APPENDIX D

Ziff Energy, Long-Term Natural Gas Supply and Demand Forecast to 2050 for Bear Head LNG (November 2014)

Long-Term Natural Gas Supply and Demand Forecast to 2050 for Bear Head LNG

November 2014

This PDF has been electronically signed by William J. Winnick, P.Eng.

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9 February 2015

Mr. John Godbold
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Houston, Texas 77002
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Re: Long-Term Natural Gas Supply and Demand Forecast to 2050

Dear Mr. John Godbold:

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Sincerely,

Ziff Energy – A Division of Solomon Associates

W.P. (Bill) Gwozd, P.Eng.
Senior Vice President, Gas Services

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1.0 Introduction

Bear Head LNG Corp. is applying to the National Energy Board (NEB) for a licence to export up to 12 million tonnes per annum[1] of liquefied natural gas (LNG)[2] for a period of 25 years between 2019 and 2044. Natural gas will be liquefied at a proposed LNG terminal to be located in Nova Scotia (NS) and transported from there by LNG carriers to markets in Europe, Asia, and other regions.

Bear Head LNG Corp. retained Ziff Energy, a division of HSB Solomon Associates LLC (Solomon), to provide an independent assessment of North American and Canadian natural gas supply, demand, flows, and costs, and to draw conclusions regarding the balance of supply and demand for the period 2019–2044, within which the applied-for export would take place.

This report presents summary findings on gas supply, demand, and market dynamics through 2050, and draws related conclusions.[3] The work is extracted from Ziff Energy's detailed proprietary sectorial and regional demand analyses, basin-by-basin gas supply work, full-cycle cost studies, and understanding of changing continental gas flows.

[1] This export volume does not include an annual tolerance which may be applied for.
[2] Approximate natural gas equivalent of 1.7 billion cubic feet per day (Bcf/d) at the liquefaction plant outlet.
[3] To allow for potential start up delays, the supply and demand analysis is extended to 2050.

2.0 Summary

During our assessment of the North American, Eastern Canadian, and Western Canadian natural gas supply, demand, flows, and costs, we noted several key findings, each of which is summarized as follows.

2.1 Gas Resources

Ziff Energy's evaluation of North American and Canadian gas resources shows productive potential exceeding projected gas demand during the forecast period. North America has 3,044 trillion cubic feet (Tcf) or 3,196 exajoules (EJ) of remaining resources as of January 1, 2014. Canada has 751 Tcf (789 EJ) of remaining gas resource, of which 6% is to be found in Eastern Canada[4] (44 Tcf, 46 EJ).

2.2 Gas Supply

Ziff Energy forecasts that the North American supply of natural gas will grow to 139 billion cubic feet per day (Bcf/d) or 146 petajoules per day (PJ/d) in 2050 from 81 Bcf/d (85 PJ/d) in 2013. After 2020, shale gas is expected to be the main type of gas produced in North America. Canadian supply is forecast to grow to 35 Bcf/d (37 PJ/d) in 2050[5] from 14 Bcf/d (15 PJ/d) in 2013. Ziff Energy assumes natural gas prices rise in line with full-cycle producer costs (including a 15% before tax rate of return). If gas prices are below full-cycle producer costs, gas-directed drilling levels are expected to decline, decreasing gas supply, which would lead to higher gas prices.

2.3 Gas Demand

Ziff Energy forecasts North American demand[6] (including LNG export) for natural gas to increase 57 Bcf/d (60 PJ/d) to 136 Bcf/d (143 PJ/d) by 2050 from 79 Bcf/d[7] (83 PJ/d)[8] in 2013, an average annual growth rate of 1.5% per year. Within that total, Canadian gas demand (currently 9.1 Bcf/d (9.6 PJ/d)) is expected to grow at a rate of 3.8% per year driven principally by a switch away from coal-fired power generation, increased gas requirements for growing oil sands bitumen production and growth in LNG exports. Canadian gas demand as a share of overall North American demand will grow to 27% by 2050, from 11% in 2013. During the forecast period, demand in the US will grow 0.9% per year driven by strong growth (1.5% per year) in the gas-fired power generation sector. Included in North American gas demand are LNG exports of 25.8 Bcf/d (27.2 PJ/d) in 2050, of which 19.7 Bcf/d (20.8 PJ/d) are from Canada.

[4] Eastern Canada includes both onshore and offshore Nova Scotia, New Brunswick, plus offshore Newfoundland and the Labrador coast
[5] Ziff Energy has modeled all NEB-approved LNG export volumes, ramping up at a rate of 0.7 Bcf/d from 2019 to a total of 18.03 Bcf/d in 2050 plus the proposed Bear Head LNG Corp. project volumes assumed at 1.7 Bcf/d.
Ziff Energy does not consider such a high volume of LNG exports from Western Canada to be likely over the forecast period.
[6] Does not include 3 Bcf/d (3 PJ/d) of natural gas exports to Mexico from the US.
[7] Ziff Energy has treated LNG export volumes as an out-flow from North America.
[8] 1 Bcf/d = 1.05 PJ/d, per National Energy Board
(http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/sttstc/nrgycnvrsntbl/nrgycnvrsntbl-eng.html).

Ziff Energy's forecast is predicated on annual North American gross domestic product (GDP) growth of 2.2% during the forecast period. Government policies, such as putting a price on carbon emissions, will tend to increase gas demand (natural gas emits approximately half the carbon emissions of coal).

2.4 Supply/Demand Balance

Natural gas markets in North America are expected to continue to function in a rational manner during the forecast period and will continue to provide appropriate market signals for development of resources to meet Canadian domestic and export demand. The North American gas market is composed of a large number of competing buyers and sellers with a multitude of available purchase and sale instruments. Energy pricing is transparent and facilitated by electronic trading systems, a vigorous futures market, and various financial instruments.

Low-cost sources of gas supply are growing, mainly from unconventional-gas plays, some of which are being developed near major market centers. The North American gas supply system is characterized by a sophisticated network of transmission and storage infrastructure. Imports of gas from the US into Central Canada via Dawn and Niagara are displacing some gas delivered previously via the TransCanada PipeLines Limited (TransCanada) Mainline system from Western Canada. This trend is expected to continue. As a consequence, Central Canada has increased choices for gas supply sources.

Gas buyers will continue to be incented to minimize delivered gas costs in a functioning North American natural gas market. Ziff Energy expects supplies of North American gas will be available to meet demand for all Canadian and North American sectors during the forecast period. During the forecast period, Canadian supply will be available for Canadian and export markets, and given a competitive market, this supply will preferentially flow to the markets providing highest netbacks.

Ziff Energy expects new North American gas supplies, principally from shale-gas and other unconventional-gas plays, to more than offset declines in conventional gas. The market, including demand for LNG exports, will therefore balance. Gas from new and expanding gas supply basins will alter North American gas flows. Eastern Canadian demand is increasing, providing growth opportunities for regional participants to expand their choices for new gas supply. Therefore, the region will be well-supplied during the forecast period with adequate supply for concurrent LNG exports.

3.0 Basin Competitive Factors

Competition for markets continues to increase between natural gas supply basins. The following text focuses on the growing North American competition.

3.1 Growing US L48 Supply and Gas Flows

While Western Canadian natural gas supply faces growing competition from traditional markets in the United States' Lower 48 (US L48), Central Canada develops opportunities for new gas supply choices. The advent of new pipeline capacity from the US Rockies[9] during the last decade has pushed back Canadian gas into the Western Canada Sedimentary Basin (WCSB), driving down prices and resulting in lower levels of gas-focused upstream activity. The Rockies Express Pipeline built in 2009 delivers US Rockies gas into the US Midwest and Northeast markets, displacing higher-cost Canadian gas in these markets. The Bison Pipeline, connected in 2011, delivers US Rockies gas into Northern Border Pipeline and could back out as much as 400 million cubic feet per day (MMcf/d) of Canadian gas destined for US Midwest markets. The Ruby Pipeline, which delivers US Rockies gas from the Opal, Wyoming Hub, to Malin, Oregon, could back out as much as 700 MMcf/d of WCSB gas from this traditional Canadian market (California).

Low-cost supply from the Marcellus shale-gas play in the US Northeast is now pushing into Eastern Canadian markets at Niagara via a reversal of the Tennessee Pipeline, thereby providing more choice to Eastern Canadian gas users. Spectra Energy, DTE Energy, and Enbridge have proposed the green-field Nexus pipeline[10] to connect Utica gas from Ohio through the Vector Pipeline into Ontario at Dawn. The Iroquois Pipeline has received a US Presidential permit allowing for the import of US gas into the Eastern Canadian market at Waddington. In summary, changes in gas supply are rippling into additional gas consumer choice.

Low-cost shale-gas supply and associated gas from tight-oil plays are altering North American gas flows, causing a major re-configuration of gas pipeline infrastructure. Currently, tolls on the TransCanada Mainline cause the delivered cost of WCSB gas in traditional Ontario and Quebec markets to be less competitive than US L48 gas delivered to the Dawn Hub, Ontario. Ziff Energy expects that transportation costs on other ex-WCSB pipelines will be too high for continued export of Canadian gas to traditional markets in the US L48 and Central Canada. This trend will continue[11] as supply in low-cost US L48 gas basins continues to attract investment and grow during the forecast period.

[9] Rockies Express (November 2009), Bison (January 2011), and Ruby (July 2011).

10 The Nexus Pipeline is being discussed as a 30 or 36 inch-diameter (in-dia) pipeline; the pipeline could deliver up to 2 Bcf/d.

11 Ziff Energy expects some Western Canadian gas supply will continue to be delivered to the Dawn Hub throughout the forecast period.

Figure 1 shows new pipeline projects within the US Northeast with expected in-service dates between 2014 and 2018. These projects would add at least 10 Bcf/d of incremental capacity and highlight the decreasing relevance of Canadian natural gas in the North American market as a result of increasing Marcellus Utica shale gas, and other US L48 supply pushing into Eastern Canadian and Northeastern US markets. New pipelines from the US Rockies have allowed increased gas-on-gas competition in the US Northeast, Midwest, California, and Canadian markets.

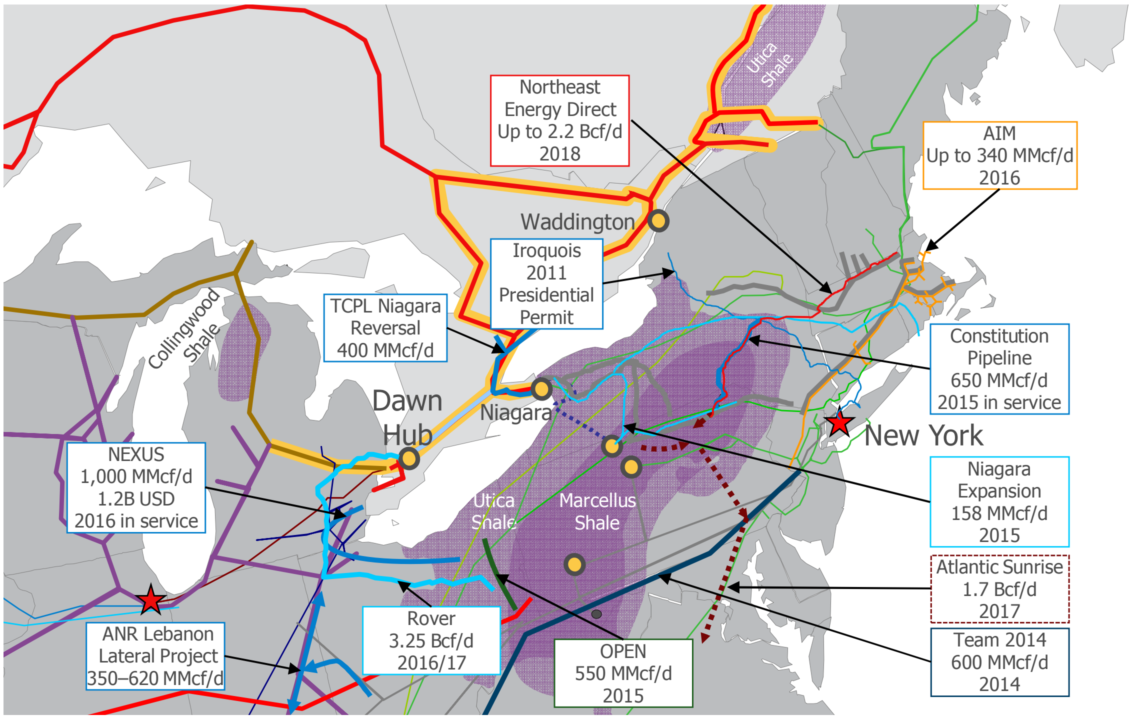


Figure 1. New US Northeast Pipeline Projects

3.2 Western Canadian and Appalachian Full-Cycle Gas Costs

Figure 2 (page 6) shows a summary of average full-cycle cost[12] for new gas supply in Western Canada and Appalachia (Marcellus and Utica). The average Western Canadian full-cycle cost (4.75 USD/Mcf), is 16% higher than the average Appalachian full-cycle cost of 4.10 USD/Mcf.

Full-cycle costs for natural gas vary markedly by basin, within a basin, by play, by producer, and by year. High-cost conventional-gas supply is being squeezed out by supply from lower-cost shale-gas and tight-gas plays. This phenomenon accelerated after 2006 as a land rush in shale-gas plays resulted in drilling activity centered on holding lands by production, even in the face of declining gas prices. Much of the drop in full-cycle costs is due to lower Finding and Development (F&D) costs of more productive unconventional wells and lower royalties payable on lower gas prices.

[12]Based on Ziff Energy's *North American Economic Ranking Study*, August 2014.

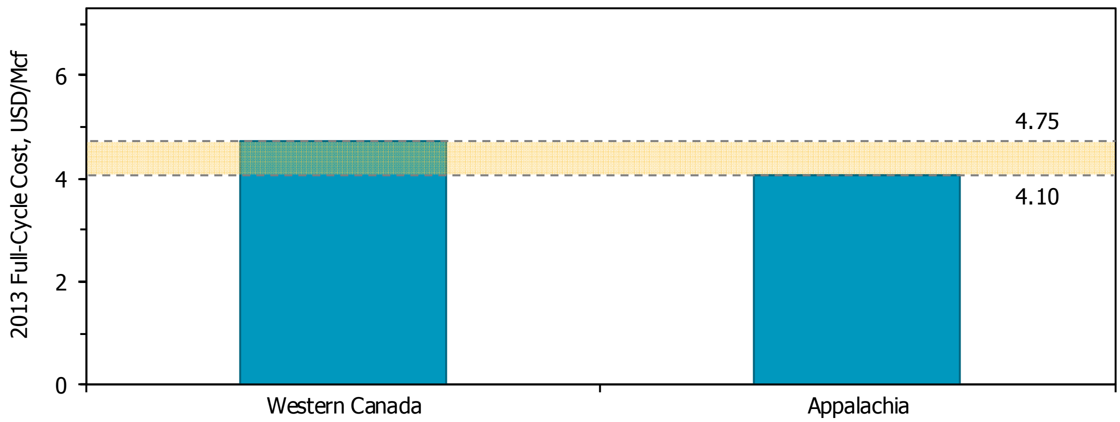


Figure 2. Western Canadian & Appalachian Average Full-Cycle New Gas Cost

3.3 Impact of Competition and Full-Cycle Costs on Basin Activity and Production

Competition from US L48 gas in Canada's traditional natural gas markets and higher full-cycle costs have led to a decline in gas-focused exploration and development activity in Western and Eastern Canada. Investment levels are recovering in Western Canada as producers focus on lower cost, high-productivity liquids-rich gas plays.

Due to the relatively short distance and well-established pipeline infrastructure, gas producers in the Marcellus shale-gas region and emerging Utica shale-gas play in the US Northeast have a much shorter distance to transport their low-cost gas to Central Canada versus Western Canadian gas producers—thus providing a higher netback, better investment returns, and more money directed to drilling, infrastructure, and development. Western Canadian gas producers are disadvantaged due to distance from markets and the associated tolls relative to natural gas produced in areas more proximate to major markets.

4.0 Gas Resources

This section describes North American ultimate and remaining potential gas resource.

4.1 North American Ultimate Potential Gas Resource

The ultimate potential resource is the total amount of gas that can be produced—including production to date, discovered reserves or resources, and undiscovered potential resources—without assessing economic viability. Ziff Energy considers North American natural gas resources to be prolific and capable of meeting consumer energy requirements at fair market prices during the forecast period. Figure 3 shows Ziff Energy's assessment of the ultimate potential natural gas resource[13] of North America by region, 4,464 Tcf (4,687 EJ).[14] The size of each pie is proportional to the gas endowment of each region as of January 1, 2014. North America has 3,044 Tcf (3,196 EJ) of remaining resource of which 358 Tcf (376 EJ) is proved.

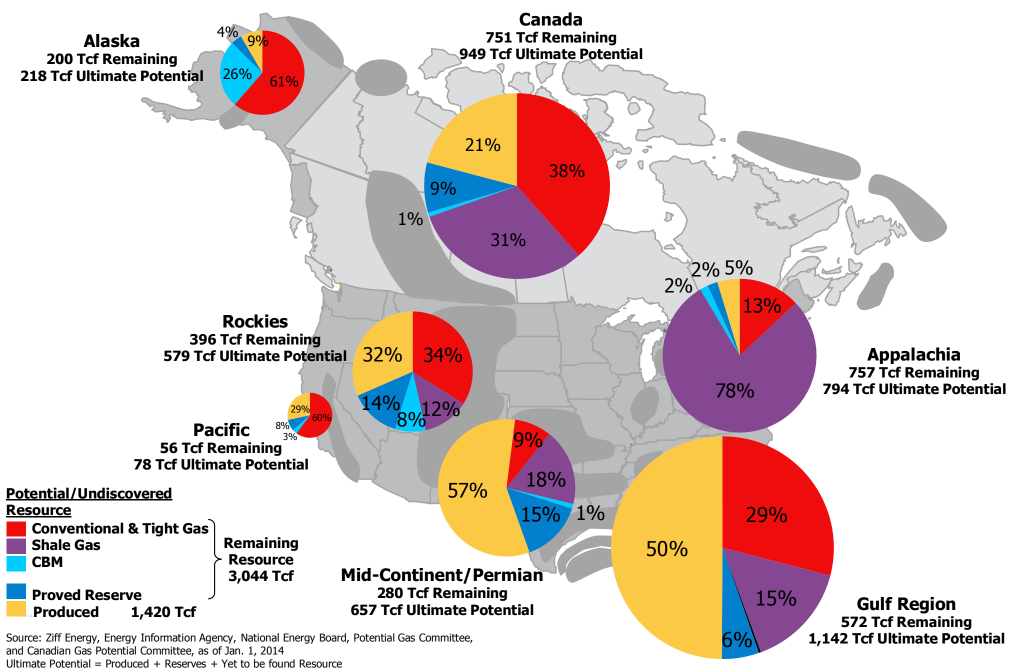


Figure 3. North American Natural Gas Resources

[13] Undiscovered potential resources are estimates of technically recoverable marketable dry gas based on existing or anticipated technology as reported by the Potential Gas Committee, the Canadian Gas Potential Committee, the National Energy Board of Canada, and Ziff Energy resource and production models; cumulative production and reserves consist of dry, recoverable gas as reported by the Energy Information Agency (US) and Canadian Regulators.

[14] While the North Central region of the US is not shown on the map in Figure 3, total resources include the region's 47 Tcf of ultimate potential resource and 32 Tcf of remaining resource.

In general, there is uncertainty with respect to undiscovered resource estimates:

- Evaluations are generally not comprehensive, nor are consistent methodologies used.
- Estimates for developing plays[15] or unproven concepts are speculative—shale-gas resources are substantial and may differ from current estimates.
- Undiscovered resource can increase with improved technologies,[16] which enhance existing plays or make other plays technically viable.

Supply responds to changes in demand, while ultimate potential resource should not—it is an estimate of the original gas resource that existed before production started, based on current information, and not limited by demand or economics. While ultimate potential resource estimates are not gas supply, they can provide an indication of an upper limit to potential supply with today's knowledge and expected technological improvement. For example, estimates of conventional-gas ultimate potential resource for Western Canada grew as knowledge of the conventional basins increased; for the last 20 years, the estimate has not changed significantly. The recent surge in unconventional-gas production, triggered by the technological combination of horizontal drilling and multistage fracturing, may continue for some time to come, and the ultimate potential resource may also grow—production is just starting from the Utica shale-gas play, increasing the shale-gas ultimate potential resource.

Resource development requires skilled labor, investment, and adequately priced gas markets to give producers a reasonable rate of return on their investments. In the long-term, producers will commit to the development of additional gas resources as they become economical, including gas discoveries that are distant from the North American natural gas pipeline grid.

[15] A play is a group of many drilling opportunities that have similar geological characteristics, such as the Horn River Basin shale-gas play.
[16] The innovation of horizontal drilling and multistage hydraulic fracturing has dramatically increased resources across North America by adding shale-gas and other plays to the ultimate potential resource.

4.2 Canadian Gas Resource

Canada has 751 Tcf (789 EJ)[17] of remaining gas resource, of which 6% is in Eastern Canada. Figure 4 shows gas resource estimates for major Canadian basins. In addition to these basins, other areas and plays have potential gas resource, such as Quebec and Atlantic Canada shale gas, BC interior, offshore basins, and Arctic Islands. These resources have not been included because they are speculative, unproven, or are a significant distance from any transport system and unlikely to contribute to supply in the foreseeable future.[18]

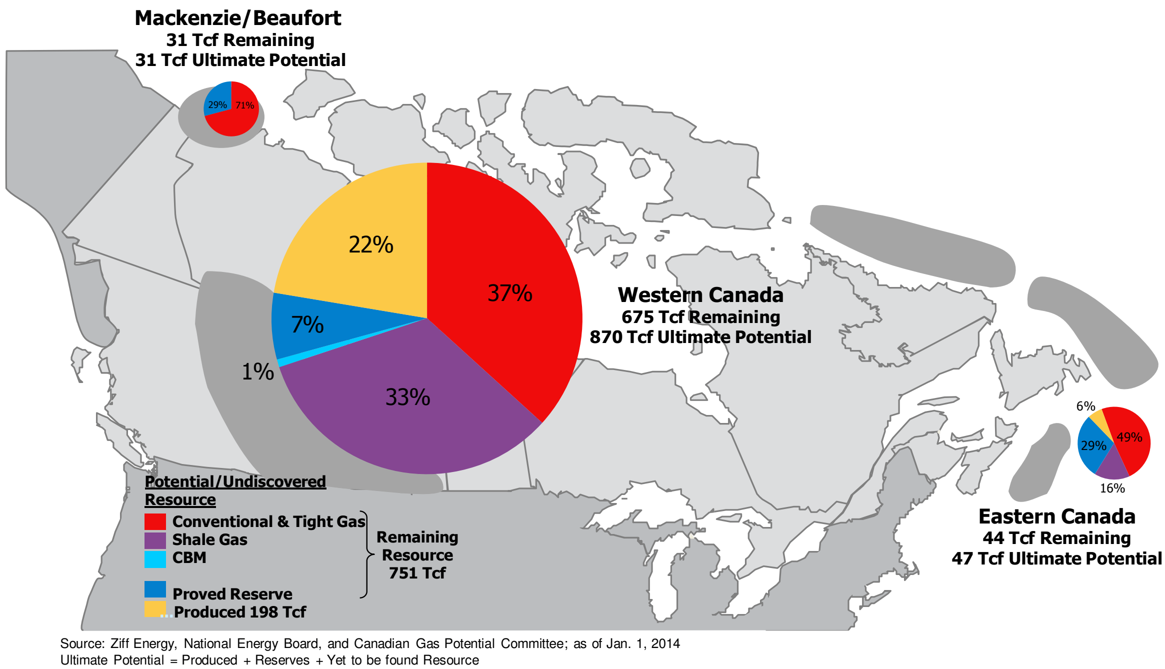


Figure 4. Canadian Natural Gas Resources

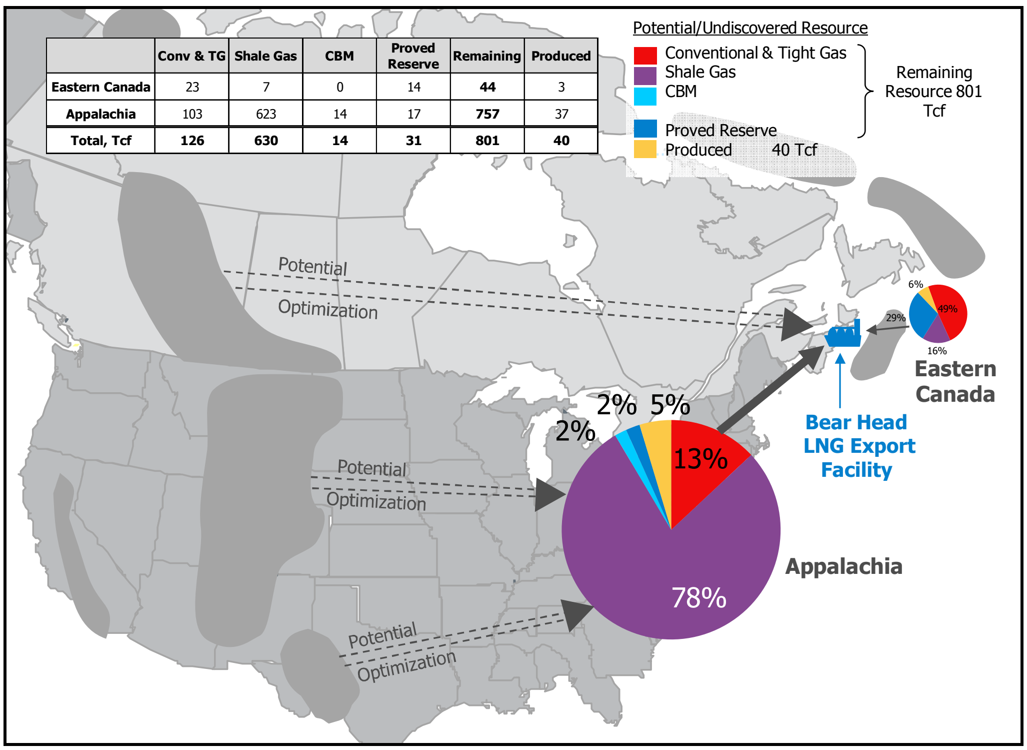
4.3 Eastern Canadian Gas Resource

Gas resources exist in Central Canada (Ontario, Quebec) and Eastern Canada. A portion of this resource is shale-based. While large quantities of this resource (including shale) have not been commercially proven, the potential exists for it to become a supply source for overseas gas markets with the appropriate gas pricing dynamics.

[17] While the Ontario gas resource is not shown on the map in Figure 4, total resources include the province's 2 Tcf of ultimate potential resource and 1 Tcf remaining resource.
[18] Collectively, these basins may contain more than 50 Tcf of gas resource potential; in general, basins that contain gas associated with oil or natural gas liquids production may be connected sooner.

Figure 5 provides a summary of Eastern Canadian and Appalachian gas resources. As of January 1, 2014, the Eastern Canada has produced 7% (3 Tcf, 3 EJ) of the ultimate potential with 44 Tcf (46 EJ) remaining. The Appalachian basin has produced 5% (37 Tcf, 39 EJ) of the ultimate potential with 757 Tcf (795 EJ) remaining. The remaining potential gas resource of Appalachia is estimated to be roughly equivalent to the Western Canada Sedimentary Basin. The remaining gas supply resource from Eastern Canada represents only 6% of the gas resource from the Appalachian basin.

Gas is currently flowing from Appalachia into Central Canada. Ziff Energy expects this to continue, due to close proximity and pricing. This gas represents a low cost choice for Central Canadian consumers. The Appalachia basin is expected to supplement the Eastern Canadian production[19], accessing New Brunswick and Nova Scotia markets, beginning as early as 2018. With no additional gas development from onshore or offshore Eastern Canada, the production profile for current Eastern Canadian production will be at the expected economic limit by 2026.



	Conv & TG	Shale Gas	CBM	Proved Reserve	Remaining	Produced
Eastern Canada	23	7	0	14	**44**	3
Appalachia	103	623	14	17	**757**	37
Total, Tcf	**126**	**630**	**14**	**31**	**801**	**40**

Figure 5. Eastern Canadian Gas Resources

[19] Economic optimization may occur within various gas supply basins in the L48 States over the forecast period, providing the opportunity for non-Appalachian gas to also fill portions of the demand requirements of Eastern Canada.

4.3.1 Nova Scotia

Figure 6 shows the location of Nova Scotia gas resources, supplied from offshore Sable Island and Deep Panuke plus the primary pipeline infrastructure Maritimes & Northeast (M&NE). Sable Island has been producing since 2000 with 2013 production averaging 130 MMcf/d. Initial production from Deep Panuke commenced in the third quarter of 2013 and is forecast to average less than 300 MMcf/d in 2014.

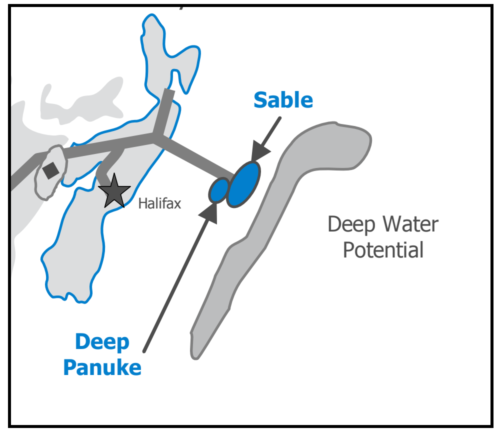


Figure 6. Nova Scotia Gas Resource Region

Production operating costs will weigh on the future economic viability of existing offshore Nova Scotian gas production. Gas production for both Sable Island and Deep Panuke is forecast to reach the end of their economic life during the forecast period.

Figure 7 illustrates the ultimate potential and remaining natural gas resource for Nova Scotia. The ultimate gas resource potential of Nova Scotia is estimated at 24 Tcf (25 EJ) of marketable dry gas with 9% being produced. The largest component of the remaining gas resource (66%) is composed of conventional and tight gas. Nova Scotia shale-gas development is still in the early exploration stages of resource development. In September 2014, the Nova Scotia government announced plans to introduce legislation for a ban on high-volume hydraulic fracturing for onshore shale gas. No timeline or process was given for removal of the ban. Ziff Energy expects that with public consultation and review, future shale-gas development and production may proceed in Nova Scotia.

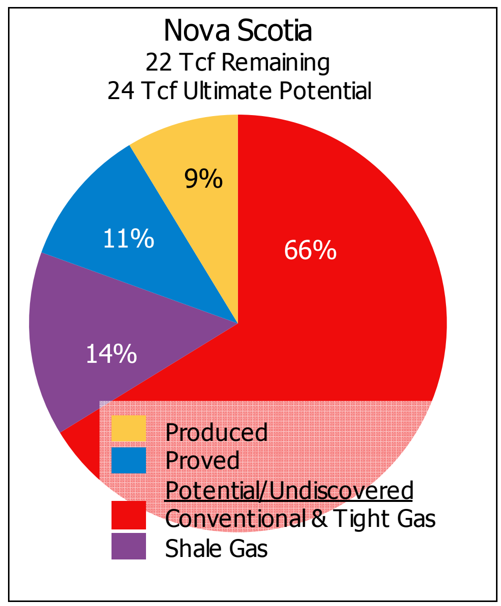


Figure 7. Nova Scotia Natural Gas Resources

Between 2012 and 2013, Shell Canada (Shell) acquired six exploration licenses, approximately 250–300 km offshore of Nova Scotia, highlighting the potential for additional resources. ConocoPhillips and Suncor have joined the venture. BP Canada also acquired exploration licenses offshore Nova Scotia in 2012 and 2013. A seismic program is planned for 2014 and 2015.

With Shell's seismic program completed, the exploration drilling program is intended to confirm the presence and prospective amount of hydrocarbons in the licensed area. Shell is expected to drill up to seven offshore deepwater wells between 2015 and 2019 in two phases (up to three wells in the first phase and up to four wells in phase two). Shell, as operator, has announced that it will commence drilling the first two exploration wells in the second half of 2015.[20] Based on a discovered resource, the operator may apply for a Significant Discovery License (SDL). Currently, there are approximately 30 SDLs for

[20] "Shell welcomes joint venture partners to offshore Nova Scotia project", June 9, 2014 press release

offshore Nova Scotia, which demonstrates via exploration efforts that there are discovered resources. Some SDLs have gas development potential, including Onondaga (100% Shell) and Glenelg (Shell/ExxonMobil majority ownership).

The potential exists for additional offshore Nova Scotia gas to be available for future North American demand, including LNG liquefaction. Offshore Nova Scotia gas resources remain a potential source of supply for Maritime demand, including LNG exports.

4.3.2 Newfoundland and Labrador

Figure 8 shows the Newfoundland offshore oil and gas resource region. The Jean d'Arc basin contains the established producing oil fields of Hibernia, Terra Nova, and White Rose. Initial commercial oil production from the Hebron field is projected for 2017. The Flemish Pass Basin is emerging with commercial oil potential from three exploration light oil discoveries. Commercial oil production has yet to commence from Flemish Pass.

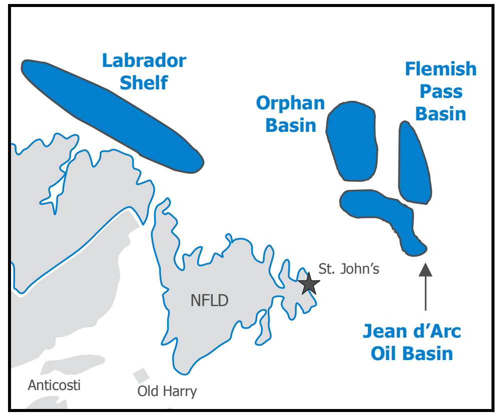


Figure 8. Newfoundland Gas Resource Region

Associated gas production from the Jean d'Arc basin producing oil fields is re-injected for reservoir pressure maintenance, used as fuel and a power source, or is being stored.

Currently, oil from the Jean d'Arc basin is loaded onto tankers for transport to market. Although natural gas is not a current focus of offshore oil operators, it could become a source of gas supply if the Eastern Canadian LNG export market becomes established.

There is no existing natural gas infrastructure[21] to move natural gas from the Jean d'Arc basin to an onshore processing facility in Newfoundland, or to Sable Island or an LNG receiving terminal in Nova Scotia. Transporting gas from offshore Newfoundland and the Labrador Shelf to Nova Scotian markets, including for LNG demand, will hinge on the relative economics of this supply versus other producing basins within North America.[22] Ziff Energy views offshore Newfoundland natural gas could be a potential source of supply in distant future.[23]

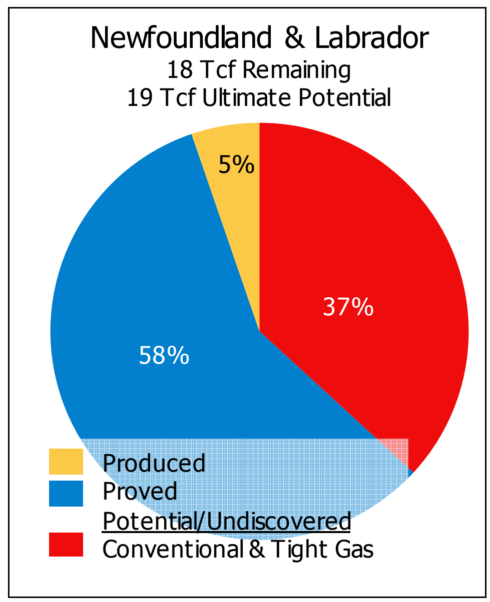


Figure 9. Offshore Newfoundland and Labrador Natural Gas Resources

Figure 9 illustrates the Newfoundland and Labrador ultimate potential and remaining natural gas resource. The remaining ultimate gas resource potential is estimated to be 18 Tcf (20 EJ) of marketable dry gas with 5% produced. Over half of the remaining gas resource (58%) is composed of proved gas reserves.

[21] For both offshore Newfoundland and the Labrador shelf, with no pipeline infrastructure in place and remoteness of the area, commercial gas production potential exists only with the appropriate gas pricing dynamics.
[22] Ziff Energy's "Grand Banks Natural Gas as an Island Electric Generation Option", prepared for Government of Newfoundland and Labrador, August 2012 regarding the viability of various natural gas supply options for power generation in Newfoundland.
[23] Morgan Stanley has applied for approval to export CNG (compressed natural gas) to Latin America countries from Texas (plant capacity of 60 Bcf per year). This technique may have potential for stranded offshore gas in Eastern Canada.

4.3.3 Gulf of St Lawrence

Anticosti Island – Initial petrophysical analysis has been undertaken for the Camasty Shale formation from vertical stratigraphic core holes drilled on the island. Due to the early stages of the exploration evaluation, the initial resource evaluation has classified the results as an undiscovered petroleum resource.

Old Harry – The Old Harry resource play is still in the early stages of exploration. Planning and regulatory processing is underway to drill the first exploration well.

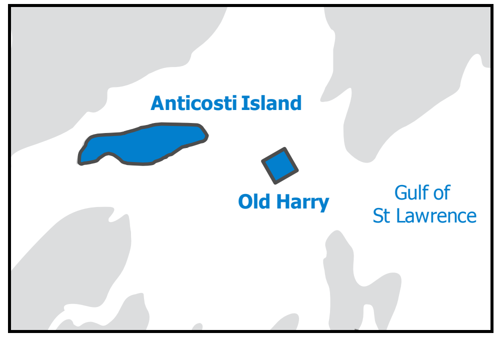


Figure 10. Eastern Canadian Potential

Both the Anticosti Island basin and Old Harry prospect could be future potential gas supply sources for East Canadian LNG export markets after exploration and development assessment.

4.3.4 New Brunswick

Figure 11 shows the gas supply region of New Brunswick, including the onshore McCully gas field and the Canaport LNG import terminal.

McCully gas production averaged 8 MMcf/d in 2013. Corridor Resources (McCully operator) is planning additional drilling over the next several years to more than double the current production rate by 2019.[24]

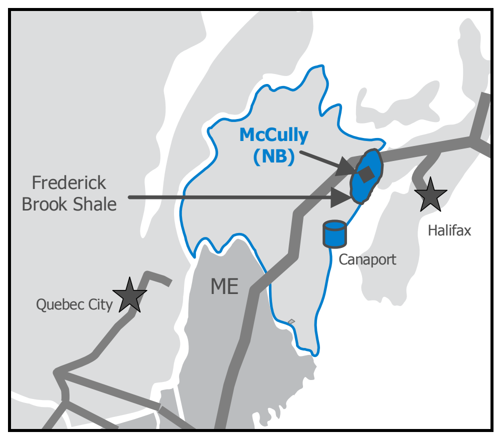


Figure 11. New Brunswick Gas Resource Region

A LNG regasification facility is operating at Canaport, New Brunswick, with imports averaging 100 MMcf/d in 2013. LNG imports are forecast to conclude before the end of the decade, displaced by more cost effective gas supply from the Appalachia basin. LNG imports via Canaport will remain a potential source of supply for Eastern Canadian markets.

[24] McCully production profile referenced from the Corridor Resources "2013 Year End Reserves & Reconciliation Report" prepared by GLJ Petroleum Consultants.

Figure 12 illustrates the New Brunswick ultimate potential and remaining natural gas resource. The ultimate gas resource potential of New Brunswick is estimated at slightly over 4 Tcf (4 EJ) of marketable dry gas with less than 1% already produced. More than 90% of the remaining gas resource is composed of shale gas, primarily in the Frederick Brook shale. In September 2014, the recently elected New Brunswick government announced plans to place a moratorium on hydraulic fracturing until further study and public consultation is undertaken. No timeline was given for completion. Ziff Energy expects that with public consultation and review, future shale gas development and production could proceed within New Brunswick.

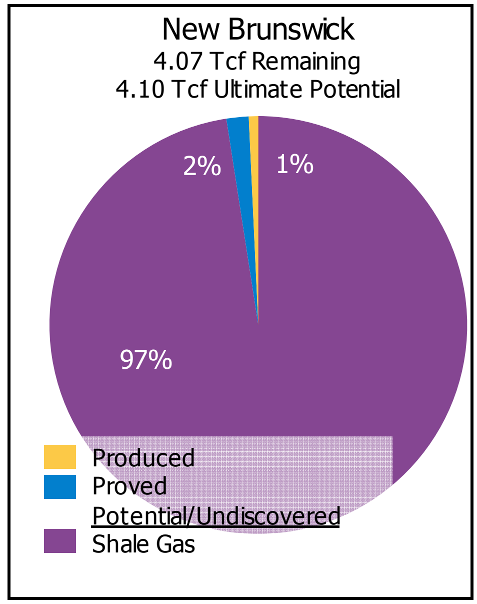


Figure 12. New Brunswick Natural Gas Resources

4.3.5 Quebec

Figure 13 shows the Quebec gas supply region. The Utica shale is considered prospective in the Montreal to Quebec City area. The Quebec government has introduced legislation to impose a ban on shale gas drilling and development until further notice. Shale gas development in Quebec has been deferred. Ziff Energy expects that with public consultation and review, future shale gas development and production could proceed within Quebec.

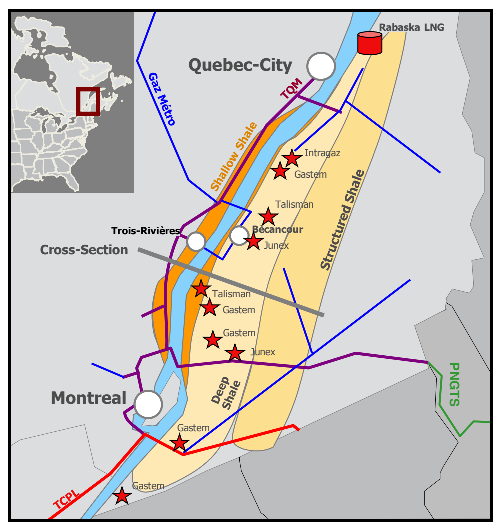


Figure 13. Quebec Gas Resource Region

4.3.6 Ontario

Figure 14 shows the Ontario gas resource region, including shale gas areas. Ontario gas production averaged 10 MMcf/d in 2013.

Ontario currently has approximately 1,400 active onshore and offshore natural gas wells, all producing conventional gas. The majority (two-thirds) of Ontario gas is produced from the Silurian play.[25]

The Antrim, Utica, and Marcellus shales are present in southern Ontario. The potential may exist for development of Ontario's shale gas resource as a source of supply for Central and Eastern Canadian markets, including LNG exports. Approximately 1 Tcf (one-half) of the conventional ultimate gas potential is remaining.

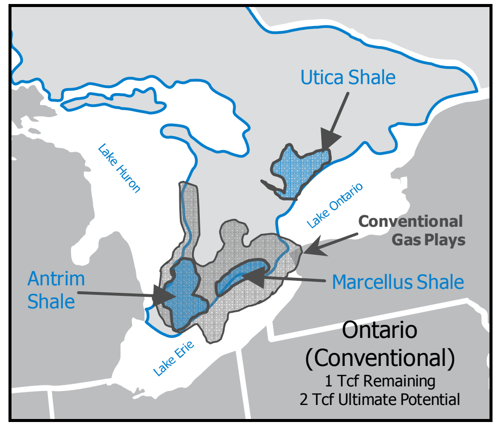


Figure 14. Ontario Gas Resource Region

4.3.7 Northern Gas

Due to the remote supply location and extensive new gas transport systems required for market connection, Northern Gas is more costly on a full-cycle basis than most unconventional gas. With the appropriate gas pricing dynamics, the potential exists for Northern Gas to flow to southern markets before the end of the forecast period.

Figure 15 illustrates the location of the Alaska resource, the Mackenzie Delta, Eagle Plain, and Peel Plateau Basins along with potential transport routes.

Alaska gas supply could be produced to deliver gas to Western Canada via pipeline. Gas associated with oil production on the North Slope is currently re-injected to maintain oil reservoir pressure(s) to enhance oil recovery.[26]

The Mackenzie Valley Pipeline has been approved to transport 0.8–1.2 Bcf/d (0.8–1.3 PJ/d) of gas through a new pipeline to Northern Alberta. The relative economics of developing less costly shale and unconventional gas in other areas of Canada and the US L48 have stalled this project. Alaska and frontier Canada gas resource, including Mackenzie Delta remain a potential source of supply for Canadian markets, and for LNG export.

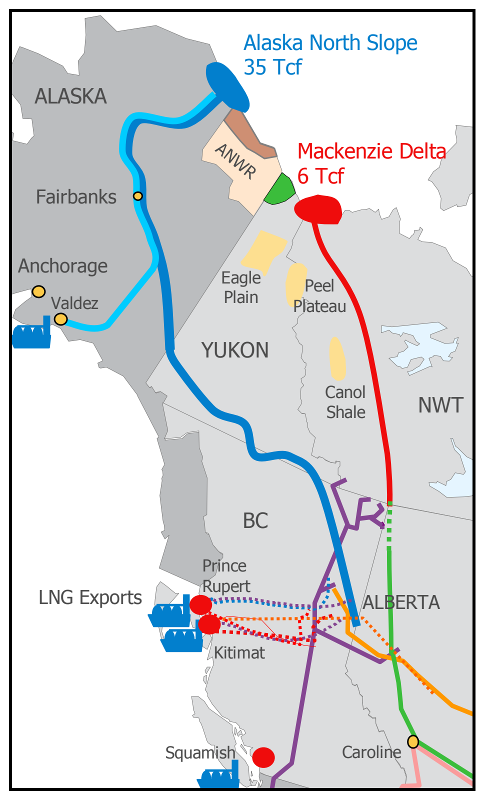


Figure 15. Northern Gas

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[25] "The Oil and Gas Plays of Ontario", Ontario Oil & Gas 2008 Edition, Ontario Petroleum Institute.

[26] An alternative LNG option is being considered via a 3 Bcf/d pipeline to Valdez, Alaska

5.0 Cost of Gas

Many factors influence natural gas supply costs. This section discusses those factors and the associated costs of developing natural gas resources in Canada.

5.1 Factors Affecting Supply Costs

Recent advances in technology (particularly horizontal wells with multistage completions), improved reservoir knowledge, and the high number of gas wells drilled in a small set of plays create gas factories, where standardized programs and continuous improvement leads to lower costs. Should drilling equipment or experienced staff become scarce in boom times, increased costs and project delays may occur.

5.1.1 Natural Gas Price versus Liquids and Oil Prices

Figure 16 shows the gap between North American gas and oil prices on an energy-equivalent basis. This value differential is currently leading producers to concentrate on oil plays or liquids-rich gas plays where the liquids make a large contribution to producer revenues.[27] In oil and gas-condensate plays, gas can be considered as low cost.

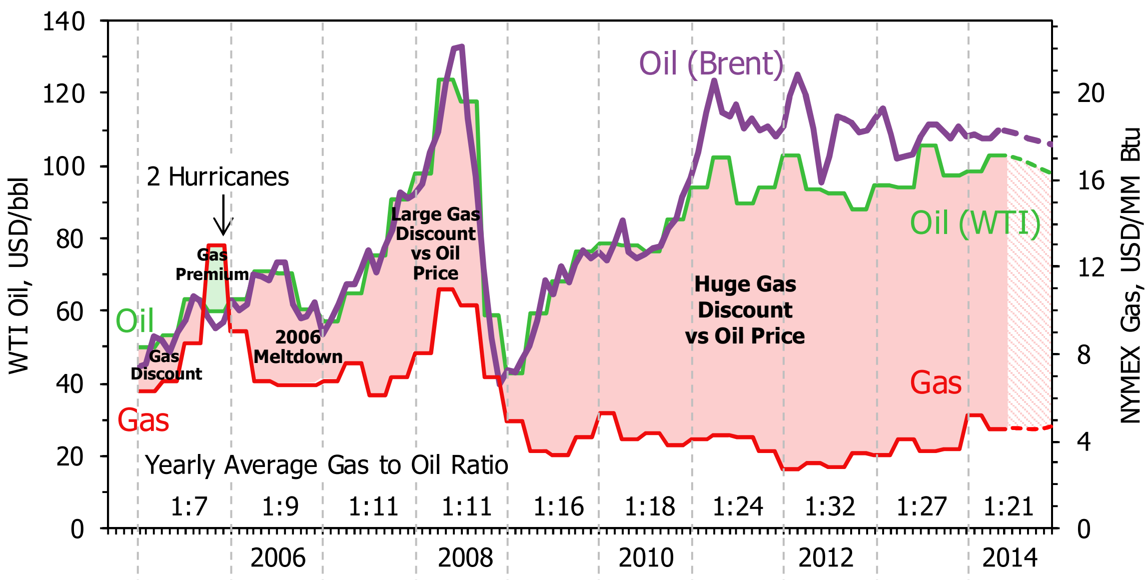

Figure 16. North American Natural Gas and Oil Prices

[27] Natural Gas Liquids (NGLs) such as propane, butane, and pentane, together with condensates have product prices that that are influenced by oil price; overall drilling economics are driven largely by oil prices.

Development of shale gas has profoundly impacted gas supply costs. During the period leading to mid-2008, gas production potential was constrained, leading to high full-cycle costs and gas prices; more than two-thirds of 1,500 gas rigs working in the US at that time were drilling vertical wells with little resulting production growth due to declining new gas-well productivity. Since the surge of low-cost shale-gas production in late 2008 to early 2009, as few as 310 gas rigs have been operating in the US, more than two-thirds drilling horizontal wells and generating high gas production growth—an increase of 31% during a 6-year time period. In 2013, the US gas-rig count dropped below 350, and production has not declined.

5.1.2 Technology

The combination of drilling horizontal wells and completing them with multistage hydraulic fracturing[28] is the most important technological change that has occurred in the last several decades, opening up a new class of global plays—shale gas. This combination has led to a surge in lower-cost gas production across North America, rendering most new conventional gas uncompetitive. Additionally, this technology combination has been successfully applied to other play types, such as tight gas and tight oil. Lower costs are primarily the result of the following:

- Longer horizontal wells with more hydraulic fracture stages. While well costs are typically increased, higher gas recovery reduces unit finding and development costs.
- A single drilling pad for multiple wells reduces the environmental footprint and allows rigs to be skidded from one well to the next, reducing access and rig move costs.

Figure 17 (page 19) illustrates the new technologies that the industry has adapted. Ongoing use of 3D and 4D seismic help reduce dry wells and increase production through better well location. Where ground conditions are soft, rig mats lengthen the drilling season, thereby lowering costs. Optimised drilling and completion programs reduce drilling time and cost, and increase gas resource produced. Collectively, operators have proven these new technologies and the gas supply can be quickly increased. Ziff Energy assumes continued technology evolution in resource assessments, resource cost curve, and production outlooks. No new step-change technology has been included in this analysis.

[28] Success of hydraulic fracturing requires cracking and propping open rock to allow trapped oil and gas to flow to the well bore.

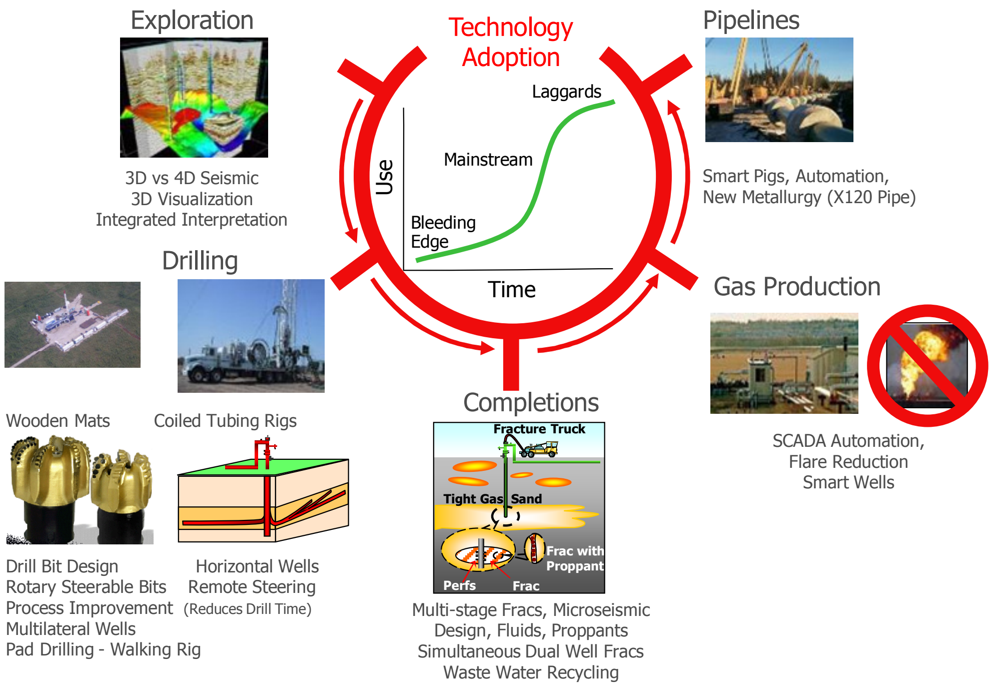

Figure 17. Technology Change

5.2 Western Canadian Full-Cycle New Gas Costs

Figure 18 (page 20) shows the full-cycle cost[29] for new gas supply in Western Canadian and Appalachian plays plus the average for each region. The full-cycle gas cost ranges from a low of 3.70 USD/Mcf for a specific Appalachian gas play to over 6.00 USD/Mcf for a specific Western Canadian gas play. Ziff Energy also calculates the NGL value uplifts for assessed plays using typical NGL yields and applies those to the full-cycle cost, reducing overall costs where applicable.

Conventional Western Canadian full-cycle costs are primarily at the high end of the North American cost curve.[30] Thus, Western Canadian gas is being squeezed out of its traditional markets in the US and Central Canada. Some Canadian plays, such as the Montney and Duvernay, are lower-cost than the Western Canadian average, and production can be expected to increase in these areas during the forecast period. Production from higher-cost conventional areas of Western Canada will continue to decline.

[29] Up to 22 data markers per play; the averages were extracted to illustrate the typical play cost. Ziff Energy's *North American Economic Ranking Study*, August 2014: Figure 28, Montney BC (14 data points); Figure 33, Cardium & Dunvegan (7 data points); Figure 19, Duvernay (7 data points); Figure 29, Montney Alberta (13 data points); Figure 32, Notikewin-Wilrich (22 data points); Figure 31, Bluesky-Cadomin (11 data points); Figure 25, Liard (1 data point); Figure 13, Northeast Marcellus Dry (14 data points); Figure 14, Southwest Marcellus Wet (10 data points); Figure 15, Other Marcellus Dry (8 data points); Figure 11, Utica (15 data points).
[30] Based on Ziff Energy's *North American Economic Ranking Study*, August 2014.

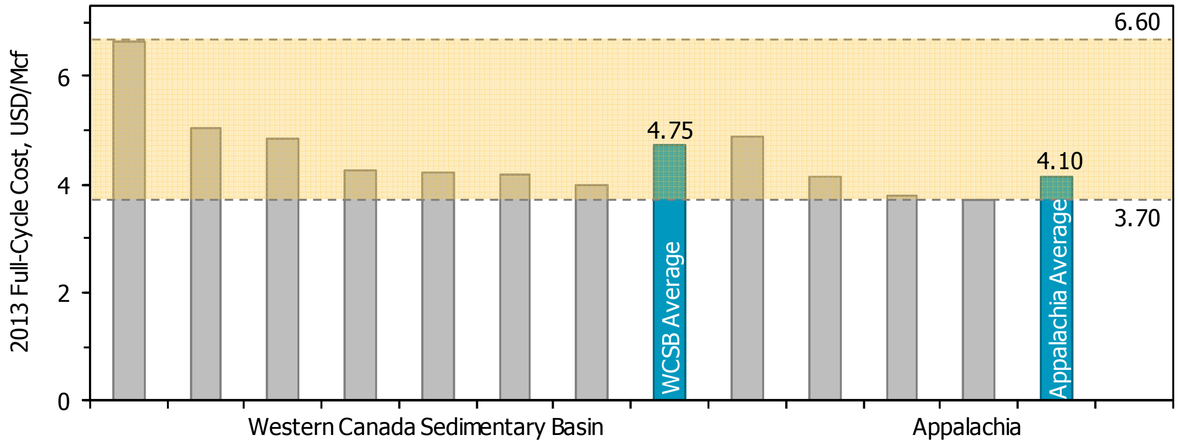

Figure 18. Western Canadian & Appalachian Full-Cycle New Gas Cost

5.3 Unconventional-Gas Resource Cost

Until 2007, the upstream North American natural gas industry was on a supply treadmill—drilling more and more wells with lower initial production and smaller estimated ultimate recoveries (EURs). The North American drilling rig fleet was fully utilized trying to meet gas demand, and gas prices were rising as LNG imports were required to balance supply and demand. LNG importers invested in new LNG re-gasification plants to meet the forecasted gas supply shortfall. This supply-constrained environment was overcome by the surge of shale-gas production that was enabled by the combination of horizontal drilling with multi-stage hydraulic fracturing. The shale-gas plays have added low-cost resources, increased North American gas production, and backed out LNG imports.

The average full-cycle costs for developing the primary North American shale- and tight-gas plays are instrumental in setting long-term natural gas prices in North America. During the period covered by this report, most of these plays are expected to mature, with costs rising somewhat as development continues beyond core areas to wells with smaller EURs. In addition to these plays, there are other North American gas resources available, such as higher-cost conventional gas and Coalbed Methane.

5.4 Full-Cycle Gas Cost Components

Ziff Energy has completed three studies[31] detailing the full-cycle cost of new natural gas production using an “apples-to-apples” comparison of natural gas costs within North America.

[31] The most recent *North American Economic Ranking Study*, assesses full-cycle costs for two dozen gas basins in North America and was issued to clients in August 2014.

Figure 19 presents the gas cost components used:

- *Basis Differential* – The difference between the gas price at the local pricing point and Henry Hub, so that the different costs may be compared on a consistent basis.
- *Rate of Return* (cost of capital) – A cost equivalent for a producer to earn a 15% rate of return before income tax rate of return on capital spending (F&D costs).
- *Overhead* – Includes all general and administrative expenditures (head office).
- *F&D* – Capital costs, including dry holes, divided by the estimated ultimate recovery.
- *Royalties & Production Taxes* – Components that fluctuate closely with natural gas prices.
- *Operating Cost* – Lifting and field processing costs.

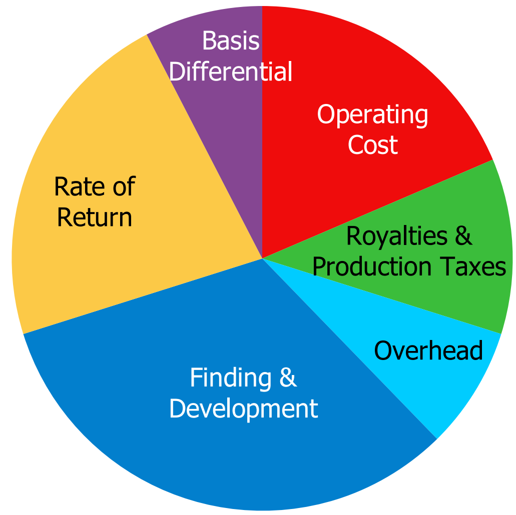

Figure 19. Gas Cost Components

6.0 Gas Supply Forecasts to 2050

This section provides Ziff Energy's North American natural gas supply forecast. The past decade has ushered in dramatic changes in North American natural gas production and supply. Game-changing technological advancements have led to rapidly increasing shale-gas production. Unconventional gas (i.e., shale gas, tight gas, and CBM) has grown to half of North American gas supply. Continuous improvement, knowledge transfer, and best operating practices have helped to reduce full-cycle costs and establish these strong production growth rates. Ten of twelve US onshore giant gas fields were discovered or rediscovered in the 1990s, and the list of giant unconventional gas fields is growing with the exploration and development of shale gas. Since 2008, the growth of US L48 unconventional gas supply[32] has negated large-scale LNG imports and is now backing out Canadian gas from its traditional US and Eastern Canadian markets.

6.1 Supply Forecast Methodology

Ziff Energy models each significant gas-producing basin in North America for its production forecast, examining numerous major gas types (i.e., shale gas, tight gas, CBM, conventional gas, and gas from oil (solution gas or associated gas)). Figure 20 shows the inputs to and outputs from Ziff Energy's spreadsheet gas production models. Ziff Energy does not model production by company; thus, a company may have access to gas supply from its lands that would not necessarily be available to the market in general.

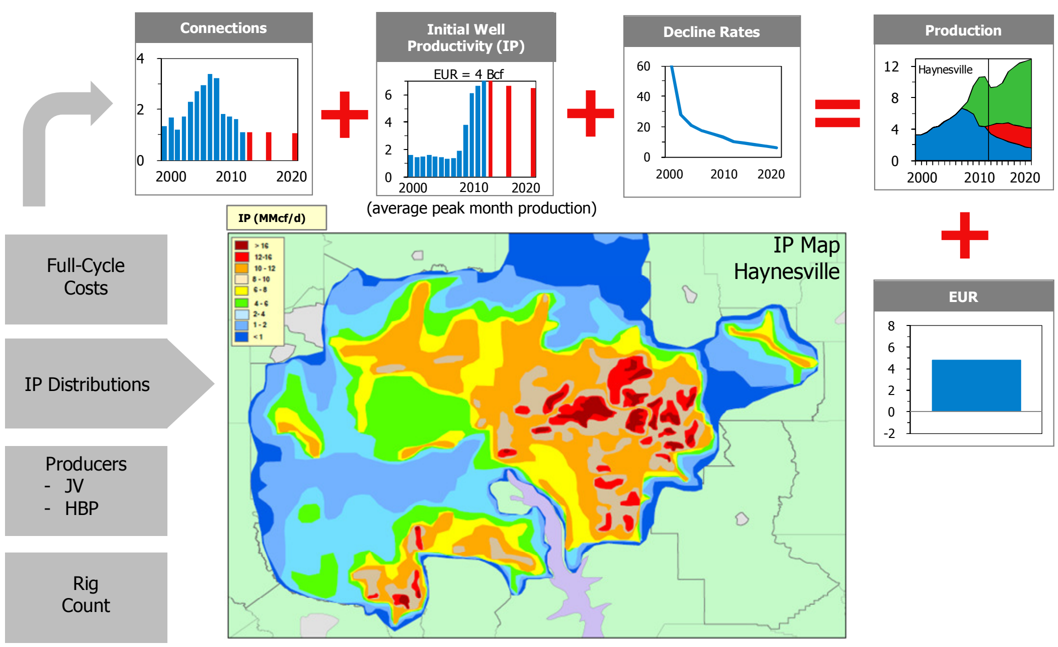

Figure 20. Gas Production Forecast Methodology

[32] US L48 gas production has increased by almost 30% since 2008, with potential to grow much higher.

6.1.1 Basin and Play Models

Ziff Energy maintains proprietary gas production spreadsheet models for each major gas basin[33] and key gas types in North America; these models use key input parameters[34] to forecast the annual average gas production for each supply source to 2050. Gas production histories used in the models come from commercial and public databases.

6.1.1.1 Gas Wells, New Well IP, EUR, and Decline Rates

The number of gas wells connected each year is based on the economic attractiveness of the gas basin or play, gas-well density, recent trends, gas reserves, resource potential, and availability of equipment. Where there are equipment restrictions or limited access to markets, drilling is deferred. New gas-well initial productivity (IP) and EUR per gas well are projected from recent trends, basin, or play maturity, and consider the potential for near-term technological improvements. Gas-well decline rates are estimated from recent trends or calculated from a type-well model using IP and EUR. The decline rates are applied to new and existing wells with consideration to the age of the well. The models generate a raw-gas production forecast, which is converted to sales gas using shrinkage factors calculated from public sources and previous Ziff Energy analyses. Minor gas basin production is modeled using recent historical production trends, economic attractiveness, and gas resource potential.

Regional drilling and completion activity, the key variable in gas production, rises and falls over time depending on:

- New well full-cycle gas supply costs relative to costs in other plays and expected natural gas prices
- Natural gas liquids content, which boosts play economics
- Government drilling and production incentives and disincentives
- Play maturity
- The need to validate recent leases through drilling
- Joint-venture agreements, which drive drilling
- Availability of cash flow

[33] Western Canada (includes Montney tight gas & Horn River shale gas); Green River (tight gas); Powder (CBM); Piceance (tight gas); Uinta (tight gas); San Juan (CBM & tight gas); Permian; Fort Worth (Barnett Shale); Gulf of Mexico Coast (includes South Texas tight gas and Eagle Ford shale gas), Shelf, and Deep Water; East Texas-North Louisiana (includes tight gas and Haynesville shale gas); Anadarko; Arkoma (Fayetteville and Woodward shale gas); Appalachia (includes Marcellus shale gas); Northern Gas (Alaska and Mackenzie Delta), and Canadian East Coast.

[34] Number of gas wells connected each year; new gas-well initial productivity; estimated ultimate recovery; gas-well decline rates.

6.2 Supply Assumptions

The Ziff Energy supply forecasts use the following general and gas-type assumptions.

6.2.1 General Assumptions

The following text summarizes key factors influencing production and Ziff Energy's assumptions for these factors.

6.2.1.1 Gas Price

Ziff Energy assumes gas prices will increase to recover full-cycle producer costs. The marginal gas required to balance supply and demand will generally set gas prices. If producers do not recover their full-cycle costs, it is expected that they will reduce gas-directed drilling or shift capital to lower-cost gas plays to ensure the lowest cost supply is connected and available to consumers.

6.2.1.2 Play Maturity

For immature plays, IPs and EURs tend to increase as the play develops, resulting in lower costs. Mature plays have falling IPs and EURs, and rising costs as most of the better locations have been drilled.

6.2.1.3 Infrastructure

Infrastructure includes gas-gathering systems, processing plants, and major transportation pipelines that are expected to be built within a reasonable period of time to provide access to the North American markets. Where infrastructure is inadequate, production is deferred by delaying drilling and completions.

6.2.1.4 Government Policies

Government policies tend to reduce gas supply.[35] Examples are drilling moratoriums in the US Rockies, offshore Florida/California, and offshore BC, Canada. Political and environmental factors that may favourably influence gas demand include legislation targeting competitive fuels with higher carbon emissions such as coal and residual fuel oil. One factor that has prompted regulatory review and investigation in some jurisdictions and may have an unfavourable influence on gas supply is hydraulic fracturing. Ziff Energy believes workable solutions will be found that balance legislators' concerns for constituents' safety and well-being with producers' ability to employ hydraulic fracturing technology in a safe and reliable manner.

[35] Royalty reductions and drilling incentives can incent drilling and increase gas supply.

6.2.1.5 Basin and Play Models

The models use assumptions (for the parameters listed above) based on Ziff Energy's analyses of historic production and expectations based on cost, basin, and play research. For example, Ziff Energy's Appalachia and Western Canada gas supply forecast uses the following assumptions:

- For Appalachia, gas-well connections will grow to approximately 2,600 in 2014, up over 400% from slightly over 600 in 2008.
- For Western Canada, while gas-well connections peaked at more than 18,000 per year in 2006, new gas-well completions have fallen by almost 90%.
- More high-productivity horizontal wells and fewer low-productivity vertical wells are expected to be drilled.
- Application of horizontal drilling will result in prospect high-grading and fewer wells drilled.
- New gas-well productivity and EUR will continue to increase in the short- to medium-term.

6.2.1.6 Access, Equipment, Services, Personnel, and Financing

Available Canadian and Appalachian gas resources are more than adequate to provide gas for LNG exports. In generating the gas supply forecasts, Ziff Energy assumed no constraints on access to land, availability of suitable drilling rigs and service equipment, skilled and experienced personnel, and financing. A temporary Canadian gas production shortfall[36] could develop if all the proposed Canadian LNG export plants are commissioned as announced. A large number of deep, complex gas wells would need to be drilled in a short time frame. The rig fleet capable of drilling these very deep wells would likely have to be quadrupled. In addition to replacing retiring baby boomers, thousands of skilled and experienced workers will be needed to staff the new rigs and pressure-pumping units, as well as to provide additional services. Upstream and LNG facility-related activity could lead to inflation pressures, similar to those seen in Australia during their LNG boom and during the oil sands boom in Alberta in the middle of the last decade.

Timely regulatory approvals and investment decisions would provide sufficient lead-time to expand the construction and potential importation of specialized rigs required in North-East US and Canadian shale-gas plays. A ramp up in requirements for pumping units, sand for proppant, water required in the hydraulic fracturing process, and related manpower will also be required.

As producers move from the evaluation to development stage in North American unconventional shale- and tight-gas plays, optimizing drilling and completion techniques (including horizontal laterals, spacing between wells, and fracture stages) will maximize economic gas recovery. Geological and geophysical (seismic) reservoir mapping and the use of micro-seismic will lead to continuous improvement in developing and enhancing the ultimate recovery of gas resources. Ziff Energy has incorporated efficiency improvements in its gas supply forecast.

[36] With timely approvals and Final Investment Decisions (FID) taken by proponents, a significant amount of up-front work can be done to pre-drill wells and build necessary infrastructure so gas is connected and available to LNG liquefiers when the LNG trains come online.

Figure 21 illustrates some of the tools available to connect natural gas resource to meet LNG liquefaction demand.

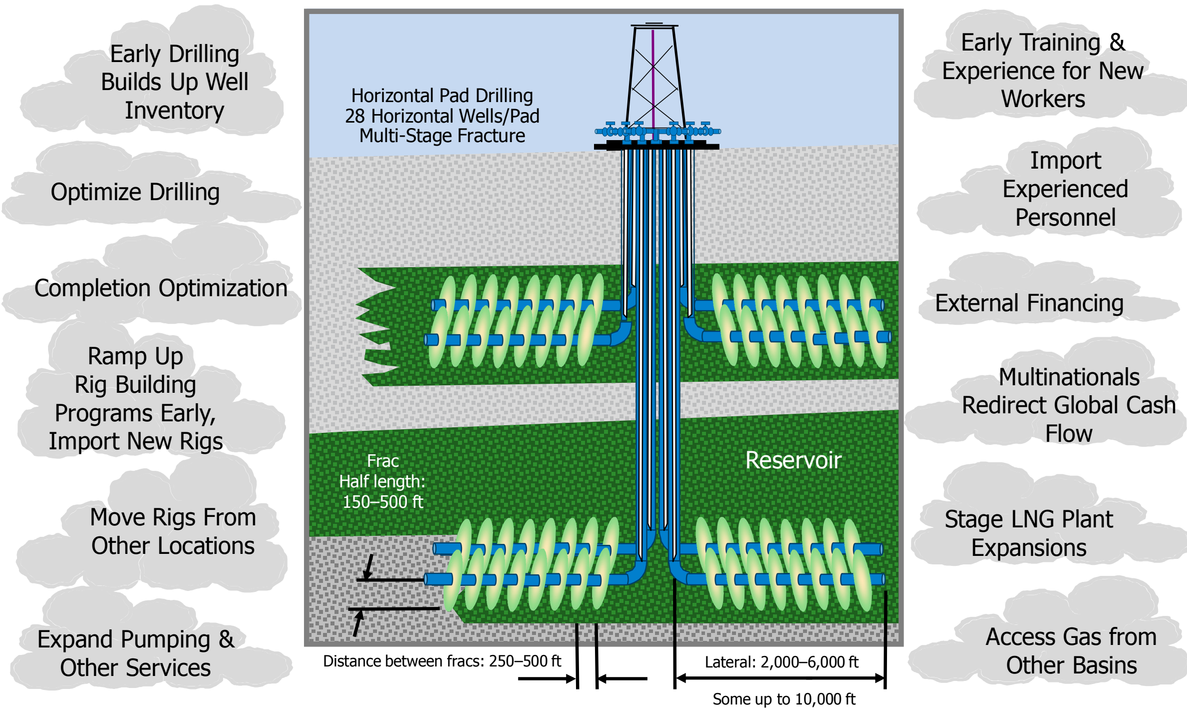

Figure 21. Ramping Up Canadian and Appalachian Supply

6.2.2 Gas Type Assumptions

The following text reviews Ziff Energy's assumptions for factors influencing production by gas type.

6.2.2.1 Shale Gas

Shale is both the source rock and reservoir; gas is held within the shale in free (in porosity) and adsorbed states. Shale-gas plays are immature and relatively low cost. Shales have extremely low permeability.[37] The commercial shale-gas success is due to a combination of horizontal drilling and multi-stage fracture completions along with rising gas prices from 2000 to 2008. The main initial shale-gas plays in North America (i.e., Barnett, Fayetteville, Woodford, Haynesville, Marcellus, Horn River, Eagle Ford, and now Utica) are each in a different stage of development. Without LNG liquefaction projects, development of some shale-gas resource will be slower.

A number of emerging and unknown future plays will likely add to gas production. Some of this gas could come from new shale-gas plays, such as the Niobrara in the Piceance Basin and expansion of existing shale-gas plays.

[37] Ability of gas to flow through reservoir rock.

6.2.2.2 Tight Gas

Tight gas is the term given to gas produced from sand and carbonate reservoirs that have very low permeability and require hydraulic fracturing for wells to be commercially viable. Tight gas was originally defined and developed in response to stimulus provided by US tax incentives in the 1980s. Most tight gas is produced in the US Rockies, South Texas, East Texas–North Louisiana, Anadarko, and Western Canada regions. Gas production growth in the US Rockies will slow as gas-well spacing in the most productive, older fields has shrunk to as low as 5 acres from 640 acres spacing, leaving little room for more wells. New fields have relatively low initial productivities and will struggle to offset declines from existing fields, though Ziff Energy believes low-cost growth opportunities exist in East Texas–North Louisiana (Cotton Valley, Bossier, James Lime, and other plays), and Western Canada (Montney and other Deep Basin plays) will emerge.

6.2.2.3 Coal Bed Methane

Gas produced from coal seams, where the gas is held in both free (in fractures and porosity) and adsorbed states (on the surface of the organic matter) is referred to as CBM. Development began in the early 1980s, spurred by US tax incentives. Production is past its peak due to high cost and generally low productivity.

6.2.2.4 Conventional Gas

Gas from reservoirs with greater permeability has been developed since the late 19th century. Most conventional-gas plays are mature, higher cost, and have passed their peak production. Reserves per well are small, resulting in high costs. Before the advent of shale gas, a record level of drilling activity was required to maintain gas production levels in North America. Aggregate gas production has been in decline for more than a decade. For example, the US Gulf of Mexico region, the former workhorse of North American gas production, is declining mainly due to the sharp fall in gas production on the shallow-water Gulf of Mexico Shelf. Some old, mature plays are experiencing a new lease on life as producers apply new and evolving technologies, sometimes with spectacular results, such as the Granite Wash in the US Anadarko Basin. Ziff Energy assumes the production declines will continue, though at a moderated pace as improved technologies (horizontal wells, multistage fractures) enhance play economics.

6.2.2.5 Northern Gas

Natural gas from Northern Alaska and the Northern Canadian Mackenzie Delta is not connected to the North American gas-pipeline grid. Due to the high proposed transportation costs, Ziff Energy does not expect any Northern gas to flow into the North American market during the forecast period. However, with the appropriate pricing dynamics, Northern gas could flow south by the end of the forecast period.

6.2.2.6 Liquefied Natural Gas Imports

LNG imports into North America have declined to 0.1 Bcf/d from a peak of more than 3 Bcf/d. North America has more than a dozen LNG regasification import terminals with capacity in excess of 20 Bcf/d (21 PJ/d) that are operating at less than 1% utilization. These terminals are potentially operational to import LNG should a need arise, though several are being repurposed for exports. Overall, North America LNG imports delivered directly into demand centers is not expected to be significant during the forecast period.

6.3 North American Gas Supply Forecast

Ziff Energy forecasts total North American dry gas supply to grow to 139 Bcf/d (146 PJ/d) in 2050 from 81 Bcf/d (85 PJ/d) in 2013. Figure 22 (page 28) summarizes Ziff Energy's supply forecast by gas type.

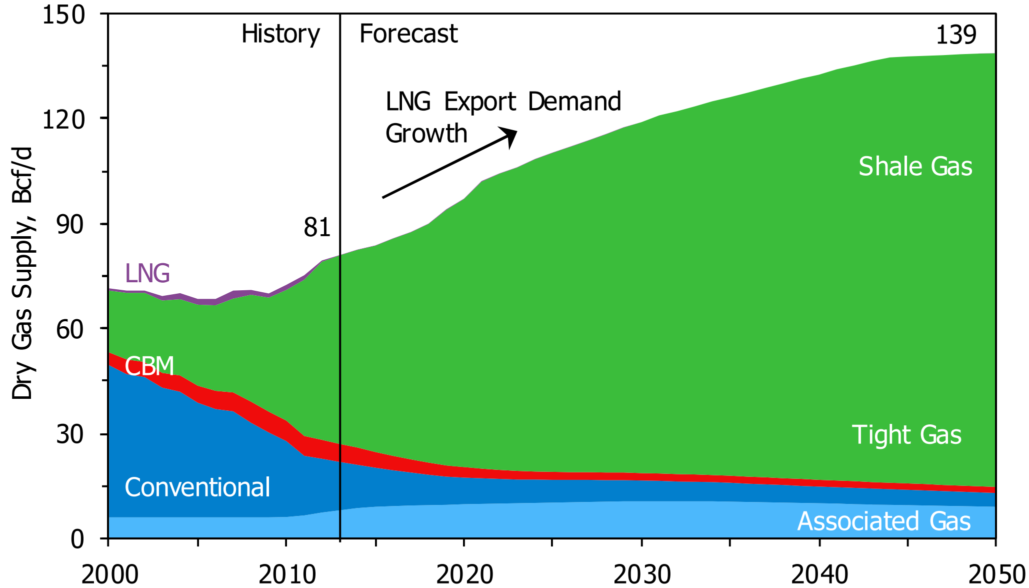

Figure 22. North American Gas Supply to 2050

6.3.1 Unconventional Gas

Figure 22 shows that by 2050, unconventional gas—consisting of the following—is expected to grow to 91% of the supply mix:

- *Shale Gas* (including new plays) will grow to 99 Bcf/d (104 PJ/d) in 2050 from almost zero at the start of this century, representing more than 70% of the North American gas supply mix. Production is from shale-gas plays and new plays.
- *Tight Gas* will grow to 25 Bcf/d (26 PJ/d) in 2050 from 20 Bcf/d (21 PJ/d) in 2013. Additional gas is being developed in East Texas–North Louisiana and Western Canada, though it may be partially offset by declines elsewhere. After 30 years of growth in this series of plays, Ziff Energy believes that production will continue to grow as new resources are developed due to the application of horizontal drilling and multi-stage fracturing.
- *CBM* will decline to 2 Bcf/d (2 PJ/d) in 2050 (1% of the supply mix) from 5 Bcf/d (5 PJ/d) in 2013. This high-cost production will continue to fall as few new wells are drilled, failing to offset declines from existing wells.

6.3.2 Conventional Gas

By 2050, conventional and associated gas—consisting of the following—will decline to 9% of the supply mix:

- *Gas from conventional-gas plays* will decline to 4 Bcf/d (4 PJ/d) in 2050 from 14 Bcf/d (15 PJ/d) in 2013 primarily due to increasing maturity of traditional natural gas basins and high full-cycle costs, which leads producers to divert capital to more profitable shale gas.
- *Associated Gas*[38] (gas from oil wells) production will grow due to tight-oil drilling to 11 Bcf/d (12 PJ/d), representing 9% of gas supply in 2030, up from 8 Bcf/d (8 PJ/d) in 2013. Associated gas will then decline to 9 Bcf/d (9 PJ/d) in 2050.

6.4 Appalachian (Marcellus and Utica) Gas Supply Forecast

Figure 23 shows the US Appalachian gas supply region, outlining the Marcellus and Utica producing areas. Figure 24 presents Ziff Energy's assessment of Appalachia gas production forecast out to 2050. Appalachian production is forecast to peak at slightly under 30 Bcf/d in the 2023 to 2033 time period, declining thereafter.

Appalachian basin production is over 95% shale gas. Within a 5-year span to 2014, Marcellus North East Pennsylvania (NE PA) production has grown from negligible to over 9 Bcf/d, and is forecast to reach 16 Bcf/d by 2021. NE PA will represent just under two-thirds of Appalachian gas supply in 2014. Utica gas production is forecast to reach 10 Bcf/d by 2036.

Appalachian gas production is situated to provide much of the gas demand requirements for Eastern Canada to 2050 (includes applied for LNG export volumes).

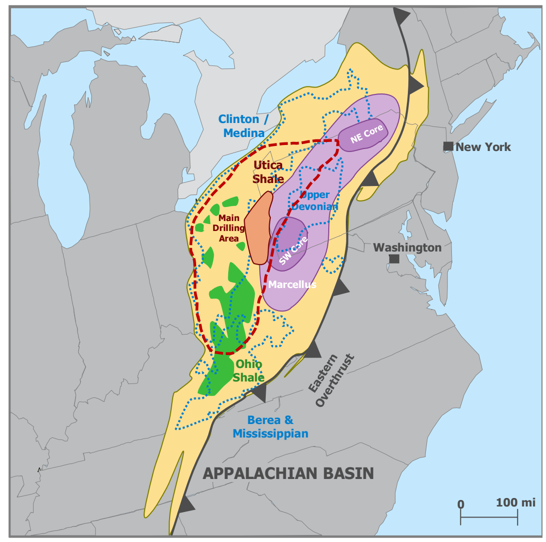

Figure 23. Appalachian Gas Supply Region

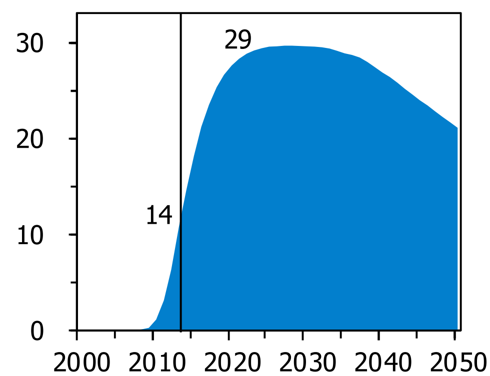

Figure 24. Appalachian Gas Supply Forecast

[38] Also known as solution gas.

6.5 Canadian Gas Supply Forecast

Ziff Energy forecasts that total Canadian gas supply will grow to 35 Bcf/d (37 PJ/d) in 2050[39] from 14 Bcf/d (15 PJ/d) in 2013 as new gas supplies offset declines of higher-cost conventional gas. Eastern Canada was the source of 2% of the Canadian gas supply in 2013. Figure 25 provides summary results of Ziff Energy's supply forecast for Canada by gas type.

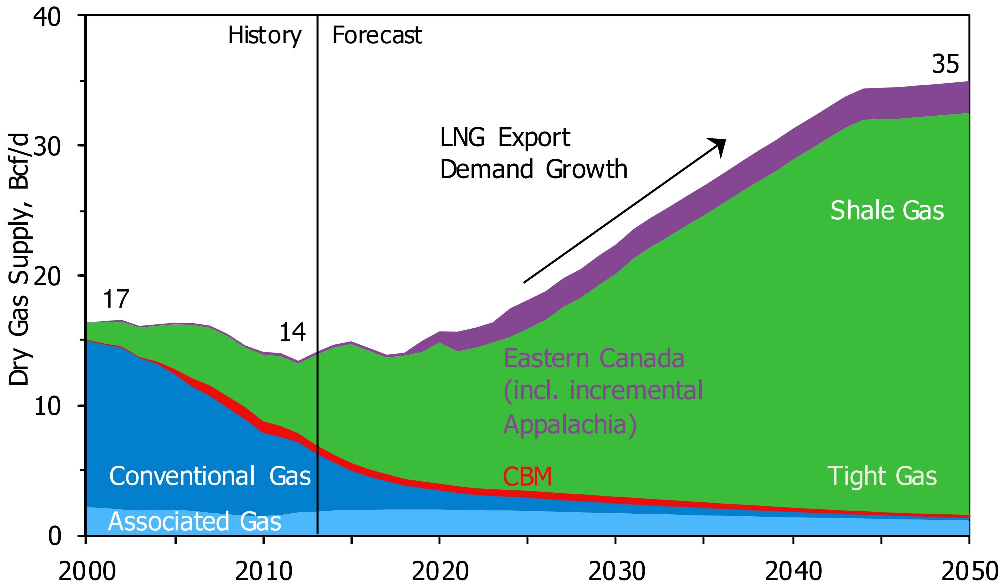

Figure 25. Canadian Gas Supply to 2050

Canadian production is currently constrained by market and competitive factors that have resulted in a low gas price. The limitation to production growth is lack of access to markets priced at levels sufficient for producer's to recover their full-cycle cost and investment—there is more resource available for production in Western and Eastern Canada. The upswing in Canadian production from 2019 reflects new market outlets resulting from NEB-approved LNG projects and the Bear Head LNG Corp. proposed export volumes.

6.5.1 Unconventional Gas

By 2050, Canadian unconventional gas will grow to 89% of the supply mix from 50% in 2013:

- *Shale and Tight Gas* including supply from the Montney, Duvernay, Horn River, Liard, and other plays,[40] will grow to 31 Bcf/d (33 PJ/d) by 2050.
- *CBM* will decline to less than 0.2 Bcf/d (0.2 PJ/d) in 2050 due to the high cost of CBM.
- Eastern Canada gas supply will account for 7% of the supply mix by 2050.

[39] Canadian gas supply forecast includes gas demand for all NEB approved LNG export projects. Ziff Energy does not believe that all NEB approved export projects will proceed, consequently Canadian gas supply will be lower than depicted in Figure 23.
[40] Gas resource potential exists for shale plays within Quebec, New Brunswick, and Nova Scotia plus offshore Eastern Canadian basins.

6.5.2 Conventional Gas

By 2050, conventional and associated gas, consisting of the following, will decline to 4% of the supply mix:

- *Western Canadian conventional gas* (from gas wells) peaked before 2000 and is expected to decline to 1% (0.3 Bcf/d, 0.3 PJ/d) of the supply mix in 2050 from 32% in 2013, due mostly to increasing play maturity and high costs, which lead producers to focus on lower cost, liquids-rich unconventional gas. New Western Canadian conventional gas[41] has some of the highest full-cycle costs in North America.
- *Associated gas* (gas from oil wells) production will grow this decade due to tight-oil drilling in Western Canada[42] to a peak of 2.0 Bcf/d (2.1 PJ/d) in 2020. Associated gas will then decline to 1.1 Bcf/d (1.2 PJ/d) 3% of gas supply in 2050, down from 1.8 Bcf/d (1.9 PJ/d) in 2013.

6.5.3 LNG Exports

LNG exports are modelled in the demand section; the supply for these exports is included in this forecast. No material LNG imports[43] are modelled for the forecast period.

[41] Includes production from Sable Island and the new development at Deep Panuke, Nova Scotia.
[42] Grand Banks gas is believed to be too expensive to bring into the North American market.
[43] Canada has one LNG regasification terminal at Saint John, New Brunswick.

6.6 Eastern Canadian Gas Supply Forecast

The Offshore Canadian East Coast is currently not a significant source of gas supply—Sable Island production is declining and will likely reach the end of its economic life by the end of this decade. The Deep Panuke mobile production module started production in third quarter 2013 and is also anticipated to reach the end of its economic life during the forecast period.[44]

Ziff Energy's forecast is for Eastern Canadian gas production to increase to 0.5 Bcf/d (0.5 PJ/d) in 2014 from the initial production capability of Deep Panuke, then declining until 2019 when it is anticipated Appalachian gas will support Eastern Canadian demand over the forecast period. Figure 26 provides summary results of Ziff Energy's production forecast for Eastern Canada by basin or import point.

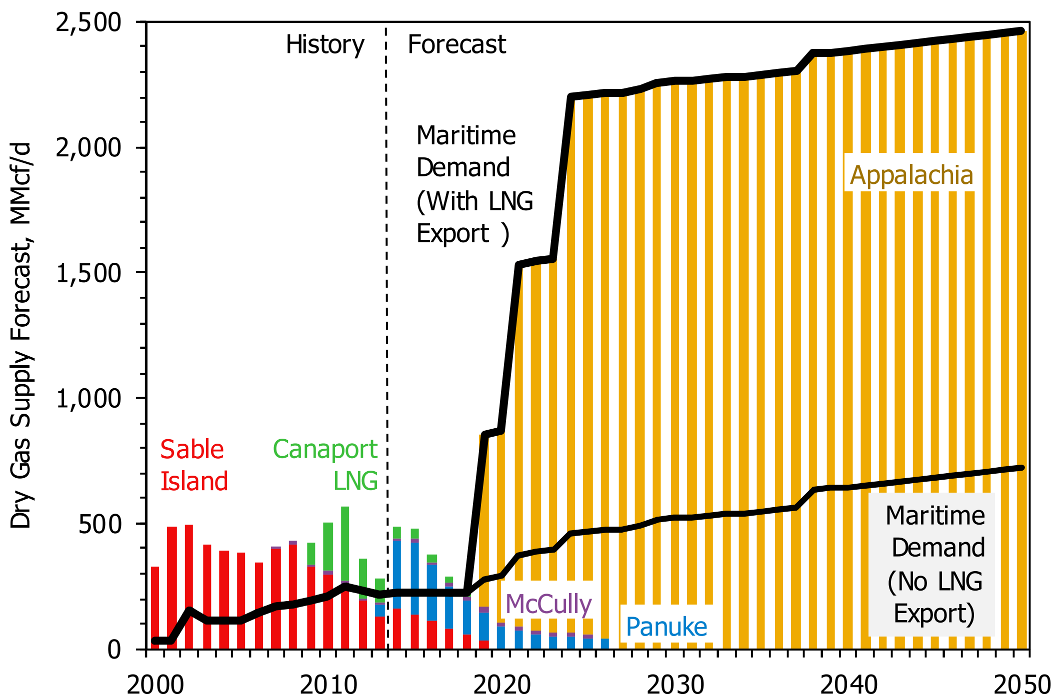

Figure 26. Eastern Canadian Gas Supply to 2050

[44] Due to the early stage of production, the Deep Panuke production profile is referenced from the "EnCana Deep Panuke Volume 2 (Development Plan), November 2006".

In addition to Eastern Canadian and Appalachian supply, it is physically (as shown in Figure 27) possible to connect supply from Western Canada via the TransCanada long haul system, or via Dawn. This supply could be delivered into the Portland Natural Gas Transmission System (PNGTS) and transit into Maritimes and Northeast pipeline (M&NE). Ziff Energy expects the M&NE system to reverse flow to bring Appalachia and possible WCSB supply into Nova Scotia. The viability of this physical route would depend on delivered costs to Nova Scotia and the price for LNG deliveries. A major factor in the economics of delivering via TransCanada and PNGTS would be the toll on both systems after expansion to accommodate volumes intended for Nova Scotia. Western Canadian supply remains a potential source of supply for Eastern Canadian demand, including LNG exports.

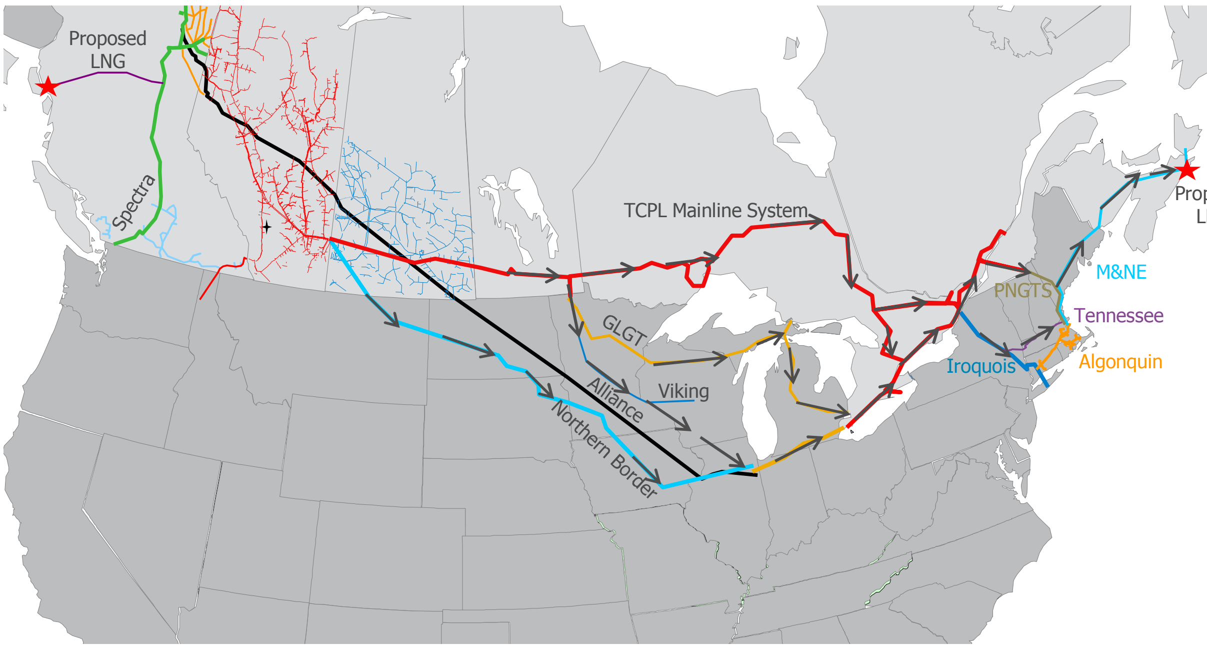

Figure 27. Western Canada Gas Flow Routes to the Maritimes

7.0 Gas Demand Forecasts to 2050

This section reviews factors influencing natural gas demand and presents Ziff Energy's gas demand forecasts.

7.1 Demand Methodology

Ziff Energy's North American[45] and Canadian gas demand forecast methodology is based on an assessment of consumption sectors and the expected rates of growth within each. A brief description of each sector and the forecast methodology used is presented in the following text:

- *Industrial Sector (30% of current overall market)* includes gas consumed by the manufacturing, construction, mining, refining, oil sands, and petrochemical industries. Ziff Energy has also included North American LNG exports in the industrial sector. Natural gas used for combined heat and power (CHP) generation for manufacturing processes is also included.[46] The industrial sector is the most price sensitive and, therefore, in general, the most elastic demand sector. In the Western Canadian industrial sector, natural gas is used to produce bitumen from the oil sands by producing steam (injected into oil reservoirs), generating electricity, and upgrading bitumen to synthetic crude oil, as well as for process heat.
- *Gas for Power Generation Sector (30% of current overall market)* includes gas consumed by natural gas-fired power stations and gas-fired CHP units used to produce electricity directly marketed into the North American power grid. Ziff Energy forecasts overall power generation based on growth factors such as GDP, residential/commercial power markets, demand side management, and industrial demand for power. A regional analysis of the North American power generation inventory is performed and assumptions of potential capacity changes are made for gas, oil, coal, nuclear, hydro, renewable, and other power sources. Natural gas for gas-fired generation tends to be more expensive on a marginal basis[47] relative to coal, nuclear, hydro, and other power sources. Therefore, once capacity and load factors for non-gas-fired stations are analyzed, the amount of gas-fired generation required to meet overall power growth is calculated. Gas required for power generation is then calculated based on expected changes to average heat rates (Btu/kWh).
- *Residential Sector (19% of current overall market)* includes gas consumed by private households (i.e., houses, apartments, condominiums) for heating and domestic purposes.
- *Commercial Sector (13% of current overall market)* consists of gas used by non-industrial and non-residential consumers (i.e., schools, hospitals, business, office structures, and motor vehicles).

  The residential and commercial sectors' demand forecasts are developed by taking into account the main purpose of the gas consumed by these sectors, namely space heating, and forecasts of regional gas customer count. Normalized values are used in the forecast methodology to account for the effects of weather on consumption patterns. In the US, Heating Degree-Day (HDD) data is based on 65 °F (18 °C), sourced from National Climatic Data Centre, and adjusted for the North American

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[45] Gas exported to Mexico is not included in North American demand; it is discussed in Section 8.4 of this report.
[46] Power used on site is included in the Industrial sector; electricity (megawatt-hour (MWh)) marketed to the grid is included in the Power Generation sector.
[47] Gas-fired generation has lower capital costs and can be put in-service faster than coal (2- to 3-year advantage) and nuclear (7- to 8-year advantage).

population. Canadian HDD data is based on 65 °F (18 °C), sourced from Environment Canada's daily mean temperature, and adjusted for the North American population. Regional gas customer counts are analyzed and then forecast for regional population growth, market penetration for natural gas, and combined with efficiency gains in normalized consumption patterns. Ziff Energy is then able to forecast overall normalized demand (Mcf per customer per HDD) as follows:

Forecasted Overall Customer Count × *Normalized HDD* × *Normalized Consumption*

- *Pipe and Lease Sector (8% of current overall market)* consists of gas consumed during the production and transmission of natural gas to end-use markets. Ziff Energy forecasts pipeline and lease-sector gas demand based on changes in North American supply and takes into account efficiency gains from optimized new builds and replacement of aging infrastructure.

7.2 Demand Assumptions

The following text highlights Ziff Energy's insights concerning demand assumptions:

- *Gas Price Effect on Industrial Demand* – The industrial sector is responsive to changes in natural gas pricing, which is adjusted regionally based on historical pricing and industrial demand response. Intensive users of gas such as fertilizer manufacturers (approximately 85% of input cost is natural gas) will be more directly impacted than less gas-intensive manufacturers such as food manufacturers. Gas demand for residential and commercial sectors is not historically impacted by gas prices. In the last decade, gas demand for power generation has increased despite increased gas prices. Recent low gas prices have led to coal-to-gas switching; however, Ziff Energy believes that longer-term gas prices will exceed coal prices on a million Btu (MM Btu) basis and continue to rise beyond that.
- *Oil Sands* – Ziff Energy's forecast of gas used in oil sands for growing bitumen production incorporates the following key assumptions:
  - oil pricing to allow oil sands projects to recover full-cycle costs; a 90% load factor
  - 1- to 5-year delay for all new projects
  - oil sands production is risked 10–90% by regulatory status;[48] demand includes gas for electrical generation, upgrading
  - 47% of oil sands bitumen is upgraded in Alberta;[49] off-gas produced in upgrading and in-situ operations is used as fuel, reducing the natural gas required[50]
- *Gas Pricing* – Ziff Energy believes that natural gas prices in North America will recover producer average full-cycle costs; the North American gas market will continue to operate in a rational and integrated manner. Consumers will continue to source supply based on least-cost sources, transporters will continue to assess opportunities to invest in infrastructure based on the relative risk of supply-demand fundamentals, and producers will allocate capital to projects that most enhance shareholder value. Gas-pricing differentials will continue to price these variables in an open, transparent, and liquid manner.
- *Electrical Power* – Ziff Energy assumes carbon emissions remain static throughout the forecast period. Uncertain future carbon costs will likely stall growth in carbon intensive fuels, such as coal, and favour gas. More specifically, Ziff Energy assumptions used in the electric power demand forecast include the following:

[48] Projects advanced in the regulatory process are more likely to proceed.
[49] Based on EUB ST98-2013, which forecasts 38% of bitumen produced, is upgraded in Alberta by 2022.
[50] Off-gas available as fuel for oil sands operations may be reduced by proposed off-gas processing plants that remove NGLs and shrink the off-gas stream, though this process has not been considered in Ziff Energy's forecast.

- GDP growth of 2.2% per year leads to power sector growth of 1.0% per year.
- Nuclear capacity will begin to increase post-2017 as new stations come online,[51] with constraints in availability of equipment and skilled manpower.
- Coal-fired power generation has some capacity expansion—load-factors creep upward as cleaner coal technology is put into service, replacing some aging stations.
- Gas-fired generation is the marginal source of power supply until nuclear capacity can be expanded.

- *Customer Counts* – Historically, residential and commercial customer count growth averages 1.4% per year. Ziff Energy assumes lower future market penetration growth and more conservative economic growth, and forecasts a lower long-term growth rate of 0.9%.
- *Normalized Consumption (Mcf per customer per HDD)* – Residential and commercial sectors are most influenced by weather. Ziff Energy assumes normalized weather (average of the previous 10 years) will occur during the forecast period. Residential and commercial normalized consumption historically declines 0.8% per year per residential/commercial unit. Ziff Energy assumes consumers make efficiency gains at a slower pace, as the most efficient conservation investments have been made, and forecasts a lower long-term rate of improvement of 0.4% per year.
- *GDP* – Since 2000, real GDP growth has averaged 1.8% per year in the US and 2.0% in Canada. The US Federal Reserve's current expectation[52] for longer run real GDP growth is 2.2–2.3% per year. Bank of Canada[53] expects the Canadian real GDP to average 2.3% during the 2013–2015 period. Ziff Energy's expectation is for real GDP to average 2.2% per year throughout the forecast period.
- *Government Policies* – Ziff Energy assumes there will be some implementation of policies to reduce carbon emissions resulting in some replacement of coal-fired power generation with gas-fired generation and nuclear power during the forecast period. Ontario coal-fired power plants are expected to be decommissioned by 2014, and other Canadian coal-fired power plants are expected to be decommissioned after a 45-year economic life and replaced with a combination of gas, nuclear, hydro, and renewable sources.

7.3 North American Gas Demand Forecast

This section presents Ziff Energy's North American demand forecast assessment by sector, with order based on current market share:

- *Industrial Sector* – Demand will grow to 53.2 Bcf/d (56.1 PJ/d) in 2050, up from 23.8 Bcf/d (25.1 PJ/d) in 2013 at 2.2% per year to become 39% of total demand in 2050. Included in 2050 industrial demand are 25.7 Bcf/d[54] (27.1 PJ/d) of LNG exports from North America, including 6.0 Bcf/d (6.3 PJ/d) from the US Gulf Coast. Ziff Energy expects growth from non-oil sands and non-

[51] On February 9, 2012, the US Nuclear Regulatory Commission (NRC) approved Vogtle Units 3 and 4 Combined Construction and Operating License (COL). Southern Company has started construction and expects Unit 3 to begin operating in 2016 and Unit 4 in 2017; however, Ziff Energy is forecasting some delays.
[52] March 18–19, 2014 Minutes of the Federal Open Market Committee – *Table 1 Economic Projections of Federal Reserve Governors and Reserve Bank presidents, March 2014.*
[53] Monetary Policy Report, April 2013.
[54] Section 8.5 illustrates Ziff Energy forecast for LNG exports.

LNG export industrial sectors at 0.1% per year as traditional industrials[55] continue to work to become more energy efficient.

- *Gas for Electrical Generation* – Sector demand will increase to 43.2 Bcf/d (45.6 PJ/d) in 2050, up from 23.6 Bcf/d (24.9 PJ/d) in 2013 at 1.7% per year to comprise 32% of total demand in 2050. Overall power growth is driven by economic activity and will grow at a rate of 1.1% per year during the forecast period. From 2000 to 2012, the gas burn for electrical generation grew at a rate of 5% per year; Ziff Energy believes gas-fired generation will continue to grow.
- *Residential* – Sector demand will increase to 16.7 Bcf/d (17.6 PJ/d), up from 15.2 Bcf/d (16.0 PJ/d) at 0.3% per year to become 12% of total demand in 2050. Ziff Energy's forecast customer count growth rate of 0.8% per year reflects lower, future market penetration and more conservative economic growth. Ziff Energy believes that normalized gas consumption per customer will continue to decline; however, at a lower rate of 0.6% per year as the easy conservation measures have been implemented.
- *Commercial* – Sector demand will increase to 11.9 Bcf/d (12.5 PJ/d), up from 10.3 Bcf/d (10.9 PJ/d) at 0.4% per year to become 9% of total demand in 2050. Ziff Energy's forecast growth reflects lower future market penetration and more conservative economic growth. Ziff Energy believes that normalized gas consumption per customer will continue to decline, though at a lower rate of 0.4% per year as the easy conservation measures have been taken.
- *Lease and Pipeline Fuel* – Demand will grow to 7.1 Bcf/d (7.5 PJ/d), up from 6.1 Bcf/d (6.4 PJ/d) to become 5% of total demand in 2050. Improving fuel efficiency in this sector should keep overall fuel use at modest levels.
- *Transport* – Demand will grow to 3.7 Bcf/d (3.9 PJ/d), up from 0.1 Bcf/d (0.1 PJ/d) to become 3% of total demand in 2050. Ziff Energy believes initial growth will be driven by the least fuel efficient vehicle sectors such as tractor trailers, city buses, and refuse transporters.

Figure 28 (page 38) illustrates Ziff Energy's forecast for total North American gas demand, which will grow at a rate of 1.5% per year to 2050, increasing to 136 Bcf/d (143 PJ/d) at the end of the forecast period from 79 Bcf/d (83 PJ/d) in 2013. Exports to Mexico will grow to 3 Bcf/d in 2050 (refer to Section 8.4 of this report) and are not included in either of these volumes, nor in Figure 28 (page 38).

[55] February 12, 2013, Andrew N. Liveris, Chairman and Chief Executive Officer, The Dow Chemical Company "Our manufacturing energy intensity, measured in British thermal units (BTUs) per pound of product, has improved more than 40% since 1990".

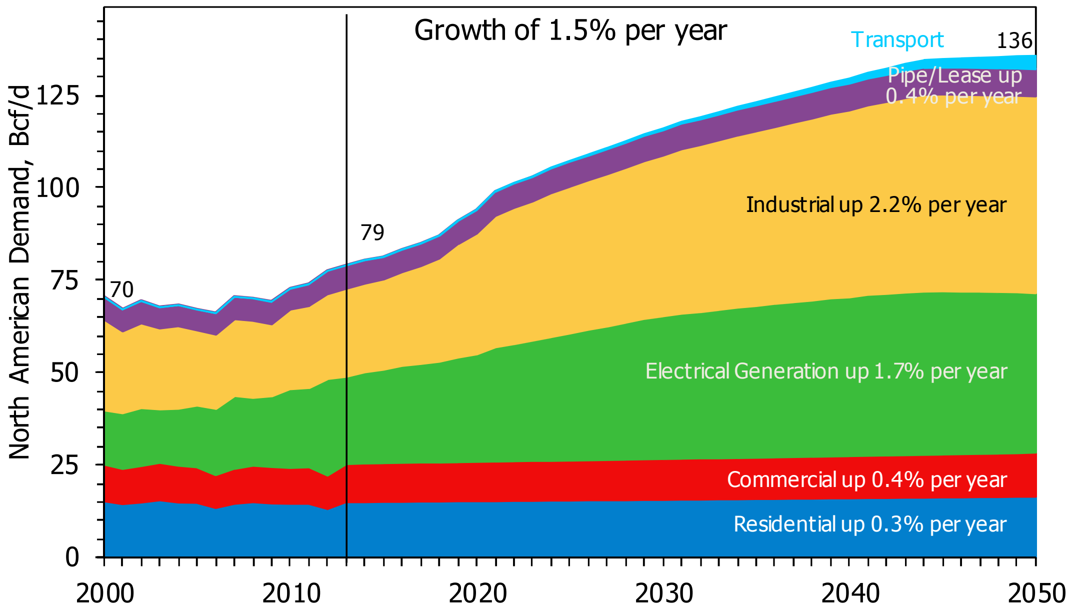

Figure 28. North American Demand Overview

7.4 Canadian Gas Demand Forecast

This section provides Ziff Energy's Canadian natural gas demand forecast by sector. Major differences from the North American demand forecast are discussed.

- *Industrial Sector* – Demand will grow to 25.3 Bcf/d (26.7 PJ/d) in 2050, up from 3.4 Bcf/d (3.6 PJ/d) in 2013 at 5.6% per year to comprise 70% of total demand in 2050. Included in 2050 industrial demand are 19.7 Bcf/d (20.8 PJ/d) of LNG exports.[56] Non-oil sands/non-LNG export industrial demand in Canada is expected to increase to 1.8 Bcf/d (1.9 PJ/d) from 1.7 Bcf/d (1.8 PJ/d).
- *Gas for Electrical Generation* – Demand will increase to 4.5 Bcf/d (4.8 PJ/d), up from 1.5 Bcf/d (1.6 PJ/d) at 3.1% per year to comprise 13% of total demand in 2050. Ziff Energy's forecasted growth rate for overall power generation from 2013–2035 is 1.0% per year, which compares closely to the NEB's 1.1% per year growth rate during the same period.[57]
- *Residential* – Sector demand will increase to 2.5 Bcf/d (2.7 PJ/d), up from 1.9 Bcf/d (2.1 PJ/d) at 0.7% per year to comprise 7% of total demand in 2050. As discussed previously (assumptions for customer count and normalized consumption), Ziff Energy has chosen conservative parameters to calculate overall residential growth for Canada. Ziff Energy's forecasted growth rate from 2013–2035 of 0.3% per year is slightly lower than the 0.7% per year rate calculated in NEB's 2013 reference case.
- *Commercial* – Sector demand increases to 1.7 Bcf/d (1.8 PJ/d), up from 1.4 Bcf/d (1.4 PJ/d) at 0.7% per year to comprise 5% of total demand in 2050. Ziff Energy has modeled conservative parameters for customer count growth and normalized consumption based on more tempered economic growth and a decline in the rate of efficiency gains outlined in the assumptions section of this report.

[56] Ziff Energy has modeled all NEB-approved volumes, ramping up at a rate of 0.7 Bcf/d from 2019, to total 18.03 Bcf/ plus the proposed Bear Head LNG Corp. project volumes assumed at 1.7 Bcf/d. Ziff Energy does not consider such a high volume of LNG exports from Western Canada to be likely over the forecast period.
[57] "Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035," November 2013–Reference Case.

- *Lease and Pipeline Fuel* – Demand will increase to 2.0 Bcf/d (2.1 PJ/d), up from 1.0 Bcf/d (1.0 PJ/d) at 2.0% per year to become 6% of total demand in 2050. Increasing Canadian gas production should increase this sector's fuel use during the 2013–2050 timeframe.
- *Transport* – Demand will grow to 0.3 Bcf/d (0.4 PJ/d) of Canadian demand in 2050 from less than 0.1 Bcf/d (0.1 PJ/d). Heavy trucking fueled by LNG will lead near-term growth.

Figure 29 illustrates Ziff Energy's forecast of Canadian gas demand, which will grow at a rate of 3.8% per year to 2050, increasing to 36 Bcf/d (38 PJ/d) at the end of the forecast period from 9 Bcf/d (9.6 PJ/d) in 2013. Canadian gas demand is currently 11% of the overall North American market; Ziff Energy is forecasting Canadian market share will grow to 27% by 2050.

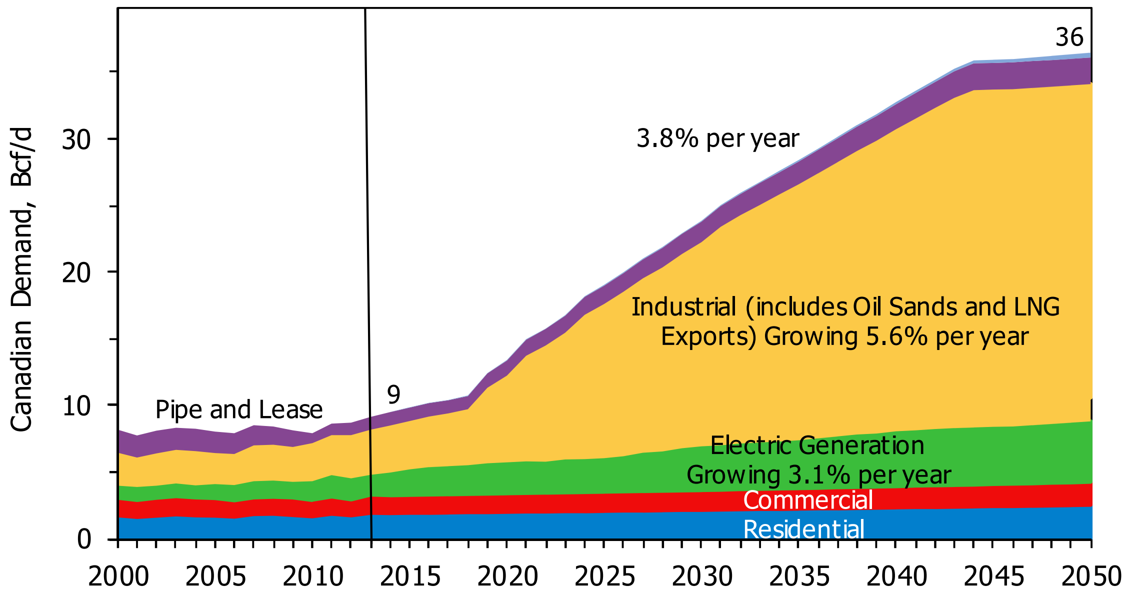

Figure 29. Canadian Demand Overview

7.5 Eastern Canadian Gas Demand Forecast

Figure 30 illustrates Ziff Energy's forecast for Eastern Canadian (Nova Scotia and New Brunswick) gas demand to 2050, growing to 2.5 Bcf/d (2.6 PJ/d) from 0.2 Bcf/d (0.2 PJ/d) in 2013.

- Bear Head LNG Corp. exports from the East Coast of Canada at 1.7 Bcf/d (1.8 PJ/d) in 2050.
- Another growing demand sector is gas required for electrical generation, which is expected to increase 3.5% per year. The growth is driven by a reduction in high carbon emitting power capacity due to Environment Canada performance standard policy.

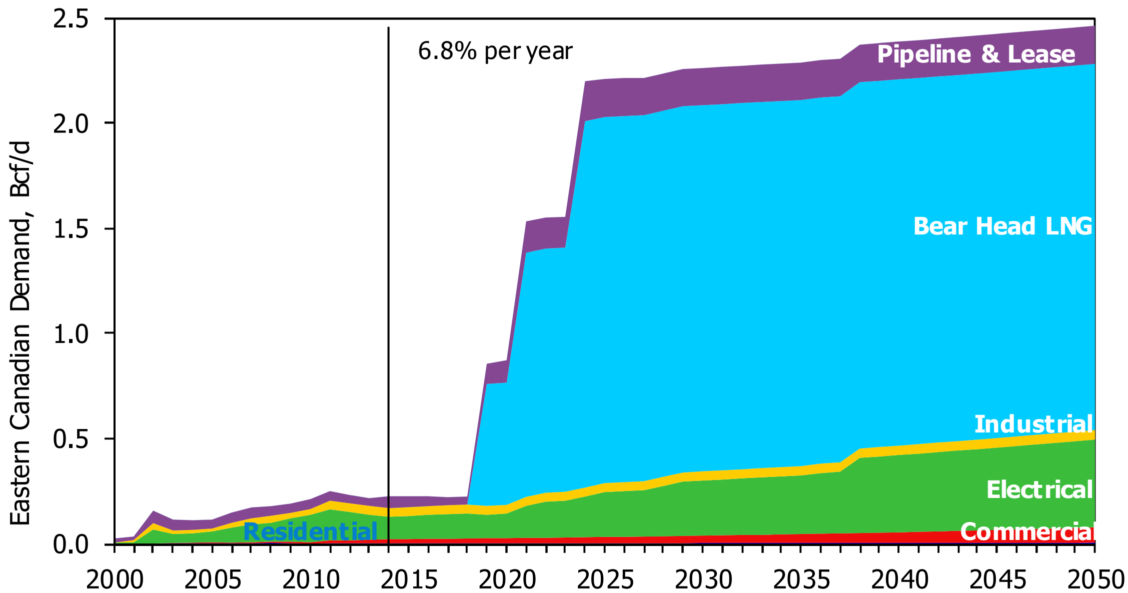

Figure 30. Eastern Canadian Demand Overview

8.0 Natural Gas Supply/Demand Balance

This section reviews current and expected natural gas market dynamics, the impact these dynamics have on the interaction between gas supply and demand, and the resulting regional natural gas flows.

8.1 Competition for Canadian Export Market Share

Figure 1 (page 5) illustrates the increased competition faced by Canadian natural gas in export markets. Throughout the 1990s, Western Canadian pipeline exit capacity was expanded to the US Pacific Coast, Midwest, and Northeast (to more than 15 Bcf/d) and gas storage infrastructure was enhanced (withdrawal capacity now 7 Bcf/d). This connectivity provided North American gas markets with a valuable continental link, giving consumers security of supply tools to mitigate seasonal energy supply disruptions such as low snow pack in the Pacific Northwest (affecting hydro-electric generation) and Gulf of Mexico hurricanes cutting gas supply.

Since 2009, the completion of the Rockies Express, Bison, and Ruby Pipelines has increased connectivity and competition from US Rockies gas, and reduced the relative value of the Canadian continental link. Increasing growth from unconventional gas sources in the Appalachia and Arkoma Basins continues to push Western Canadian gas (with a geographic disadvantage) away from traditional US Midwest and Northeast markets. Without new outlets for Western Canadian production such as LNG exports or unconventional demand (LNG for heavy trucking, gas to liquids), Western Canadian production will decrease in importance in the North American market, and production will continue to decline.

Western Canadian gas demand is primarily satisfied by supply from Western Canadian production. Historically, demand in Ontario and Quebec has also been satisfied primarily by Western Canadian supply. In recent years, Ontario and Quebec have sourced natural gas from the US, imported into Ontario via the Dawn Hub, and recently through the Niagara and Waddington border points, as the pipeline grid and infrastructure have adapted to source the least-cost supply available. Figure 31 (page 42) shows that in 2013, 1.5 Bcf/d more gas was imported into this region than was delivered to export pipelines out of this region. Imports of gas from the US are replacing gas delivered via the long-haul TransCanada Mainline system. Consumers in Ontario and Quebec have access to multiple supply sources via multiple pipeline connections and are sourcing more low-cost imported natural gas via the Dawn Hub and Niagara/Waddington. This sourcing is expected to continue given the following developments:

- Completion of the Northern Access Pipeline (bi-directional capability), which allows Marcellus gas direct access to Ontario at Niagara.[58]
- An amended Presidential permit received by Iroquois Pipeline in September 2010 for gas exports to Canada at Waddington, and associated potential to connect growing Marcellus supply with the Iroquois system.
- Recently proposed Nexus Pipeline, which would connect growing Utica supply to Dawn; 2 Bcf/d backed by DTE Energy, Enbridge, and Spectra Energy for a 2016 in-service date.

[58] From November 2012 to December 2013 imports at Niagara averaged 410 MMcf/d.

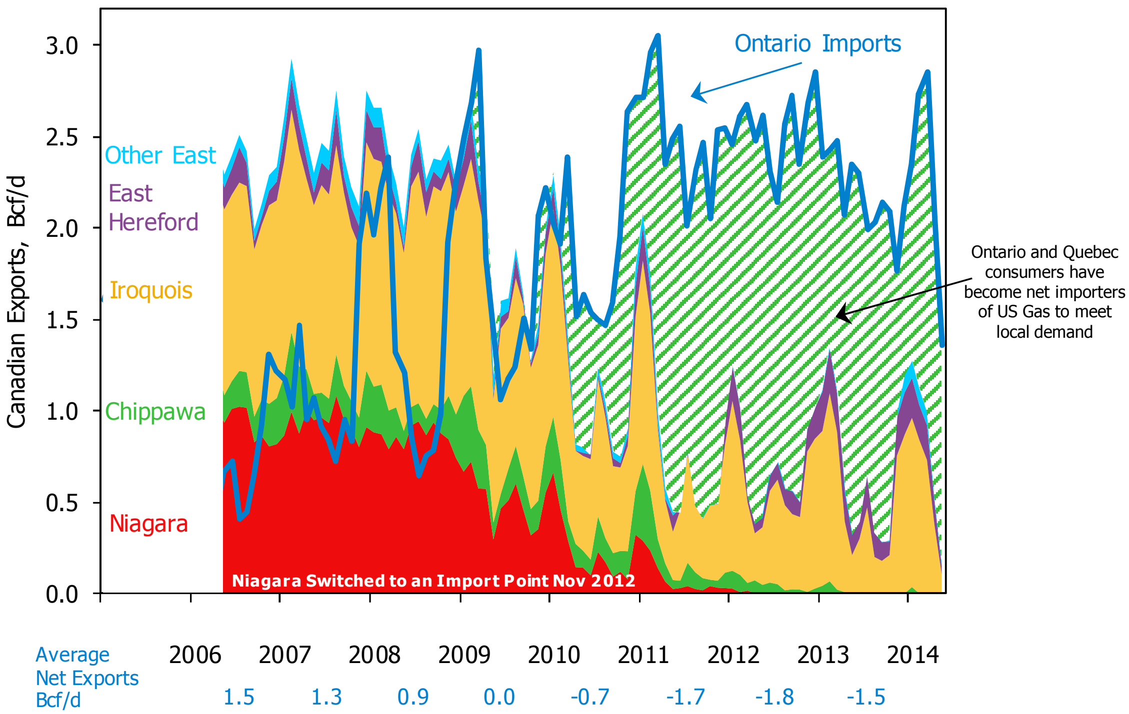

Figure 31. Canadian Gas Supply/Demand Allocations

8.2 North American Natural Gas Market Dynamics

North American gas supply traditionally has been regionally dispersed among the following major regions:

- Western Canada
- US Mid-Continent
- US Gulf Coast
- US Rockies

A new supply region in the US Northeast has evolved with growth in Marcellus and Utica shale-gas production. Natural gas is consumed in each supply region, particularly in Western Canada, the US Northeast, and the US Gulf Coast, with excess supply transported to regions lacking adequate local supply. Premium natural gas demand centers are located in New England, Central Canada, California, and the US Midwest. In some regions, natural gas must be imported to satisfy demand. Natural gas consumption varies seasonally because of temperature-sensitive heating loads and, to a lesser extent, because of temperature-sensitive electricity demand for cooling.

To deal with geographical and seasonal variables, the North American gas supply system is characterized by a sophisticated network of gas transportation and storage facilities transferring gas inter-regionally to meet both base load and peak demands.

Subsequent to commodity price deregulation and open access to pipelines, the natural gas delivery infrastructure has developed and adapted in response to changing gas supply and demand. If physical connectivity becomes a challenge, price differentials[59] widen and market participants step in to build required infrastructure to enhance linkages. The process of infrastructure enhancement is ongoing and relies on market signals and pricing differentials between trading hubs, storage fields, producing basins,

[59] A natural gas pricing differential is the difference in gas prices between two natural gas trading hubs.

market centers, and LNG facilities. For example, the current market differential between the WCSB and Ontario is approximately 0.50 USD/Mcf, while the transportation cost is approximately 1.50 USD/Mcf, rendering WCSB supply unattractive for Ontario consumers who can source US supply more cheaply.

Producers invest capital (CapEx) in gas plays that earn a rate of return under then current pricing conditions. Indeed, the marginal plays at the time generally set gas prices. Investing CapEx in the lowest cost plays and moving expenditures out of higher-cost ones causes supply to grow in some areas and decline in others. The supply response based on marginal resource costs has been dramatic since 2008. Development of low-cost, shale-gas volumes or changes in regional demand for gas—such as for electrical generation—can cause pricing differentials to respond and signal the economic opportunity to create new infrastructure such as new pipelines and laterals or LNG import/export terminals. Similarly, pricing differentials can render existing transportation systems too costly and under-utilized. This process of transportation rationalization is continuous. The physical integration allows gas to be produced, transported, and stored or withdrawn from storage, to respond to changes in gas supply and demand fundamentals. Gas can also be parked, swapped, or backhauled, which are all industry arrangements for efficiently clearing supply and demand.

The natural gas market is characterized by large numbers of competing sellers, buyers, intermediaries, and huge trading volumes. It is highly liquid, price transparent, and facilitated by electronic trading platforms, a vigorous futures market, and availability of financial instruments to enable price hedging and related activities. The NYMEX natural gas futures contract clears at Henry Hub (Louisiana) where many gas pipelines and storage facilities interconnect. Prices at major trading hubs relate to Henry Hub and generally respond to local supply and demand conditions, and availability of transportation and storage capacity. Some hubs, such as AECO/Nova Inventory Transfer (NIT) and Westcoast Station 2 in Western Canada, are not physically connected to Henry Hub via pipeline infrastructure; however, prices at all major hubs are expressed relative to Henry Hub.

Shippers on major inter-regional and international pipelines may be producers, marketers, or end-users. Pipeline transportation services can be firm or interruptible, and long or short term, pursuant to regulated rates and conditions of service. Shippers are able to re-sell contracted capacity in an open secondary market for pipeline transmission. The existence of this secondary market provides the gas commodity market with another important element of flexibility and contributes to the formation of a fair market commodity price.

The North American natural gas market's commercial structure and activities within that structure reflect market behaviour which results in market clearing prices. Consumers will generally purchase at the lowest possible delivered gas price, taking into account security of supply, financial strength of the supplier, and length of term. Consumers are generally indifferent as to the geographical source of their gas supply. All of the above attributes contribute to the development of a highly liquid, open, and efficient North American natural gas market.

8.3 Gas Market Integration

Some areas, such as Western Canada and the US Gulf Coast region,[60] produce more natural gas than they consume, so prices will typically be lower than market areas such as California or Ontario, which need to import supply. Gas hubs, such as Dawn in Southern Ontario, that have access to natural gas storage

[60] With increased power and LNG demand, the US Gulf Coast region may become a net demand region.

infrastructure, balance temperature-sensitive gas demand on a seasonal, monthly, and day-to-day operational level.

Most markets can access natural gas from multiple sources. The US Midwest can access gas from Canada, US Gulf Coast, US Rockies, and US Mid-Continent, and other sources. US Rockies supply can access US Northeast, Midwest, Canadian, California, US Pacific Northwest, and other markets. North American and Canadian consumers have the choice to purchase the lowest cost delivered gas, and producers can choose to transport gas to the highest paying markets on a netback basis. Pipeline, storage, and midstream companies ensure facilities are built to connect supply with demand and charge fees for transmission, processing, and storage.

The dynamics of supply and demand have changed since deregulation of natural gas markets in the US and Canada. New sources of gas supply have emerged and new pipelines and other infrastructure constructed. In some cases, new supply has backed out supply from traditional sources because transportation differentials are lower and, therefore, the netback to the producer is higher. Producers move capital to gas supply areas earning the highest returns. In these areas, production will grow at the expense of higher cost or lower netback areas. Overall, North American markets will continue to allocate gas supply to markets based on arbitrage opportunities created by market prices and pricing differentials.

8.4 Mexican Net Imports

Since 2005, net pipeline imports into Mexico from the US have ranged from 0.7–3.0 Bcf/d. Production forecasts include volumes for export to Mexico; however, the gas demand forecast presented in Section 7.0 excludes Mexico exports.

Mexico's constitution was amended on December 21, 2013 to reduce direct government intervention in the energy sector. Ratification from the Mexican upper house was approved in August 2014. If reforms are successful in attracting incremental natural gas investment, imports from the US L48 may stagnate. Non-associated gas reserves are primarily located in the Burgos and Veracruz basins. In September 2012, it was reported that PEMEX would spend 200MM USD on a program to exploit the Eagle Ford shale. The PEMEX March 2013 corporate presentation highlighted 200 exploratory opportunities to develop shale gas in Mexico.

It is Ziff Energy's view that in spite of new constitutional and regulatory amendments, and promising resource potential, future gas production in Mexico will continue to be uncertain going forward.

Figure 32 (page 45) shows Mexico gas reserves and resources[61] by region. The allocation of gas resources in 2010 is as follows:

- 58% in the Northern region (35 Tcf) and 15% in the Southern region (9 Tcf)
- 20% in Southeast Marine region (12 Tcf) and 7% in the Northeast Marine region (5 Tcf)
- Largest reserves decline (from year-end 2008) is in the Northeast Marine region (7%); reserves additions are reported in Southeast Marine region (28%)

[61] 17 Tcf Proven, 20 Tcf Probable, and 24 Tcf Possible. Mexico reserves definition system is incompatible with SEC reserves disclosure requirements.

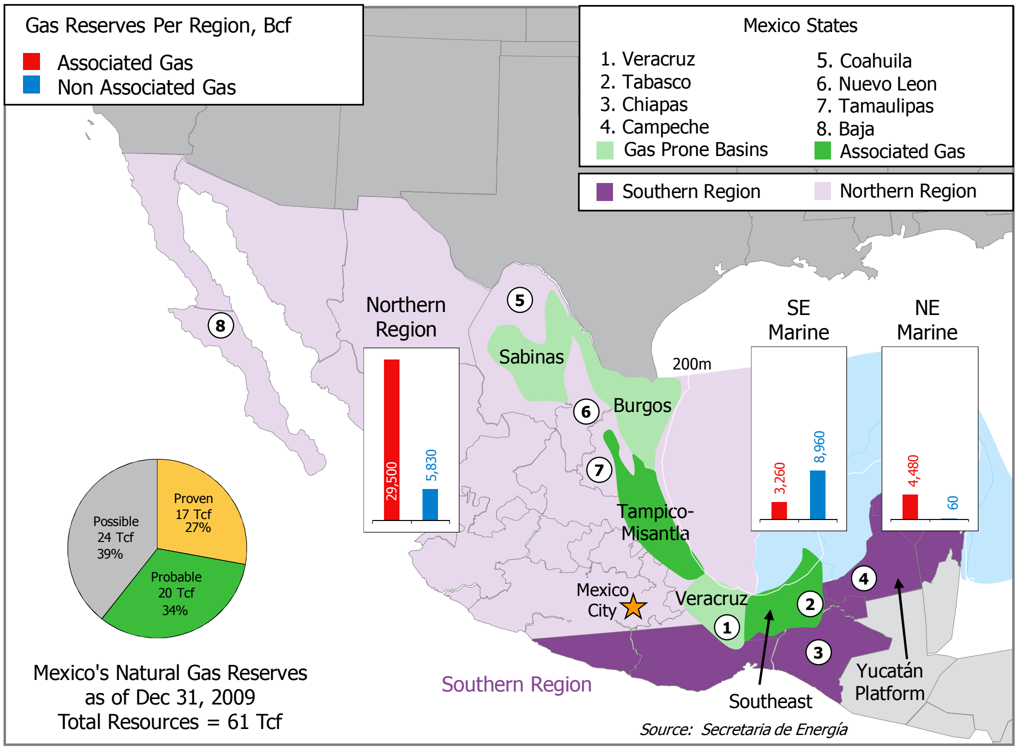

Figure 32. Regional Mexico Gas Reserves and Resources

8.5 North American Intercontinental LNG Trade

This section presents the LNG export scenario used in this report, the potential gas resource cost, and changing North American gas flows.

8.5.1 LNG Export Assumptions

Table 1 provides a summary of NEB-approved BC West Coast exports. Ziff Energy does not believe all NEB-approved projects and expansions will be developed independently as shown. Ziff Energy has modeled the potential full volume of approved exports beginning in 2019 at 0.7 Bcf/d and growing at 0.7 Bcf/d per year until the full 18.0 Bcf/d of NEB-approved exports is reached. NEB-approved Oregon State LNG volumes have been excluded.[62] Modeling the fully

Table 1. NEB-Approved Long-Term BC West Coast Exports

Approved Export License	Bcf/d
KM LNG Operating General Partnership	1.3
BC LNG Export Co-operative LLC	0.2
LNG Canada Development Inc.	3.2
Woodfibre LNG Export Pte. Ltd.	0.3
WCC LNG Ltd.	4.0
Prince Rupert LNG Exports Limited	2.9
Pacific NorthWest LNG Ltd.	2.7
Triton LNG LP	0.32
Aurora Liquefied Natural Gas Ltd.	3.11

[62] Ziff Energy believes that a fully functioning and integrated North American natural gas market would allocate and deliver lowest cost North American gas to any potential Oregon LNG project(s) , irrespective of gas origin. US Rockies supply could be considered for Oregon State LNG projects, on Sept 22, 2014: Veresen Inc. (Jordon Cove LNG proponent) announced it had an agreement to purchase 50% of Ruby pipeline system (Sourcing gas from Opal, Wyoming to the Malin, Oregon – the supply hub which will connect to Jordon Cove LNG).

approved volume is meant as a stress test for the Canadian natural gas market. Economics and market differentials will ultimately determine if increased liquefaction investment by buyers and sellers is warranted. Ziff Energy does not consider the current level of NEB-approved LNG export volumes to be likely.

Figure 33 illustrates North American LNG Export assumptions. Ziff Energy forecasts LNG exports reaching 25.7 Bcf/d during the forecast period, based on the following observations:

- 1 Bcf/d of US Gulf Coast facilities exports beginning in 2016 and increasing within the US to 6 Bcf/d in 2021.
- 0.7 Bcf/d of other Canadian exports beginning in 2019 and growing at 0.7 Bcf/d per year to 18.0 Bcf/d in 2036.
- The proposed Bear Head LNG Corp. project beginning in 2019 and ramping up to 1.7 Bcf/d at capacity.

8.6 North American Supply/Demand Balance

This section summarizes natural gas supply, demand, and resultant flows of gas over the forecast period. Pipeline transmission and infrastructure are expected to continue to adapt, connecting gas from growing supply regions to major demand centers. Ziff Energy forecasts significant changes in North American gas flows will take place in the forecast period through 2050. The elements for some of these changes have already begun to appear. Ziff Energy models demand for the Bear Head LNG Corp. project's 1.7 Bcf/d (1.8 PJ/d) LNG terminal outlet as a North American gas out-flow.

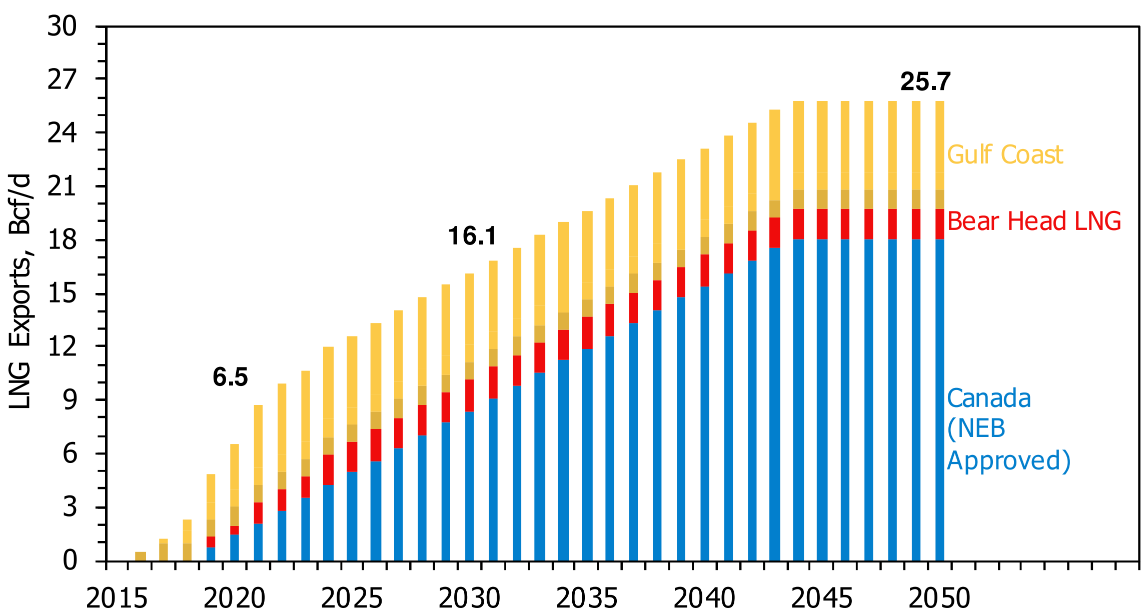

Figure 33. North American LNG Exports

The US Northeast demand has traditionally been satisfied from several supply basins, including the US Gulf Coast, US Mid-Continent, and Western Canada, which has also been the primary supply basin for

Ontario and Quebec markets. Canadian gas from Sable Island has flowed into the US Northeast since 1999,[63] and the Rockies Express Pipeline has brought US Rockies supply to the northeast since 2009.

The US Northeast is now sourcing increasing quantities of gas from the Marcellus and Utica shale-gas production areas. Imports of US gas into Ontario and Quebec are replacing gas delivered from Western Canada via the TransCanada Mainline, which is underutilized. This trend is likely to continue as existing pipeline connections are enhanced and as US gas deliveries to Ontario and Quebec continue through the Dawn Hub and Niagara/Waddington delivery points. Excess Eastern Canadian production has been exported to US northeast markets via the Maritimes and Northeast (M&NE) Pipeline. With access to low-cost Appalachia supply, development of Eastern Canadian shale and offshore supply is challenged, which could result in a reversal of the M&NE Pipeline.

Historically, Northern California has been an important market for Western Canadian gas delivered via the Gas Transmission Northwest (GTN) system from Kingsgate, BC to Malin, Oregon. Expansion of production in the US Rockies area has resulted in the Rockies Express Pipeline, which connects this supply to points east. The Ruby Pipeline, completed in summer 2011, connects the Opal, Wyoming delivery hub to Malin, Oregon. This pipeline has pushed gas back into Canada that was previously accessing the California market. The Bison Pipeline has connected US Rockies supply to the Northern Border system for delivery into the Chicago area and possible re-delivery into Ontario via Dawn. Bison deliveries from the US Rockies can also back out Western Canadian gas volumes that would otherwise flow through Foothills Pipeline into the Northern Border system. Bakken oil production in North Dakota has grown rapidly, and with it, the amount of associated-gas production. The connection of the Prairie Rose Lateral and recent success of the Tioga Lateral open season will increase gas flows into the Alliance US Pipeline utilizing allowable uprate pressure; any further connection of liquids-rich associated Bakken gas will likely come at the expense of gas flows from Canada.

The North American gas pipeline grid is interconnected and responsive to changes in Henry Hub and local pricing. Supply-demand fundamentals can change regionally more quickly than enhancements to the North American pipeline grid, which can cause differentials between pricing points to increase, signalling the need for more transmission capacity. With development of growing low-cost supply sources, pipeline infrastructure is enhanced, and gas flows adjust accordingly.

Figure 34 (page 48) illustrates Ziff Energy's view of the lowest cost 1,000 Tcf of North American natural gas. Observations include the following:

- During 2013–2020, 256 Tcf of gas resource is required:
  - To meet growing North American demand
  - For exports of LNG and gas via pipeline to Mexico
  - To offset declines from currently producing supplies
- Canadian natural gas:
  - 120 Tcf of Canadian gas resource will be competitive within the first 250 Tcf for North American gas markets
  - 210 Tcf of competitive Canadian supply is at a cost under 4.85 USD/Mcf within the first 1000 Tcf of North American gas markets

[63] Declining Sable Island production and newly connected Deep Panuke, and other local supply are not expected to be sufficient to cover Eastern Canadian demand; for this reason, a reversal of M&NE Pipeline is likely.

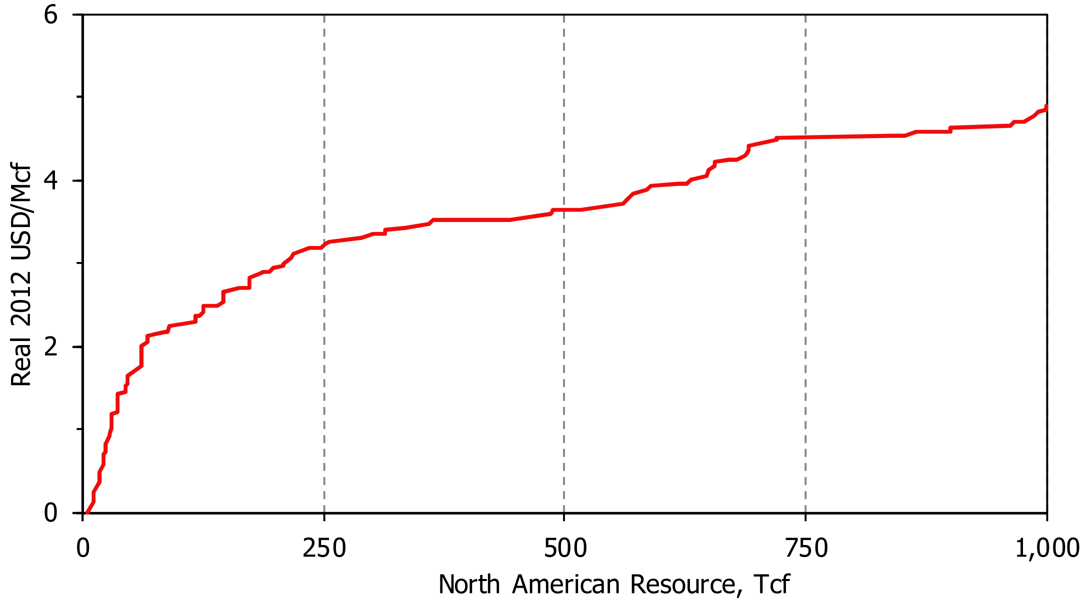

Figure 34. North American Full-Cycle Gas Resource Cost at Henry Hub

Based on this cost analysis, Ziff Energy believes that Western Canada will continue to compete with US L48 supplies, albeit with reduced near-term exports to Midwest and Northeast markets.[64] US Rockies gas supply is facing similar cost pressures and may decline during the near term. The combination of Western Canada and higher-cost new US Rockies supply will create a premium-priced market on the US Pacific Coast. Connections westward from the growing Permian basin should become highly utilized going forward. Longer term, competitive Western Canada gas supply is available for Canadian consumption, US L48 exports, and LNG exports.

Figure 35 (page 49) shows net inter-regional flows in 2010 and gross Dawn imports, which reflect supply and demand fundamentals and corresponding pipeline and delivery infrastructure. Buoyed by shale-gas growth, the US Southwest (Texas, Louisiana, Oklahoma, and Arkansas) had 22.1 Bcf/d of gas out-flows in 2010. With the completion of the Golden Pass LNG regasification facility in late 2010, the US Southwest has 11.9 Bcf/d of regasification capacity; however, only 0.4 Bcf/d of LNG imports were realized. On a net basis, the US Northeast sourced 83% of gas demand requirements from other regions and LNG.

[64] Canadian pipelines operating under a cost of service recovery model without long-term contracts will be challenged to compete with US L48 pipelines with the ability to discount tolls.

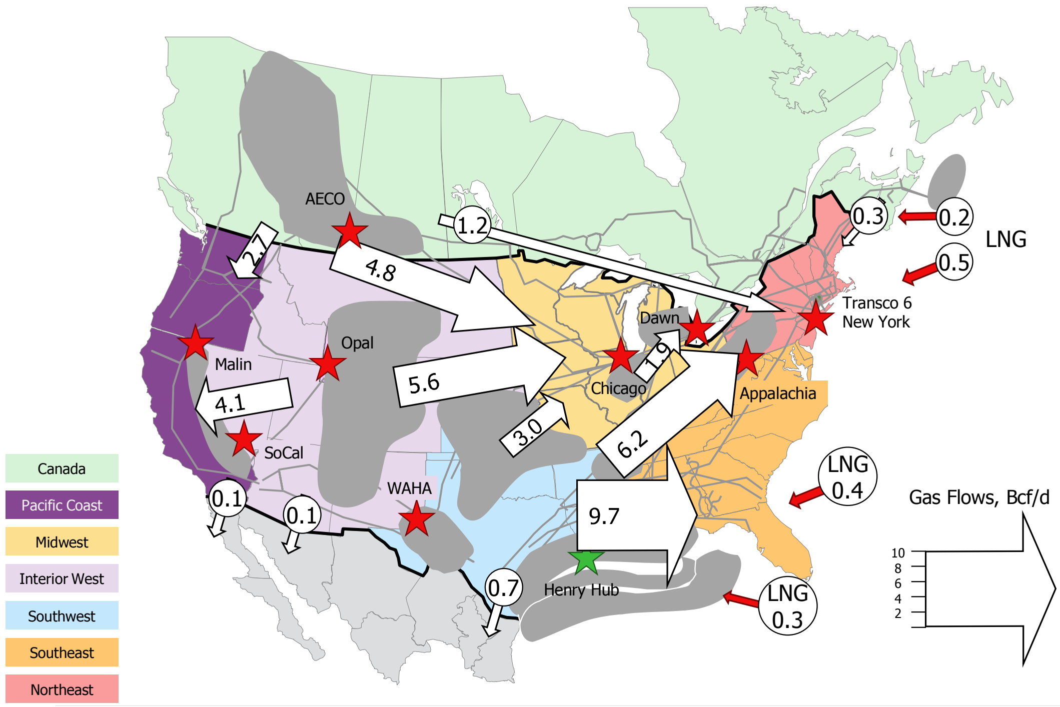

Figure 35. Inter-Regional North American Gas Flows (Bcf/d), 2010

Figure 36 (page 50) shows expected net inter-regional flows in 2050, which reflect supply and demand fundamentals and corresponding pipeline and delivery infrastructure. Growth in US Interior West and Southwest supply due to new play development allows for demand growth in the US Midwest and Southeast. The US Northeast becomes a net export region with demand covered by in-region supply. Ziff Energy believes gas flows from Eastern Canada will be reversed with gas supply likely sourced from Appalachia.

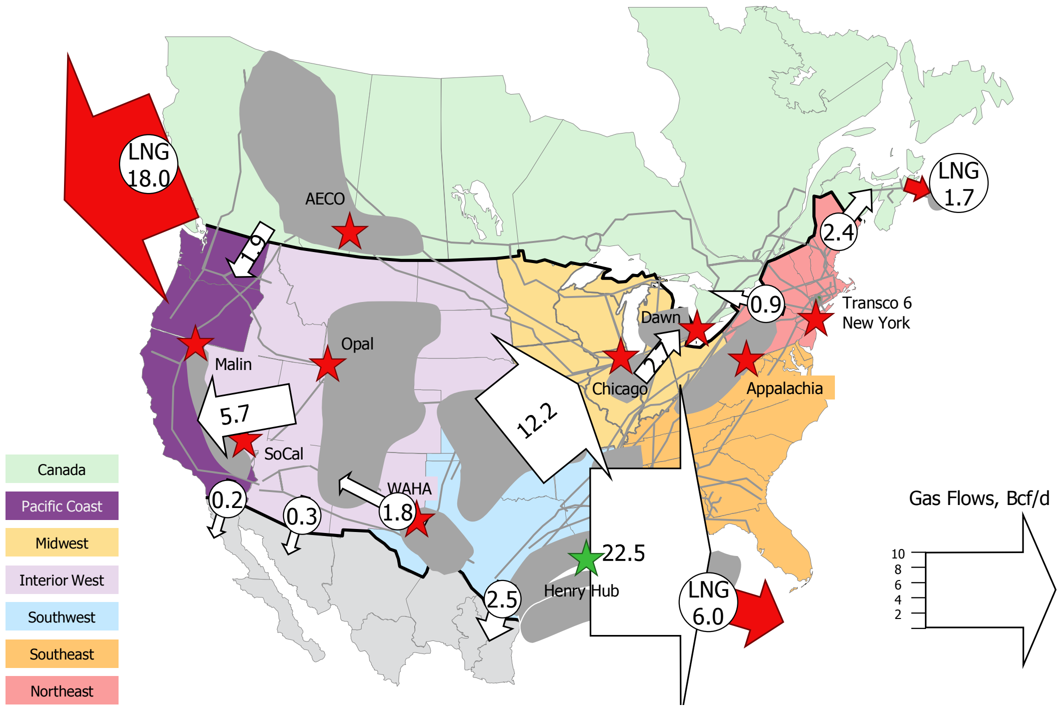

Figure 36. Inter-Regional North American Gas Flows (Bcf/d), 2050

8.7 Canadian Supply/Demand Balance

Gas supply in lower cost/higher netback areas is growing. The growth in Marcellus and Utica shale-gas supply has prompted pipeline, midstream, and storage operators to propose and develop infrastructure recognizing changing supply dynamics. Western Canadian gas supply will be available for Canadian domestic and export markets, and given a competitive market, will preferentially flow to the markets providing highest netbacks.

Western Canadian gas displaced by downstream pipeline developments (Niagara Reversal into Central Canada and proposed Nexus Pipeline) will access growing Western Canadian demand, primarily for heating and processing growing oil sands production, for power generation, and planned LNG exports. Commercial decisions for disposition of this gas will hinge on prices in downstream markets, transportation costs, and resultant netbacks to producers, versus market prices in Western Canada. Western Canada will have adequate supply for in-region use, exports to other jurisdictions (including Central Canada), and planned LNG deliveries.

Figure 37 shows Ziff Energy's analysis of supply, demand, and disposition of Canadian gas in 2010.

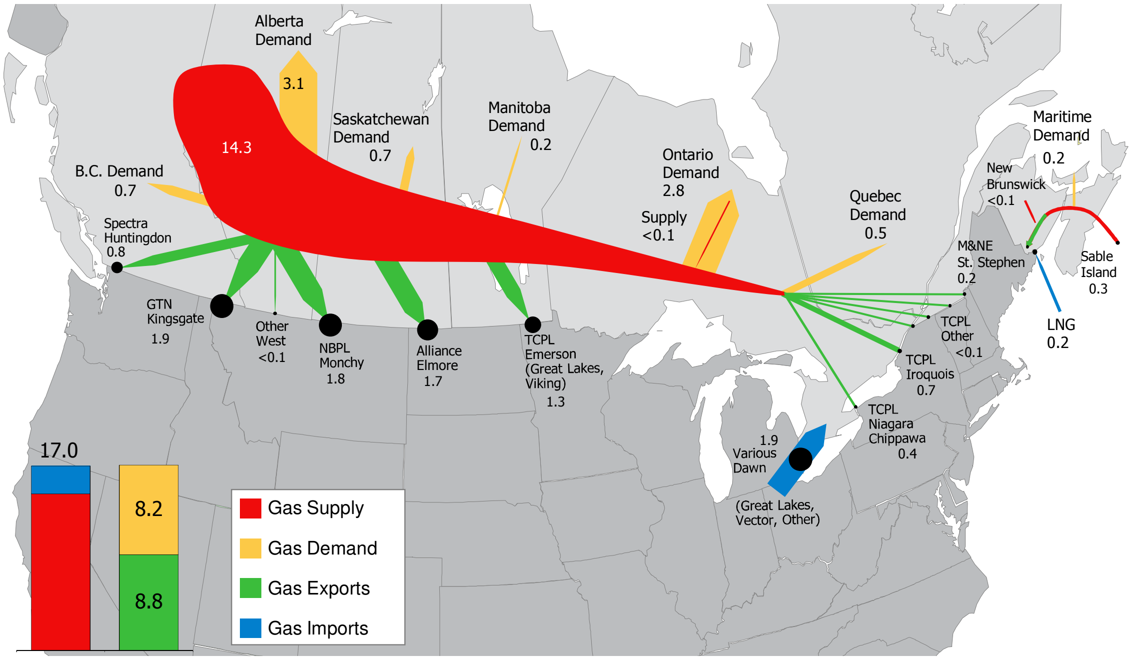

Figure 37. Canadian Gas Imports and Exports (Bcf/d), 2010

Figure 38 (page 52) shows Ziff Energy's expectation of supply, demand, and disposition of Canadian gas in 2050. Observations as previously discussed:

- Western Canadian supply increases to 36.4 Bcf/d (38.4 PJ/d) in 2050
- Alberta demand increases to 7.8 Bcf/d (8.2 PJ/d) in 2050
- Ontario demand remains steady at 3.9 Bcf/d (4.1 PJ/d)
- Imports of US gas into Ontario grow to 3.8 Bcf/d (4.0 PJ/d)
- Reversal of Maritimes and Northeast Pipeline
- Export pipelines at the eastern terminus of the TransCanada system are expected to receive low volumes of gas supply or reverse to deliver gas to Eastern Canada

Ziff Energy has made the assumption that upstream incremental transportation will be constructed to meet the needs of Spectra T-South domestic, and T-South export consumers, Eastern Canadian consumers and the Bear Head LNG Corp. project.

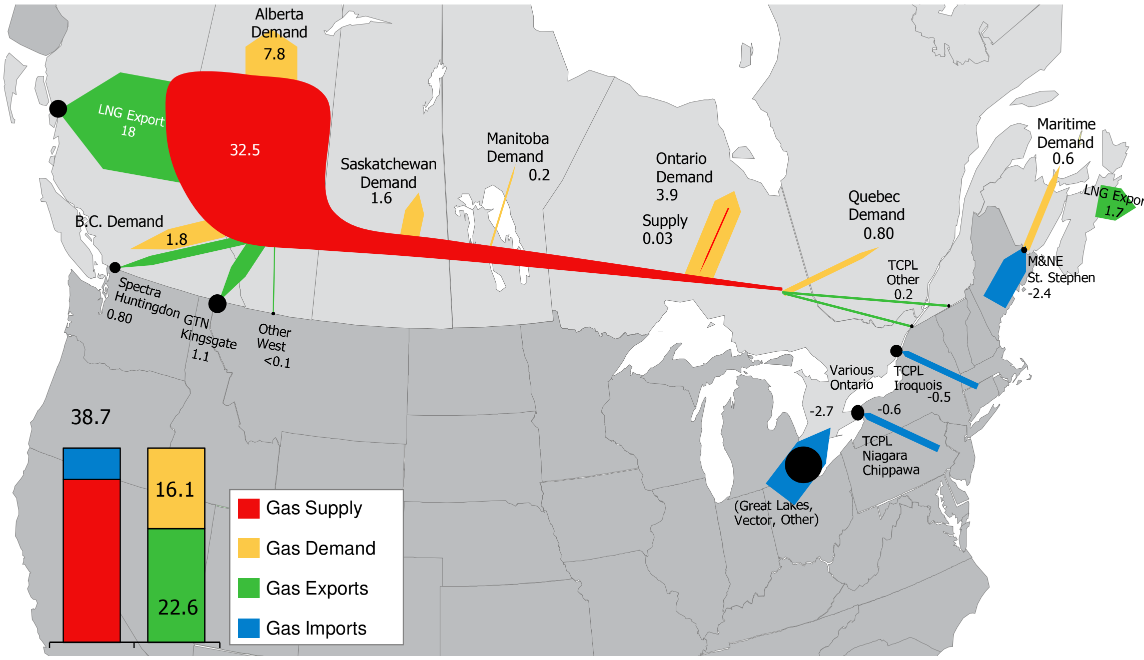

Figure 38. Canadian Gas Imports and Exports (Bcf/d), 2050

8.8 Eastern Canadian Supply/Demand Balance

Eastern Canadian customers are currently located at the beginning of the North American pipeline grid, with local supply from offshore Nova Scotia and onshore New Brunswick supply sources. Gas production is sufficient to satisfy local demand, and provide gas for export markets in the US Northeast. Sable Island supply offshore Nova Scotia is currently in decline and Ziff Energy expects this trend to continue. Even though Deep Panuke production has begun, the Eastern Canadian region, consumers, with or without potential LNG exports, will transition from a gas export region, to a gas import region. With or without potential LNG exports, market prices will reflect this new reality.

Functioning natural gas markets and resultant commercial terms will ultimately decide how pipeline links in the Eastern Canadian and New England states will be enhanced and reconfigured. Ziff Energy believes robust low-cost supply from the US Appalachia region will be available to cover Eastern Canadian demand, including for LNG exports in an integrated and fully functioning North American market based on open and transparent pricing.

9.0 Gas Price Sensitivity

This section discusses the impacts of Bear Head LNG Corp.'s LNG export on Henry Hub gas prices and a higher demand scenario.

9.1 Impact of LNG Exports on Gas Price

The shale-gas revolution has been made possible by the ability to fracture horizontal wells multiple times, thereby lowering full-cycle costs.

Figure 39 illustrates the inconsequential production of pre-shale technology using average Western Canadian IPs during the 2004–2006 pre-shale era with a representative 1,030 cumulative wells (more than 50,000 wells were connected in Western Canada during this period) for comparative purposes.

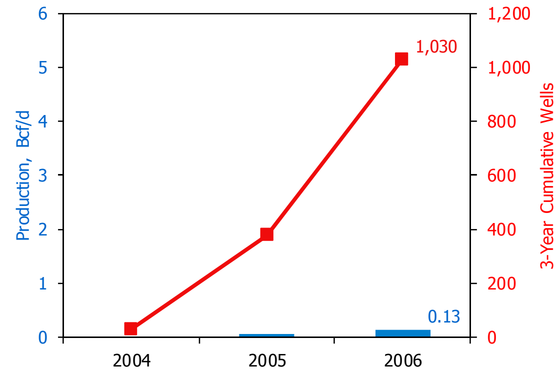

Figure 39. Average WCSB

Figure 40 shows 4.75 Bcf/d of actual US Haynesville shale-gas production resulting from 1,030 wells drilled from 2008–2010 (50 times greater than a traditional WCSB well). This production growth benefited from established natural gas plant and pipeline infrastructure that had developed in Louisiana and Texas to gather and process gas for markets upstream of Henry Hub.

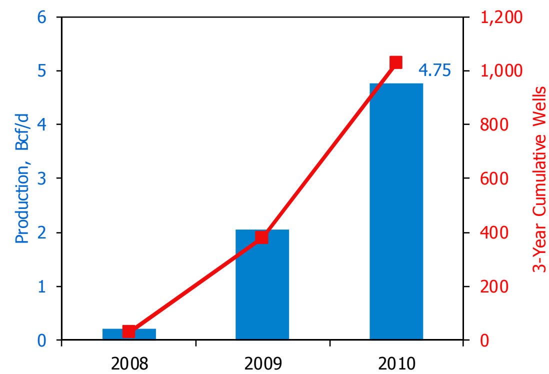

Figure 40. Haynesville

Figure 41 shows the 3-year production from 1,030 wells using Ziff Energy's forecast for Canadian Horn River IP and decline rates. This forecast drilling results in 4.7 Bcf/d of production, 2.7 times greater than the 1.7 Bcf/d required for Bear Head LNG Corp.'s proposed export.

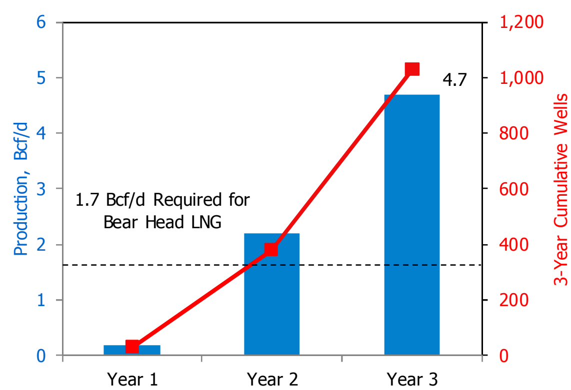

Figure 41. Horn River

Ziff Energy believes producers can quickly respond to increased LNG export demand by drilling highly productive shale-gas wells, thereby preventing a return to supply-constrained market conditions and muting sustained upward pressure on natural gas prices. Increases in demand can be quickly matched by increased supply, which will mute price increases. During the pre-shale period, increased demand caused price spikes and LNG imports were feasible as North American supply was effectively constrained. The availability and exploitation of the low-cost North American unconventional gas resource endowment is the primary driver for consideration of LNG exports.

North American and Canadian natural gas markets are highly integrated and liquid, providing gas purchasers and sellers multiple options to ensure that the most economic natural gas is developed, transported, and sold into the market at any given time.

Operating an LNG facility and terminal at high load factors will ensure the lowest unit cost and best economics for the project and provide incentive for proponents to employ various options to secure gas supply, including:

- Purchasing and developing proprietary or joint venture acreage
- Using forward markets to secure physical natural gas supplies (North American forward exchanges are robust and well established.)

Large quantities of low-cost resource are available for additional gas market growth as illustrated in Figure 34 (page 48). Properly functioning markets encourage more efficient producers to bring on additional production.

9.2 Price Impact and Canadian Demand Sensitivity Increased 20%

Figure 42 (page 55) illustrates the increased demand by region of 20% more gas demand in 2050. The growth rate increases to 4.1% per year, up 0.3% per year. This incremental 3.8% per year Canadian demand sensitivity is delineated between the Eastern and Western Canada regions (excluding stressed LNG export volumes). In the sensitivity, Ziff Energy has allocated incremental provincial demand on a yearly basis based on provincial market share of Canadian demand modeled in Section 7.4 (page 38). For the sensitivity, Ziff Energy assumed the following:

- All incremental Central/Eastern Canadian demand is supplied by US L48 imports from a well-functioning North American market. Incremental Western Canada demand is supplied by ample Western Canadian resources.
- Pipeline exports from Western Canada remain the same as the Reference Case volumes.
- Incremental demand is prorated among sectors based on Reference Case market share(s).

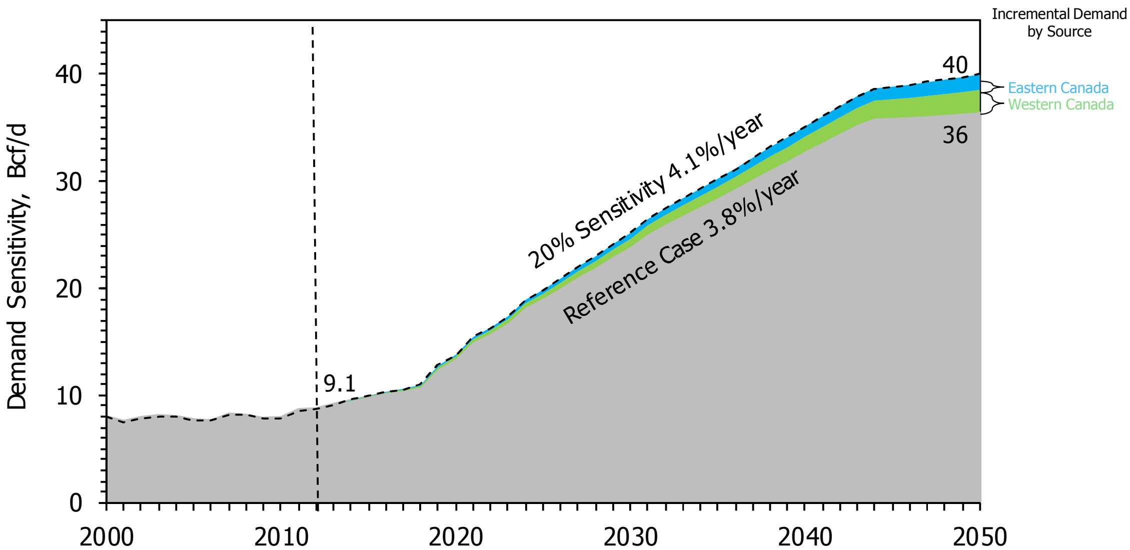

Figure 42. Canadian Demand Sensitivity

Figure 43 (page 56) illustrates that the average incremental impact of the Bear Head LNG Corp. project on Henry Hub natural gas prices during the forecast period is 0.04 USD/Mcf. To put this in perspective, Henry Hub prices have averaged 5.63 USD/MM Btu since 2005.[65] When the Bear Head LNG Corp. project begins operation, the most prolific shale gas and tight gas plays will still be relatively immature and at the low-cost end of the cost curve.[66] As we move forward in time, lower productivity wells are drilled and movement up the cost curve is accelerated slightly, resulting in marginally higher-cost natural gas. Ziff Energy expects that technology enhancements will lower the cost of producing from less productive areas. Ziff Energy also expects the marginal resource cost curve Figure 34, page 48 will flatten in later years as technology improves and emerging[67] and new unconventional-gas plays are identified and exploited, all of which will likely further mute the price impacts of the proposed gas export.

The 20% increase in Canadian demand sensitivity produces an average price impact of 0.08 USD/Mcf, and does not change the overall conclusions of this report.

[65] Monthly Bid Week Index January 2005 to December 2013 during which prices ranged from 2.03–13.93 USD/Mcf.
[66] Illustrated in Figure 34 (page 39).
[67] Unconventional-gas resources exist in plays other than those currently attracting capital expenditures for development. Gas resources have been identified in a myriad of other plays, including the Quebec Utica, the Collingwood play in the Michigan Basin, the Maverick/Pearsall play in Texas, the Colville play in the Northwest Territories, and the Niobrara play in the US Rockies. Other plays have already been identified, and more are expected. New and emerging plays are not represented in Figure 34 (page 39).

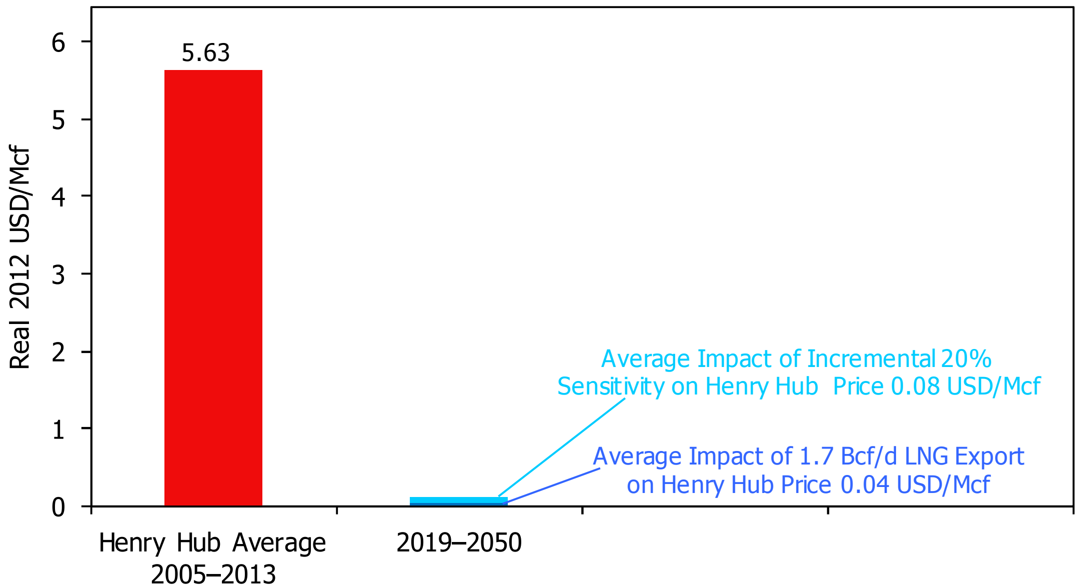

Figure 43. Impact of the Bear Head LNG Corp. Project on Natural Gas Price

10.0 Conclusions

This report presents Ziff Energy's North American and Canadian natural gas supply, demand, and inter-regional flow forecasts to 2050. This analysis has taken into account Bear Head LNG Corp.'s proposed licence to export up to 12 million tonnes of liquefied natural gas per annum[68] during the forecast period. Ziff Energy's main conclusions concerning demand, supply, and market dynamics during the forecast period are as follows:

1. North American and Canadian gas resources are robust and continue to grow with the development of horizontal drilling and multi-stage fracture technologies.
2. North American and Canadian accessible gas supply is not constrained to meet projected base demand, including NEB-approved LNG exports[69] and incremental demand from the Bear Head LNG Corp. project during the forecast period.
3. There is an abundance of low-cost natural gas resource available in North American and Canadian shale-gas plays and unconventional-gas plays.
4. Canada and the US have productive natural gas potential resources in excess of projected demand during the forecast period, having regard to trends in the identification of gas resources, particularly unconventional gas, and in the development of cost-competitive production from those resources as a result of technological advances referred to in Point 1 (above).
5. Canada and the US have potential natural gas supply in excess of projected demand,[70] including NEB-approved LNG exports, and incremental demand from the Bear Head LNG Corp. project during the forecast period.
6. Canadian gas supply is expected to grow to 35 Bcf/d (37 PJ/d) in 2050, up from 14 Bcf/d (15 PJ/d) in 2013, as new gas supplies more than offset declines of higher-cost conventional gas. In 2013, Eastern Canada was the source of 2% of Canadian gas supply, the majority (two-thirds), coming from offshore Nova Scotia[71].
7. Eastern Canada will transition from a net supply region to a net demand region over the forecast period.
8. With or without demand from the Bear Head LNG Corp. project, Eastern Canada is likely to require supply from other North American supply basins, including the US Appalachia Region.
9. Other North American supply could access Eastern Canadian Markets, including demand for the Bear Head LNG Corp. project. This supply could come from Eastern Canadian onshore and offshore gas resources, Newfoundland offshore, Quebec Utica shale resource, or from Western Canada.
10. Western Canadian natural gas is facing competition and significant displacement in traditional markets, including in Central Canada, from low-cost US L48 gas, such as the Marcellus.

[68] Natural gas equivalent of approximately 1.7 Bcf/d (1.8 PJ/d).
[69] Ziff Energy has modeled all NEB-approved volumes, ramping up at a rate of 0.7 Bcf/d from 2019 to total 18.03 Bcf plus the proposed Bear Head LNG Corp. project volumes assumed at 1.7 Bcf/d. Ziff Energy does not consider such a high volume of LNG exports from Western Canada to be likely during the forecast period.
[70] Assumes access to land for exploration, development, and pipeline routing.
[71] The percentage of Eastern Canada gas production from offshore Nova Scotia will increase in 2014, with a full year of production from Deep Panuke.

11. The North American market is highly liquid, open, and efficient.
12. Despite declining Western Canadian gas production since 2001, Western and Eastern Canadian gas markets have been adequately supplied and this trend is forecast to continue; these markets are a component of the integrated North American market.
13. North American gas demand growth will be driven primarily by gas-fired electrical generation, gas for growing oil sands gas demand, and LNG export liquefaction.
14. Canadian gas demand growth is expected to be driven principally by a switch away from coal-fired power generation, gas for growing oil sands production, and LNG export liquefaction.
15. Canadian gas demand is expected to increase at an average of 3.8% per year during the forecast period and will make up a larger component of North American demand, increasing market share to 27% in 2050 from 11% in 2013.
16. The market impact from the proposed Bear Head LNG Corp. project will be muted by the abundance of low-cost gas resource available in Western Canada and US L48.
17. The incremental price impact of the Bear Head LNG Corp. project on Henry Hub natural gas prices over the forecast period will average 0.04 USD/Mcf.
18. Natural gas markets will continue to function during the forecast period with natural gas buyers and sellers establishing fair market prices based on supply and demand fundamentals.
19. Ziff Energy considers that the export of gas proposed by Bear Head LNG Corp. will not cause Canadians any difficulty in meeting their natural gas requirements at fair market prices during the forecast period.