CANADA WEST FOUNDATION POWERING UP FOR THE FUTURE INITIATIVE

Seismic Shifts

THE CHANGING WORLD OF NATURAL GAS

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Powering Up for the Future Initiative

The Powering Up for the Future Initiative focuses on public policy challenges at the interface of the economy, the environment and energy. Powering Up is driving informed discussion on policy choices shaping our energy future, for the benefit of western Canada and all Canadians.

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Executive Summary

Natural gas has been a key part of the Canadian economy for many decades. It has generated strong returns for Canadian industry and governments while providing secure and affordable energy for consumers across the country. Because of the recent development of shale gas, the world in which Canada's natural gas industry operates has fundamentally changed. Public policy needs to be adapted judiciously to deal with this new reality.

This report starts with a reminder of the benefits of natural gas to Canada over the past 50 years and how sound and stable public policy has ensured that the benefits have spread across the country. Driven by the emergence of shale gas, however, many expectations have been turned on their heads. Shale gas has created conditions immensely favourable to *consumers*, but with mixed implications for Canadian *producers*. As we consider the implications of this seismic shift, we need to be cautious about forecasts and keep history in mind. Above all, policymakers need to avoid reinventing the wheel or making public policy hostage to forecasts that may well prove incorrect.

We then examine two different perspectives on the new world of natural gas: a consumer's perspective and a producer's perspective.

For consumers, the news could hardly be better. US and Canadian natural gas resources are abundant, secure, reliable and relatively low cost. They look to stay that way well into the future. Just as important, natural gas has a long and growing list of applications in energy markets that will give consumers multiple options. This will create flexibility in the energy system that will help underpin economic competitiveness, provide us with an affordable and practical way forward to reduce greenhouse gas emissions, and provide a long-term foundation for a clean, diverse and resilient energy system.

Canadian producers, however, face several challenges. Canadian natural gas resources are immense, but so are those in our one currently available export market—the United States. Relatively slow growth in the US economy will mean soft energy demand growth overall. This is a good thing for the environment, but a challenging context for energy suppliers. Many Canadian natural gas plays are cost-competitive, but the challenges of remote northern production conditions and distance from markets mean that many Canadian producers, and the jurisdictions in which they operate, will face thinner returns than we have come to expect over the past decade.

Out of all of this we draw several implications for policymakers. Policy should:

- reaffirm the basics—markets work and we should be cautious about calls from interest groups for governments to somehow fix things;
- recognize natural gas as a foundation of a sustainable energy future—including one in which greenhouse gas emissions are steadily declining;
- keep the consumer front and centre and make sure energy policy emphasizes consumer value, safety, reliability, affordability and choice;
- approach carbon management through pricing rather than regulation—in an even-handed carbon pricing environment, natural gas is a strong competitor that will contribute to reducing Canada's greenhouse gas emissions;
- be adaptable to future uncertainties—avoid trying to pick winners and use performance measures in preference to specified technologies when designing programs or regulations; and
- help Canadian producers to deal with our competitiveness challenges by facilitating access to Asian markets, making environmental approvals more efficient, and ensuring that fiscal regimes are competitive in a Canada-US context.

Canada's natural gas world is changing: potentially underpinning a truly sustainable twenty-first century energy revolution, potentially growing bigger as we reach to other markets, and continuing to generate economic opportunities and fiscal returns to governments. Natural gas has been good for Canada for over half a century. With sound public policy, it will continue to be good for Canada far into the century ahead.

1. Natural Gas is Good for Canada

Natural gas has been a core component of the North American energy system since around 1960. Natural gas markets in North America have evolved over those five decades—most recently from a widely held expectation of declining productive capacity and increasing imports to growing productive capacity, domestic oversupply and soft prices. To attempt to understand where we might be going in the next decade it is important to keep an eye on history, consider the contributions of natural gas to Canada's wellbeing, and reflect on the conditions that contributed to that value.

The role of natural gas in the Canadian economy increased significantly after the 1973-1979 oil crises and accelerated again in the late 1980s after deregulation of the market and the implementation of the Canada-US Free Trade Agreement. Before deregulation and free trade, natural gas was essentially treated as a strategic commodity governed by significant regulation. This included government price setting and controls on exports and mandated reserve-to-production levels.[1] As reserve restrictions were relaxed and trade barriers were lifted, investment levels in Canadian natural gas jumped, as did Canadian production levels and export flows. Contrary to the dire expectations of some, the changes—including the drawdown of reserves—caused wholesale prices to decline even as energy flows expanded across the Canada-US border. Therefore, as producers benefited from new investment and freer access to the US market, consumers enjoyed competitively low pricing and a system designed to attract investment in new supplies.

These investments expanded the western Canadian natural gas industry, created jobs, generated government revenues, and improved national energy security by adding to supply. Canada was well on its way to becoming the world's fifth largest energy producer, the third largest natural gas producer and the largest energy supplier to the US that it is today. Natural gas has been a significant source of economic strength in western Canada and it will continue to create jobs and contribute to a strong economy well into the future (see Appendix A). From a consumer's perspective, natural gas now accounts for about one-quarter of Canadian energy end use as well as a growing share of fuel for electricity generation.[2]

Shifting conditions in the world around us both enhance some of the benefits of natural gas and put others at risk. The emergence of shale gas has fundamentally changed the game.[3] Shale gas was being minimally produced until recently. In 2000, shale made up only 1% of total US natural gas supplies (Yergin 2011). In the US alone, shale gas has increased technically recoverable natural gas resources by close to 50% over the last decade. Some 63% of Canadian production and 26% of US production is expected to come from shale gas in 2035 (US Energy Information Administration 2010b).

1 Export licenses would be granted by the National Energy Board only after a determination that Canadian reserves would remain at or above a specified number of years of consumption.

2 The term "end use" refers to the energy being used by the actual consumer of energy as opposed to gas used for electricity generation, which is considered "intermediate use" with the generated power consumed defined as "end use."

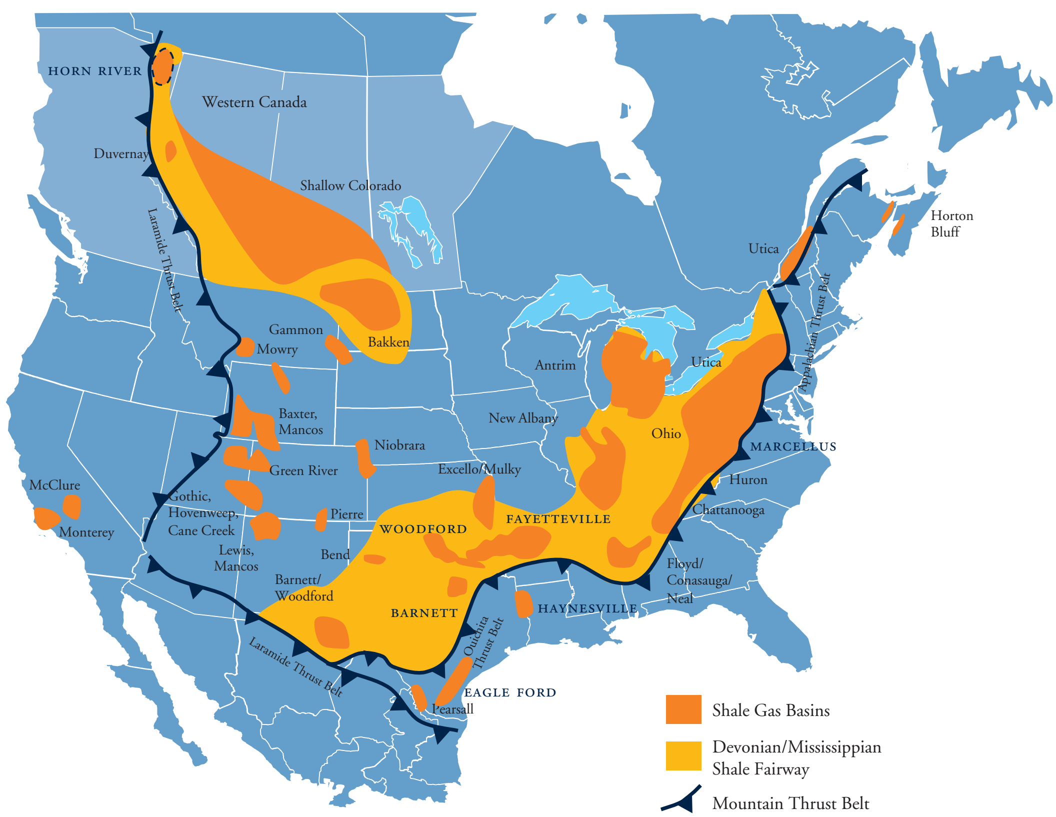
3 The first commercial gas well in the US, drilled in New York State in 1821, was in fact a shale gas well (Massachusetts Institute of Technology Energy Initiative 2011). However, because such limited amounts of gas were actually produced from these shallow, difficult to fracture, impermeable rock formations, these plays were easily overlooked. Technology has fundamentally changed this fact.

WHAT IS SHALE GAS?

"Shale gas" is natural gas that has been trapped in very fine-grained rocks usually called shale. Millions of years ago, burial, heat and increasing pressure caused mud and silt from ancient oceans to form into shale. Organic materials contained within the mud and silt turned into natural gas. Some of the natural gas migrated from these shales to form "conventional" natural gas reserves. The natural gas that remains locked in the rock is known as "shale gas." The advents of hydraulic fracturing (where a mixture of highly pressurized sand, water and chemicals is discharged to cause fractures in the sediment) and horizontal drilling have made it possible to release the natural gas (Canadian Society for Unconventional Gas 2010).

Shale gas has also changed the geography of natural gas supply because of the distribution of shale deposits (see Figure 1). These shifts have changed the game for western Canadian natural gas producers. More natural gas is not only being found, it is also economically feasible to produce in vast areas of the US and potentially in eastern Canada. This is creating strong competition for western Canadian natural gas, which faces disadvantages of both distance to markets and more costly production due to remoteness and seasonality.[4]

FIGURE 1: MAP OF NORTH AMERICAN SHALE GAS RESOURCES

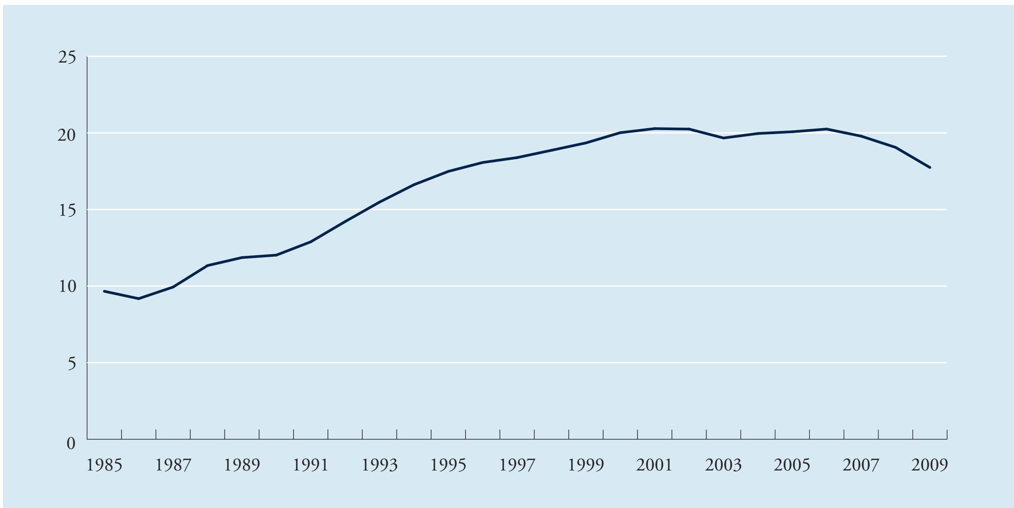


Source: Ziff Energy Group (modified by the author)

4 It is estimated that a natural gas well in Alberta is 12-14% more expensive to drill than one in the US with identical technical specifications (Government of Alberta 2010).

Canadian natural gas production from conventional reserves began to decline around 2006 (see Figure 2). That decline was reflected in reduced export sales such that Canadian natural gas now supplies 14% of US consumption compared to the almost 17% peak in 2005 (US Energy Information Administration 2010a). Until recently, the anticipated natural gas story in Canada was one of slowly declining production feeding a tight and high-priced North American market that was expected to rely increasingly on liquefied natural gas (LNG) imports. The shale gas revolution has changed production prospects in Canada for the better, but it has also lowered prices and unhinged our competitive position.

FIGURE 2: CANADIAN MARKETED NATURAL GAS PRODUCTION (BCF/D)



Source: Canadian Association of Petroleum Producers (2011a)

Total US natural gas production increased from 53.2 billion cubic feet per day (BCF/d) in 2006 to 59.2 BCF/d in 2009 (see Figure 4).[5] This increase is made all the more remarkable by the fact that it occurred during a major recession and at the same time that conventional reserves were in relatively steep decline (Park 2010). North America is now looking at a supply that experts suggest could last more than a hundred years at current consumption rates. The revival in production has flooded North American natural gas markets and foreshadows an era of persistently low prices. With the US increasingly able to feed its natural gas markets with shale gas at significantly lower costs than importing natural gas from Canada, and eastern Canadian customers potentially able to access eastern US supplies, western Canadian producers are at a competitive disadvantage.

5 See Appendix B for information on the units for measuring natural gas.

WHY DRILL IF THE PRICE IS LOW?

There has been much speculation into the economics of drilling for shale gas in the face of soft prices. Some producers are drilling despite prices below their apparent supply cost. There are several reasons for this. The production could be hedged by forward prices locked in before the onset of current prices. Land positions may need to be protected by living up to drilling obligations. Probably most importantly, many shale plays are "liquids-rich" and high oil prices drive the price of natural gas liquids. "Liquids" are other petroleum resources like butane, pentane and propane that can be present in shale gas plays. In these cases, the "dry" gas is essentially a by-product and not the main focus of the play.

The positive news for consumers should not be allowed to get lost in this story. Natural gas is potentially the sole part of the energy system not facing increasing commodity costs in the coming decade. Given its abundance and relatively low greenhouse gas emissions, natural gas is a natural foundation fuel in an increasingly carbon constrained world. While North American energy demand will grow only slowly in the coming decades, environmental and cost constraints on other energy options could make natural gas an even more competitive option. Natural gas has an opportunity to increase its overall market share of North American energy consumption even as energy consumption in general grows ever more slowly in the face of increased efficiency. The same is potentially true in global markets where North American (including Canadian) supplies would be competitive, although a global natural gas market has yet to fully emerge.

How and when a global market emerges will define Canada's "world of natural gas." The "world" of natural gas for Canadian producers and consumers has essentially been North America since the mid-1980s. Over the past ten years, we have seen signs that this reality might change, and to the extent that it does, it should be all the better for both consumers and producers because it can extend both supply and market options.

One thing the natural gas "world" is not about is Canada alone. Although the early dynamics of natural gas in Canada were dominated by the building of the TransCanada Pipeline bringing Alberta natural gas to Ontario, virtually every major development since, from the building of the West Coast system in BC to the recent development of a major liquefied natural gas (LNG)[6] regasification plant in New Brunswick, has been driven by North American market dynamics. Half of Canada's domestic natural gas production is exported, all of it to the US. Canadian consumers use mainly Canadian natural gas, but much of it transits through the United States and US natural gas looks likely to be increasingly competitive in eastern Canadian markets. US consumer choices dominate the demand dynamic for Canadian gas and prices are driven off US market hubs in Louisiana and Illinois.

How this world might change in the future is outward—in two directions.

6 There are two ways to transport natural gas: in gaseous form via pipeline or in liquid form, usually via tankers.

For the last decade, natural gas market observers have recognized the growing potential for North American imports of LNG mainly through the US Gulf Coast. As it turns out, the expected volumes have not materialized, much to the dismay of investors in LNG regasification capacity. For North American consumers, on the other hand, this underutilized regasification capacity creates potential to mitigate price volatility and add to already highly secure supplies. Connecting to the wider world is a good thing.

Connecting to the wider world in the other direction, i.e. exports, could also be a good thing. North American natural gas suppliers face a potentially long period of market oversupply and low prices. In growing Asian markets, with large and growing energy demand, most supply is in the form of LNG and prices are set by oil-indexed contracts. LNG prices have thus remained high, increasing the price disconnect (and potential value of trade) with North America. Recently, the Asian spot LNG average price has hovered around $10 per million British thermal units (Reuters 2011). Extreme sensitivity to security concerns in industrial economies with little indigenous energy supply such as Japan, Korea and Taiwan and a fast growing Chinese market combined with prices based on long-term contracts linked to oil, currently in the vicinity of $100 per barrel, make Pacific Basin natural gas prices potentially very attractive to North American suppliers.

Canada is moving more quickly to tap the Asian market than the US (though not as fast as other Pacific basin players) with an increasingly viable project at Kitimat, BC with potential to move natural gas into Pacific markets by 2015. In North American terms, the initial volumes are not large (about 1% of North American demand) and will have virtually no impact on North American prices. For western Canadian suppliers, on the other hand, the potential for improved netbacks is significant and investors are voting with financial commitments.

This is a development of strategic significance for Canada. As it currently stands, we are tied to a single export market for natural gas, and that market is significantly oversupplied and looks to be for the long-term. Further, despite broadly favourable trade relations, Canada-US trade is subject to all manner of capriciousness on the political front driven by environmental aspirations or thinly disguised protectionism. Options, especially in the fast growth markets of Asia, are in Canada's interests. Finally, as we have seen time and again over the past thirty years, good policy that is in producer and investor interests can also be in the interests of both government revenue agencies and domestic consumers.

From both a supply perspective, with imports of LNG in North America's east and south, and from a demand perspective, with the opening of exports in the West (and possibly the North some day), Canada's world of natural gas will work better for everyone the larger it grows.

A WESTERN CANADIAN FOCUS

The natural gas story in Canada is one that matters to customers in all but two provinces (PEI and Newfoundland and Labrador) and gas production is an east coast offshore story as well as a western story with future promise onshore in Quebec, Nova Scotia and New Brunswick. That said, the natural gas industry in Canada is essentially western and concentrated in Alberta and BC. Therefore, while this report looks at the overall North American marketplace and the benefits to consumers throughout Canada and North America, its production focus is western Canadian.

Good public policy is critical

These shifting conditions have resulted in many uncertainties for the western Canadian energy sector and raise important questions for all Canadian energy policymakers:

- → How large is the economic natural gas resource base opened up by shale gas in North America?
- → How will environmental concerns and public opposition play out in the development of shale gas?
- → How will Canadian producers maintain a competitive position in North American natural gas markets?
- → How fast will natural gas move from a continental to a global market?
- → Will natural gas occupy a growing share of the total energy market and what will be its role as we move toward a more sustainable energy future?
- → How will carbon policy measures such as carbon prices or caps, renewable mandates or subsidies affect natural gas?
- → How will governments respond to reduced fiscal returns from natural gas?

While the outlook is uncertain, governments do have latitude to design policy that is robust and can make the best of whatever hand we are dealt in the coming decade. In the face of the historic strength of natural gas as a western Canadian asset, combined with these recent developments, this report looks at the future prospects for natural gas for consumers in North America and for producers and governments in western Canada. It seeks to address the impact of shale gas on the energy system and provide a framework for understanding the implications for policymakers, upstream producers, transmission companies, distributors and customers.

FORECASTS SHOULD BE VIEWED WITH CAUTION

Public policy necessarily relies on forecasts, and well-grounded forecasts provide many insights for policymakers. But they also create traps. The following sections of this report cite various forecasts and make assertions about how the future looks set to unfold. However, we should always be cautious.

In its 1999 report, the US National Petroleum Council (NPC) made the following statement: "US natural gas productive capacity [is projected] to increase from 19 TCF in 1998 to 25 TCF in 2010, and could approach 27 TCF in 2015" (National Petroleum Council 1999). A much gloomier future was suggested by its 2003 report: "It now appears, however, that natural gas productive capacity from accessible basins in the United States and Western Canada has reached a plateau" (National Petroleum Council 2003). The 2003 forecast proved more accurate, as annual US natural gas production over the decade 2000 to 2010 only slightly exceeded the 1998 figure, averaging little more than 20 TCF per year.

On the demand side, the prognostications were equally far off. The 1999 study projected that US natural gas demand would grow from 22 TCF (including net storage fill) in 1998 to approximately 29 TCF in 2010 and could rise beyond 31 TCF in 2015. Actual demand has been approximately flat, although the mix has changed as demand has shifted out of industrial use and toward electricity generation.

Price outlooks were equally off the mark. The 1999 report saw a price band out to 2010 of $2.50 to $3.50 (per mmBtu). By 2003, the increasing evidence of market tightness led to a projected price band over the decade of approximately $4.00 to $6.00. According to the BP Statistical Review of World Energy 2010, the actual annual average price for the remainder of the decade was above the projected band in every year except 2004 (when it was $5.85) and 2009 when it fell below (to $3.89).

The point of the above discussion is not to cast aspersions on the NPC, which is a highly reputable body with access to the best data and analysis available. In fact that is just the point. Even the best of the experts can get trapped in expectations of the future driven mainly by conventional wisdom and the recent past; in 1999, a recent historical trend line for natural gas production and demand would have mirrored the NPC's outlook to an uncanny degree.

Today the continuing success in shale production combined with several factors that have sustained production drilling at levels that are not strictly economic, along with the persistence of US economic weakness mean that the market remains oversupplied. Current prices reflect this. Unsurprisingly, many commentators are now projecting a medium-term future with a strong resemblance to the present and the immediate past.

It would be wise to keep the cautionary tale of the last decade firmly in mind as we think about the coming one. Forecasts can be upset by surprises from many directions and public policy should be robust under multiple scenarios.

2. The Outlook for Consumers

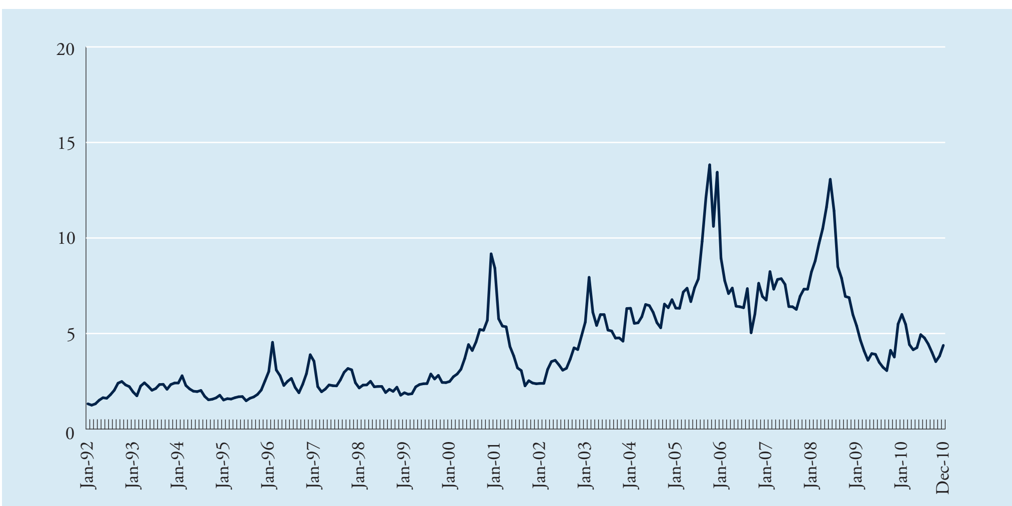
Natural gas and its delivery system are part of the foundation for a sustainable energy future

The past decade witnessed a North American natural gas market in tight supply/demand balance with prices trending steadily upward and marked by volatility (see Figure 3).

Weakening productive capacity in both the US and Canada (see Figure 4) and the lagged emergence of LNG import capacity led to expectations that natural gas was somehow running out even though estimated resources were around 80 years at then current consumption rates. Expectations were that governments would radically suppress fossil fuel use and that renewable sources would easily take up the slack. Natural gas was increasingly dismissed as yesterday's fuel.

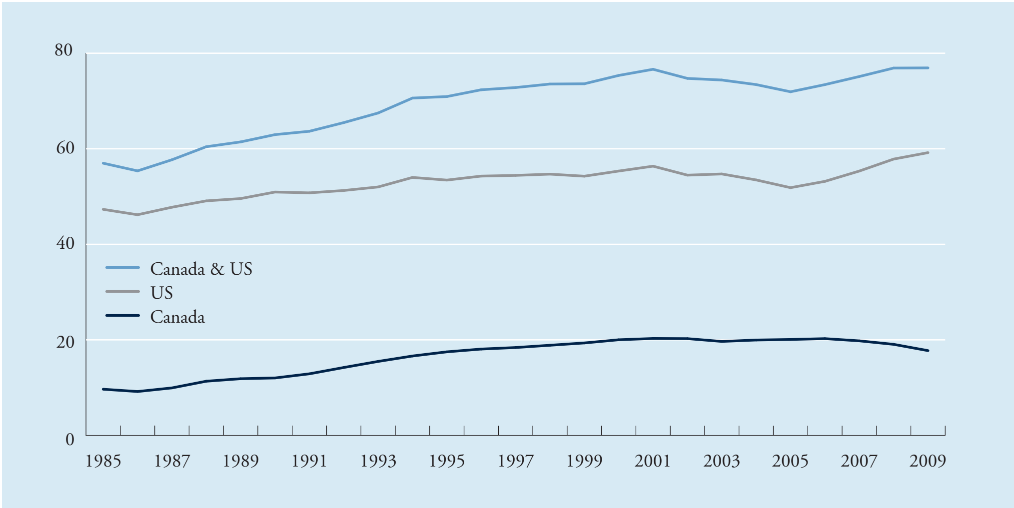
A more accurate assessment of the situation—even before the emergence of shale gas—paints a rather different picture. For several reasons natural gas remains a core component of a well functioning energy system due to abundance, reliability, responsiveness, efficient markets and multiple applications, even in a carbon constrained future.

figure 3: price of natural gas at henry hub (us$/mcf)



Source: US Energy Information Administration (2011c)

FIGURE 4: MARKETED NATURAL GAS PRODUCTION IN CANADA AND THE US (BCF/D)

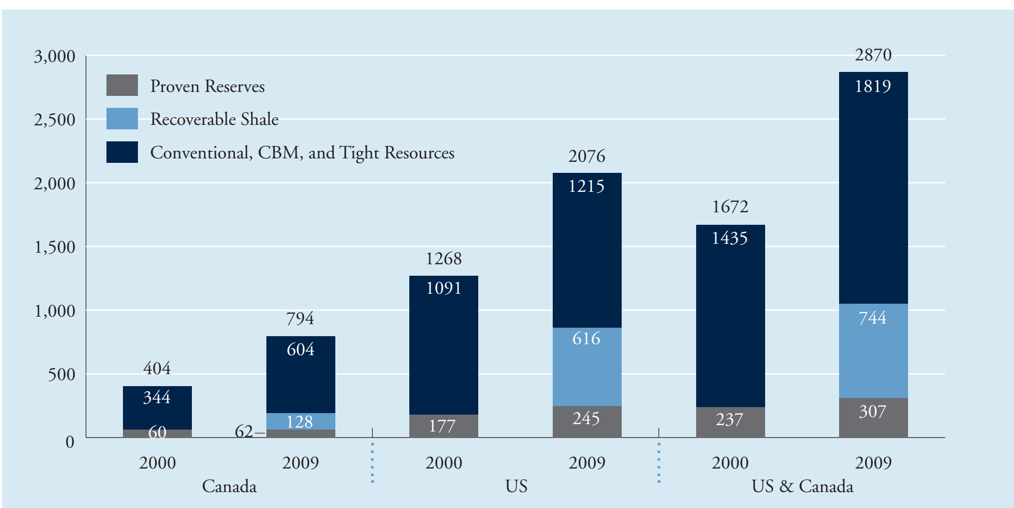


Sources: Canadian Association of Petroleum Producers (2011a) and US Energy Information Administration (2011d)

Natural gas is abundant

Although the medium-term productive capacity of the natural gas industry in Canada and the US had (at best) flattened by around 2005, the resource base remained very large (see Figure 5). In addition to the existence of gas in Alaska and the Mackenzie Delta, new LNG import capacity was either built or being built (see Figure 6) while a huge growth in worldwide liquefaction capacity was nearing completion.

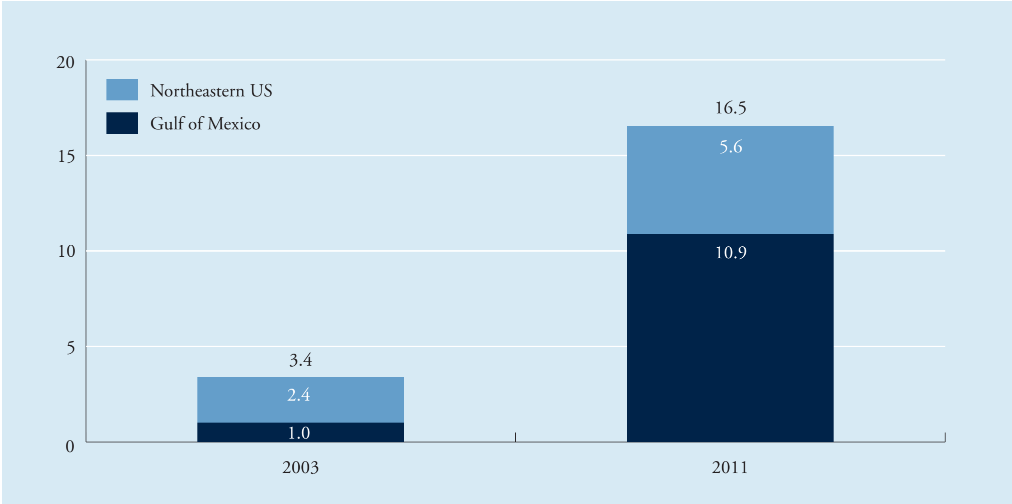
FIGURE 5: US AND CANADA NATURAL GAS POTENTIAL (TCF)



Sources: Author's calculations from US Energy Information Administration (2010c), Canadian Association of Petroleum Producers (2011a) and Canadian Gas Association (2010) Notes:

- Annual consumption in North America in 2009 was approximately 27 TCF (US Energy Information Administration 2010b).
- Proved (or proven) reserves are those quantities of energy sources that are recoverable with existing economic and operating conditions and the location, quantity and grade of the energy sources are considered to be well established. In other words, proved reserves make up the immediate supply readily available to the market.
- Recoverable conventional and unconventional resources, are believed to exist based on geologic analysis and forecasts from proved reserves and are recoverable under current operating conditions and technology, but the location, quality and grade of the resources are unknown and thus such resources cannot serve as immediate supply to the market.

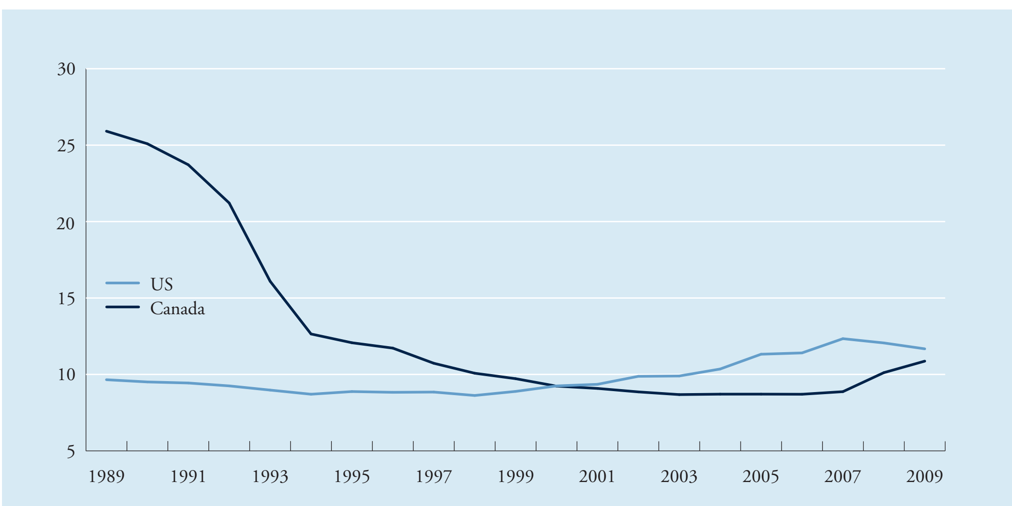
figure 6: existing us capacity to receive lng imports, 2003 and 2011 (bcf/d)



Sources: US Federal Energy Regulatory Commission (2011a) and US Energy Information Administration (2003)

Shale has created several effects that contribute to this picture. First it added substantially to resource estimates, bumping them up from around 80 years to more than 100 years (see Figure 5). Second, it immediately upped productive capacity and has moved the US and Canadian reserve-to-production ratio from under 10 years to 12 (see Figure 7).[7] Even if shale gas plays end up producing less than hoped, under most scenarios over the next two decades, the natural gas market will remain well supplied.

figure 7: natural gas reserve-to-production ratio (years)



Source: BP (2010)

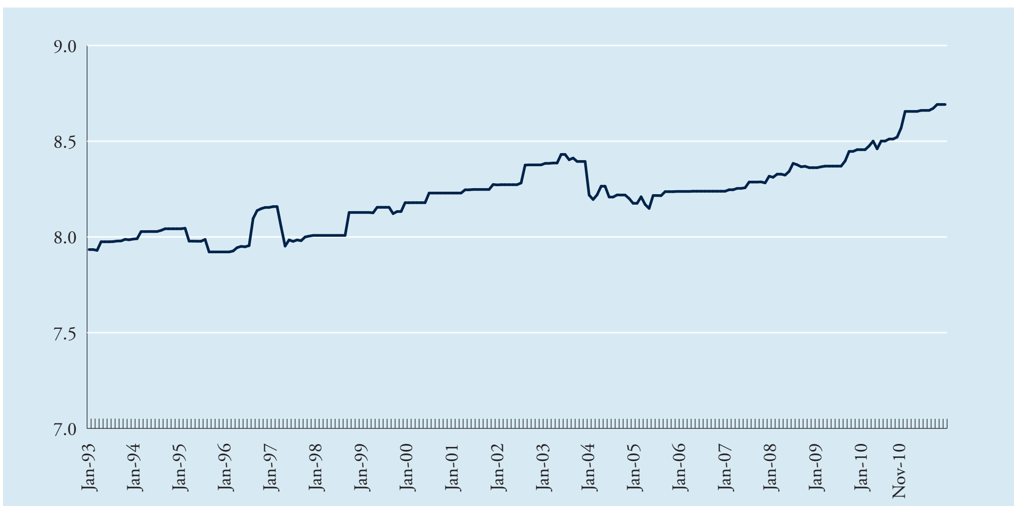
7 The R/P ratio (reserve-to-production ratio) is an indicator of readily available supply. This is analogous to inventory in any other industry. The R/P ratio appears to have stabilized around 10-12 years which seems to reflect a level which the market perceives as adequate.

As it stands, current prices in the $4-4.50 range are probably unsustainable from a Canadian producer perspective.[8] But prices from $5.00 to $7.00 would likely sustain supplies of natural gas from domestic sources. If need be these sources could be supplemented by readily obtainable imports for a very long time into the future.[9] Natural gas is—simply put—abundant.

The delivery system is highly reliable[10]

The track record of the North American natural gas system in delivering natural gas reliably is not a product of good luck or accident. The North American system, developed over a century, is characterized by a dense network of pipes, sophisticated controls and intense scrutiny and oversight that together provide redundant pathways and protect against disruptions in delivery. Storage capacity not only helps mitigate disruptions, it also helps reduce price volatility and manage weather-induced demand spikes. Storage ensures fast fuel response to the electricity system and adds to overall energy system reliability. The electricity system effectively has two big storage media: hydroelectric reservoirs and natural gas storage. American natural gas storage capacity has been growing over the past twenty years (see Figure 8).[11]

FIGURE 8: US TOTAL NATURAL GAS UNDERGROUND STORAGE CAPACITY (TCF)



Source: US Energy Information Administration (2011e)

8 Prices throughout spring and summer 2010 ranged from $3.75-4.50/mcf (US Energy Information Administration 2011a).

9 World supplies of conventional gas are abundant but relatively concentrated. On the other hand, world shale gas resources may well prove to be as prolific and as widely distributed as those in Canada and the US. It has recently been estimated that technically recoverable shale gas makes up approximately 5,400 TCF in 30 countries outside Canada and the US (US Energy Information Administration 2011b).

10 The reliability factor of the Canadian system is over 99.999% expressed as the percent of total customer hours possible that the system is available. It is based on compiled data from local distribution companies across Canada (Canadian Gas Association 2005).

11 Gas storage capacity in the US and Canada combined is close to 10 TCF.

The responsiveness of the supply system extends across all time horizons

Traditionally, the natural gas industry has had very fast short-term responsiveness (days/weeks) due to the availability of natural gas storage and multiple pipe options. The North American investment environment underpins long-term responsiveness (multiple years) by creating stable conditions for investors in both supply and transportation infrastructure. Until recently, the system was much less nimble in the medium-term (months). The recent emergence of widely distributed, close-to-market shale gas resources (see Figure 1), combined with the extensive and largely underutilized LNG regasification capacity (see Figure 6) and growing underground storage capacity (see Figure 8) now make for very high medium-term responsiveness.

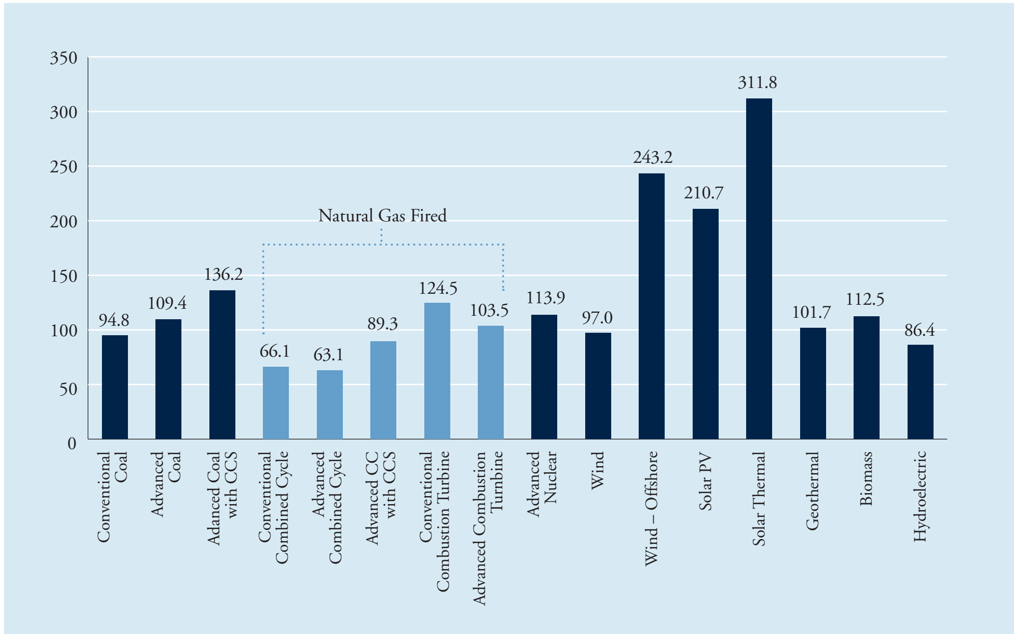
Natural gas markets in North America are the most efficient in the world

Standing on the physical infrastructure of pipes and storage infrastructure are two vital institutional structures. One is a tested and effective system of economic regulation to deal with the natural monopoly aspects of the system. The other is a highly competitive commodity trading system and contractual framework organized around several highly liquid trading hubs, both at the supply end of the system such as Henry Hub in Louisiana, Nova Inventory Transfer (NIT) in Alberta and market hubs such as Chicago or Dawn in southwestern Ontario. Combined with efficient markets in pipeline and storage capacity, this system provides natural gas purchasers with price transparency and multiple supply and pathway options with much more inherent flexibility than any other energy source.

Natural gas has a very promising long-term future in both electricity generation and end use markets

At some point, carbon constraints may severely limit the use of carbon-based fuels, including natural gas, coal and petroleum products. That being said, gas is by far the lowest carbon fossil fuel and that advantage is compounded by the fact that it can be used in technologies such as combined cycle gas turbines or condensing boilers whose efficiency can effectively double the relative carbon advantage of natural gas over coal or other fossil fuels (see Figure 9). Given the challenges faced by most alternatives, natural gas is a cost-effective pathway to a cleaner energy system and arguably a foundation for a low-carbon energy system over the long-term. Looking to the future, consumers will be able to count on natural gas for multiple energy options in homes, businesses, institutions and communities. The attributes of the fuel and the system make it the best, and in some cases the only, realistic choice in diverse circumstances.

FIGURE 9: ESTIMATED LEVELIZED COSTS FOR PLANTS ENTERING SERVICE IN 2016 (US$/MWH)



Source: US Energy Information Administration (2011d)

Note: The highlighted bars represent the natural gas fired options, which are among the electricity generating choices with the lowest levelized costs of building new capacity. "Levelized costs" represent the present value of the total cost of building and operating a generating plant over its life.

Natural gas will be the essential source of flexibility in the electricity system for several reasons

Low-carbon base load electricity options are proving to be elusive. New nuclear capacity requires an economic bet that no corporate balance sheet can easily support. Until experience is built with third generation nuclear technologies, costs remain an open question.[12] The recent Japanese nuclear disaster has likely led to overreaction, but it also seems inevitable that increased public scrutiny and enhanced regulatory requirements will add to costs. Coal with carbon capture and storage (CCS) looks more like an expensive option and short of dramatic technical breakthroughs, the energy penalty of CCS is daunting. Adequate carbon pricing is also a hurdle for CCS technology.[13] Hydroelectricity looks like an attractive option for clean energy generation. However, new hydro with big impoundments will face environmental and social opposition. Additionally, most options are remote and the potential is limited relative to total North American electricity demand.

12 Only a handful of third generation reactors have been built. No one can say with any certainty what costs will be until more have been built (World Nuclear Association 2011). The International Energy Agency also notes incremental costs of "first-of-kind" reactors and a study in 2004 by the Department of Energy concluded that costs drop after the first several builds, but remain high initially.

13 Estimates of the carbon price needed to underpin CCS have varied widely over the years. In the Canadian context, it has recently been suggested that the carbon price may need to be as high as $70 to $80 per tonne for CCS to be feasible (Integrated CO2 Network 2009). In addition to a carbon pricing framework, which is currently absent at the federal levels in both Canada and the US, other government incentives are likely necessary to assist in technology demonstration. The absence of a regulatory framework for dealing with CCS projects at scale, particularly issues of liability in the event of potential negative outcomes, is also a significant barrier to the implementation of scale CCS (Fernando et al. 2008).

Base load natural gas, in contrast, is efficient and low emitting and can be built quickly, although even natural gas generation faces local opposition. Apart from its role in base load generation, natural gas is the only fuel with the flexibility to fill roles in intermediate (cycling) capacity, peaking and strategically distributed electricity to ease grid congestion.

Natural gas is the most efficient and cleanest means to get heat

Over half the energy we use in the economy is heat for building warmth, hot water and industrial processes. No other widely available fuel can compete with natural gas on efficiency with the exception of high efficiency heat pumps whose deployment faces several constraints. The flexibility and clean combustion characteristics of natural gas make it the only practical option in many industrial processes. Emerging sources such as natural gas from bio-sources (farm waste, land fill, wood waste) will compete on a carbon basis, but not yet on cost and they will, in any event, use the same local infrastructure. In this sense, the natural gas system, as much as the fuel itself, is a foundation for a sustainable energy system.

Natural gas, because of its flexibility, is the essential balancer for renewables

This is particularly true of centrally generated electricity such as wind and solar where intermittency demands a fast response backup. Natural gas is also essential in many cases to backup local heat sources such as geothermal and solar which are normally unable to handle 100% of requirements especially on peak.[14] Natural gas uniquely complements the different forms of renewable energy in ways that improve the reliability and performance of our energy infrastructure.

Natural gas and its delivery infrastructure are the essential foundation for more effective heat management and capture of energy from waste

Over half of the primary energy entering the Canadian economy is lost as waste heat (Natural Resources Canada 2006). The potential from better heat management is illustrated by a combined cycle gas turbine whose efficiency (close to 50%) is around 1.5 times that of a simple cycle turbine (Soares 2006) simply because the heat is better utilized. Further extension through a combined heat and power (CHP) application increases the total efficiency to levels approaching 90% (Institution of Engineering and Technology 2007). More effective use of residual heat from buildings and industrial processes (in exhaust air and wastewater) can only be achieved based on an underlying piped energy system. Many other sources of waste (sewage, landfills, wood wastes) are only logistically practical if tied into a piped energy system. In short, no other technology/fuel/infrastructure combination has the reach and site flexibility to create these sorts of opportunities.

[14] It is generally impractical and uneconomic to design local renewable or waste-based systems to handle thermal peak loads; characteristically, biomass, solar and geothermal systems are gas-connected to ensure peak capacity and reliability.

SNAPSHOTS OF NATURAL GAS IN SOCIETY AND THE ECONOMY

→ Commercial/institutional and district energy: District energy has potential in widespread applications. Natural gas provides the foundation and the system, in turn, provides the backbone for waste heat management and introduction of local renewable sources and the application of CHP (see below). As an example, the Lower Lonsdale district of North Vancouver utilizes a district heating system, comprised of three mini-plants containing several natural gas-fired condensing boilers providing 800-900 kW of energy. By the end of 2010, the Lonsdale development was expected to heat two million square feet of building area, and planned to incorporate solar and geothermal power into its system (Cleland 2011).

→ Industrial/commercial and combined heat and power (CHP): SaskEnergy, SaskPower and Natural Resources Canada are supporting Inland Metal's implementation of a CHP system. The local ventilation manufacturer will be able to use CHP to heat and power the building, as well as supply excess electricity back to the grid. It is expected to reduce greenhouse gas emissions by 55% compared to traditional power production, as well as be able to utilize up to 86% of the total energy in natural gas (Government of Saskatchewan 2010).

→ Transportation: Air quality and GHG benefits favour applications of natural gas in transport such as transit and waste haulage especially under legislated carbon constraints or prices. In February 2011, Waste Management and Terasen Gas collaborated to begin converting all waste collection trucks in Metro Vancouver and the lower mainland area to compressed natural gas. The initiative will reduce Waste Management's emissions by 15% while increasing fuel efficiency by 15% (Waste Management 2011).

Natural gas looks good to consumers in a wide range of applications and many possible futures

Despite the warnings of skeptics, the evidence is accumulating that shale gas has indeed changed the game in North America and may well do so elsewhere in the world, making imported supplies a realistic backstop.

Even under significantly higher prices than today, natural gas provides security, flexibility and good value for consumers in multiple applications.

When carbon constraints start to bind, gas will still be a favourable option in many applications and its position is improved where it competes against coal (electricity generation) and petroleum products (transport). Until such time as renewables become much more cost effective, reliable and widespread, high efficiency natural gas is the most practical way to restrain carbon growth.

Natural gas combines high efficiency capabilities with a flexible system that accommodates waste heat management and incorporation of renewables. This gives it inherent sustainability compared to other options.

3. The Outlook for Producers

Natural gas markets have a mixed outlook

The flipside of the almost unreservedly positive consumer perspective on natural gas is a Canadian producer perspective filled with question marks. While today's low natural gas prices, combined with the many other positive attributes of natural gas, could spur significant demand growth, there remain many factors that constrain those growth prospects. If relatively low prices persist, then high cost suppliers will face thin returns. Many Canadian suppliers are unavoidably high cost because of remote northern production environments and distance to most North American markets.

The macroeconomic outlook in North America is for modest growth at best

Economic forecasters envisage North American economic growth in the next few years running in the range of 2–3% annually, somewhat below the average in the past decade prior to the recession. While forecasts—as noted earlier—need to be treated with caution, most of the underlying fundamentals suggest that relatively slow economic growth may well be a North American reality well out into this decade and beyond. The aftershocks of the 2008/2009 recession look likely to continue for some time, thereby creating a drag on global growth. North American governments and consumers continuing to grapple with debt will tend to create economic drag; alternatively, they may choose not to address debt, in which case artificially enhanced growth in the medium-term may well end at an economic cliff late in the decade. The simple weight of demographics in the form of slowing population growth and growing age dependency ratios will also weigh down economic growth with only enhanced immigration or accelerated productivity growth available to provide some offset.

While the above sounds like a rather gloomy assessment, it is very difficult at this stage to see many factors that might brighten the picture. Although North American growth is likely to outpace European growth, it will be slower than historical experience and natural gas will largely remain a domestic industry with only limited opportunity to access fast growth economies.

North American natural gas markets will thus largely reflect North American population and economic growth, with a few other factors potentially negative or positive. On the positive side low natural gas prices will encourage expansion in electricity generation or emerging market sectors such as transportation. Should governments move forward with evenhanded carbon pricing, natural gas would benefit relative to other fossil fuels. On the other hand, governments may choose to mandate or subsidize renewables with mixed implications for natural gas. Underlying trends in energy efficiency and the continuing emergence of viable competitors in some markets will be negative for natural gas.

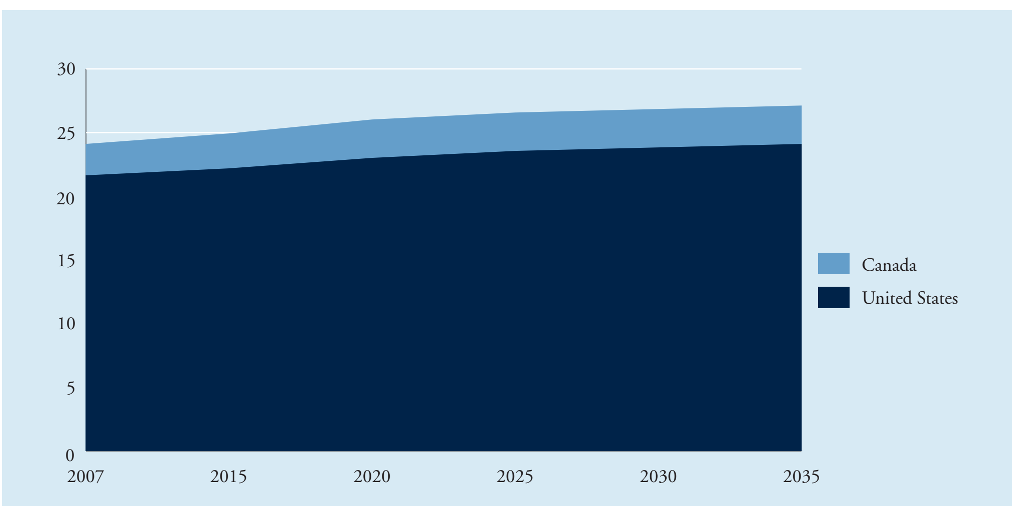
CARBON POLICY AND NATURAL GAS

Carbon management policy is a mixed bag for natural gas. As a general rule, measures such as technology mandates, low carbon standards, portfolio standards and feed-in tariffs are designed specifically to drive renewables or require zero carbon. They do not have to be designed this way, but tend to be because it is politically popular to do so. Market-based measures such as carbon taxes are more likely to favour more cost-effective approaches such as efficiency and reduced (but not zero) carbon emissions. Given that most of the competition for natural gas in the energy system is still other fossil fuels, natural gas competes well in a market-based carbon management system even at carbon prices in excess of any that have been seriously considered to date by legislators in Canada or the US.

Traditional natural gas markets show flat demand

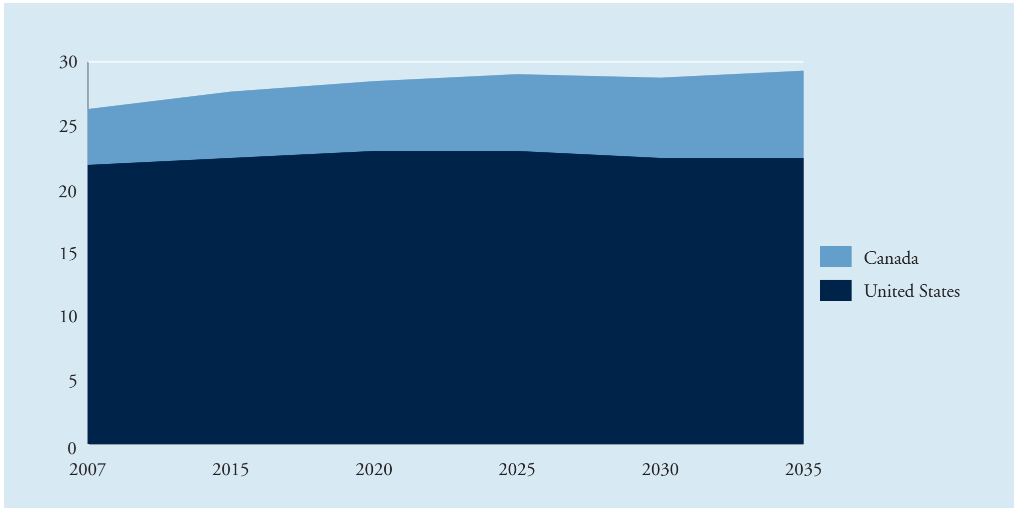
Traditional markets—residential, commercial, institutional (RCI), and industrial—seem likely to continue to be flat. The reference case for EIA's latest international projections shows minor growth in demand for these sectors (see Figures 10 and 11). Slow population growth inherently limits RCI market growth and improved efficiency suppresses it further. Canada, despite its cold climate, has witnessed steady annual declines of per customer natural gas use for almost two decades. These declines have been slightly offset by customer additions (IndEco 2010). In the US, the fastest population growth is occurring where heating loads are modest. Canadian and US industrial natural gas use will likely continue to experience flat growth or even decline. The major exception to the trend in industrial use is likely to be the Canadian oil sands, which is expected to drive potential industrial use increases in Canada (US Energy Information Administration 2010b).

FIGURE 10: PROJECTED RESIDENTIAL AND COMMERCIAL END USE NATURAL GAS DEMAND (BCF/D)



Source: US Energy Information Administration (2010b)

FIGURE 11: PROJECTED INDUSTRIAL END USE NATURAL GAS DEMAND (BCF/D)



Source: US Energy Information Administration (2010b)

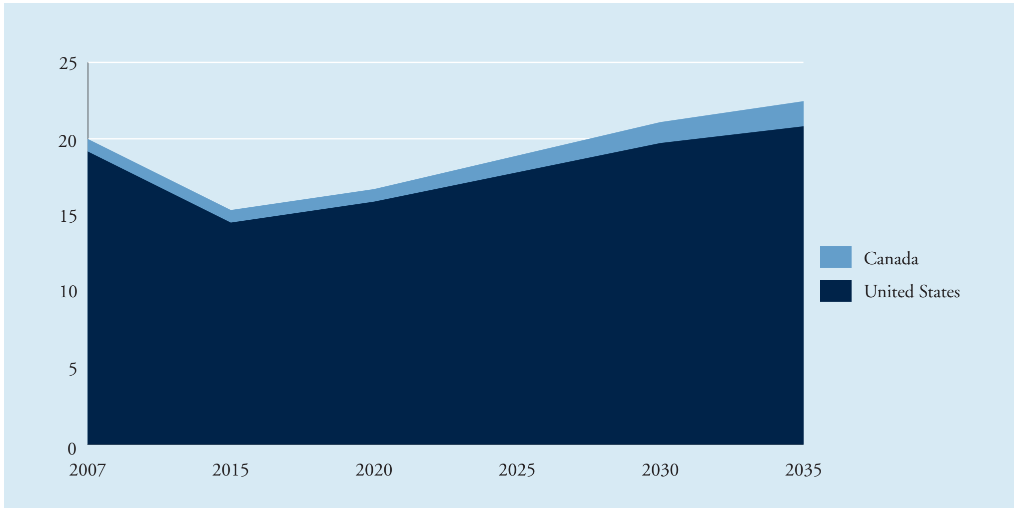
Electricity generation is a big potential upside

Electricity generation demand has the potential to generate strong natural gas demand growth in both Canada and the US. The EIA is predicting that, although electricity generation demand for natural gas will fall initially to a low of approximately 15 BCF/d in 2015 in the US and Canada, it will rebound to greater than 22 BCF/d by 2035 (see Figure 12). Other analysis is much more bullish on natural gas electricity demand growth. IHS Cambridge Energy Research Associates (IHS CERA) envisages a near doubling of North American electricity generation natural gas demand from 20 BCF per day in 2009 to 38 BCF per day in 2035 including strong growth in Canada led by Ontario (2010). This would amount to growth of 1.4% annually in overall electricity compared to less than 1% annually over the past decade.[15] Under a scenario with strong electricity generation demand growth, North American natural gas demand overall could grow by 0.5% annually over the next two decades (faster than the past decade but much slower than the 1990s).[16]

15 In Canada, electricity demand for all fuel types grew by 0.7% annually between 2000 and 2008 (Natural Resources Canada 2010). In the US, electricity demand for all fuel types grew by 0.6% annually over the same time period (US Energy Information Administration 2010e).

16 Natural gas demand in the US averaged 1.9% growth during the 1990s (US Energy Information Administration 2011f). Natural gas demand in Canada grew 2.4% on average during the same period (Canadian Association of Petroleum Producers 2011a).

FIGURE 12: PROJECTED ELECTRICITY GENERATION END USE NATURAL GAS DEMAND (BCF/D)



Source: US Energy Information Administration (2010b)

However, the outcome on electricity generation is far from certain and several factors are worth watching. The long anticipated advent of electric power vehicles could boost growth, but electric vehicle penetration is still very modest and moving relatively slowly. One study of the US market suggests electric vehicles will make up only 3.1% of the American market in 2020 (Deloitte 2010). Sluggish new vehicle sales and continued improvement in internal combustion engine vehicles could be a drag on electric vehicle growth. Demand side barriers to adoption include the higher price of electric vehicles and their limited range as well as concerns about the size of electric vehicles (Deloitte 2010).

Consumer demand for electricity could be diminished if the growth in new electric gadgets is slower than anticipated, as chastened consumers restore their balance sheets and find new credit elusive. Moreover, power authorities may find it prudent to redouble efforts on efficiency—a rational response to higher prices and tighter markets combined with the desire to minimize controversies over the building of new facilities and to slow carbon growth. More emphasis on demand restraint may increasingly look like a relatively low risk alternative to new generation.

Fuel costs continue to favour coal in existing plants and a large, mainly depreciated coal-fired electricity fleet will be a strong competitor. Natural gas has many advantages for new electricity generation plants and will compete particularly well in cycling and peak load, strategically sited generation (where transmission constraints bind) and combined heat and power (see Figure 9). However, investors in base load plants who were burned by the onset of the decade-long price and volatility run up from 2000 to 2010 will still look longingly to less fuel price sensitive options. As noted earlier, such options appear relatively scarce except at very high capital cost or daunting technological or carbon risk. Natural gas supplies based on long-term arrangements on prices might look like a very good bet.

Carbon pricing remains a wild card. According to several sources, natural gas looks favourable at prices above $30/tonne for dispatch of existing plants.[17] A realistic prospect of carbon prices in that range and then slowly escalating over the next two decades would make new high efficiency natural gas relatively attractive. In the longer horizon to 2050, no fossil alternative looks viable held against North American carbon management aspirations unless CCS becomes a practical alternative for widespread application. However, policymakers have been reluctant to hit consumer pocketbooks with carbon pricing, preferring stealthier options such as renewable technology mandates.

Underlying the prospects for increased demand for natural gas in electricity generation rests one other big question: are natural gas producers willing to enter into long-term shared price risk arrangements with electricity producers? Most industry experts including producers have stated their expectation that low North American natural gas prices will be with us far into the future. But, as noted earlier, electricity plant investors, having been burned a decade ago, are wary. At current low natural gas prices, the economics are favourable for natural gas fired electricity generation but no other option is as sensitive to fuel prices. Electricity producers may be unwilling to build natural gas plants with 25-year life spans, especially if the alternative is to extend the life of existing coal-fired plants. Unless natural gas producers back their enthusiasm for the fuel and their expectations of low prices by sharing some of the price risk, increases in electricity generation could well remain modest. Except in the face of meaningful carbon prices the low carbon attributes may not be enough to encourage significant demand growth in electricity generation.[18]

Unconventional markets—transport and exports—help modestly

Transportation demand for natural gas seems likely to grow based on robust engine technology and substantial GHG benefits, but the volumes will likely be very modest. The most probable prospect—compressed natural gas (CNG) in heavy-duty urban fleets—accounts for only a small part of fuel use. A bigger prize is the long distance heavy-duty sector using LNG, but cost barriers for both refueling infrastructure and vehicle capital cost make a steep climb without either aggressive carbon pricing or significant subsidies. The light duty sector is on the gas industry's radar but to an even greater extent than in the heavy duty segment limited refueling infrastructure, cost and convenience disadvantages (range and bulk of the fuel tanks) are obstacles that make natural gas unlikely to compete well with standard internal combustion vehicles, hybrids or electrics.

Exports from North America are looking plausible. The opportunity in Asia is driven by current and prospectively large spreads between North American prices and landed cost of LNG in large Asian markets such as Korea and Japan. Against that, the Pacific basin has a great deal of liquefaction capacity and several aggressive competitors. Long-term contractual

17 One such study suggests that a carbon tax of $15/tonne results in over 70% higher coal prices, but only 8% higher natural gas prices in the US (Rausch et al. 2009). Another study examines, amongst other climate and energy policy scenarios, the effects of a $30/tonne carbon price and a $60/tonne carbon price in the US. Under either scenario, natural gas would maximize at about 31% of US primary energy in 2040 and remain at about 25% of the US primary energy in 2050 (Hartley and Medlock III 2010).

18 Alternatively, electricity producers could integrate upstream—acquiring gas resources as a natural hedge—but this would take them into a business that is unfamiliar both to the electricity generators and regulators.

arrangements for Canadian supplies in Pacific markets remain to be seen, but investors seem to be voting with their wallets. Volumes are likely to be around 700 MMCF/d possibly growing to double that with a second liquefaction train (Vanderklippe 2011). These volumes are potentially significant relative to nearby productive capacity in northeast BC, but modest in a North American context and therefore unlikely to have an impact on North American prices.

Supply, prices and production and transportation costs create an uncertain environment for Canadian producers

Against a demand outlook that is relatively weak with one potentially very big upside (electricity generation) and several potential downsides, production looks robust, diverse, and likely to keep the market well supplied. The big question is the extent to which shale gas production stands up and at what price for the marginal molecule.

Supply looks most likely to be very robust

While most observers continue to believe that shale gas has truly changed the game, questions remain about decline rates and the ability to sustain production growth. A small number of contrarians continue to counsel caution and in some cases characterize the "shale gale" as wildly exaggerated.[19] However, between the shale gale advocates and the views of the contrarians is a shale story that lands somewhere in the middle—less of a gale but still lots of shale. If that is the case, then North America still has access to very large amounts of natural gas. Shale will continue to be produced with close to 100% certainty. The question is how much.

Shale gas and LNG

SHALE AND REGASIFICATION

No one was caught more by surprise by the shale revolution than the builders of North American LNG regasification capacity. As recently as 2005, North American natural gas outlooks included 10-15 BCF/d or up to 20% of the market being supplied from offshore sources and investors bet heavily on this expectation.[20] At the time of writing, regasification capacity in the US, most of it in the US Gulf coast, is 16.54 BCF/d. In 2009, LNG imports at these terminals totaled just 1.24 BCF/d according to the EIA. Importantly, the world market is oversupplied with liquefaction capacity and a significant share of this capacity can easily serve the Atlantic basin market, the one most relevant for North American consumers.

19 For example, a recent *New York Times* article on shale gas in the US by Ian Urbina claims that the bullish forecasts about shale gas are overblown and have created a speculative bubble.

20 Annual Energy Outlook 2005 (US Energy Information Administration 2005) forecasted LNG imports reaching 6.4 trillion cubic feet by 2035.

Prices seem unlikely to get back to pre-recession levels in the foreseeable future

One recent analysis of multiple North American plays gives some guide to what market clearing North American prices might look like in coming years (see Figure 13). Even if North American demand growth is extremely robust, which as we have discussed is far from certain, total US and Canada demand is unlikely to exceed 86 BCF/d by 2035 (US Energy Information Administration 2010b). Even in such a demand environment, the supply costs of different plays indicate that the marginal molecule comes in at Henry Hub prices in the vicinity of $5. Compared to today's prices (around $4.00) this is an improvement for producers.

FIGURE 13: BREAKEVEN HENRY HUB PRICE FOR PRODUCTIVE CAPACITY OF SELECT NORTH AMERICAN PLAYS

Price ($ per MCF)	Maximum North American Production of Shale Natural Gas (BCF/D)
Less than $3.00	18.2
Less than $3.50	64.4
Less than $4.00	70.5
Less than $4.50	72.5
Less than $5.00	74.1
Less than $7.00	108.6

Source: IHS Cambridge Energy Research Associates (2010)
Note: Forty years of plateau proved, possible and potential productive capacity assumed in this estimate.

There is, needless to say, much uncertainty as to what the breakeven price may be. A more recent study estimates that the vast majority of shale gas production is economical between $4.00 and $8.00 (Massachusetts Institute of Technology Energy Initiative 2011). This suggests that prices around $5.00 may not be enough to spur high cost producers into production and that the market clearing price would be substantially higher, albeit well below much of the experience of the past decade.

Two other major factors bear on this outlook: transportation costs and environmental and social constraints.

Transportation reduces relative returns for Canadian producers

Against the uncertainty of prices stands the certainty of transportation costs for western producers. Transportation costs for western Canadian producers to market hubs such as Chicago or Dawn produce netbacks that are approximately 75 cents to $1.00/mmBtu lower compared to other North American supply sources such as the Gulf Coast or Marcellus. While low cost western Canadian supplies such as the Horn River shale or Montney tight gas can successfully compete in the current market, production of the higher cost western Canadian conventional plays will only be economic in a more robust pricing environment (B. Kenney, June 28, 2011, e-mail message to author). Add to that the risk of underutilized pipeline capacity, especially the TransCanada mainline, and the transportation story looks daunting.

The TransCanada mainline has been delivering natural gas from west to east for 65 years. At the turn of the century, natural gas volumes on the mainline peaked at 7 BCF/d but in 2009 hovered around 4 BCF/d (TransCanada Corporation 2009). The contributing factors to this drop include production declines and new competing sources of natural gas and competing pipes (Alliance). Given the structure of the tolling system, a decrease in the amount of natural gas shipped cross-country causes an incremental increase in the tolls, creating a negative spiral effect on producers. In attempting to make tolls competitive, TransCanada Corporation proposed lower long haul rates by deferring recovery of approximately $300 million in under-collected 2010 mainline revenues (TransCanada Corporation 2011). Although an interim toll has been approved, the NEB has yet to grant approval to the proposal, and a revised application is currently under review. This pipeline problem is an urgent concern because with uncompetitive tolling rates for Canadian producers, US competitors will see an opportunity to ship natural gas up to eastern Canada, particularly from the Marcellus where the distance is shorter and transport cheaper.

US GAS IN CANADA

On May 19, 2011, the US Federal Energy Regulatory Commission (FERC) authorized Empire Pipeline Incorporated to construct its Tioga County Expansion project. Currently, the Empire pipeline permits a one-way flow of natural gas from Canada into the US, but the recently authorized project will also enable Empire pipeline to flow natural gas from the US to Canada. The project will allow Empire to receive up to 350,000 Dth per day (dekatherms per day, with one dekatherm equal to 1 mmBtu) of gas from the Marcellus shale play (US Federal Energy Regulatory Commission 2011b). Thus, it appears to be only a matter of time before American shale gas producers will be able to pipe natural gas to eastern Canadian markets.

Environmental and social constraints are real, but manageable

Environmental and social concerns surrounding unconventional natural gas are matters of physical reality and perception, but both are matters of practical reality for the industry. As natural gas production has increased, so have its potential environmental and social impacts. Proximity to urban areas and high population density has created heightened sensitivity, especially in the Marcellus and Utica plays.

There are a variety of environmental impacts of natural gas extraction, transmission and utilization. These impacts include land use and habitat effects as well as air pollution. The issues provoking the most concern, however, relate to hydraulic fracturing, water use, and greenhouse gases.

Hydraulic fracturing is a practice with a safe history of use, provided that best practice standards are deployed by industry, but more public discussion is needed to allay concerns

Hydraulic fracturing is the process whereby a mixture of water, sand and chemicals is pumped underground at high pressure to create fractures in the shale to allow the natural gas to be extracted, Although hydraulic fracturing has a safe history of use in North America, *providing that best practice standards are deployed by industry,* concerns remain about cost and social resistance, particularly in eastern plays such as Marcellus and Utica.

When industry resists disclosure of the chemicals they are employing, health and social concerns are hardly a surprise. Even though most chemicals being used can be purchased at a local grocery store, the perceived lack of transparency produces a tainted image in the public eye. As time has passed, natural gas producers and governments have been getting better at informing the public. The Environmental Protection Agency (EPA), under direction from the US Congress, is conducting a study to understand the relationship between hydraulic fracturing and drinking water resources.[21] With time and transparency, and the authority of bodies such as the EPA, concerns may be alleviated, but more public discussion will be needed.

The chemicals used in hydraulic fracturing usually only make up a small percentage of the fracture fluid. The vast majority—often greater than 99%—of the fluid is water and sand. The exact makeup of the fluid depends both on the company's proprietary formula and the specific features of the natural gas reservoir. The water used may come from local freshwater sources, but may also be recycled water from other fracturing operations or may be non-potable brackish water. Sand is present to prop the fractures open once they have been made to allow the natural gas to continue to flow to the wellbore. The remaining less than 1% of the mixture is usually a combination of everyday chemicals that have a specific function in the fluid. Some examples of these chemicals include ethylene glycol and citric acid. Citric acid is used to prevent the precipitation of metal oxides. Ethylene glycol helps prevent scale deposits. When the fracturing is completed, the fluid is returned to the surface for safe disposal in accordance with regulations or is reused to fracture other wells (American Petroleum Institute 2010).

[21] On February 7, 2011, the EPA released their draft plan for their two-year study of the potential impacts of hydraulic fracturing on drinking water resources. To access the draft plan, see: www.water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/upload/HFStudyPlanDraft_SAB_020711.pdf.

The biggest risks lie in the areas of water management, natural gas or fracture fluid contamination of aquifers and the effective disposal of fracture fluids. A recent Massachusetts Institute of Technology study surveyed a sample of widely reported shale gas incidents. Of their sample, nearly half of the incidents involved natural gas or fracturing fluid contamination of groundwater. Most of those incidents, in turn, involved natural gas contamination. However, the study's authors feel that these issues can be mitigated through an inter-state regulatory review and adoption of best practices and appropriate regulation (Massachusetts Institute of Technology Energy Initiative 2011). Indeed, a recent study found that there may be a link between proximity to shale gas wells and groundwater contamination with natural gas. However, the study concluded that the contamination was likely from older wells that were improperly cased, not from the recent shale gas development that has been occurring. Moreover, the authors found no hydraulic fracturing fluid contamination (Osborn et al. 2011)

The water issues surrounding hydraulic fracturing can be broken down into three important questions: what is the total consumption of water, how much waste water is produced and how much risk is there of leakage into the water tables?

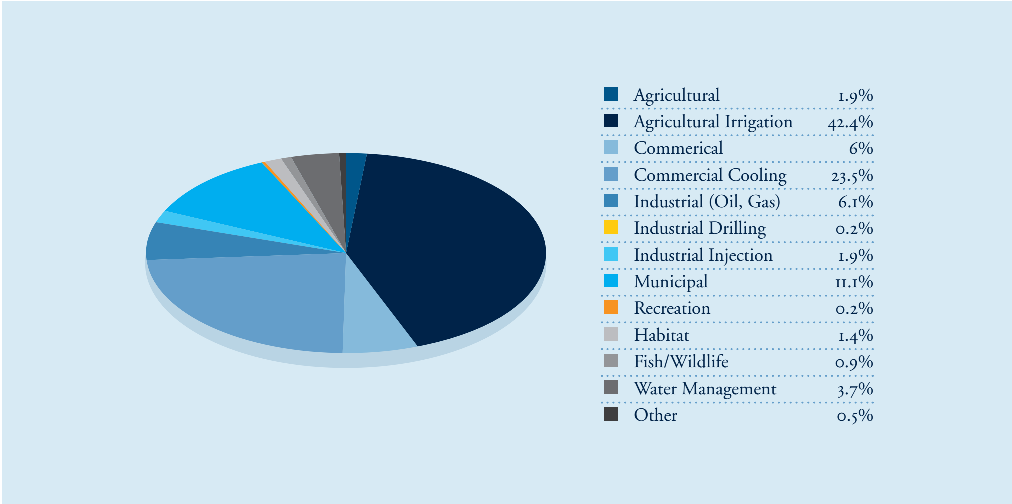
What is the total consumption of water?

Issues surrounding shale gas water consumption have not been a major media preoccupation as compared to hydraulic fracturing. In addition, water use profiles and impacts in the energy sector vary across jurisdictions.

In November 2010, Canadian Association of Petroleum Producers (CAPP) and the Oil Sands Development Group (OSDG) released a guide to water conservation, efficiency and productivity for Alberta, but excluded shale gas water because they did not expect commercial production to occur until after 2015 (Golder Associates 2011). Water consumption is greater in unconventional drilling than in conventional drilling. Talisman Energy estimates it uses 15 million litres of water to hydraulically fracture a typical well (Talisman 2010). Chesapeake Energy estimates it uses anywhere between 245,000 litres and approximately 2.3 million litres to drill a deep shale gas well, and approximately 17 million litres to hydraulically fracture the well (Chesapeake Energy 2011).

Despite the increased water volumes required for unconventional production, Alberta water allocation in the oil and gas industry is still less than 10% (see Figure 14).

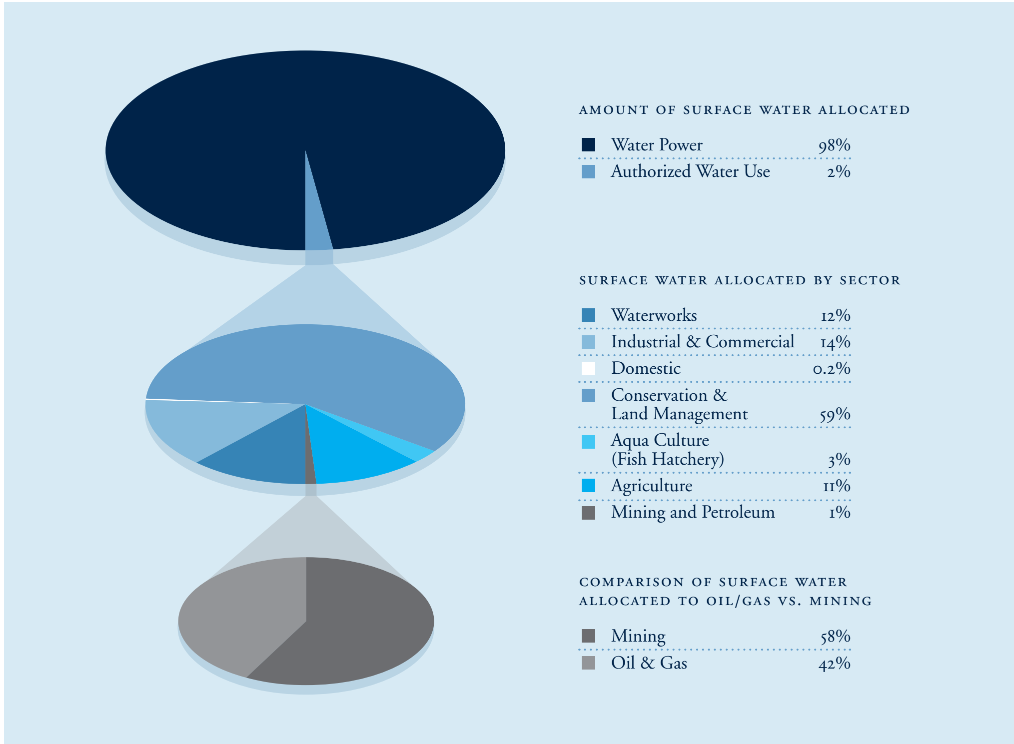
FIGURE 14: WATER ALLOCATIONS BY SECTOR IN ALBERTA (2008)



Source: Alberta Environment (2011)

In BC, the Oil and Gas Commission (OGC) regulates the fossil fuel industry. Although the OGC does not publish a list of assigned water permits, in August 2010 they published a report on water usage in the oil and gas sector. According to the report, 98% of allocated water is used for hydropower and only 2% is used by all other sectors. Of that 2%, less than 1% is allocated to the oil and gas industry (British Columbia Oil and Gas Commission 2010). Therefore, it is difficult to imagine that water used for shale wells would create challenges in the overall supply of water resources (see Figure 15). Regardless, hydraulic fracturing operations are still considered water-intensive and the oil and gas industry is working to reduce the amounts of water used.

FIGURE 15: BC WATER ALLOCATIONS



Source: British Columbia Oil and Gas Commission (2010)

GOING IN THE RIGHT DIRECTION

The 2011 Responsible Clean Energy Award for environmental performance was presented to Apache and EnCana for their joint venture partnership Water Steward in Practice: The Debolt Water Treatment Project. Within two years, Apache and Encana have decreased their use of surface water and set up a secure access to an integrated water treatment and distribution system, which allows for the full recovery and reuse of fracture stimulation fluids (Canadian Association of Petroleum Producers 2011b).

How much wastewater is produced?

The amount of water being recycled and reused depends on the producer's production techniques. In the Marcellus shale, on average, 60% of the "flowback" water comes to the surface over the first four days after pressure is released. After this initial flowback, the wells continue to generate wastewater, but at lower volumes, averaging a few thousand litres a day. This wastewater is known as brine because of its high saline content. In the Marcellus play, anywhere from 9% to 35% of the initial hydraulic fracturing fluid will return to the surface as flowback. The vast majority will remain deep underground, in the horizontal chamber drilled for fracturing (University of Maryland School of Public Policy 2010).

Reusing the fluid to fracture another well is the most cost effective and environmentally effective choice for disposing of this wastewater. However, the flowback must always be treated, and even diluted flowback can adversely affect a well's production capabilities. A time will come when the water can no longer be used, and the waste is taken to a facility where the solids are separated out, and ideally reused again for fracturing. Disposal wells, also known as service wells, then return the saltwater brine back into deep subsurface formations (British Columbia Oil and Gas Commission 2010).

REUSING WATER

Chesapeake Energy has founded the Aqua Renew program which utilizes state of the art technology in an effort to recycle fracture fluids. At each well site, used fracture water is stored in holding tanks before being transferred to central filtration locations. On average, this system filters and reuses 40 million litres of produced water a month in the Marcellus fracturing operations (Chesapeake Energy 2010).

How much risk is there of leakage into the water tables?

The risks associated with leakage cannot be entirely discounted, but they are very small. Generally, multiple layers of cement separate the fracturing fluid and natural gas from aquifers and other underground formations. Regulations and policies recognize this risk, though regulations are not uniform across jurisdictions. In Alberta, for example, regulation requires an extensive well barrier, both vertically and horizontally, between stimulation zone and existing water tables, as well as isolating the fractured zone and aquifer (Canadian Association of Petroleum Producers 2010).

Public perceptions remain a challenge. The lack of knowledge generated by the perceived novelty of fracturing technology was reason enough for some governments to ban hydraulic fracturing. The EPA's study on hydraulic fracturing will provide much needed knowledge on these drilling practices and hopefully help ease the minds of the public.

PUTTING DEPTH IN PERSPECTIVE

Vertical well depths in Horn River and Montney shale

Domestic water < 150 m
Montney wells: 2,000 to 3,000 m
Horn River wells: 1,800 to 2,500 m (British Columbia Oil and Gas Commission 2010)

How deep is a shale gas well?

The difference between the peak of Mount Victoria and the elevation of Lake Louise is slightly less than 2,000 m, in other words, less than the minimum depth for a Montney or Horn River well.

The water issues—the amount of water being consumed, the amount of wastewater being produced and contamination—are real, but appear manageable. However, until there is a better understanding of these potential risks, it is difficult to know to what extent they will materially affect production costs or put production out of bounds, as has been the case in several US states on the Marcellus shale.

What are shale gas's greenhouse gas effects?

Aside from the water issues, there is one other environmental issue that has recently become more prominent—carbon dioxide. In January 2011, Quebec Natural Resources Minister Nathalie Normandeau downplayed the dangers of CO_2 from shale gas by saying, "dairy cows emit more greenhouse gases than shale gas wells" (Dougherty 2011). For the most part, shale plays are no more CO_2 intensive than conventional production. The Horn River resource play in BC, however, is particularly CO_2 intensive, with solution CO_2 at approximately 11-12% compared to 2-4.5% typically in BC's conventional reservoirs (CGA 2010).[22] Significant production from Horn River would add materially to the already large challenge facing BC in meeting its CO_2 targets. Capture and reinjection would solve the CO_2 problem, but at substantial cost.

Additionally, a widely publicized study released in April 2011 concluded that the greenhouse gas footprint from shale gas is at least 20% higher than that of coal. The basis of this conclusion appears to be significantly higher methane emissions from flowback gas during completion of shale wells compared to conventional natural gas wells (Howarth, Santoro and Ingraffea 2011).

Others dispute the findings of the study, arguing that the authors overestimated the average volume of gas vented during flowback stages by 60-65% and overestimated the impact of emissions during well completions by 90% (Wood Mackenzie 2011). The study also does not reflect the recent industry trend in green completions. Green completions significantly reduce emissions and allow producers to capture flowback gas. Green completion practices are now being utilized in developed shale plays such as the Fayetteville and Barnett shales. It is estimated that through 2020 such practices can lead to saving nearly 0.9 TCF from being vented or flared, adding approximately US $9 billion of incremental value from the Haynesville shale alone (Wood Mackenzie 2011).

The American Clean Skies Foundation (ACSF) published a report that concluded that existing natural gas fired generation is still, on average, about 51% less greenhouse gas intensive than existing coal-fired generation. The report also alleges that the Howarth publication significantly underestimated the energy output efficiency of modern natural gas plants (Staple and Swisher 2011).

[22] Other Canadian gas shales, like the Montney, Colorado Group, and Utica, have 1% or less carbon. Carbon contents in the Horton Bluff Group of Nova Scotia appear to average around 5% (National Energy Board 2010b).

Another lifecycle analysis of coal and natural gas by the US Department of Energy came to a very different conclusion than the Howarth study. The National Energy Technology Lab (NETL) found that the global warming potential of natural gas extraction and delivery was 54% lower for natural gas than for coal over a 100-year time horizon (Skone 2011).

Overall, the bulk of evidence confirms that natural gas is less greenhouse gas intensive than coal-fired generation

When all is said and done, Canadian producers are still in the game

Canadian marketed natural gas production in 2009 was 17.7 BCF/d, down from a peak of 20.3 BCF/d in 2006 (see Figure 2). Prior to the emergence of shale, most authoritative outlooks envisaged a slow and steady decline for Canadian production, which would have been boosted around 2015 by MacKenzie natural gas at around 1.8 BCF/d followed by further flows through Canadian pipe of Alaskan natural gas (National Energy Board 2010a). Although the Alaska and Mackenzie Delta pipelines have been years in the planning, neither is likely to be completed before the end of this decade or possibly long after. In fact, the Denali Pipeline, TransCanada's main competitor in the proposed Alaska pipeline, withdrew from the race to build the $35 billion project in May 2011, citing low natural gas prices as the primary reason.

Shale has had two effects with opposite implications. The North American price effect is negative, but the same technology that unlocks Barnett and Marcellus also unlocks significant potential in Canadian unconventional plays, notably the Montney (tight sands) and Horn River (shale) in northeast BC. Significantly, these plays have relatively attractive supply costs and they are luring investment.[23]

The amounts of capital being invested in shale production are immense. It is not uncommon to go only a few months before hearing about another multi-billion dollar deal in the unconventional sector. Given the opportunities discussed earlier about LNG exports to Asia, significant investment has been made in this area. Not only British Columbia, but also Alberta and Saskatchewan have unconventional reserves that will become targets for drilling. Given that the Western Canadian Sedimentary Basin (WCSB) is rich in infrastructure and take-away capacity combined with a generally supportive public policy environment, it remains a target for investment capital even in the face of soft North American markets.

23 BC (oil and gas, but mostly gas) land sales in 2010 grossed the fourth-most since CAPP began tracking. Alberta conventional (oil and gas) land sales set a record.

Several factors could modestly improve the competitive position of Canadian producers: shale may be less of a revolution than shale boosters think, and if the contrarians are even partly right, costs for the marginal molecule could be higher than current projections suggest. Electricity markets driven by carbon constraints could conceivably boost demand toward levels that push the marginal molecule above $6. Access to Asian LNG markets would be positive, although unlikely to affect prices in North America.

Other factors could also make it tougher for natural gas. Carbon costs cut both ways in natural gas markets and add to costs, especially for high content reservoirs such as Horn River. Environmental issues such as water and concerns about land impacts will likely add costs or in some cases put resources off limits to production, but this effect would likely be to the relative advantage of western Canadian producers compared to those in the Marcellus or Utica, for example. On balance it seems likely that Canadian producers will still be in the game and able to sustain production, but the high growth days from 1985 to 2005 and the high price days of the past decade will be hard to replicate.

KEY CANADIAN CAPITAL PROJECTS

Kitimat LNG Terminal: Apache, EOG Resources and EnCana venture targeting 2015 for first shipment, fed by Apache and EOG fields in Alberta and British Columbia; designed to open up Asia Pacific market.

Montney Shale: Talisman Energy and Sasol announced in December 2010 a $2 billion agreement to partner on the development of shale gas resources in the Montney formation. Talisman estimates that production in the region could ultimately reach 45 to 50 wells with capital expenditures approaching $1 billion.

Fort Nelson: EnCana has proposed development of a natural gas processing plant in the Fort Nelson area. The last provincial government update noted the project had received environmental certification and that the project's development was progressing.

4. The changing world of natural gas has implications for policymakers

Canadian policymakers in federal, provincial and territorial governments all have a large stake in how our natural gas future unfolds. That is not the same as saying that they have large latitude to shape it directly given the importance of markets as the principal arbiter of that future. But there are several ways that Canadian governments can play the hand they have been dealt in ways that maximize our advantages and minimize our disadvantages.

Natural gas, as noted at the outset of this report, has been very good for both Canadian consumers and producers. Just as important, the policy leadership on natural gas shown by federal and provincial governments in the 1980s has been good for producers, consumers and the jurisdictions in which they live. That policy framework will likely serve us well in the future albeit with modifications to meet evolving circumstances.

Circumstances have changed, some of them profoundly. The carbon debate barely existed at the time of deregulation and free trade. At that time, many alternatives to fossil fuels and the potentials of much higher efficiency were mainly the domain of dreamers who were not viewed seriously in many energy policy circles. Today carbon is a real issue (even if it has temporarily faded from public view) and we are arguably on the cusp of an energy technology revolution from production through delivery to end use. In the mid-1980s, natural gas was abundant because large resources were physically and technically accessible. Investment flowed into the industry in response to policy and brought those resources to the market. Relatively low prices were advantageous for consumers. Today, natural gas is again seen as abundant after a hiatus of a decade and prices have returned to levels by no means as low as the 1990s, but significantly lower than much of the decade just past.

For consumers, the future looks extremely positive. Lower natural gas costs can underpin the competitiveness of the Canadian economy, especially in energy intensive economic sectors. Abundant, reliable, affordable natural gas, especially in combination with new technologies and institutional innovations creates or makes feasible multiple energy options. None of the following options would be as feasible or cost-effective without natural gas: increased overall system efficiency, hybrid heating systems, a more diverse, reliable and low impact electricity system, and low emissions heavy-duty vehicles.

For governments looking for realistic options to reduce carbon and create sustainable energy systems over the long-run, natural gas is the lynchpin. It is one of the most technically feasible and affordable short-term options and the foundation for making long-term options resilient and reliable. However, the returns to government will be more limited with material consequences especially for provinces that are heavily reliant on natural gas revenues (although for Alberta, reduced natural gas costs will improve royalty returns from oil sands production). Gas will still be an important source of employment and economic activity as well as a positive contributor to trade balances, but it will not be the fiscal golden goose that it was until recently.

The Canadian producer perspective is a little less rosy, but far from dire. Canada has lost competitive ground in its sole external market (and potentially in domestic markets). The North American price environment seems likely to make producer returns less robust than in much of the past decade. But Canada will still be in the game. We have abundant, widely distributed resources, which are cost-effective to produce albeit far from markets. We have a strong industry with global reach, and one of the most competitive policy environments in the world.

With the above in mind, the following are the key issues for public policymakers.

Reaffirm the basics

The natural gas success story of the past 25 years rests on a solid framework of minimal economic regulation, market pricing, free trade, and open investment. These ideas should be touchstones for policy in the future and governments should be wary of measures designed to mandate energy choices, control prices or directly subsidize energy projects.

Recognize gas as the foundation of a sustainable energy future

Even a very low carbon future will need fossil fuels for much of the rest of this century and natural gas has the lowest carbon. Its properties make it the most flexible fuel as well as the best adapted to providing the foundation on which other energy options will operate. Policy needs to embrace this reality.

Emphasize value for consumers

Canadian governments should avoid discouraging the use of natural gas in markets where it is the sensible choice. Policy should not be based on the rhetorical value of energy choices (especially when many often prove to be passing fads or simply wrong-headed), but rather on the real merits of all choices in providing affordable, reliable, environmentally responsible energy, both in the near term and beyond.

Think carbon pricing not carbon regulation

Natural gas is a strong competitor in an environmental and carbon policy context that emphasizes market economics supplemented by market sensitive and performance-based environmental policy. In other words, a level playing field that prices environmental costs, including carbon, evenhandedly and transparently is key. As compared to worlds where governments either prevaricate on carbon or regulate emissions through specified technologies, the world of transparent carbon pricing is the one most favourable to natural gas across the range of applications.

Ensure adaptability to an uncertain future

The future of technologies, energy commodities and energy costs is highly uncertain and consumers, producers and governments are best off when policy avoids trying to pick winners or direct the market. Many winners could well prove to be hybrid technologies or integrated systems based on natural gas—or something else entirely—and the only reliable arbiter for investment and consumer choices is price.

There is a market failure rationale for governments to support technologies at the research, development and demonstration stage. If the criteria guiding decisions to provide support are based on outcomes such as energy efficiency, carbon reduction, air contaminant reduction or contributions to energy system integrity and reliability, then natural gas will often be a competitive option.

Help overcome competitive headwinds in the North American marketplace

The development of access to world markets should be a Canadian priority. For governments, that should entail positive message support and regulatory facilitation for market-based west coast export solutions.

Continuing to ease the cost, time burdens, and uncertainties of environmental approval should be a priority for all aspects of the energy supply industry including natural gas.

Provincial governments have in the past few years taken a realistic approach to royalty regimes to ensure that they reflect market realities. For the most part, Canadian tax regimes are competitive, but governments need to be vigilant to ensure that Canadian natural gas production faces competitive fiscal circumstances, particularly compared to the US and as market realities change over time.

5. Conclusion

Canada has benefited enormously from a successful natural gas industry—from wellhead to burner tip, from west to east, and north to south—and will continue to do so along the full value chain as long as it sustains a supportive public policy environment. Much of this policy environment should be built on the foundation laid in the mid-1980s, but adapted to a world that has changed in important ways with respect to supply sources, markets, environmental imperatives and technology opportunities. Given a world full of uncertainties, policymakers can create a framework in which producers, consumers, and distributors can be confident in their energy choices. Canadian policymakers and stakeholders need to refresh this framework as part of the broader dialogue on energy that is currently taking place.

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Appendix A: Economic Impact Indicators

SELECT MACROECONOMIC INDICATORS

		BC	AB	SK
Gross Domestic Product (GDP) Derived from Natural Gas Industry in billions (2010-2035)		$ 396.6	$ 859.5	$ 73.6
Employment Impact (2010-2035) (thousand person years)		2,975.1	4,500.7	629.0
Natural Gas Exports in millions	2010	$ 2,006	$ 12,745	$ 200
	2009	$ 1,857	$ 13,535	N/A
	2008	$ 3,146	$ 28,149	N/A
	2007	$ 2,682	$ 24,436	$ 0.281
	2006	$ 3,014	$ 23,938	$ 15

Sources: Gibbins and Roach (2010) and Industry Canada (2011) Notes: "thousand person years" = total number of jobs (times 1,000) that last for one year. Includes conventional natural gas from BC, Alberta, and Saskatchewan and unconventional natural gas from Alberta and BC.

SELECT INDUSTRY INDICATORS

		BC		AB		SK	
		# of Hectares (000s)	Value (mill.)	# of Hectares (000s)	Value (mill.)	# of Hectares (000s)	Value (mill.)
Oil and Natural Gas Crown Land Sales	2010	370	$844	3,853	$2,388	453	$463
	2009	389	$893	1,741	$732	307	$118
	2008	757	$2,662	2,024	$938	766	$1,119
	2007	596	$1,047	1,872	$711	405	$250
	2006	691	$630	2,693	$1,472	455	$177
	Fiscal Year	Value (mill.)	Percent of. total prov. budget rev.	Value (mill.)	Percent of total prov. budget rev.	Value (mill.)	Percent of total prov. budget rev.
Natural Gas Royalty Revenue	2009-2010	$406	1.08%	$1,525	4.28%	$39	0.38%
	2008-2009	$1,314	3.43%	$5,834	16.29%	$126	1.02%
	2007-2008	$1,132	2.85%	$5,199	13.62%	$134	1.36%
	2006-2007	$1,207	3.14%	$5,988	15.75%	$165	1.91%
	2005-2006	$1,921	5.34%	$8,388	23.60%	$269	3.27%

Sources: Canadian Association of Petroleum Producers (2011a), Government of British Columbia, Alberta Energy (2011) and Saskatchewan Energy and Resources (2010)

Appendix B: Measuring Natural Gas

The world of natural gas is one that uses several different and sometimes confusing units of measurement. What gets used is contingent on context.

Although Canada uses the metric system, when we are referring to wholesale or bulk volumes we tend to use imperial measures like trillion cubic feet (TCF) or billion cubic feet (BCF) because that is what is used in the US and is, therefore, the prevailing North American practice. The rest of the world uses metric.

Resources and reserves are typically expressed in TCF. Production is either TCF/year or —more often—BCF/day.

Liquefied natural gas (LNG) quantities are most often expressed in weight (tonnes) or in cubic meters (to conform to international metric use), although this report has used million cubic feet per day (MMCF/d) because we link it to North American production.

Wholesale market values are often expressed in heating value terms to reflect variation in the composition of natural gas. Market natural gas is not pure methane but can include small amounts of nitrogen, carbon dioxide or heavier hydrocarbons such as ethane. Because of this the heating value may vary and what the customer is buying is heating value: $/one million (MM) British Thermal Units (Btu) or giga-joules (GJ).

At the consumer sales end, Canada uses metric. Consumers pay for cubic metres of natural gas (1 cubic metre equals about 35 cubic feet). The composition of gas delivered to consumers is essentially methane and therefore heating values conform closely to volumes within extremely narrow tolerance ranges. Conveniently, one million Btus are equivalent to 1.05 gigajoules, which corresponds roughly to the energy content in one thousand cubic feet (MCF) of natural gas.

Energy and measurement conversions for natural gas are based upon natural gas being held at 60 degrees Fahrenheit and 14.73 PSIA of pressure.

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