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Attachment
Piped Gas and LNG Discussion Paper - DraftApril 18.docx

These are some notes I drafted a while back. Its not a report per se but rather a collection of considerations regarding gas and how public discourse does not seem to capture these issues. Either one of the issues can be expanded.

First cut... It rambles a bit. Obviously need to cut it down, simplify, put a "report" style on it etc...but it represents the latest collective "wisdom".

In the end.. a whole series of debate points can be extracted.

Jim

Piped Gas and LNG Discussion Paper - DraftApril 18.docx

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# Grand Banks Natural Gas for Electricity Generation

## Introduction

The International Energy Agency's *"World Energy Outlook"* offers a projection called the "Golden age of gas", it sees annual world production rising by 1.8tcm between now and 2035, when it reaches 5.1tcm. The abundance of natural gas coupled with its environmental soundness compared to other fossil fuels,, means that natural gas will continue to play an increasingly important role in meeting demand for energy around the world. While forecasts made by different consultants and agencies may differ in their exact expectations for the increased demand for natural gas, one thing is common across studies: demand for natural gas will continue to increase for the foreseeable future. Natural gas is emerging as a promising solution to some of the world's energy challenges.

Can natural gas play arole in the island of Newfoundland's electricity energy needs? This is the central question that this paper will address. This paper will summarize how Nalcor Energy screens out project alternatives, and in so doing, highlight and explain why two concepts for natural gas fuelled electricity (piped gas from the Grand Banks and forign supplies of liquefied natural gas (LNG)) were not considered for further review beyond Decision Gate 2.

Key Message No.1

| Both piped Grand Banks Gas and imported LNG were screen out at DG2. |
|---|

Nalcor Energy utilizes a decision gated process in the identification, selection and execution of its capital projects. This paper provides the reader the opportunity to better understand Nalcor Energy's approach to project screening and concept section and in particular the rationale for screening out of Grand Banks natural gas. This report will, in simple terms, summarize the complex decision making process and special technical and commercial considerations which led to the screening out of the natural gas options for fueling the island's electricity needs.

## Nalcor Energy's Decision Gate Process

Large capital projects are, by definition, unique endeavours. This implies unknown factors, uncertainty and risks. Capable organizations draw upon proven and effective strategies in dealing with such risks to ensure that the right project concept solution is selected for the right reasons and the concept selected is then executed in a safe, efficient and value creating manner using industry accepted "best practices".

Initially, during the very early phases of a project, the particular need is identified and verified. In this phase where ideas are generated and high level scoping economics and technical reviews undertaken, costs are first incurred and they rise gently. As the project matures and more in-depth analysis and study is required more time is taken and more costs incurred. Each phase has the objective of reducing the risk of subsequent phases in a cost-effective way; with the principle that a relatively small amount of financial resources is spent on a phase to lower the risk of subsequent phases. If the risk of subsequent phases cannot be reduced sufficiently, the project can be terminated at the end of an early phase. The cumulative cost of a project typically follows the "S-curve" shape.

The end of a particular phase is an important milestone in the lifecycle of a project where the project team typically presents the work performed to a project review board that often comprises of executive leadership, experienced third party verifiers, and other stakeholders. This review point is called a

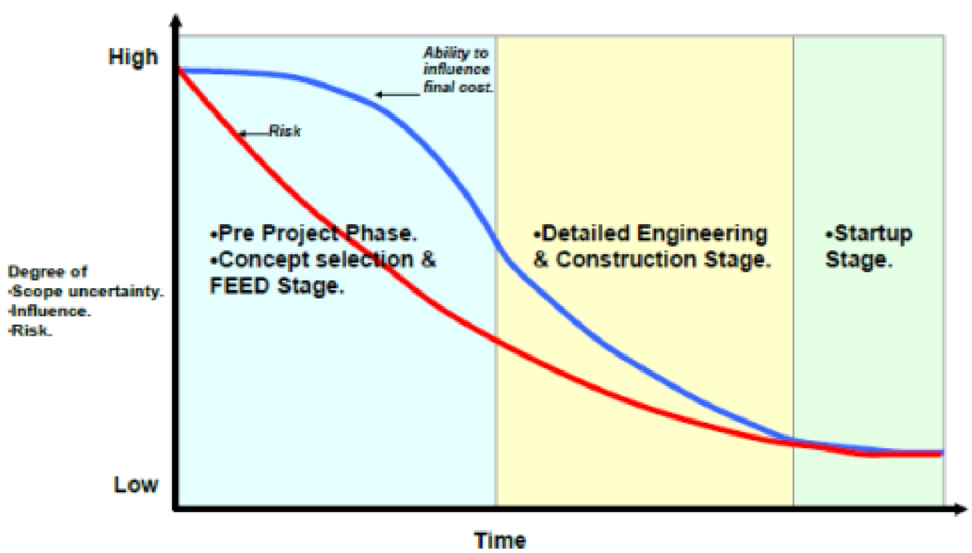
Decision Gate. This point also serves as a gate that needs to be opened for work on the succeeding phase to be authorized, resources committed and funds allocated.

The chart below demonstrates that the greatest ability to influence costs is at the front end of the project. It is also the place where by risks are greatest. The purpose of maturing design development and project planning and commercial structuring in these early phases is to reduce these uncertainties over time while acknowledging that as the project passes from phase to phase and commences, the ability to influence costs declines.

Key Message No.2

| The greatest ability to influence costs is at the front end of the project. |
|---|

This chart illustrates the reduction in risk and the ability to influence final cost as the project moves through the Project Phases.




At Nalcor Energy, the lifecycle of a project has been is grouped into five sequential project stages, each composed of one or more phases interspersed with Gateways and Checkpoints, at the logical juncture in a Project's execution in which a decision must be taken on whether to proceed to the subsequent phase, recycle or stop activities. In summary, the decision gateway process applies through the following stages of a project:

Gate One – Idea Generation/Business Opportunity

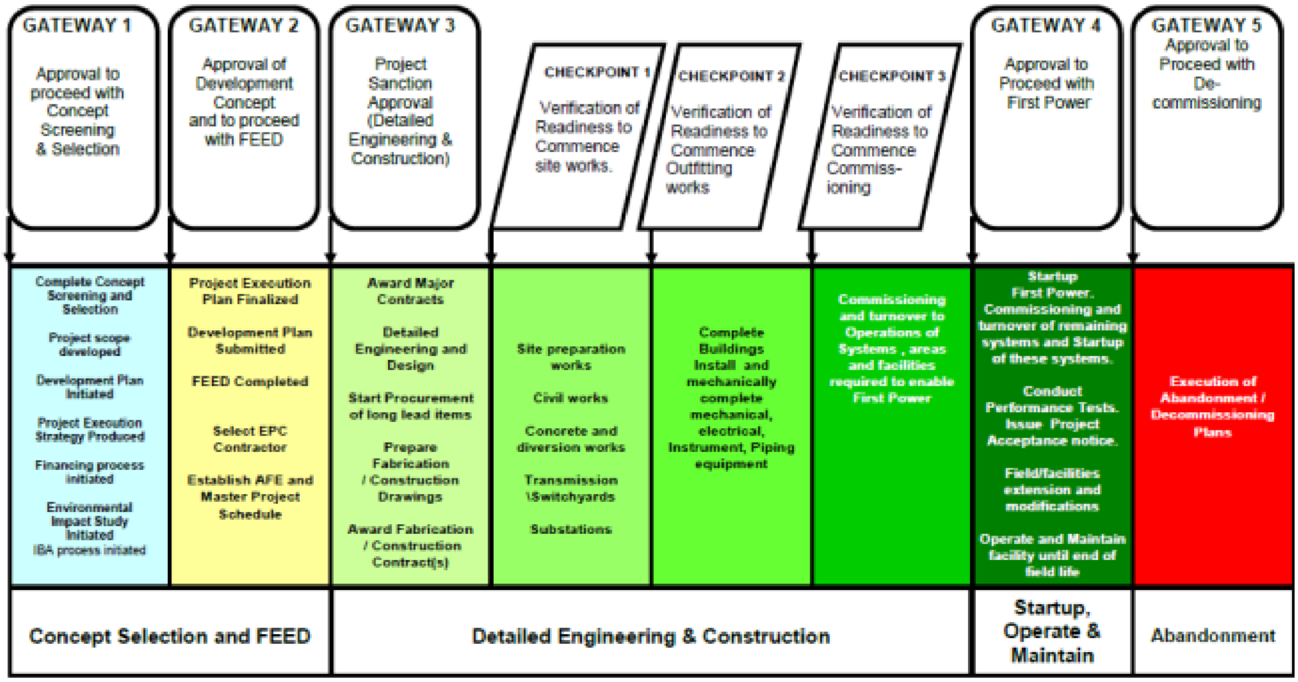
Gate Two - Concept Selection and FEED Stage

Gate Three – Detailed Engineering and Construction Stage

Gate Four – Start-up, Operate and maintain Stage

Gate Five – Abandonment /De-Commissioning Stage

The Gateway Process builds on the typical project development cycle. The figure below illustrates the Gateway Process and its use of decision points, hereafter known as Decision Gateways (DG), and verification reviews, known as Checkpoints.




The Gateway Process has the following objectives:

- To provide a process to enable best value-adding potential to be captured and utilized.
- To screen alternatives and improve cost and schedule accuracy through design development and execution;
- Identify and mitigate project risk;
- To provide a mechanism for the Nalcor Energy leadership team to verify readiness to move from one phase to another in a systematic and focused manner during the lifecycle of a project;
- To demonstrate due diligence checks and balances are being applied during the execution of Nalcor Energy managed and operated projects and those Operated- by- Others; and
- To provide a means to pre-define "readiness" deliverables required for a project to progress from one project phase to the next (i.e. Gateways and Checkpoint Reviews).
- To create alignment with shareholder and stakeholders with respect to project expectations.

To specifically address how and why Nalcor Energy screened Grand Banks natural gas some further discussion regarding the activities leading to DG2 are required.

The use of formal Decision Gates facilitates decision making by establishing and documenting the state of readiness of a project to move from one phase to the next, whereby the capital intensity of the phase increases. The Gatekeeper (Nalcor Energy's CEO) uses structured decision points, in consultation with Nalcor's Board of Directors and in agreement with the Shareholder, to make appropriate decisions whether to:

- hold all activity pending receipt of some final clarifications or supporting information is received;
- move to the next sequential phase; or

- stop/terminate all activity to proceed to the next project phase.

Key Message No.3

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| A decision gate process with clear and visible criteria removes a development portfolio of weaker projects so resources and focus can be applied to the preferred project to create and maintain value. |

### Gate Two - Concept Selection and FEED Stage

Most relevant to the screening of options is a brief description of the outputs from DG1 – *Approval to Proceed with Screening and Concept Selection.* At the conclusion of this stage, various studies and analysis have been carried out to a sufficient level of detail to confirm that a need for new electricity generation exists and that economically viable development is likely through a series of various options, and that there is support from executive leadership, board of directors and shareholder to pursue a solution. At DG1, the decision is made to proceed into the DG2 - *Concept Screening and Selection Phase*. At this Gateway a workscope is agreed and budget approved in order to fund the completion of concept screening and selection process leading to the next decision gate.

After proceeding through DG1, facilities concept screening investigation begins. During this phase the technical, financial, environmental, aboriginal and commercial strategies and plans are advanced to a point at which a Front End Engineering & Design (FEED) basis may be specified. Facilities concept screening studies are conducted, permits are pursued and commercial discussions initiated, and ultimately a Development Plan is initiated with regards to the preferred option.

Through this DG2 process, power generation supply options for both the Isolated Island and Interconnected Island alternatives generated a host of supply options. When considering specific supply options Nalcor Energy also considered the current and future portfolio of electricity supply options that could be theoretically considered to meet future generation expansion requirements for the island of Newfoundland. These individual supply options represent a range of choices/alternatives from local indigenous resources, to importing energy fuels from world energy markets, to interconnecting with regional North American electricity markets.

Specific supply options are initially considered and screened based on initial screening principles that aligns with Nalcor's/NLH's mandate. The initial screening is important as it enables NLH to concentrate further consideration on only the technologies and alternatives that offer the highest potential to ensure effective expenditures of ratepayers' money and to realize the vision of the Energy Plan. In addition, prudent pricing assumptions are essential for fuel based generation alternatives. Those options that remain following a high level screening are input into the generation planning software models for further analysis and ultimately for the recommendation of the preferred generation expansion plan.

The screening of alternatives was conducted according to the following screening principles.

## Screening Principles

1. Security of Supply and Reliability

Security of supply and reliability are the two most important criteria for evaluating the supply investment decision.

NLH is mandated to provide reliable least cost electrical supply to the people of the province. As part of its mandate, NLH must maintain a long-term plan that demonstrates its ability to continue to supply the expected requirements. A realistic plan is particularly important for the island portion of the province as it is isolated from the rest of the North American electrical grid and cannot rely on support from neighboring jurisdictions should there be problems because of the application of unreliable technologies.

Because of the importance of having a realistic plan, NLH has developed an Isolated Island expansion plan that is a least cost optimization utilizing only proven technologies to ensure they can meet the required expectations from security of supply, reliability, and operational perspectives. There must be a high level of certainty that all elements of the Isolated Island alternative plan can be permitted, constructed and integrated successfully with existing operations. Generation technologies that do not meet these rigorous requirements are excluded from further consideration.

2. Cost to Ratepayers

NLH's mandate, as defined in Section 3(b) of the Electrical Power Control Act, 1994, is to ensure that all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in the most efficient manner such that power delivered to consumers in the province is at the lowest possible cost consistent with reliable service. Least cost for ratepayers is a key objective of the company and guides its business decisions, expansion plans and overall strategic direction.

3. Environmental Considerations

Environmental stewardship is one of Nalcor's guiding principles. This principle is also embodied in Focusing Our Energy: Newfoundland and Labrador Energy Plan15 (the Energy Plan) and provides guidance to Nalcor in making investment decisions. The company must meet any current environmental regulations laid out in both provincial and federal legislation and also must consider potential new environmental legislation due to the longer term nature of its generation expansion decisions. The company must also adhere to any provincial policy provided in this regard.

4. Risk and Uncertainty

Given the magnitude of the decisions being undertaken for generation expansion and the expenditures proposed, risk and uncertainty are key decision criteria. Nalcor considers this in its investment decision-making.

5. Financial Viability of Non-Regulated Elements

Consideration of financial viability is important to ensure that the shareholder makes an adequate rate of return and any project investment can obtain debt financing and can meet debt repayment obligations.

Key Message No.4

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|---|
| Nalcor's sceening process focused on five citeria.<br>1 .Security of supply and reliability.<br>2. Cost to ratepayers<br>3. Environmental Considerations<br>4. Risk and Uncertainty<br>5. Finanical Viability of Non-regulated Elements |

A screening process was used to evaluate alternatives based on the aforementioned principles. The outcome was a list of viable alternatives that would be further evaluated and costed for system planning purposes. The remaining alternatives were then grouped into two broad categories, or options, of development alternatives. One option is categorized as the Isolated Island alternative. In this alternative, the electrical system on the island of Newfoundland continues to operate in isolation from the North American grid such that new generation capacity is limited to what can be developed on the island itself. The second option is categorized as the Interconnected Island alternative and is described in. The Interconnected Island alternative depends on at least one transmission interconnection with the North American grid and utilizes generation sources predominantly located off the island.

This process resulted in a number of alternatives being categorized as unsuitable for future feasibility studies. The initial screening is important as it enables NLH to concentrate further consideration on only the technologies and alternatives that offer the highest potential ensuring effective expenditure of rate payers' funds. The Grand Banks natural gas option was one such option screened out prior to this grouping exercise.

Those alternatives which were deemed acceptable for consideration and costing were grouped into two broad categories:

1) an Isolated Island alternative, in which the electrical system on the Island of Newfoundland continues to operate in isolation of the North American grid such that new generation capacity is limited to what can be developed on the Island itself; and
2) an Interconnected Island alternative which utilizes generation sources predominantly off the Island and depends on at least one transmission interconnection with the North American grid. Industry standard technology was used to optimize the configuration of generation sources in each category.

The screening process employed rigorous and proven methodologies. The Cumulative Present worth (CPW), a common metric for this industry, was calculated for each alternative to determine the present value of all incremental utility and operating costs. CPW's were then compared to confirm the long term least cost generation expansion plan. A further evaluation occurred to ensure transmission reliability was comparable and not compromised by either alternative.

The outcome of this system planning process found that the least cost option for the long term supply of generation for the Island was the Interconnected Island alternative, featuring the development of Muskrat Falls coupled with the construction of a transmission interconnection between central Labrador and the Island of Newfoundland. This recommended investment alternative has a CPW preference of almost $2.2 billion over an isolated island alternative, and is robust under a broad range of sensitivities.

Key Message No.5

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| Two least cost options were carried through DG2. Isolated Island and Interconnected Island. Interconnected island was preferred by a CPW of $2.2 billion. |

## Nalcor Energy's Natural Gas Experience

Nalcor Energy's team is comprised of several hundred professional engineers many with advanced degrees, expert in power systems design and operation. Since 2005, Nalcor has augmented this team with geophysicists, geologists, petroleum engineers and process engineers specialized in offshore oil and gas development and operations. Nalcor's oil and gas team has come from the offshore regulator (CNLOPB), large Canadian explorers and producers and the international "super major" oil companies. More importantly, most have come to Nalcor having been involved in every producing project in our offshore. Nalcor's approach to natural commercialization is shaped by the institutional knowledge of its staff that have formed and led teams in the study of natural gas development with these organizations throughout the last decade.

Nalcor Energy also has been engaged with internationally renowned firms in the area of oil and gas market and consulting including PIRA, Wood Mackenzie, and Platts.

Furthermore, Nalcor Energy over the last several years has also undertaken a series of natural gas commercialization studies with private sector partners in efforts to demonstrate a viable natural gas project for Newfoundland and Labrador.

Key Message No.6

> Nalcor Energy's team includes oil and gas specialists with specific experience in studies for the commercialization of NL's offshore natural gas.

## Nalcor's Involvement with Natural Gas

In July 2007 Nalcor issued a call for Expressions of Interest (EOI's) for Engineering and Feasibility Studies for Domestic Natural Gas Transport and Natural Gas Onshore Storage Systems. At the time, Nalcor decided on a phased approach (first to study CNG, then LNG, and finally Pipeline options) in keeping with the priority of its offshore partners who had turned away from pipeline options in favour of the understanding the potential of lower cost transportation options that would reach larger and more lucrative markets.

The Grand Banks gas fields, like many offshore gas fields are too small or too remote to produce by pipeline to shore. The liquefied natural gas (LNG) industry has advanced to fill the need in respect of larger gas fields by creating an "floating" LNG or FLNG production concept where an LNG processing and refrigeration plant, complete with LNG storage, is integrated into a ship or barge and moored at a gas field. LNG ships are then used to off take the LNG and deliver it to markets, where it is stored and regasified as needed. FLNG projects have many technical and economic challenges, but recently in May of 2011 Shell announced its final investment decision for the Prelude FLNG project as a testament to the work and commitment that the industry has invested in FLNG. However, a simpler and less expensive way to produce gas from many fields is to avoid liquefaction altogether and instead just compress the gas into CNG ships, which then deliver it to regional markets. Marine CNG serves markets that fall between subsea pipeline markets and long distance LNG markets. Nalcor and our offshore partners agreed that CNG required evaluation.

On that basis, Nalcor commissioned EnerSea to perform a feasibility study for production and transport of the non-associated natural gas from the North Avalon gas field in Husky's development area of the Grand Banks. This study evaluated the technical and commercial feasibility of developing and transporting gas reserves as CNG from the North Avalon reservoir to a delivery point near the proposed refinery owned by Newfoundland Refinery Corporation (NLRC) which was considered to be the "anchor tenant". All studies up to that time, whether commissioned by government or industry associations and publically available, or commissioned by the offshore operators and thereby commercially sensitive, concluded that the small domestic market for natural gas used solely for the purpose of power generation was not viable. Therefore the opportunity presented by the proposed new refinery had the potential to create a threshold market, together with power generation, that may have economic potential and thereby required study. For the study, the proposed mode of development for gas production, transport, and delivery concept assumed the use of a floating Gas Production/Storage/Shuttling (GPSS) system plus storage facilities at the delivery site. Enersea had the backing of a large Asian based multi-national, they were among the first to have "class certification" of their technology, and they were considered most advanced on design development, and were pursuing similar studies and developments with "super major" E&P companies for similar applications. Nalcor's strategy was to have the technology "de-risked" and proved by others and then to follow closely how to adapt the technology to harsh environments. As the purpose of this study was to determine the technical viability and cost of transportation leg of gas delivery, it was expected in turn to reveal the remaining netback verses the cost of the fuel oil currently being burned at Holyrood. This netback, if any, would be available to use to purchase offshore gas. In the end, the refinery proposal was abandoned, demand volumes were significantly reduced, significant technological challenges remained and further work on landing gas via CNG was suspended.

Key Message No.7

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|---|
| In July 2007 Nalcor issued a call for Expressions of Interest (EOI's) for Engineering and Feasibility Studies for Domestic Natural Gas Transport and Natural Gas Onshore Storage Systems. |

More recently, in response to spike continental natural gas prices through 2008, in April 2009, Nalcor commissioned EnerSea to evaluate the feasibility and commercial viability of the option for gas export from the same Grand Banks field to Nova Scotia with onward transport via onshore pipeline for sale to Canadian and United States gas markets. This price spike occurred just as initial results from shale gas developments were occurring. Just as suddenly as continental gas prices, the emergence of shale gas and the dramatic downward revision of price forecasts led to the suspension of that export study.

Nalcor concluded that the CNG technology risks were best resolved in other gas fields worldwide and not as part of an integral utility style development. Nalcor continues to monitor the development of CNG technology but to date no substantial advances forward have been made by the existing proponents of the technology.

Key Message No.8

> Nalcor evaluated the technical considerations of transporting for Grand Banks gas to the island as well as to North America.

In July, 2009 Nalcor was approached by Excelerate Energy L.L.C. regarding the use of Liquefied Natural Gas (LNG) to replace the existing fuel source at Holyrood. A Memorandum of Understanding (MOU) was signed in September, 2009 between the two companies which established a term of one year in which they would mutually explore the viability of the concept proposed. This concept was based on a floating Shuttle and Re-gasification Vessel (SRV) which would anchor at Holyrood during the months that demand for power on the island is beyond the existing hydroelectric supply.

A workshop was held in November, 2009 with Excelerate to explore the concept including an in-depth discussion of the technology and its uses around the world. At that time, Excelerate was operating SRV's in several locations including Kuwait and Argentina. Their seasonal operations during the summer months meant that the same SRV's were available in the winter months for use in colder climates. This seasonal arbitrage meant that the SRV would be available to dock at Holyrood for approximately five months in the winter. Excelerate indicated that they believed this could be an interim optimized solution until the Lower Churchill in-feed line was completed. In the short term, the possibility to purchase lower priced "spot" LNG showed some potential benefits; however, floating regasification is not a long term solution nor is reliance on spot gas purchases over long term contract purchases. While ship based regasification costs were advantageous in the short term, it was not a long term solution. The LNG supply price proposed by Excelerate was near residual oil parity.

Key Message No.9

> In November of 2009, an offer for a short term seasonal supply of LNG through a specialized regas vessel was proposed to Nalcor at a price that was near residual oil parity.

In January of 2011 Nalcor completed a review of a draft study by Propel Applied Energy Research Inc. entitled "Western NL Gas Utilization Study". This report explored the technologies and the potential markets of any domestic onshore natural gas resources in Western Newfoundland. Ultimately the report found that resources were currently ill-defined, but that if adequate quantities of land based natural gas were discovered, small domestic power generation could be economic as a minor supplement to existing island power supply at the time.

Key Message No.10

In January of 2011, a study determined that there could an economic onshore gas development project so long as certain criteria were met regarding resource and finding and development costs.

In August of 2011, a Memorandum of Understanding (MOU) was signed between Nalcor and Hoegh LNG Ltd. of Norway. Nalcor had been approached by Hoegh in early 2011 concerning the development of NL offshore natural gas reservoirs using Floating Liquefied Natural Gas (FLNG) technology. Hoegh is one of several leading companies worldwide who have developed this new technology and are searching for appropriate applications of this concept. This work is still ongoing in the information exchange and exploratory phase. Similar to CNG, FLNG has economics which seem acceptable at a scoping level for an appropriate resource size. However, several technical issues such as tandem offloading will need to be solved prior to the development of this technology in NL's harsh offshore environment. To date, only one major FLNG project has been sanctioned worldwide (the Shell Prelude offshore Australia).

In November of 2011, a Confidentiality Agreement (CA) with North Atlantic Refining Ltd. (NARL) was signed to jointly study the use of LNG as both a fuel stock for the refinery at Come By Chance and other potential uses on the island. To date, minimal interaction with North Atlantic has occurred as they continue to evaluate the opportunity internally prior to proceeding beyond a conceptual phase. NARL's interest would be in "spot" LNG purchases where price arbitrage may exist between the fuel currently burned at the refinery and the purchased LNG.

In February of 2012 a Confidentiality Agreement was signed with Union Fenosa Gas of Spain. The purpose of this CA was to jointly explore the potential of the development of natural gas offshore NL with a combination pipeline and onshore LNG liquefaction plant concept. While still in the early stages, several meetings have been held between Nalcor and Union Fenosa. It is our view that larger volumes of natural gas are required for this export scenario to evolve. Most recently in March or 2012, Nalcor Energy together with other Atlantic Canadian based natural gas interests met with officials of the Indian National Oil Company and their LNG subsidiaries in efforts to explore opportunities to develop and export LNG.

Many more meetings, discussions, position papers have been taken by Nalcor including discussions on the once proposed LNG Transshipment Facility at Grassy Pointe and various natural gas infrastructure owners in Atlantic Canada. Nalcor Energy has also participated in various research and development studies including in 2007 a study "Screening Study of Production Options for Labrador Gas". All these studies and undertakings are consistent with the policy actions outlined in the Province's Energy Plan to identify and evaluate the potential for in-province utilization of natural gas and secondary processing opportunities in Newfoundland and Labrador.

## Confidential Nature of Analysis

These studies, analysis, discussions participated in or undertaken by Nalcor Oil & Gas are protected under an array of confidentiality agreements. The purpose of the confidentiality agreements is to protect the proprietary technical data and intellectual property of the potential seller, customer or service provider. Confidentiality also protects both the commercial interests of both the counter party (as they have global activities and negotiations that could be adversely affected) and to protect the commercial interests of Nalcor should any proposal be advanced to a stage where negotiations with third parties would be anticipated.

As a co-venturer in the White Rose, Hebron, and Hibernia fields Nalcor Energy has access to data and information that is restricted in use, commercially sensitive, and not publically available. With this dataset, we are able to form our own opinion (verified in part by our external reserves certifier – Sproule Associates Ltd.) as to the extent of oil and gas reserves present in the offshore fields and their potential future use.

Key Message No.11

> These studies, data, analysis, discussions whether participated or undertaken by Nalcor Oil & Gas are protected under an array of confidentiality agreements.

While the natural gas is physically available for commercialization, it has not been commercialized. No arrangement exists, nor potentially exists with any degree of certainty, whereby a buyer and seller can agree mutually acceptable terms that achieves the objectives of each party. The oil companied who are the natural gas owners, have been continually engaged by Nalcor on matters regarding gas commercialization. These companies have the benefit of full transparency in the purchase requirements of Nalcor, namely being the gas delivery rate, seasonal requirements, load projections, timing, total required volumes and most recently our alternative options including capital, operating and fuel costs, yet they do not see a sufficient business case to justify their investment nor warrant their participation.

## *Why was Grand Banks Natural Gas Screened Out?*

Central to the rationale for why Grand Banks gas was screened out at DG2 is the consideration for the strategic needs of both buyer and seller in such a transaction. Chiefly, each parties understanding of and the very small market for natural gas that exists on the island and its ability to bare costs coupled with each investor's long term plans for offshore development, the significant risks of offshore operations and pipeline transportation and how such challenges cannot justify the endeavor.

Bringing gas to shore has been studied numerous times over the past decade or more. It has been studied on behalf of government, NOIA, the industry as a whole and by oil companies individually. Nalcor is privy to many of these studies and some of our key oil and gas staff were involved and engaged in the studies. It is clear from this work the low gas volumes required for our island's electricity generation does coupled with the price the electricity consumer is willing to pay does not generate the kind of return that oil companies are interested in. This has also been validated in Nalcor's discussions with the oil companies operating offshore NL and was also recently confirmed the Canadian Association of Petroleum Producers (CAPP) which represents and speaks for local oil companies and Husky Energy the operator of the largest gas field.

## *Needs of the Buyer – Nalcor Energy*

Grand Banks natural gas failed on four of five screening principles used in its decision gate screening process, passing only on the *Environmental Considerations* principle due to natural gas's lower level release of harmful emissions, including carbon, nitrogen oxides (NOx), and sulfur dioxide (SO2) when compared to fuel oil.

### Security of Supply and Reliability

While natural gas may now physically available, near term availability is focused on the White Rose field as both Hibernia and Terra Nova currently require their gas to provide pressure support. However, it must be noted that all fields, including the White Rose field, anticipate that natural gas will be needed to support future oil production. In some areas of the White Rose field, field namely in the southern most end called the "terrace" of the South Avalon area and the South White Rose Extension area (targeted for future oil development), reservoir pressure support using gas injection has been modeled and is the preferred approach in order to maximize oil recovery. The characteristics of these areas indicate that cycling gas through the reservoir with existing gas in place will ultimately produce more oil over time.

[redacted] "intra-field" gas transfers maybe viable, where one resource owner with surplus gas will send gas to a gas deficient resource owner to enhance total economic oil recovery.

Key Message No.12

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| Two of the existing fields require their natural gas to support oil production. White rose field is also considering the use of its stored gas for offshore production. |

Notwithstanding, this likelihood, a natural gas solution may have the best chance of meeting the screening criteria a the White Rose field. So focus in this discussion will be with regards to White Rose natural gas.

At White Rose however, there are the following supply risks that need to be addressed.

1. While there exists many decades of natural gas volumes sufficient for electricity production on the island, the range of potential oil reserves at White Rose indicates that oil production may continue as late to 2028, however, current trends, third party reserves depletion reports and the current approved development plans forecast oil production to only 2023. This means that any pipeline scenario using natural gas associated with oil production has a possible commercial horizon for only for 6 to 10 years. There is no certainty afterwards. What are the costs for commercially securing gas deliveries beyond 2028? Does it make sense to install a $1 billion pipeline with a 30 year design life for as little as 6 to 10 years of

use? Does it make sense to invest the hundreds of millions more in platform modifications, subsea equipment and gas production wells?

Key Message No.13

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| At best, White Rose could only offer a 10 year supply agreement. Where does the gas supply come from afterwards? |

2. Should Nalcor Energy commercially secure gas deliveries beyond oil production what would that scenario look like? Can it be commercially achieved? What other factors must be considered?

   - What price must Nalcor pay for gas to maintain the interest of the operator? It can only be concluded that Nalcor should expect to pay a price for Natural Gas that meets the needs of the seller when the seller compares its alternative returns elsewhere in the world with commensurate risk.
   - If the operator decides not to remain in the field past 2028, what are the options for Nalcor? Neither the government nor the CNLOPB can require the operator to remain in production if the operator chooses not to continue. The operator choses is own economic cut-off.

Key Message No.14

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| The provincial government cannot compel companies to remain in production. They cannot expropriate or nationalize the field. |

3. Nalcor will have to consider the alternative of relying on fuel oil for power generation compared to the purchase the FPSO and the subsea infrastructure, the cost of operating the facilities, the environmental risk and liabilities and abandonment obligations and of course, a value for the natural gas itself. Also to be factored is that the FPSO has a life design life span of 30 years. This means that its useful life is projected to end at 2035. That production facility would need to be replaced. With what? How much would it cost?

Key Message No.15

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| To secure gas supplies beyond this timeframe a wholesale purchase of the license area would likely have to occur. |

4. Consideration of tying in Hibernia gas post 2028 is highly uncertain. Hibernia is a very successful oil producing project. The predicted economic life of the Hibernia Field has been extended and recovery efficiency improved by repeated contact with lean gas. Hibernia concluded in the DPA submission for Hibernia South that, *"As a result, over 2.8 Gm3 (100 GCF) of additional gas may be required to maintain voidage balance in the gasflood than can be provided from the waterflood. Alternatives to optimize produced oil will be evaluated in the case of insufficient gas to replace voidage. For example, in 2007 waterflood production declined to a point that insufficient gas was produced to maintain gasflood production at*

*well capacity. This happened to an extent that gasflood production was cut back and gas compression capacity was not fully utilized."*

Hibernia continues to review its gas injection strategy and has concluded, *"Prior to any gas sales, produced gas beyond operational needs for fuel and flare will continue to be re-injected in the reservoir for storage, and to support oil recovery. Optimization of oil recovery will be a major factor in timing of gas commercialization. Gas sales should be delayed until exploitation of the oil resource is well advanced to optimize oil recovery…A number of other factors are also essential to the viability and timing of commercialization of Hibernia gas resources. Firstly, markets must provide long term demand and prices to support gas development. The Newfoundland and Labrador market alone is not anticipated to provide sufficient demand to support Hibernia gas development during the project timeframe."* Reinforcing the current reality at Hibernia, oil reserves are continuing to increase, even since this DPA was issued. Clearly, access to natural gas is important for oil production and it is too early to determine when and if natural gas will be available commercially.

While drilling over the past decade has added significant oil volumes that same cannot be said for known gas volumes. More than 165 wells have been drilled since 2001. While more oil reserves have been added to reserves reports, there have been no reported discoveries of unassociated gas. This is not surprising as the companies are targeting oil plays. Drivers for commercializing natural gas have not improved based on an expanding reserves base.

Key Message No.16

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| Hibernia is not an option. Gas sales should be delayed until exploitation of the oil resource is well advanced to optimize oil recovery. |

5. Unlike harvesting our own hydropower or relying on our own thermal plant with readily available residual or fuel oil, utilizing Grand Banks gas means that consideration must be given to extending a "utility mindset" to the offshore operating environment. This may be achieved through a combination of technical and commercial requirements or contingencies that are not typical of a conventional pipeline "interruptible" gas delivery stream where other sources of natural gas can be acquired by the customer to address momentary shortfalls due to planned and unplanned maintenance and shutdowns. This is likely to be a complex arrangement with no mutual alignment of interests.

Key Message No.17

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| A unique commercial arrangement with utility provisions would have to be applied against a traditionally interruptible offshore production process. |

6. Back-up onshore fuel oil supplies and storage would are required even with a natural gas pipeline. It is not unlikely that we could experience offshore facility availabilities of less than 85%. Given the frequency of platform shutdown and maintenance offshore, even for a

Grand Banks natural gas option, it is likely that 10-20% of the fuel consumed at Holyrood would not be natural gas but rather fuel oil. Conversely, the offshore operator still needs a gas storage capability for those times of the year when gas is not needed or when the gas buyer's requirements are less than the associated gas being produced offshore. While a timing deferral of gas storage wells maybe achieved, they cannot be avoided altogether.

Key Message No.18

Over 15-20% of the fuel consumed would be back up fuel oil for when the offshore production would be interrupted.

7. Reliability of the gas production train is of particular importance if gas supplies were dependent on only one well. While the associated gas stream (gas produced with oil in oil wells) may come from several oil producing wells the levels of associated gas will be deficient for the most critical winter months when demand is highest and gas deliveries are required to be in excess of 80-100 mmscf/d. With no mobile drill rig in the field after 2025, any offshore well problems requiring workovers or sidetracks may take a year or more to rectify.

Key Message No.19

Single well reliability or even reliance of availability mobile drill rigs for work overs or well maintenance could render loss of gas supply for a year or more.

## Risk and Uncertainty

Risks in offshore oil and gas production are well known and widely acknowledged. The nature of the oil and gas industry has seen the evolution of land based production evolve to the offshore driven primarily by the growth in global demand and the limitations is economic supplies onshore. Even oil and gas companies with established track record in offshore development will always choose onshore production over offshore production if their economic benefits are equal because of the increased risks to offshore development. Does it make sense therefore for Nalcor to increase its supply, reliability, economic and environment risks if there are lower or even similar economic alternatives more readily available? What are some of the particular risks to pipeline gas for electricity development?

1. Iceberg scour is a chief concern. Direct lay on the Grand Banks is not without risk. On the Grand Banks of Newfoundland and Labrador where natural gas has been discovered, icebergs pose a high risk of damage to subsea gas pipelines, especially considering the fact that large icebergs can cut a trench in the seabed several metres deep. At this point, it is not even clear that adequate trenching on the Grand Banks can be achieved. The oil industry is currently engaged in study work to determine if an adequate trenching system relevant to Arctic and Subarctic waters can achieve this. The Joint Industry Project (JIP) is sponsored by the Hibernia, Terra Nova, White Rose and Hebron Projects. The goals of the new trenching system will be a system which is capable of: a) trenching to depths greater

than current industry norms (burial depths greater than three meters, with potential trench depths as much as seven meters); b) trenching in soil conditions that are difficult and highly variable, including the presence of boulders; trenching in water depths beyond the majority of trenching requirements (water depths up to approximately 300 meters); and d) operating in harsh marine conditions (for example, the Western North Atlantic).

Every study into pipeline routing on the Grand Banks have concluded that that there is a risk of iceberg scour and that threat must be overcome or managed before any investment would be undertaken. At this point industry broadly believe that the best routing of a pipeline is not the direct route, but rather an indirect route off the shallow Grand Banks in order to avoid iceberg scour. This route would nearly double the straight line route to over 650km.

Key Message No.20

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| Iceberg scour risk has not been mitigated. Very recent JIP hopes to shed more light on this risk. |

2. Gas production well performance is risk. There will be a need for at least one gas producing well in any piped gas scenario. Gas producing wells can fail (mechanically) for a variety of reasons. Vulnerability in the specialized downhole equipment or the surface mounted X-mass trees, wellheads and control systems can cause failures at rates of 1 with every 10 years of use.

Key Message No.21

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| Gas production well performance risk with limited redundancy. |

3. The extreme cold water temperatures in this area also severely hamper the movement of natural gas through the pipeline. The presence of carbon dioxide ($CO_2$), hydrogen sulphide ($H_2S$) and free water can cause severe corrosion problems in oil and gas pipelines. Internal corrosion in wells and pipelines is influenced by temperature, $CO_2$ and $H_2S$ content, water chemistry, flow velocity, oil or water wetting and composition and surface condition of the steel. A small change in one of these parameters can change the corrosion rate considerably, due to changes in the properties of the thin layer of corrosion products that accumulates on the steel surface.

Key Message No.22

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| Hidden and localized corrosion could prematurely put the pipeline at risk. |

4. The multiphase flow (gas and liquid) in a pipeline may have some advantages with respect to landing a "wet" gas onshore for recovery of natural gas liquids (NGL's), should there be a local market. The disadvantage of this option is the pipeline must be operated at a higher pressure (more expensive) and has to have substantial liquids receiving facilities (slug

catcher) to cope with operational interruptions of the pipeline. Furthermore it requires a totally coordinated approach to development and control operations as all primary field owners will have to keep the gas in the dense phase, whatever the composition of the well fluids and whatever operational difficulties they might be facing. Moreover the liquids volumes expected would only range between 500-1500 bbls/d likely too small to warrant the incremental pipeline system costs.

Key Message No.23

Multiphase flow requires more investment in slug catchers with potential pipeline integrity issues. Also requires active management of flowstream which could have impact on oil production.

## Cost to Rate Payers and the Financial Viability of Non-Regulated Elements

The total capital costs of a piped gas solution can be estimated to be in excess of $3.3 billion. The present value of the 10 year stream of operating costs is in excess of $XX, not including the cost of the gas itself. Estimates are class five estimates (+100%/-50%)

Nalcor estimates the following cost for a 10 year gas delivery. Extending the service beyond 2028 will require and replacement of the existing FPSO and a purchase of the hydrocarbon rights from the license owners. This is not a realistic commercial opportunity that could be modeled at this time. The license owners would simply not be interested in such and advance "sale" nor would it be reasonable to expect either party to place a valuation on such a transaction.

| Element | Cost ($2012) |
|---|---|
| **640 km 14"** pipeline (partial trench) | $1.0-1.5 billion |
| **FPSO modifications** | $200-250 million |
| **Gas producing wells (2)** | $150-200 million |
| **Subsea** modifications/tie-in | $100-300 million |
| **Onshore slug catcher/terminal** | $50 million |
| **3x170 MW CCGT Power Plant** | $900 million |
| **Offshore** operating costs (boe share) | $60-250 million per year |
| **Onshore** operating costs | $30 million per year |

The rate of return on the capital costs would be required to be in excess of 15-25% to be comparable with the level of risk and the alternatives provided to the unregulated portions of Nalcor and the offshore operators. The required price of natural gas delivered to a new CCGT generation plant would be in excess of $XX mmcf. This is higher than our current cost of fuel at Holyrood.

Key Message No.24

At more than $3.5 billion capital for a 10 year investment, the required price for Natural Gas exceeds that of fuel oil.

## *Needs of the Sellers – the Oil Companies*

### Rate of Return and Global Investment Options

Once oil companies offshore NL, are granted a production license, they in essence own and control the type of development that occurs on the license subject to the approvals of the CNLOPB. The decision to invest billions of dollars in a natural gas development is based on a determination of which project provides the greatest return on investment – a company's chief obligation to its shareholders. Oil and gas companies have to decide whether the price paid for the gas will exceed the cost of development and production by enough to make the project worthwhile. The project must have the potential to provide a reasonable return on an investment of hundreds of millions or even billions of dollars. Furthermore, are there other options for the operator worldwide to deploy their competence and expertise for greater return in growth sectors verses expending effort and on fixed terms and durations?

Production costs are affected by many variables, some of which are obvious — such as the nature of the geology where the gas is located, the physical environment in which the gas field is located or the distance to the marketplace, which adds to transportation costs. Other important but less obvious variables include government taxes and royalties, the complexity of the regulatory process and political stability. In making a development decision, companies try to predict all costs over the life of the project and compare them with the potential price for the gas. Then they compare the costs and profit for a particular proposed project with those of competing projects in other parts of the world. The oil and gas industry is truly a global industry and proposed projects must be globally competitive. Many major exploration and production companies have holdings in various parts of the world from which to choose potential projects for development.

Key Message No.25

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| Any investment by oil companies must meet their global alternatives. |

### Strategic Options for Future Development

What are the operator's plans beyond going forward? It can be safely assumed that the operators are in business to produce oil. Natural gas is a means by which operators derive greater oil production. Any commercialization of natural gas therefore must first consider that oil production must not be jeopardized. Oil companies (like utilities) invest for the long term and generally select the most robust projects and seek to keep their options for enhancement and expansion open until those opportunities are at risk of disappearing. This way, as oil and gas being both a non-renewable resources, incremental value is usually attained by waiting for greater market certainty through appreciation of resource base, market share or commodity price or some combination of all three.

In the case of offshore gas, the priorities are likely to be:

1. Offshore power.
2. Offshore oil production pressure support.

3. Once oil is depleted or additional significant un-associated natural gas resources identified, export to larger oil-indexed LNG markets.

Key Message No.26

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| Natural gas is playing an important part in oil production. Oil companies will not want to jeopardize this. Likely only the prospect of a large export LNG project will encourage commercialization of natural gas. |

# Globally Supplied LNG for Electricity Generation

## Introduction: Imported LNG

Natural gas is expensive to store or transport in large quantity. These two factors are the core reasons natural gas prices can be far apart between different markets, especially between distant international markets.

- LNG prices are typically set on the principle of alternative cost. Meaning, suppliers in an under supplied market will command prices up to the next best alternative cost that the buyer is paying. This is why historically LNG sells on long term contracts referenced to oil.
- Geographical separation adds costs to transportation, sometimes dramatically creating regional markets.
- LNG is the most cost-effective and most flexible way to minimize inter-regional differences in natural gas prices but even this solution is far from ideal and has not yet created a global market price for gas.
- Liquefaction projects have always been expensive and time-consuming to execute. New ones are ever costlier as the LNG industry has had to overcome more challenges than the past. It employs expensive methods such as extracting expensive coal bed methane for feedgas or sourcing gas in distant offshore locations. Even after growing for decades, LNG trade represents only a small portion of global gas trade and its influence on global gas price overall is rather limited.
- LNG export projects are usually "built-to-order" to meet demand and their outputs are locked into multi-decade sale and purchase agreements. Short-term, or spot, sales represent a relatively small portion of the market and whose availability. Availability of spot volumes can suddenly become restrictive, which may prompt bidding wars between competing buyers.
- Long-distance LNG transportation is time- consuming and expensive. The longest route can last about 40 days each way. LNG cargo movements are mostly intra-regional as a result.

Hence, high costs erect high barriers to exportation of natural gas over long distance transportation time delays response time and constrains inter-regional influence on prices (i.e. it inhibits true arbitrage); and fulfillment of rigid contractual obligations keep most cargoes from being diverted even when and if other markets may become more desirable. All these factors limit the possibility to obtaining a uniform global price. Notwithstanding, LNG links together markets that were once separate through global competition, with gas on a ship open to diversion to a higher-priced market in a way that gas in a fixed-route pipeline never was. For example, in an island economy like the UK, which is emerging as Europe's biggest LNG buyer as its North Sea natural gas production declines, cargoes have been delivered from as near as Norway and as far away as Australia.

Key Message No.27

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| LNG is a high cost endeavor. LNG trades in an inefficient market predominantly linked to oil prices. |

## LNG Markets

There are currently six significant regional markets importing LNG – Northeast Asia, Continental Europe, North America, the UK, Southern Asia and South America. Two of these – Northeast Asia and Continental Europe – have developed their gas industries based largely on imported supplies. Two others – the US and the UK – have developed their industries based on indigenous natural gas, but have become significant potential LNG importers after a history of relative self-sufficiency. The last two – Southern Asia and South America – have had comparatively small gas industries based on local production, but now envision substantial growth based on imported supplies.

Not surprisingly, the markets differ significantly not only in the balance of energy sources that compete with natural gas but also in the logic of regional gas pricing. Gas pricing in Northeast Asia and Continental Europe is a product of the price negotiations that buyers have had over the years with their suppliers who wanted to get the highest possible netback for the depletion of their national resources. On the other hand, both North America and the UK have liberalized their gas industries, and their gas pricing has reflected competition among indigenous suppliers for outlet. Upstream taxation in both countries applies equally to all producers and can be treated as a cost when the seller decides on pricing. In Southern Asia, China and India – newly emerging LNG importers – have a history of local gas pricing that has been heavily influenced by regulation and has been largely oblivious of the price structures at which LNG is traded internationally. South America has emerged similarly as it has source contracts from both suppliers to the North American and Asian markets. The concept of a uniform international approach to LNG pricing may be a theoretical ideal, but it is far from a reality in current LNG markets.

Newfoundland and Labrador has characteristics most similar to Asia island states like Japan or Korea where there are no indigenous supplies, isolated from pipeline networks, is seasonally variable, has no natural storage capability and is heavily reliant on crude oil for base load power. Yet Newfoundland does not hold any of the market scale advantages for Japan or Korea. Newfoundland's demand for LNG will be less that 0.5% of global supply.

Key Message No.28

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| A NL LNG market will have characteristics most similar to Japan without the market scale or buying power. |

## Cost verses Price

Currently there is no consistency of contract prices or pricing formulas across regional markets. The only certainty in LNG pricing is that price can never be consistently below cost; therefore, cost information is useful in establishing a floor price but is otherwise of limited utility especially when demand outpaces supply. This is the situation for the foreseeable future. Since construction of a natural gas liquefaction project is meant to meet demand of specific buyers, pricing can and often do differ in each case. Though for a seller, obtaining a price that renders a profit that meets a given hurdle rate of return is technically all that is needed to sanction a project, sellers will understandably want to elevate the selling price as high as possible. In an undersupplied market, LNG sellers will always look to the market for what it can afford to pay based on the buyers alternatives. In Newfoundland, that alternative for the near term is No.6 residual oil (heavy fuel oil). In our future that choice of fuel would make way for a more efficient but more costly No.2 fuel oil (light fuel oil).

These are some of the factors a seller will consider. Many of the conditions below now permeate the Asian market. As a result, many prospective LNG marketers are targeting Asia. Even though many sellers in the Atlantic Basin will have trouble successfully executing trades to Asia, it will not stop them from using this as a negotiating leverage.

- Extent of global LNG demand/supply balance or imbalance. (Supplies will be tight to under-supplied for the foreseeable future.)
- Buyers' alternatives such as nuclear energy, domestic gas, and pipeline gas imports, and other competing LNG sellers.
- Ease of seller to supply a given buyer and conversely the difficulty of a buyer to find an alternative seller. (Scale of purchase is a lever.)
- If the seller is in a "distressed" condition. For example, if it has an incomplete subscription for a total supply volume and that deficit prevents investment in the export project. This is rare condition and a feature of timing that only the largest of buyers can optimize.

Key Message No.29

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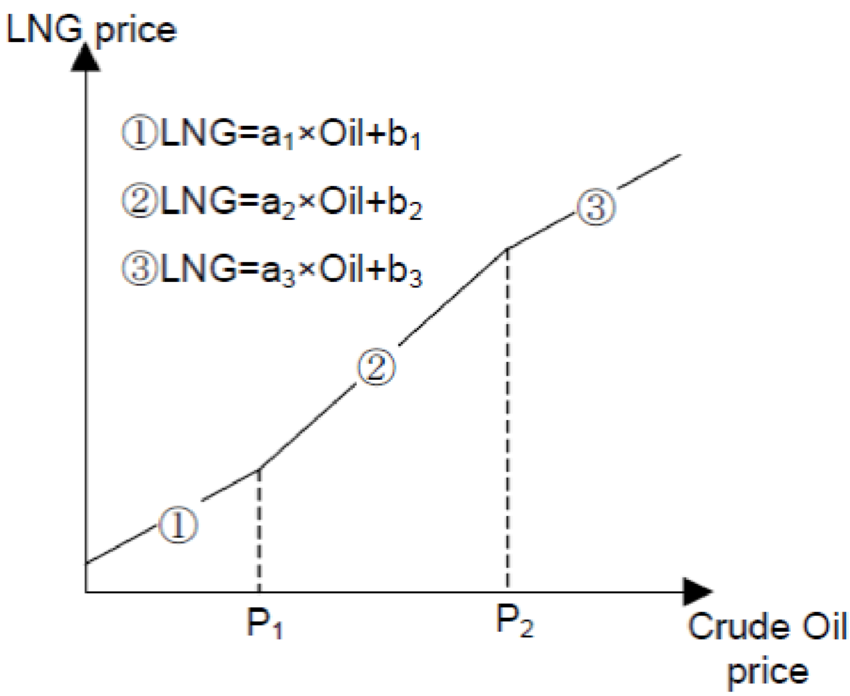
| In an undersupplied market, LNG sellers will always look to the market for what it can afford to pay based on the buyers alternatives. |

## Asian Market Dynamics

LNG is mainly bought and sold through long term bilateral contracts of over 15-20 years rather than on the basis of a traded market price. In negotiations for these long term contracts, the transaction price is determined by the buyer and seller agreeing to a price formula indexed to crude oil prices. The price formula is negotiated in the context of market circumstances such as the balance of supply and demand and crude oil prices, so a variety of formulas are used depending on the circumstances at the time. The formula conventionally used to be a linear formula directly proportional to crude oil prices, but from the 1990s, mainstream formulas have used S-curves with the slope determining the proportional relationship to crude oil being a gentler slope at low price bands and high price bands than at middle price bands. The use of the S-curve represents the spirit of mutual aid between buyer and seller, alleviating the seller's risk of declining earnings at low price bands and alleviating the buyer's risk of increased costs at high price bands. The buyers appreciate the need for this spirit of mutual aid in long term contracts, but in view of the recent high crude prices sellers are now calling for linear formulas to avoid the opportunity loss at the top end of the S-curve.

In practice, LNG price formulas index to the crude oil prices for several months ahead, at certain price triggers a different behavior in the relationship between prices would occur. In the chart below a simplified model of LNG Sale Purchase Agreement (SPA) is shown. Between $P_1$ and $P_2$ a linear relationship in price is exhibited between oil and LNG. At oil prices less that $P_1$ the relationship changes to protect the seller. At prices greater than $P_2$ a change in the relationship between prices protects the buyer.




Recently however, the rise in oil prices has had another major effect. The price caps and S-curves that were designed to prevent oil market upsets from influencing LNG prices had the effect of holding down LNG price increases as oil prices rose. If the new oil price levels are assumed to be permanent, rather than temporary, then the price-capping mechanisms have effectively broken the traditional link between oil and LNG. This is evident in the growing divergence of existing contract delivery prices.

The net effect of these developments has been to create a very difficult environment for the LNG contracting process. Sellers contend that the new high prices for gas represent the new world market price for gas. Buyers do not see why they should pay such higher prices since they do not appear to be driven by higher costs. The negotiation leverage however swings to the seller in the undersupply market place. Recent contracts in Asia have seen these price caps removed.

Other trends in LNG contract pricing are appearing. There also has been some interest in abandoning the Japanese Crude Cocktail (JCC) measure of oil price levels in contract. The JCC, while transparent, suffers from two problems. First, it does not represent a more freely-traded crude oil, such as North America's West Texas Intermediate (WTI) or North Sea's Brent. And second, the average crude oil into Japan is comparatively heavy, while LNG is expected to compete with lighter, low sulphur crude oils.

One Asian contract reportedly utilized Brent as a measure of crude oil pricing this is in addition to the effort to eliminate the price capping mechanisms altogether. This trend would eliminate the de facto de-coupling of oil prices and LNG prices that the caps and S-curves have provided and drive LNG prices higher.

Key Message No.30

LNG indexation will not disappear for foreseeable future. Leverage remains with the sellers. New trends in contract renewals are seeking to close the oil/gas gap that has emerged in recent years.

## European Market Dynamics

European gas markets offer two distinct types of gas pricing that are both accessible to LNG markets. Spot gas prices dominate in North West Europe, while the rest of the Continent is largely under the auspices of oil indexation. The difference between these two prices can be significant for long periods of time. While oil-indexed gas price markets offer higher returns for sellers, they are much more difficult to access than markets dominated by spot gas. In an oil-indexed market, a buyer (or two) of the LNG cargo is needed and the sale typically will occur in a market where access to either the LNG terminal or the downstream network is more limited than in a market such as North America, the U.K., or the Netherlands. The original goal of this pricing system was for gas to be able to compete against gas oil and fuel oil in the residential/commercial and industrial sectors respectively. In a market driven by spot prices, LNG is sold to the market itself without a buyer necessarily attached to the sale. The seller loses some value, but gains in the form of liquidity and ease of sale.

Europe is almost always in a position to buy more pipeline gas if LNG is not available wth the noted exception of peak winter demand months. During this period, the price of European spot will climb to the level of oil- indexed prices and may even move above for brief periods, but the oil-indexed gas price in Europe should be considered the ceiling for European spot prices on a sustainable basis. Nalcor's delivery period also falls within Europe's high demand season; therefore, pricing will be unfavorable.

LNG markets can penetrate oil-indexed markets at several locations in Europe, with a predominant bias toward Mediterranean buyers. Spain, southern France, Italy, Greece, and Turkey all largely operate within the context of oil-indexed gas pricing. All of these countries possess LNG import terminals with limited third party access that can have a great deal of influence over gas prices

Key Message No.31

Europe offers some discount to oil indexation due to abundance of piped gas competition. However, seasonal demands mean oil type price levels dominate in the winter for spot sales.

## European Oil indexed Contract verses Asian Oil indexed Contract

In many analyst's outlook for oil-indexed (or "contract") gas prices in Europe and Asia, the forecast for prices in Asia will tend to be \$3-\$5.60/MMBtu higher than European contract (oil-indexed) prices. The key differences between these regional prices are twofold. First, the European price is indexed to gas oil and fuel oil, but the base price for the gas is set at or below the prevailing fuel oil parity. Prices move up or down based on a six-month rolling average of gas oil and fuel oil prices from the prior six to nine months. This simply means that European contracts will tend to lad Asian contract prices.

All European prices contain price re-openers, where the base price for the gas can be renegotiated every 1-5 years depending on the size and seasonal load factor contract. Since the recession of 2008, re-openers have become shorter and shorter in length due to market volatility and the encroachment of spot gas pricing in areas previously dominated by gas contract marketers. The loss of this contract has forced gas producers and their biggest gas marketing clients to lower the base price for contract gas from 5%-10% above fuel oil parity to levels below. This however is a localized phenomenon.

Second, Asian contract (oil-indexed) prices are tied to the average import price of Japanese crude oil. The prices are typically signed at ~90% of crude oil parity, while fuel oil prices (low sulfur fuel oil versus Brent) have averaged 80% of crude oil parity over the past decade. The key difference between Europe and Asia is that European contract prices must contend with significant competition from a highly liquid spot gas market, while Asian spot gas markets are highly limited to bilateral, over the counter deals. Asian spot prices move above and below Asian contract prices, where typically a premium is paid because cargoes are bought for the purposes of meeting peak demand. The spot market in Asia would be considerably more liquid if a location existed to store large amounts of gas at lower prices on a seasonal basis. However, most of the Asian LNG markets do not possess seasonal storage as does Europe and North America. The largest markets of Japan and South Korea are limited to high-cost LNG storage at import terminals. Therefore, spot gas is typically purchased on a need-to-consume basis. In recent years, some buyers have swapped out contract cargoes for spot cargoes to save money, but this type of activity is highly limited.

Analysts believe that most Asian buyers will continue to be willing to pay a premium for contract gas despite mounting evidence that the North American gas surplus is spreading to other markets. Besides this willingness, rising costs for new LNG export projects in the Asia Pacific region have put a high floor on the absolute minimum price on new transactions. European buyers are less and less willing to pay for oil-indexed gas at all and are angling towards a continent-wide spot market in both the judicial and political realm. Asian buyers are showing no desire to reduce exposure to oil-indexed pricing due to a lack of regional spot gas market and a lack of agreeable price indexation alternatives. With most Asian buyers having limited or no domestic production, reliance on imports is almost complete. Buyers with domestic production and a stronger domestic outlook such as China and India have considerably more leverage in negotiations. In the case of both, pipeline imports are also becoming more of an option to limit the LNG price premium. Japan, Taiwan, Korea as well as other smaller buyers do not have such an option. Security of supply is paramount for most of these countries and the sellers know it. Therefore, a premium is placed into these contracts above European oil-indexed levels to reflect more necessity and less choice than buyers in other regions.

Key Message No.32

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| While structural differences exist in both contract markets leading to a \$3-6/MMBtu price difference, the slight advantage of the European contract is not expected to impact NL prices other than to set a possible floor price +/- shipping costs. |

### Why North America supply should not be considered for NL

Nalcor understands that abundant shale gas may eventually change the oil indexation model of LNG contracts, but it will be a very slow process. While this has been the source of some academic debate, we see that oil-indexed markets for new LNG supply will be a sustaining force in the long run. In a recent interview, David Knox, CEO of Santos, an equity holder in the Gladstone LNG project in eastern Australia said virtually all the 10.2 Bcf/d of gas of planned new Australian LNG production has been sold under long-term contracts indexed to oil prices. "Our project would produce about 8 million mt/yr at a cost of $16 billion," he said, explaining that would be a high cost of production that could only be borne by long-term supply contracts indexed to oil prices. "The only way we are able to do it is through long-term, 20-year contracts based on a 15% discount to oil." With global LNG production expected to reach 425 million mt/yr by 2025, North American exports based on spot prices would not represent more than 10% of the market, so global pricing dynamics should not be changed significantly, he said. Nalcor Energy and our global oil and gas consultants agree.

While it may be argued that Newfoundland and Labrador may be able to benefit from new LNG exports from the East Coast and Gulf Coast of the U.S., it will do so at the expense of supply stability. Up to now, practically all existing LNG export projects have generally used stranded gas and/or are otherwise supported by a national oil company. In other words, domestic competition for the gas is weak and political support is strongly in favour of export projects. However, on the other hand, export projects in the U.S. East and Gulf Coasts will utilize marketable gas, which has raised political and public pressure on its prohibition. Industrial users have also lobbied against it.

In February of 2012, The U.S. Energy Department said it wouldl not make a decision on future liquefied natural gas exports until it has weighed the potential consequences of sending U.S. gas abroad. Energy Secretary Steven Chu said there was concern that exporting the nation's surplus natural gas could lead to higher prices, but that had to be balanced against the economic benefits of increasing the U.S. exports. "We're not going to do anything until we make a determination what the impact would be," Chu told lawmakers at Senate energy committee hearing on the Obama administration's budget request. The Energy Department has approved one export application from Cheniere Energy for its Sabine Pass terminal, and other companies including Southern, BG, Dominion and Sempra have also requested permission. The department is conducting a study due out later in the in 2012 that would analyze the economic effects of allowing more exports.

Even as the U.S. government issued permission to export LNG, it retained the right to revise the permit anytime. This is highly negative to LNG supply stability in an industry that has missed few deliveries in more than four decades since its inception. The several buyers that have signed new agreements to purchase LNG from the U.S. are buyers that have a diverse portfolio of gas alternatives. They have means to handle some disruption should the U.S. government interfere with cargo deliveries from a U.S. export project. In the opinion of our advisor [redacted] the degree of risk in and success of U.S. projects will require the presence of big buyers who could absorb the uncertainty. "it is not the place for Nalcor Energy."

The foreign companies have bought gas reserves in the U.S. for different reasons. Some appear to have done so in hopes of feeding the gas into LNG export plants while others may also be interested in gaining knowledge in unconventional gas production. In general, these activities are more suitable for big buyers that can tolerate the risks and integrate the activities with their regular operations.

Indeed, Cheniere, which sponsors the Sabine Pass LNG export project in the U.S. Gulf, was able to add some profit margins to the liquefaction portion of the equation in its agreements with buyers. Based on the formula in Cheniere's first contract would result in a delivered price of $9.54/MMBtu to its first customer before the costs of regasification or power generation. The company was reportedly able to elevate this price higher still in later agreements as its project gained more and more supported from the investment community. [redacted] projects that a similar contract from a Gulf Coast LNG project that can alternatively sell to Western Europe should demand at least $10.21/MMBtu from Newfoundland and Labrador to maintain parity on pricing. [redacted] expects U.S. LNG volumes to be ordinarily commanding no less than Western Europe parity except for projects that need to charge less in order to attract buyers' capital infusion. Notwithstanding, reliance on US sourced LNG for supply should only be considered for spot cargos or for diversification an existing supply contract series. Neither case is advised for Nalcor.

Key Message No.33

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| There is significant risk to future LNG supplies sourced from the US. Nalcor's advisors caution against using US supply as its primary source of contract LNG. |

## South America as a Reference

Newfoundland and Labrador will need to monitor South American LNG activities closely because they are some of its closest competitors. They are eyed by some of Nalcor's potential suppliers, in West Africa and North America, not only because of their relative proximity but also their high price tolerance.

[redacted] believes Nalcor's offer price should more closely resemble European or South American prices. The main reason is that as much as suppliers in the Atlantic Basin like buyers to believe that they can target Asia, they are many obstacles to accomplish that. First, Asian buyers still prefer to buy within the region not only because to keep shipping costs at a minimum, but also because of the higher risks involved in bringing volumes from distant places. Atlantic Basin producers may overcome this by offering a small group of Asian buyers with a high degree of project participation; however, many remain reluctant to lose control on pricing. Second, [redacted] projects those South American buyers will offer rather attractive prices to sellers due to relative economic in oil substitution – similar to Newfoundland. The difference between what South American and Asian buyers are willing to pay averages only about $3/MMBtu from 2017 onward. For an Atlantic Basin seller, the $3/MMBtu difference will be greatly diluted by the much higher transportation cost to Asia. This also entails seeking capital to build extra LNG tankers at great costs. Regardless of who is responsible for shipping (i.e. FOB versus DES sales), someone will have to commit at least hundreds of millions of dollars upfront to build these expensive vessels.

Nalcor should expect to pay in 2017 in excess of $16.21 MMBtu for LNG in competition with a South American buyer for LNG from West Africa.

Key Message No.34

South American buyers will be in the same market at the same time as Newfoundland considering 2017 deliveries and are likely the closest analogue. Forecast prices there fall between Asian European contracts.

## Newfoundland LNG Market Price

The development of import dependence – whether the gas sector was developed on domestic gas or based on imported gas – plays the decisive role for differences in pricing mechanisms which developed in different regions. Countries whose gas consumption can predominantly be covered by domestic production have regulatory control of supply (upstream) and demand (downstream) and thus a major influence on the gas pricing mechanism. These are areas like the US and the UK. Import-dependent countries have little influence on the regulation of the supply side; these areas are similar to Asia. While Newfoundland is physically located between the US and the UK, our market price will more closely resemble that of Asian dynamic or even the emerging markets of South America. The nearby UK and European Contract market may provide the "floor price" reference where a seller should accept no less than what is offered there; the ceiling will be residual fuel or diesel fuel as the case maybe.

Notwithstanding the financial crisis in 2009, slowing global energy consumption combines with the retreat of the U.S. from LNG importation to loosen LNG supplies; there is consensus from analysis that this will be temporary. Not only has growing demand in China and India, among other countries, continued to call on more LNG supplies, the nuclear power situation in Japan has all but guaranteed that the country's power utilities will have to resort to burning more LNG to avoid shortfalls. This pits Nalcor, a relatively small buyer against some of the world's largest LNG buyers. It is highly improbable that bargains will exist. Additionally, considering that other large buyers will have a better negotiation leverage through their sheer size and via potential capital infusions into liquefaction projects, we project that Nalcor must pay at least a comparable price as other buyers.

For new supplies to begin deliveries in 2017, Nalcor will be in the market at the same time as several main categories of LNG buyers:

- Asian oil indexed buyers and Japanese buyers in particular that must depend on more LNG in place of nuclear power since the earthquake in March 2011. The incident not only destroyed a number of nuclear reactors from the country's power generation portfolio, it also dimmed the long-term prospect of nuclear power in Japan in general.
- Rapidly growing economies such as China and India. The buyers in these countries are also more aggressive than other Asian countries in securing rights to supplies in the Atlantic Basin, which is otherwise the logical choice to supply Nalcor.
- Relatively small LNG buyers in Asia such as Singapore and Thailand. These are price-takers that must accept prices that are set by other trades within the region.
- Oil substitution markets of island economies like Hawaii and isolated costal markets like South America.
- Oil exporting countries that can save more oil for exports by using more gas domestically.

- Continental European markets which offer both oil-indexed and spot-based markets that are influential in global LNG pricing, especially for export projects that do not target the Asian market.

The majority of these markets use oil as a price reference, although the actual mechanic and motivation can be quite different.

Key Message No.35

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| European oil-index contract is the floor price reference. Full oil parity on a substitution basis is the ceiling. This range of fuel cost plus the cost of regassifcation plus new CCGTs offers no clear advantage over the isolated island scenario. |

## Contract Renewals

Most long-term LNG contracts last about 20 years. This is mostly related to the need to spread the high cost of LNG construction over a long payback period, but it can also be related to other matters:

- Reserves issues. An LNG producer needs to be secure that there is enough gas to fulfill its LNG contracts. Similarly, LNG buyers need assurance that their supply contracts can be honored.
- The selling or buying party or both do not want to be locked up with the same counterparty for an even longer period of time.
- Potential structural changes that are not foreseeable. There are always limitations in the ability to forecast. By the end of a 20-year forecast, its accuracy is tenuous at best. Most planners would rather wait and re- evaluate later. Thus, they avoid committing too much too early.

Contracts in the Atlantic Basin have had a greater tendency to end without a renewal. For example, some contracts with Algeria, including those with the U.S. ended as scheduled without any extensions. Those that got renewed were extended by a much shorter duration and sometimes at lesser volumes.

Analysts expect this trend to continue. The further into the future, the more likely the volumes in renewals will be lower and the duration shorter. [redacted] believes that more sellers will want to explore other potential sales opportunities such as ever more liquid spot sales or sales to higher priced markets. These export projects will have paid off their debt and no longer truly need as steady a stream of revenue so they can afford more volume risks in pursuit of higher sales prices.

Should Nalcor obtain a 20-year LNG supply contract and begin imports in 2017, its first contract with expire in 2036. In general, our advisor, [redacted] advises LNG buyers to presume that a new long-term LNG contract that is signed now will NOT be renewed. This is both based on observations of past events and the expectation of the future. Many factors can certainly change today's views on global gas developments and global gas trades. Overall, [redacted] expects that LNG trade will become far more developed especially in spot trades thanks to LNG importing locations proliferating worldwide. This prospect adds considerable price risk in the future. Pricing of LNG will be far less stable because it will respond to market changes near and far. The volatilities that have been observed in other commodity markets, including oil and metal, will also apply to the LNG market. Needless to say, large parties will exert far greater influence than small ones in price directions.

At best, a price formula that applies to one contract at one time can only be used as a reference for later negotiations and rarely for direct replication. This degree of unreliability is further worsened if the energy market (i.e. including not only gas but also other fuels such as oil) has gone through rapid supply-demand changes such as the last decade. At worst, it gives a mistaken impression that the formula can be duplicated because timing and other individual circumstances can radically alter the outcome.

Key Message No.36

There is no certainty in contract renewal. Likely the best leverage is in the first contract. Subsequent contracts mean that the buyer has become "dependent".

## The Newfoundland LNG Case

Our advisor, PIRA has never encountered an LNG market that is comparable to Newfoundland and Labrador (NL). Its projected degree of dependence on one single fossil fuel, LNG, for thermal power generation is almost exclusive. Even Japan, probably the best known case of import dependence, has a much more diverse energy supply portfolio. Even when the consideration is expanded to include pipeline natural gas, whether via domestic production or imports, PIRA is unaware of any market that relies so much on just one fuel. This dependence on a single imported fuel means that Nalcor must demand a higher degree of security of supply than any other countries. While LNG import-export in general has been dependable, disruptions are not unheard of.

Nalcor has assumed the following criteria for a potential LNG import case.

- Heat rate of 7,200 MMBtu/GWh for natural gas consumption at three new 170 MW combined-cycle gas turbine power plants.
- A minimum of 30 days of LNG buffer inventory in above ground storage.
- The LNG vessels used will be of a capacity of 145,000 m3. This capacity in this vicinity is currently referred as a "standard" size.
- Each LNG tanker will deliver a full cargo at each discharge. Partial loading and partial delivery are technically possible but relatively uncommon.
- The LNG import terminal will have only one jetty; therefore, it can receive only one LNG carrier at a time.
- The import facility is to utilize a submerged combustion vaporizer (SCV), which returns the LNG to gas form. SCVs do not create water discharges and are common in locations that have stringent environmental standards. However, this kind of vaporizer uses natural gas to heat the LNG. Therefore, 2% of LNG imported will be consumed in the vaporization process.
- Each cubic meter of LNG expands to ~615 cubic meters of regasified natural gas while each cubic meter of natural gas is equal to ~37,660 Btu (average for OECD imports and typical for North America).
- Each LNG tank at the import facility has a capacity of 180,000 m3. In order to fulfill every requirement such as maintaining sufficient LNG for at least 30 days at least two LNG storage tanks of 180,000 m3 will be required for approximately the first 10 years of operation.

Afterwards, an additional third tank will be needed and this will satisfy the same requirements until at least 2067.

On this basis, the optimal amount for Nalcor to contract initially is the equivalent of 8 cargoes per year. Most contracts allow for some ramp up volume in the initial years while an assumption of a one cargo reduction per year is not out of the norm. Based on load projection, it will be 2030 when before we need to secure one extra cargo above the contracted amount.

We estimate that the two LNG storage tanks that are required from commencement may cost upward of $400 million to construct, with the jetty, vaporizer, LNG pump, etc. to account for another $450 million of construction costs. On a class 5 estimate basis, Nalcor should expect to spend $900 million to $1 billion on the construction of this facility that will consist of two storage tanks. About 10 years after operation, a third tank will become necessary and it should expect to spend no less than $250 million for its construction.

PIRA has never encountered an LNG market that is comparable to Newfoundland and Labrador (NL). Its projected degree of dependence on one single fossil fuel, LNG, for thermal power generation is almost exclusive. Even Japan, probably the best known case of import dependence, has a much more diverse energy supply portfolio. Even when the consideration is expanded to include pipeline natural gas, whether via domestic production or imports, PIRA is unaware of any market that relies so much on just one fuel. This dependence on a single imported fuel means that Nalcor must demand a higher degree of security of supply than any other countries. While LNG import-export in general has been dependable, disruptions are not unheard of.

The capital and operating costs of the regas facilitates will add between $6-10MMBtu to the delivered cost of LNG before that LNG is converted to natural gas.

At this level, LNG imports on South American or any other oil-indexed contract basis offers no clear advantage to our current isolated island alternative.

Key Message No.37

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| Delivered LNG prices plus capital and operating costs show that LNG imports on South American or any other oil-indexed contract basis offers no clear advantage to our current isolated island alternative in contract renewal. |

## Conclusion

In conclusion, both Grand Banks gas and imports of LNG to fuel power generation have been screened at DG2. Furthermore, natural gas does not compete with hydropower's superior emissions advantage, it would not provide much needed power for Labrador development, nor would it enable the strategic linkage through transmission to the continent. Even with the development of the Muskrat Falls project, Nalcor Energy together with our offshore partners remains committed to commercializing our natural gas resource. The full utilization of our energy warehouse can only be achieved by using all our available energy endowments to the greatest commercial extent possible.

Screening these options out on the criteria most important to the province and its electricity consumers is justified on both a risk and economic basis.