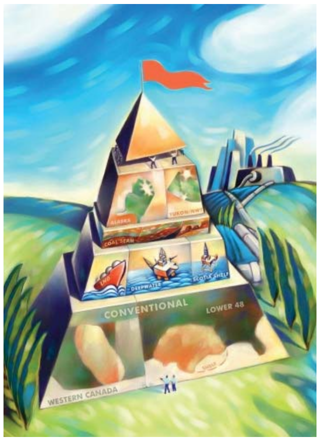


NATURAL GAS AS AN ISLAND POWER GENERATION OPTION

Prepared for:

Government of Newfoundland and Labrador

Calgary, Alberta

October 30, 2012

12GC-2013-05

ziff ENERGY GROUP
Global Energy Advisors

180, 6025 - 11th Street S.E. Calgary, Alberta T2H 2Z2
Tel: (403) 234-4299 Fax: (403) 261-4631
E-mail: bill.gwozd@ziffenergy.com
Toll Free 1-800-853-6252 ext.299

4295 San Felipe, Suite 350 Houston, Texas 77027
Tel: (713) 627-8282 Fax: (713) 627-9034
E-mail: paul.ziff@ziffenergy.com
Toll Free 1-888-736-5780

NOTICE

This Study has been prepared by Ziff Energy Group and is provided to Government of Newfoundland and Labrador (Government) for their use. Use of this Study by any other Party or for any other purpose without the express written permission of Ziff Energy Group is prohibited. Ziff Energy Group represents and may in future represent many clients in a diverse range of industries and businesses. Ziff Energy Group may continue to represent existing clients and undertake to represent existing and new clients in any matter that is substantially unrelated to our work for Government, even if the interests of those other clients in such matters are directly adverse to Government's interest, including litigation or other proceeding (application, hearing, etc.) to which Government is or may become a party or participant. Ziff Energy Group maintains and will maintain confidentiality of all confidential information provided to us by our clients.

WARRANTY

The data contained in this Study, although believed to be accurate, is not warranted or represented by Ziff Energy Group to be so. Ziff Energy Group expressly disclaims all responsibility for, and liability in respect of all loss and/or damage howsoever caused, including consequential, economic, direct or indirect loss, to any party who relies on the information contained in the Study.

NATURAL GAS AS AN ISLAND POWER GENERATION OPTION

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This Report examines the availability and feasibility of natural gas as feedstock for power generation on the Island of Newfoundland (the Island) at Holyrood. The Report has been commissioned in the context of an aging oil-fired power plant at Holyrood and plans to develop a new hydro-electric power project at Muskrat Falls, Labrador. Natural gas considered in this Report would originate either from the Grand Banks or world-sourced Liquefied Natural Gas (LNG). Grand Banks gas would be delivered to the Island via offshore pipeline. World-sourced LNG would be transported to the Island via specialized tanker and converted to natural gas at a Regasification (Regas) facility located on the Island before transport to Holyrood via pipeline.

Grand Banks pipeline supplied natural gas is not a viable replacement for the current oil-fired Holyrood electric generation facility. While natural gas is physically available offshore Newfoundland and Labrador, it is not available on commercially viable terms for power generation. Current surplus gas production is either injected for use in oil recovery, or stored for later use in oil recovery or for future monetization. Oil and gas companies have evaluated natural gas monetization opportunities and have yet to identify an economic project. The power generation demand on the Island is so small that any investment in offshore infrastructure (facilities, wells, and pipeline) plus associated operating costs cannot produce the return(s) on capital required for oil and gas companies.

Notwithstanding any future policy objective to develop Grand Banks natural gas, the Government of Newfoundland and Labrador cannot compel Operators to produce and sell gas to the Island power generation market, nor can it mandate a price that the Operator(s) must accept for their gas. The Government of Newfoundland and Labrador has no legislative authority to order a non-economic development of offshore natural gas. Ziff Energy concludes that even if Grand Banks natural gas were commercially available it would be prohibitively priced for Island power generation when compared with the proposed Muskrat Falls hydro-electric power and the current oil-fired power generation at Holyrood.

LNG supplied natural gas for power generation is not a viable alternative to the current oil-fired Holyrood generation of electricity. In order to address utility supply risks, LNG should be sourced under long term contracts which are predominantly oil-indexed. Oil-indexation suggests long term pricing at approximately 80 to 90% of World Oil Prices (Brent). Despite the abundance of shale gas in North America, oil indexation for LNG will be a sustaining commercial model going forward. The low and variable volumes of gas required to produce power at Holyrood are an economic barrier to securing long-term firm LNG Supply. The required investment in Regasification (Regas) and storage infrastructure, when amortized over such low and variable volumes, renders LNG as an Island power generation option uneconomic. Full cycle LNG supply costs will likely be similar, or in excess of, the current oil-fired power generation at Holyrood and higher than the proposed Muskrat Falls Project.

KEY FINDINGS

This report examines the availability of offshore domestic gas and LNG and their viability to produce electricity at Holyrood. The key findings are:

1. Grand Banks natural gas is stranded and not available to flow:
    - while the gas offshore Newfoundland and Labrador is in place, there is currently no viable market for offshore Newfoundland gas; there is no pipeline to commercial markets and there are no commercial contracts in place to sell the gas to market. This gas could be referred to as 'stranded'
2. Associated Gas produced with oil offshore Newfoundland is used to power oil production systems or is re-injected to enhance oil recovery ("EOR"), and is not available:
    - natural gas surplus to fuel needs on the platforms is re-injected into the reservoir(s) to enhance oil recovery or conserved should a commercial opportunity become available
    - at White Rose, Husky is evaluating gas re-injection options for EOR and has no current plans to produce and market the gas for Island power generation
        - the White Rose field contains gas resources, however oil production could be depleted as early as 2023-28 based on remaining reserves; there are no current opportunities that the operator has deemed economic to commercialise the gas
    - using Associated Gas to enhance oil recovery is a long-term benefit for Newfoundland and Labrador resource owners, who would be negatively impacted by using gas for island electrical generation
3. The Government of Newfoundland and Labrador cannot compel the sale of Grand Banks natural gas to the power generation market, nor can it mandate a price that the Operator(s) must accept for the gas:
    - the three current operators have a production license to produce oil. This license cannot be unilaterally altered to force companies to produce gas that is uneconomic
    - jurisdictions seeking to attract investment dollars in a competitive world context cannot alter agreements and licences unilaterally without long term consequences
4. Capital cost to develop Grand Banks gas is high and the return is not sufficient to justify the expense:
    - it is unlikely that producers of offshore Newfoundland gas resources will accept North American domestic prices for their offshore gas when the costs will be more than 4 to 5 times that price, and world LNG prices are primarily priced off an oil index

- producer shareholders insist on economic viability for capital expenditure decisions; capital is mobile, producers have significant choice as to where to invest, and can adjust portfolio decisions based on where they generate the highest rates of return
- in most oil and gas projects, production peaks early so producers have an early recovery of their investments and return on investment, recovering as much as 80% of the investment in the first 10 years of a project's life. In the case of a gas pipeline for Holyrood, the opposite is true - power demand and associated gas production is very low in the beginning, only reaching a peak at the end of the project

5. The power market in Newfoundland is demonstrably small, and the load profile fluctuates, with demand spikes in winter months, and very little demand in the summer. This poses a challenge for development:
   - the gas volume required to replace oil and meet load growth would be comparatively small for the size of capital investment and unevenly spaced throughout the year
   - due to the low annualized volumes of gas required for Island Power Generation and the high capital cost of developing and transporting Grand Banks gas, the unit cost of the gas landed at the generation plant gate renders this option uneconomic

6. A subsea pipeline is costly and a significant challenge:
   - the length of the pipeline is a balance in cost and risk. A shorter pipeline will be subject to iceberg scour risk and will need extensive trenching and dredging. A route away from icebergs along the edge of the continental shelf will double the length of the pipeline
   - high level cost estimates indicate a pipeline toll of over \$6.71/Mcf[1], based on a pipeline cost of \$640 MM, which would rise to more than \$12.22/Mcf, based on a pipeline cost of \$1,165 MM, if a longer route to avoid iceberg scouring and associated trenching costs, is considered. Figure 1 utilises the mid-point of \$9.46/Mcf

7. As there is currently no low cost natural gas available on the Grand Banks for Island power generation, the most likely scenario to develop gas on the Grand Banks would be a standalone gas project. Such a development would take several years for permitting, exploration and development. The estimated cost of finding, developing, and bringing natural gas from a Grand Banks standalone project to the Holyrood power plant inlet would be about 2012C\$33/Mcf:
   - a potentially lower cost alternative would be to consider integrating gas development with the Well Head GBS that Husky is evaluating for

[1] North American Pipeline tolls are generally below \$1.50/Mcf

development of West White Rose. The full cycle cost of such a development would be about 2012C$22/Mcf, rising to $28/Mcf after oil production ceases

- a re-fit of the existing FPSO at White Rose would cost 2012C$21/Mcf, rising to $27/Mcf after oil production ceases

8. The low and variable volumes of gas required to produce power at Holyrood would be a challenging economic barrier to securing long-term firm LNG Supply on world markets; LNG landed in Newfoundland would be prohibitively priced over the long term:

    - Newfoundland would most likely compete with world markets for higher priced LNG Cargoes (influenced by oil linked contracts). World sourced LNG would cost $16.30 - $18.35/Mcf[2] FOB Newfoundland and $25.10 - $27.15/Mcf at the regasification plant outlet
    - US Gulf Coast LNG priced off the North American Henry Hub Index is not likely to be available to the Island under similar terms and conditions as the proposed project by Cheniere Energy at Sabine Pass

9. Reliance on world spot LNG markets would bring unacceptable utility supply risk as peak demand periods for LNG spot cargoes coincide with peak requirements at Holyrood during winter months; Ziff Energy therefore would recommend long-term oil indexed supply contracts with major LNG players who have diversified supply options.

[2] 80-90% of EIA AEO 2012 forecast of $118.31/Bbl for 2017 imported crude (weighted average of delivered to U.S. refiners) in Real 2012$ at 5.8 MMBtu/Bbl

NATURAL GAS POWER GENERATION

The developers of the Newfoundland and Labrador electric power system concluded in the 1960's that number 6 fuel oil supplies would be the fuel to produce steam that would spin the turbines for the Holyrood Thermal generating plant at Conception Bay, initially at 300 MW and later expanded to 490 MW. This development has served Island consumers well through past decades.

For several decades, generation of electric power by combusting natural gas has become more established. Oil and coal tend to have higher emissions of pollutants and greenhouse gases. Current and potential future regulations tightening emissions levels have strongly encouraged operators to shift to natural gas fueled new power generation facilities. Technological advancement of gas fired power generation has increased overall efficiency of using natural gas. Like all gas used throughout North America, most natural gas combusted for electric power generation needs to be processed and conditioned to ensure safe use. The current methods are:

1. steam generation – natural gas is combusted in a large water boiler to produce steam which is then used to spin a turbine to generate electricity
2. gas turbines[3] – the natural gas is combusted and gases discharged are used to power the turbine
3. combined cycle – is both a gas turbine and a steam generator. Hot gases combusted spin the turbine and the exhaust heat is used to produce steam to also spin the turbine.

There is no specific regulatory requirement or policy in place stipulating that electric power needs to be fueled by natural gas. Such infrastructure decisions are arrived at after considering costs, emissions, future emissions risks, and availability of feedstock. Gas for power generation is becoming the preferred way to generate new electricity due to the extensive distribution of natural gas producing fields in most parts of continental North America and the strong interconnection of gas fields through large diameter gas transmission pipelines and distribution pipelines into cities and various communities. With North America natural gas at a decade low price, many electric power consumers are enjoying the lower cost for their electric power.

[3] also called combustion engines

HOLYROOD THERMAL GENERATING PLANT

Reliability Requirements for Utility

If an electrical power company had a single annual power failure for 1 hour between 5:30 pm to 6:30 pm on a week day in mid-January that failure would be remembered by consumers for some time even though the overall reliability for the year exceeded 99.9%[4]. End use consumers demand reliability in essential utility services. Consumers are willing to pay for high levels of reliability. As a consequence, essential utilities undertake extensive analysis to identify plant components that can fail, establish operational plans for spare part optimisation, and planned replacement prior to normal failure. The overall goal is to mitigate unscheduled downtime through prudent replacement of equipment before it fails[5]. Reliability analytics may include: the duration of the failure, the time between failures, and the mean time to recover from a failure. Utilities should enhance operational plans designed to seek improvements each year to strengthen overall reliability for the utility.

Converting Gas to Electricity

The expected lead time to construct a natural gas to electricity generation facility is typically assumed to be 2 to 3 years, perhaps 4 times faster than siting a new nuclear or coal fired power plant. Additionally, unique consumer requirement for instant electricity (power needs to be available at the flip of a switch) aligns very well with the ability of natural gas power generation plants to start up or shut-down more rapidly than nuclear or coal fired power plants. Further, gas to electricity plants can be added in incremental steps to better align with market growth opportunities versus building the ultimate sized facility for growth expectations later in the facility life.

Combined cycle power generation is an efficient and widely used method of converting natural gas to electricity. The process is well established. Compressed air (oxygen source) is mixed with natural gas and burnt in the turbine combustion chamber to liberate high temperature gases and expanding by products (Carbon Dioxide, water vapour, and remaining air). These hot gases are channeled through a narrow nozzle which spins the turbine, turning the shaft to generate electricity. The hot exhaust gases are then stripped of their remaining heat energy in a steam generator to generate incremental electricity.

Load Profile

Gas demand requirements for end-use markets are typically referred to as the load profiles and are influenced by several factors: time of day, day of week, and annual season.

Time of day - Residential use profiles tend to have two daily peaks, one in the morning with family preparation for the day, and the second when the family returns from school and work in the late afternoon and early evening. Commercial load profiles can be sustained during the normal working day and tend to taper off in the evening. The common trait among residential and commercial load profiles is very small usage from the late evening and into the early morning. In some communities

[4] 99.9886% = (1 – (1 hour failure / 365 days * 24 hours per day) * 100%
[5] consumers will recognise the similarity of the principle through the annual battery replacement in their household smoke detectors. The batteries are replaced prior to failure to ensure ongoing and continued reliability

across North America, utilities are financially encouraging users to change their normal load profile by undertaking some activities earlier or later than the typical peaks. As an incentive, the utility may offer a time of day power rate. When everyone wants to use power, the rate is highest; conversely, when few want to use power, the price is lowest. The aim of these incentives is to 'flatten' the load profile by reducing the incremental peak demand.

Day of week – Typical school and work days during the week have similar load profiles. Noticeable shifts occur on weekends and statutory holidays. On these days, residential load profile peaks are naturally flattened in the mornings with consumers undertaking their days on a more relaxed basis. Similarly, the evening peaking load profile is more flattened. Commercial load profiles are generally reduced with the closure of many offices.

Annual season – Two major factors that influence load profiles on a seasonal basis are daily sunshine hours and cold / warm temperatures. The traditional power consumption peak may occur just prior to Christmas. Not only is December 21 the darkest day of the year in the northern hemisphere thereby requiring more lighting, it is also a festival season with festival lighting decoration loads increasing the overall load. Coupled with the traditional coldest day of the year occurring mid-January which requires an ever increasing amount of heat to ensure families and businesses are warm and comfortable, load profiles are traditionally higher during the core winter months. Conversely, during summer months, the abundance of natural light and traditionally milder weather tends to reduce the load.

Since start-up of the Holyrood fuel oil electrical power plant in 1970, the load profiles have been analysed and used to help plan for future electrical needs. Electrical growth is observed through several influences: population growth spurring increased residential housing, corresponding increases in commercial activity and new uses for power (two refrigerators, multiple televisions, computers, and appliances) increases the annual load and increases the peak of the load profile. Increased consumer awareness and annual energy efficiency improvements are offsetting demand side management factors that have reduced load profiles.

Gas Requirements

Based on the overall load profile analysis, planners can develop a forecast for future natural gas demand requirements. Ziff Energy received insight from the Government of Newfoundland and Labrador regarding the gas requirements in 2 cases for the next half century starting in 2017. The two cases are: 'Minimum Renewable' and 'Medium Renewable' with natural gas requirements outlined for 2017, 2022, 2028, 2035, and 2067. Gas requirements are 12 to 14% higher in the Minimum Renewable cases than the Medium case as less renewable energy is available to the Island energy grid.

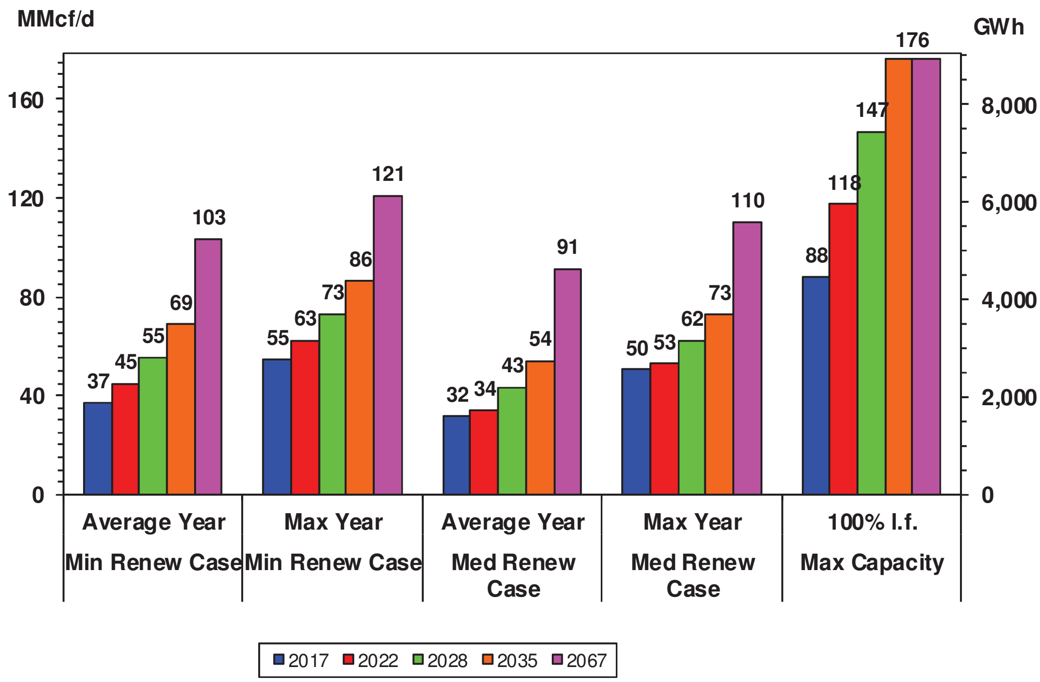
Ziff Energy has studied the forecast gas demand for the Holyrood power plant currently serving Newfoundland:

- average year loads vary from 37 MMcf/d in the Minimum Case in 2017 to 121 MMcf/d for the whole year in 2067

- the maximum daily load is forecast to increase to be 176 MMcf/d. Any facilities designed to deliver natural gas as a feedstock for electrical power generation must be sized to deliver this volume at a minimum, to ensure electricity is available for end-users
- average year loads range from 32 (Medium Case) to 103 MMcf/d (Minimum Case).

Figure 2 provides a summary of the average year LNG requirements for Holyrood to 2067. The analysis considers 5 separate cases. As Holyrood would be relied on to meet peak-day requirements, infrastructure would have to be overbuilt to handle extreme days when the full output capacity at Holyrood is most required. As a consequence, large initial capital investments will be required and low utilization load factors will drive unit costs upward.

Figure 2
Holyrood Natural Gas Requirements



Dual Fuel Power Plant

Cost of Redundant Capacity – A high level of health, safety, and economic welfare has been achieved in the industrialized world through access to highly reliable power and energy supplies. Due to extreme cold weather in Canadian winters, safety on very cold days becomes paramount (life and death) for Local Distribution Companies (LDCs) providing electricity and natural gas required for home heating. Therefore, the cost of undersupplying energy supplies to consumers is far greater than ensuring 'security of supply' by overbuilding and procuring excess supply. Regulators and LDC's must work together to determine an acceptable level of infrastructure and supply redundancy with the least amount of cost to ratepayers.

Even after securing natural gas as a feedstock, there will still be a requirement for redundant dual fuel capacity to insure consumers are safe on cold winter days. Due to the potential for offshore disruptions, LNG supply disruptions, LNG regas facility disruptions, and scheduled maintenance requirements, some form of redundancy or backup power is required. This requirement is not theoretical. Without redundancy, any natural gas supply disruption would mean a cessation of power from Holyrood. This would have serious implications for the core market, including residential customers and critical infrastructure such as schools and hospitals. A dual fuel capability can help ensure that power users have electrical power at all times.

GRAND BANKS GAS AS AN ISLAND GENERATION OPTION

Grand Banks Producing Region

Natural gas development is not a focus for Operators on the Grand Banks at this time:

- oil can be transported by tanker quickly and efficiently, whereas natural gas requires often costly infrastructure and supporting gas markets. A Brent Oil price of $105/Bbl is equivalent to a natural gas price of $18/MMBtu, 8 times the current Alberta market price
- Hibernia and Terra Nova are using Associated Gas for oil production support and Husky Energy is studying gas re-injection options for White Rose

Today, the Grand Banks oil field developments produce 250,000$^+$ Bbl/d representing approximately 10% of Canada's crude oil production. Offshore oil exploration started in the 1960s and the first commercial oil discovery was made in 1979 at Hibernia in the Jeanne d'Arc Basin. Since then, more wells have been drilled and oil fields discovered. The first offshore oil field placed on production was Hibernia in 1997, followed by Terra Nova (2002), and White Rose (2005). Hebron, the 4th oil project, may start production before 2017. In each of the projects, the focus is on oil production and the associated produced gas is re-injected[6]. Exploration continues, though the pace is slow particularly since the operators moved into the deep water with wells in the Orphan Basin and the Laurentian Basin. Recent discoveries in the Jeanne d'Arc Basin at the Ballicatters prospect and in the Flemish Pass Basin at the Mizzen discovery (102 million barrels), show promise and exploration continues in the region. It is important to note that natural gas development is not a focus at the current time. This is not surprising given offshore crude is sold into a Brent referenced oil market, and natural gas prices in North America languish near $3/MMBtu at time of writing.

Gas Availability during Oil Production

The current commercial production offshore Newfoundland and Labrador is oil. To ensure that oil is marketable, it needs to be cleaned to meet specific oil sales specifications. Removal of natural gas entrained in the oil is one initial and important step. In this operation, the gas may be viewed as a by-product of oil production. While the gas is physically available during the production of oil, there are no current opportunities that the existing offshore operators have deemed to be economic to commercialise the gas and as a consequence, the gas is re-injected into the reservoir to enhance oil recovery. Plans for gas utilization including gas flaring or venting are filed annually with the Regulator as part of the process for receiving an Operations Authorization.

[6] White Rose gas is currently produced and stored for future use

Oil versus Gas Development

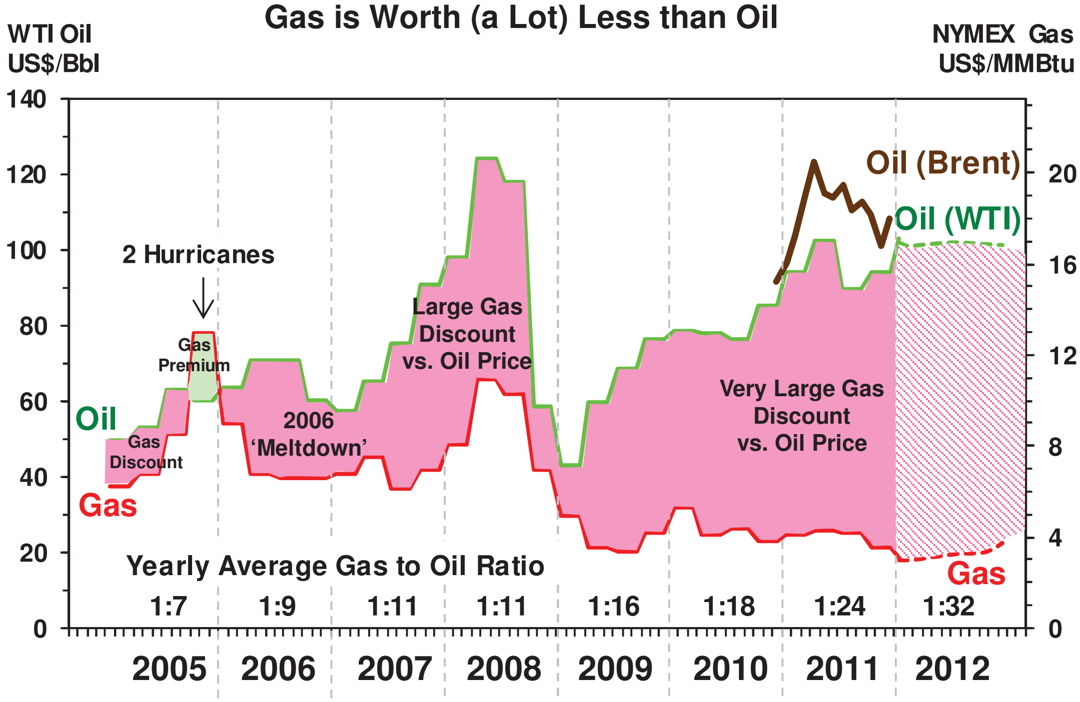
Near Term Viability – Oil Production has Greater Value than Gas

Offshore development is currently focused on oil and not gas and as a consequence, the gas resources of the offshore basins are not being developed at this time.

A key question: can current gas markets support the costs of gas development after the oil is depleted? After oil production has ceased, gas would have to cover all the capital and operating costs while providing a reasonable return. Currently, the energy equivalent price of natural gas is so heavily discounted relative to oil, that offshore development of gas resources distant from a pipeline grid is likely uneconomic and maintaining oil production has greater value than diverting gas for Newfoundland power generation.

Figure 3 shows the value gap between oil and gas in the North American market. Ziff Energy has analysed the full cycle cost of new natural gas supply[7] for 24 gas basins across North America. Full cycle costs ranged between US$4 and $7.50/Mcf at the end 2009 in a large, fully functioning market with excellent price discovery. Costs have fallen significantly since 2007 due to a combination of horizontal drilling and multistage fracture completions technologies, resulting in lower royalties realized due to the precipitous drop in North American gas prices.

Figure 3
Gas is Worth (a Lot) Less than Oil



© Ziff Energy Group, 2012

[7] full cycle cost studies analyze cost components including rate of return and a basis differential calculation for each North American gas play

GRAND BANKS NATURAL GAS COST ANALYSES

Offshore Infrastructure Capital Requirements

Associated Gas produced at offshore oil fields is currently used by the developments:

- Hibernia and Terra Nova produced gas is used for fuel to power each platform; the remaining gas is re-injected into the reservoir for pressure maintenance to maximize higher value oil production
- White Rose gas is used for fuel and the surplus is currently being stored; Husky continues to evaluate opportunities to re-inject gas to maximize oil production
- the Hebron proponents intend to use produced gas for fuel; any surplus would be injected for later use[8].

The conclusion is that there is no low-cost Grand Banks natural gas available for transporting to shore for domestic use.

Cost of Developing Grand Banks Gas Resource

With no existing gas available, gas supply for Holyrood would likely have to come from a standalone Grand Banks gas development[9] or redevelopment of an existing oil production facility. Ziff Energy's analyses of full cycle costs of natural gas supplies include the costs for several offshore or frontier projects. One critical factor in using past costs is to correct them for inflation to today's (2012) dollars. While the consumer price index has increased moderately (2-3% per year) over the last decade, the same cannot be said for upstream oil and gas projects. Between 2004 and late 2008, upstream oil and gas capital costs more than doubled before retrenching modestly with the first financial crisis in 2008. In late 2011, capital costs were approximately double those of 2004. Similarly, operating costs grew by half between 2004 and 2012.

There are several key steps that need to be undertaken to transport natural gas from an offshore production facility. The operator would condition gas so that it would be free of entrained water, and other impurities that could cause corrosion to the underwater pipeline. The operator would plan, design, construct, and operate the infrastructure, based on the maximum daily natural gas volume needed for Holyrood (Figure 2, 100% load factor Maximum Capacity). However, costs would have to be covered by the lower average throughput leading to higher unit costs than those seen elsewhere in North America.

Planning and installation will need a long lead time, perhaps more than 5 years including time for negotiations with the producers. To give the high degree of reliability needed for power generation, some extra redundancy and duplication will be needed, increasing costs. On the North America natural gas transmission system, these incremental costs can be avoided because of the multiple gas supply options available from a mature and highly connected pipeline grid.

---

[8] Hebron Project Development Application Summary, April 2011, page 1-8

[9] such a development would alleviate concerns from the effect of oil production waning in the longer-term, that is, the infrastructure for gas production may only be available during the life of the oil production. Any shared infrastructure costs would be recovered increasingly from gas production, until oil passes its economic limit and ceases flowing. At that time, operating costs could increase to the point where gas production would be uneconomic

Alternative Development Scenarios

Ziff Energy has analysed 3 possible development scenarios for the gas resources at White Rose:

- a standalone development
- modification of the White Rose floating production, storage and offloading (FPSO) system
- integrate the gas development with the Well Head Gravity Based Concrete Structure (GBS) that Husky is evaluating for development of West White Rose.

The following assumptions are common to all three scenarios:

- annual gas production growing to 103 MMcf/d as indicated in Figure 2, Average Year, Minimum Renew Case; a total of 1.4 Tcf
- capacity sized for a peak of 176 MMcf/d[10]; however, costs per Mcf have to be borne by the smaller, actual throughput
- 3 initial wells at 2012 Cdn$50 million each
- one new well every 3 years at 2012 Cdn$50 million each to maintain well deliverability for Maximum Capacity (Figure 2); all wells would be subsea, drilled by an offshore drilling rig and tied back to the production system except for the West White Rose option
- well Initial Production ("IP") of 60 MMcf/d and Estimated Ultimate Resource ("EUR") of 85 Bcf
- **Producer Return:** Producers are able to invest in many different opportunities and will seek the highest return for their shareholders. A minimum of 15% before income tax rate of return[11] is used in this analysis. In the case of the Newfoundland projects, the unit return cost ($/Mcf) is higher than other projects because of the production profile needed for Holyrood[12].
- gas conditioning plant (on platform) 2012 Cdn$400 million[13]
- life extension reconditioning after 25 years at 25% of the original capital costs in 2012 Cdn$[14]
- maintenance capital of 1% per year of the depreciated capital costs
- **overhead** cost of 2012 Cdn$0.40/Mcf, based on analysis of more than 30 companies
- excludes past costs, project administration, project financial costs during construction, and abandonment costs
- a gas **royalty** of 2012 Cdn$0.50/Mcf[15]
- **Operating costs** are dependent upon the dehydration type, NGL removal, and compression type. Fixed costs, like preventive maintenance, taxes, daily operation, and labour, would need to be recovered and generally run at 80 to 90% of total operating costs.

[10] plant and pipeline is sized for the maximum day requirement (Figure 2, 100% load factor at maximum capacity)
[11] equates to the approximate after tax cost of capital for the oil and gas industry
[12] in most gas projects, production peaks early so producers have an early recovery of their investments and the return on investment, recovering as much as 80% of the return in the first 10 years of a project's life. In the case of Holyrood, the opposite is true – production grows, reaching a peak at the end of the project. Thus the producer will not recover its investment until late in the project and the return is earned over 50 years, in heavily discounted dollars

Stand Alone Development

This scenario assumes a dedicated GBS – 2012 Cdn$2.4 Billion for GBS[16], plant, and initial wells. With the low gas volumes for Holyrood, remote offshore location, and high fixed costs, the unit operating costs for a standalone development would initially be about 2012 Cdn$11/Mcf[17] falling to 2012 Cdn$4/Mcf as production increases to 103 MMcf/d. The full cycle cost is estimated to be about 2012 Cdn$33/Mcf.

FPSO

A refit of the existing White Rose FPSO system (the SeaRose) would allow gas to be produced and processed. The capital cost could be less than a standalone development, though would greatly exceed the gas conditioning plant cost of $400 Million. This evaluation assumes an initial capital cost for the existing FPSO refit of $600 Million for the gas plant and FPSO modifications[18], and a replacement cost of the FPSO vessel of $450 Million[19] in 2030 when a replacement of the FPSO would be required to continue operations. Gas development would have to bear all of the capital and operating costs once the oil reserves have been produced, possibly by 2028, close to the end of the useful life of the existing FPSO. Thus, operating costs are split ⅔ oil, ⅓ gas until the oil runs out, then gas carries all the cost. Currently, oil production operating costs are in the order of $250 MM/year (these costs equate to about $18/Mcf based on 37 MMcf/d of initial annualized gas flows in 2017).

The evaluation assumes the FPSO would be on station continuously; however, this is unlikely to be the case over a 50 year life. In 2012, the SeaRose was off station for maintenance with a shutdown

---

[13] a 176 MMcf/d gas plant in Alberta could cost $175 to 260 Million; the cost to build and install such a plant in a remote offshore location could be double that or more, depending on the gas composition, facility design, volume, and location

[14] while the production platform can be designed for a 50 year life, other parts of the production system will need to be replaced or refurbished after 25 years to extend facility life an additional 25 years

[15] the Newfoundland and Labrador natural gas royalty is a progressive royalty with two components: Basic Royalty and Net Royalty. The Basic Royalty provides a revenue stream to the province at all stages of a project and is linked to realized sales prices. Net Royalty is based on project profitability and reflects the revenue (also based on realized gas sales prices) and costs associated with a particular project. Where profitability of a project is higher, the province will share in that profitability. Where profitability is less or declining, the Net Royalty Rate will be lower and the province's share will decline. This creates a challenge in this analysis in that the gas would not be sold in an open market. Thus, Ziff Energy has used a royalty of $0.50/Mcf, which is similar to royalties paid for other North American offshore projects (Figure 4)

[16] a cost of 2012 Cdn$1.5 Billion for the GBS with room for a gas conditioning plant and compressors (based on a reported cost estimate of up to Cdn$1.4 Billion for the Husky West White Rose Well Head GBS and an estimated 2009$1.8 Billion for the full sized Hebron GBS). Ziff Energy assumes additional facilities to recover Natural Gas Liquids from the gas would be located onshore and the costs and revenue for these liquids would accrue to the producer

[17] annual operating costs for White Rose are over Cdn$200 million per year; Hebron is projected to have costs of about Cdn$150 million per year growing over the life of the project to Cdn$180 - 200 million per year; from these costs, Ziff Energy assumes the operating cost would be about 2012 Cdn$150 Million for a smaller gas development spread over an initial production of 37 MMcf/d

[18] using costs from the Husky Energy White Rose Development Plan Amendment, August 2007 (for North Amethyst Tie-back), turret and vessel modifications would likely exceed Cdn2012$200 Million, plus the Cdn2012$400 Million for the gas conditioning plant

[19] 2012 costs for a new build FPSO are US$800 to $2,000 Million depending on size; conversion of an existing vessel is US$250 to $800 Million; and Redeployment and conversion of an existing oil FPSO would be more than US$250 Million for the vessel plus an assumed US$200 Million to transfer the gas plant to the vessel

to start-up cycle time of just under 103 days. During off station maintenance, the alternative fuel for Holyrood would be used. The full cycle cost is estimated to be about 2012C$21/Mcf, increasing to 2012C$27/Mcf after oil production ceases.

In addition, oil production would likely have to be suspended, while installing the new systems representing a significant loss of revenue to the producers and to Newfoundland and Labrador. This opportunity cost has not been included in the evaluation of this scenario.

Integrated West White Rose

A potentially lower cost alternative to a standalone development could be to integrate the gas well development with the Well Head GBS that Husky is evaluating for development of West White Rose. This scenario assumes an incremental platform cost of 50% of the standalone platform cost[20]. Such a development may not be technically feasible given the need for incremental well slots and gas conditioning systems. It could also delay some oil production reducing producer and provincial revenue. Similar to the FPSO option, gas development would have to bear all of the capital and operating costs once the oil reserves have been produced. Thus, operating costs are split ⅔ oil, ⅓ gas until the oil runs out, then gas carries all the cost. The full cycle cost is estimated to be about 2012C$22/Mcf, increasing to 2012C$28/Mcf after oil production ceases.

Other

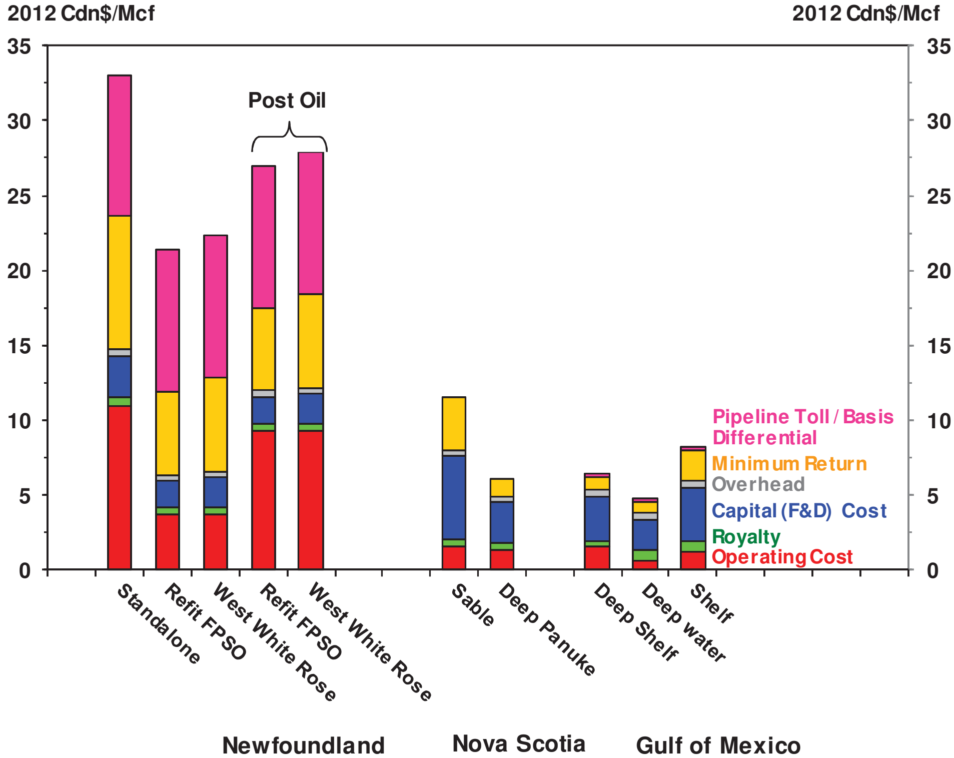
The three scenarios presented above provide a range of options to be studied and analyzed for offshore Newfoundland gas development. Another possibility is the subsea development of gas similar to the Norwegian Ormen Lange gas field. There, all the gas wells have been completed on the seabed with no structures above the sea and the raw gas piped to land for processing. The wells are controlled remotely from the shore. As challenging an environment as the Norwegian Sea presents, conditions off Newfoundland can be even more severe, with the added complication of potential iceberg scour.

[20] total initial capital cost of 2012C$1.1 Billion

Estimated Costs to Land Gas on the Island

Figure 4 presents the results of Ziff Energy's analyses of the full cycle cost components of new natural gas supply for the three scenarios presented above for Grand Banks Newfoundland, offshore Nova Scotia developments[21], and plays in the Gulf of Mexico, inflated to 2012 Canadian dollars.

Figure 4
Full Cycle Cost[22] of New, Offshore Gas



Ziff Energy uses a 15% before tax rate of return in all full cycle cost calculations. The rate of return cost shown here (yellow bars) is a minimum and may need to be higher to compete with other producer investment opportunities and attract the necessary investment. At a 25% before tax rate of return, the full cycle cost of gas would increase by 2012 Cdn$1.45 (Refit FPSO scenario) to 4.80/Mcf (Standalone scenario).

It should also be noted that the comparison projects in Nova Scotia and the Gulf of Mexico all have access to a fully functioning, liquid continental gas market with physical flows over 78 Bcf/d and clear price discovery at a number of major gas hubs where gas is traded in much greater volumes. The system includes storage fields which handle seasonal and peak day loads, allowing wells to be produced continuously at their maximum rate. This represents a cost saving over the Newfoundland offshore options where facilities have to be built, and wells completed to meet the peak winter load, and remain underused the rest of the year.

[21] the costs for Deep Panuke are prebuild cost estimates, the as built costs are likely to be higher, in part due to the much delayed delivery of first gas
[22] U.S. dollars converted at par to Canadian dollars

Pipeline (Tariffs)

The design, construction, and eventual operation of a 350 km (220 mile) to 640 km (400 mile) underwater gas transmission pipeline for gas allocated to the Holyrood generator requires ample lead time to ensure operation by 2017. The Ziff Energy North America gas pipeline cost database shows an initial average cost of Cdn$182,000/inch-mile.

The question of pipeline size is an important consideration. While the estimated gas requirement in 2017 is 32 to 37 MMcf/d, these estimates are for an average day, and not a peak day. Further, gas loads are expected to grow, with a 100% load factor peak of 176 MMcf/d. A 16 inch diameter pipeline, which is capable of transporting gas volumes to meet maximum peak day requirements leads to an estimated capital cost range of Cdn$640-$1,165 million[23]. A smaller pipeline would be insufficient to meet growing demand. A shorter route through shallower water could involve significant costs for trenching. A longer route to avoid iceberg scour and trenching costs would also be more costly.

Sizing the Pipe: Peaking vs. Average Day Requirements

Power demand in Newfoundland and Labrador is highly dependent on:

- thermal heating requirements which change through the year – in the winter power is required at high load factors and almost no thermal power is required in summer
- differences throughout the day for non-thermal requirements – ranging from maximum daily loads in early evening when household chores[24] are being done to in the middle of the night when there is almost no non-thermal power demand.

To account for variations in both seasonal and daily fluctuations the natural gas pipeline has to be sized for peak-day power loads in order to insure reliability on the coldest winter days. The pipeline has to be sized for peak day flows of 176 MMcf/d in 2067, up from 88 MMcf/d in 2017; however, the tolls will be based on the small annual average daily flows.

Prohibitive Toll on Small Average Day Volume

As a large amount of capital has to be invested today, the unit cost (of average day volume) would be prohibitive. Transportation tolls may be estimated from a pipeline cost of $0.6 to $1.2 Billion from Grand Banks to shore (dependent on pipe diameter and route – 220 to 400 miles). There are offshore infrastructure challenges to be considered and the initial toll (37 MMcf/d[25]):

- will be $6.71/Mcf based on a capital cost of $640 MM
- will be $12.22/Mcf based on a capital cost of $1,165 MM[26]

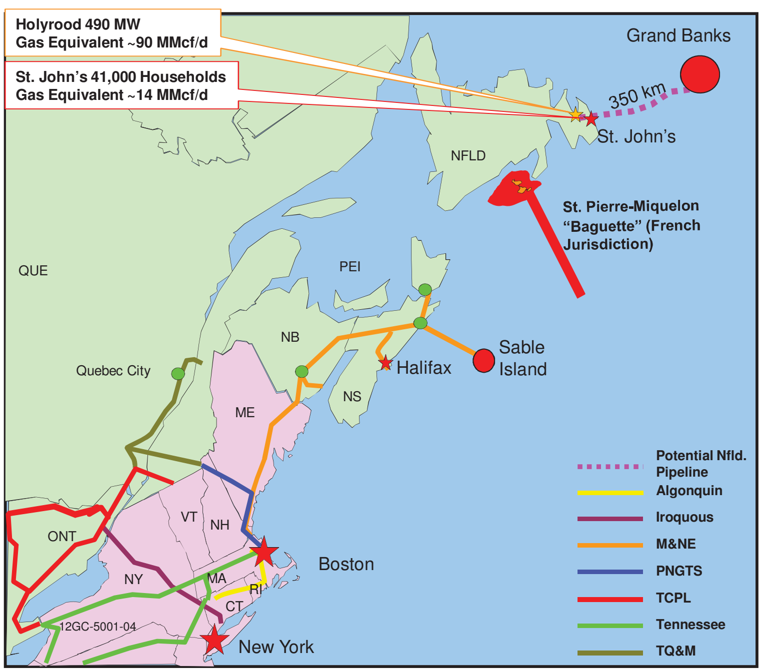
[23] Ziff Energy's North American Cost database for recent pipelines would suggest $390-875 Million capital cost. However, offshore Newfoundland harsh operating conditions may increase costs; a March 28, 2012 lecture by Dr. Steve Bruneau suggested capital costs for such a pipeline of $760-950 Million
[24] power required for oven, dishwasher, washer-dryer, and lights
[25] increased viability of renewable energy would displace required gas volumes thereby, increasing unit cost (toll)
[26] higher tolls based on a longer deep water route used to avoid potential costly iceberg trenching

Other initial challenges are:

- large initial investment – needs thorough engineering and design so that size, route, and specifications are defined and a complete risk review undertaken
- cost of drilling and completing gas producing wells
- very low gas volume - little incentive for producing company to invest unless the gas price is based on an oil index, which is already the price being paid for the fuel oil
- variable gas volumes to meet peaking nature of Holyrood
- processing, gathering, metering, odorizing, and corrosion protection infrastructure
- gas quality: CO_2, NGL, and others may need removing.

Figure 5 provides a bird's eye view of the Grand Banks area, the proximity to St. Johns, and other key features.

Figure 5
Interconnection of Grand Banks Gas



- **$640 -1,165MM: Estimated Pipeline Cost Based on the North American Average $182,000/inch-mile**

350 Km Route:
- **$6.71/Mcf toll Based on 37 MMcf/d of flow Volume (35% load factor)**
- **$2.76/Mcf toll Based on 90 MMcf/d of flow Volume**

640 Km Route:
- **$12.22/Mcf toll Based on 37 MMcf/d of flow Volume (35% load factor)**
- **$5.02/Mcf toll Based on 90 MMcf/d of flow Volume**

Other Considerations

Life of Facilities

Oil and gas production equipment is typically designed with a 20 to 25 year life expectation, although many facilities can be coaxed to survive longer through prudent operation and ongoing preventive maintenance. During the normal life cycle of oil and gas operations, equipment will be exposed to mechanical stresses such as gas compressor and oil pumping vibrations, continuous seawater water wave action, along with physical environmental wear and tear from continued daily use. Monitoring and preventive maintenance can help to offset premature equipment failure. Thus producers typically align production of the oil and gas resource over the same time period. To cover the 50 year time frame for Holyrood gas supply, offshore facilities may have to be replaced in the latter half of the period.

Single Phase versus Multiphase Pipelines

Typical natural gas transmission pipelines across North America are single phase[27]. Transporting gas along with natural gas liquids (propane, butanes, and pentane plus) is an example of two phase flow which could be expected in transportation of Associated Gas from offshore fields via a new underwater gas pipeline. Engineering design of pipeline and related equipment for the receiving station onshore would need the anticipated size of the liquid flow[28] that is commingled with the gas and amount and type of liquid storage. Commercial review would determine whether any local end use of liquids can be considered. It may be possible to design the Holyrood electrical power plant to accept a gas and liquids two phase flow as feedstock.

Liquids Considerations

Should liquids arrive with the offshore gas at onshore receiving station, a business opportunity arises to use liquids for other commercial purposes versus simply burning them for power generation. Liquids generally have a higher market value that can be realised. For example, liquids could be used in a petrochemical business to capture a higher overall value, similar to operations in Alberta. If local uses are not available, it would be possible to ship liquids to other locations that have a direct need. Such a plan would require insight on the liquids shipping frequency, location and size of liquids storage tanks, and current and planned quantity of liquids.

Long-Term: Potential to Develop LNG Export Facilities

Producers in the Grand Banks have invested billions of dollars in the development of Newfoundland and Labrador oil resources. As such, any risk to their existing investment must not only have a rate of return which accounts for this risk, the return must also have a relevant scale as well. The potential exists in the long term to develop LNG export facilities from the Grand Banks and receive oil values for the gas which would provide the scale of return worthy of capital risk. Sustainable development of the Crown resource should not shortchange future generations.

[27] phase behaviour relates to the volume that the oil or gas takes under specific temperatures and pressures. In this case, at very high pressures and warm temperatures, gas is normally in a single gas phase; whereas, at low pressures and cold temperatures, portions of the gas (propane, butane, and pentane plus) may condense and flow as a liquid. The combined flow of gas and liquids is referred to as two phase flow

[28] large quantities of entrained NGL liquids may cause a significant pipeline pressure drop thereby reducing the overall pipeline flow. The long underwater pipeline may require additional underwater compression to ensure that gas and liquids continually move through the underwater pipeline. Overall, this requires significant engineering and complex 2 phase pipeline flow modelling

LNG AS AN ISLAND GENERATION OPTION

The purpose of this section is to examine the viability of importing LNG as a feedstock to generate power on the island.

Background

Low current natural gas prices in North America are an economic driver for many LNG liquefaction proposals from coastal regions of the U.S. and Westcoast of Canada. These projects are intended to arbitrage inexpensive North American gas into premium gas markets in Europe and Asia which are primarily linked to world oil prices. One U.S. LNG facility[29] has received U.S. Department of Energy (DOE) blanket approval to export domestic gas to offshore markets. LNG delivery contracts for the off-take from this proposed LNG facility are for firm quantities, large volumes, long term, and the facility is fully contracted. The DOE licence states explicitly that the DOE can review the licence if the DOE deems continued LNG exports are not in the public interest.

[29] Sabine Pass Liquefaction Project, developed by Cheniere Energy Partners, L.P.

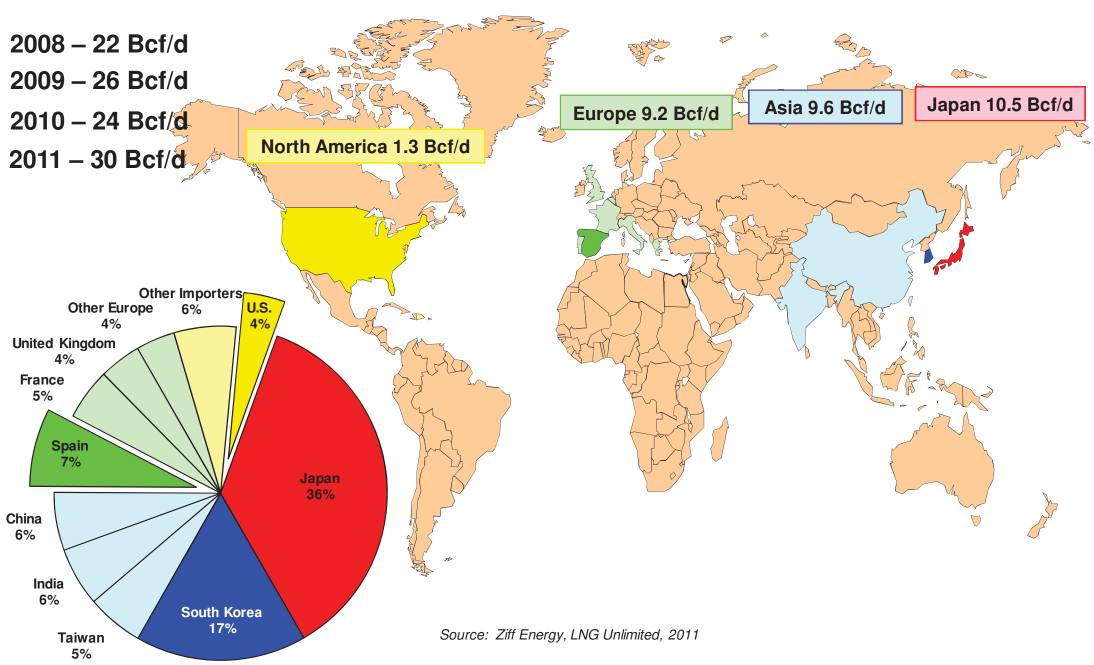
WORLD LNG MARKET

LNG is transported to various countries in the world to supplement their fuel choices. Ziff Energy estimates that the world supply of LNG is 30 Bcf/d in 2011, twice the entire gas production of Canada and less than half U.S. gas production. Natural gas requirements for the Holyrood power plant of 0.037 Bcf/d (2011) to 0.176 Bcf/d (2067) would comprise a very small part of the World LNG market (from 0.12% to 0.59%). Figure 6 provides world perspective for LNG markets.

Firm LNG off-take is contracted based on long term contracts with minimum take requirements. The low volumes of gas required to produce power at Holyrood would be a challenging economic barrier to securing long-term firm LNG supply. To underpin the proposed LNG facilities in the U.S., Ziff Energy believes that LNG operators will require contracts of much larger volumes of LNG for 20 years, based on Henry Hub pricing plus a locational differential premium, plus a facility toll for liquefaction.

Ziff Energy believes that the Holyrood facility should not be captive to LNG spot markets which are less reliable and primarily priced off oil indexes.[30] Long term LNG contracting with major LNG Suppliers[31] would be required to ensure security of supply. At present, Ziff Energy does not foresee world LNG pricing deviating from the current linkage to oil prices.

Figure 6
LNG Holyrood vs. World LNG Buyers



---

[30] the spot market made up 10% of world LNG trade in 2005, this share has since grown to 20%. *Sources: IGU World LNG Report – 2010, Platts.*

[31] while LNG could be available from new players or entities with a single source of supply, an LNG Supplier with a diversified portfolio could continue to deliver if there were a supply disruption at an LNG liquefaction facility

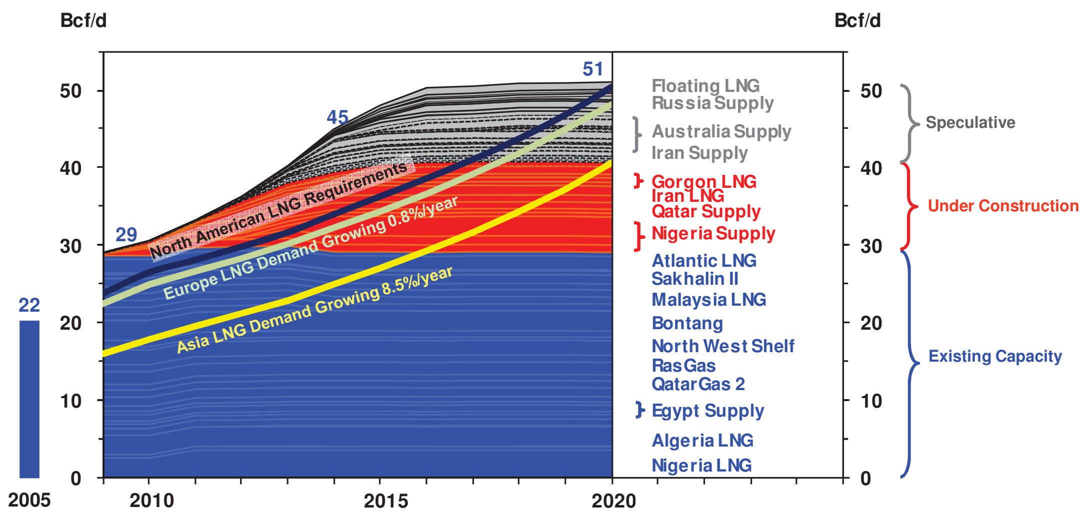
LNG Supply and Demand Forecast

World LNG Supply is growing. By 2020, Ziff Energy believes world LNG supply may exceed 50 Bcf/d, more than double the supply in the 2005 to 2010 era. LNG demand is increasing. Ziff Energy's analysis suggests that by 2015/2016 LNG demand could out-strip LNG available or the overall balance could become very tight. Even with new LNG export projects from Australia and Qatar; these projects may not be sufficient to satisfy growing LNG demand in Asia and Europe.

The next tranche of LNG projects may be viewed as speculative as they would originate from Iran, Russia, and Nigeria. There is a high degree of uncertainty that large investments in these jurisdictions will come to fruition. Potential for LNG supply shortages and price spikes for spot LNG during the winter could become the norm. In an undersupplied LNG world; suppliers will have negotiating leverage and buyers relying on spot cargoes could face real supply risk.

Figure 7 provides a summary of world LNG supply and demand. The LNG shown at the bottom in **blue** is already built. **Red** projects are under construction. **Grey** projects are speculative, and Final Investment Decisions have not been made.

Figure 7
LNG Supply Outlook



Assumptions:
- Existing Capacity operating at 80% Load Factor (LF)
- Capacity Under Construction operating year one at LF = 20%, then 85%
- Proposed Capacity is assumed to be 50% successful and operating year one at LF = 20%, then 85%

LNG Transportation Costs

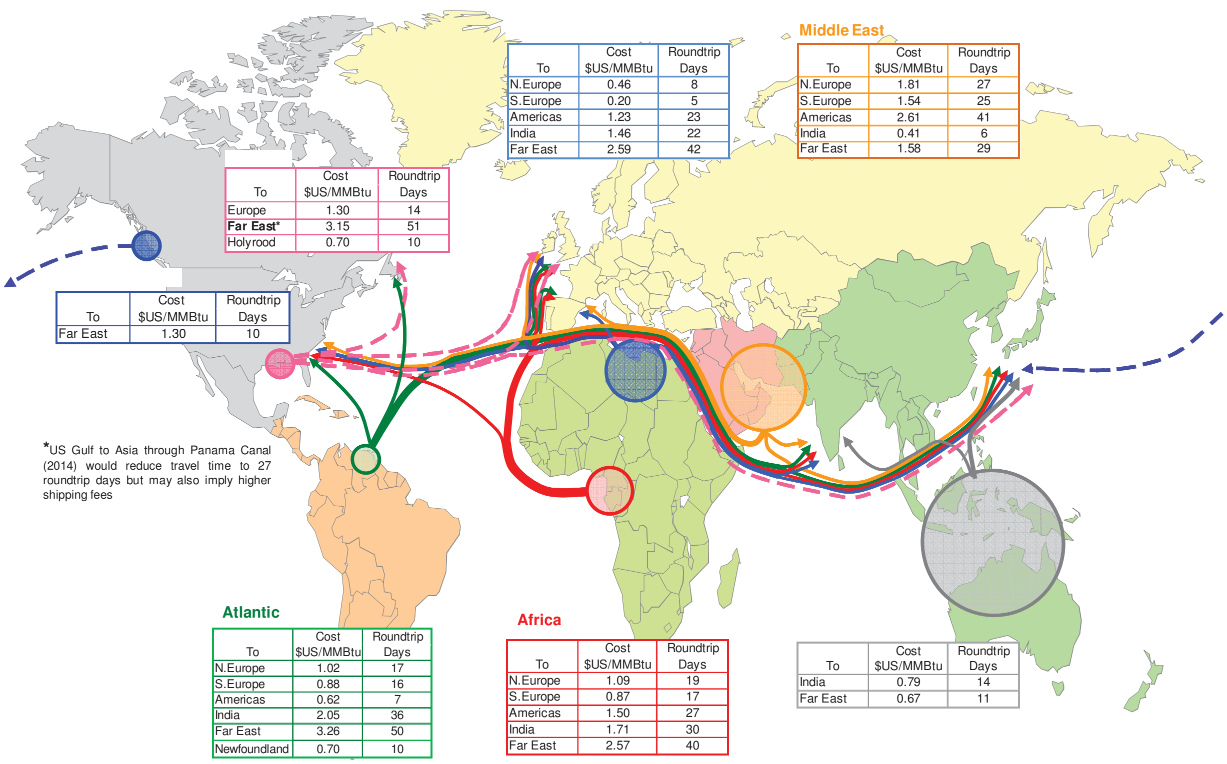
LNG has been safely transported for decades. There are hundreds of LNG tankers that transport LNG from a liquefier to a LNG receiving terminal. LNG tankers have increased in size thereby allowing users to transport ever increasing amounts of LNG. LNG transportation costs can be quickly calculated based on the route, repeatability, on-loading and off-loading time, along with frequency of the trip.

Ziff Energy estimates a toll to deliver LNG from the U.S. Gulf Coast to Holyrood would be about \$0.70/Mcf and the LNG tanker round trip time could be 7 to 10 days depending on the location of the LNG source. The toll to Holyrood from Trinidad and Tobago would be similar. Our estimate is based on two other quotations:

1. the LNG toll from Trinidad & Tobago to the U.S. Southeast cost is \$0.62/Mcf
2. LNG transportation from the Gulf of Mexico to Europe would be \$1.30/Mcf.

Figure 8 summarises world LNG tolls from 7 regions. The toll summary provides an estimate of the duration of time that the LNG cargo ship will require for a typical return trip. For example, a ship journey from the U.S. Gulf Coast to Europe (United Kingdom) and back is 14 days.

Figure 8
Typical Shipping Costs



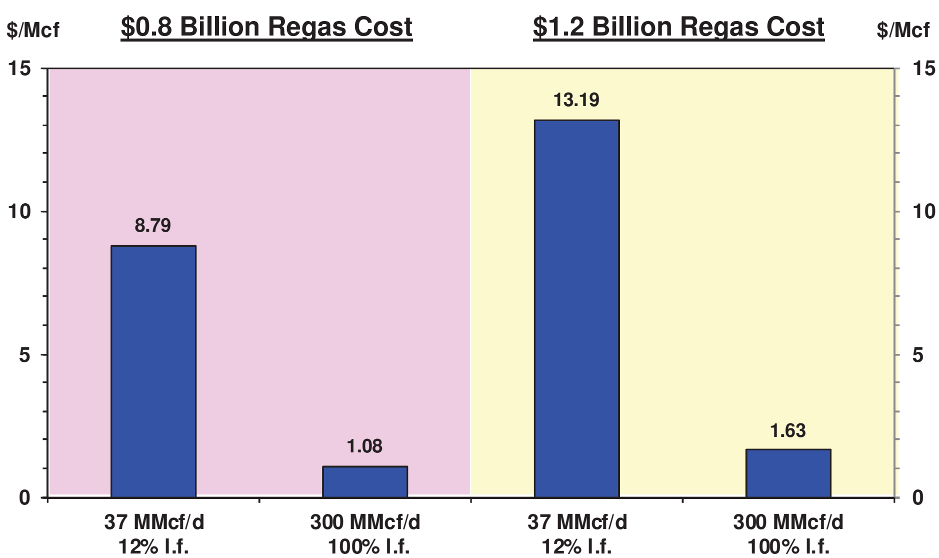
LNG Regasification Costs

Estimates of LNG regasification costs depend on many factors. Considerations are: size of the facility, ease of obtaining a construction permit, and time (and effort) to gain regulatory approval. Typical costs of a regasifier[32] are estimated at under Cdn$0.8 to up to $1.2 Billion. For a small regasification facility (0.3 Bcf/d) costs may be lower for vaporizers. However, storage will still be required to accommodate vessels in the 3-5.5 Bcf range. Additionally, regardless of vaporization size - jetty and handling facilities are still required, potential for additional pipelines and the remoteness of Newfoundland would all likely offset any savings from smaller vaporizers. Ziff Energy estimates that a typical regasifier facility can be constructed within 3 to 5 years, though the exact timetable can become longer for many reasons. Some regasifiers in the U.S. Northeast and U.S. west coast faced fierce opposition and projects and proposals were shelved and abandoned.

LNG regasification facilities are relatively simple: the facility itself needs to be designed for a specific site, a deep port established, and various piping and low pressure storage tanks constructed. North America has 2 dozen such facilities. An initial life span may be 3 dozen years, perhaps longer.

Figure 9 illustrates how operating costs for a regasifier will depend on the annualised volume being delivered. More deliveries can lower the unit operating costs and facilities with larger throughputs benefit from economies of scale. North America regulated cost for a 100% load factor (l.f.) facility typically is in the $0.33[33] to $0.75[34]/Mcf range. Unit costs for a regasifier supplying gas to a small power plant such as Holyrood would be substantially higher reflecting much lower load factors and lesser scale. Ziff Energy has modeled the unit cost of a $0.8 or $1.2 Billion, 300 MMcf/d regasification facility operating at 37 MMcf/d[35] (12% l.f.) and 300 MMcf/d (100% l.f.).

Figure 9
Holyrood LNG Regasification Cost



[32] See Figure 10 illustrating recently constructed and proposed projects
[33] Cove Point LNG in Maryland 1.8 Bcf/d of send out capacity
[34] Southern LNG in Georgia 1.2 Bcf/d of send out capacity
[35] Min Renew Case in 2017,- increasing overall Renewable capacity would reduce load factor, increasing LNG costs

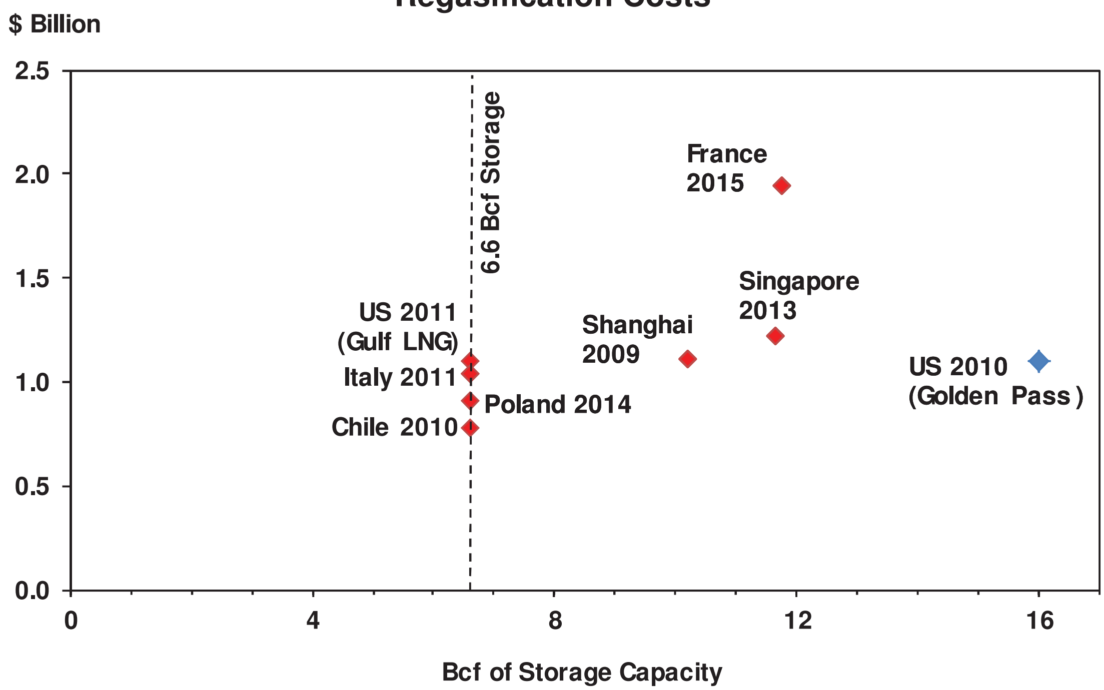
Regasification Cost versus Storage Capacity

Figure 10 illustrates the cost versus storage capacity of recently constructed and proposed regasification facilities around the world. Newfoundland needs a minimum amount of LNG storage to handle the unloading of a standard LNG tanker (3 to 5.5 Bcf). Ziff Energy is not an engineering firm and we have not done an in-depth study on minimum requirements of LNG storage for Newfoundland, however, two storage tanks (6.6 Bcf) would likely be required to ensure that large tankers could be off-loaded. Recent facilities which include 6.6 Bcf storage projects:

- high range is the Gulf LNG (El Paso/GE) project completed in late 2011 at a cost of $1.1 Billion
- lower cost range is a 2010 project in Chile at $0.8 Billion.

Potential for increased cost of pipeline facilities to move gas from the regasification facility to the power plant inlet could increase costs. For example, if a regasification plant were required to be sited in St. Mary's to ensure year round ice free access for security of supply reasons, a 45 mile pipeline costing $130 Million[36] would be required.

Figure 10
Regasification Costs



[36] $182,000/inch-mile x 45 miles x 16 inch = $130 Million Pipeline

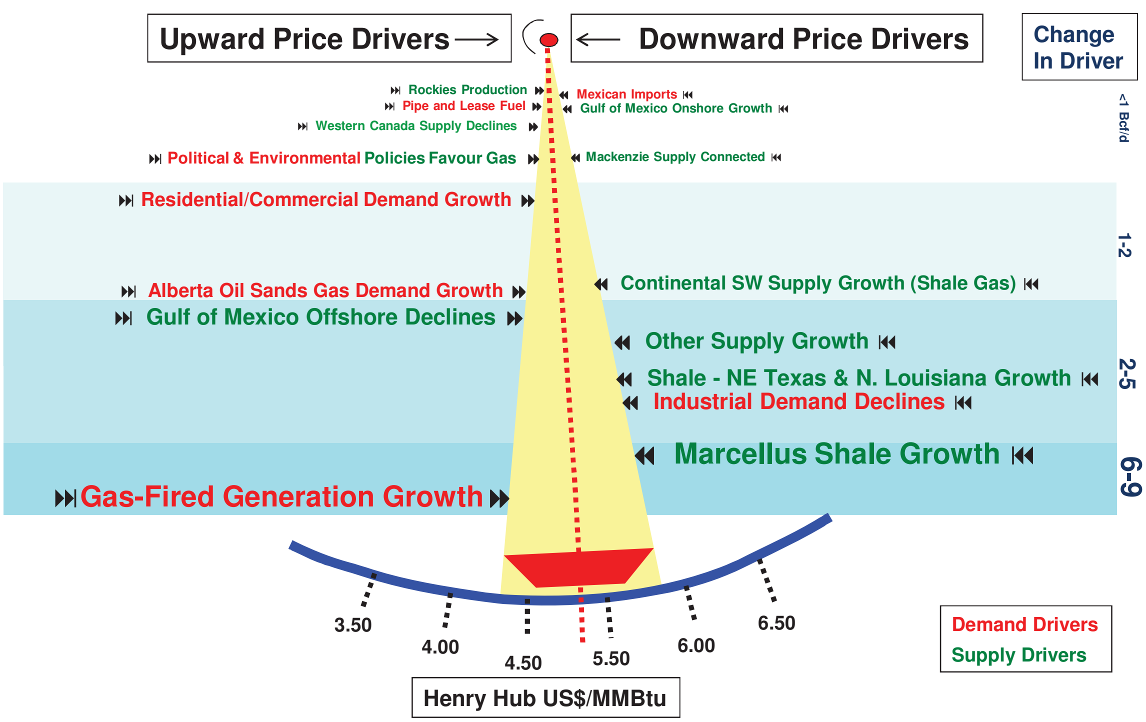
North American Gas Price Influences to 2020

To assess long term gas prices, Ziff Energy uses its proprietary imbalance pendulum model. The model considers over a dozen primary long term gas supply and gas demand factors that could exert a significant influence on gas price during the period of time being analysed. Each driver/factor is ranked in terms of change to supply or demand. For example:

- incremental gas demand for power in North America is expected to grow by 9 Bcf/d by 2020. This factor exerts a large upward influence on the (price) pendulum
- conversely, strong downward pressure is exerted on the gas price pendulum by strong growth of gas supply from the Marcellus and other gas plays
- the cumulative influence of all factors results in the ultimate direction of gas prices.

Figure 11 summarises over a dozen factors that influence gas price. **Red** text denotes demand influences and **green** text refers to supply influences. The size of the font is important – **larger** text is more important and exerts a larger influence. The bottom of the pendulum suggests that the equilibrium price between 2012 and 2020 should fall in the high \$4 to the mid-\$6 range (real 2011). Note that short term factors such as weather, gas storage levels, or outages are excluded for the long term forecast as short term factors are normalised[37] and thus do not exert any long term impact on gas price.

Figure 11
Holyrood LNG Price Influences Short Term 2012-2020



[37] example: what is the average temperature across a province in the year 2024? Ziff Energy assumes it is normal and not warmer or colder, thus there is no influence of weather on long term price forecasts

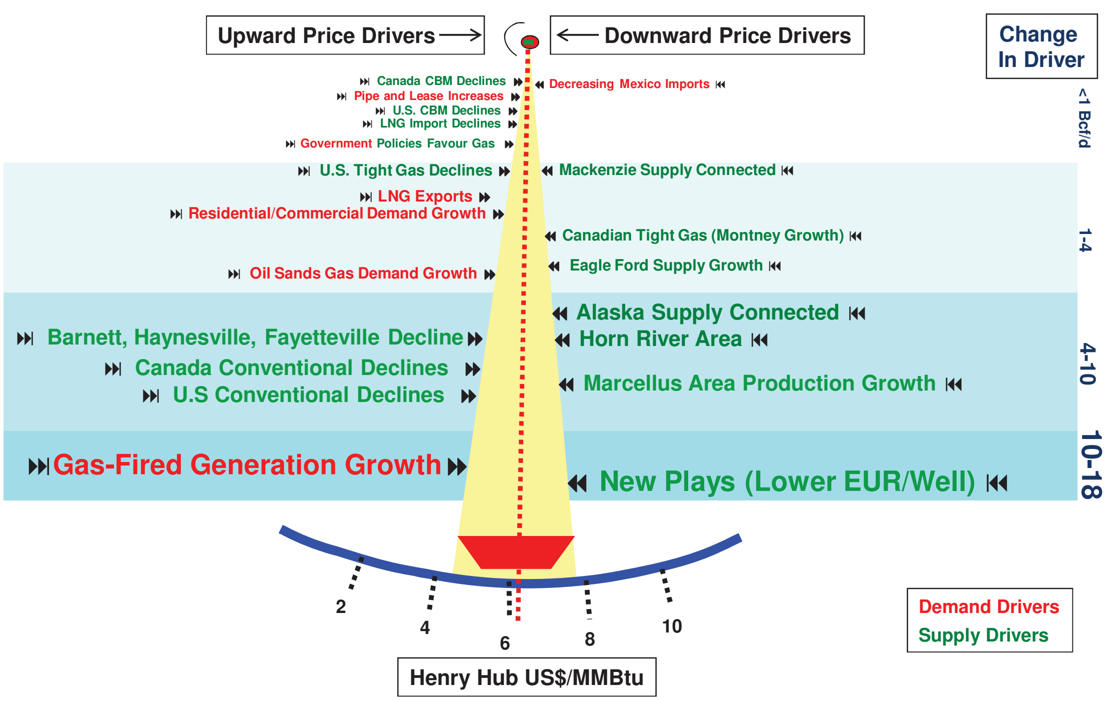
North American Gas Price Influences to 2035

The Ziff Energy gas price model has been extended to 2035 to determine how gas supply and demand factors will interact. Some items, such as long term policies to reduce the number of coal fired electrical generation plants by mothballing facilities over 45 years of age, can become a key factor or a potential sensitivity. The eventual commercialisation of Alaska and Mackenzie Delta gas supply may exert influences in specific years.

The major upward drivers on price will be gas fired electrical generation growth, declines in supply from mature gas plays, and demand growth for Oilsands and LNG exports. Continued supply growth from unconventional gas plays and connection of northern gas supply will push prices down. The result suggests that gas prices may range between over \$4/Mcf to under \$8/Mcf (real 2011).

Figure 12 provides factors that in Ziff Energy's opinion will influence gas prices to 2035.

Figure 12
Holyrood LNG Price Influences to 2035



Landed Cost of LNG

Full Cycle Cost of US Gulf Coast and World-Sourced LNG

LNG landed in Newfoundland would be prohibitively priced over the long term. Newfoundland would most likely compete with Europe and the Far East for higher priced LNG Cargoes (influenced by oil linked contracts). Figure 13 shows the cost of world-sourced LNG would be $16.30 - $18.35/Mcf[38] FOB Newfoundland and $25.10 - $27.15/Mcf at the regasification plant outlet.

Long term LNG offtake deals from the U.S. Gulf Coast[39] have been structured for firm volumes of LNG from the Cheniere Sabine Pass facility. These deals are at Henry Hub gas price plus a 15% premium to reflect the pipeline costs to bring gas into the Liquefaction inlet. Other costs to Holyrood would include:

- Cdn$2.50 liquefaction toll
- $0.70 shipping via tanker
- premium to compensate off-takers from not taking NBP prices[40]
- volatility in Henry Hub pricing throughout the 2017-2067 period.

The Sabine Pass facility is fully subscribed under long term contract. It should also be noted that the contracts are structured primarily as 20 year deals[41], meaning that even if capacity were available today for contracting, Holyrood would be at risk of significant price escalation after the primary term, up to world-sourced LNG pricing. The project structure also involves cross-subsidization between the already built Regas and the proposed Liquefaction projects. This approach has led to disputes among parties in other U.S. LNG Liquefaction proposals. Ziff Energy is of the opinion that U.S. Gulf Coast LNG will not be available in future under similar terms and conditions.

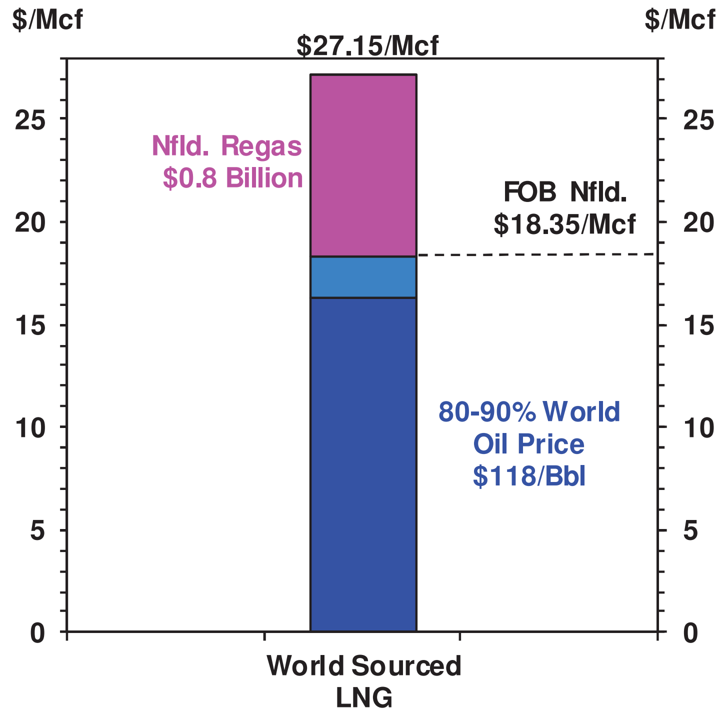
[38] 80-90% of EIA AEO 2012 forecast of $118.31/Bbl for 2017 imported crude (weighted average of delivered to U.S. refiners) in Real 2012$ at 5.8 MMBtu/Bbl

[39] the U.S. DOE export approval for the Cheniere/Sabine Pass LNG Liquefaction project can be re-examined if continued exports are deemed not to be in the Public Interest. On May 20, 2011 the U.S. DOE provided an order conditionally granting long-term authorization to export LNG from Sabine Pass. Although a long-term order, Page 32 of this decision highlights considerable uncertainty with regards to the long-term validity of the export order and the risks associated with investing billions of dollars into this project. Specifically the DOE will have continuous market monitoring stating: “We intend to monitor those conditions in the future to ensure that the exports of LNG authorized herein and in any future authorizations of natural gas exports do not subsequently lead to a reduction in the supply of natural gas needed to meet essential domestic needs. The cumulative impact of these export authorizations could pose a threat to the public interest. DOE is authorized, after opportunity for a hearing and for good cause shown, to take action as is necessary or appropriate should circumstances warrant it”

[40] it should be noted that once a large investment is made in a gas-fired power plant/regasification facility the NBP price essentially becomes the floor price for spot cargoes. International LNG sellers from time to time may be able to exercise monopoly power and extract associated rents from Holyrood (price cap would be dependent on ability to burn substitute/back-up fuel such as No. 6 or No. 2 Heating Oil)

[41] Sabine Pass does not provide FERC regulated open access services, rates have been reached via negotiation

Figure 13
LNG Supply Cost



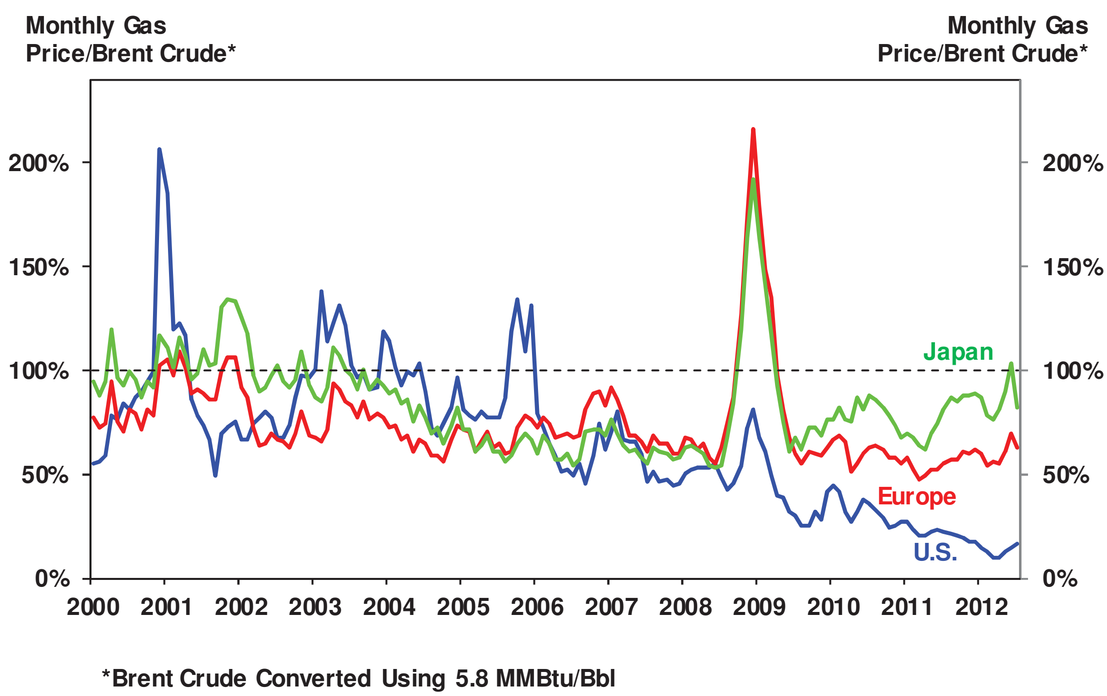
The NEB has granted export licenses to two projects from the West Coast of Canada eyeing premium Far East markets. To attract these volumes, Newfoundland would need to compete with the highest priced market worldwide (Japan has averaged $12.30/MMBtu since 2009 and $16.35/MMBtu year to date 2012) and be willing to pay for incremental transportation costs and Panama Canal levies.

A high level of health, safety, and economic welfare has been achieved in the industrialized world through access to highly reliable power and energy supplies. Due to extreme cold weather in Canadian winters, safety on very cold days becomes paramount (life and death) for Local Distribution Companies (LDC's) providing electricity and natural gas required for home heating. Therefore, the human cost of undersupplying energy to consumers is far greater than ensuring 'security of supply' by overbuilding and procuring excess supply. Regulators and LDC's must work together to determine an acceptable level of infrastructure and supply redundancy with the least amount of cost to ratepayers.

North American LDC's typically are well connected to pipeline and storage facilities. This gives them the ability to work with multiple counter parties using multiple tools[42] to ensure peak day security of supply. The isolated nature of Newfoundland from the North American pipeline grid will require more robust infrastructure which will allow for the storage of LNG to withstand interruptions in upstream supply. Although a small percentage of the supply portfolio could rely on spot markets for opportunistic purchases, Ziff Energy would expect an isolated island relying on LNG for the majority of power and heating requirements to contract with a well-established LNG supplier with multiple supply sources worldwide to ensure delivery diversification from upstream risks[43]. Although the supplier may have access to Henry Hub sourced gas and could deliver gas to Newfoundland, Ziff Energy does not believe it would be made available at anything less than the world price for long-term contracted LNG – 80-90% of world oil price.

Figure 14[44] shows that since 2009 U.S. gas prices have decoupled from Brent oil prices[45] averaging 25% of oil price, while European and Japanese gas pricing has remained highly correlated, averaging 62% and 80% respectively.

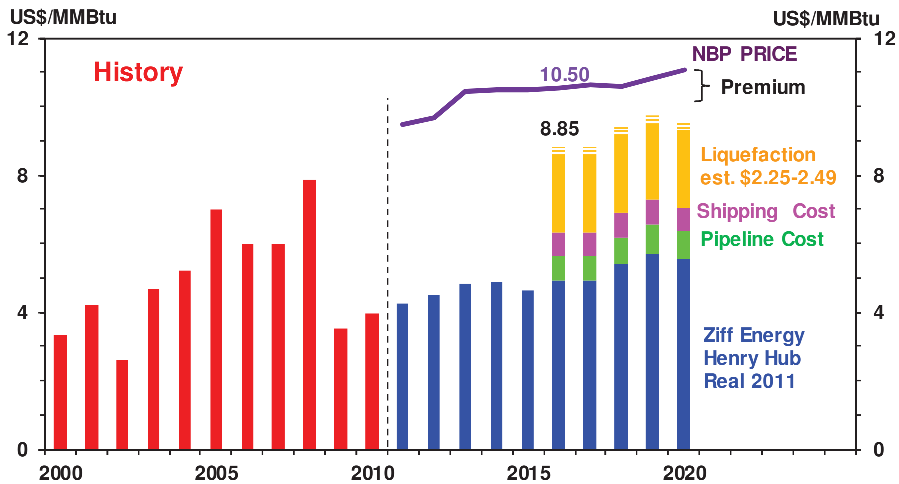
Figure 14
World Gas Price Compared to Brent Oil



[42] owned storage, third party storage, LNG peak shaving facilities, and/or a robust spot market with multiple pooling Hubs
[43] mitigating geopolitical risk completely may be difficult as a majority of LNG worldwide is controlled directly or in partnership by National Oil Companies (NOC). The recent decision of the U.S. government to delay the Keystone XL oil pipeline project illustrates that even with a strong energy trading history, and free trade agreement, geopolitical risk remains
[44] data sourced from World Bank Pink Sheets
[45] Ziff Energy has used a 5.8 MMBtu/Barrel conversion factor

Figure 15 illustrates that from 2016 to 2020, the forecast full cycle cost of delivered Gulf Coast LNG to Holyrood would be substantially similar to gas delivered to England[46]. It is unlikely that a potential supplier would contract long-term to sell LNG to Holyrood at a price substantially less than NBP[47], or indeed for a price substantially less than the alternative supply in Newfoundland (Residual Fuel Oil No. 6).

Figure 15
Gulf of Mexico LNG Export to Holyrood (No Regasification)



- **2015-2020 Average:**
  - Henry Hub - $5.17/MMBtu
  - Estimated LNG Price based on NBP $10.68/MMBtu

→ **Arbitrage Opportunity $5.51/MMBtu**
  - Offset by $4.38 – 4.62/MMBtu of Pipeline (0.83), Maritime (1.30), and Liquefaction (2.25-2.49) Costs

[46] liquefaction costs are based on Sabine Pass contracts. Liquefaction costs could be higher at other brownfield facilities, and certainly higher at greenfield projects.
[47] National Balancing Point (NBP) is a liquid natural gas trading Hub in England

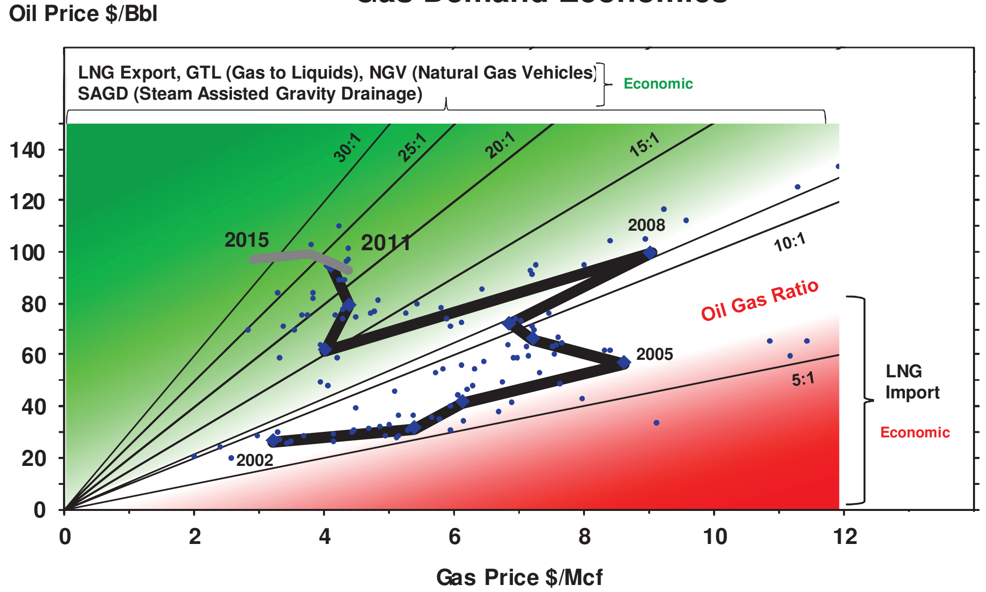
ADDITIONAL GAS MARKET POTENTIAL

Due to the small gas requirements at Holyrood for electrical generation, additional markets would be required to justify large infrastructure investments in jetties, storage, and regasification facilities.

Ziff Energy estimates the residential market could add approximately 14 MMcf/d[48] if all households convert to gas (conversion to gas would be partially or potentially wholly offset by decreased power requirements). The residential market would be subject to high winter peaks and very little summer demand, similar to Holyrood power loads. As such, this market would require gas storage to levelize the loads to make investment more attractive to producers. The conclusion is that these additional residential markets are not sufficient to generate economies of scale to reduce operating costs, or to leverage long term firm gas supplies based on Henry Hub net forward pricing.

Figure 16 shows gas project economics based on the ratio between oil and gas prices within the North American[49] pipeline grid. The **red** area is the region of oil to gas price ratio where LNG imports are economic. The **green** area represents high oil to gas price ratios where it is economic to export gas as LNG, build GTL plants, use gas in SAGD projects, and for natural gas vehicles. As both areas converge to white[50], all these projects become economically uncertain. The **thick black** line shows the combination of annual average oil and gas prices since 2002 and the forward strip prices till 2015. The **thin black** lines provide the oil to gas ratio. The small blue dots represent monthly price data. 2012 oil and gas prices are uneconomic for LNG imports and are economic for LNG export, GTL production, NGV, and SAGD.

Figure 16
Gas Demand Economics



48 approximately 1/3 of Holyrood's requirements in 2035
49 North America is the largest deregulated market for natural gas. Worldwide natural gas markets are highly regulated and typically based on long term contracts based on oil indexation
50 heating value parity is at 5.8 MMBtu of Gas per 1 Bbl of Oil

Producers must be competitive with their allocation of capital and as such potential Oil and Gas projects within a producing firm compete for investment dollars based on largest risked return. Both oil and gas wells require large capital investments upfront however after an initial production ramp up begin to decline over time. Therefore without constant additional investment overall aggregated production will eventually decline. As North American gas prices continue to be depressed, projects exploiting natural gas production will be less competitive with those which primarily focus on oil. As this occurs supply will begin to decline and demand sources will compete at higher price levels for reduced supplies. This will bring gas market fundamentals back into balance and could close the gap between oil and gas markets.

The high value of oil to gas is also a focus of Grand Banks producers who utilise gas floods (re-injected associated gas production to extract more high valued oil production). Due to operating cost of re-injecting gas, this option may not be as attractive or viable at $50/Bbl[51] however, may become an excellent option to extract additional oil resources when oil prices rise to $80 - 100/Bbl^{+}. Eventually[52] gas floods will run their course in stemming oil production declines and Grand Banks producers will assess potential gas monetisation options. As discussed earlier in this report, scale is an import factor in developing LNG as it helps to bring unit costs lower. A large scale LNG liquefaction project may or may not be viable in the harsh offshore Newfoundland environment. If the project were to be economically viable based on pipelining gas on-shore, selling Grand Banks volumes to the Newfoundland market would likely be viable based on:

World LNG Price (NBP) – Marine Shipping – Liquefaction + 0.01

In this scenario, Newfoundland consumers would essentially be ‘free riders’ benefiting from producer investment and risk taking. Newfoundland regasification facilities would not be required and if built would could essentially become a white elephant.

---

[51] WTI oil averaged $56.70/Bbl in 2005, the year White Rose began operations
[52] this will be based on a number of factors, some of the most influential are: incremental capex, operating costs, market price for both oil and gas. Specifying an exact date is therefore difficult but is likely beyond 2020

COMMENTS ON PRESENTATION BY DR. STEPHEN BRUNEAU

In the context of this report and the proposed scope of work, the Department of Natural Resources also requested Ziff Energy to review a lecture by Dr. Stephen Bruneau, given at the Harris Centre on March 28, 2012. This report provides analysis that differs in a material way from statements, assertions and conclusions of Dr. Bruneau:

1. Dr. Bruneau asserts that: “According to the CNLOPB and Husky Energy, natural gas cannot be used for enhanced oil recovery at White Rose or North Amethyst, thus a marketable gas opportunity arose in 2006 and continues through today and will continue until the end of life of that project.” His Conclusion 1 states that: “Natural Gas is available for domestic import now and for a long time into the future, but no plans or efforts have been made to access it.”

    - Ziff Energy’s discussions with representatives of Husky reveal that the operator has studied monetizing the gas resource and this analysis is ongoing. The Operator wishes to maintain the optionality to use White Rose natural gas for enhanced oil recovery as in Hibernia and Terra Nova. The Operator asserts that, at time of writing, White Rose natural gas is not being considered for any use other than enhanced oil recovery as they assess the technical and commercial viability. This situation may change in the future as the oil resource is depleted. Husky representatives indicate that the most likely commercial option for development of gas resources offshore Newfoundland involve LNG liquefaction and export to oil-referenced markets

    - It is Ziff Energy’s opinion that if the natural gas is not commercially available because the Operator may have a use for it in enhanced oil recovery, there can be no consideration of Grand Banks natural gas when required for Island Generation option[53].

2. Dr. Bruneau’s Conclusion 2 states that: “Natural Gas is being produced at a rate that exceeds our domestic electrical needs – can sustain our requirements for a long time.”

    - Ziff Energy finds that the small domestic power generation requirements are a barrier to commercial viability as the massive costs of production and pipeline infrastructure would need to be recovered from a very small rate base, rendering the natural gas feed costs (and generated power) uneconomic (from 2012C$21/Mcf to $33/Mcf for the most likely standalone gas development).

3. Dr. Bruneau’s Conclusion 3 states that: “Natural Gas reserves and resources on the Grand Banks are in quantities that exceed domestic electrical requirements for the foreseeable future.”

[53] physical availability differs from commercial availability, see Page 24 of this Report

- Ziff Energy agrees that natural gas reserves and resources are physically available in quantities in excess of domestic electrical requirements. Ziff Energy finds that natural gas, at time of writing is not commercially available. Further, the cost of bringing natural gas to the Island for power generation is punitive (from 2012C$21/Mcf to $33/Mcf for the most likely standalone gas development), given the low volume requirements now and in the future. These factors militate against commercialization of the natural gas solely for power generation.

4. Dr. Bruneau asserts that icebergs were considered too risky for Grand Banks pipelines 30 years ago. Further that: "Today, 30-Platform-years later, the safe and reliable production and operation has proven the effectiveness of management practices and the relatively low risks that icebergs pose – particularly to seabed equipment, flowlines and offshore loading pipelines."

   - Ziff Energy notes that offshore operators have chosen to transport Grand Banks oil via marine shipping rather than pipeline. The iceberg risk to a platform are considerably less than risks to a pipeline which has a longer and larger footprint and therefore a higher risk of impact over the term of use. Even with trenching, the assertion that iceberg risk for a several hundred kilometre pipeline can be managed is questionable and this practice is unproven on the Grand Banks. Dr. Bruneau cites other projects analogous to a Grand Banks pipeline, including Australian, Norwegian, Vancouver Island and Tobago projects. Some are in harsh climates, however, Ziff Energy notes that none of these other projects face the unique risk associated with icebergs off Newfoundland. Security of supply and economic and environmental consequences from a pipeline failure required for powering homes and businesses cannot be understated[54].

5. Dr. Bruneau concludes that: "Capital costs are very low relative to the alternatives presently under consideration for domestic electricity supply."

   - Dr. Bruneau excludes the "Platform modification" component, saying such costs are "to be considered in the context of gas price." Ziff Energy does not agree with Dr. Bruneau's conclusion, and finds the total costs of gas resource development and transmission are punitive given the small domestic electric generation load

     - Ziff Energy estimates costs to refit the White Rose FPSO at 2012C$600 MM, with a replacement of the FPSO vessel required in 2030 costing an additional $450 MM

[54] current operators with expertise in harsh conditions have been unwilling to undertake such a project, the Government of Newfoundland and Labrador, or an agent thereof, would be well-advised not to attempt such an undertaking based on theory and not sound and tested practice

- natural gas development would have to bear all of the capital and operating costs once the oil reserves have been produced, possibly by 2028, close to the end of the useful life of the existing FPSO. Thus, operating costs are split ⅔ oil, ⅓ gas until the oil runs out, then gas carries all the cost. Currently, oil production operating costs are in the order of $250 MM/year (these costs equate to about $18/Mcf based on 37 MMcf/d of initial annualized gas flows in 2017).

6. Dr. Bruneau makes the following assumption: "For domestic power production NL pays US utility market price for fully processed, pipeline ready and compressed gas at a metering station/pipeline launch point on the platform…."

   - Ziff Energy does not agree with Dr. Bruneau's simplifying assumption. Grand Banks natural gas is not physically connected to the North American gas grid (nor is Newfoundland). Grand Banks gas would not be sold on the mainland into a market which has experienced unprecedented supply growth and that is priced off gas on gas competition. The opportunity cost of selling gas to Newfoundland at a North American gas price index is punitive, given the full cycle cost of production. If gas were to be developed for commercial sale, Grand Banks producers would most likely sell into European or Asian markets in the form of LNG. Natural gas in these markets is primarily priced off an oil index, adjusted for BTU content[55]. Newfoundland consumers would therefore pay a price based on these alternative markets, and not a North American utility price[56]. Dr. Bruneau's analysis and demonstrated fuel cost savings are based on this simplistic assumption and are therefore incorrect.

[55] Figure 14 shows the correlation between internationally traded crude oil and gas prices in Europe and Asia
[56] even if the Newfoundland Government were to purchase the natural gas resource after oil production had ceased, assuming the Operator and interest holders would agree and are not interested in commercial exploitation, there would be a cost or negotiated price. It is not fair to assume that interest holders (with a legal fiduciary duty to shareholders) would simply give up the resource and commercial potential for nothing.

APPENDIX A: BACKGROUND INFORMATION

Types of Natural Gas

Associated Gas – when oil is produced, natural gas may be inter-mixed with the oil. In Canada, we refer to this gas as 'Solution Gas', whereas in the U.S. the term used is 'Associated Gas'. In Western Canada, Solution Gas represents 10 to 15% (2 Bcf/d) of total gas production. The gas produced offshore Newfoundland and Labrador is associated with oil production, or Associated Gas.

Free Gas – natural gas produced without oil is typically referred to as 'Free Gas' or Non-Associated gas, that is, gas that is not inter-mixed with oil. In addition to Conventional Gas, there are several types of Unconventional Gas: Shale Gas, Tight Gas, and Coal Bed Methane (CBM).

Composition of Gas

Natural gas is formed from long term decay of organic material buried millions of years ago. Natural gas composition varies from one location to another. Depending on location, the organic material is buried under various depths of sediment for varying periods of time in an underground formation that can allow leakage. All gas samples will therefore have some differences. Industry has analysed millions of gas samples which results in a wide range of components. Raw natural gas is typically processed and some components of the natural stream flow may be taken out to ensure the gas is of merchantable quality, thus the composition usually changes for final delivery. While the actual composition of a gas wells' natural gas can vary, Table 1 provides typical ranges for raw natural gas composition and those for the gas cap of the South Avalon Pool at White Rose. The major component of natural gas is methane. Some natural gas wells contain varying quantities of poisonous Hydrogen Sulfide which needs to be removed.

Table 1
Typical Raw Natural Gas Composition, %

Gas Component	Minimum	Average	Maximum	White Rose – South Avalon Pool Gas Cap
Methane	65	90	93	87.7
Ethane	3	5	12	4.5
Propane	1	3	10	2.5
Butanes	under 0.2	0.2	3	1.4
Pentane plus	under 0.1	0.2	1	1.3
Hydrogen Sulfide	0.0002	under 1	10 to 45	0
Carbon Dioxide	0.5	under 2	3 to 10	1.5
Helium	trace	0	1 to 4	–
Nitrogen	under 1	1	5 to 10	1.2
Other Components	trace	under 1	under 1	–

Enhanced Oil Recovery

Production of oil without injected energy is referred to as *primary* oil production. However, to recover more oil from a reservoir, assistance is eventually required. One method to achieve incremental oil recovery is injecting natural gas to boost the oil reservoir pressure. This technique is common in Alaska where oil has been produced for several decades from Prudhoe Bay. To further enhance the oil recovery, some operators inject a chemical solvent, or perhaps a solvent mixture of ethane and propane into the well bore. This solvent 'washes' the reservoir, thereby increasing oil production. This overall process is termed Enhanced Oil Recovery, and is given the acronym, 'EOR'. Currently, natural gas is utilized for enhanced oil recovery in the Hibernia and Terra Nova fields in the Grand Banks region and as the White Rose project begins to mature, gas floods could become viable to enhance and extend oil development.

Physical Availability versus Commercial Availability

A completed and tied in natural gas well has the ability to flow gas, that is, gas is physically available. In Alaska, 8 Bcf/d of gas is physically available to flow[57]; however, there is no pipeline in place, thus the gas is stripped of some of the natural gas liquids, about 1 Bcf/d is used to power operations, with the balance of the gas re-injected to maintain reservoir pressures for oil production. While the gas offshore Newfoundland and Labrador is physically available, there is no pipeline to commercial markets and there are no commercial contracts in place to sell the gas to market. This gas could be referred to as 'stranded'.

Factors Affecting Oil and Gas Investment Decisions

Producers are in business to earn a profitable rate of return on their oil and gas investment for their shareholders. They undertake oil and gas activity that is safe for staff and contractors, ensuring minimal disruptions to long term production. Producers strive to develop oil and gas operations that are environmentally sustainable as they typically live within the community. Safety and environmental standards are strictly monitored by various regulatory bodies and levels of government.

Cash Flow Economics

While many oil and gas projects may be evaluated by producers, only projects that achieve specific economic hurdles are ultimately chosen for investment. For example, a producer may have 10 oil and gas projects to be evaluated: however, only 7 of these may have a payback of capital[58] deployed that meets the company's requirements. Of these 7, only 5 may have rates of return that meet or exceed their internal benchmark or hurdle rate[59]. Oil and gas production economic evaluations help maintain management discipline to ensure oil and gas operators are steered towards investments that add financial value. There is generally internal competition for investment dollars.

[57] this represents 10% of North America gas production
[58] simple payback of capital may be 2 or 3 years whereas 4^{+} year payout projects tend to be of questionable value
[59] producers tend to seek a 15% or higher rate of return before income tax, though this metric is closely guarded and rarely divulged

Producers will calculate the annual cash flow that an approved project brings. Cash flow projection helps a company determine how much money is needed to be borrowed and for how long to finance projects. Additionally, the overall value of a project can be estimated by discounting the net cash flow at the developer's prescribed internal rate of return. Larger projects, in general, typically require more management time and as a consequence, some smaller projects in the producers' overall investment portfolio may not achieve the priority needed to ensure that a smaller project actually proceeds.

Portfolio Decision Making

Capital is mobile: oil and gas explorers can undertake projects in many countries. This is natural as it allows producers to undertake similar types of projects in various locations where they have prior experience that can be transferred, thereby creating a competitive advantage. Internal competition arises when producers have multiple projects competing for capital and people. Oil and gas producers can further high grade the selected projects to only consider the 'best of the best' projects that exceed all of the economic hurdles. In this situation, the producer is now making portfolio decisions.

For example, a producer may have 20 projects that meet the economic hurdles. However, due to limited funds and people, the company may choose to invest in just half of the projects. Thus some projects that achieve the basic predefined economic hurdles are not undertaken as the producer chooses to invest and earn a better rate of return elsewhere. In addition to economics, the producer may introduce additional criteria[60] to pare down the overall investment portfolio. The end result of these portfolio decision making analyses is that the producer is typically quoted as "due to uncertainty, we have chosen to delay our investment" or "we have had to prioritise our internal resources to focus on a select list of projects". Whatever the words used, the end results are the same – that is, the oil and gas producer has made a portfolio decision to invest elsewhere.

Price versus Costs

There is currently no viable market for offshore Newfoundland gas. The potential market in Newfoundland is demonstrably small, and the load profile fluctuates, with demand spikes in winter months, and very little demand in the summer. The price paid by natural gas consumers on mainland North America is not relevant to the price of gas in Newfoundland. Mainland natural gas is not physically connected to Newfoundland. North American and Newfoundland gas prices (if there were a Newfoundland gas price) would not correlate.

When market prices are less than full cycle costs, producers cease exploration and development, and divert capital to areas, regions or plays where they can earn a (higher) rate of return. The average[61] full cycle cost of exploring, developing, operating, and ultimately producing new natural gas in North America averaged[62] $5.50/MMBtu at the beginning of 2010. The current NYMEX natural gas

[60] criteria may include potential for political interference or regime change, risk of a government changing a royalty rate, or potential for a competitor to capture the opportunity
[61] not all gas plays are equal. A wide range exists whereby some natural gas plays are significantly more expensive to explore, develop, and operate
[62] Ziff Energy has undertaken two detailed 85 page private studies on the full cycle cost of gas across North America, an updated study is currently under development

market price is around $3.50/MMBtu. Producers have responded by significantly reducing the number of gas wells drilled to focus on only the best prospects, or they have shifted to drilling for oil, or gas wells with significant natural gas liquids content to enhance economics and producer returns.

North American natural gas producers are also considering arbitrage of natural gas into European and Asian markets via LNG. As there is currently no competitive natural gas market in Newfoundland, the price paid by any potential natural gas buyer will reflect the cost of producing and bringing offshore gas to the Island, and producer netbacks from alternative markets in Europe or Asia.

Shareholder Expectations

Shareholders can invest in resources (oil/gas, minerals, forests), agriculture (wheat, corn, vegetables, fruits), services (banks, IT, airlines), or other industries. A strategy may be to diversify one's holdings to 10 sectors, in several countries, with various amounts of perceived and real growth opportunities. Stock appreciation and dividends result in incremental value for shareholders; consequently, the economics of the underpinning investment would rank high among the reasons for shareholder investment.

Oil and gas shareholders expect to earn a reasonable return on their investment and they expect their company to grow. Investing in a project that has little economic upside or with economics that do not meet expectations, are key reasons to withdraw shareholder support for a company. Selling shares applies a downward price influence and that reduces the company's overall value, thus company executives strive to ensure that shareholders expectations are always met, and if feasible, exceeded. Frequently, company executives are strongly rewarded financially for meeting and exceeding shareholders expectations. This win-win mechanism creates an overall feedback loop of shareholders expectation to management of the firm. Conversely, the share price of many companies has been severely punished when the company fails to meet shareholder expectations.

Regulatory Process in Newfoundland and Labrador

Jointly Administered by Federal Government and Province

On February 11, 1985, the Atlantic Accord Agreement was signed between the governments of Newfoundland and Canada establishing the legislative framework governing petroleum resource development. On April 4, 1987, the principles governing the Accord Agreement were legislatively proclaimed under the Canada-Newfoundland Atlantic Accord Implementation Acts.

The Canada-Newfoundland-Labrador Offshore Petroleum Board (CNLOPB) reports jointly to Federal and Provincial Ministers of Natural Resources and is responsible for petroleum resource management in the Newfoundland and Labrador Offshore Area.

CNLOPB as an Independent Regulator

To provide a stable and fair offshore management regime, the CNLOPB, a joint federal/provincial agency was created. The CNLOPB is an independent regulator of oil and gas activities in the offshore area. The commitment to joint management is stated in Section 3 of the Atlantic Accord and Section 9(1) of the Accord Acts.

It is significant that the Preamble to the Accord Acts states that both governments "have agreed that neither Government will introduce amendments to this Act or any regulation made thereunder without consent of both governments".

The CNLOPB does not insinuate itself into matters of private sector business strategies or governmental policy. It does not pick winners and losers, but focuses its attention on assessing the safety, environmental and technical aspects of exploration and development applications placed before it by producers for consideration.

Rights Issuance

Exploration Licence

Each year the CNLOPB determines which offshore lands[63] will be made available for offshore exploration. The administrative process is straight forward – the Board invites industry in the fall of each year to nominate lands of interest through the call for nominations. Interested companies provide a confidential preliminary response by Christmas with an indication of those lands of interest for a potential 5 year work bid commitment. Based on this response, the Board initiates a formal call for bids in the spring of the following year, with an industry response due by the fall. The Board evaluates which company is successful using a specified single criterion which historically has been the highest work commitment bid, and based on the Board's evaluation, issues an Exploration Licence (EL) to the company, typically by the middle of January of the next year. The Board requires a quarter of the planned spending be received as a security deposit, though this amount is debited against actual expenditures. The company is required to undertake certain activity in a specific time period, comprised of Period I and Period II which cannot exceed 9 years in total.

Significant Discovery Licence

If a drilling program results in a significant discovery and a declaration of significant discovery has been made, an interest owner is entitled to a significant discovery licence. A declaration of significant discovery is a pre-condition to the issuance of the significant discovery licence. A significant discovery is defined in the Acts as:

> "a discovery indicated by the first well on a geological feature that demonstrates by flow testing the existence of hydrocarbons in that feature and, having regard to geological and engineering factors, suggests the existence of an accumulation of hydrocarbons that has potential for sustained production."

Upon receipt of an application for a declaration of significant discovery, the Board first determines whether a significant discovery has been made, and secondly, if so made, indicates the portions of the offshore area where there are reasonable grounds to believe the significant discovery may extend.

[63] the CNLOPB administrative jurisdiction is 185 million hectares, typically 200 miles out from shore or the outer edge of the continent

Production Licence

Should the company then continue with additional exploration and development activity which results in the possibility of oil or gas production, then the Board may provide the company with the right to produce through a Production Licence (PL) for a term of 25 years. Some projects can be approved as deferred developments (could require development plan amendments before going into production).

Hibernia (operated by Hibernia Management and Development Company, HMDC), Terra Nova operated by Suncor, and White Rose operated by Husky, are the *three regulated offshore projects.*

Role of the Regulator

The Regulator (the Board[64]) in summary has a mandate and a role to interpret, apply, and implement the provisions of the Atlantic Accord to facilitate the exploration and development of oil and gas in the NL offshore area. The Regulator's role includes major objectives such as:

- safety – ensure processes are in place so that workers get home safely
- environment – ensure Operators meet Canadian Environmental requirements
- management – maintain good oil and gas production practises for land, accounting & 'know how'
- enforcement – relates to benefits for Canada/Newfoundland & Labrador manufacturers, contractors, consultants, and service companies to obtain employment, education and training, research and development, and to supply goods and services on a competitive basis reflecting market price, quality, and delivery schedules.

Stability of Regulatory Regime

The CNLOPB has been stable over the past quarter century and 10 employees have been on staff since formation. The Board has established proven teams to focus on specific issues, which helps ensure continuity from year to year. The Board documents significant accomplishments each spring in their annual report, while financial auditors scrutinise the Board's financial performance. In summary, the Board is run like a prudent company that adheres to specific written procedures that help to maintain annual stability.

Role and Rights of the Operator

The historic signing of the 14 page, 68 clause Atlantic Accord between the Government of Canada and the Government of Newfoundland and Labrador on February 11, 1985 provided the overall policy framework that defines the role and rights of the offshore operators. Once granted a production operating licence, Operators are expected to produce the commercially viable resource in a safe and environmentally sound manner consistent with industry good field practises.

[64] the board is deemed to be a non-profit organisation, and is therefore exempt from income tax

Development and Production

Oil and gas development activity follows successful exploration. On-going development drilling activity is highly focused in very specific geographical locations with the aim of establishing an inventory of offshore wells that can later systematically 'harvest' the discovered oil and gas. Development requires planning, coordination, and construction of oil and gas production equipment to ensure effective gathering, processing, and distribution systems to allow oil and gas to become commercially viable for end market use. Production of oil and gas can commence after the initial development is completed and typically represents the start of a quarter century of ongoing activity.

Producing oil and gas is the reward for the initial exploration and development activity. Production operators Offshore Newfoundland and Labrador are:

1. HMDC processes hydrocarbons at the Hibernia field from the Hibernia and Ben Nevis-Avalon reservoirs using a Gravity Based Structure (GBS)
2. Suncor produces from the Jeanne d'Arc reservoir at the Terra Nova field from a Floating, Production, Storage, and Off-loading vessel (FPSO)
3. Husky produces from the Ben Nevis-Avalon reservoir at the White Rose and North Amethyst fields via an FPSO.

Once the offshore facilities are operating, on-going exploration, development, and further production activity can be undertaken concurrently to evaluate nearby resource potential. An example of such activity is Hebron, the 4th oil project currently slated for production in 2017.

Natural gas development is not a focus for operators on the Grand Banks at this time. Offshore crude oil is sold into a Brent referenced oil market, and natural gas prices in North America hover at the $3/MMBtu level at time of writing. As a consequence, oil is the current focus of producers and the gas potential of the offshore basins is not being considered for commercial development at this time.

APPENDIX B: OVERVIEW OF ZIFF ENERGY

Ziff Energy Group, founded in 1982, is a leading international energy consulting firm providing sophisticated industry and operational business analysis, specialized consulting, and learning services to the worldwide energy industry. We have offices in Calgary and Houston, the two principal oil and gas centers in North America. Our staff of 40^+ includes **many senior industry specialists**, with **15 – 25^+ years of domestic and international experience**.

The firm focuses its efforts principally in two areas:

- **Gas Services**: Ziff Energy Group is recognized for its in-depth analysis of North American as well as regional gas markets, gas and liquids supply, transportation, midstream, storage, regulatory affairs, and long term gas pricing forecasts.

- **E & P Services**: more than 100 North American upstream producers have been involved in field level operating cost and finding and development cost studies that cover most North America onshore and offshore production basins, and 40 foreign countries.

Gas Consulting Services

We are a major provider of natural gas customized consulting services to our growing list of clients. We undertake Gas Consulting assignments that address specific client needs in the areas of operations, strategies, and regulatory matters. Some specifics include:

- comprehensive advice on emerging gas industry issues and developments within North America and elsewhere internationally; our technical knowledge and detailed fundamental analysis on emerging supplies and demand sectors are particularly strong
- unbiased opinions on complex natural gas industry issues, supported by an understanding of your business challenges; our candid view of industry trends and developments
- expert testimony on gas pricing, supply, transportation, storage, and pipeline tolls
- early reporting on changing business conditions; strong competitive intelligence
- clearly written, focused research that can help you identify business opportunities and threats; efficient delivery of knowledge.
- Ziff Energy provided expert evidence in support of KM LNG's successful NEB Export Licence Application and for the LNG Canada Project which has recently filed an application with the NEB to export LNG.

Ziff Energy's Gas Team

Paul H. Ziff – CEO, founded Ziff Energy Group in 1982 and co-led the international expansion of Ziff Energy Group, which is now active in 40+ countries. He conceptualized the theme of 'World Asset Types'. Mr. Ziff has three decades of assessment experience for the oil and natural gas industry. A specialist on natural gas industry strategies and upstream corporate performance, Mr. Ziff conceived and directed a wide range of benchmarking studies and consulting projects in upstream corporate performance. Prior, he directed energy research for a major investment firm, gas pricing analysis for a key Alberta government agency, and energy lending analysis for a major bank. Mr. Ziff is an honors graduate of Harvard University, and attended the Université de Paris (Sorbonne) and the Institut d'Études Politiques.

W.P. (Bill) Gwozd, P.Eng. – Senior Vice President, Gas Services, has over three decades of natural gas experience regarding gas supply contractual purchases and gas storage strategies, directing gas control functions for transportation contractual arrangements, and preparing written regulatory applications. Other experience includes transportation planning of natural gas liquids pipelines and storage facilities. Mr. Gwozd oversees forecast assessments, semi-annual client debriefings, and our expert witness testimony service offerings. Focus is on long-term natural gas price outlooks for LNG, LDC, Pipeline, power, and acquisitions. Mr. Gwozd is a frequent guest contributor to various TV stations, radio, newspapers, and magazines.

Edward Kallio, B.A. – Director, Gas Consulting, has over three decades of gas industry experience in trading, marketing, portfolio management, supply, forecasting and policy analysis in the private and public sectors. Mr. Kallio's experience includes analysis of pipeline rate applications, economic analysis of major domestic and cross-border gas transactions and contracts, and negotiation of storage, transportation and supply arrangements. He has advised clients with respect to natural gas and electricity supply transactions and hedging programs. Mr. Kallio has traded natural gas in several North American gas supply basins and managed production and supply portfolios in eastern and western Canada and the U.S. He has advised Canadian and U.S. companies with respect to deregulation of retail energy markets. At Ziff Energy, Mr. Kallio conducts analyses of gas and liquids issues and fundamentals and leads client presentations and briefings.

Simon Mauger, P.Geol. – Director, Gas Supply and Economics, has three decades of experience in the upstream oil and gas industry as an exploration and development geologist in the Western Canadian Sedimentary Basin and other locations. Mr. Mauger planned, evaluated, and economically modeled gas resources for a leading international exploration and production company; prepared and optimized long term gas supply plans for growing gas markets; and developed the regional exploration component of the North American integrated natural gas strategy. Mr. Mauger develops a gas supply outlook for each North American gas producing region, authors technical research reports on supply, demand, and transport, issues, and assesses gas costs of North American gas basins.

Cameron Gingrich, B.Sc., B.A. – Senior Manager, Gas Services, has a decade of natural gas experience. Responsible for analytical support and in-depth customized data analysis, trending, and modeling. Focuses effort toward the North American Gas Strategies Retainer Service, multi-client studies, and custom consulting projects include: analysis of pipeline tolls, gas supply/storage load duration modeling, gas demand outlooks, and gas price modeling. Mr. Gingrich was the lead analyst on the Northern Gas and Evolution of Dawn Multi-client studies, and authored papers on: Summer Gas Storage Analysis, Canadian Gas Exports to 2025, Natural Gas Price Forecast to 2045, and LNG Outlook to 2035. In addition to the Canadian Securities Course, Mr. Gingrich has two degrees: a Bachelor of Science from the University of Alberta and a Bachelor in Arts in Economics from the University of Calgary where his studies focused on strategic energy and financial markets.

Dr. Lev Virine, P.Eng., Ph.D. – Manager, Gas Consulting, has over 2 decades of technical experience, economic evaluation of oil and gas reserves, decision and risk analysis, portfolio management, and oil and gas reserves management. He assisted leading national and international exploration and production companies in establishing reserves evaluation and decision analysis processes. Dr. Virine is the author of more than 40 scientific papers and articles, 7 patents, and two books. His current focus is gas production outlooks, gas supply decline analysis, and full cycle cost assessment. He has spoken at conferences and symposiums around the world. Dr. Virine received his doctoral degree in engineering and computer science from Moscow State University of Railway Engineering.

Zuzana Jurickova – Gas Analyst, for the past half dozen years, has assisted with projects in the areas of gas supply and demand research and forecasting analysis. Over this period she has worked on the Western Canada Reserve Replacement (F&D) Cost Study, a study on North American Cost Inflation for a major producer, and a study of North American pipeline expansions for a major steel producer. She is currently working on North American Gas Supply costs for 20 basins (and LNG). Prior to joining Ziff, Ms. Jurickova worked in corporate credit and finance. Ms. Jurickova obtained her five-year Degree in Economics from University of Economics in Bratislava, Slovakia.

Julia Sagidova – Gas Analyst, is responsible for gas supply (including LNG import/export analysis), gas demand, gas transport, gas storage, and gas price data management for the Gas Services team. Client project activity pertains to analysis of natural gas fundamentals and supporting analytics for North American regional multi-client gas studies, the North American Gas Strategy retainer service, and in-depth client consulting projects. Prior experience in petroleum economics and analysis of gas supply issues, along with pricing, forecasting, and analyzing gas market trends. Julia holds a Master’s degree in Economics from University of Calgary.