From:	Bruneau, Stephen
To:	Admin
Cc:	M Clair
Subject:	Request to submit information for consideration by the C.o.I
Date:	Monday, February 12, 2018 8:55:29 PM
Attachments:	Bruneau - NQ Fall 2012.pdf Bruneau - PUB sumission FEB 2012.pdf

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Greetings,

It isn't clear to me whether the Public Notice request for submissions includes the terms of investigation for those charged with conducting the financial audit. It is for you to decide whether this note belongs here or elsewhere.

I recommend that the auditors review a few papers and a presentation that I prepared in 2012 prior to project sanction. I attach two of these, one is my submission to the PUB the other is an article published in the Newfoundland Quarterly. The third and most important is to be found here: http://www.engr.mun.ca/[redacted] [Note: Third document attached to this submission.]
As a presentation/public lecture and forum on viable alternatives to Muskrat Falls. It was with disappointment that after the forum, questions were raised in the House of Assembly which led to backtracking by the sitting government and the commissioning of a bogus study of natural gas options for the island. A completely disingenuous white wash to cover the false claims of prior research by Nalcor.

It is important for Grant Thornton to know that the Oil Companies are also complicit in the failure of the sitting government to follow its own energy plan. They were all too aware of the folly of our government. The auditors would be well advised to be cautious of hydrocarbon development advice offered to them by the stakeholders with assets off our coast. The public and most in government have been carefully led to believe that natural gas is unavailable to us – and there is no-one but tenured professors or retirees that can afford the risk to call them out.

Regards,
S.E.Bruneau

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Discussion Points - Natural Gas for Island Electrical Generation.

S.Bruneau Feb/2012

Need for new dispatchable power

Estimates of Newfoundland Island demand forecast are a matter of public record, and essentially reflect a modest growth between 1 and 2% per annum compounded going forward. Island thermal generation (primarily the near-end-of-service Holyrood station) is the primary seasonal capacity infill with a relatively low annualized capacity factor between 15 and 30% but with a maximum output approaching 100% capacity. This wide seasonal range suggests limited utility of non-dispatchable energy sources due to the maximization of pre-existing hydro reservoir storage and the unacceptability or water or wind spillage. Ideal replacement of existing thermal generation points to new hydro or new thermal generation for the island.

Relative value of hydroelectricity and natural gas-fired generation

Environmental stewardship suggests that electrical generating options that lower atmospheric emissions of CO2, NOx and SOx (and other particulates) are preferred. The reduction in CO2 emissions when electrical generation switches to natural gas from fuel oil or coal is typically around 40%. Reductions in the harmful pollutants and particulates are even higher. The benefit of hydro-electric generation in this regard is highest amongst the realistic replacement options though not complete for various Life-Cycle-Analysis reasons. Thus the greatest environmental benefit is realized when hydro power replaces coal or oil-fired generation and much less so when hydro power replaces natural gas fired generation. For most environmental concerns, the jurisdiction in which fuel replacement occurs is irrelevant as the atmosphere is entirely fluid, mixing and non-jurisdictional. Thus where natural gas is available but is not used in favor of hydro power which may otherwise be directed to jurisdictions where coal and oil persist, environmental benefits are not maximized.

Common choice for Islands w/ isolated grids - replace oil & coal with natural gas via pipeline

The successful replacement of oil and coal-fired generation with new gas-fired generation on insolar island grids via the construction of a subsea pipeline link has occurred in Tasmania, Tobago, Sardinia, New Zealand, Ireland, Vancouver Island and elsewhere. Costs for new combined cycle dual fuel generation facilities may be inferred from recent construction projects around the world, likewise, pipeline costs may also be estimated on the basis of pipe size, length, depth, pressure/throughput, material specification and special risk mitigating expenses. To the point, the capital and operating costs for a domestic natural gas delivery and power generation system may be estimated from recent infrastructure developments elsewhere and can be shown to be a compelling economical option for electric generation on isolated grids with nearby natural gas resources.

Oil and gas industry growth in Newfoundland and Labrador

Oil production, responsible for the much improved prosperity of the Province, is moving into a mature phase in which declines and tie-ins, explorations and new developments characterize the activities. The financial, technological, regulatory and political risks have subsided to a near routine industry level as far as offshore development, operation and maintenance is concerned. The pioneering and novel technologies and bold leadership required to start the industry here necessitated the focus on oil production alone, especially where open markets for marginal reserves of natural gas were too far away to support the rate of return and net present value required for producer business interest.

Natural gas Industry background in Newfoundland and Labrador

In the late 1990's the Sable offshore energy project (SOEP) was developed. It involved the establishment of a subsea and overland (MNE) gas transmission system from an offshore N.S. gathering system to markets in the US Northest. Negotiations between industry partners and the governments of NS and NB resulted in certain withdrawal contracts for domestic gas use and/or resale. The success of those contracts and fuel transportation and re-sale arrangements have been such that Nova Scotia now considers Natural Gas to be the primary generation back-up for intermittent renewable energy supplies, it has purchased a significant ownership share of the main transmission MNE pipeline, has invested in other pipelines and is planning significant increased investment in access to natural gas as a key component in its future generation strategy. As one of the key pressures for this they cite the federal government intentions to require thermal coal units to meet GHG emission levels equal to or better than a natural gas combined cycle generating unit.

As a result of the original SOEP-MNE application for gas transmission the NEB received competitor applications for transmission rights. A compelling proposition was advanced by an independent private organization, NAPP (for whom I was regional manager of operations), to use a considerably larger transmission system for the SOEP project so as to make economical the stranded natural gas reserves offshore Newfoundland. The application was rejected as the regulator and province of NS were under considerable pressure by the energy partners of SOEP to not delay the development process. At stake for the province of Newfoundland and Labrador was future natural gas market accessibility and costs. As the producers offshore Newfoundland were focused on the oil-production risks alone there was little appetite for third party meddling in the secondary interest of a gas business – especially with others collecting secure contract tariffs for their gas while they carried the principle resource development risks. Thus the natural gas industry discussion for the province of Newfoundland and Labrador was very soundly put on ice and the third party proponents for development eventually acquiesced.

Natural Gas Industry Misunderstood

One of the regrettable outcomes of these events is the considerable misunderstanding that the informed public holds to this day – that the Grand Banks natural gas industry that was deemed too risky and uneconomical over a decade ago is one and the same as the concept for a business arrangement with an offshore producer for the supply of natural gas for domestic thermal generation. In other words, what would in most jurisdictions appear to be a very attractive business proposition to purchase nearby and surplus stranded gas for replacement of foreign oil – was seemingly passed over by those responsible for securing long term generation security for the Island. Remarkable for its absence, a good faith discussion with a producer for the long term supply of natural gas has either not happened or failed for reasons that have not been explained. It would be very unusual for an offshore producer to initiate these kinds of discussions when it would appear to contradict or interfere with local government policy or politics as would now be the case. Furthermore the business case for selling gas to a regulated government utility entity for domestic requirements is usually low risk but is also of marginal interest due to its small net present value relative to the primary business of producing oil for international markets. Thus the incentive and the obligation to put forward a business proposition for the purchase of natural gas sits squarely on the desk of local authorities, not the producers.

The Navigant report for Nalcor called "Independent Supply Decision Review" has a chapter called Consideration and Screening of Island Supply Options. In that chapter Navigant presents its assessment of the reasonableness of the supply options considered by Nalcor for Island supply. Navigant does not conduct an analysis of natural gas as a supply option, but rather defers to Nalcor's choice to exclude natural gas as an option because it was deemed by Nalcor to be commercially unavailable.

The exact source cited to support the claim of "commercial unavailability" was a 2001 report by an industry group that was contracted by Government to assess "the technical and economic aspects of developing THE offshore gas and gas liquids resources of Newfoundland and Labrador". Included were considerations for use of gas on the island for generation, however, it must be very clearly understood that the explicit and implicit purpose of the study was to look at the development of the natural gas resources in their entirety and for their transportation and sale in the North American energy grid. This fact is further obviated by the finding that a sustainable production rate of 700 million standard cubic feet of gas per day was required in order to maintain the economics of the system that they were considering. This flow rate equates to 4200MW continuous production - far in excess of all conceivable domestic requirements. In an inexplicable reversal of logic, present authorities have taken this to mean that natural gas can only be brought to the Island for domestic use today if demand for 700 million cubic feet of gas per day can be arranged. Therefore, the question of whether natural gas can be purchased from the producers for domestic use only, has neither been asked nor answered.

The depth of the misunderstanding is underscored by the apparent lack of knowledge expressed by Navigant in its summation of natural gas availability in Newfoundland. They correctly state that gas is available as an associated product from NL off-shore oil production, and are superficially correct that the nearest gas pipeline is in Nova Scotia. But the statement that gas is generally re-injected into reservoirs to maintain or increase oil production is misleading.

All Grand Banks production platforms use natural gas for power generation. In 2010, the withdrawal and use of natural gas as a fuel for electrical generation and heating was greater for Hibernia alone than was the total oil-fired energy used at Holyrood for the same year. This point must be taken in and considered carefully to fully understand the scale of the natural gas energy resources already used and/or are presently available for use. Remarkably, the quantity of natural gas that is produced, rerouted and reinjected into a storage reservoir at WhiteRose annually is considerably more than double the amount required for all thermal generation needs in Newfoundland. Since reinjection into the oil producing reservoirs is detrimental to oil production at White Rose all gas that is not used as fuel is packed away for future access if a market arises. The natural gas quantities produced at Hibernia are much higher though the reinjection in some cases is also used for supporting oil pressure and so not all can be said to be available for sale if a market were to exist. The natural gas reserves presently accessible with existing wells and production facilities is considerably greater than the total cumulative thermal energy requirement of the Island for the next thirty years, thus the long term supply question is in little doubt. Worrying to those who know is the permanent loss of a portion of the natural gas that has already made it to the surface but is reinjected for preservation. Though the exact figures are unclear it is very likely that more gas is permanently lost in this way than would be required for Island thermal needs - yet it needn't be so if arrangements to buy surplus gas were made.

The absence of effort to examine natural gas viability

The risks associated with icebergs, platform modifications or equipment additions, production disruptions and business losses are all a matter of technological and financial planning and are of the same order as those that have been carried out countless times in the past for successful natural gas developments in other jurisdictions around the world. The primary uncertainty in the argument for the viability of gas-fired generation for the island is the matter of willingness to negotiate a mutually rewarding gas price.

As an example of just how realistic it is for Producers and Government to agree on terms that are mutually beneficial recall the following: in 2008 the Province of Newfoundland and Labrador approved the decision to permit North Amethyst development by Husky, PetroCanada and itself as an equity stakeholder. The Government was pleased to point out the excellent value for all stakeholders, the quick turnaround time for the development plan assessment, and the overall good business elements of the deal. In particular the best possible overall value from the project was realized through "equity participation, royalties and local benefits". All parties were very happy.

Natural Gas Price – the only real uncertainty

Though arrangements for natural gas purchase and transport to the Island would undoubtedly be more complicated than North Amethyst Oil, it is difficult to understand how or why they could not take place, or why they would not also result in an agreement that would be mutually beneficial. The gas price remains the single greatest uncertainty in the equation as there are many factors and considerations involved. Some of those that may ultimately influence a business arrangement to purchase natural gas from a producer offshore include:

- Consideration of irretrievable losses of reinjected gas,
- North American open market gas prices,
- Natural gas royalty regime or the creation thereof,
- Replacement cost for the consumer,
- Producer opportunity cost/book value for future sale in alternate market,
- Price equivalency for gas energy used by producers on the platform
- Cost of O&M for all associated platform equip. mods etc
- Cost of well schedule and production changes to accommodate export
- Cost saving associated with market access vs reinjection handling
- Good will and mutually beneficial trading of value between partners
- Competition amongst producers for the business
- Platform and infrastructure development plans
- Upside of increased demand and new markets for greater quantities
- Potential to move oil in the pipeline or a looped line
- Value of other industrial benefits and add-ons such as a fibre optic cable

Concluding viewpoint

It is my opinion that Grand Banks (probably White Rose) gas is likely the cheapest source of long-term (30 years) dispatchable energy for island electricity generation if good faith bargaining were to take place. Dual-fuelling with oil storage on standby could provide supply security for a new thermal generating facility at or near Holyrood. Of considerable importance to note is the prospect for another fixed platform at or near White Rose. With prior arrangement, this facility may prove to be the ideal launching site for a pipeline to the Island. Many possibilities exist for gas export arrangements including third party ownership and operation of various parts of the gas compression and transmission system. The retirement of Holyrood and the construction of a new gas fired facility may also be a very attractive regulated business proposition for numerous private enterprises.

Stephen E. Bruneau

Feb.2012

NATURAL GAS BETTER THAN LABRADOR HYDRO FOR ISLAND ENERGY REQUIREMENTS

DR STEPHEN BRUNEAU

THE TWENTY-EIGHTH IN A SERIES OF ARTICLES DEVELOPED FROM REGULAR PUBLIC FORUMS SPONSORED BY THE LESLIE HARRIS CENTRE OF REGIONAL POLICY AND DEVELOPMENT. MEMORIAL PRESENTS FEATURES SPEAKERS FROM MEMORIAL UNIVERSITY WHO ADDRESS ISSUES OF PUBLIC CONCERN IN THE PROVINCE.

The Government of Newfoundland and Labrador is proposing to meet the expected future demand for electricity on the Island of Newfoundland by constructing a new hydroelectric dam at Muskrat Falls in Labrador and transmission facilities to the Avalon, at a cost currently estimated at $6.2 billion. But what if there was a much less expensive alternative to provide this energy? This article questions why the government of Newfoundland and Labrador is not exploring the potential of utilizing natural gas from the Grand Banks to provide electrical power to the Island of Newfoundland.

In a public presentation given by this author in March 2012,[1] the following points were made:

- The main challenges facing the province's electrical system are the replacement of the Holyrood thermal generating station and the need to keep pace with the Island's slow demand growth.
- There are sufficient gas supplies offshore to generate all the electricity we need on the Island of Newfoundland. There are many reasons why it would be beneficial to the offshore operators over the next decade to have a natural gas marketplace: improved oil recovery, longer development life, additional revenue streams, etc. In fact, expectations are that there will be so much natural gas that the operators will have difficulty pumping it back into storage reservoirs.
- The technology to land gas onshore is commonplace around the world and the natural environment of the Grand Banks (such as icebergs) is not a deterrent to landing gas onshore here.
- The technology for transforming natural gas into electricity is both widely used and scalable – that is, generating stations can easily grow to meet increasing demands for electricity.
- The Crown has all the authority it needs to negotiate (and, if need be, compel) the petroleum producers to land natural gas onshore.
- The better use for Muskrat Falls is to replace oil-fired and coal-fired generating stations in the North American marketplace when and if that marketplace can bear the actual development costs.

In Nova Scotia, the private energy company Encana has just built an offshore natural gas platform, drilled and completed all production wells, constructed a 175-km, 22-inch subsea pipeline, and has begun selling its natural gas to a Liquid Natural Gas facility in New Brunswick – all for a grand total of $700 million.[2] This Scotian shelf project was privately funded, has a gas carrying capacity many times greater than what we would need in Newfoundland if it were being built to satisfy our local electrical needs, and the entire development is based on a gas field that is much smaller than what is available at Hibernia and about one-quarter the size of what lies idle at White Rose.

The Government of Newfoundland and Labrador has stated that using offshore natural gas for domestic power requirements is uneconomical and can't be justified on the basis of our modest electricity requirements, so it is a waste of time to speculate on the timing of Grand Banks natural gas commercialization. And, by extension, that it is best to assume that our offshore oil operators will for decades to come do nothing commercial with the natural gas under their platforms, even as the oil play matures and associated gas volumes become excessive and problematic. Another view is that oil producers in Newfoundland simply do not "want" to commercially develop natural gas resources, thus Newfoundland officials would have to try and force them to do so at our peril, as it might jeopardize future oil exploration and development plans. Is it possible that using Grand Banks gas for Island energy needs will indefinitely be too complex, expensive, and potentially damaging or risky to oil production operations, profits, and planning?

It is more likely that the only danger in having a frank discussion with operators about Island domestic gas use is that it threatens to undermine the delicate financial assumptions and vulnerable market claims supporting the current Muskrat Falls power proposal. This is why offshore oil operators have been given zero-to-negative incentive by the Government of Newfoundland and Labrador to reveal any details on possible gas delivery strategies.

The argument advanced to date by the Government of Newfoundland and Labrador against developing the offshore natural gas resource has been that it is not yet commercially attractive for the operators to connect to the national marketplace for natural gas sales. However, this argument is disingenuous in that it does not address the issue at hand, which is whether it is economical for the Province to negotiate a purchase of, or access to, natural gas to power the Island of Newfoundland. Sadly, the argument that there is no *national* market has served as an excuse for the Crown to avoid the discussions and negotiations necessary for a mutually beneficial trade involving natural gas use on the Island. And this virtual armistice has cleared the way for the "Labrador-hydro-and-wires-around-Quebec" plan to take hold as the only viable alternative for the Island's energy needs.

Originally, Government's Energy Plan (2007) made it clear that the Lower Churchill project was to be the priority because it provides many wide-ranging social, environmental, and industrial benefits to the citizens of Labrador and, to a lesser extent, the people on the Island of Newfoundland. Thus it is a "nation building" policy, insensitive to market realities, that actually created the now-evolved Muskrat project in the first place. More recently, however, the project has been hailed not only as the lowest cost option for Island electricity needs, but as the only viable means which satisfy Holyrood thermal power replacement and future demand growth. It is doubtful that this new project justification can be maintained, but to our great loss it appears that those in charge are so far entrenched in this Labrador-hydro-for-the-Island plan that even if certain financial hardship were now revealed, some alternate justifications would emerge to, once again, make it the only viable choice for patriotic Newfoundlanders.

Here's what we stand to lose by opting out of natural gas:

- The public services and wise investments possible with the billions in savings realized by opting for a less expensive electricity generation method.
- Long term, reliable, inexpensive, scalable, and dispatchable[3] thermal power for the Island.
- In its native form, a new low-cost fuel source for industrial activities and possibly for domestic use.
- The potential to grow into a gas exporter via pipeline interconnection or Liquid Natural Gas production. These in turn would usher in a new era in offshore exploration and development.
- Extended life and productivity of oil developments, which would come about as a result of an additional revenue stream and extra gas handling options.[4]
- The Province's opportunity to have much greater stake in the longer-lived natural gas play than that of oil.
- An avenue through which Labrador shelf hydrocarbons may become monetized.
- A miniscule environmental impact, including a tiny ecological footprint and low risks compared to most other energy sources and megaprojects.
- And an opportunity to develop and manage the Churchill River hydro resources to its full extent and capacity in an economically optimal manner, at a time when markets want it and will pay for it.

What we get by opting out of natural gas is a remote source of seasonal power for the Island, a huge debt beyond all proportion to the domestic utility service that it renders, a very expensive interconnection with Labrador that does not improve system reliability for either Labrador or Newfoundland, and a follow-on interconnect with Nova Scotia which apparently allows us to give them free power and compete with Quebec's cheaper surplus power elsewhere.

Recently it was suggested by a Crown official that the case made for Grand Banks gas utilization at the previously mentioned Harris Centre Forum in March 2012 was appreciated, but flawed for a few reasons:

- *No costs for well-drilling, platform modifications, or ongoing operations were taken into consideration in the assessment.* I raised this point myself during the presentation, stating that it was beyond the abilities of any one person to perform all the analyses required to come up with these costs. For instance, the White Rose/North Amethyst oil developments require new wells and development plan amendments for meeting gas storage challenges. Whether the gas is sold to the Island or not, wells have been drilled and will need to be drilled to handle the surplus gas. Determining

how the costs should be divided is a complex task best performed by operators, Nalcor, and specialized consultants as part of negotiations and due diligence in proposing the "best" method of providing electricity to the Island of Newfoundland.

- *The White Rose FPSO would be too costly to operate, keep and/or replace in order to provide natural gas to the Island beyond 2026.* However, the Canada-Newfoundland and Labrador Offshore Petroleum Board, in November 2001, stated: "The Proponent describes the cost to modify the FPSO for gas export. These costs range from $75 million to $180 million..." Further, the White Rose Benefits Plan actually goes out of its way to explain the routine technology, methods, and costs for converting the Sea Rose FPSO to a gas exporter whilst oil production continues.

- *The gas was freely taken and not paid for, no value was assigned to it, and the operators were paid nothing.* This point can be charitably called a misinterpretation because the assessment given during the presentation made the clear and simple assumption that offshore producers would be paid the North American (Henry hub) market price[5] for produced gas while still stranded at a production facility on the Grand Banks. Actual price would depend greatly on the negotiated division of the capital and operating costs, royalties, and general value trading that would naturally arise between the crown and a supplier. For example, the cost of arranging for a seasonal sale of gas would have to take into consideration the optional and complimentary seasonal reinjection costs, the blending of normal gas handling operations with gas export operations, inter- and intra-field gas movements that may result, new equipment costs, etc. Clearly, the situation does not lend itself well to being over-simplified. It would be a bad idea to speculate from afar as to just what the best arrangement would be and with which operator(s) the best arrangements may be made – but it is quite clear that such arrangements can and could be made to great mutual benefit some time in the next decade.

- On the last claim by the Crown that they have no authority with which to encourage or enforce oil operators to do fair business selling gas for isolated domestic use, recall this from the CNLOPB (Nov. 2001): "... Concern was also expressed during the Public Hearing that White Rose gas might not be made available for export if gas transportation infrastructure was put in place. The Board, on its part, would expect in such circumstances that access to White Rose gas, subject to conservation considerations, would be realized through normal commercial negotiations. As discussed later, the Legislation does, however, provide the Board with authority to issue a Development Order should such a course of action be required."

It could be argued that it is an abdication of responsibility for the Government of Newfoundland and Labrador and its Crown energy company not to insert themselves into natural gas negotiations with Grand Banks operators – as they did into North Amethyst Oil, Hibernia South Oil, and Hebron Oil developments. The timing for such an intervention is perfect as a new Gravity-Based Structure is under consideration for White Rose, the shared costs for which would be of huge mutual benefit as it would provide the ideal location and structural configuration for a future export pipeline. Market prices for oil (being high) and gas (being low) are not in favor of the debt-heavy, long-term hydro-power pact, but are perfectly in step for maximizing local benefit from natural gas utilization. NQ

Dr Stephen Bruneau *is a member of the Faculty of Engineering and Applied Science at Memorial University.*

Reference

Canada-Newfoundland and Labrador Offshore Petroleum Board (CNLOPB), 2011, (www.cnlopb.nl.ca/news/decisions.shtml).

1 During a Harris Centre-sponsored public forum held on the St John's Campus of Memorial University. Watch the video at www.mun.ca/harriscentre/policy/memorialpresents/2012b/2012b.php.

2 *The Chronicle Herald*, "Encana keeps Deep Panuke, at least for now", Feb 17, 2012.

3 That is, available when it is needed, for example during periods of heavy use, like during the winter.

4 The CNLOPB, the White Rose Partners, and Hibernia Management are all on record saying that eventually gas exploitation and sales would extend the economic life of oil production by permitting additional oil to be recovered. (CNLOPB decision reports, 2001 … 2011).

5 The Henry hub is a distribution hub on the natural gas pipeline system in Erath, Louisiana. Due to its importance, it lends its name to the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange.

Grand Banks Natural Gas for Island Electric Generation

Dr. Stephen E. Bruneau March 28, 2012

The objectives of this talk are:

To demonstrate that Grand Banks natural gas is technically available and also economically compelling in the time frame and in quantities suitable for our **domestic** needs.

Provide a discussion of the technical elements, costs and possible scenarios for natural gas delivery and use for **domestic** electricity generation.

To answer common questions, expose red herrings and point out how natural gas can help meet our common goals.

Contents:

PART 1

PART 2

PART 1

Recall the Independent Supply Decision Review Mandate:

- Whether the Interconnected Island alternative represents the least cost option that also fulfills the additional criteria requirements of security of supply and reliability, environmental responsibility, and risk and uncertainty

We know that the conclusions of that Independent Supply Decision Review by Navigant in 2011 were given as:

(Means Muskrat Falls)

Based on its independent review, Navigant has concluded that the Interconnected Island alternative is the long-term least cost option for the Island of Newfoundland. NAVIGANT

☆ ... but, it turns out that ***Natural Gas was not reviewed*** or considered an option:

18. **Nalcor appropriately excluded natural gas generation in both generation expansion alternatives because natural gas is not commercially available on the Island and there are, as yet, no firm development plans to bring natural gas to the Island.**

NAVIGANT

Lets look at this more closely . . . that Grand Banks natural gas is ***not commercially available*** and that no firm plans are yet in place to bring it to the Island.

The term "**commercial availability"** may be somewhat ambiguous in the context above. The CNLOPB puts it this way:

> Future exploitation of gas resources will extend the economic life of the White Rose Field and permit additional oil recovery (NGL's). The timing of gas availability at the White Rose Field for commercial purposes is dependent on economic and technological factors.

To say that natural gas will not be investigated in our economic model because it is not commercially available is the same as saying ***we don't know*** if it is available commercially because we have not looked at the economics or technical issues.

So let us look at the availability of Natural Gas

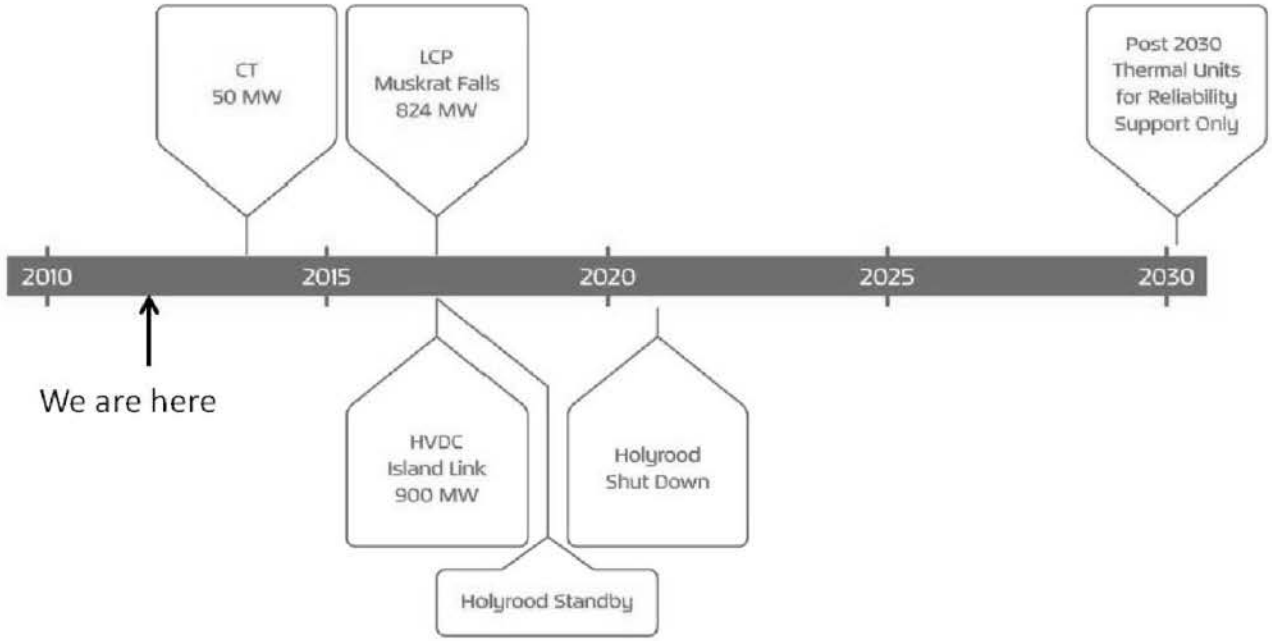
Availability implicitly refers to :

- **Time frame** in which it may be available and in which we may need it.
- **Rate** of gas production that we may wish to purchase.
- The total **quantity** of gas available or accessible.

NATURAL GAS AVAILABILITY: TIME FRAME

This is the timeline of the Muskrat Proposal from Navigant

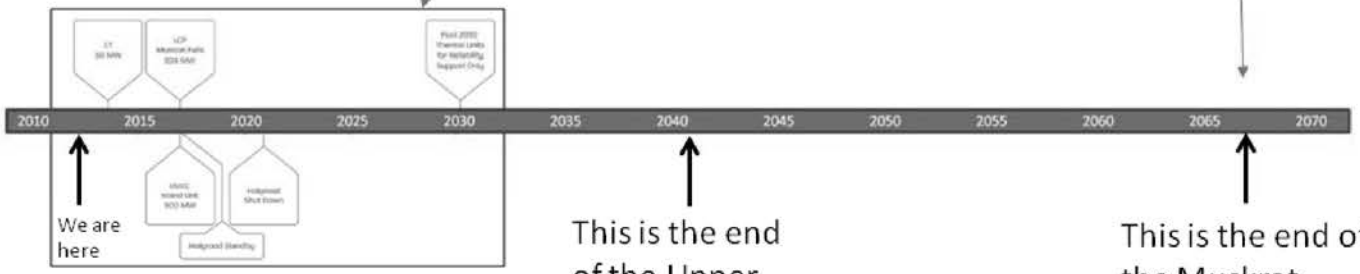
Interconnected Island Generation Expansion Plan



Source: Nalcor Energy

This is the same timeline but extended to include the Muskrat Falls contract duration

Figure shrunk from previous page

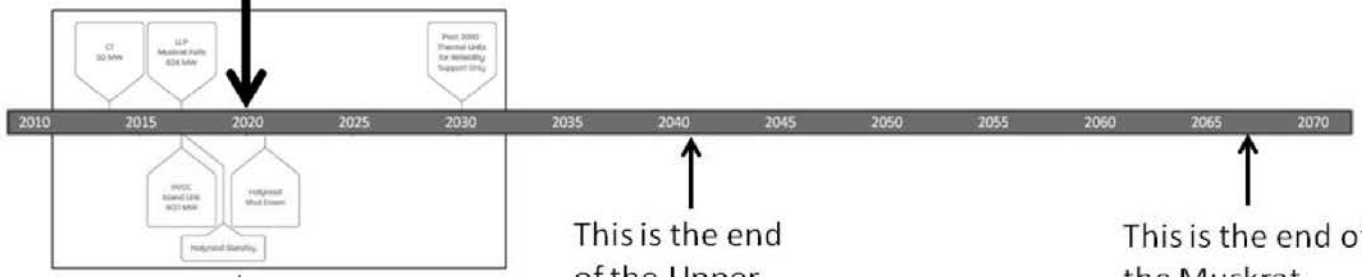


We are here

This is the end of the Upper Churchill Power Contract

This is the end of the Muskrat Proposal Contract

This is timeline of the marketable production of Grand Banks Natural Gas according to the 2007 Provincial Government Energy Plan



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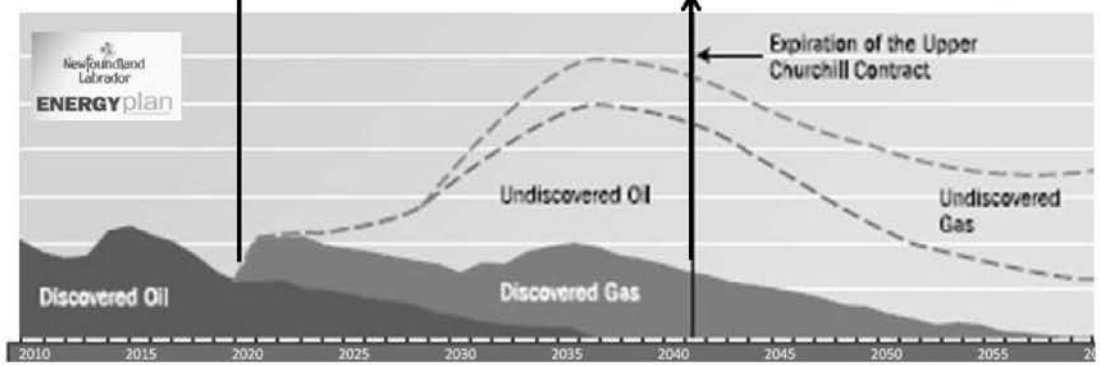
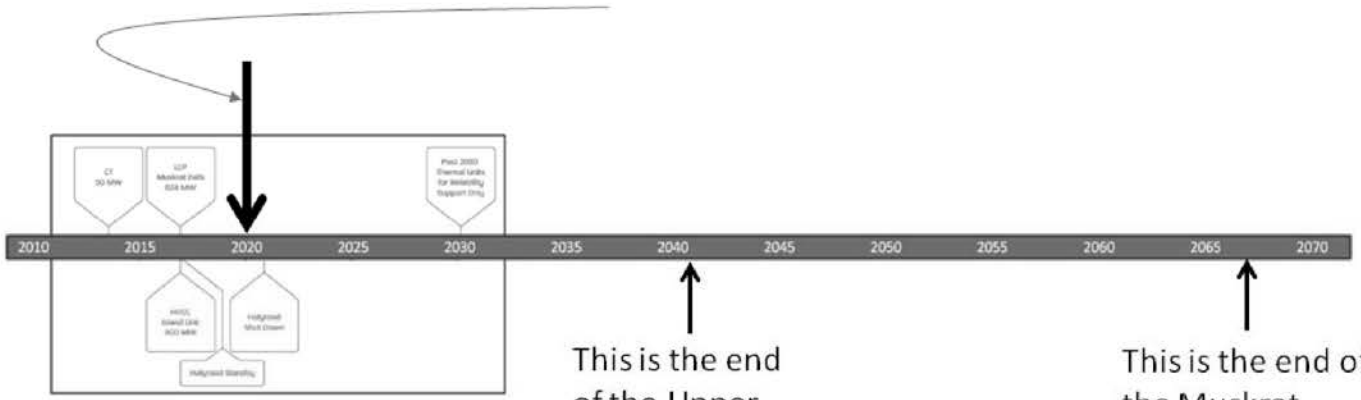


This is the timeline of the marketable production of Grand Banks Natural Gas according to the National Energy Board of Canada



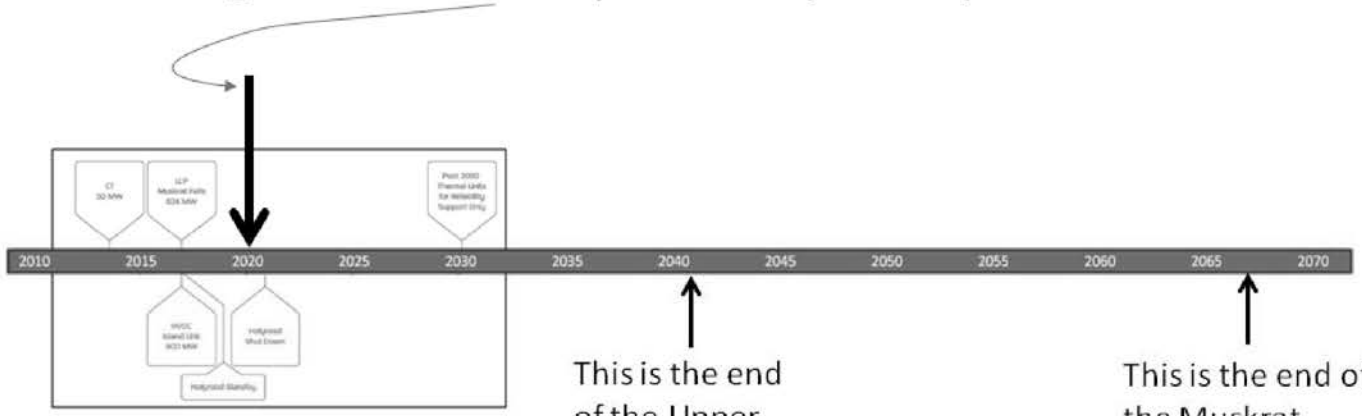
This is the end of the Upper Churchill Power Contract

This is the end of the Muskrat Proposal Contract

According to the National Energy Board Canada, NEB Annual Report 2011, the most likely scenario for Newfoundland Natural gas is that it will reach market in 2020 – 8 years from now.

"In the Reference Case, Newfoundland gas is slated to reach market in 2020, but this could be delayed by the discovery of additional oil pools or unfavourable economics of bringing the gas to market. In 2020, Newfoundland marketable production is projected at 8.9 million m3/d (313 MMcf/d) and ramps up to an estimated 14.2 million m3/d (500 MMcf/d) from 2021 to 2035."

This is timeline of the possible Natural Gas sales of Grand Banks Natural Gas according to the Hibernia partners (HMDC)



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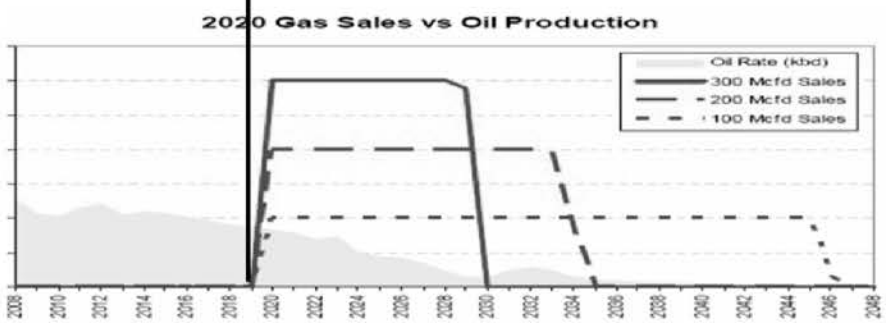
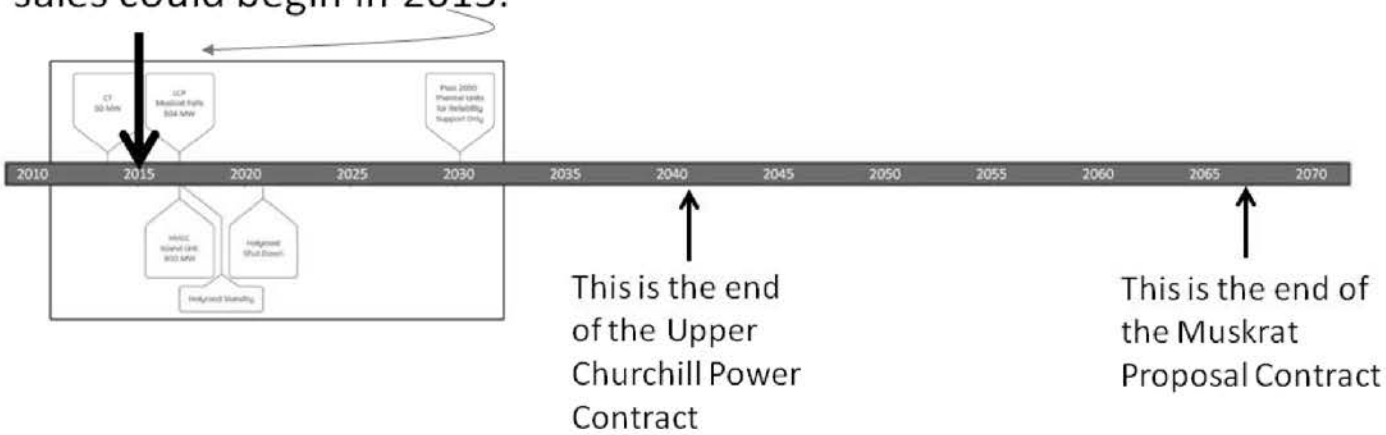


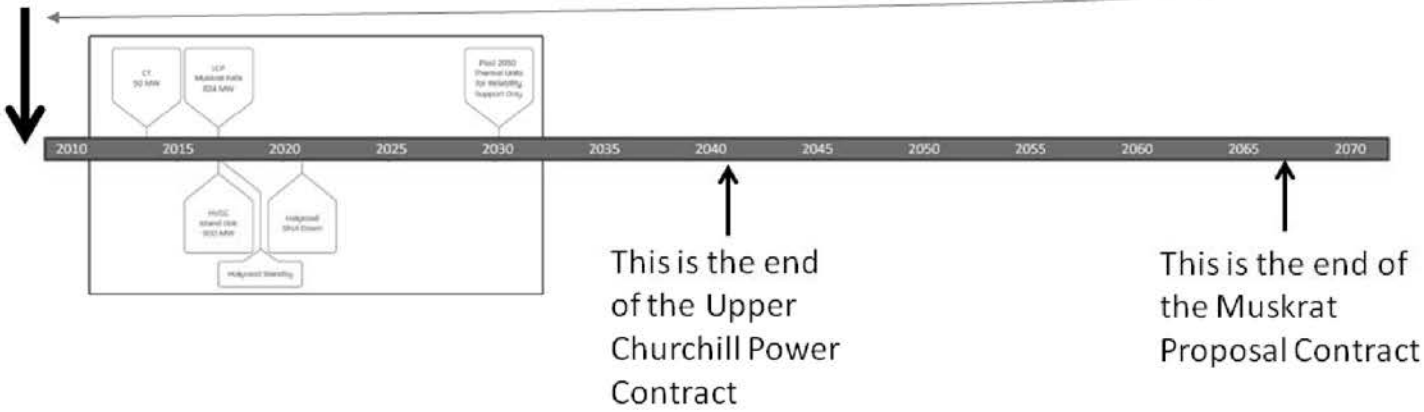
Possible 2020 Gas Sales vs. Oil Production (Source: HMDC)

According to Feasibility study on Natural Gas done for the Provincial Government in 2001* the authors, J.P.Kenny and Pan-Maritime state after all due considerations for maximizing oil value, that initial gas sales could begin in 2015.



[12] *Technical Feasibility of Off-shore Natural Gas and Gas Liquid Development Based on a Submarine Pipeline Transportation System, Off-shore Newfoundland and Labrador, Final Summary Report* to the Government of Newfoundland and Labrador, Department of Mines & Energy, Petroleum Resource Development Division, submitted by Pan Maritime Kenny – IHS Energy Alliance, October 2001

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.



Summary of Grand Banks Natural Gas availability **TIMEFRAME**:

SOURCE	yr
Provincial Government Energy Plan	2020
National Energy Board of Canada	2020
Hibernia (HMDC)	2020
Contractor report used by Navigant	2015
CNLOPB and Husky	now

Conclusion 1	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.

Natural Gas Availability: **RATE**

Lets be more specific about the ***rate*** of natural gas production - and ask only this:

"Is the rate of natural gas production at existing production platforms sufficient for satisfying domestic power needs?"

First, what is the domestic power need – in terms of natural gas?

According to the Navigant report:

A 500 MW natural gas-fired Combined Cycle Combustion Turbine (CCCT) would require 84,000 Mcfd[15] of gas delivery capacity. NAVIGANT

Navigant suggested an annual average natural gas rate to run this 500 MW plant as a replacement for Holyrood would be:

35 mmscf/d

(mmscfg/d = million standard cubic feet of gas per day)

(ie. About 210 MW average annual power rate)

Note: In 2010 all thermal production for the Island of Newfoundland was 792 GWh which averages out to be 2.17 GWh/day = **90.4 MW a LOT less than 210 MW**

The actual needs for 2010 were = 12.7 mmscf/d

Next, what is the actual Natural Gas production on the Grand Banks?

BACKGROUNDER:

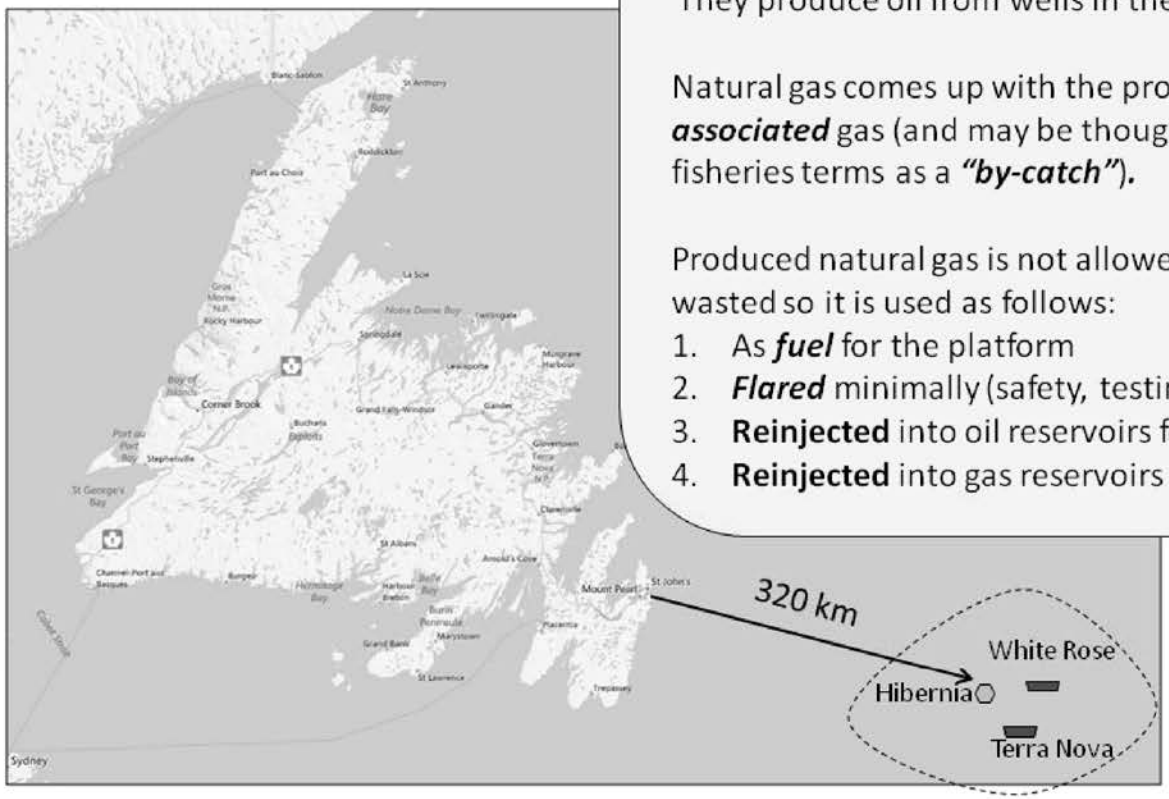
There are three production platforms now active on the Grand Banks.

They produce oil from wells in the sea bed.

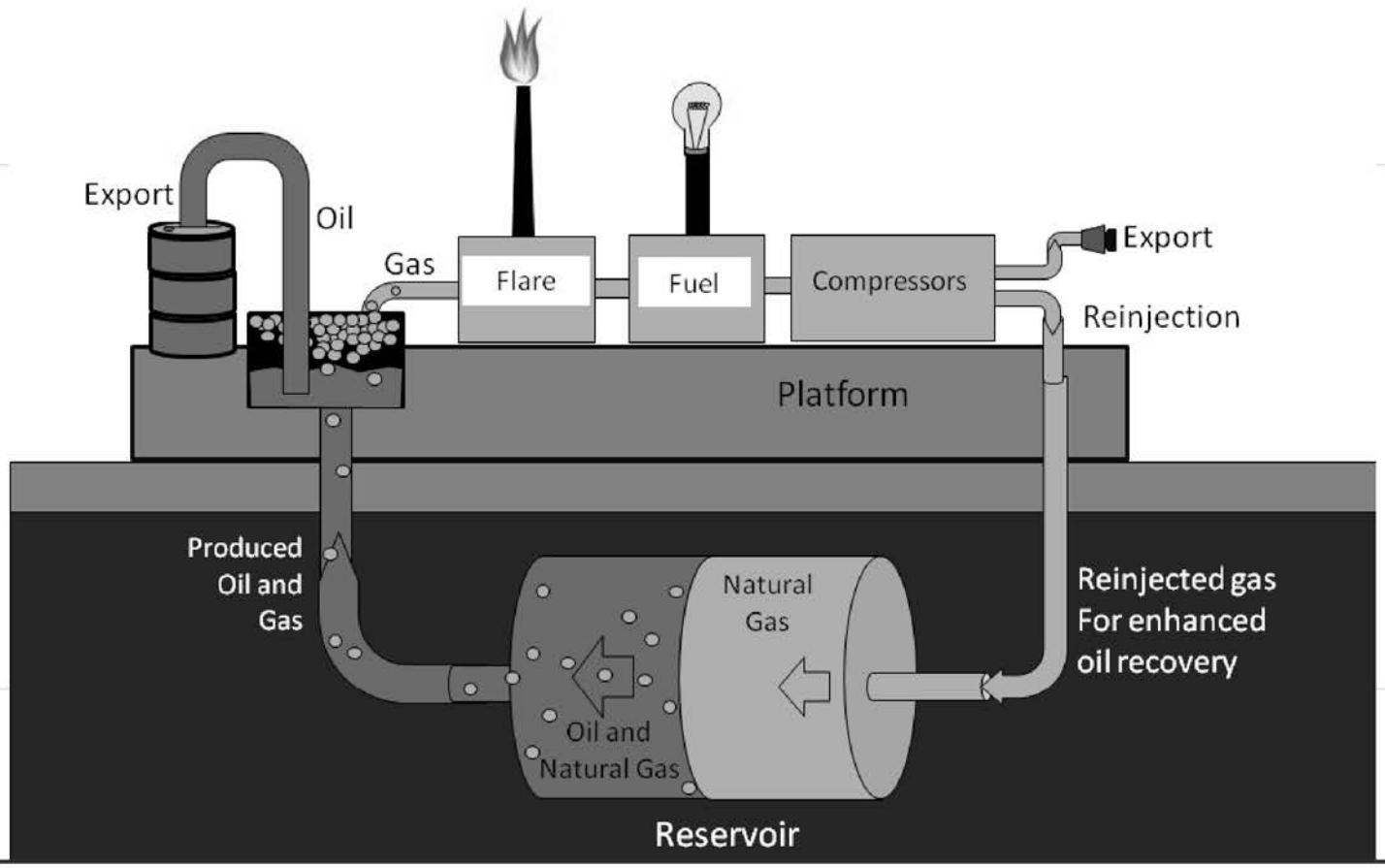
Natural gas comes up with the produced oil as ***associated*** gas (and may be though of in fisheries terms as a ***"by-catch"*).**

Produced natural gas is not allowed to be wasted so it is used as follows:

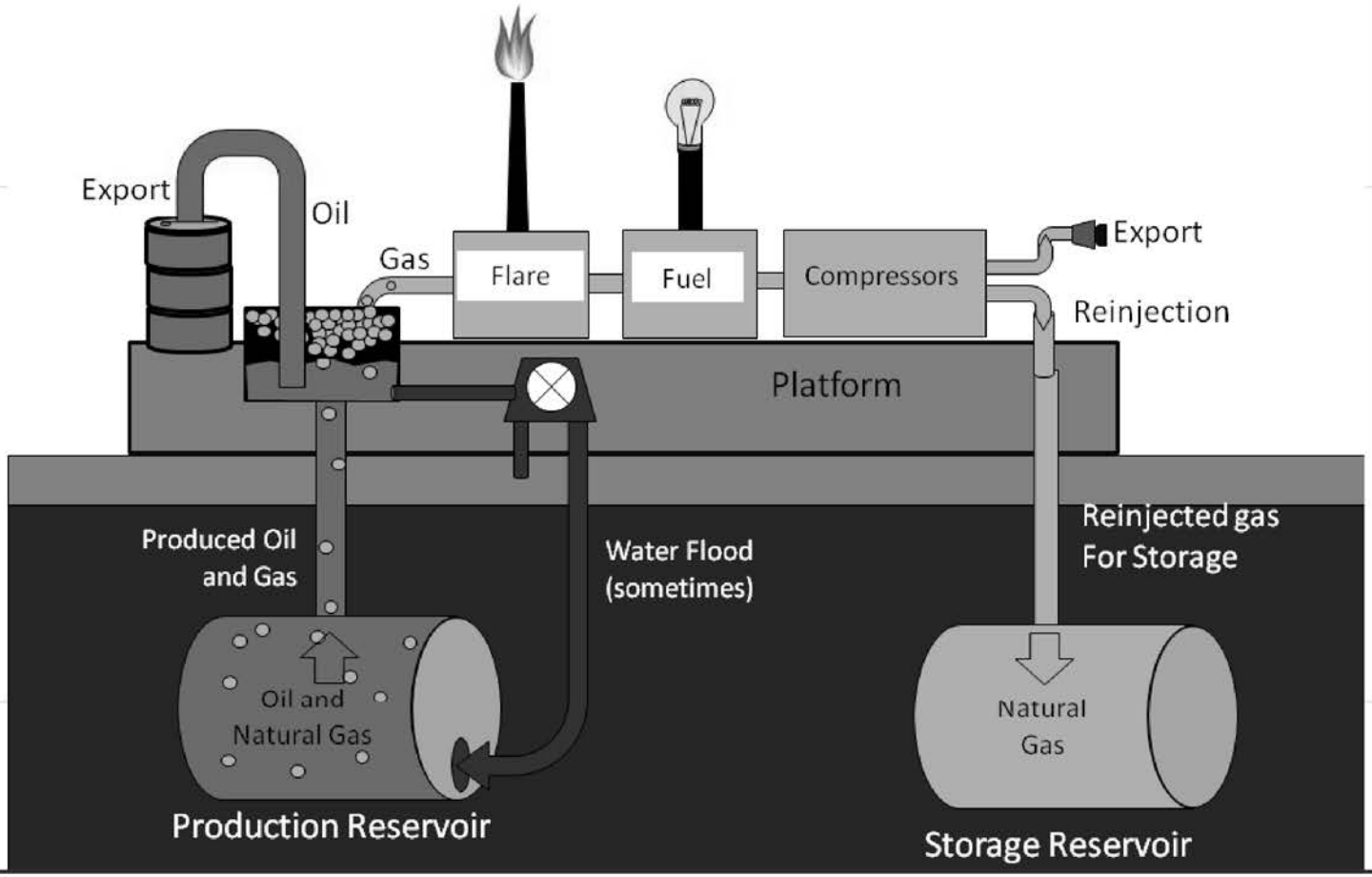
1. As ***fuel*** for the platform
2. ***Flared*** minimally (safety, testing etc)
3. **Reinjected** into oil reservoirs for pressure
4. **Reinjected** into gas reservoirs for storage



Simplified Grand Banks Oil Production Schematic – with Gas used for Oil Production Support

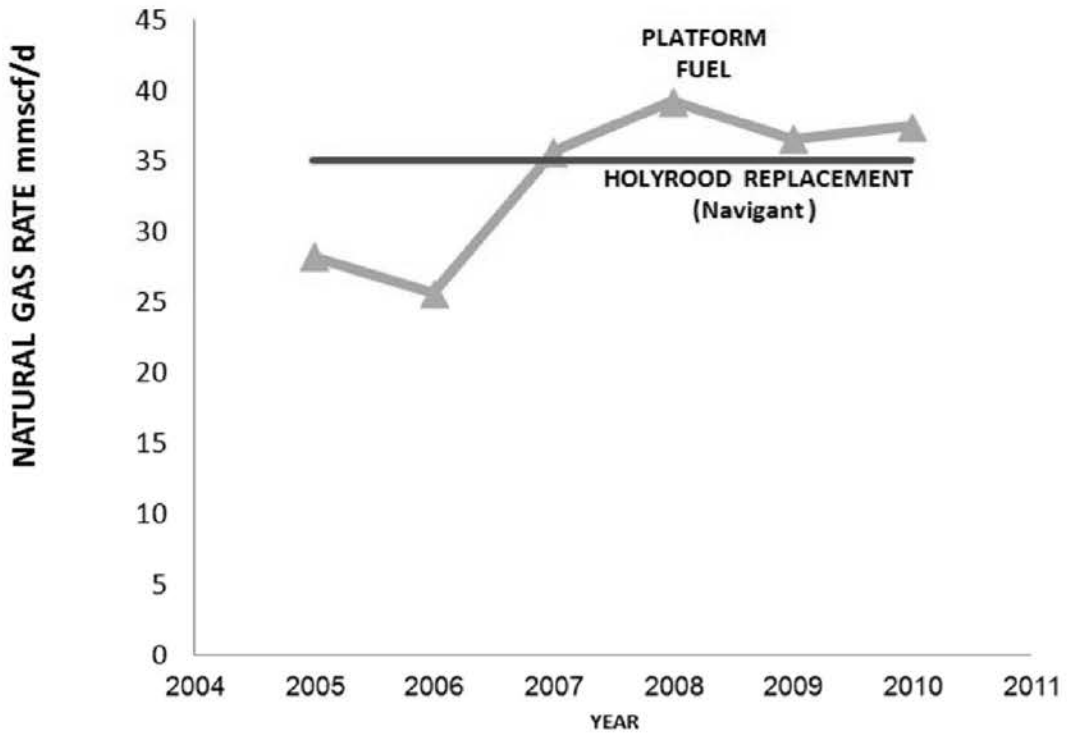


Simplified Grand Banks Oil Production Schematic – Where Gas Can't Help Oil Production

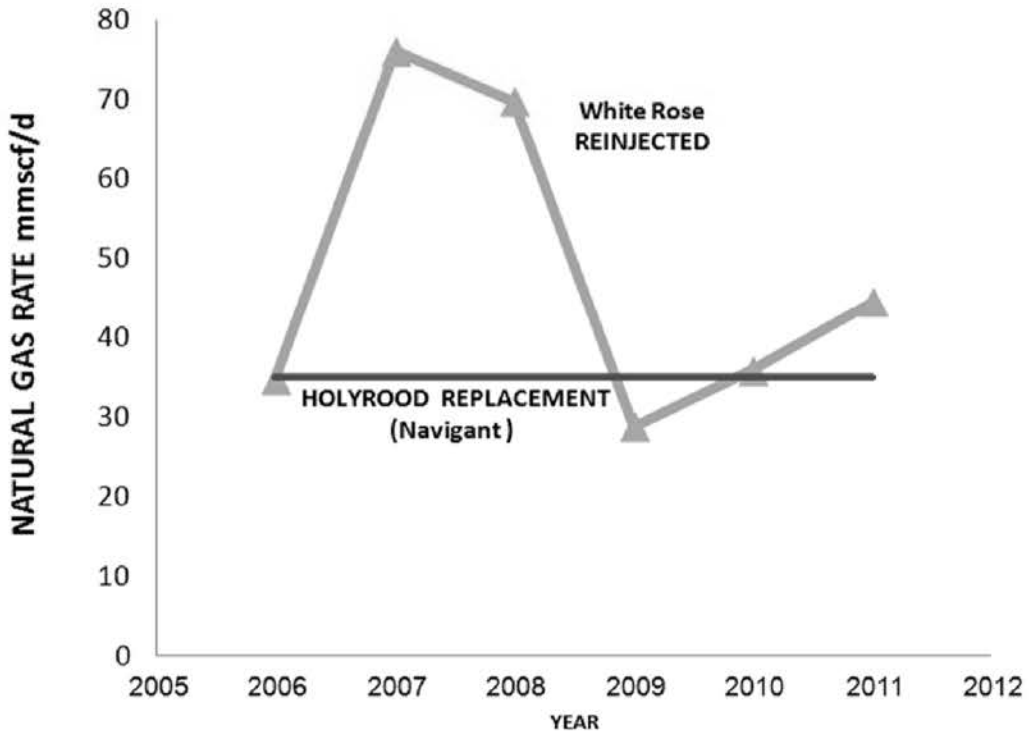


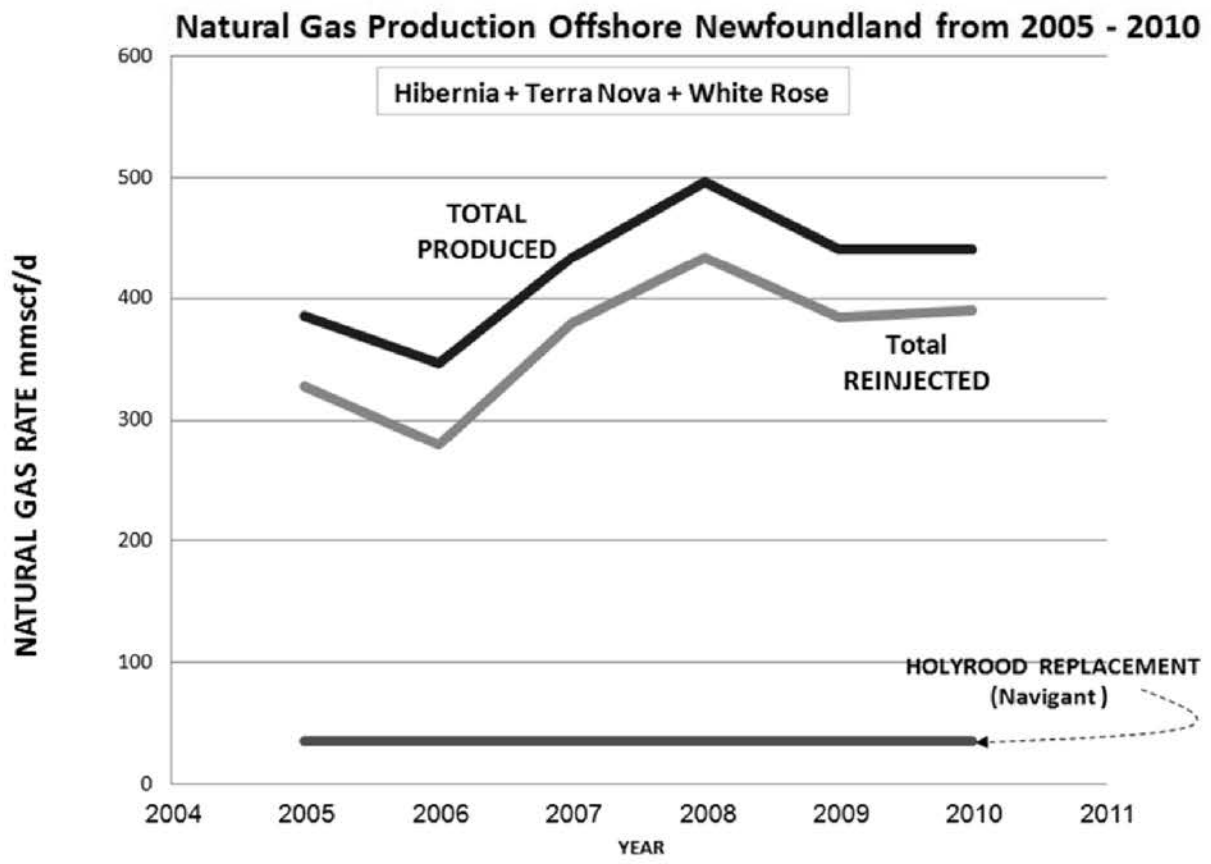
Natural Gas Use Offshore Newfoundland from 2005 - 2010

Hibernia + Terra Nova + White Rose

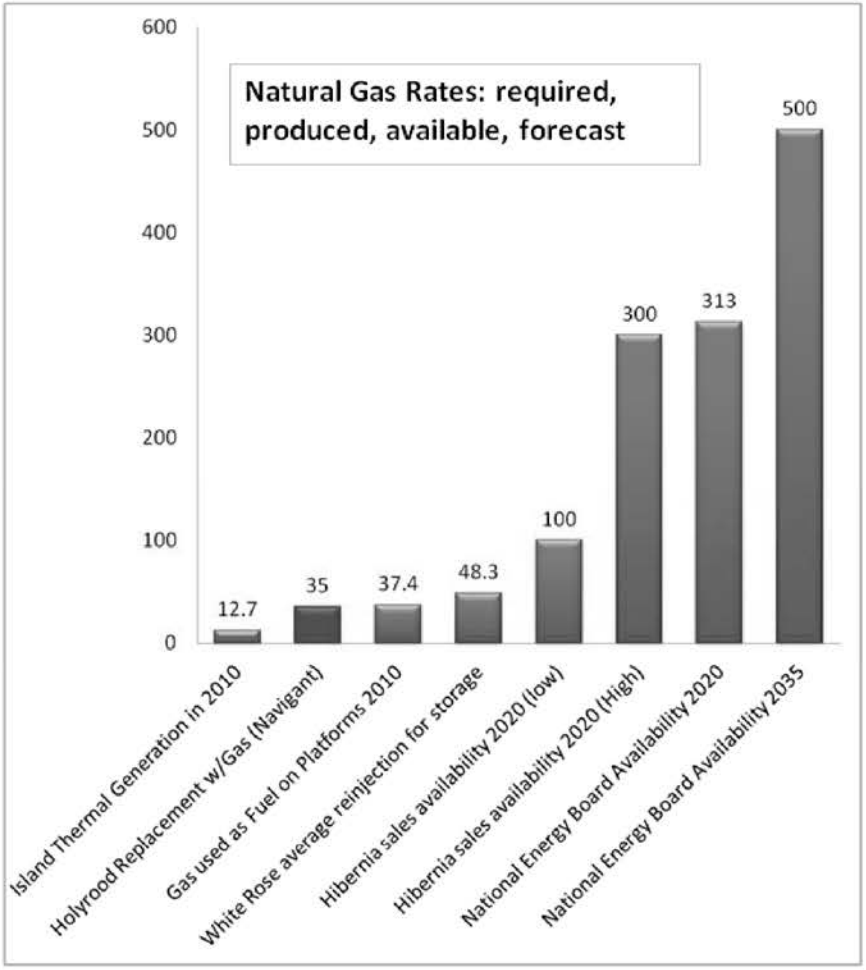


Natural Gas at White Rose:
Reinjected gas is SURPLUS to ALL other NEEDS




Natural Gas Production Offshore Newfoundland from 2005 - 2010
Hibernia + Terra Nova + White Rose
TOTAL PRODUCED
Total REINJECTED
HOLYROOD REPLACEMENT (Navigant)
NATURAL GAS RATE mmscf/d
600
500
400
300
200
100
0
2004
2005
2006
2007
2008
2009
2010
2011
YEAR

Summary of Natural Gas **RATES**



Conclusion 2

Natural Gas is being produced at a rate that exceeds our domestic electrical needs – can sustain our requirements for a long time.

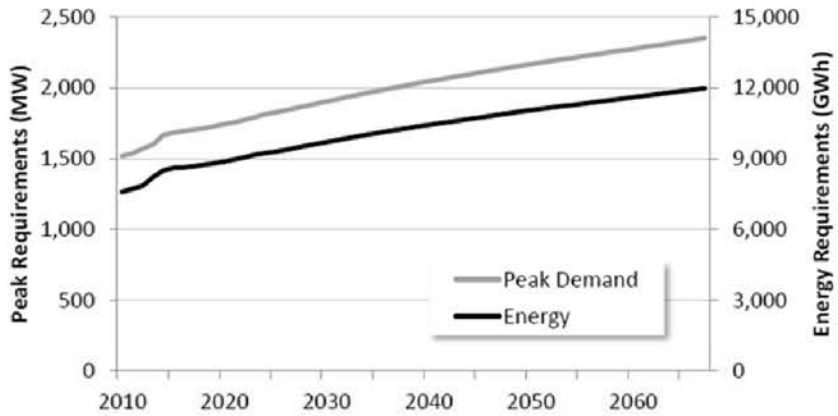
Natural Gas Availability: **Total Quantity**

We have shown that according to HMDC, NEB, Gov NL natural gas will be available from existing offshore oil production facilities by 2020 at the latest and at production rates greater than the Island thermal electric generating requirements.

But how long can it last? How much gas is there?

First, here is the forecast for total electricity demand given by the crown:

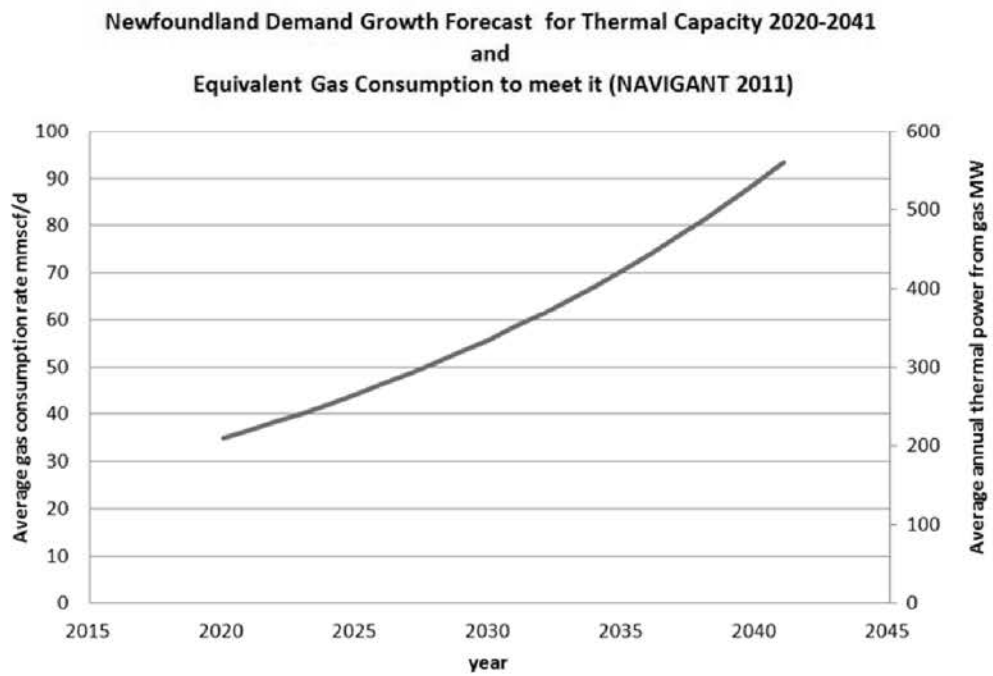
Figure 15: Newfoundland Peak Demand and Energy Requirements



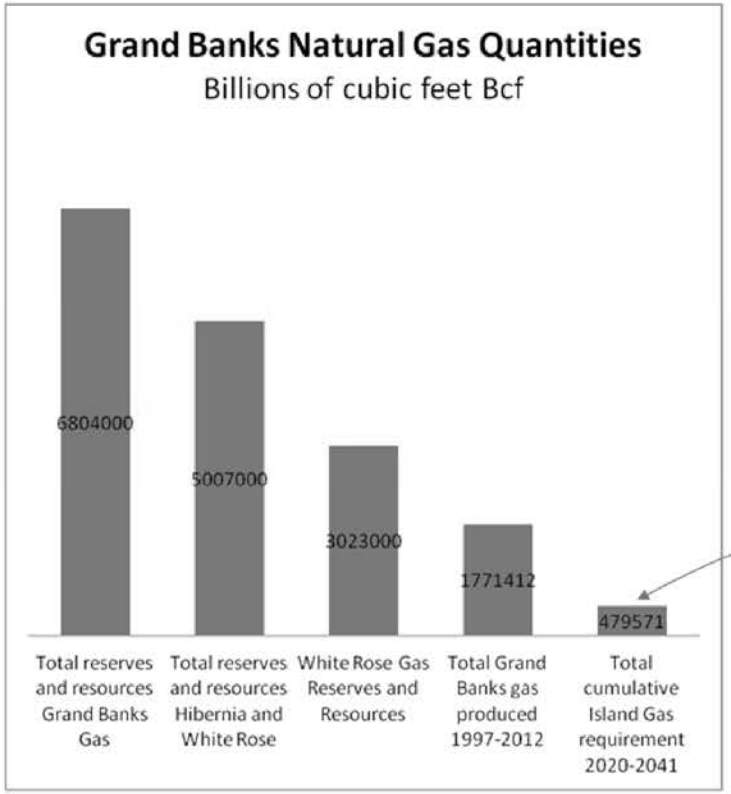
Source: Nalcor. "Synopsis of 2010 Generation Expansion Decision" Exhibit 13b. July 2011

Shows annualized capacity growth of 350 MW from 2020 to 2041, roughly 4.79% compounded annual growth rate.

If we assume that all new generation requirements are met by CCGT (ie. natural gas) then using the figures from Navigant we have a thermal capacity and Natural Gas demand from 2020 – 2041 as shown:



So how much natural gas would be required in total to meet these domestic electricity requirements from 2020 to 2041 ?

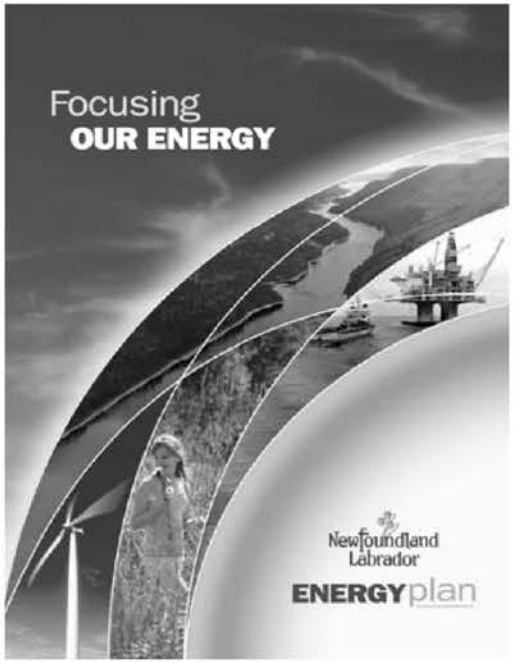


Here it is!

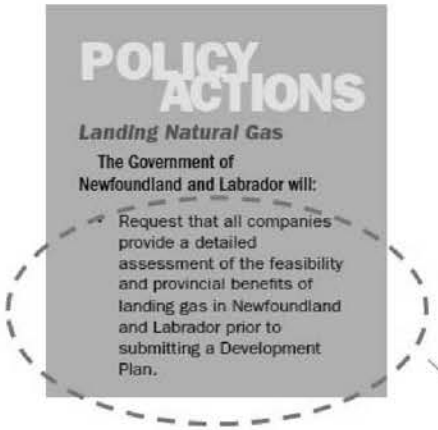
Conclusion 3 Natural Gas reserves and resources on the Grand Banks are in quantities that exceed domestic electrical requirements for the foreseeable future.

So, given Conclusion 1, 2 and 3 tell us that natural gas is available in the (1) timeframe, (2) rate, and (3) quantity required for domestic needs, what **policies** may further compel us to investigate the Natural Gas option?

Here is **THE** over-arching Statement of Provincial Energy Policy:



Here is **what it says:**



POLICY ACTIONS

Landing Natural Gas

The Government of Newfoundland and Labrador will:

- Request that all companies provide a detailed assessment of the feasibility and provincial benefits of landing gas in Newfoundland and Labrador prior to submitting a Development Plan.

Lets look in more detail

PEROGATIVE in more detail :

Landing Natural Gas

Natural gas is in the early stages of development in Newfoundland and Labrador. To succeed, we need to gain a clear understanding of the strategic importance of landing gas in the province. Natural gas can be used in industrial processes such as oil refining, secondary gas processing, petrochemical manufacturing, and in the generation of electricity. All viable options must be fully assessed for the development of our gas resources to ensure they provide an appropriate level of benefits to the province and a fair return to the investor.

The Provincial Government understands the unique challenges of using this resource within the province, but there are also opportunities. To ensure these opportunities are fully assessed, the Provincial Government will request that companies provide detailed "landing in the province" options prior to submitting a Development Plan. More information on potential natural gas development is found in **Section 4 – Electricity** and **Section 6 – Energy and the Economy.**

. . . Detailed "Landing in the province" options will be requested from all companies submitting a development Plan. . . .

Where are these?

There have been a few Development Applications since 2007 . . ?

Further in the Energy Plan one finds this. . .

To ensure that we can meet our future electricity needs, we must also have an alternate plan in the event Lower Churchill does not proceed as planned. In this case, we will provide future electricity needs from the most economically and environmentally attractive combination of thermal, wind and smaller hydro developments. These sources could provide an additional 100-200 MW of power. The remainder would come from thermal generation. NLH is studying these sources in parallel with planning for the Lower Churchill to ensure the future energy supply for the province is secured. NLH is also studying the potential for landing gas in the province from our offshore resources to fuel a thermal electricity generating plant.

"NLH is also studying the potential for landing gas in the Province from our offshore resources to fuel a thermal electricity generating plant."

Landing gas from our offshore resources can only mean landing a **pipeline** as there are no other proven or conventional technologies to do so.

So where is this pipeline "landing gas" study for thermal generation?

CONCLUSIONS of Part 1

The reason for excluding Natural Gas from the expansion alternatives considered by Navigant appears invalid.

There is a policy-mandated duty to the public to investigate the natural gas option – as described in the Energy Plan.

RECOMMENDATION for Part 1

An independent review of the ***natural gas-for-domestic-power*** option be required before a final decision is made w.r.t. committing the public to a **50 year** binding agreement to Muskrat Falls.

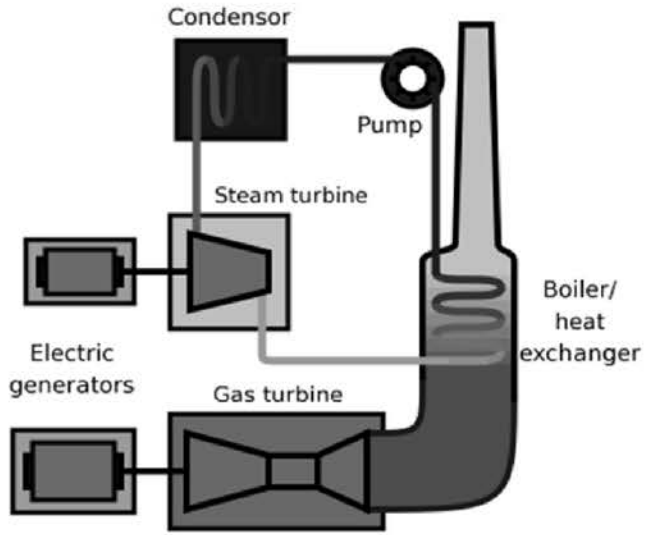
PART 2

Island Electricity from Grand Banks Natural Gas

Possible scenarios, examples, costs, benefits . . .

Things you may want to know

Generating electricity with natural gas – **CCGT** technology



↑ Diagram CCGT, a combination of a gas turbine and a steam turbine. Efficiency ~ 59 %.

Called ***Combined Cycle Gas Turbine*** because you get electricity produced from both a gas turbine (engine where the natural gas gets burned), and, from a steam turbine that gets its steam from the exhaust of the turbine.

Many CCGT plants are **DUAL Fuel** ie. Other liquid fuels can be substituted for Natural Gas if availability is disrupted.

A description of over 1200 CCGT power plants around the world is provided on the www.industcards.com website. Dozens of these are in Canada and a few are very similar to the kind we need here on the Island. Here are some examples:

Brighton Beach

Location: ON
Operator: Atco Power
Configuration: 580-MW, 2+1 CCGT with 7001FA gas turbines
Operation: 2004
Fuel: natural gas

Quick facts: Brighton Beach is owned by a 50:50 JV of Atco Power and Ontario Power Generation. **The plant was built at the site of the former J Clark Keith power station**.

Portlands

Location: ON
Operator: Portlands Energy Centre
Configuration: 550-MW, 2+1 CCGT with 7001FA gas turbines
Operation: 2008-2009
Fuel: natural gas
EPC: SNC-Lavalin

Quick facts: The Portlands Energy Centre project was launched in 2002 by a 50:50 partnership of Ontario Power Generation and TransCanada. **The site is adjacent to the retired 1,200-MW Hearn power station** in an industrial section of Toronto's Portlands district. Construction was declared complete on 23 Apr 2009, somewhat ahead of schedule and under budget at a final cost of CND$730mn.

Pearson Airport

Location: ON

Owner: Greater Toronto Airports Authority

Configuration: 117-MW, 2+1 CCGT with LM6000PD gas turbines CHP

Operation: 2005

Fuel: natural gas

EPC: SNC-Lavalin

Quick facts: This was the first plant of its kind in Canada and supplies electricity plus thermal energy for heating and cooling. Pearson Airport's peak electrical demand is about 38 MW and this is expected to rise to about 70 MW by 2015. **Surplus electricity is sold to the grid** under a Clean Energy Supply contract between GTAA and Ontario Power Authority. Development began in 1998 and studies began in 2002/03 following provincial deregulation of electricity supply in May 2002. In Jan 2004, the GTAA Board voted to proceed with the construction of the plant and hired SNC-Lavalin as EPC and operations contractor. Construction started in Jul 2004 and the plant went online in Feb 2006.

This is smaller project that would be very interesting for the University (MUN) to consider because a small CCGT power plant could supply electricity to the grid and steam to the campus achieving ultra high efficiencies of near 80% !

Becancour, Quebec - Trans Canada Pipeline

- 550 MW CCGT power plant
- $500 million CAD (2006)
- Natural Gas Combined cycle Power with steam sold to nearby industrial park
- Plant won the competition from Hydro Quebec Distribution's RFP for new generation.
- **Built, Owned and operated by Trans Canada Pipeline Limited**
- Required new pipeline under the St. Lawrence river.

Where might this new power generation facility go?

Many factors point to the brownfield site that is the existing Holyrood Thermal Generating Station. All infrastructure (transmission, water, tanks etc) is in place already and there is plenty of space. New gas-fired power plants have small footprints. Other possible sites include Soldiers Pond, Robin Hood Bay, Southern Shore Area, etc.

Approximate scale and look of new gas-fired plant

So how much would the power plant cost?

Typically approximated by cost per KW or MW various sources report figures as follows (adjusted to 2011 dollars):

USD Per KW	Source
$850-$900	Combined Cycle Journal
$652	Pickett, Adams, Combined Cycle Journal
$835	Northwest Conservation Council
$1000	International Gas Union

The average of these would imply that a 500MW plant would cost 840*500000 = 420 million USD

Given that the previously mentioned 550 MW plant in Ontario PORTLANDS ended up with an all-in price of $730 million CAD in 2009 (when CAD was low relative to USD) and the 550MW Becancour plant was $500 CAD million in 2006 . . .

It seems reasonable to expect a new 500 MW CCGT plant at Holyrood to cost somewhere in the range of 500 – 800 million CAD.

Note that distillate or diesel fuel storage – required to secure fuel supply in the event of gas supply disruption – already exists at the Holyrood site.

Now the Pipeline

Some background . . .

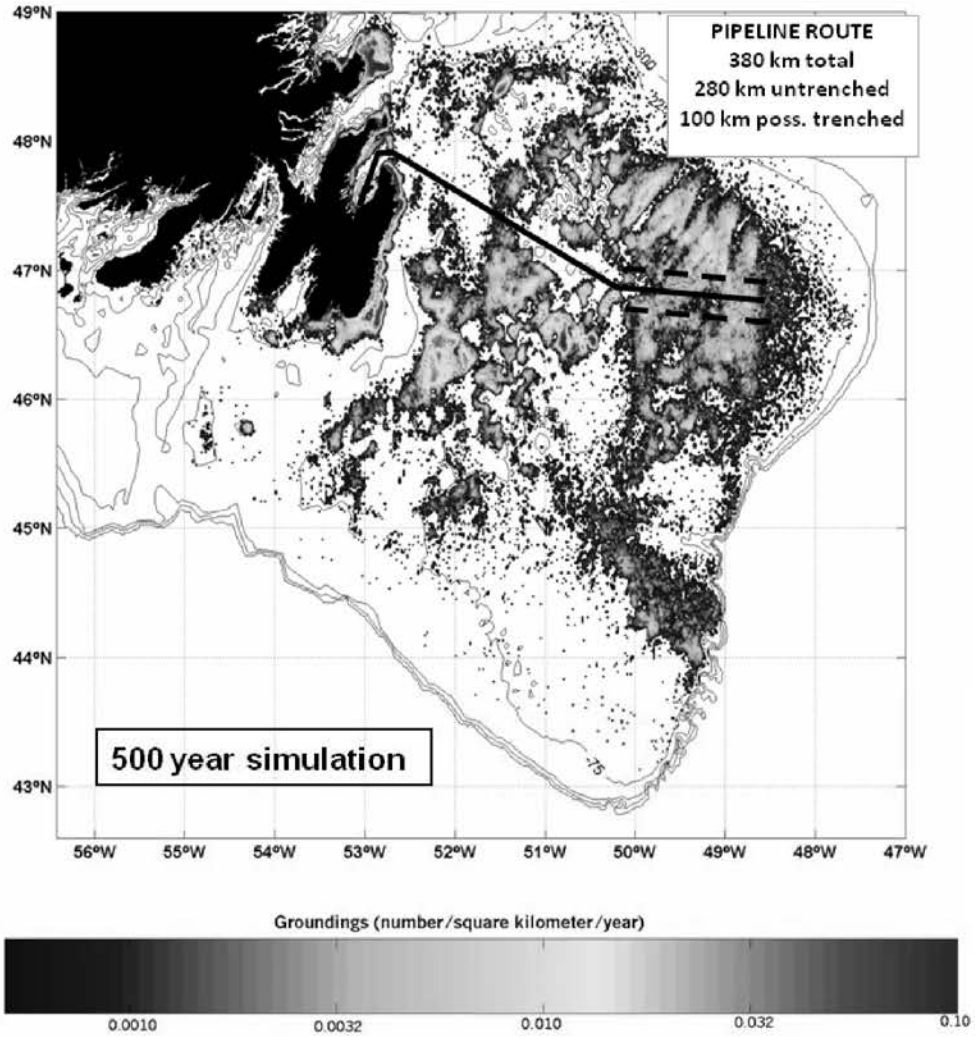
- Icebergs considered too risky for Grand Banks pipelines 30 yrs ago

- Analysis in 1990s indicated risks of a subsea pipeline being ruptured by an iceberg could be managed, through strategic routing, trenching and improved repair practices – to be equal or less than the typically accepted operational risks to pipelines elsewhere in the world.

- 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.

For the purpose of this discussion a pipeline route is required. . .

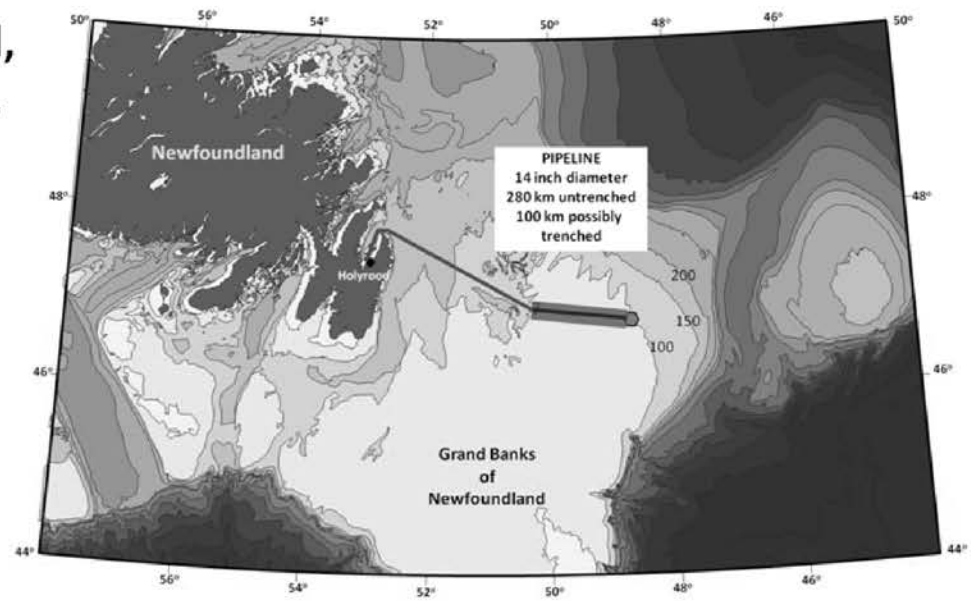
Iceberg Grounding and scour risk chart:
The pipeline route has been selected here on the basis the shortest distance subsea to Holyrood and following a low-iceberg risk zone.



What about the pipeline size and characteristics?

The final design and route of a pipeline that would be used to carry natural gas to the Island of Newfoundland for Domestic power requirements remains to be detailed as a matter of standard engineering and economic practices. For this discussion I have selected the following plausible characteristics (Recall the gas flow rate that would be required to meet the absolute maximum demand for electricity from a 500MW plant would be 84 mmscf/d according to Navigant)

Rate = 100mmscf/d,
Diameter = 14 inch,
Length = 380km,
Depth = 70 – 180 m



And what about the costs of a pipeline?

Estimates can be roughly approximated on the basis of $/in.-km. The indicative pricing given by NATGAS.info suggests the cost of offshore lines has reduced from more than $100,000/in.-km to around $25,000 to $40,000/in.-km. (USD) in recent years.

Even at the higher level that would suggest a cost of
100,000 * 380 * 14 = **532 million USD**

Another estimate may be gleaned from the 2001 study Cited* by Navigant and referenced below. A Grand banks pipeline was selected for the economic model with the following characteristics:

Rate = 1,000 mmscf/d
Diameter = 36 inch
Length = 620 km
Trenching = 110 km, 3m
Depth range = 80 – 220m

Cost = **795 million CAD (2001)**

* *Technical Feasibility of Off-shore Natural Gas and Gas Liquid Development Based on a Submarine Pipeline Transportation System, Off-shore Newfoundland and Labrador, Final Summary Report* to the Government of Newfoundland and Labrador, Department of Mines & Energy, Petroleum Resource Development Division, submitted by Pan Maritime Kenny – IHS Energy Alliance, October 2001

Perhaps the **best source** for estimating this cost would be a sampling of North Sea Projects of similar scale:

	Pipe Diam. in	Pipe Capacity mmscf/d	Pipe Length km	Ocean depth m	Cost 2011 MMCAD	Unit Cost MMCAD/km
Haltenpipe	16	213	250	290	543	2.172
Draugen Gas Export	16	194	75	250-340	96	1.28
Heidrun Gas Export	16	387	37	350	198	5.35

These figures all exceed the required 100 mmscf/d throughput. The Haltenpipe at 250 km appears to have less distortion from terminus effects though.

Conclusion: Given a length of a 380 km it seems reasonable to suggest that for a smaller throughput capacity of 100 mmscf/d but greater length – we can roughly estimate costs without regard for diameter and pressure – to be between 2 and 2.5 million CAD per KM,

or, <u>760 to 950 million CAD</u>.

http://www.energy.gov.tt/content/249.pdf

Lets summarize the Natural Gas **Plant** and **Pipeline costs:**

	$CAD million
500 MW CCGT Power Plant	500 – 800
14 inch 380 km pipeline	760 – 950
Other elements	100
Platform mods	to be considered in the context of gas price
Backup fuel storage	Already in place
Transmission etc	Already in place

Approximate Range of Cost: 1400-1900 $CAD million

Conclusion: Capital costs are very low relative to the alternatives presently under consideration for domestic electricity supply.

So if this is the case, what about the cost of the fuel, the natural gas?

The price of gas – what would or should we pay?

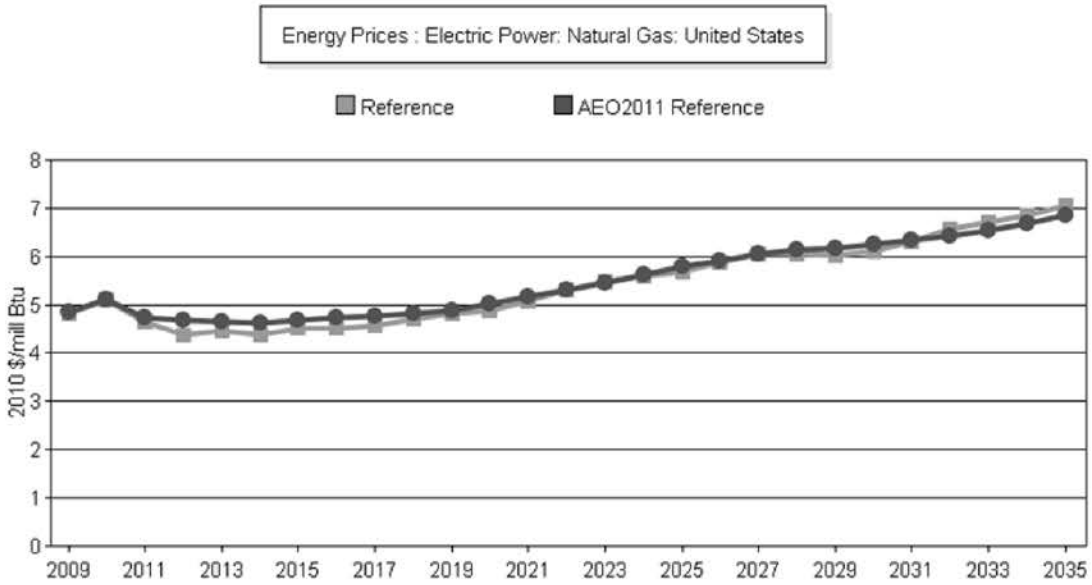
IN a written submission to the PUB last month I suggested that the price we may pay for the purchase of natural gas from a producer operating on the Grand Banks would be negotiated arrangement taking into consideration many factors. I listed the factors and so they are a matter of public record.

For this discussion I would like to make the following simplifying 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. ie platform preparation expenses are the expense of operator(s) and thus must be recovered through the gas sales revenue.

So what is the price of Natural Gas in the Marketplace?

The Energy Information Administration in US provide the following projections for natural gas price:

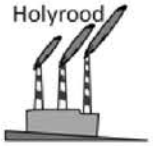


eia Independent Statistics & Analysis U.S. Energy Information Administration

Yes, BUT what do these prices mean?

EXAMPLE: Lets compare operating costs between Holyrood and new CCGT . . .

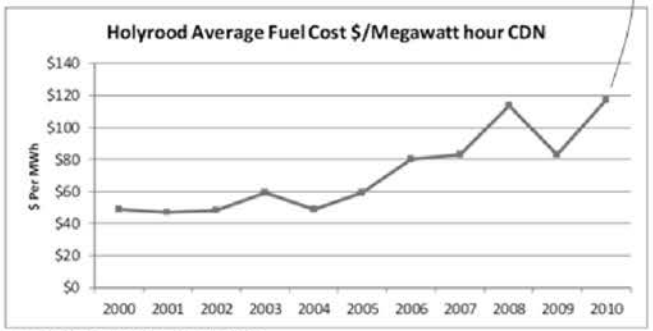
Holyrood Thermal Power Plant 2010



Total thermal produced = 792 GWh
(equiv rate of 90.4 MW-yr)

Cost of $119,000 /GWh = **$94.2 million**

Source:



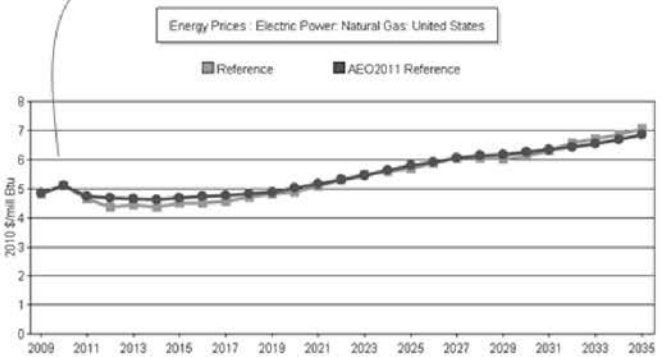
Source: Nolcor Energy, March 2011

CCGT power plant for 2010

Total thermal produced = 792 GWh
(equiv rate of 90.4 MW-yr)

Cost of 12700 mscf/d * 365* $5 = **$23.2 million**

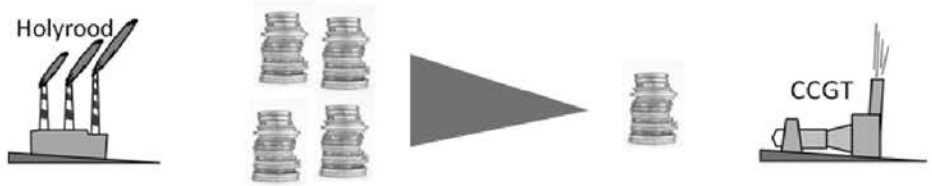
Source:



eia U.S. Energy Information Administration

This means that using new natural gas-fired turbine technology would have:

Reduced our fuel bill by a factor of FOUR ($94.2mm / $23.2mm = 4)



Thus if we paid the US Market price for gas as predicted by the EIA for all the gas we would need to generate electricity from 2020 to 2041, the price of this, plus all the pipeline and power plant infrastructures would be:

$CAD BILLION(s?) cheaper than the two alternatives considered by Navigant

It is imperative that full economic analysis of this option be undertaken as there are many factors and methodologies for determining the present value, tax and interest influences the risks associated financing etc etc - well beyond the scope of this presentation.

What about ***other gas pipeline projects*** like this one?

There are MANY, MANY to look at and so I have selected a few examples of pipeline projects ***that demonstrate a range of conditions*** and scenarios of interest:

1. Same size and flow rate pipeline but lower pressure and shorter length – horizontal drilling required for landfall. ***Reindeer Pipeline***, Australia

2. Extreme northern harsh climate deep water pipeline – **Luva Gas Pipeline**, Norway

3. Canadian pipeline, Owned and Operated by Newfoundland Based Company, connecting Island for power generation – ***Vancouver Island Pipeline***

4. Isolated Island in need of natural gas for electric generation while major industry players produce oil and gas nearby – **Tobago Natural Gas Pipeline**

Example 1 – same size pipe, same throughput

Reindeer Gas Field, Australia

- **16 inch subsea pipeline**
- 105 km, 90 km subsea in 60m water
- 2.5 km directional drilling at landfall
- Gas Production = **101 mmscf/d**
- Pipeline Cost = $170 million (2010)

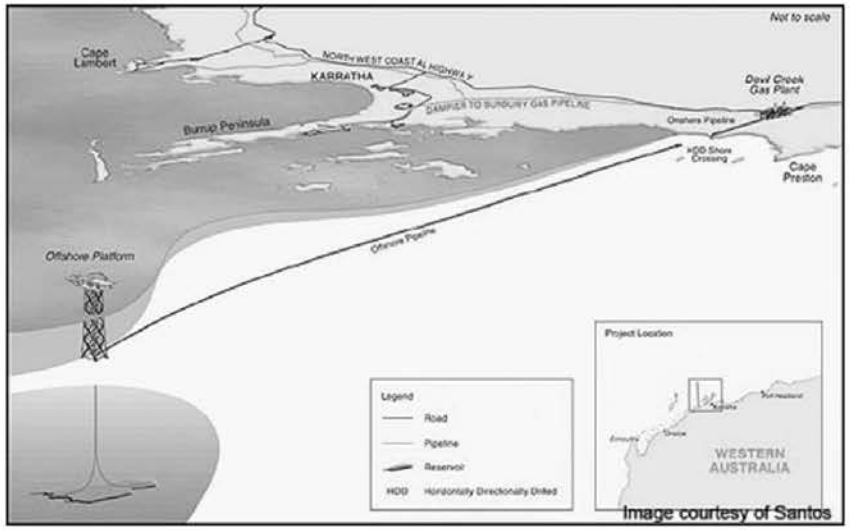


Image courtesy of Santos

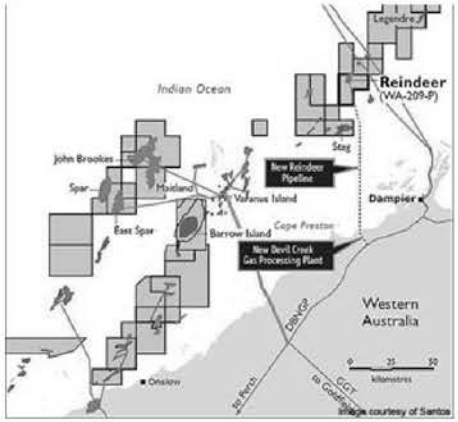


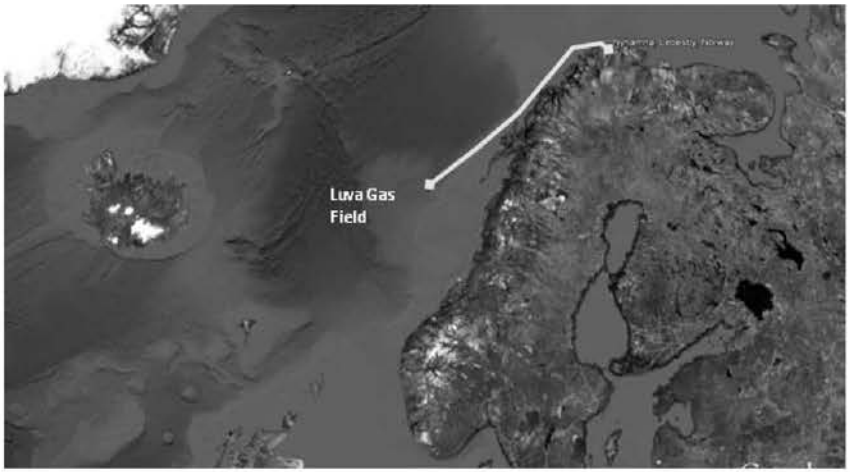

Image courtesy of Glen Dillon

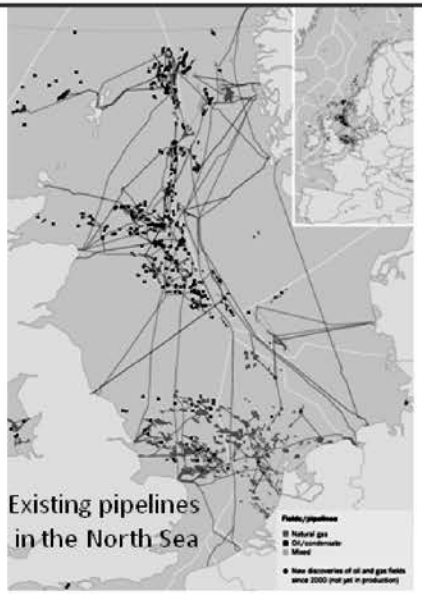
Example 2 – Extreme environment similar length

Luva Field, Offshore Northern Norway

- 30-36 inch subsea pipeline
- 482 km, up to 1300m arctic water (above arctic circle)
- Gas Production = 800-1000 mmscf/d
- Pipeline Cost = $1900 million (2012)

Pioneering new Spar platform also being built – entire development is for Natural Gas and gas products for a field that has LESS natural gas than White Rose alone!

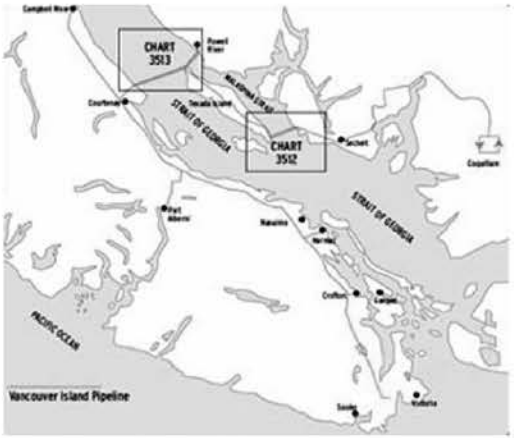




Example 3 – Canadian Island gets connected

Vancouver island pipeline

- Various sizes including , twin 10.75" subsea pipelines
- 550 km, up to 425m deep very rough terrain
- Gas Production = 100 mmscf/d
- Pipeline Cost = $355 million (1991)



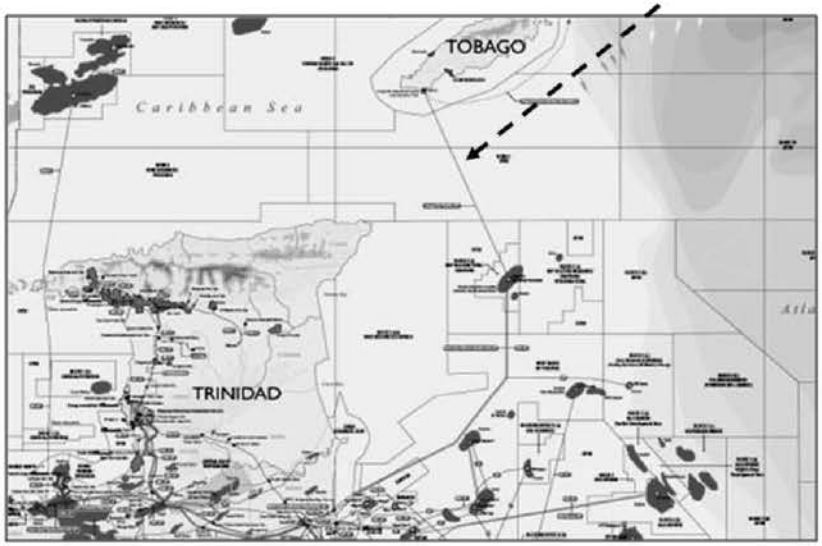
IN addition to the pipeline a gas storage tank (peak shaving) holds 1.5 billion cubic feet of liquefied natural gas (LNG), with the structure measuring approximately 60 metres in diameter and about 50 metres high. In service 2011.

FortisBC Energy, Inc., formerly known as **Terasen Gas**, is the largest distributor of natural gas in British Columbia, Canada, serving approximately 920,000 customers in over 125 communities. The company owns and operates 44,100 kilometres of gas distribution pipelines and 4,300 kilometres of gas transmission pipelines.

Example 4 – Small pipe from big oil to satisfy local domestic needs.

Tobago Pipeline Project

- 12 inch
- 54 km
- Gas throughput = 110-120 mmscf/d
- Pipeline and platform cost = $164 million (2011)
- Start Construction April 2009
- Completion of Project June 2011



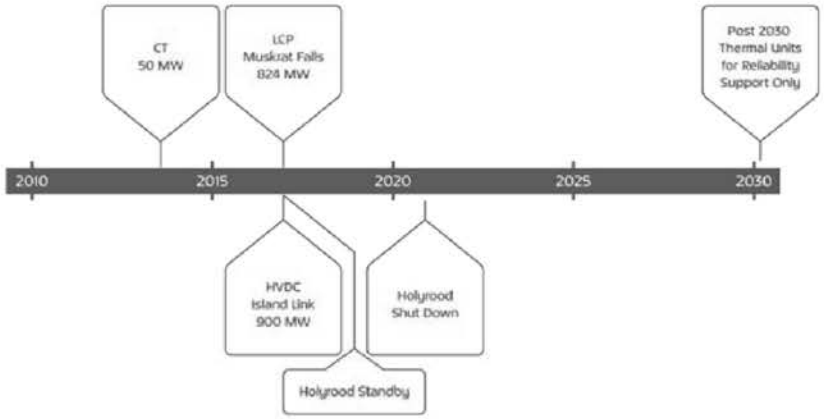
Project Drivers

1. Gas Supply to Power Generation Plant at Cove Estate
2. Gas Supply to light Industry at Cove Estate
3. Transportation of Gas for Future Eastern Caribbean Gas Pipeline
4. Domestic Supply to Tobago

What about the **Schedule** and construction timeline if it were to happen?

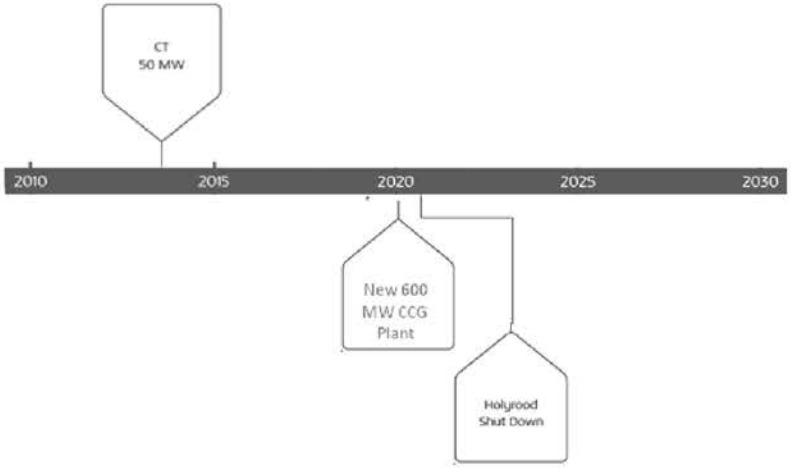
Construction time for CCGT power plant:	Typically 2 years **(ETP, EIA, IGU)**
Construction time for a 380km 14" subsea pipeline:	Typically 2 years for a pipeline of this nature in this kind of environment **(Offshore-Technology.com)**
Estimated Duration of entire construction project from go-ahead:	From go-ahead, approximately 3 years **(Based on projects of similar type and scale Offshore-Technology.com)**
Actual Timeline for a Grand Banks gas pipeline for domestic power requirements:	THIS, depends on whether we (the Province) want this, ask for it and then negotiate mutually beneficial terms - it could look like this:

Here is the Muskrat option:

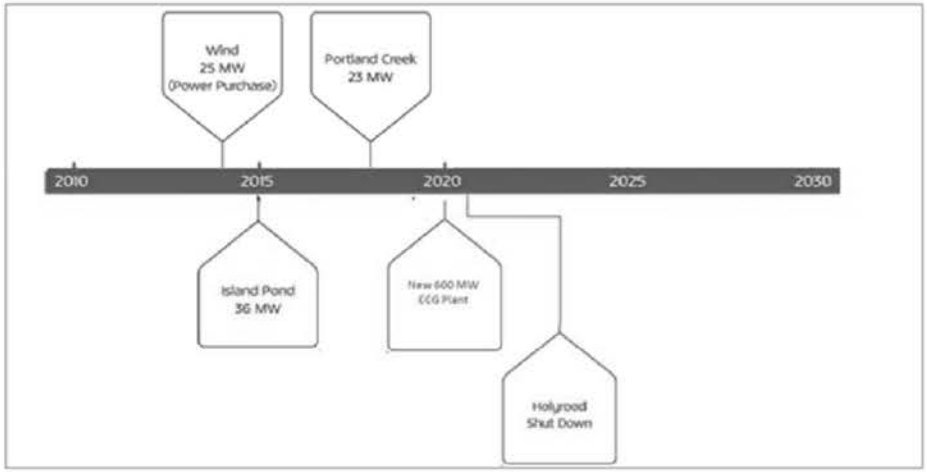


AND

Here is the natural gas option:



Alternatively, the Natural Gas Timeline could look like this (with small hydro helping us through until gas is ready):



OBSERVATION:

This hypothetical timeline takes into consideration the previously stated availability of gas for market sales by at least 2020. If negotiations resulted in gas sales arrangements before this then gas-fired generation may begin earlier, 2016 at the earliest. The Holyrood oil-fired plant would then shut down much earlier than in the Muskrat falls option.

BUT beware the Red Herrings. . .

Gas to Wire, Offshore CNG/LNG production, "All gas is reinjected!"

- Grand Banks Gas-to-Wire (GtW) is only a **Red Herring** in the timely policy discussion here. Gas-to-wire means importing natural gas, generating electricity with it ***and then exporting*** that electricity to some other market – It is explicit that that GtW as far as our Energy Plan is concerned does not involve using the electricity domestically.

- The technology for <u>producing</u> CNG or LNG on the Grand Banks is **remote** and **unproven** and therefore should be considered another **Red Herring** in this timely domestic policy discussion. The ONLY proven, reliable, safe, robust and common method of moving natural gas from offshore fields to land is by **PIPELINE**.

- **"All gas is currently reinjected and not available for sales"** is another **Red Herring** we have heard. Gas that is not used as fuel or flared – is reinjected <u>either</u> because it is needed for enhanced oil recovery (like at Terra Nova and Hibernia in the near term), <u>or</u>, it is reinjected because there is no one there to buy it. White Rose has more gas in their storage reservoir - than could conceivably be used by any or ALL producers and still have **lots** to sell us for our domestic needs.

"With respect to the depletion plan for North Amethyst, the proponent intends to . . produce the North Amethyst oil and inject the associated produced gas into the North Avalon Pool. . . Gas injection was also considered as an (oil) displacement strategy, **however . . Water flooding is the preferred recovery mechanism** . . "

http://www.cnlopb.nl.ca/news/pdfs/sadev.pdf

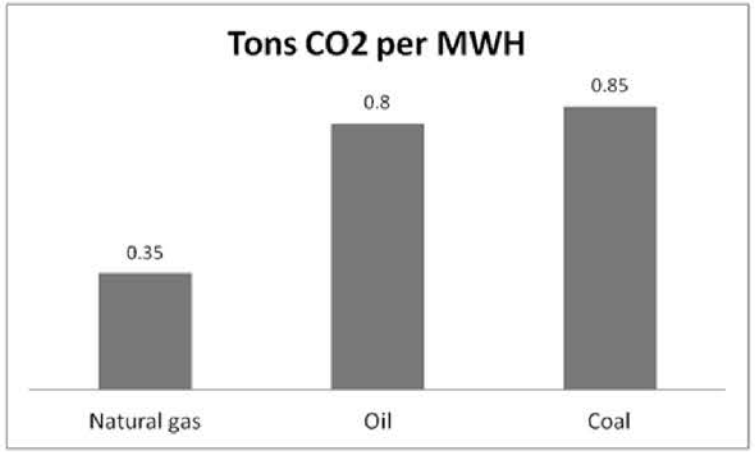
What about the Lower Churchill? What about the environment?

If developed together efficiently and sold into Ontario Markets for **Coal** replacement, the entire Lower Churchill Power Project including Gull Island and Muskrat Falls would have significantly improved environmental benefits over current plans.

We in NL can use natural gas - Ontario needs more than just gas **and** they have the money to pay for it. That province also brings a new negotiating and experiential perspective on the transmission and sales of electricity and natural gas through Quebec and other provinces. It just makes more sense for us to export the power and import the revenue.

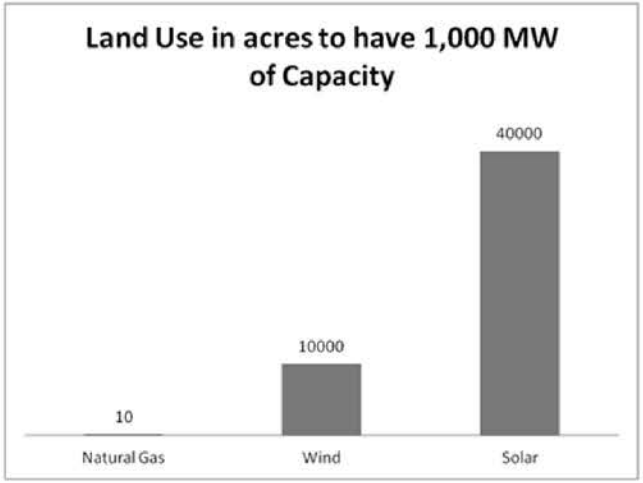
Interesting note:

The length of transmission lines in the Muskrat/Nova Scotia Project alone is over 1600 km exclusive of upgrades between the Avalon and Granite Canal.
YET,
The length of transmission lines to get from Gull Island to Ottawa, Ontario – less than 1600 km



Natural Gas fired generation:

Smallest ecological footprint for power generation



For high volume energy transportation:

8 power transmission masts of 3 GW each are equal to 1 gas pipeline (48 inch)

Source: based on data from Union Gas Ltd.

Why not produce LNG on shore and ship it to market?
Why not make a bigger pipeline?

BECAUSE, the current discussion revolves around a domestic electricity supply problem, expanding business opportunities are not part of the decision review process. It is a matter for the producers to decide how they may wish to expand this opportunity.

What about Wind Power sales from the Island?

The most compelling case for non-subsidized wind power in this province is to use wind for hydraulic transfer between watersheds and into the massive Smallwood reservoir in Labrador. This water then becomes new dispatchable hydropower energy – through one or more hydro plants that will already be connected via transmission lines to the national marketplace.

What about improved security of supply and reliability based on having or not having the interconnection ?

Navigant says there is no difference as far as the Labrador link is concerned – to them burning oil on the island is just as reliable and secure as the Labrador link.

Security of Supply and Reliability

Nalcor has investigated the level of exposure and unserved energy due to transmission failures in both alternatives. Based on the Nalcor analysis, in the worst case scenarios (transmission failures occurring in the worst two week window in terms of system load and available generation) both alternatives yield unsupplied energy of less than 1 percent of the annual energy forecast which represents increased security of supply and reliability as compared to the current situation.

Interestingly it is suggested that the largest single "contingency" that the Island system can accommodate without instability is 175MW. This is easily managed with the highly flexible arrangement of turbine sizes available in standard CCGT units.

What about oil developments, does this hurt productivity or economics?

Hibernia

While the gas resource is currently used for fuel and for reservoir pressure support to exploit the oil reserves, it will eventually be available for production. Future exploitation of the gas resources may also extend the economic life of the Hibernia Field, permitting additional oil to be recovered. The Proponent conducted a preliminary review of gas commercialization in the Application. The timing of gas availability at the Hibernia Field for commercial purposes is dependent on the gas requirements for the exploitation of the oil reserves, and the natural gas liquids resources. According to the Proponent, Hibernia could support gas sales of 200-300 million standard cubic feet per day starting after 2020, in order to ensure that optimized reservoir oil exploitation occurs (Figure 4.3.7.1).

http://www.cnlopb.nl.ca/news/pdfs/hibsadev.pdf

White Rose – North Amethyst

The solution gas resource will be either stored, used as fuel or flared. Reservoir simulation indicates that 87% of this solution gas will be available for storage. The gas cap recovery is estimated to be 70%.

Future exploitation of gas resources will extend the economic life of the White Rose Field and permit additional oil recovery (NGL's). The timing of gas availability at the White Rose Field for commercial purposes is dependent on economic and technological factors.

'news/pdfs/sadev.pdf

White Rose – North Amethyst (cont)

Remarkably, the combined gas production from White Rose and North Amethyst is expected to EXCEED the storage capabilities of their current subsurface storage licence granted to them by the CNLOPB (#1001). . ..

Thus, the Proponent needs to identify additional gas storage in order to produce the oil from North Amethyst Field in conjunction with the South Avalon Pool and other potential satellite developments. The Proponent has indicated in technical briefings that they are evaluating several gas storage options for the North Amethyst Field, which include:

- Injection in the West Avalon White Rose pool;
- Injection in the South Avalon White Rose pool;
- Combined water and gas injection in North Amethyst Field.

All of these options would require additional Board approval, in terms of changes to the current Subsurface Gas Storage licence, Development Plan Amendment to the South Avalon pool or a development plan amendment of North Amethyst Field. **Staff believes the Proponent must resolve the gas storage issue before North Amethyst oil is produced, as surplus gas flaring will not be permitted above the authorized flaring allowance.**

http://www.cnlopb.nl.ca/news/pdfs/sadev.pdf

White Rose – North Amethyst (cont)

We are Partners in North Amethyst !

- North Amthyst natural gas production could supply a large part of our needs right now, it is completely surplus to all conceivable needs on the Sea Rose FPSO platform or for oil production and - we are an equity stakeholder in it.

- The operators were (in 2010) apparently looking at drilling new wells in alternative gas storage reservoirs. The costs of doing this if new wells and or a new glory hole is required can easily exceed $100 million CAD.

- According to Maersk and Husky in 2004 the maximum cost to prepare the white rose FPSO for gas export via pipeline was determined to be around $100million CAD.

- **But using the FPSO may not be ideal and would not be necessary if accommodation were made for gas export on the proposed GBS for white rose. The company has targeted 2016 to start production from a new wellhead GBS!**

- The white Rose development application states that it recognises the Province of Newfoundland as one of the principal beneficiaries of the resources offshore and so respects the spirit and terms of the Atlantic Accord

This wellhead GBS is probably the single greatest opportunity we will have to partner with operators to kick-off our domestic gas pipeline project – we should be involved.

Final Word on Grand Banks Natural Gas for Domestic Electric Generation in the Island . . .

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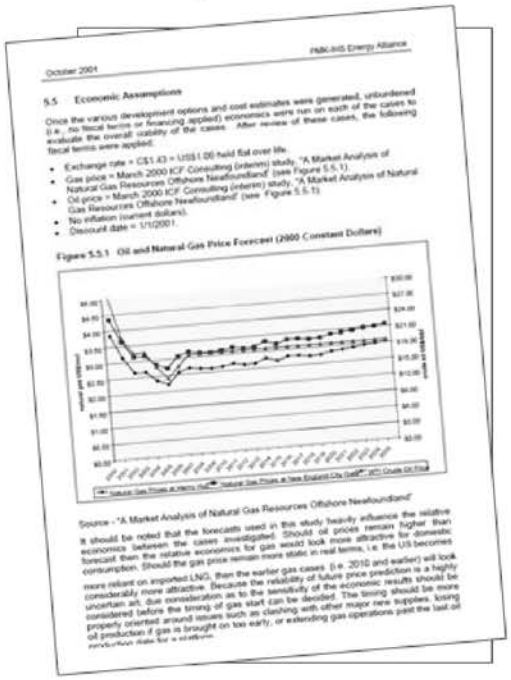

October 2001 PAN-IHS Energy Alliance

5.5 Economic Assumptions

Once the various development options and cost estimates were generated, unburdened (i.e., no fiscal terms or financing applied) economics were run on each of the cases to evaluate the overall viability of the cases. After review of these cases, the following fiscal terms were applied:

- Exchange rate = C$1.43 = US$1.00 held flat over life.
- Gas price = March 2000 ICF Consulting (interim) study, "A Market Analysis of Natural Gas Resources Offshore Newfoundland" (see Figure 5.5.1).
- Oil price = March 2000 ICF Consulting (interim) study, "A Market Analysis of Natural Gas Resources Offshore Newfoundland" (see Figure 5.5.1).
- No inflation (current dollars).
- Discount date = 1/1/2001.

Figure 5.5.1 Oil and Natural Gas Price Forecast (2000 Constant Dollars)

Source - "A Market Analysis of Natural Gas Resources Offshore Newfoundland"

It should be noted that the forecasts used in this study heavily influence the relative economics between the cases investigated. Should oil prices remain higher than forecast then the relative economics for gas would look more attractive for domestic consumption. Should the gas price remain more static in real terms, i.e. the US becomes more reliant on imported LNG, then the earlier gas cases (i.e. 2010 and earlier) will look considerably more attractive. Because the reliability of future price prediction is a highly uncertain art, due consideration as to the sensitivity of the economic results should be considered before the timing of gas start can be decided. The timing should be more properly oriented around issues such as clashing with other major new suppliers, losing oil production if gas is brought on too early, or extending gas operations past the 'last oil

This is the Natural Gas study done for NL government in 2001 – and was used by Navigant to conclude that Natural gas is not commercially available.

Here's what it says if their predictions for oil prices are too low:

"Should oil prices remain higher than forecast then the relative economics for gas would look more attractive for <u>domestic consumption</u>"

They predicted oil staying at US$18/bbl past 2025 . . .

"Should the gas price remain more static. . ., then the earlier gas (development) cases (i.e. 2010 and earlier) <u>will look considerably more attractive</u>"

Gas prices have flattened are expected to be flat for long time.

[2] *Technical Feasibility of Off-shore Natural Gas and Gas Liquid Development Based on a Submarine Pipeline Transportation System, Off-shore Newfoundland and Labrador, Final Summary Report* to the Government of Newfoundland and Labrador, Department of Mines & Energy, Petroleum Resource Development Division, submitted by Pan Maritime Kenny – IHS Energy Alliance, October 2001

In conclusion:

- Natural gas is available in the timeframe and quantities we need for domestic electricity. The costs for natural gas infrastructure and fuel are very low compared to the alternatives.
- Many examples of similar kinds of projects abound.
- Beware of Red Herrings.
- The lights will not be going out in the warehouse – lets take a closer look at our natural gas options and perhaps consider more profitable ways to develop the Lower Churchill in its entirety.

Thank you for your attention

Grand Banks Natural Gas for Island Electric Generation

Dr. Stephen E. Bruneau March 28, 2012