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

Exclusion of Grand Banks Natural Gas from Independent Review

Availability of Grand Banks Natural gas

Why it needs to be considered now - and what to ask

PART 2

Natural Gas for Electricity - Infrastructure Costs and Examples

Time line if Natural Gas were Utilized

Red Herrings, Common Questions and the Environment

Conclusions

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.

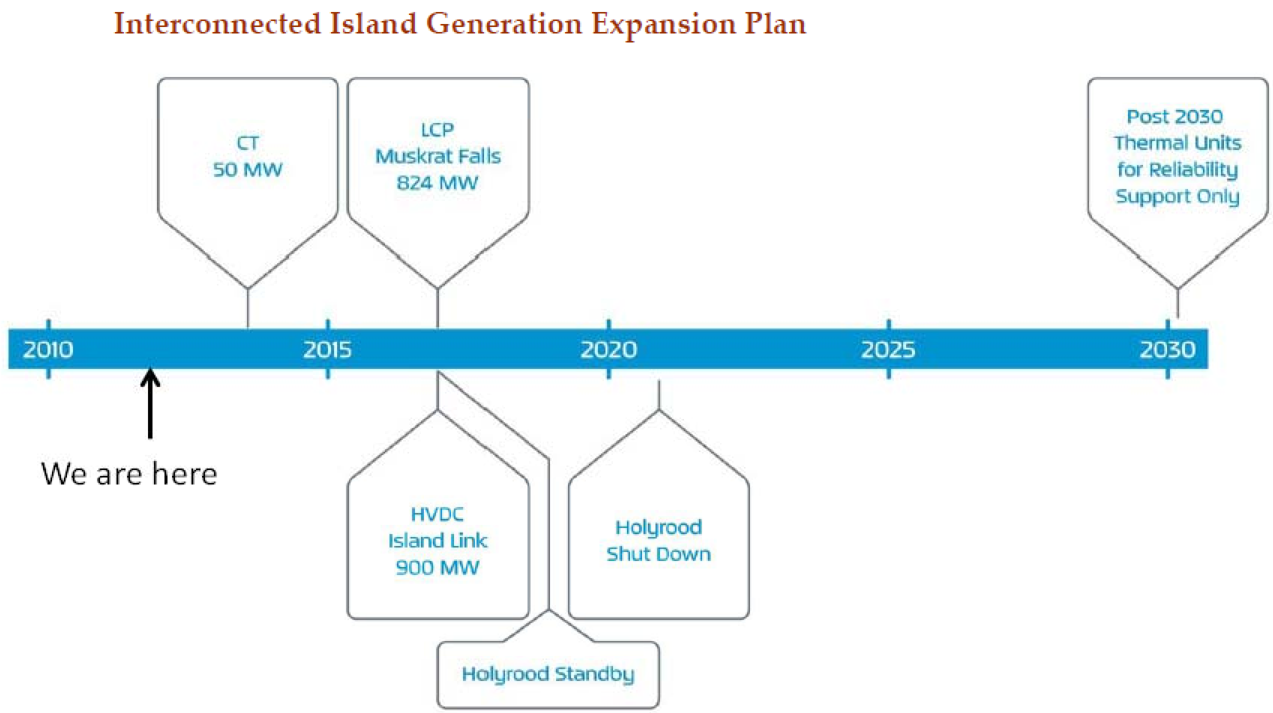
So let us look at the availability of Natural Gas

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.

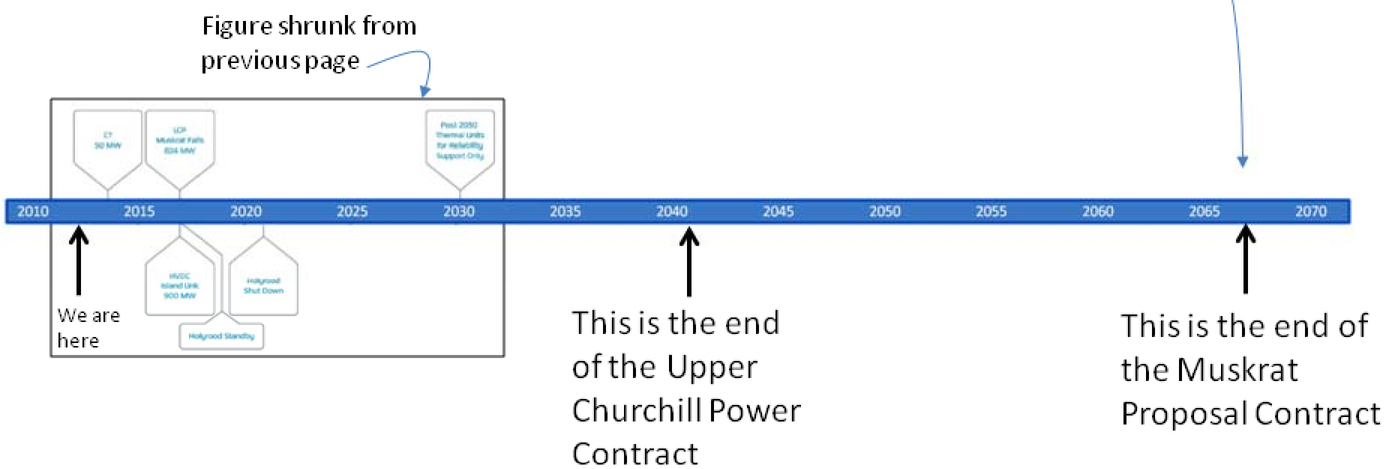
NATURAL GAS AVAILABILITY: TIME FRAME

This is the timeline of the Muskrat Proposal from Navigant

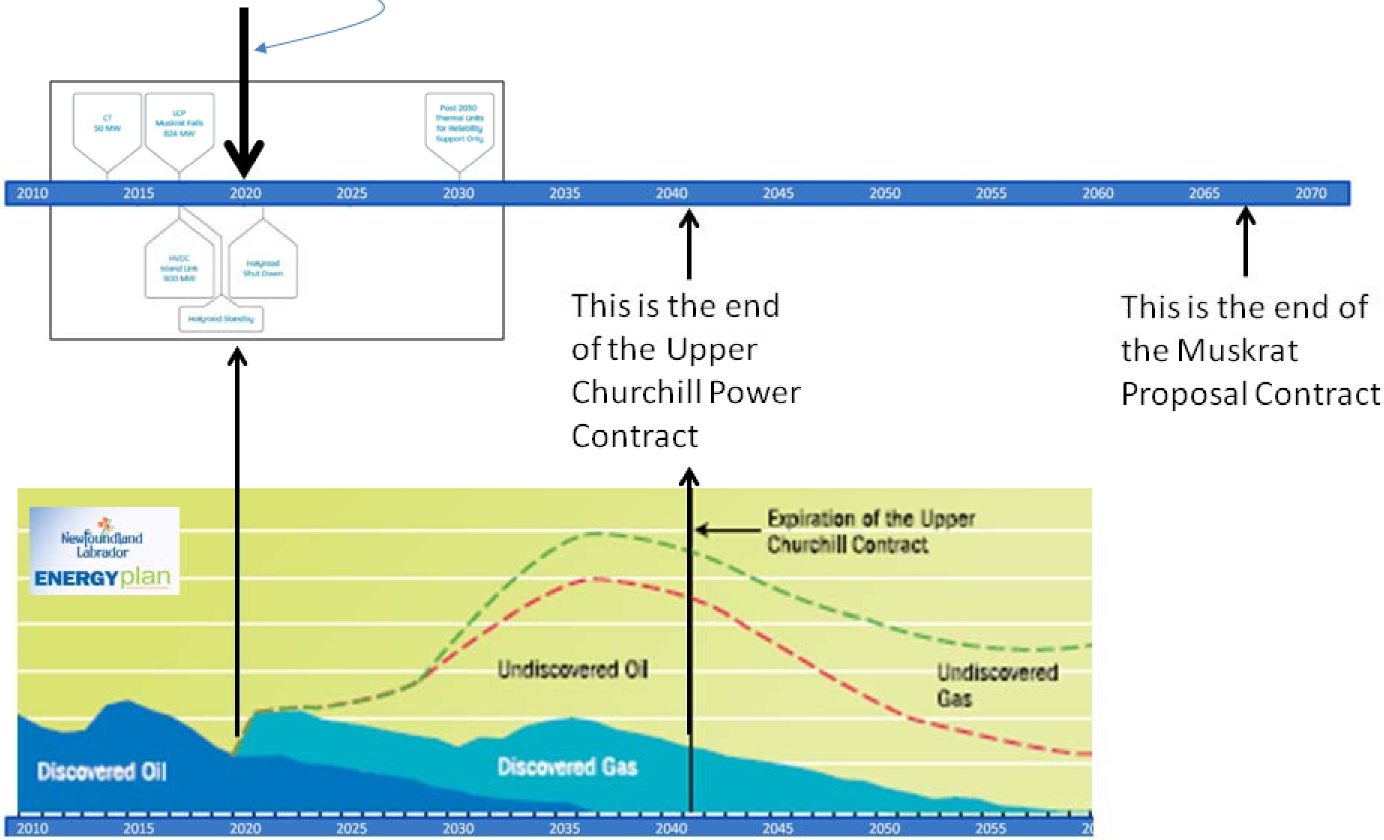


Source: Nalcor Energy

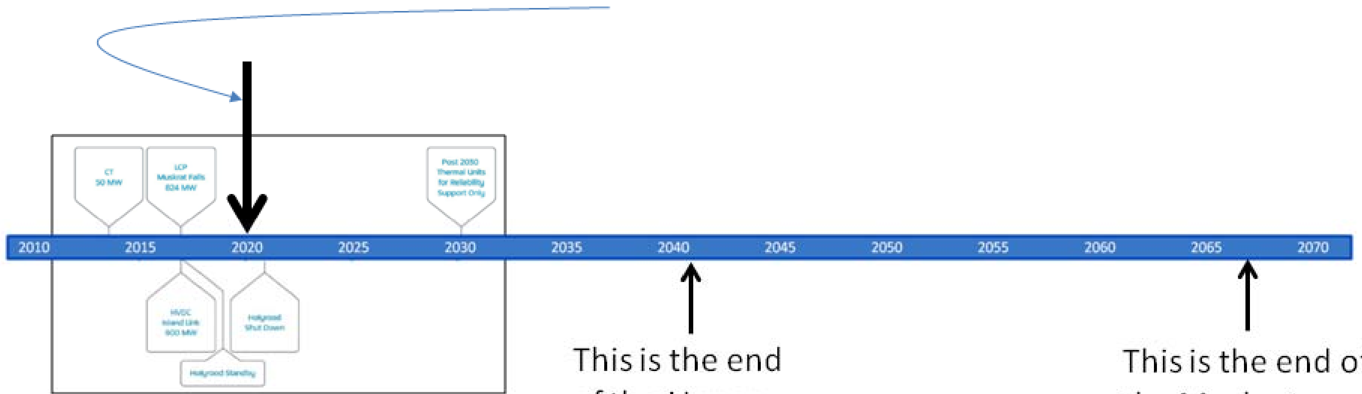
This is the same timeline but extended to include the Muskrat Falls contract duration



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



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



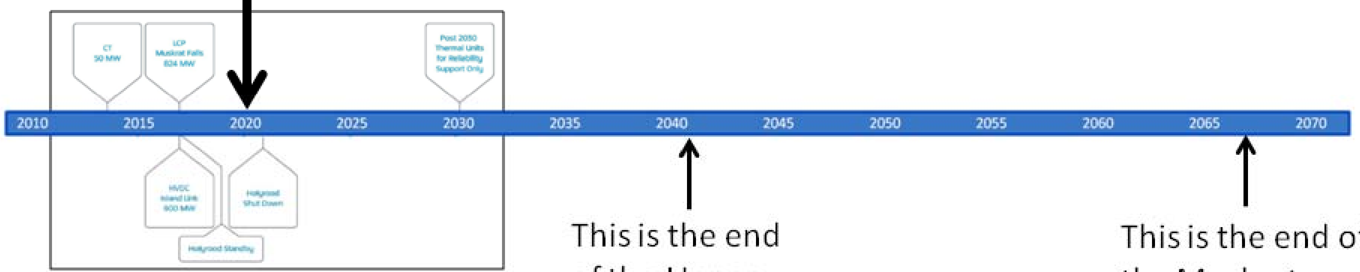
This is the end of the Upper Churchill Power Contract

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 <u>will reach market in 2020</u> – 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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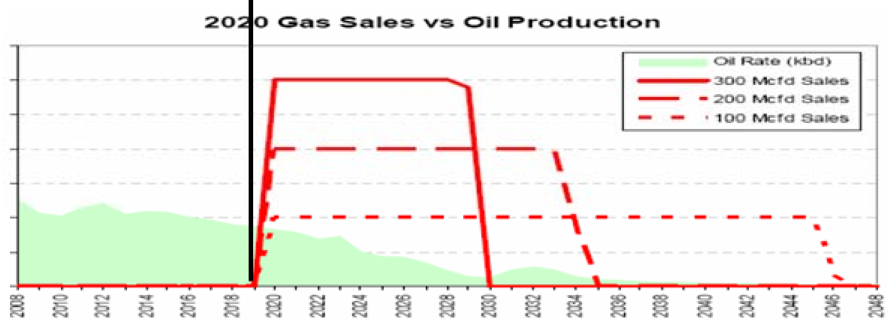
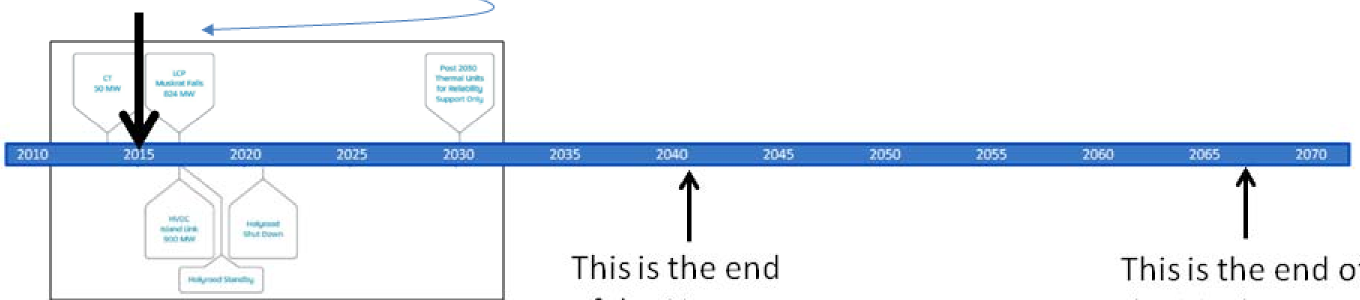


Possible 2020 Gas Sales vs. Oil Production (Source: HMDC)

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.



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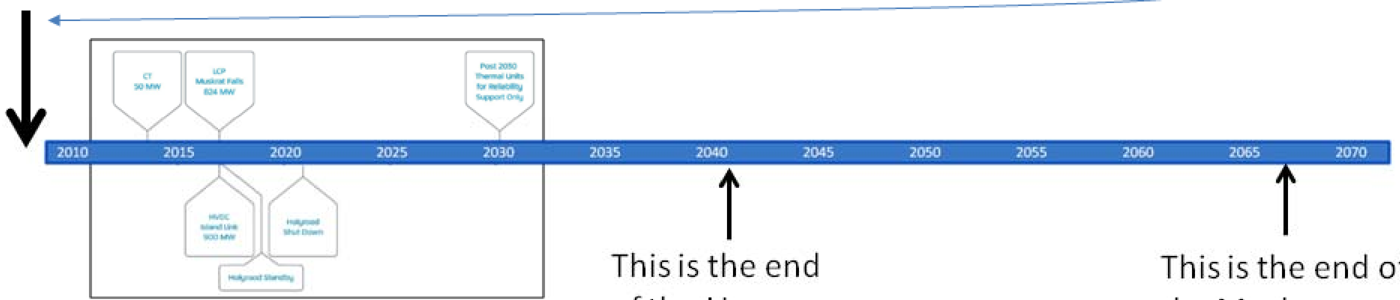
[12] *Technical Feasibility of Off-shore Natural Gas and Gas Liquid Development Based on a Submarine Pipeline Transportation System, Off-shore Newfoundland and Labrador, Final Summary Report* to the Government of Newfoundland and Labrador, Department of Mines & Energy, Petroleum Resource Development 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.



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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:

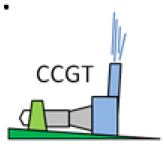
"Is the rate of natural gas production at existing production platforms sufficient for satisfying domestic power needs?"

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:

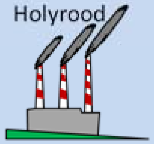


<u>35 mmscf/d</u>

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

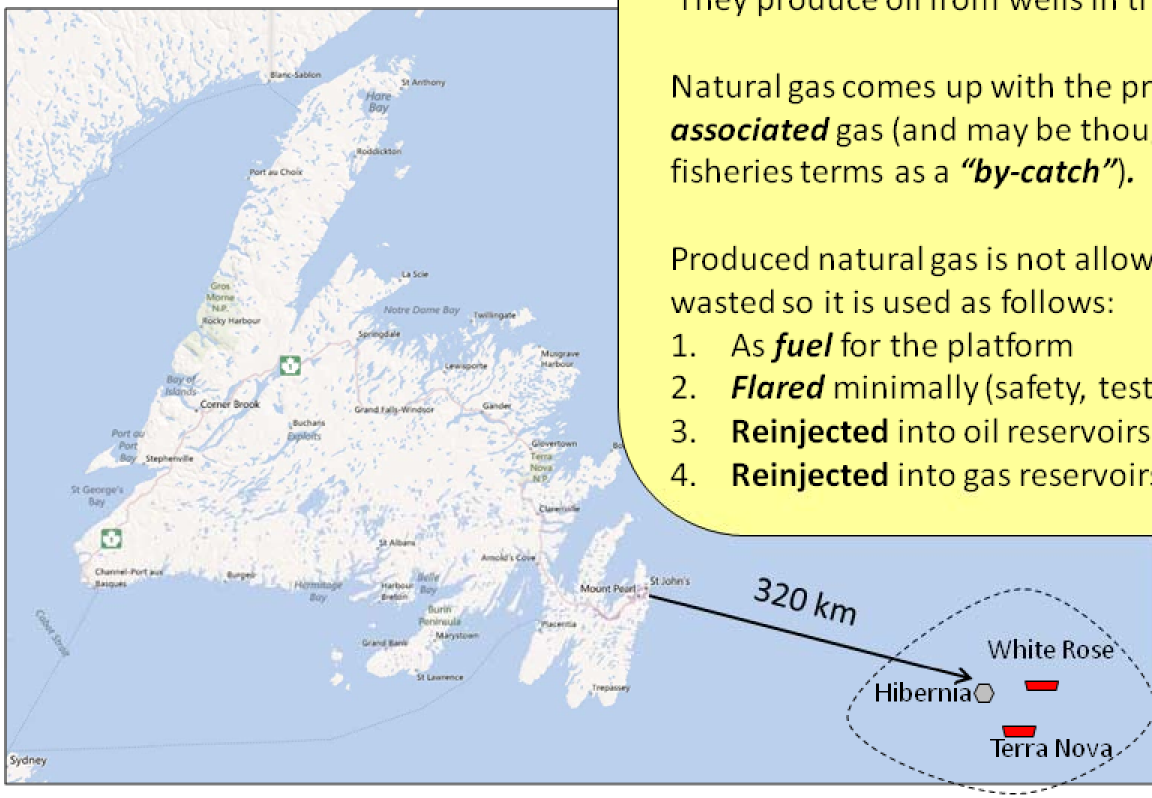
(ie. About 210 MW average annual power rate)

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 = <u>12.7 mmscf/d</u>

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



BACKGROUNDER:

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

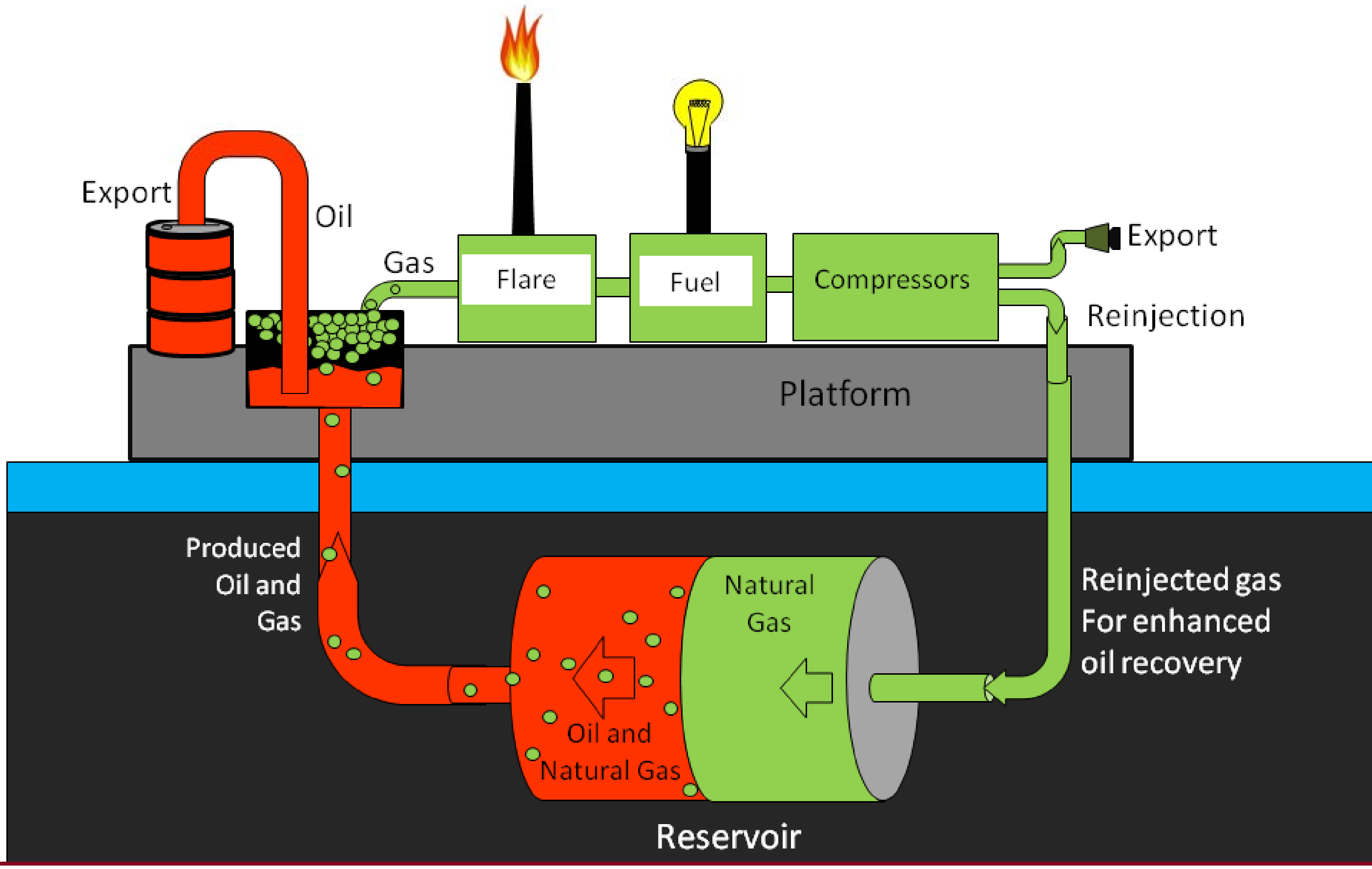
They produce oil from wells in the sea bed.

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

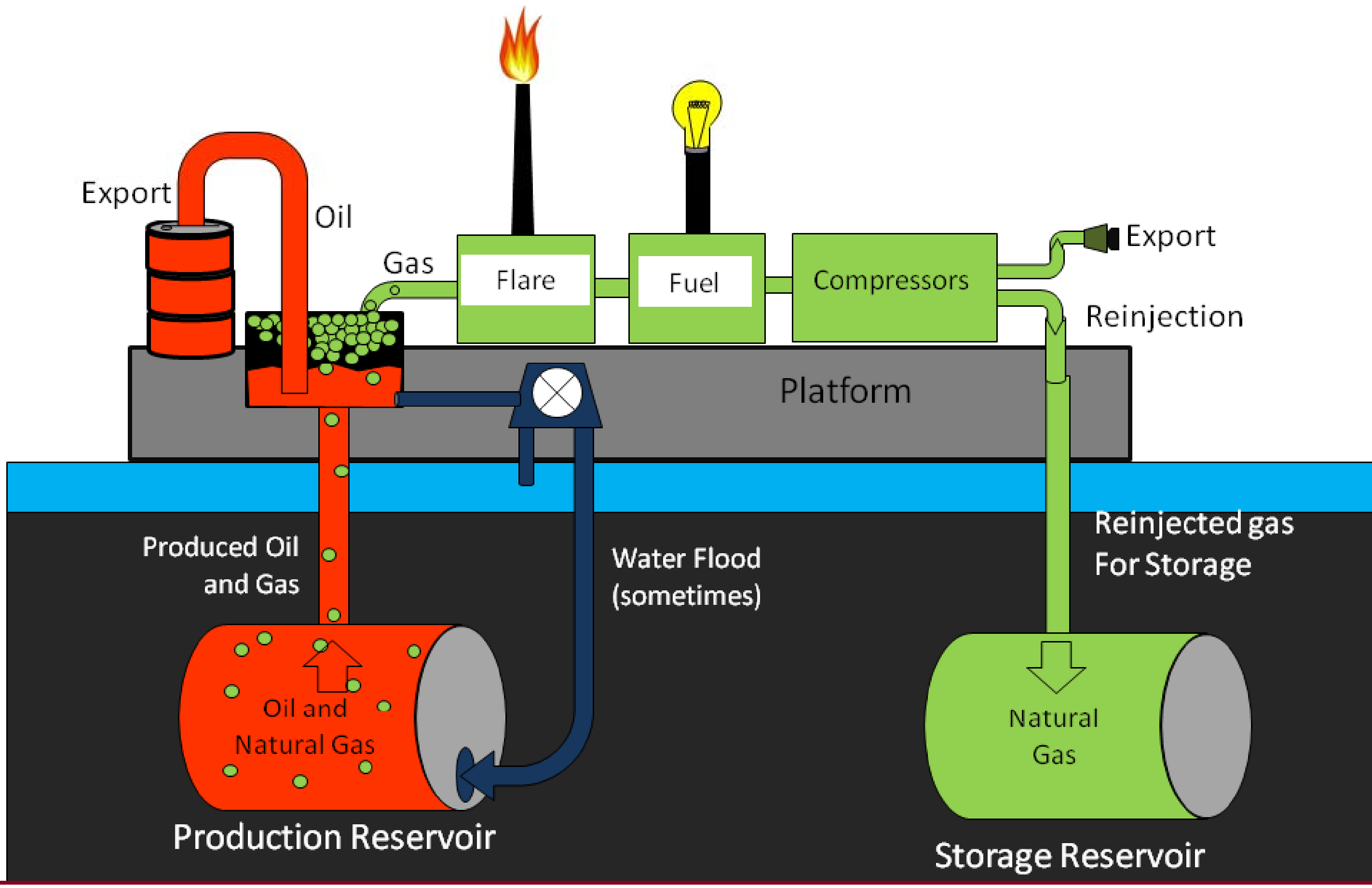
Produced natural gas is not allowed to be wasted so it is used as follows:

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

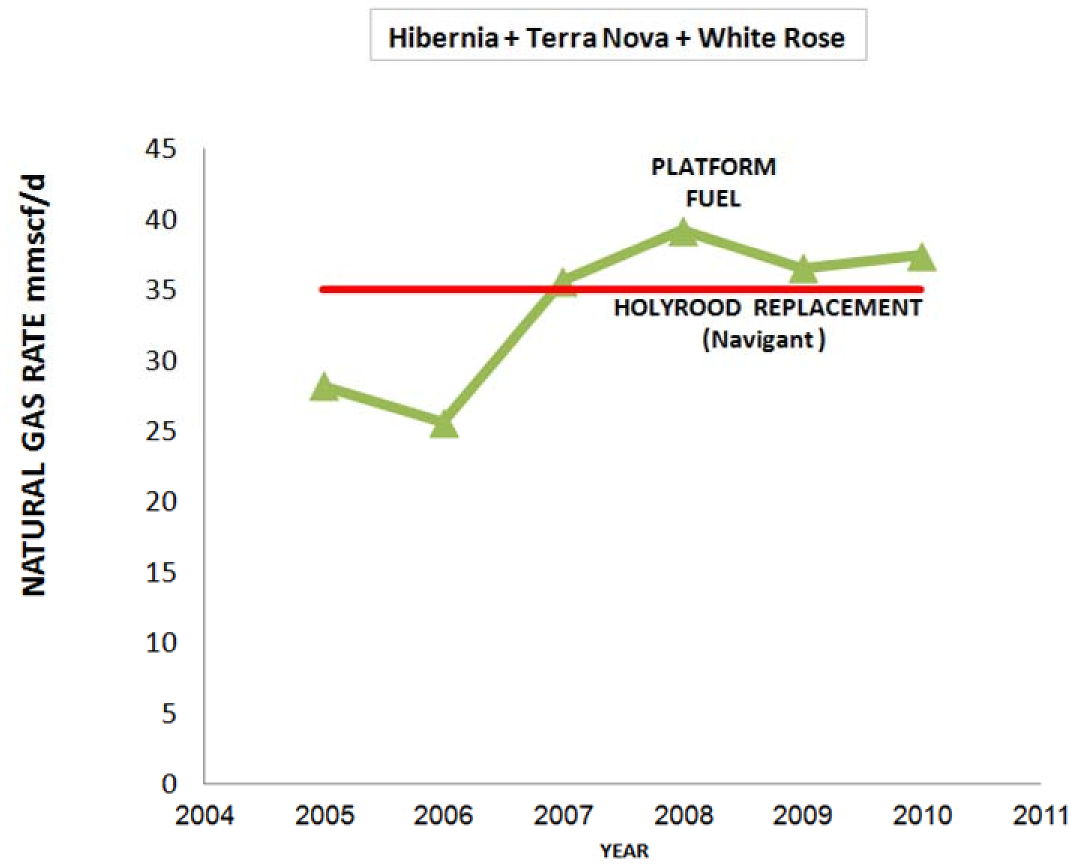
Simplified Grand Banks Oil Production Schematic – with Gas used for Oil Production Support

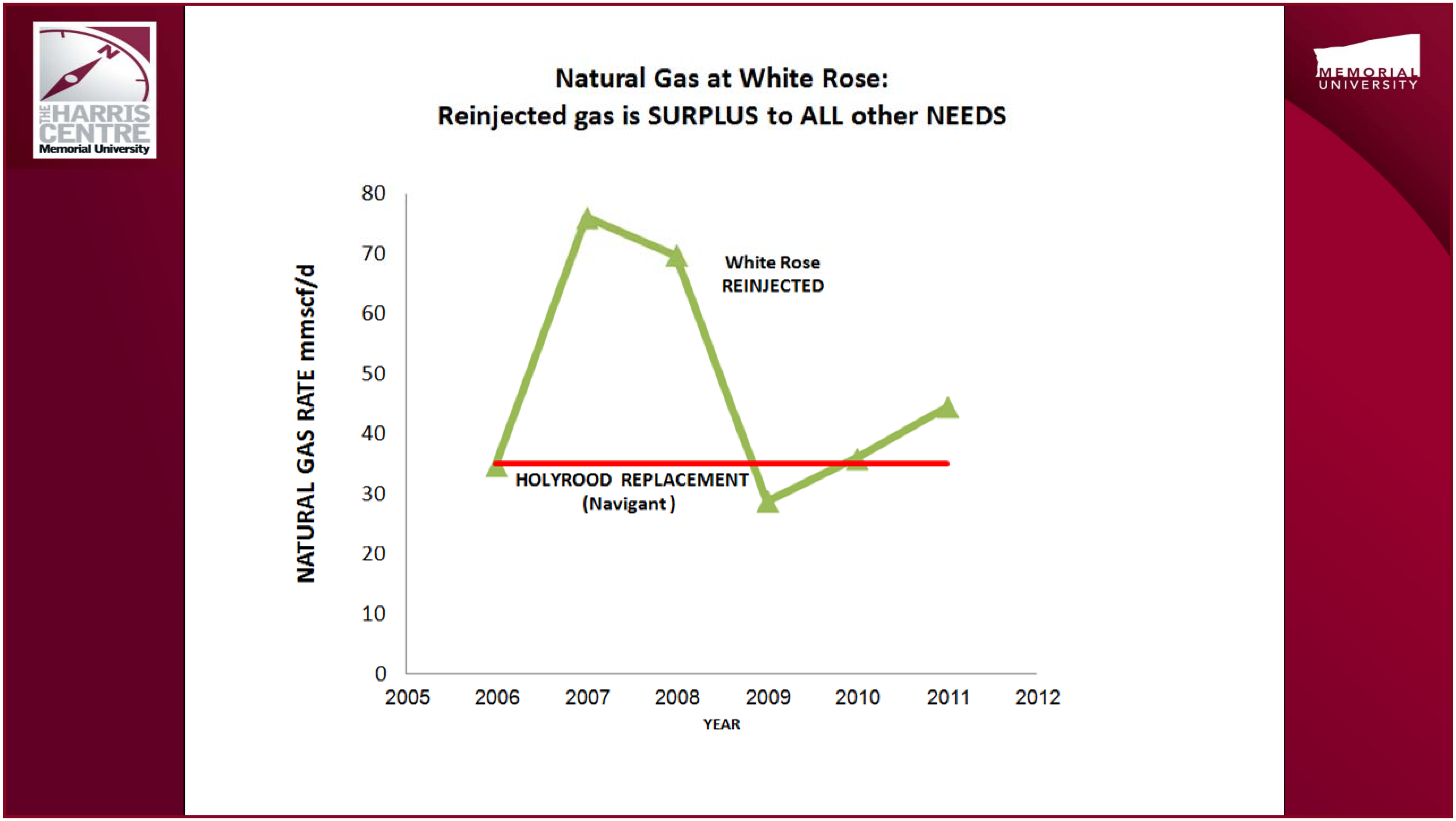


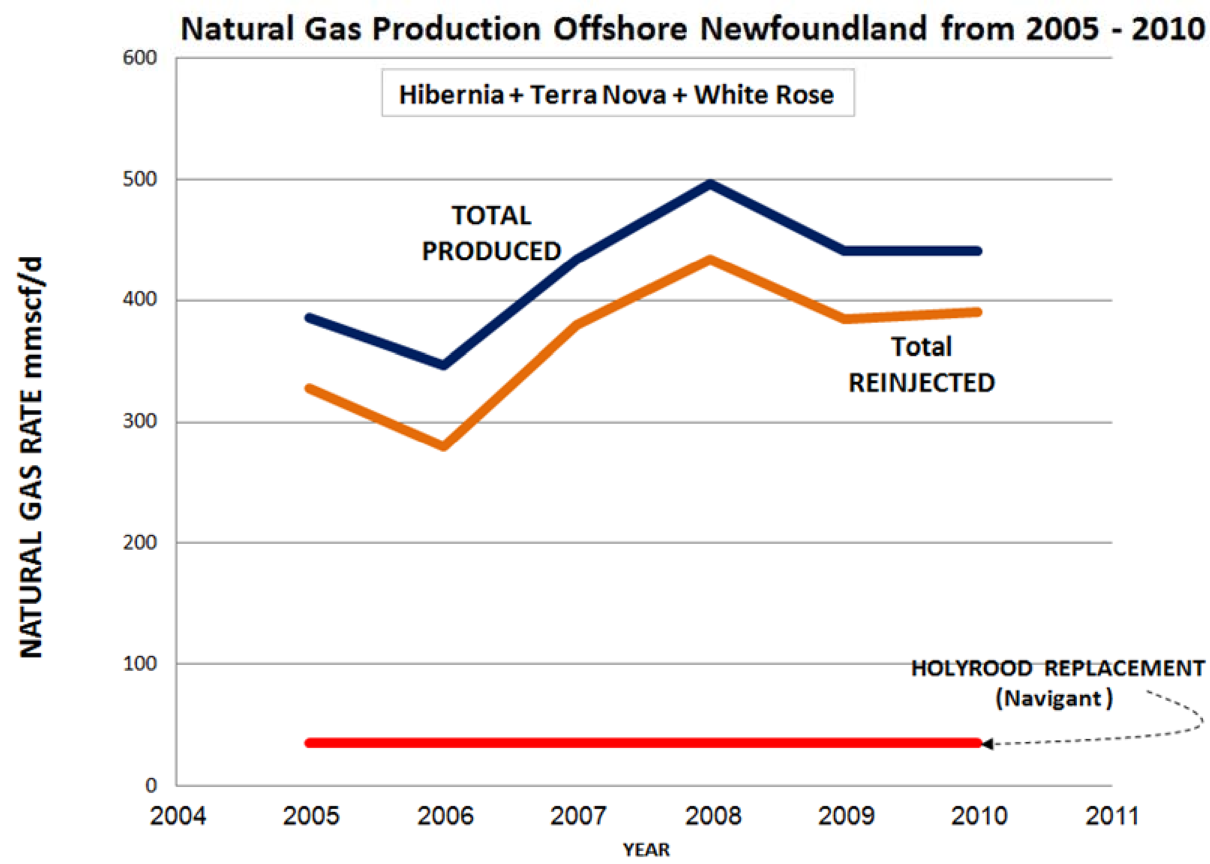
Simplified Grand Banks Oil Production Schematic – Where Gas Can't Help Oil Production



Natural Gas Use Offshore Newfoundland from 2005 - 2010

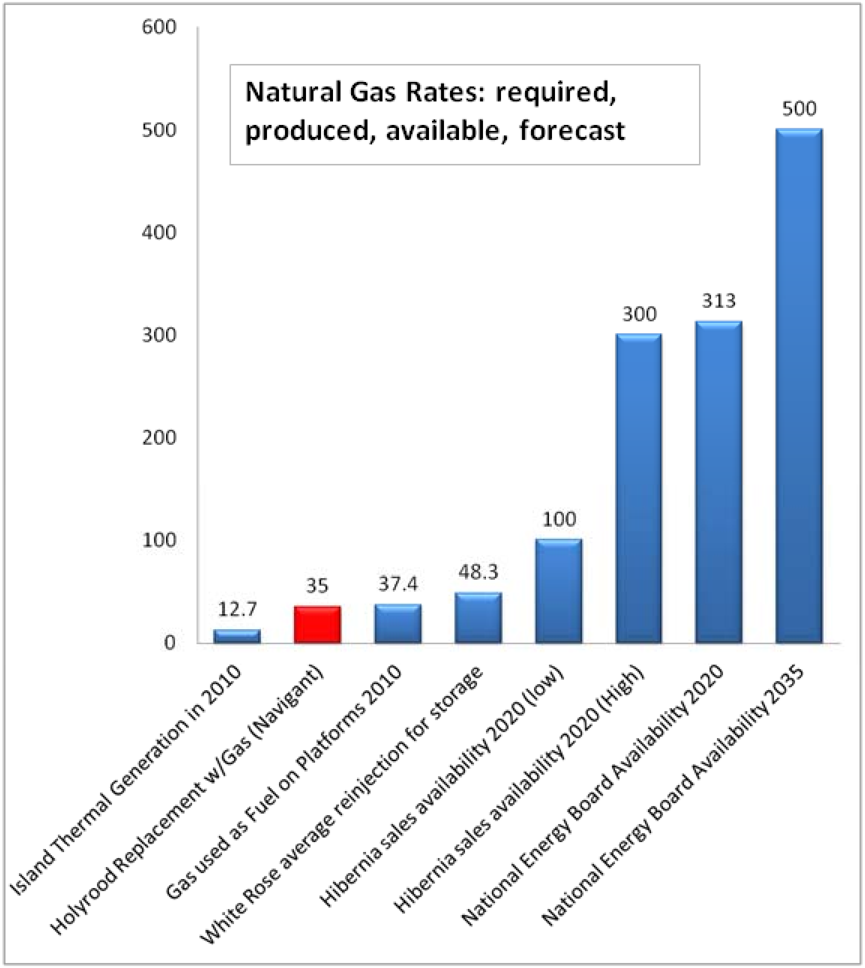



THE HARRIS CENTRE
Memorial University
MEMORIAL UNIVERSITY
Natural Gas at White Rose:
Reinjected gas is SURPLUS to ALL other NEEDS
NATURAL GAS RATE mmscf/d
80
70
60
50
40
30
20
10
0
2005
2006
2007
2008
2009
2010
2011
2012
YEAR
White Rose
REINJECTED
HOLYROOD REPLACEMENT
(Navigant)



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
YEAR
0
100
200
300
400
500
600
2004
2005
2006
2007
2008
2009
2010
2011

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.

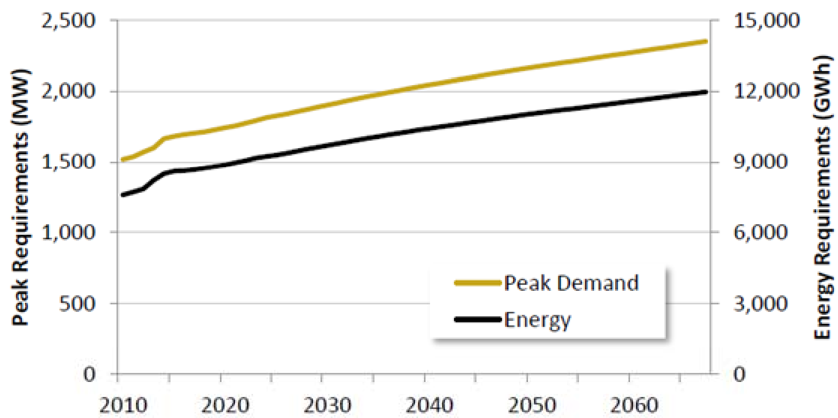
Natural Gas Availability: **Total Quantity**

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:

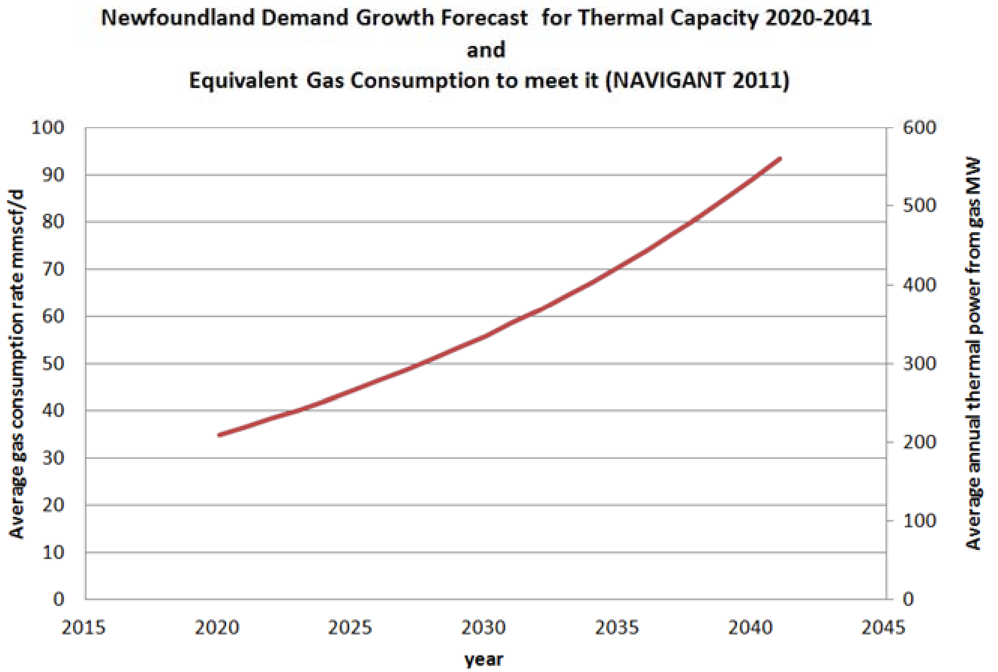
Figure 15: Newfoundland Peak Demand and Energy Requirements



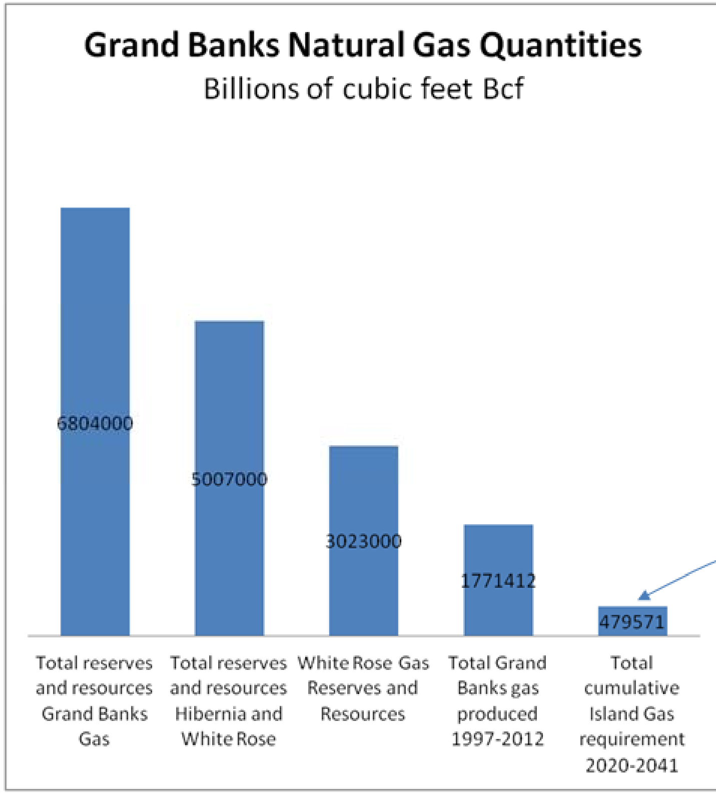
Source: Nalcor. "Synopsis of 2010 Generation Expansion Decision" Exhibit 13b. July 2011

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 ?

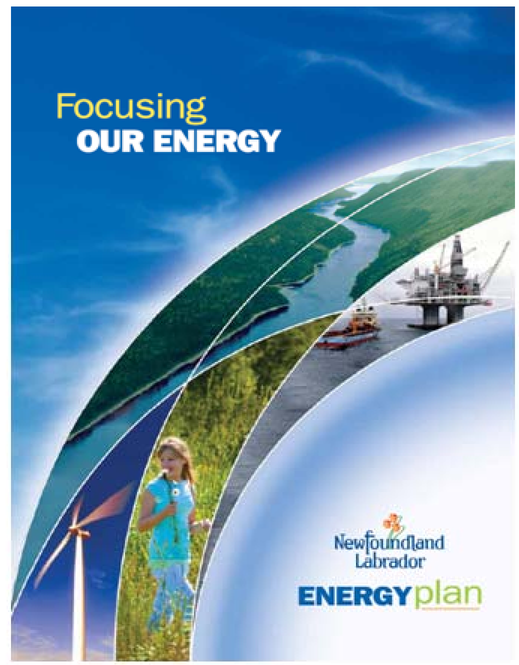


Here it is!

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.

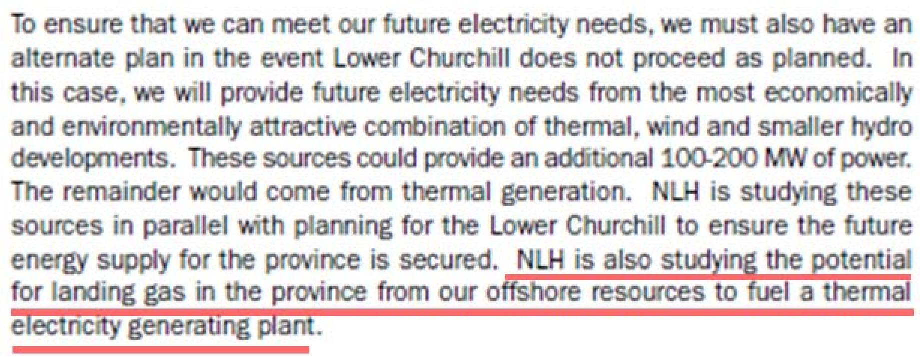
The Provincial Government understands the unique challenges of using this resource within the province, but there are also opportunities. To ensure these opportunities are fully assessed, the Provincial Government will request that companies provide detailed "landing in the province" options prior to 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.

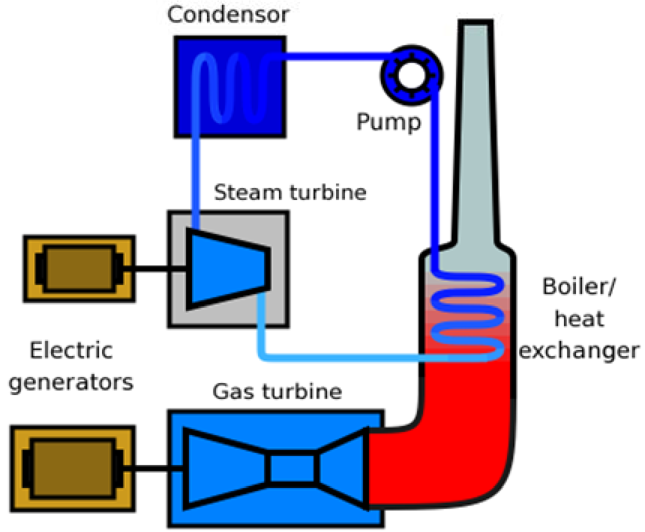
PART 2

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 . . .

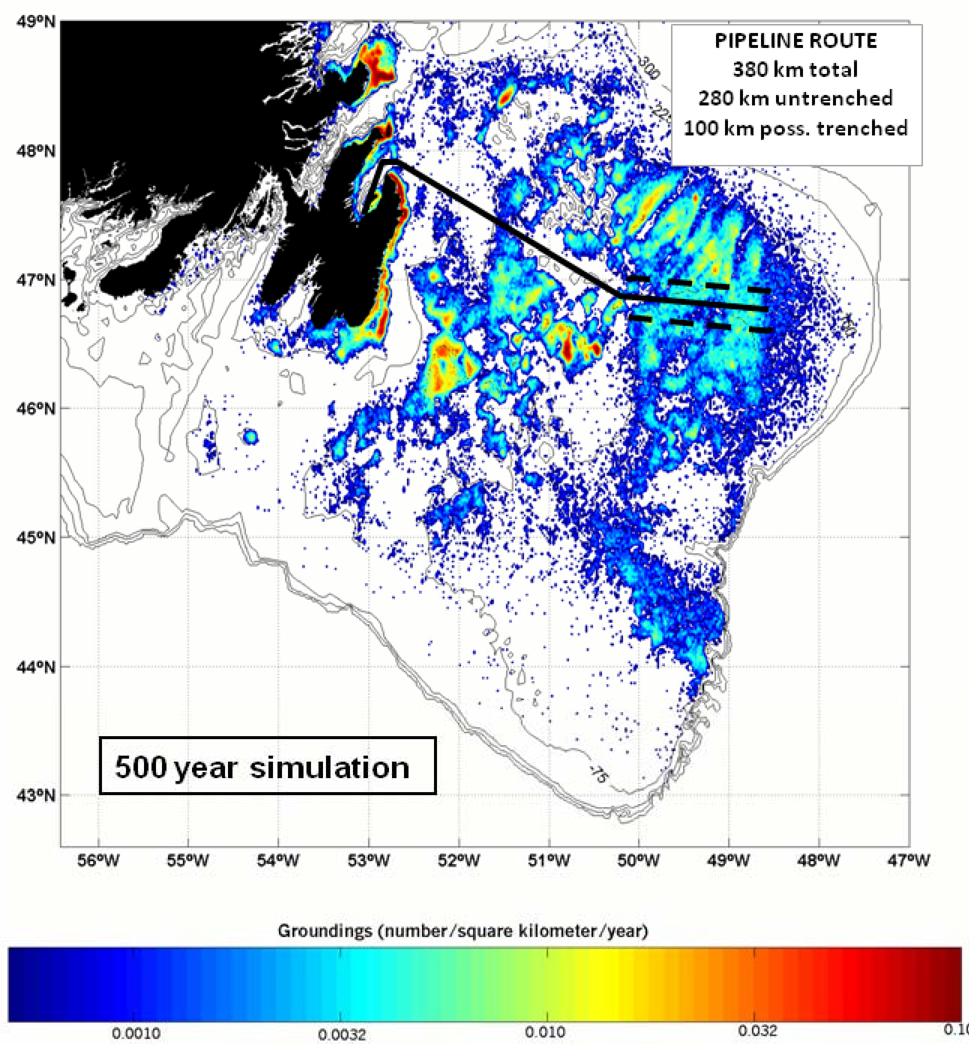
- Icebergs considered too risky for Grand Banks pipelines 30 yrs ago

- 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. . .

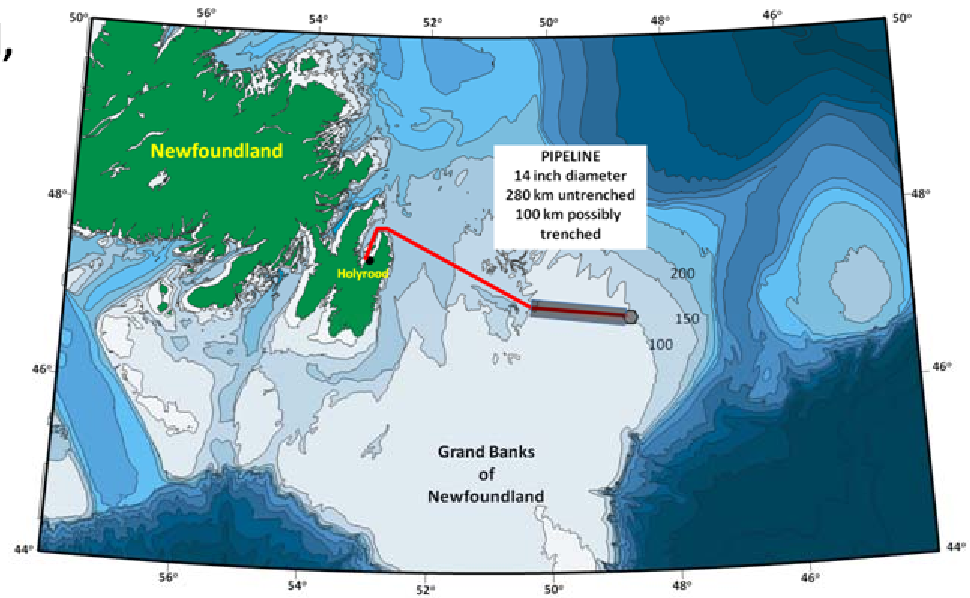
Iceberg Grounding and scour risk chart:
The pipeline route has been selected here on the basis the shortest distance subsea to Holyrood and following a low-iceberg risk zone.



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?

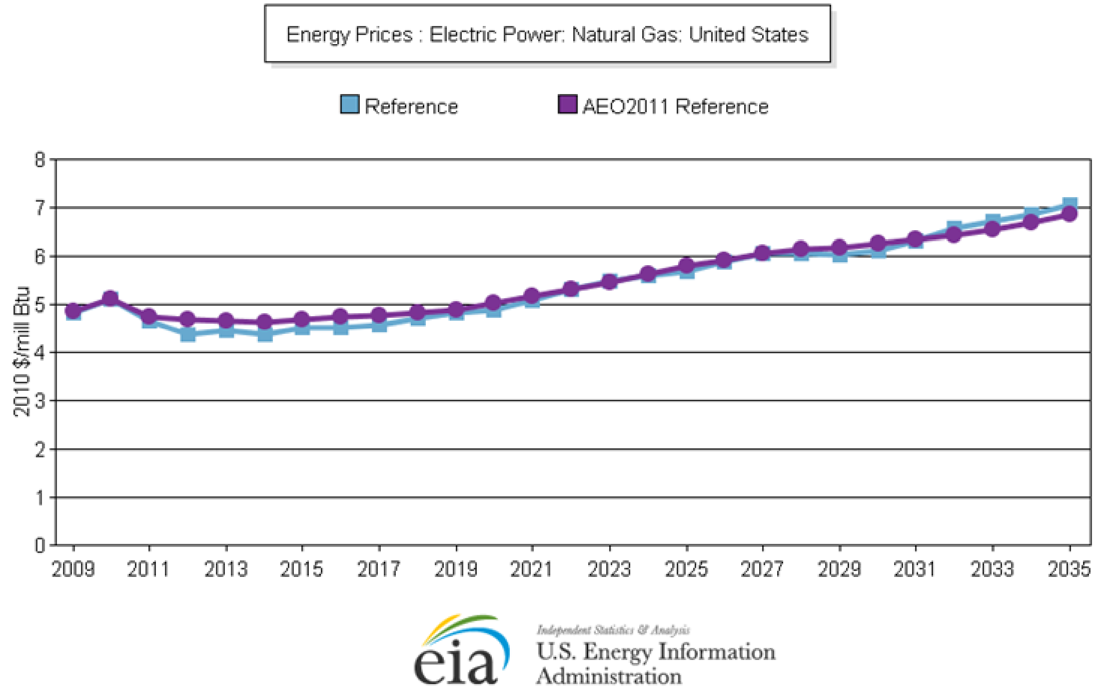
IN a written submission to the PUB last month I suggested that the price we may pay for the purchase of natural gas from a producer operating on the Grand Banks would be negotiated arrangement taking into consideration many factors. I listed the factors and so they are a matter of public record.

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?

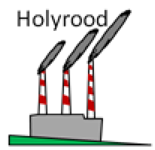
The Energy Information Administration in US provide the following projections for natural gas price:



Yes, BUT what do these prices mean?

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

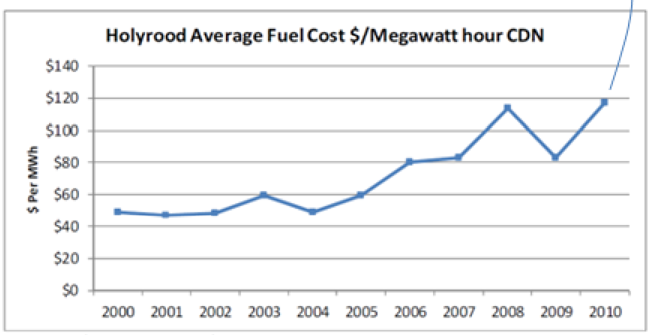
Holyrood Thermal Power Plant 2010



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

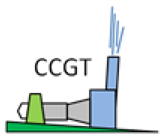
Cost of $119,000 /GWh = **$94.2 million**

Source:



Source: Nalcor Energy, March 2011

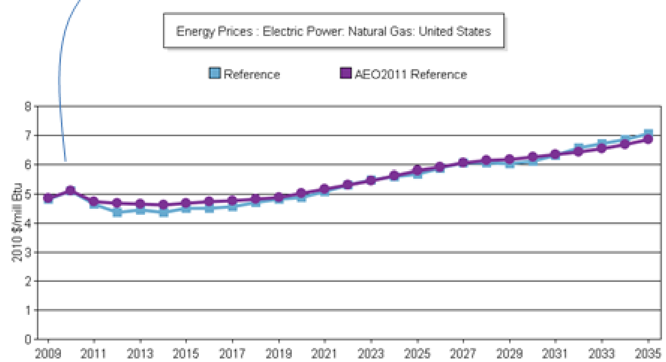
CCGT power plant for 2010



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

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

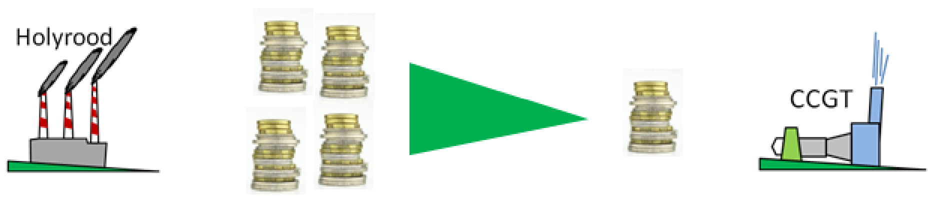
Source:



eia U.S. Energy Information Administration

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

Reduced our fuel bill by a <u>factor of FOUR</u> ($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 ***<u>other gas pipeline projects</u>*** 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

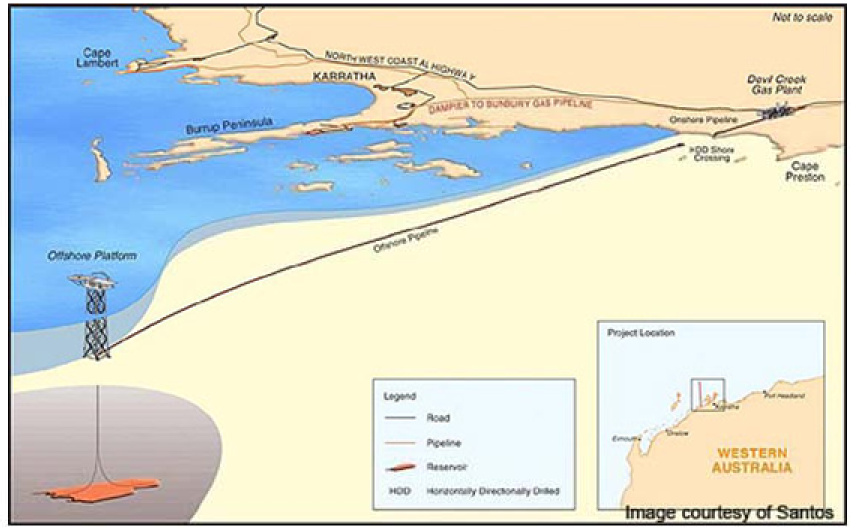
3. Canadian pipeline, Owned and Operated by Newfoundland Based Company, connecting Island for power generation – ***Vancouver Island Pipeline***

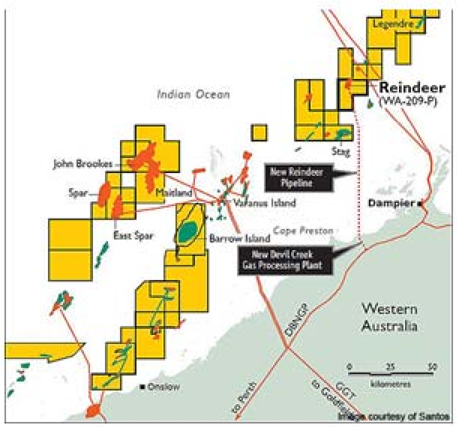
4. Isolated Island in need of natural gas for electric generation while major industry players produce oil and gas nearby – **Tobago Natural Gas Pipeline**

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)





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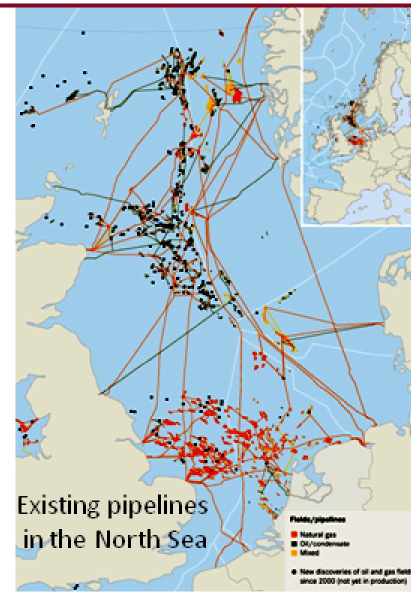
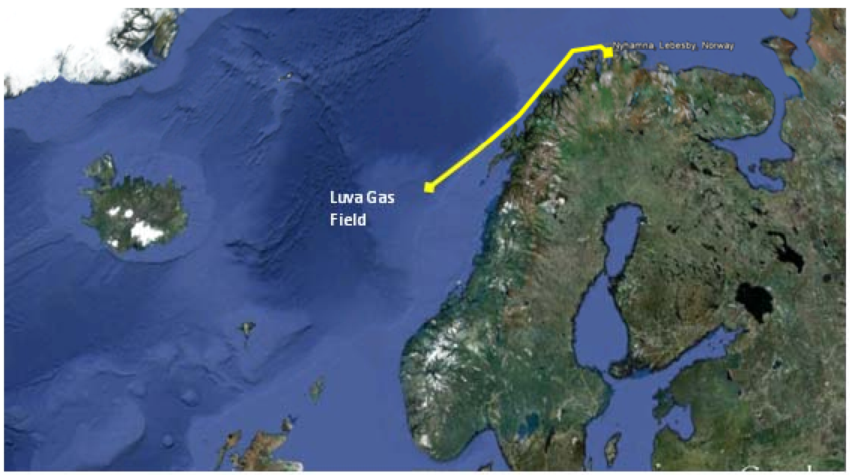
Example 2 – Extreme environment similar length

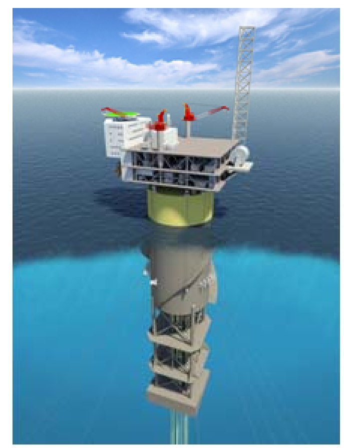
Luva Field, Offshore Northern Norway

- 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!



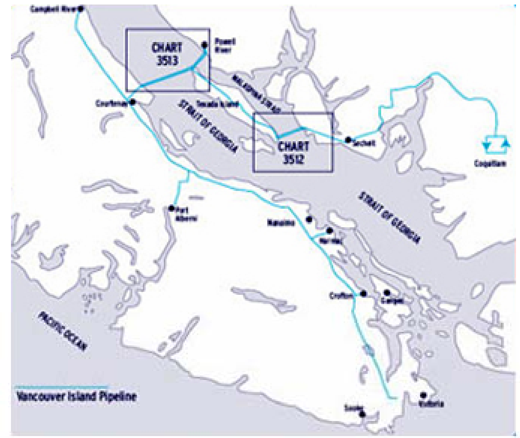




Example 3 – Canadian Island gets connected

<u>Vancouver island pipeline</u>

- 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)



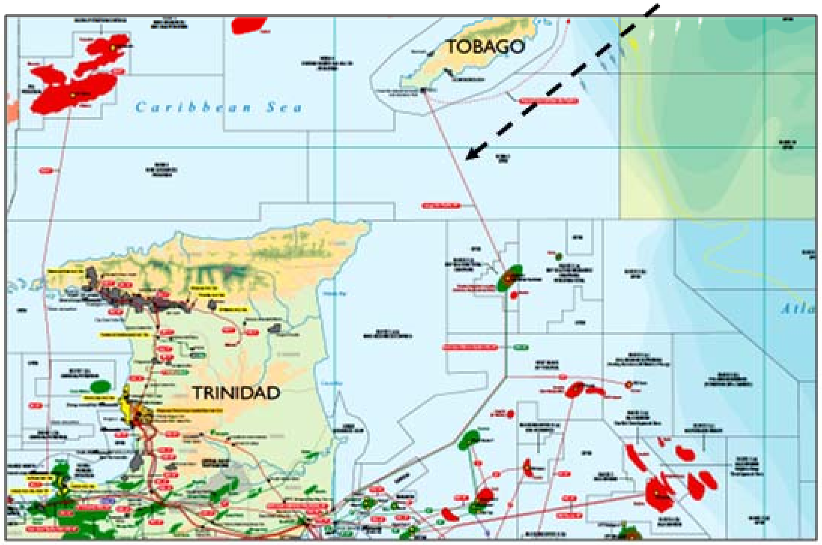
IN addition to the pipeline a gas storage tank (peak shaving) holds 1.5 billion cubic feet of liquefied natural gas (LNG), with the structure measuring approximately 60 metres in diameter and about 50 metres high. In service 2011.

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



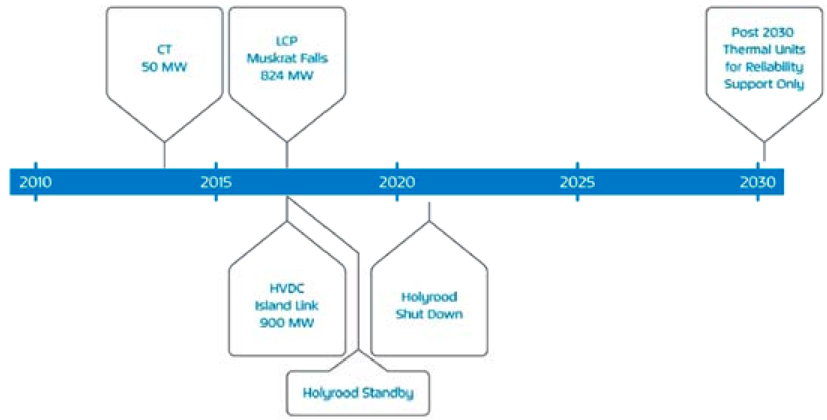
Project Drivers

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?

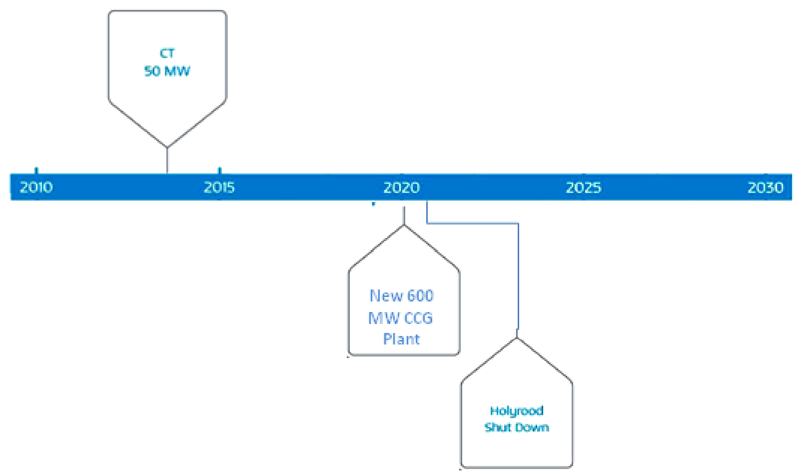
Construction time for CCGT power plant:	Typically 2 years **(ETP, EIA, IGU)**
Construction time for a 380km 14" subsea pipeline:	Typically 2 years for a pipeline of this nature in this kind of environment **(Offshore-Technology.com)**
Estimated Duration of entire construction project from go-ahead:	From 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:

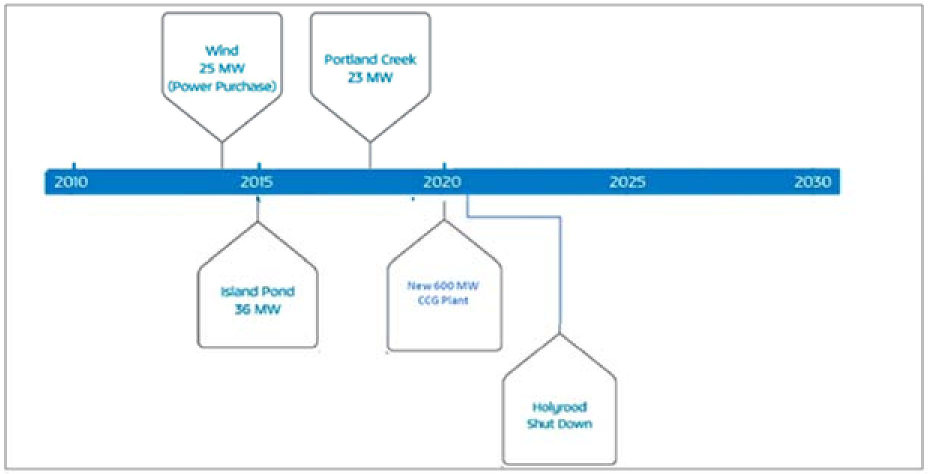


AND

Here is the natural gas option:



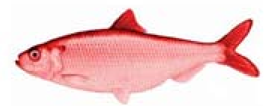
Alternatively, the Natural Gas Timeline could look like this (with small hydro helping us through until gas is ready):



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

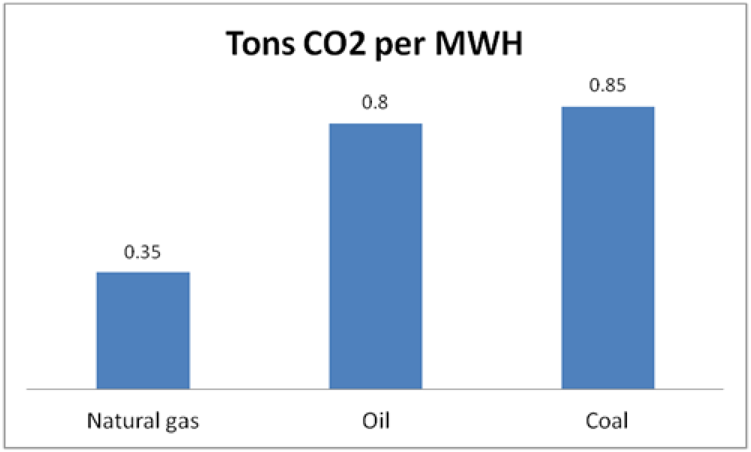
What about the Lower Churchill? What about the environment?

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.

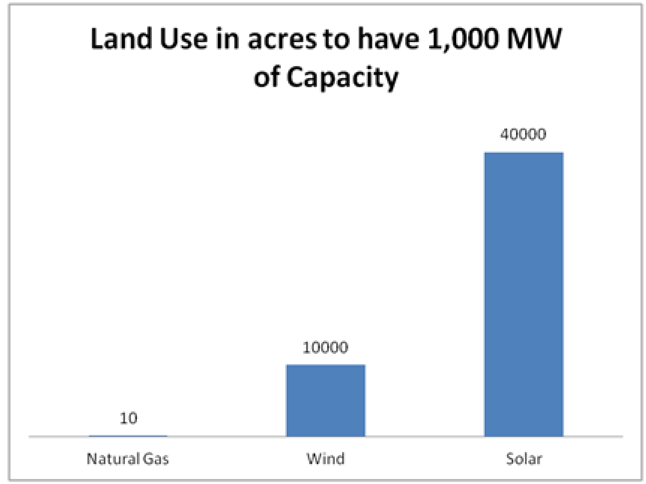
Interesting note:

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.**

CANADA-NEWFOUNDLAND and LABRADOR OFFSHORE PETROLEUM BOARD

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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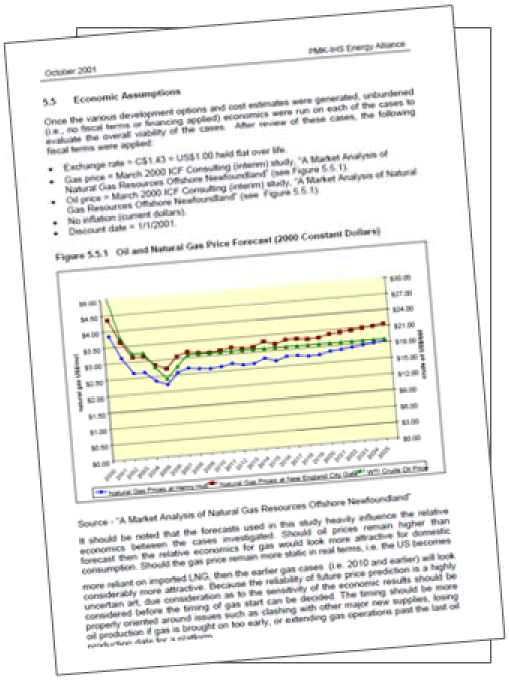

October 2001

PMK-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 supplies, losing oil production if gas is brought on too early, or extending gas operations past the last oil production date for a platform.

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.

[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

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

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Grand Banks Natural Gas for Island Electric Generation

Dr. Stephen E. Bruneau March 28, 2012