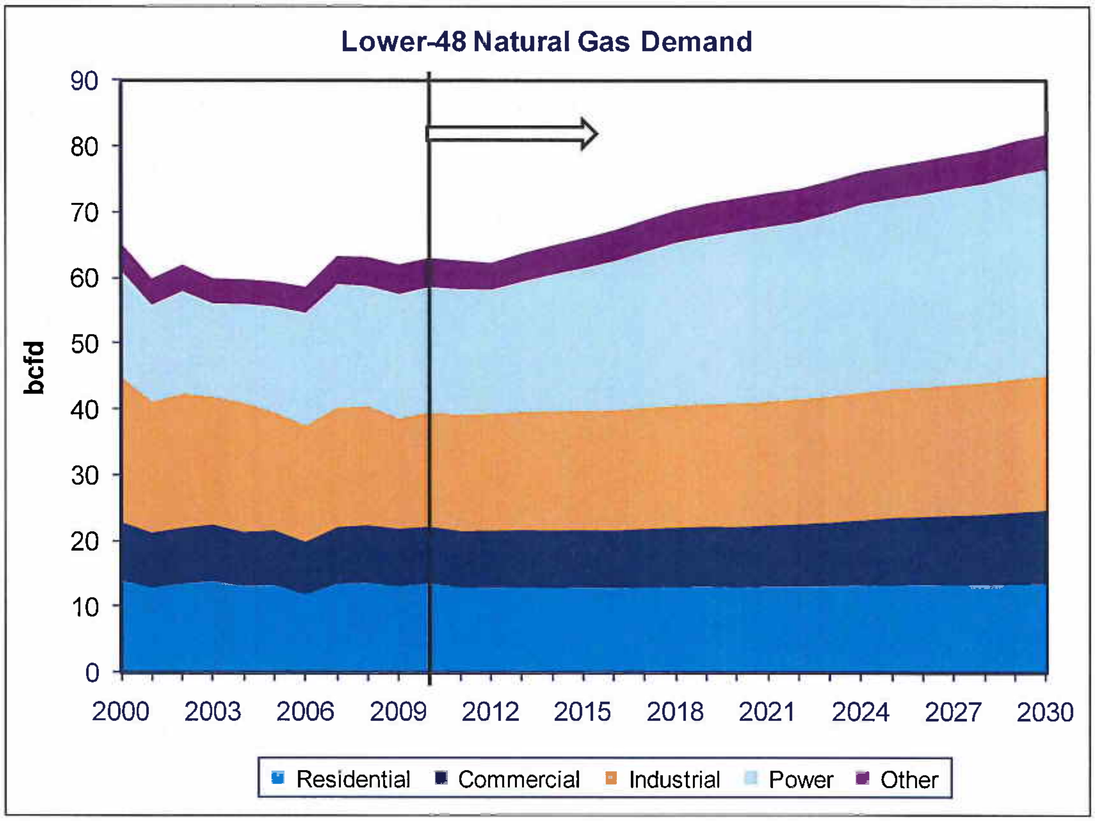
Figure 18: Total U.S. Electricity Net Generation by Energy Source[26]



The EIA forecasts that electricity demand will increase by about 2% per year to 2025. It is expected that natural gas demand will grow in response to this and its increasing share of power generation. Figure forecasts total North American natural gas demand out to 2030. Most of the growth in gas demand will come from increases in power generation.

[26] U.S. Energy Information Administration – Annual Energy Review 2010 – August, 2010.

Figure 19: Total North America Gas Demand[27]



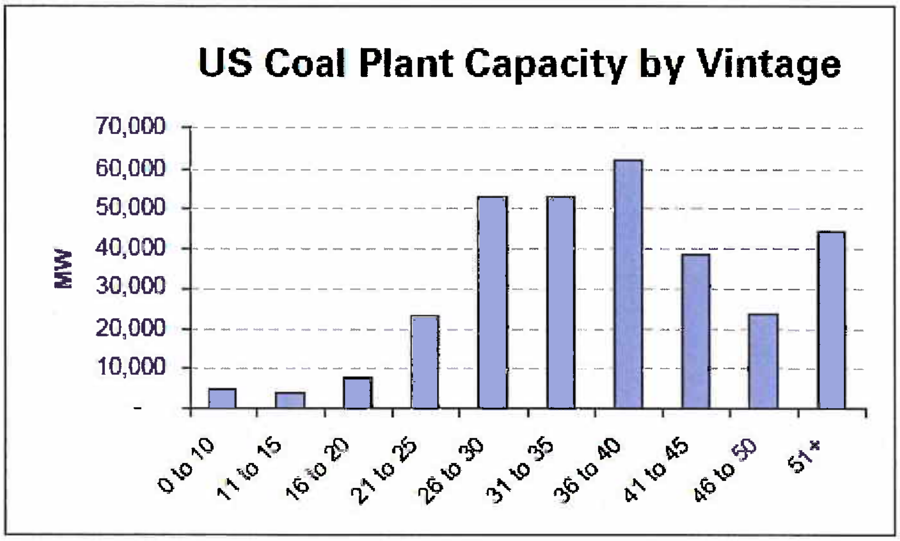
Contributing to this power demand growth for natural gas over the next number of years are the retirement of old existing coal fired plants and the increased demand for electricity in general. Natural gas is expected to be the fuel of choice for power generation for a variety of reasons, including:

- Capital Investment – natural gas fuelled power plants can range in size from being large-scale generation plants to very small-scale plants using micro-turbines.
- Environmentally Responsible – Most current power generation in the U.S. originates with coal, which is extremely polluting. Natural gas is the cleanest burning fossil fuel and coupled with federal and state environment initiatives to limit GHG emissions places natural gas in a favourable position to become the fuel of choice for power generation.
- Efficiency – Natural gas power generation units are very efficient compared to coal fired plants. Modern natural gas fired plants are about 60% efficient versus about a 35%

[27] Wood Mackenzie North America Long Term View – September 2010

efficiency for traditional coal-fired boiler units.[28] Therefore, more electricity can be generated per unit of input fuel by choosing natural gas over coal. Additionally, with an estimated 70% of all coal fired plants being close 50 years old, these coal plants require more maintenance and cannot be run as hard as they once were, as displayed inFigure 20.

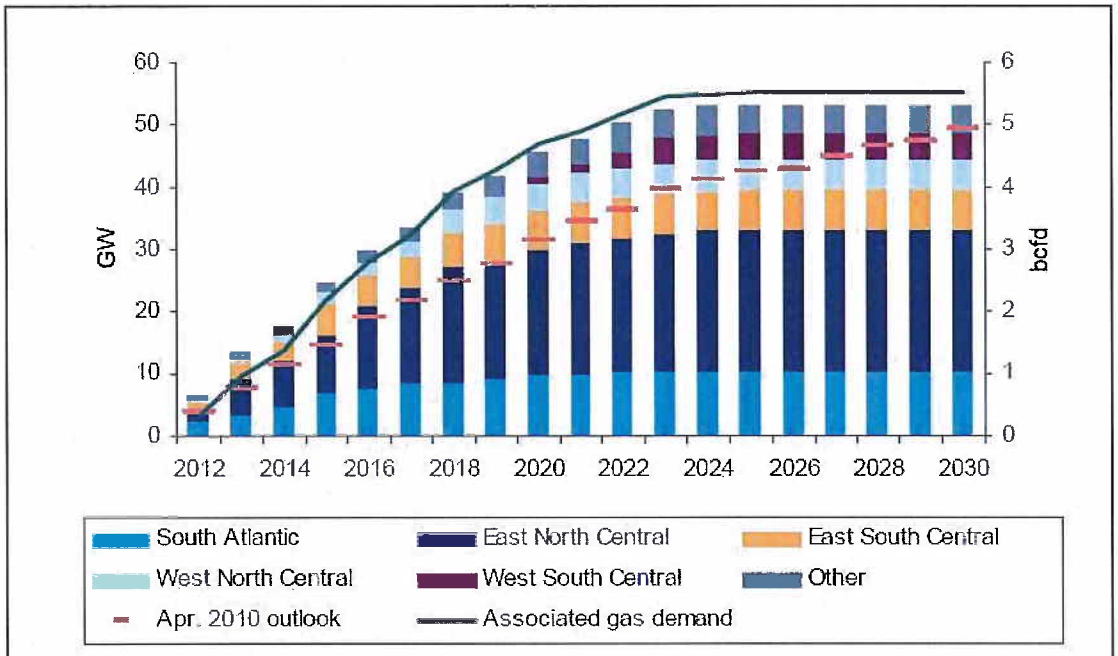
Figure 20: Coal Plant Capacity by Age[29]



The EIA forecasts that coal-burning facilities will account for about 10% of total new capacity in 2013, down from about 18% in 2009. Natural gas demand is expected to increase substantially for power generation use to 82% of new capacity in 2013, up from 42% in 2009. Figure 21 illustrates forecast coal-fired plant retirements after 2012 and the associated increase in demand for natural gas these retirements will cause. By 2030, about 50 GW of coal-fired capacity will have been retired and will be replaced with about 5.5 Bcf/d of natural gas supply to generate the same quantity of electricity.

[28] U.S. Energy Information Administration
[29] U.S. Energy Information Administration – Short Term Energy Outlook, September 2010.

Figure 21: Coal Retirements and Associated Demand for Natural Gas[30]

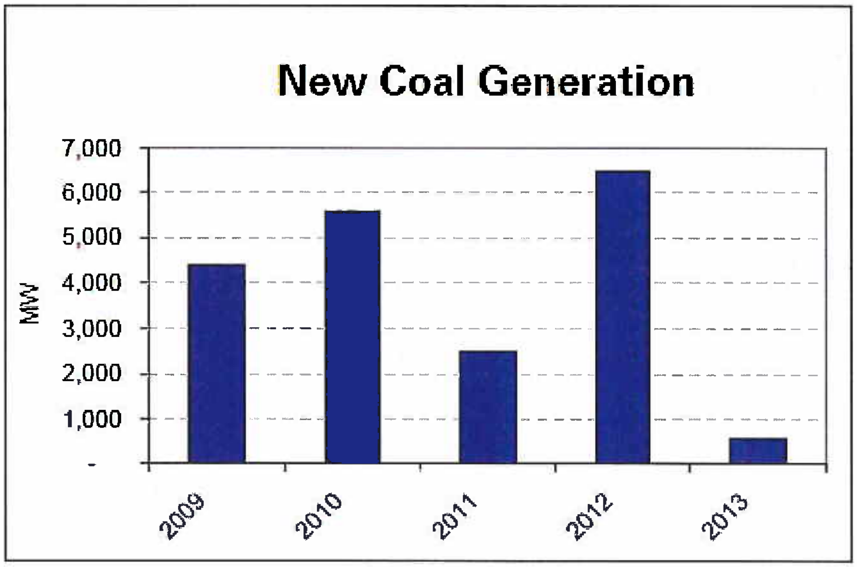


Source: Wood Mackenzie

[30] Wood MacKenzie – Natural Gas Long Term View, September 2010

Additionally, according to the EIA there will be a reduced level of coal generation additions after 2012 as shown in Figure 22.

Figure 22: New Coal Generation[31]



Therefore, fewer coal plant additions are expected to come online in the future coupled with existing coal-fired plants either being retired or retrofitted due to tighter environmental regulation.

While the cost to upgrade newer and more efficient coal-fired power plants is lower than that for older plants, a significant portion of the coal-fired generation fleet is old enough that retrofits are not generally economical. This will lead to significant increases in gas-fired generating plants in the years ahead.

In summary, in terms of total new capacity volumes, electricity generated from coal-burning facilities is expected to halve and electricity from natural gas-fired generators is expected to double by 2013. The level of coal displacement by gas-fired generation will depend on timing of carbon policy implementation, emission allowance levels, and gas pricing levels. The result of this increased natural gas demand will be support for higher prices, all else being equal.

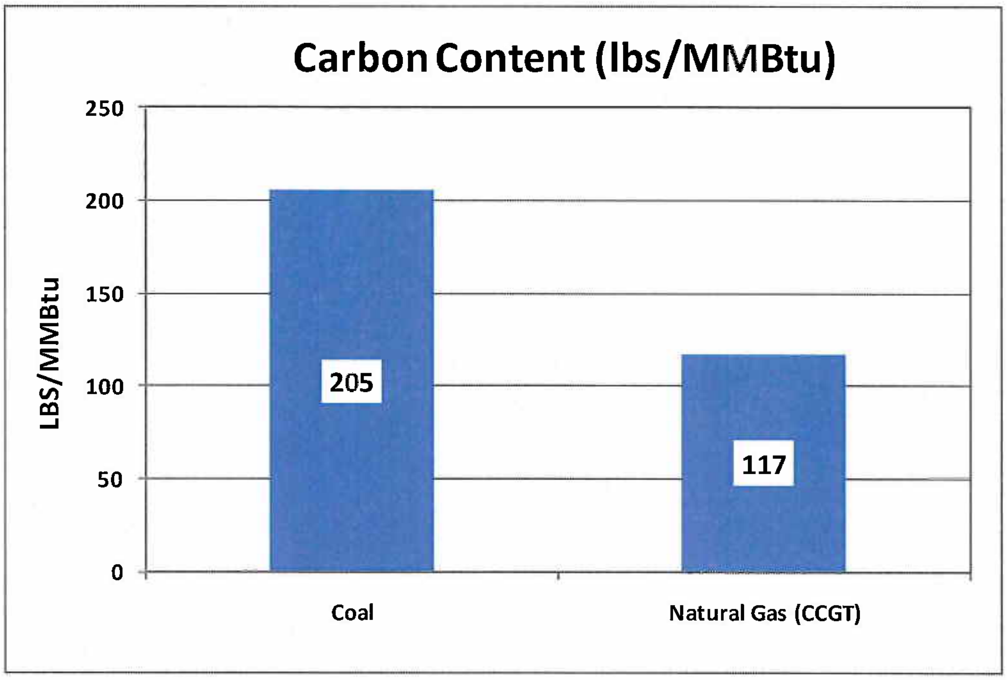
3.3.1 GREENHOUSE GAS EMISSIONS

Lower greenhouse gas ("GHG") emissions for natural gas power generation relative to coal-fired generation are one of the main reasons for the increased popularity of natural gas to generate

[31] U.S. Energy Information Administration – Short Term Energy Outlook, September 2010.

electricity. Figure 23 illustrates the carbon content of coal and natural gas for power generation. Coal emits approximately two times more carbon than natural gas (combined cycle gas turbine ("CCGT") plant) for power generation. As a result, the Environmental Protection Agency ("EPA") is imposing stricter regulation regarding harmful GHG emissions from coal-fired facilities. Many coal-fired plants will either have to be retrofitted and scrubbed or retired altogether.

Figure 23: Carbon Content of Coal and Natural Gas[32]



The EPA released its Clean Air Transport Rule ("CATR") to replace the Clean Air Interstate Rule ("CAIR") on July 6, 2010. The CATR is a stricter regulation that calls for greater reductions in sulphur dioxide and nitrogen oxide emissions between 2012 and 2014. The CATR also proposes a reduction in mercury emissions resulting from coal-fired generation with a 90% reduction in mercury emissions by 2015. Also, the safe disposal of ash, a by-product of using coal for electric generation, will be regulated by CATR. The CATR, and any new legislation, highlight greater uncertainty regarding coal-fired generation facilities.

The obvious benefits of using natural gas as a fuel to generate electricity will only increase in importance as demand for electricity grows in the future. Additionally, expected federal and state legislations against controlling GHG emissions will also place a greater reliance on using

[32] U.S. Energy Information Administration

natural gas for power generation. This increased incremental demand will position natural gas as the preferred fuel of choice; however, this increased demand will have the potential to put upward pressure on gas prices in the future.

3.4 Natural Gas Demand for Transportation

Increasing environmental concerns combined with disconnected gas prices (relative to crude oil product prices) greatly enhances the competitive position of natural gas as a transportation fuel. Vehicles fuelled by natural gas produce fewer pollutants than gasoline or diesel engines and can operate at a significantly lower cost.

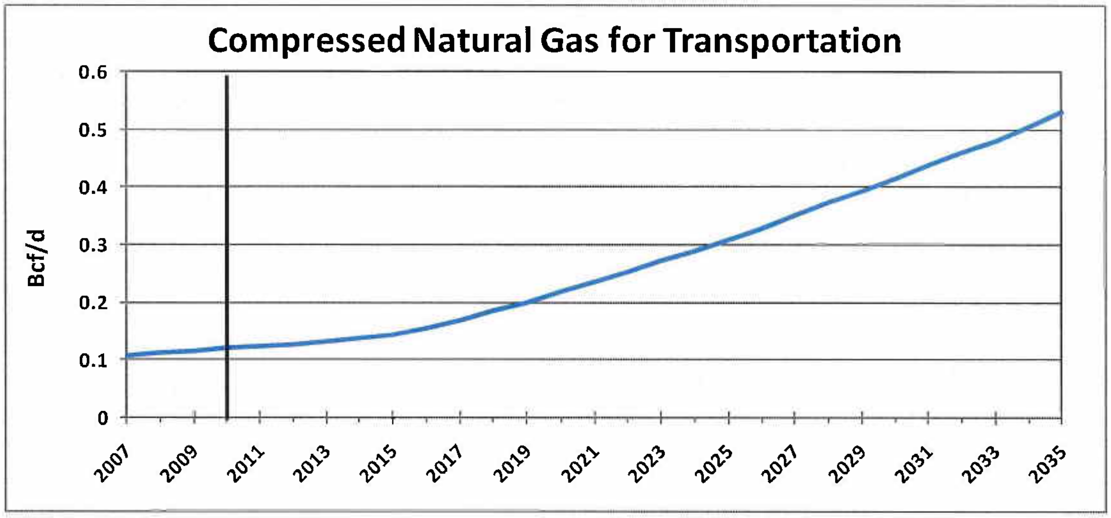
Natural gas use in the transportation sector is typically used in one of two forms; compressed natural gas ("CNG") and liquefied natural gas ("LNG"). CNG is the preferred fuelling method for light and medium natural gas vehicles ("NGVs") and LNG is typically used for heavy-duty NGVs. Some of the benefits associated with NGVs are:

- Significantly lower GHG emissions, like CO2 (carbon dioxide), NOx (nitrogen oxide) and SOx (sulphur oxide), than traditional fuels such as diesel and gasoline
- Lower fuel costs – 25% to 50% less than gasoline pump prices
- Lower maintenance costs due to cleaner burning properties of natural gas versus diesel and gasoline
- Supports climate change initiatives of provincial and federal governments to reduce dependence on crude oil

Historically, consumption of natural gas for the transportation sector has been generally stable (see Figure) from about 1970 to 2009. Natural gas used for vehicle fuel only accounted for less than three percent of overall gas consumption on average per year.

According to the EIA, demand for natural gas used for fuel in the transportation sector is expected to grow substantially in the future, as shown in Figure 24. Demand is expected to increase from about 0.1 Bcf/d currently to about 0.55 Bcf/d by 2035.

Figure 24: Compressed Natural Gas for Transportation[33]



Recently, there has been a fundamental shift in the way natural gas is and will be used in the transportation sector going forward. Government climate initiatives and coupled with the environmental benefits of using natural gas as a relatively clean burning fossil fuel will all contribute to the attractiveness of natural gas for the transportation sector. Over the last couple of years there has been a large number of natural gas fuelling stations built across the U.S. and many trucking companies have explored using natural gas as a part of the fuel mix for their truck fleets. Additionally, the price disconnection between oil and natural gas prices that has occurred over the last few years (discussed in Section 1.3) has lent support towards the feasibility of using natural gas as a transportation fuel. Since the price for gasoline and diesel is typically positively correlated to crude oil prices, strength in the price of crude oil will result in a greater shift towards alternative fuel sources, namely compressed natural gas, for use in transportation. As more stringent emissions standards are adopted, both at the federal and state level, the automotive industry will likely increase the development and production of natural gas vehicles that are more environmentally sound than traditional gasoline and diesel powered vehicles and meet consumer preferences.[34]

3.4.1 TERASEN GAS – NATURAL GAS FOR TRANSPORTATION

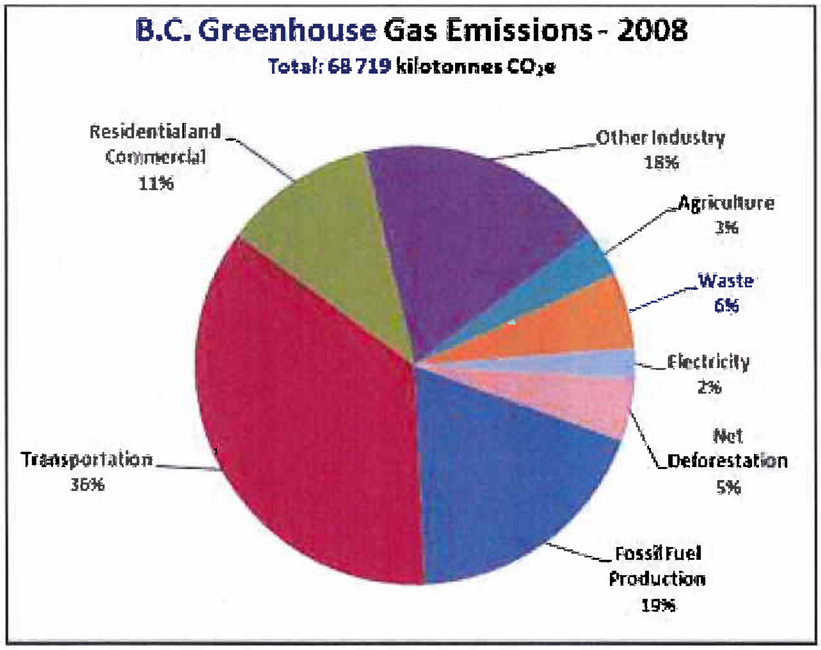
GHG emissions from the transportation sector account for more emissions than in any other use of energy in B.C. According to Figure 25, from the Province of British Columbia Ministry of Environment, transportation accounts for about 36% of all GHG emissions in B.C. Therefore,

[33] U.S. Energy Information Administration
[34] http://www.naturalgas.org/business/demand.asp#electricdemand

this sector provides the greatest opportunity for emissions reductions by adopting cleaner burning fuels.

Data from Natural Resources Canada indicates heavy-duty NGVs emit 19% to 29% less GHG emissions than their diesel counterparts. Light-duty vehicles emit almost 30% less GHG emissions compared to their gasoline equivalents. NGVs also emit 50-80% less air quality contaminants such as NOx, SOx and particulate matter.

Figure 25: GHG Emissions by Sector in B.C.[35]



Terasen Gas is currently proposing to leverage its existing infrastructure to adopt natural gas as a fuel for transportation use. Terasen Gas filed an application for Commission review in December 2010 seeking approval to introduce an energy delivery service that will offer compressed natural gas ("CNG") and liquefied natural gas ("LNG") for use in buses, heavy-duty and vocational trucks.

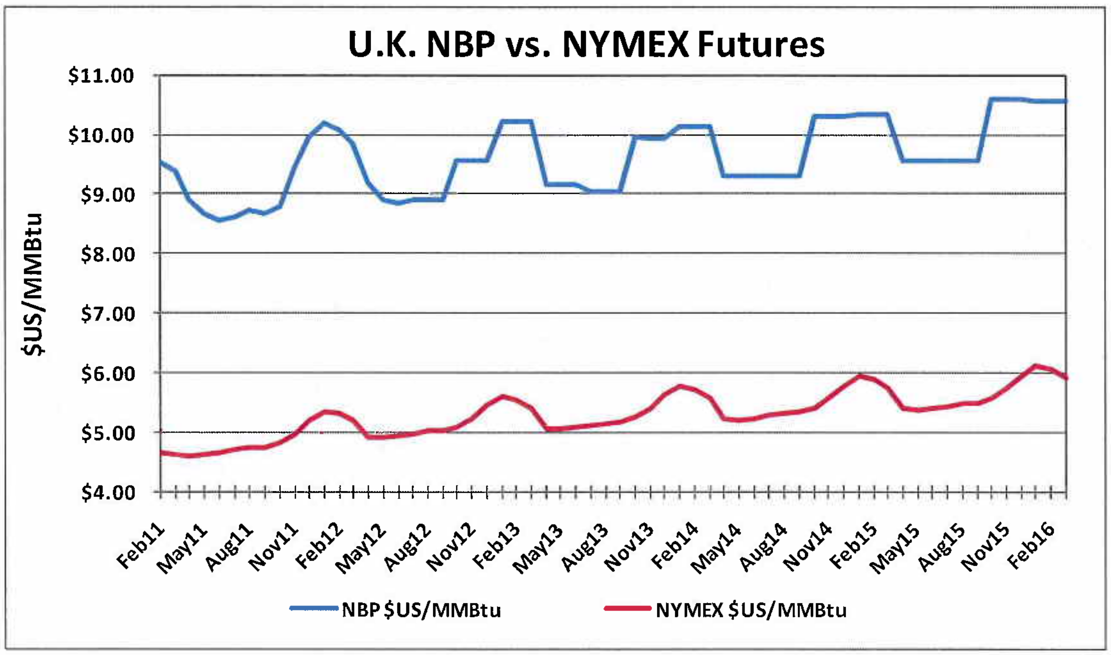
For governments to achieve fewer carbon and GHG emissions, natural gas will need to play a greater role within the transportation sector to help with achieving these objectives.

[35] http://www.oee.nrcan.gc.ca/transportation/tools/greenhouse-gas-info.cfm?attr=16

3.5 Other Sources of Demand for Natural Gas

Historically North America has been a net importer of LNG to help supplement domestic supply to match demand. However, there has recently been a shift in expectations of LNG importing activity. The shale gas revolution has caused a shift towards lower LNG imports into North America and more proposed LNG exports in North America to serve increasing global demand for natural gas. Supply sourced in North America can be shipped to either Europe or Asia, where demand is growing and prices are relatively much higher than in North America. Figure 26 depicts the futures price curve for natural gas deliveries in the U.K. at the National Balancing Point ("NBP"), the main delivery point for natural gas in Europe, and the NYMEX futures price curve, all as of January 1, 2011. Coupled with a current price differential and abundant North American gas stocks, there is a strong incentive currently to export LNG supplies to Europe and Asia.

Figure 26: U.K. NBP vs. NYMEX Futures Price



According to the EIA, there has recently been a dramatic decrease in LNG imports to the U.S. In January 2010, the EIA forecasted for about 1.87 Bcf/d of LNG imports in 2011 however, in January 2011 that forecast has been revised downwards for 2011 to about 1.13 Bcf/d.[36] This dramatic shift downwards may be attributed to two factors. Firstly, increased domestic supply from shale gas plays in North America reduces the need for LNG imports to supplement domestic production. Secondly, reduced LNG imports to North America can be a result of

[36] Energy Information Administration – Short Term Energy Outlook, January 2011

increased global natural gas demand, thus bidding away LNG supply that might have originally made its way to North America. Many industry observers feel that exporting U.S. natural gas may add more optionality for producers and allow them to fetch higher prices, which can be had abroad in Asia or Europe, for gas supplies.

Up until recently, most LNG facilities in North America were designed to be import facilities. However, there have been two recent applications to the U.S. Federal Energy Regulatory Commission ("FERC") and the U.S. Department of Energy ("DOE") for conversion of existing import only LNG facilities into LNG export facilities. These include Cheniere Energy and Freeport LNG, both Houston-based companies which own LNG terminals in the Gulf of Mexico. The proposed facilities will eventually have export capabilities of about 2 Bcf/d for Cheniere and about 1.4 Bcf/d for Freeport of domestically produced LNG. Expected start-up for these projects, provided they receive appropriate regulatory approval, is 2015. The uncertainty about whether these projects are ultimately realized through to production will depend almost entirely on their ability to secure the proper regulatory approvals from the various regulatory bodies in the U.S.

3.5.1 KITIMAT LNG

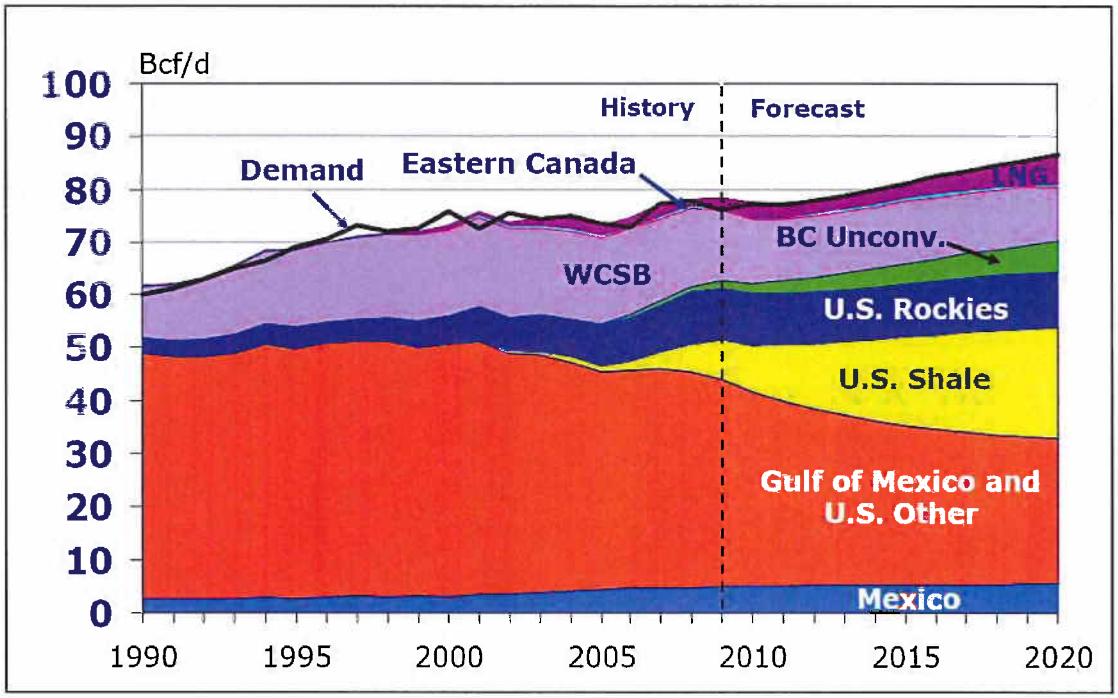
Kitimat LNG, a proposed export, liquefaction and send-out facility near Prince Rupert, is another potential source of natural gas demand, particularly in western Canada. When in service, Kitimat LNG will be able to initially export about 0.75 Bcf/d of natural gas to markets abroad. If this project proceeds, it will take gas supply from the WCSB and northeast B.C. and ship LNG to markets abroad, mainly to Southeast Asia and Japan.

In the long run, if more domestic North America supply is exported abroad via LNG it may cause natural gas prices in North America to increase in response to this increased global demand.

3.6 Summary – North American Supply and Demand Balance

In the recent past, the supply and demand balance in North America has generally been characterized by higher domestic demand than domestic supply with LNG imports making up the difference. The following figure helps to illustrate this point. Figure 27 shows the historical and forecast supply in relation to expected demand. Currently, however, domestic supply is greater than domestic demand due to depressed demand in response to reduced economic activity and strong production mainly from unconventional shale gas plays. The result has been record high storage levels and depressed natural gas prices.

Figure 27: Supply - Demand Balance to 2020[37]



As discussed in Section 1.2, North American gas demand is expected to recover in the future. The increase in demand for natural gas is expected to occur from power generation with coal plant retirements and increased electricity demand, increasing activity from the industrial sector as economic recovery continues, and increased use of natural gas in the transportation sector. This expected recovery in gas demand will tighten the current loose supply and demand balance and therefore may create the potential for higher prices and volatility in the future.

[37] TransCanada – North America Natural Gas Presentation, Bill Langford, September 28, 2010.

4 NATURAL GAS PRICES

Natural gas prices in North America are determined by the numerous supply and demand factors discussed in the previous sections. The factors that have been discussed are generally longer term in natural, impacting natural gas prices over periods of years rather than months. However, weather events and significant changes in the prices of competing fuels can have adverse affects on natural gas prices in the short term, for periods of several months or longer. Given the multitude of supply and demand factors and the ability to for some of them to change quickly and affect the supply and demand balance, prices have been very volatile and difficult to predict in the past. Looking forward, changes in future supply and demand factors will continue to impact natural gas prices and volatility. This section will explore historical natural gas prices and volatility, current forecasts for future prices and the factors that influence prices.

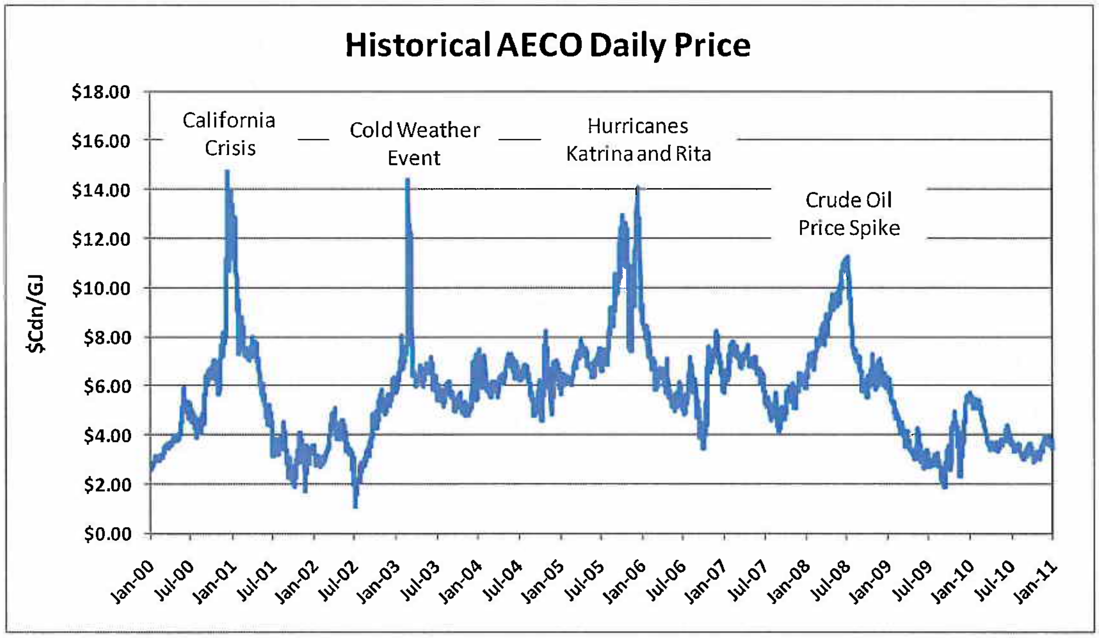
4.1 Historical and Current Prices and Volatility

Natural gas prices have been highly volatile in the recent past. There are a multitude of factors that have caused natural gas price spikes and great volatility in prices. Some of the factors that can affect natural gas prices in the short term are:

- Supply disruptions such as pipeline constraints during peak demand periods.
- Weather related supply disruptions such as hurricanes that knock production offline during the active hurricane season in the summer months.
- Unusually hot summer temperatures increase demand for natural gas for air conditioning loads. This is more important than in the past since natural gas is becoming more popular for power generation loads (as discussed previously).
- High demand for space heating in the winter months.
- Relative prices of competing fuels, such as crude oil or coal.

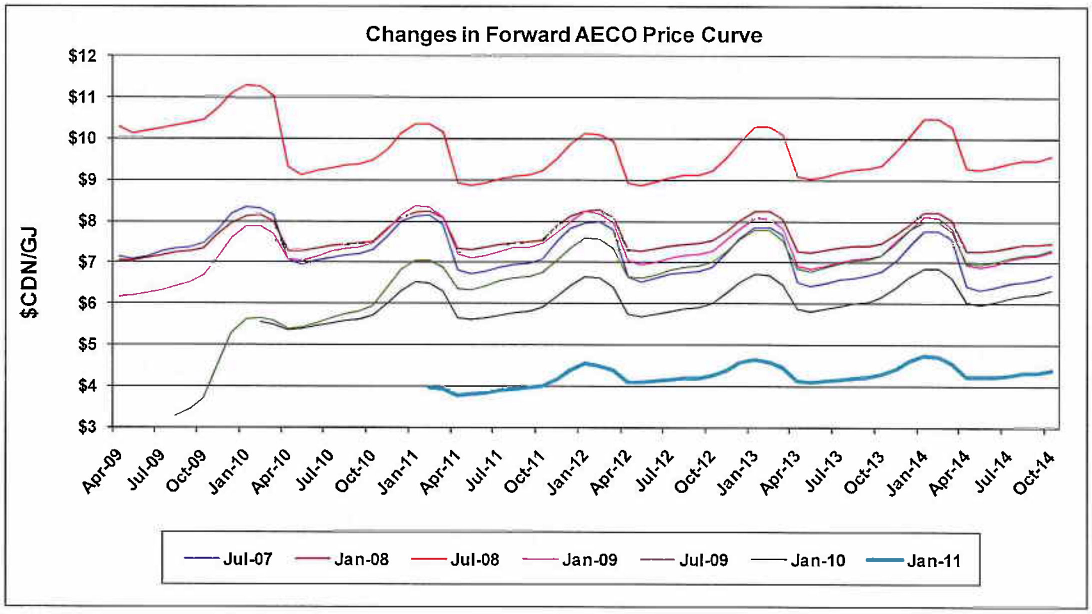
Typically, these factors affect natural gas prices temporarily but dramatically. For example, in January 2003 an unusually cold winter caused prices to spike and in the summer of 2005 the devastation of hurricanes Rita and Katrina negatively affected Gulf of Mexico production. It should be noted that gas price spikes are not only limited to winter periods but can spike even in lower demand summer months as was the case in the summers of 2005 and 2008. Figure 28 shows the actual daily AECO settled prices since January 2000.

Figure 28: Historical AECO Prices



This price volatility is also reflected in forward natural gas prices. Figure 29 shows AECO forward price curves at various points in time. The back end of the forward price curves, such as the summer 2014 term, have generally traded within a narrower band than the front end terms, such as summer 2009 or winter 2009/10, given the greater uncertainty of information and lower number of contracts traded for terms further out in time. Of particular note is the dramatic increase in the forward curve as of July 2008 compared to the previous curves and then the dramatic fall in the forward curve in July 2009, a price difference for winter 2009/10 of about $5.70/GJ in about twelve months. As the graph shows, the AECO forward curve as of January 2011 is at its lowest level of the last few years, due to the current environment of depressed demand and strong production levels.

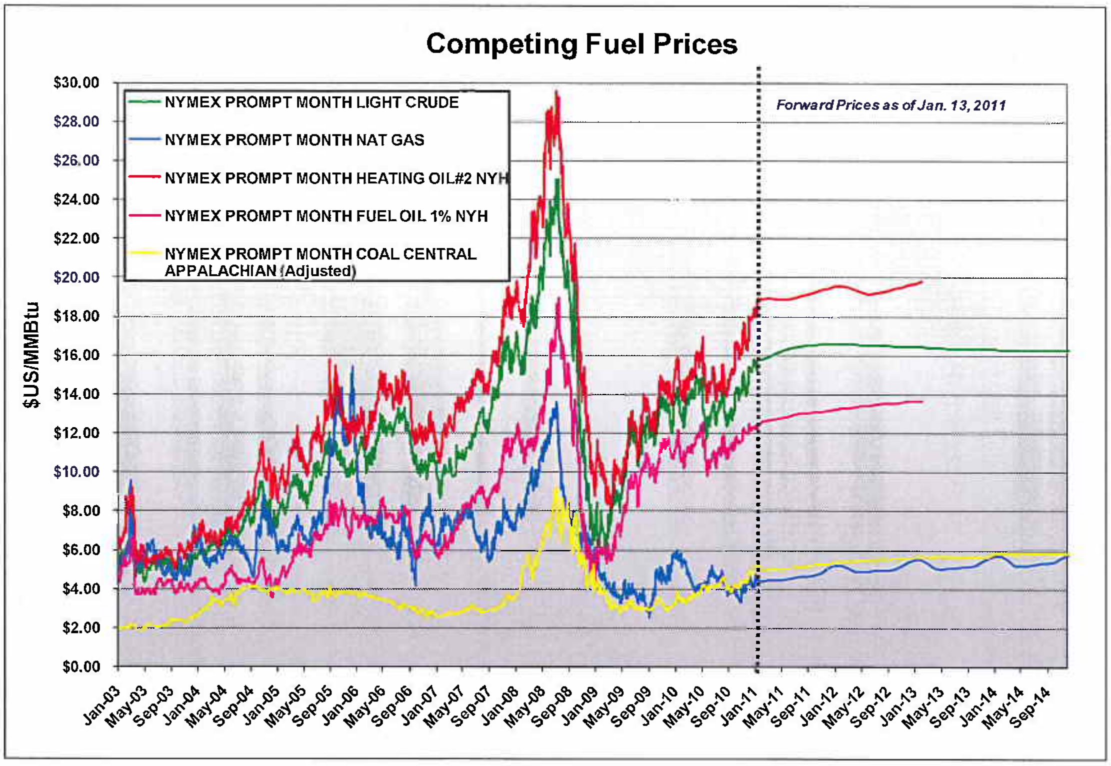
Figure 29: Forward AECO Price Curves



Gas prices can also be adversely affected in the short term by prices for other fuel sources. The run up in crude oil prices during mid 2008 dragged up prices for all other competing fuel sources as well. In particular, prices for heating and fuel oil and natural gas increased in response to higher crude oil prices. For 2008 the correlation between crude oil prices and natural gas prices was very high at approximately 88%. However, during the three years prior to 2008 and in the time since 2008 the correlation has averaged less than 16%. So, price volatility in crude oil prices can significantly and adversely affect natural gas prices regardless of the supply and demand balance in the natural gas market.

Figure 30 shows the actual prompt month settlement prices for crude oil, heating oil, fuel oil, natural gas and coal prices, with all prices standardized into $US/MMBtu for comparative purposes. Crude oil traded at an all-time high of about $145 US/bbl and NYMEX natural gas traded at about $14 US/MMBtu in 2008. At the present time, WTI crude oil, after hitting a post-2008 low of about $35 US/bbl in February 2009, is currently trading at about $90 US/bbl. NYMEX natural gas, after hitting a post-2008 low of about $2.50 US/MMBtu in September 2009, is currently trading at about $4.50 US/MMBtu. The futures prices as of January 13, 2011 are also shown in the graph.

Figure 30: Competing Fuels Prices ($US/MMBtu)

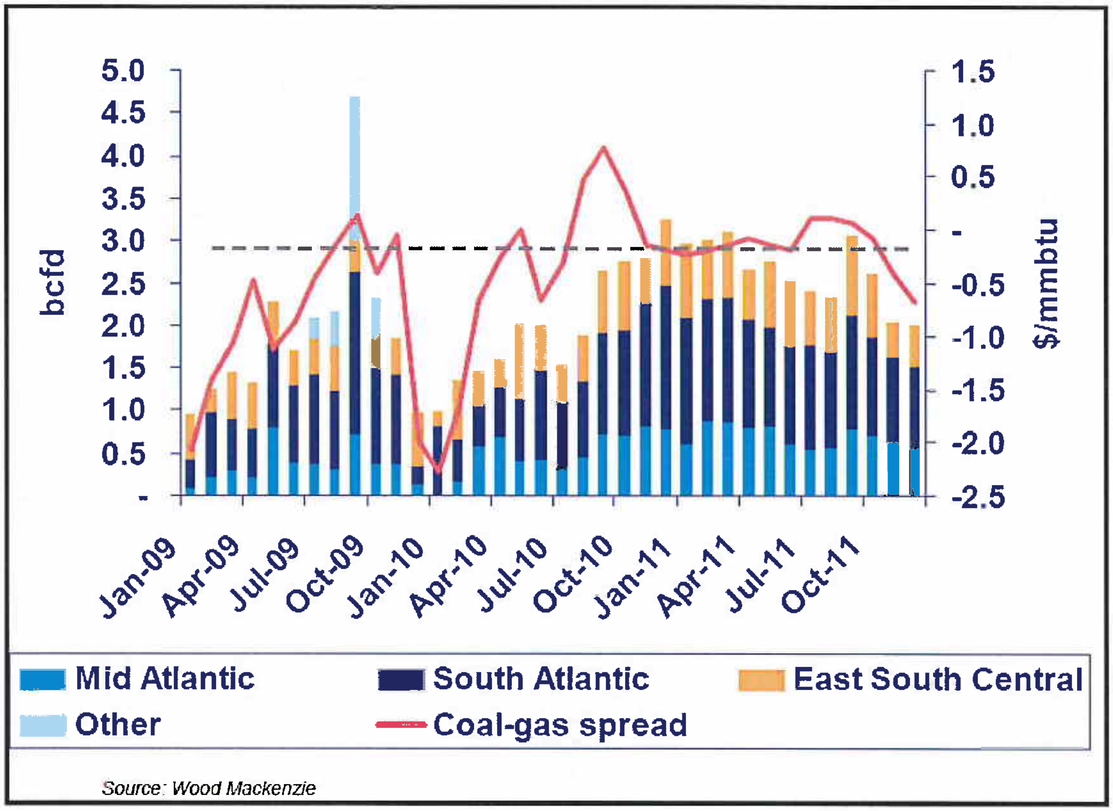


Historically natural gas traded within a band between heating oil (as the ceiling) and fuel oil (as the floor) and breakouts were seldom and short-lived. However, since heating oil and fuel oil typically follow trends in crude oil prices, the recent run up in crude oil prices has resulted in natural gas prices separating from both heating oil and fuel oil prices.

The next level of major support for the price of natural gas recently has been the price of coal. Coal provides a "soft" floor for natural gas prices because of the ability of some power generators to switch between natural gas and coal depending on market prices.

The level of fuel switching to natural gas depends on the relative prices of gas versus coal. The following figure shows that fuel switching can account for up to about 4.5 Bcf/d of incremental gas demand depending on the relative price differential between coal and natural gas. As the price differential widens in favour of natural gas, then the amount of gas substitution increases. An estimate of the current price levels and associated incremental volume demand is provided in the following figure.

Figure 31: Coal-to-Gas Switching vs. Price Spread[38]



These prices that encourage fuel switching change over time as supply and demand factors influence both natural gas and coal prices. For example, recently coal prices have increased in response to the cold winter weather in key consuming areas of the U.S. that has raised power demand and drawn down coal inventories faster than originally expected.

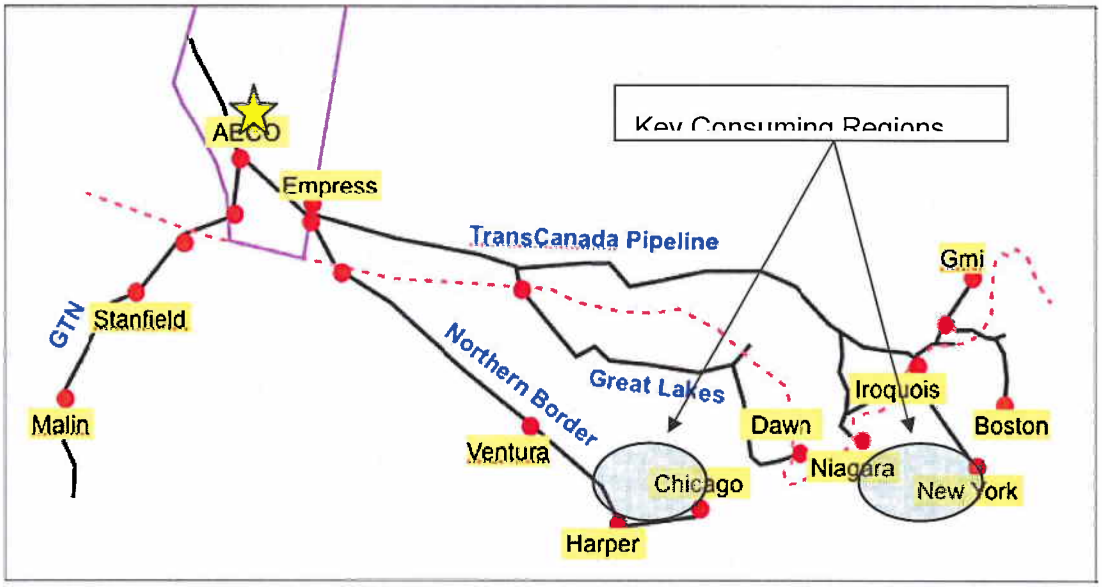
4.2 AECO Basis

The recent surge in unconventional supply has impacted North American prices in general but also affected the basis differential between eastern and western market hubs. As discussed in the supply section, the emergence of unconventional gas supply in the Marcellus region of the U.S. will lead to a decreased reliance on gas sourced from Alberta and B.C, all else being equal. As a result, this is leading to an increased level of decontracting on the TransCanada Pipeline ("TCPL") mainline system, which carries gas sourced in Alberta to key consuming regions in eastern Canada and U.S. such as Chicago and New York. Figure displays

[38] Wood Mackenzie – North America Gas Forum Key Messages, December 1, 2010

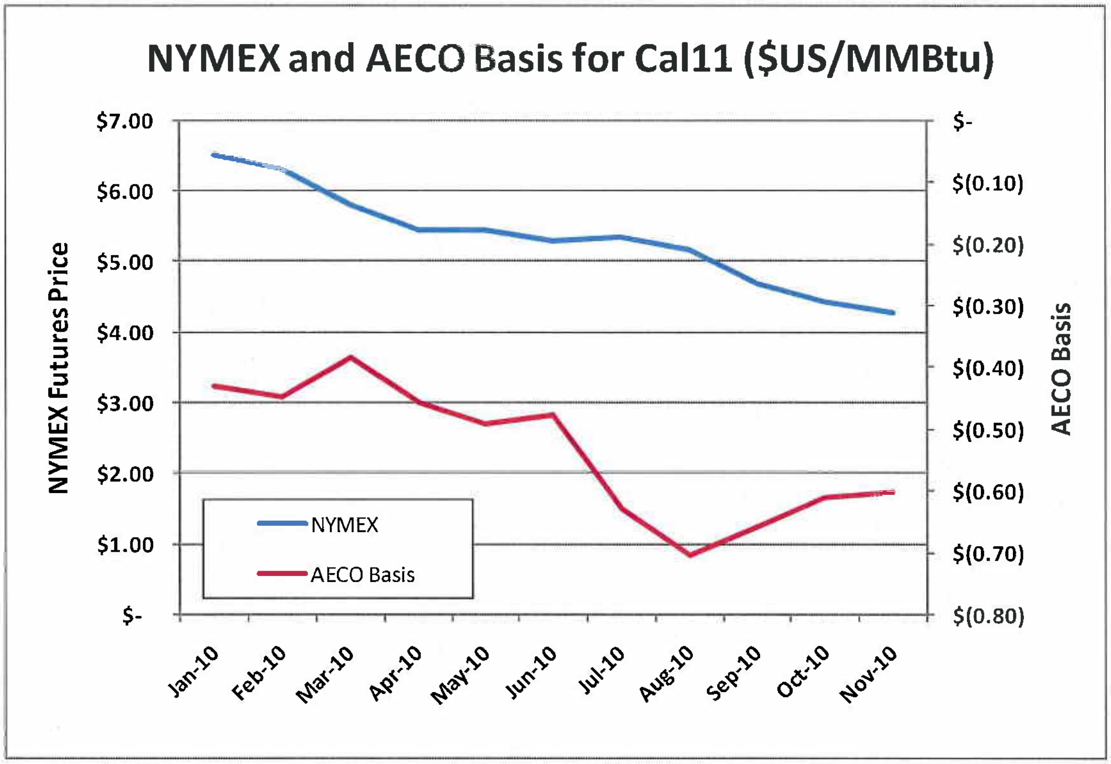
graphically the TCPL mainline pipeline that carries supplies from the WCSB to eastern Canada and U.S.

Figure 32: WCSB Supply Markets



The AECO basis, or differential from NYMEX prices, which is generally reflective of the cost to transport gas from AECO to the eastern markets, has widened recently largely in response to the increased supply for the east from the Marcellus play. The following graph illustrates this change during 2010 for the 2011 forward prices. Figure 33 shows the average NYMEX futures price and AECO basis for the period January 2011 to December 2011. The graph shows that while the average NYMEX price declined steadily throughout 2010 the AECO prices declined even more due to the widening AECO basis. Typically, in the past, as the NYMEX price declines the AECO basis, which reflects the variable cost of transportation of moving AECO supply to market, tightens, or decreases. However this was not the case for 2011 as the AECO basis widened largely due to increased Marcellus supply displacing some AECO gas for eastern markets.

Figure 33: Average NYMEX and AECO Basis for Calendar 2011



However, while AECO prices have decreased during 2010, along with other North American market hub prices, they too will be influenced by the numerous supply and demand factors that can impact natural gas prices and price volatility in general now and in the future.

4.3 Forecast Natural Gas Prices

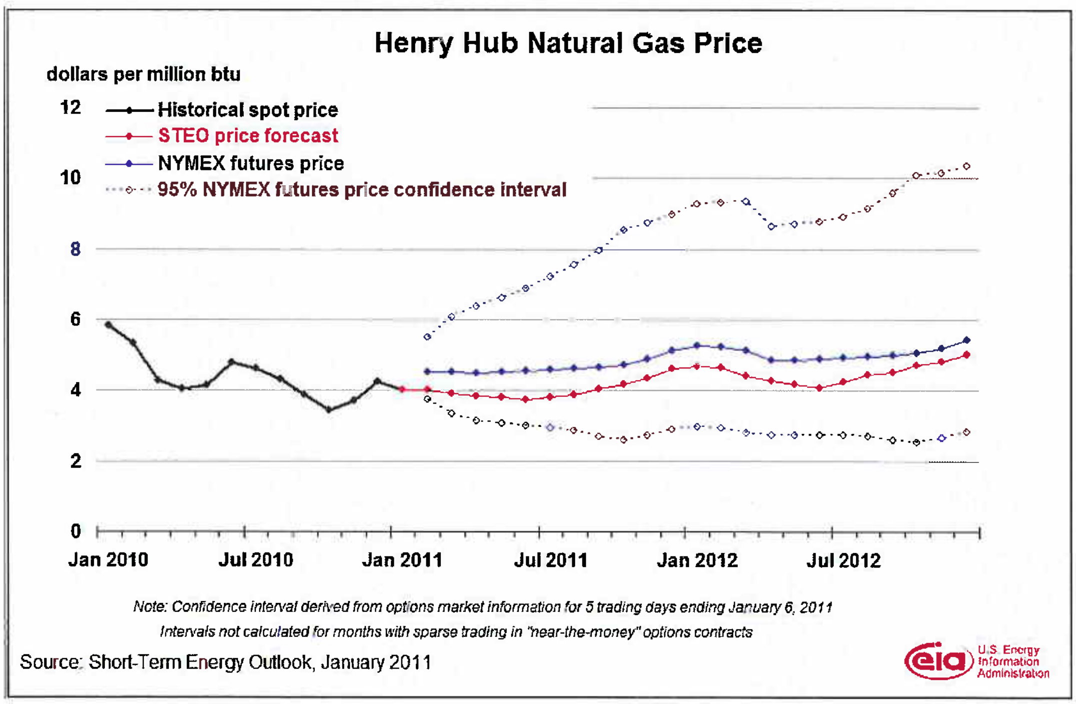
While natural gas prices are currently depressed relative to recent historical values, there is certainly the potential for higher prices and volatility going forward. The multitude of short term and long term supply and demand factors that have been discussed will certainly influence market prices and volatility in the years to come. Industrial demand recovery and increased demand for power generation will add to the demand for natural gas while natural gas supply growth will likely slow as producers seek higher netbacks from crude oil drilling. Hurricanes may also affect natural gas production in the Gulf of Mexico and the degree and extent of cold weather during future winters or hot spells during future summers will continue to significantly influence natural gas prices in the future. Crude oil prices continue to be volatile, influenced by global economic growth, China's demand for oil, the strength of the U.S. dollar relative to the Euro, OPEC production decisions, geo-political concerns such as Nigerian militant activity and Iran's nuclear program, speculative trading and hurricane activity.

Natural gas price forecasts take into account the longer term factors that influence market prices as the shorter term factors such as weather related impacts, while still possible, are more difficult to predict.

4.3.1 PRICE FORECASTS

Figure 34 displays the EIA Henry Hub natural gas price forecast as of January 2011. It also provides a 95% confidence interval forecast. This range indicates a 95% probability of the range of natural gas prices in the future. In other words, the EIA expects the December 2012 gas price to settle in between a range of about $3 US/MMBtu and $10 US/MMBtu with a 95% probability. This wide range of forecast future prices helps to underscore the fact there is great uncertainty with respect to future natural gas prices and that prices are very difficult to predict with any degree of accuracy.

Figure 34: Henry Hub Natural Gas Price Forecast[39]

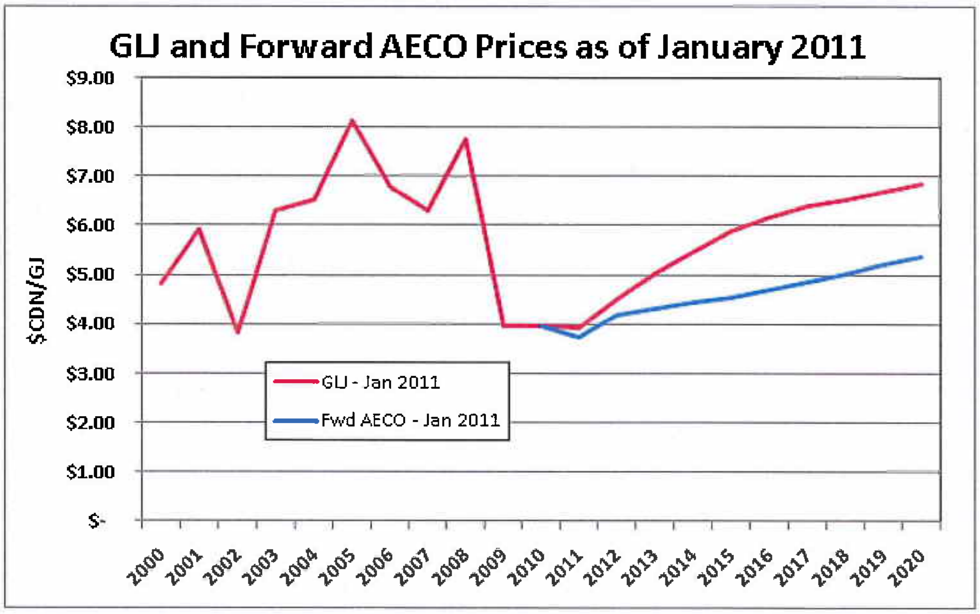


The long term AECO gas price forecast according to GLJ Petroleum Consultants Ltd. ("GLJ") as of January 1, 2011 is presented below as an independent source's assessment of supply and demand factors which influence forward prices. GLJ forecasts prices to average higher than the forward price curve average as of January 1, 2011 by about 25% due to GLJ's belief that

[39] U.S. Energy Information Administration

current forward prices are not sustainable and that long term prices should trend towards the marginal cost of new supply, which is believed to be above current forward market prices.

Figure 35: GLJ Price Forecast as of January 1, 2011 ($CDN/GJ)



4.4 Summary

This discussion of market supply and demand factors, historical prices and these price forecasts indicate that there is the potential for higher natural gas prices and price volatility in the future. As always, the degree of price movements and volatility is highly uncertain and difficult to predict with any degree of accuracy. The level of natural gas prices and volatility has a direct impact on Terasen Gas' competitive position and rate volatility. Therefore, management of market price risk is critical for Terasen Gas and its objective of offering relatively stable rates and cost effective gas supply for customers. This is particularly important for Terasen Gas also because of the unique natural gas marketplace in which it operates.

5 THE B.C. MARKETPLACE

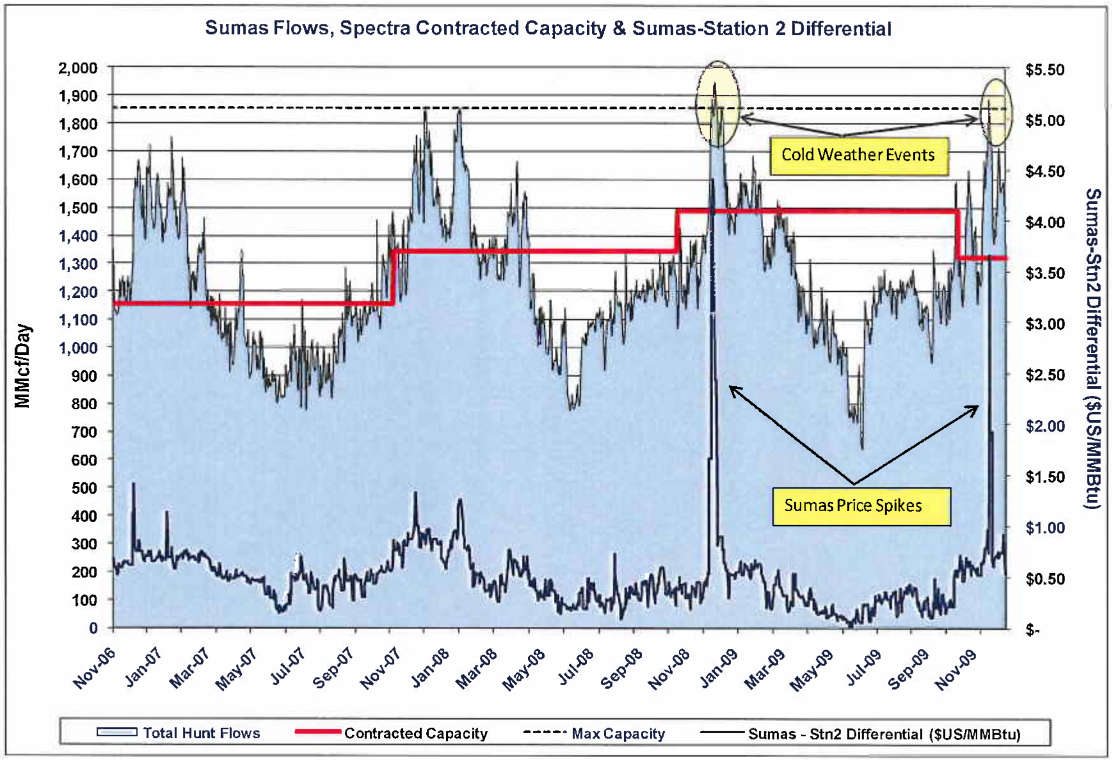
The B.C. marketplace has unique characteristics that present challenges for Terasen Gas. Terasen Gas operates in a region constrained by infrastructure which results in exposure to regional price volatility which is typically greater than that for NYMEX or AECO pricing. During periods of high demand, Sumas prices can disconnect and move significantly higher than other regional prices.

5.1 Constrained Regional Infrastructure

Natural gas deliveries made to and within B.C. are serviced primarily by only two pipelines. Spectra Westcoast ("Spectra") mainly delivers gas from northern B.C. to the Canada-U.S. border at Sumas and TransCanada's B.C. Foothills system delivers from the Alberta market into B.C. to East Kootenay and then down to the B.C.-Idaho border to Kingsgate.

Infrastructure, such as pipeline capacity and storage resources, in the Pacific Northwest ("PNW") is limited relative to demand from utilities and industrial customers in the area. For this reason, in times of high demand during colder winter months, pipelines will tend to operate at maximum capacity to serve heating demand load in the area. This constrained regional infrastructure in the PNW results in price volatility and uncertainty. The figure below shows actual pipeline flows at Sumas, contracted and maximum capacity on the Spectra system and the Sumas–Station 2 price differential from November 2006 to December 2009. During cold spells in December 2008 and December 2009, flows at Sumas exceeded maximum capacity temporarily. This also resulted in the Sumas daily price to disconnect from the Station 2 daily price.

Figure 36: Sumas Flows, Spectra Pipeline Capacity and Sumas-Station 2 Differential

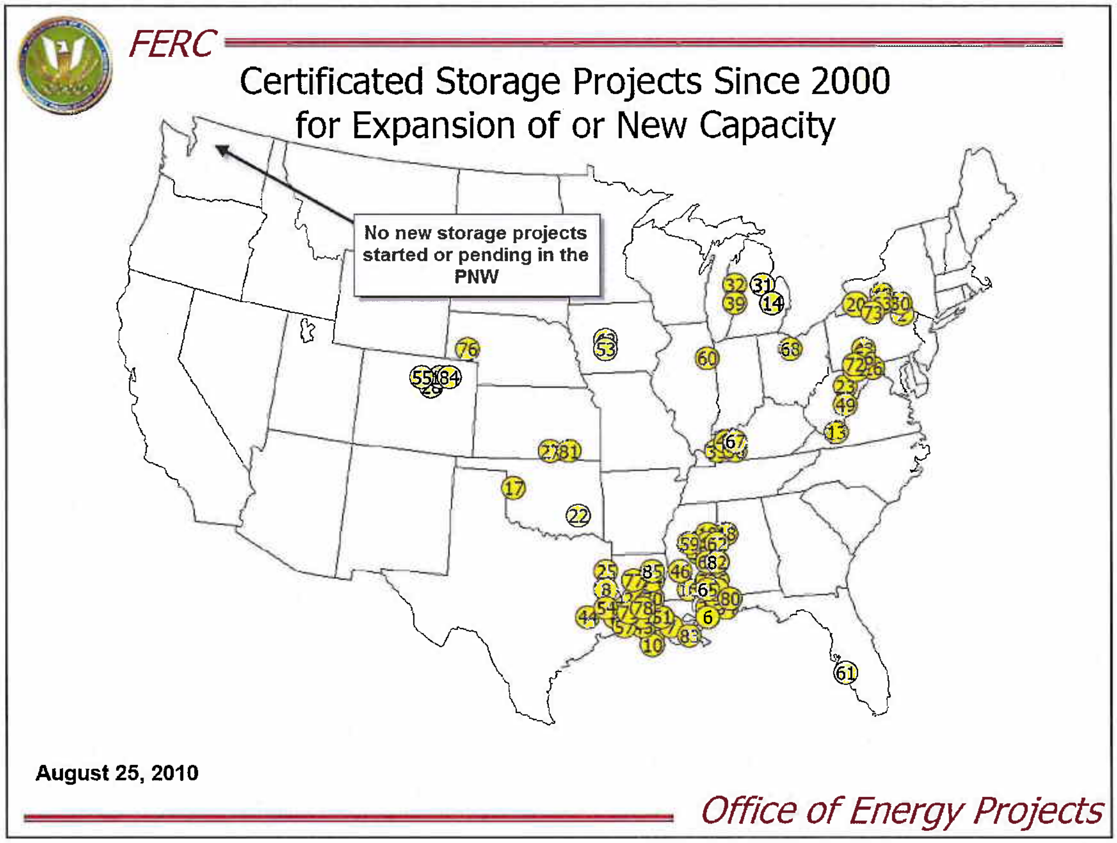


Constrained infrastructure in the PNW is most evident during periods of high demand on the pipeline systems in the region, typically during the winter months. This results in access by various utilities and businesses to limited resources to cause prices to spike abnormally and result in higher costs for customers. By contracting for regional storage, Terasen Gas can mitigate these price spikes to some degree by ensuring access to gas supply in times of high regional demand by accessing these contracted storage facilities.

Terasen Gas contracts for storage capacity at four storage facilities located in northern B.C., Alberta, Washington and Oregon. However, on an overall basis the availability of storage capacity in the PNW is limited. There are only two large storage facilities in the U.S. PNW; Jackson Prairie Storage ("JPS") operated by Puget Sound Energy, and Mist operated by Northwest Natural Gas Company. Both of these facilities are currently fully contracted and have no availability for additional contracted capacity. In addition to Terasen Gas' Aitken Creek storage capacity, JPS and Mist are used to supplement peak demand periods, particularly during colder winter months. The ability to nominate on an intraday basis for JPS and Mist allows Terasen Gas the flexibility to manage load swings and demand changes on a daily basis.

Limited storage capacity in the PNW is further illustrated in Figure 37, which shows expansion of or new storage capacity in the U.S over the past decade. Note the absence of any new storage or expansions of capacity in the PNW.

Figure 37: Expansion or New Storage Projects Since 2000[40]



Fully contracted regional storage in the PNW coupled with constrained regional pipeline infrastructure all lead to a tight supply-demand balance in the PNW during periods of high demand. These factors contribute to price volatility and upward pressure on prices in the PNW as demand in the region is expected to grow in the future.

5.1.1 REGIONAL PRICE DISCONNECTIONS

This constrained regional infrastructure often leads to regional price disconnections. Gas prices at the Sumas market are more susceptible to price disconnections, typically in the colder higher demand winter months. A period of price disconnection occurs when demand in the PNW,

40 Federal Energy Regulatory Commission

including B.C., results in insufficient gas deliverability at Sumas thus causing prices to increase significantly and disproportionately above Station 2 and AECO prices. The two figures below illustrate this period of price disconnection during the past two winter periods; winter 10/11 (to date) and winter 2009/10. Sumas prices disconnected from Station 2 and AECO prices during cold spells in the PNW which causing an increase in demand and maximum pipeline flows on Spectra Energy's system. During the past two winter periods the price at Sumas increased by $1.40/GJ and $4/GJ, respectively, over prices at AECO.

Figure 38: Daily Sumas less Station 2 and AECO - Winter 10/11

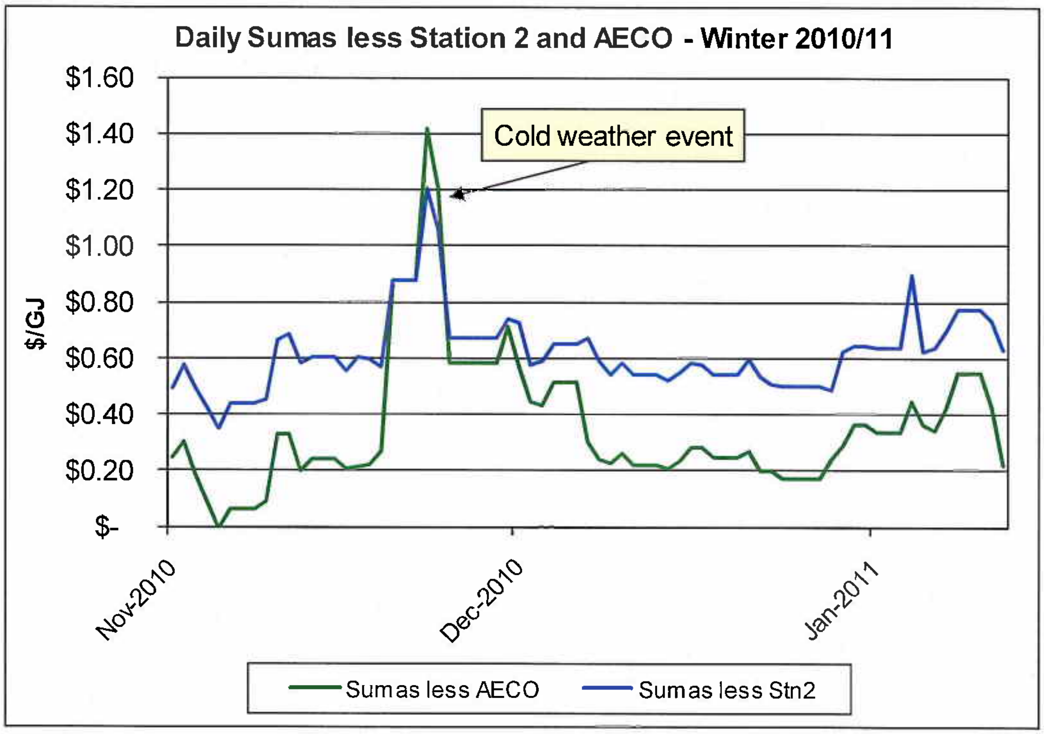
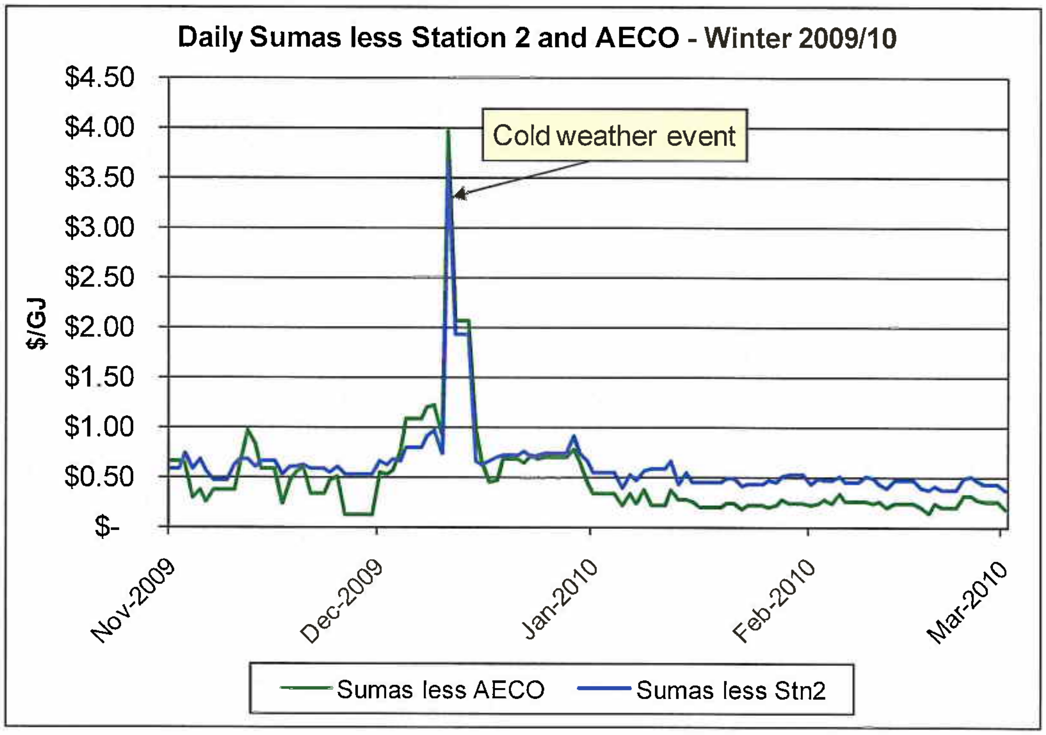


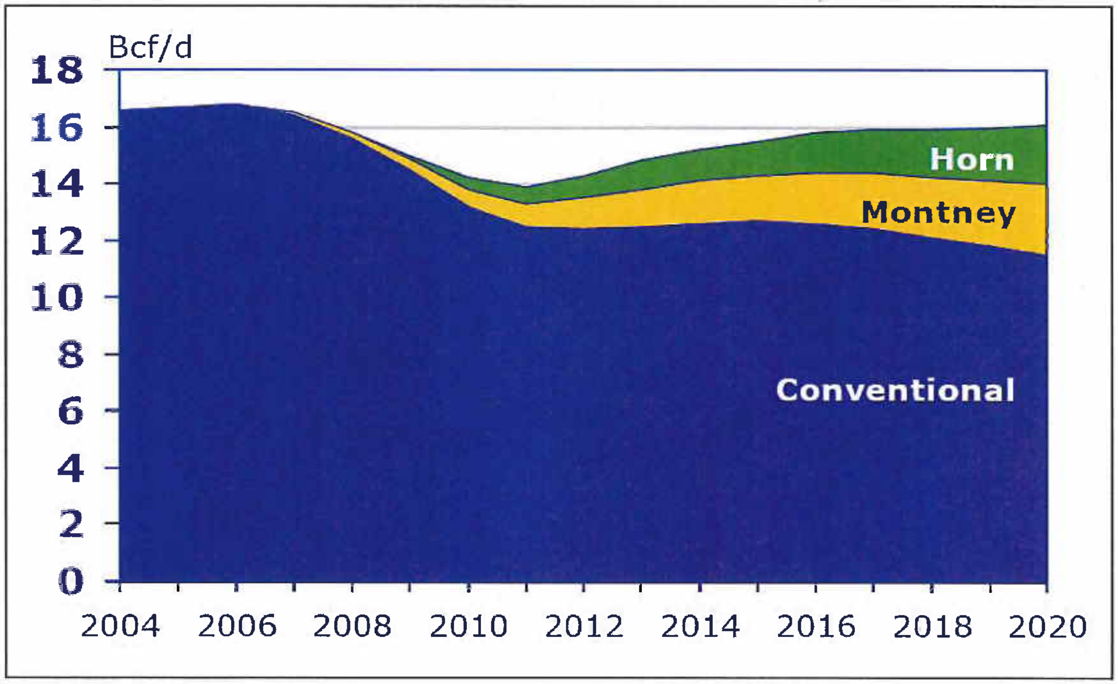
Figure 39: Daily Sumas less Station 2 and AECO - Winter 09/10



5.2 Supply and Demand Balance

While there is a surge in unconventional gas production occurring in north eastern B.C., particularly within the Horn River and Montney plays, export pipelines may move significant amounts of this new supply to eastern, overseas markets (via LNG export) and Alberta oil sands production. The full potential of these gas plays will only be realised if the infrastructure is available to connect these supplies to markets outside of B.C. Furthermore, although supply from the Horn River and Montney regions is expected to steadily increase to over time, these increases may not fully offset the decline in conventional production that has occurred since 2006. Figure 40 shows forecasted supply originating from the WCSB out to 2020.

Figure 40: WCSB Supply Forecast[41]



Although the developments in shale gas production in northeast B.C. are among the most prolific in North America, offsetting demand for this supply will ensure that regional natural gas prices and volatility will continue to be influenced by the supply and demand factors that affect North America prices in general. Furthermore, during period of high demand in the PNW, regional infrastructure constraints will likely continue to result in Sumas price disconnections in the future.

[41] TransCanada – North America Natural Gas Presentation, Bill Langford, September 28, 2010.

6 SUMMARY

History has shown that natural gas prices are volatile and difficult to predict with any degree of accuracy. This is not expected to change going forward. Numerous supply and demand factors can influence natural gas factors over the long run, while weather, production disruptions and competing fuels prices can adversely impact prices in the short term. The natural gas supply picture has changed significantly in just a few years, with some of the largest developments taking place in B.C. The costs of producing and drilling have been reduced through technological advances such that near term natural gas prices look more favourable than they had just a couple of years ago. However, there is still a great deal of uncertainty with regard to future prices given the multitude of supply and demand factors that can impact prices. While prices are currently depressed due to weakened industrial demand and strong production, recovery in industrial demand, increased demand for natural gas from power generation and an easing in production growth will tighten future supply and demand balances and potentially lead to higher prices and volatility in the future. Furthermore, this abundant supply situation is largely the result of factors unaffected by low market price signals, such as producer hedges and drilling to hold land leases. As has been discussed, this will likely result in reduced supply growth once these hedges and lease hold conditions expire after 2011 and natural gas prices are not likely to be sustainable at current levels.

Ultimately, higher prices and volatility impacts Terasen Gas' competitive position relative to other sources of energy and affects Terasen Gas' ability to manage rate stability and ensure cost effective supply for customers. Therefore, Terasen Gas believes it is prudent and appropriate to manage this price risk going forward in the best interests of its customers.