



# ***Further Rationalization for Piping Natural Gas to the Avalon to Meet Domestic Energy Needs***

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**Last fall at NOIA the merits of transporting natural gas to the Avalon in order to meet the thermal electric energy needs of the Island were discussed. The key features of that talk were:**

- Assessment of options for Island's non-hydro electric power.
- Rationalization of natural gas as the optimal choice.
- The source of this gas was identified in broad terms.
- The means of delivery via a small conventional pipeline was described.
- The resulting affect on electricity price and emissions was indicated.
- Some suggestions for making it move forward were made.

That presentation is available on NOIA's website



**Today at NEIA I plan to discuss the questions and lingering doubts pertaining to the merit of the Avalon pipeline. Topics will include:**

1. Pipeline Costs with examples
2. Producers costs and oil production losses during refit.
3. Reliability/vulnerability of natural gas fuel supply.
4. Availability of offshore gas resources for our domestic use
5. On-Island demand weakness and seasonal variability.

**Then I will attempt to explain, if its such a good idea . . .**

- Why hasn't it been done?
- Why do we need gas brought to the island now?
- How do we make this concept move forward?

*Lets have a quick review of the concept as proposed*

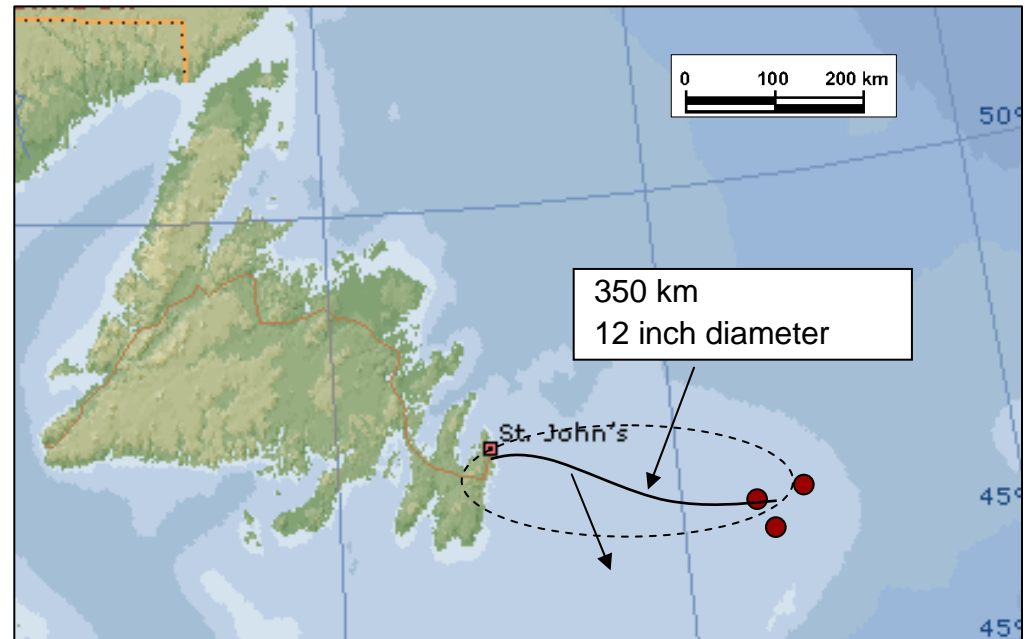




## *From Previous Presentations*

### **Avalon Pipeline** **Concept:**

- 12" diameter pipeline  
350km
- ½" wall thickness
- 3000psi inlet pressure
- 90 mmscf/d (= 600MW  
new Siemens CCG)



Pulled through existing J-Tube at Hibernia, trenched, bermed, reeled or laid, coated, anodes, labour, engineering, contingencies etc etc

2005 cost = \$300 mmUSD



## From Previous Presentations

### Sample Gas Dev Economic Case Study:

CAPEX and OPEX conservatively estimated as follows:

***All in millions of USD***

- Platform preps = 100, Operating = 5
- Offshore Pipeline = 300, Operating = 10
- On-Shore Pipeline = 12.5, Operating = 2
- Power generation = 400, Operating = 15 + Fuel



## *From Previous Presentations*

### **Sample Economic Case Study RESULTS:**

Utility-like IRR of 12% for each element independently, with a netback to producers of 2.0 USD per mscf results in:

***less than 5 cents per KWh at Holyrood gate.***



## *From Previous Presentations*

### **Upside**

- Proven operation of gas pipeline will quickly promote looping (adding another pipeline) for enhanced deliveries for other end uses including on-Island LNG production. Looping provides additional supply security, and opens up other marginal developments on the Grand Banks.
- When gas throughput volumes increase, the IRR for the platform and the onshore infrastructure climbs providing flexibility for improved netback to producers and better electricity prices for consumers.



## *From Previous Presentations*

### **Summary**

- Resource base is easily in place today for Island requirements - major export pipeline gas quantities are not yet proven.
- Proposal uses gas from existing oil developments.
- Eliminates gas reinjection wastage and realizes higher present value of salvaged gas.
- Initially, gas remains stranded in Province for use/processing unlike a large grid-connecting pipeline with “postage stamp” tariff structure, i.e., the price of stranded gas would be lower than the grid price





***Now a look in more detail at the following:***

1. Pipeline costs with examples
2. Producer's costs
3. Reliability/vulnerability of natural gas fuel supply
4. Availability of Natural Gas Resources
5. On-Island demand weakness and seasonal variability



# Pipeline Costs



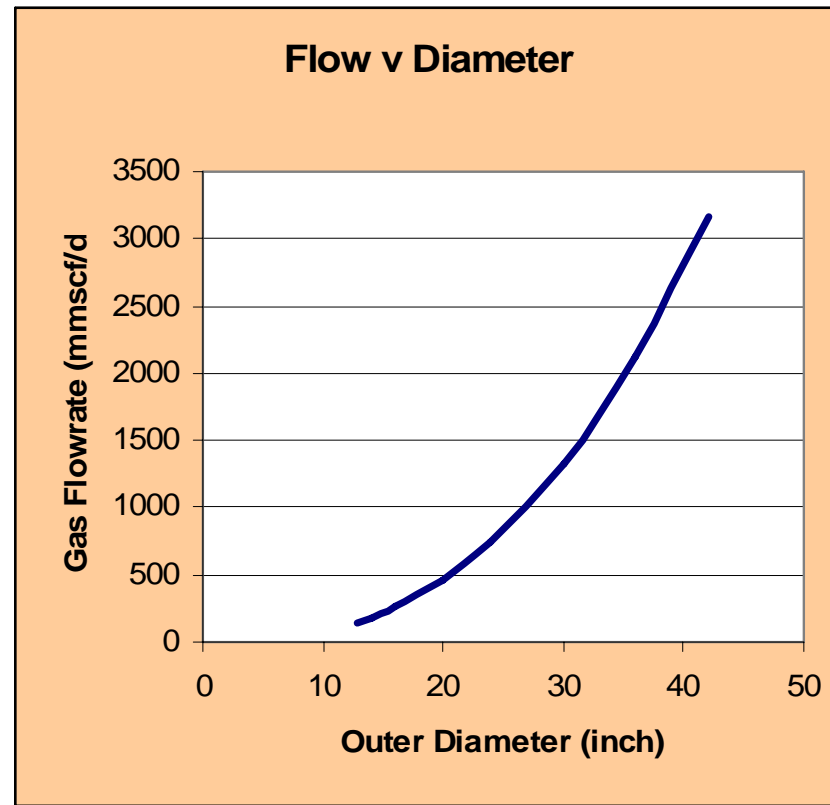
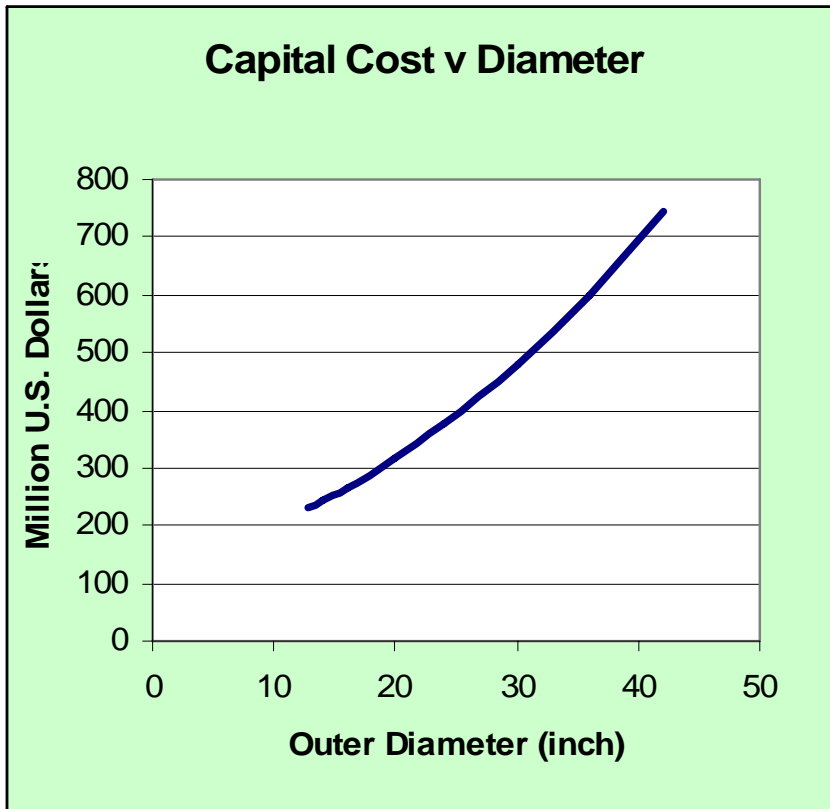


# Pipeline Cost Details

Source : Private communic J.P.Kenny, EXXONmobil Corp., Others (2005)

Input Data	
Pipe Length	330 Km
Pipe Outer Diameter	14 inch
Pipe Wall Thickness	0.486 inch
Pipelay Rate	4.1 km/day
Trenching Rate	2 km/day
% Route Trenched	100 %

*Lets Compare* 

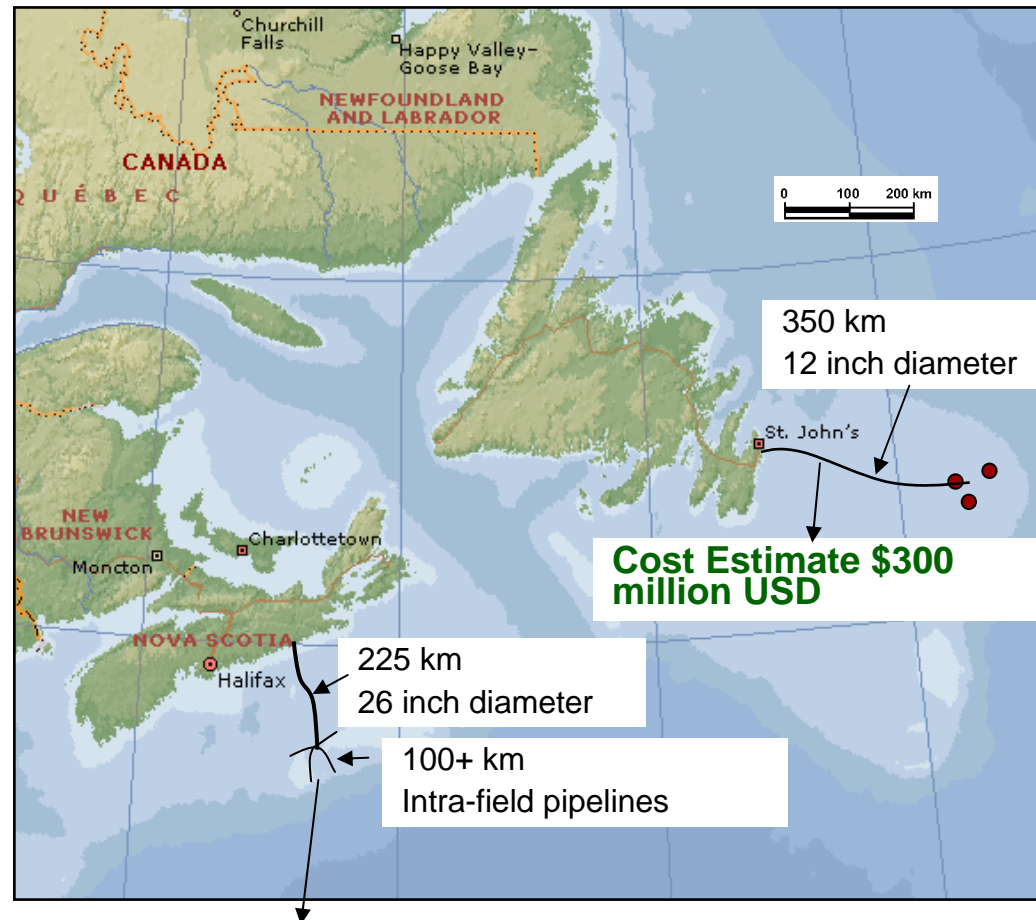




## SOEP – Sable Pipeline

### Sable Gas Pipeline

- 225 km 26 inch pipeline
- 100+ km 18 inch, 12 inch
- \$250 million CAD
- 23 months to complete
- Throughput up to 500 mmscfd

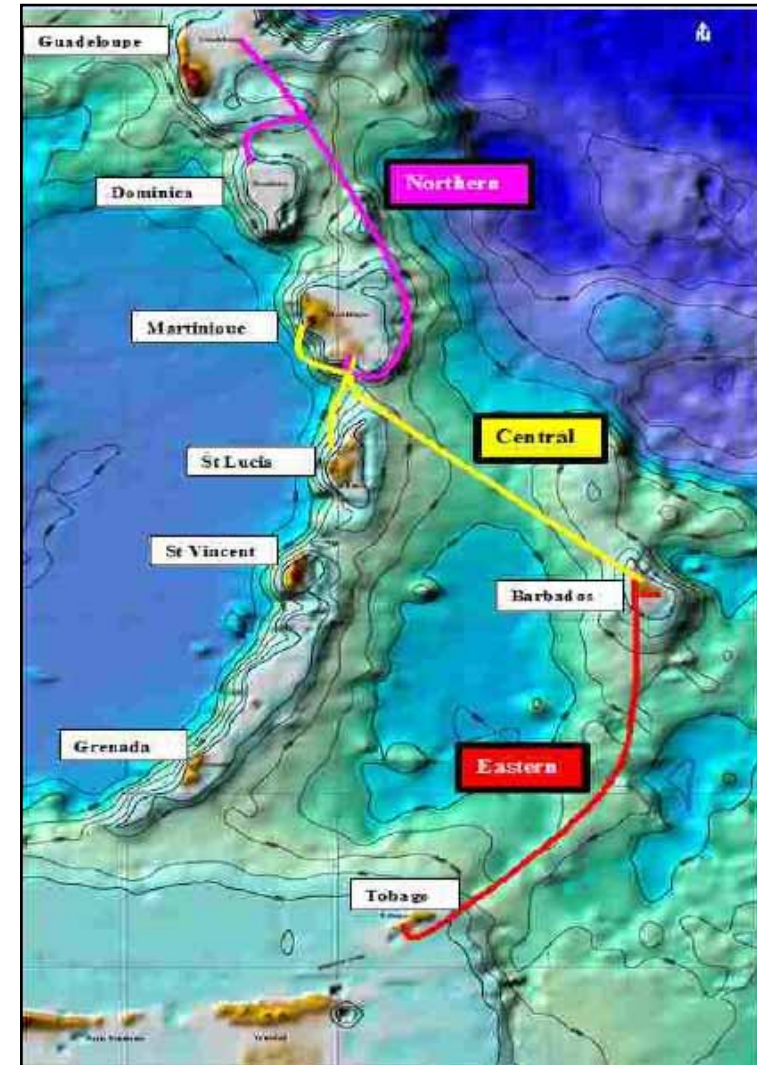


**Approx \$200-250 million USD to build subsea pipelines in 1999**



## Eastern Caribbean Pipeline Project

- 900-kilometre pipeline between 5 islands
- Maximum water depth 2000m
- Routing minimizes earthquake problems, hurricane wave problems, coral reefs sensitivities, volcanoes, fishery
- 12 inches, 10 inches, 8 inches
- Delivery of 150 mmscf/d
- Cost \$550 million USD
- Commercially viable according to producers and contractors but not yet built due to political environment



Source: Doris Inc. Technical and Economic Feasibility of the Eastern Caribbean Gas Pipeline 2002



## Vancouver Island Pipeline 1991

Westcoast Energy, Centra,  
Terasen

- 550-kilometre pipeline
- Mountainous terrain and along the ocean floor
- One of the world's deepest underwater pipelines 400m+
- Twin 10 inch subsea section
- \$355 million CAD
- Delivers over 100 mmscf/d
- Population of Vancouver Island is 690,000



Source: Centra Gas (B.C.)

**Natural Gas and its Impacts on Greenfield Areas**

*Submitted to Atlantic Canada Petroleum Institute*

*By Gardner Pinfold Consulting Economists Limited September 2002*





## Last note on pipeline costs

### Iceberg Scour Risk to pipeline...

- NOIA study declared the problem “manageable”
- White Rose field pipeline analysis indicates low risk
- Proposed Avalon pipeline to be trenched
- In worst case normal repair protocols, times, costs applicable
- A lot safer than the alternative tanker traffic carrying crude.





## Producer's Costs and Oil Production Risks



## Producers Costs and Oil Production Risks

Not known clearly, but indicators exist

In approving the White Rose Development the CNLOPB reports that Maersk and Husky studied the refit question in 2001 and found that the most likely scenario was a refit cost of \$75 million CAD with 12 weeks downtime – in order to facilitate a 150 mmscfd export pipeline (approximately double Island requirements). This figure would, in all likelihood, move downwards as detailed engineering and operational optimization of scheduled maintenance were performed.





## Owners Costs and Oil Production Risks

It is also probable that the modification costs and downtime associated with a domestic export line launched from Hibernia would be lower than this, and, that accommodation for same could be made on the yet-to-be-designed Hebron platform

Regardless, it appears that the likely maximum cost to the producer approaches \$200 million USD if downtime oil is considered “lost”. We will look at the impact of this increase later.



# Supply Reliability and Storage requirements



## **Energy Storage and Supply Security for natural gas-fired electricity on the Island of Newfoundland:**

No free or simple solution to this but options include:

- Standby oil-fired facilities or dual-fuel capabilities
- Standby distillate tank for combined cycle gas plant
- LNG peak shaving plant
- Third party storage facilities for backup fuel supply, such as
  - the proposed LNG trans-shipment,
  - NARL inventories
  - New Refinery


Preferred solution not known but lets look at an example:





# Recall the Vancouver Island Pipeline . . .

In 2004 the following application was made:



**LNG STORAGE PROJECT**

IN THE MATTER OF the Utilities Commission Act,  
R.S.B.C. 1966, Chapter 473 (the "Act")

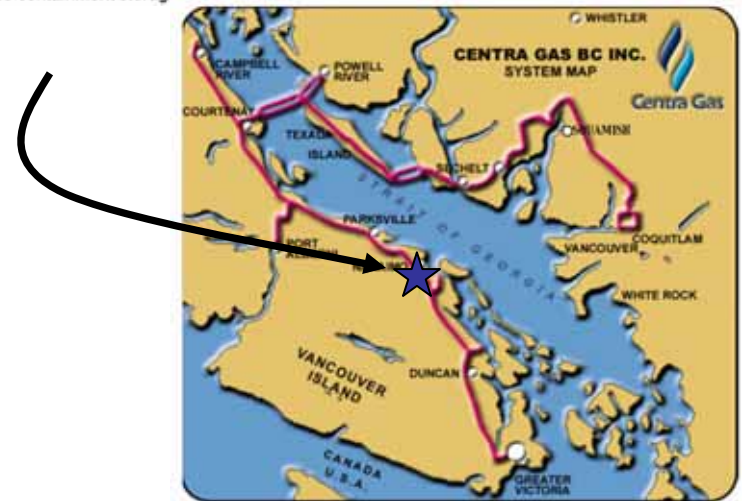
AND IN THE MATTER OF an Application by  
Terasen Gas (Vancouver Island) Inc. for a  
Certificate of Public Convenience and Necessity  
Pursuant to Section 45 of the Act

Submitted to the  
British Columbia Utilities Commission

August 2004



Conceptual Single containment storage tank with secondary containment earthen dike



Source: Centra Gas (B.C.)



## Supply storage example

The LNG Storage Plan was devised to secure supply and meet increased Island peak demands without building a new supply pipeline

**Figure 14.1 LNG Facility Capital Costs (2004\$millions)**

EPC Costs	73.8
Owners Costs	
Land	1.6
Interconnecting Facilities	9.3
Project Services	7.9
Contingency	1.8
<b>Total</b>	<b>94.4</b>

**Figure 14.2 LNG Facility Operating Costs (2004\$000)**

Fixed Operating	\$ 930
Variable Operating (excl gas)	\$ 557
<b>Total</b>	<b>\$1,487</b>

Figure 9.1 Primary Codes and Regulations

Code	Edition	Description
B.C. Pipeline Act and Pipeline Regulation	2002	Regulation of the Design, Construction and Operation of Pipeline Facilities
CSA Z 276	2001	LNG Production, Storage, and Handling
CSA 2062	2003	Oil and Gas Pipeline Systems
NBC	1995 & Revisions	National Building Code of Canada
C.E.C.	2002	Canadian Electrical Code Part 1, 19 <sup>th</sup> Edition
API 620 App. Q	10 <sup>th</sup>	Design and Construction of Large, Welded, Low Pressure Storage Tanks
CSA B51	1997	Boiler, Pressure Vessel, and Pressure Piping Code
CAN/CSA A23.3-94 (R2000)	2000	Design of Concrete Structures
Terasen Standards	As Applicable	Standards for Equipment, Materials, Construction Procedures, Inspection, Testing, Security and Safety

The powerline will be designed and constructed to BC Hydro Engineering and Construction Standards. The design and construction of the electrical substation will conform to the Canadian Electrical Code CSA 22.1

Terasen (owner) says:

- 30 months from start to finish
- Very robust, safe, economical
- Will liquify gas during low demand and regasify during high demand
- All codes and regs are in place
- Project has been approved by BC regulators



## LNG Elsewhere in N. America

Peak shaving LNG storage located at strategic points along gas pipelines are increasingly in use to provide additional grid storage. There are approx. 50 such facilities in the US.

The production, storage, truck transport and regasification of LNG is also well established in Canada

Currently three LNG plants operating in Canada - Tillbury Island (BC Gas), Hagar LNG plant (Union Gas), Montreal (Gaz Met.)

### Pine Needle Peak Shaving Facility, North Carolina

- 4 billion scf storage, 400 mmscfd regasification, 20 mmscfd liquifaction

- Total cost 107 Million USD



### Tilbury LNG Plant (1971)

0.60 bcf storage, 200 mmscfd regas.



### Hagar LNG Plant (1969)

0.61 bcf storage, 90 mmscfd regas.



### Montreal LNG Plant (1970)

2.0 bcf storage, 280 mmscfd regas.



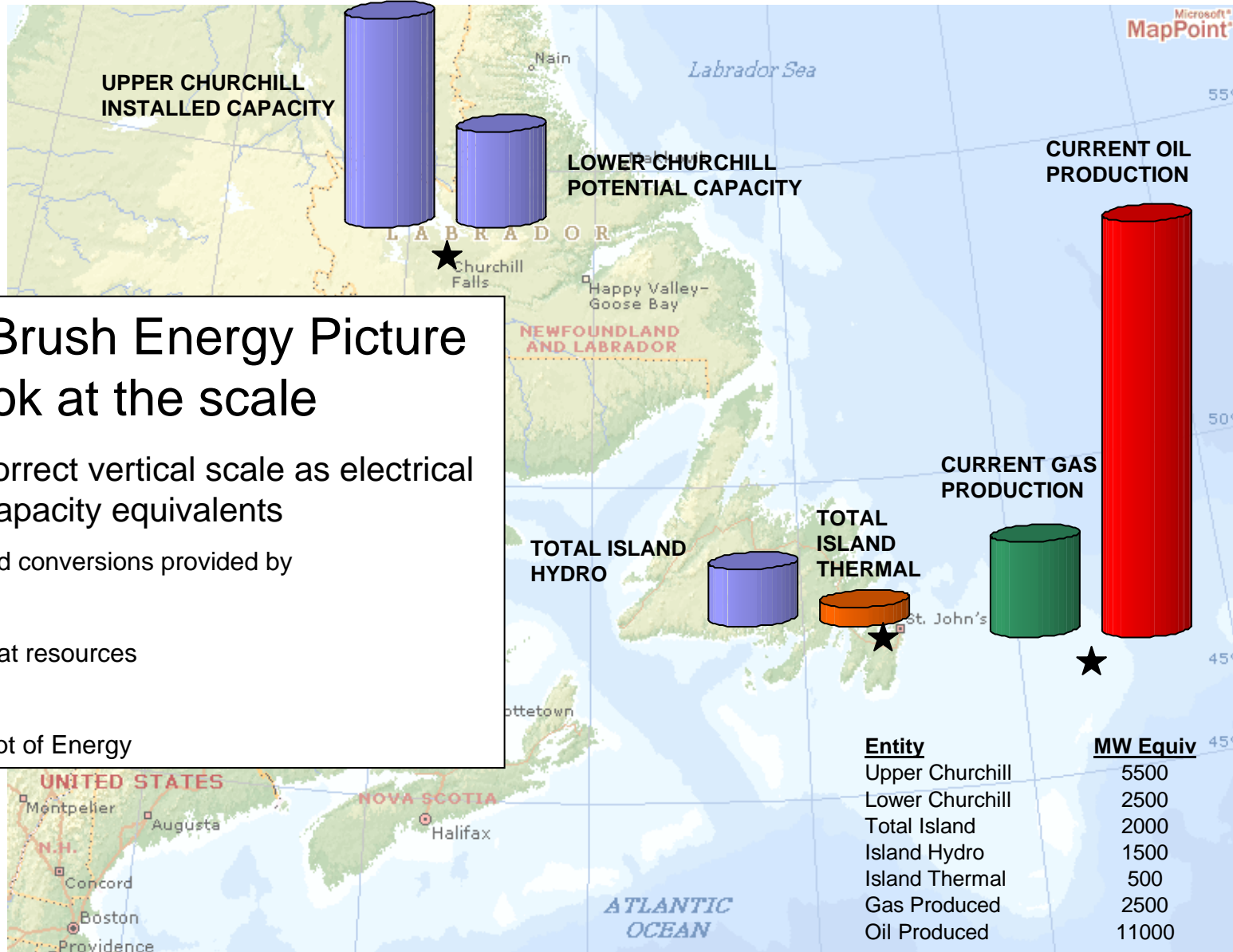




# Natural Gas Resource Availability



# Availability of Gas Resources for On-Island Use



## Broad Brush Energy Picture – a look at the scale

drawn to correct vertical scale as electrical energy capacity equivalents

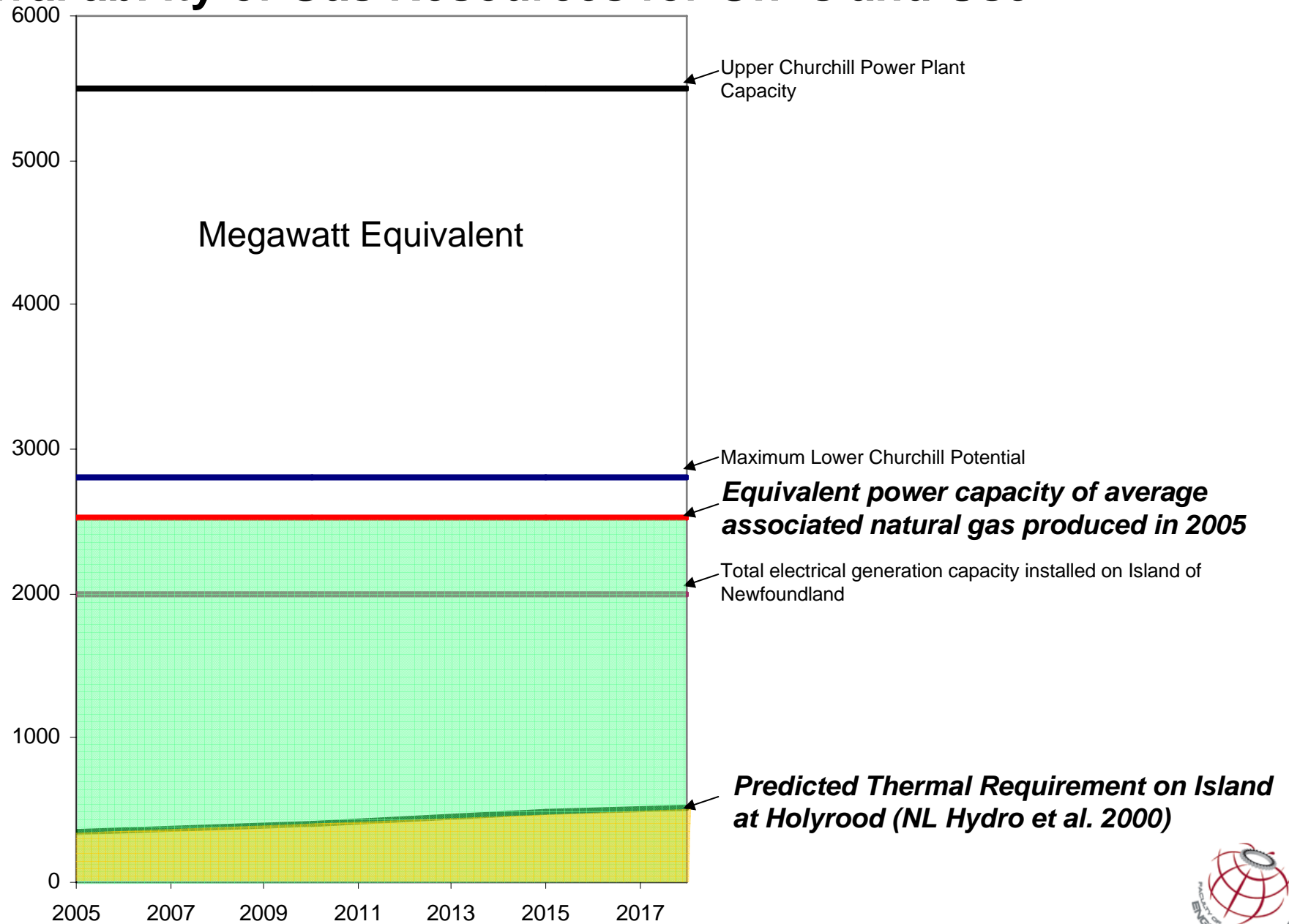
Information and conversions provided by

- N.L. Hydro
- Gov Dept Nat resources
- CNLOPB
- EIA, US Dept of Energy





# Availability of Gas Resources for On-Island Use





## Availability of Gas Resources for On-Island use

The average daily production of natural gas

- Hibernia in 2005 = 273 mmscf/d
- Terra Nova in 2005 = 106 mmscf/d
- White Rose in 2006 = 53 mmscf/d
- Therefore It can be safely assumed that:

***The average daily production of associated natural gas in 2006 and beyond will be in excess of 400 mmscf/d***

- Total gas consumed on these platforms for electrical power is around 15 or 20 mmscf/d
- The amount of gas required to enhance oil recovery is not common public knowledge – it appears that 100% at Terra Nova, 50% at Hibernia and 0% at White Rose are reasonable guesses, ie. 250mmscf/d leaving 150+ available.
- The amount of gas that has been assumed (for the Avalon Pipeline economics) to supply our electrical energy needs in 2010 is 80 mmscf/d
- The amount of gas that is produced now but reinjected and lost permanently may be over 100 mmscf/d (CNOPB assumed 70% salvageable at W.R.)



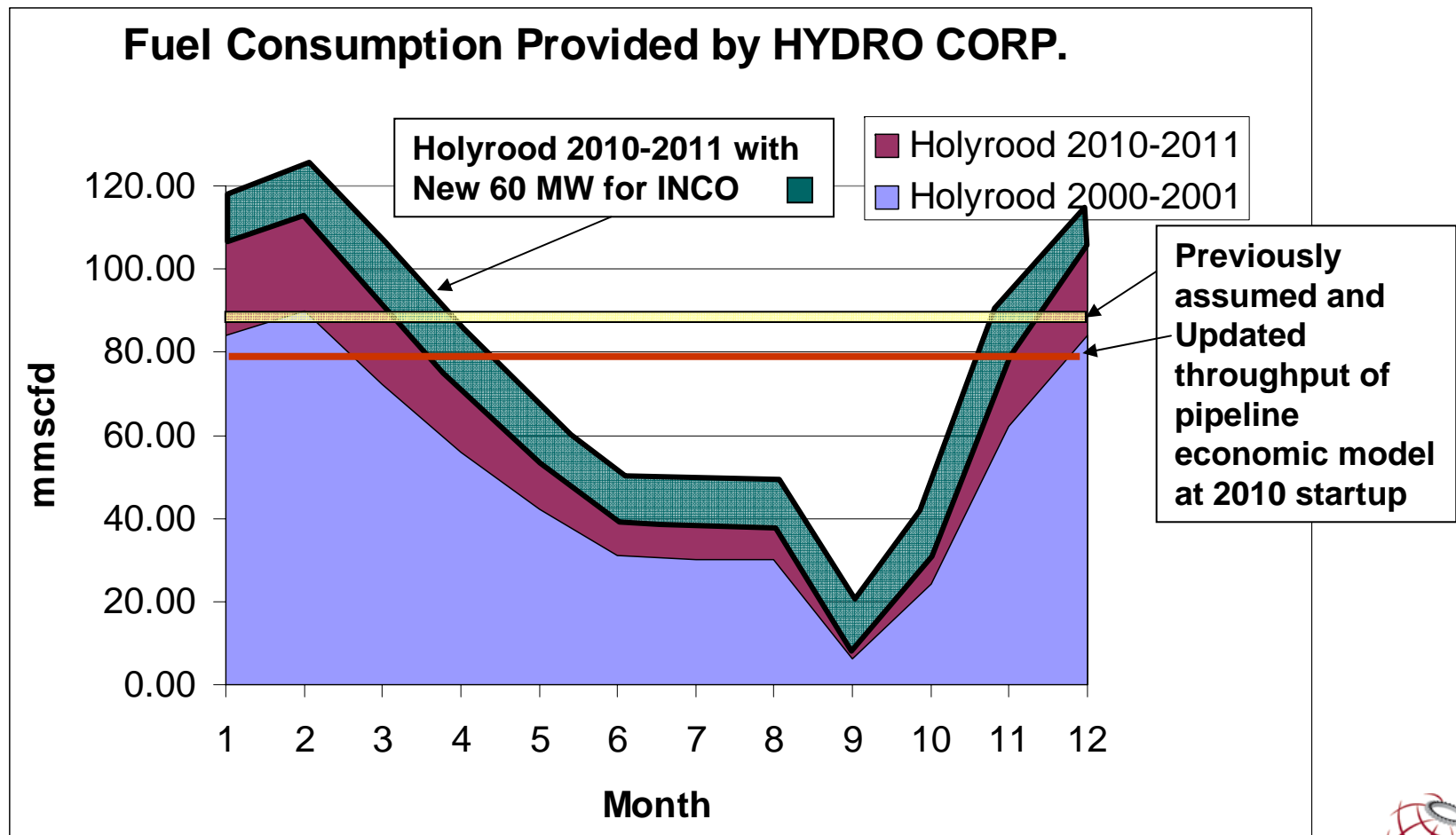


## On-Island market size and seasonal variability



## On Island Market and Seasonal Variability

Absolute minimum gas demand would be Holyrood conversion **only** with low-level demand growth forecast as follows:





# On Island Market and Seasonal Variability

Other potential conversion customers in the future may include:

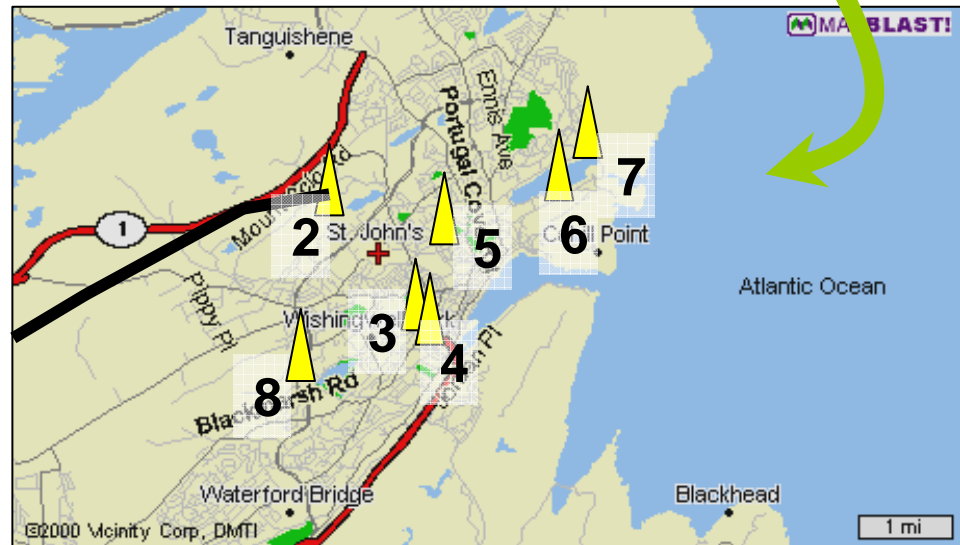
Legend

Potential Gas Customer



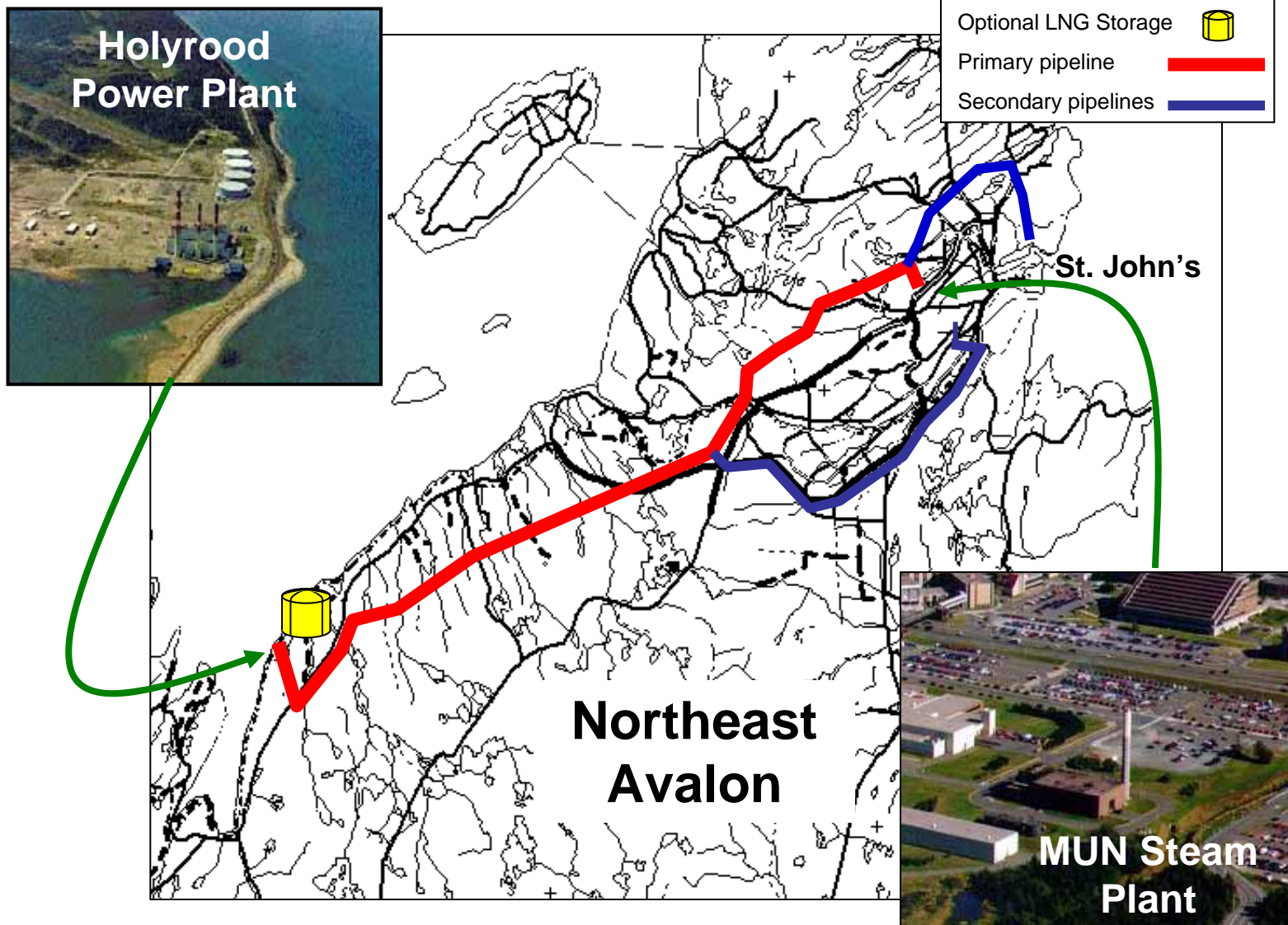
Facilities considered

- 1 - Holyrood Power Generating Station
- 2 - Memorial University Steam Plant
- 3 - St Claire's Hospital
- 4 - Labatt Brewery
- 5 - Molson Brewery
- 6 - Miller Center
- 7 - Pleasantville Steam Plant
- 8 - Metrobus
- 9 - Come By Chance Oil Refinery





# On Island Market and Seasonal Variability



Opportunity here for combined cycle generation on campus with waste heat used for MUN







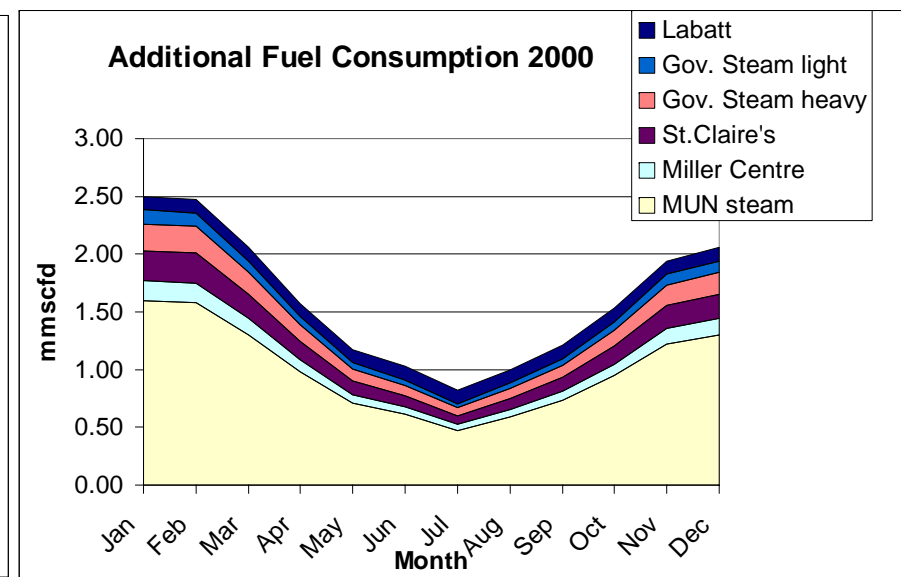
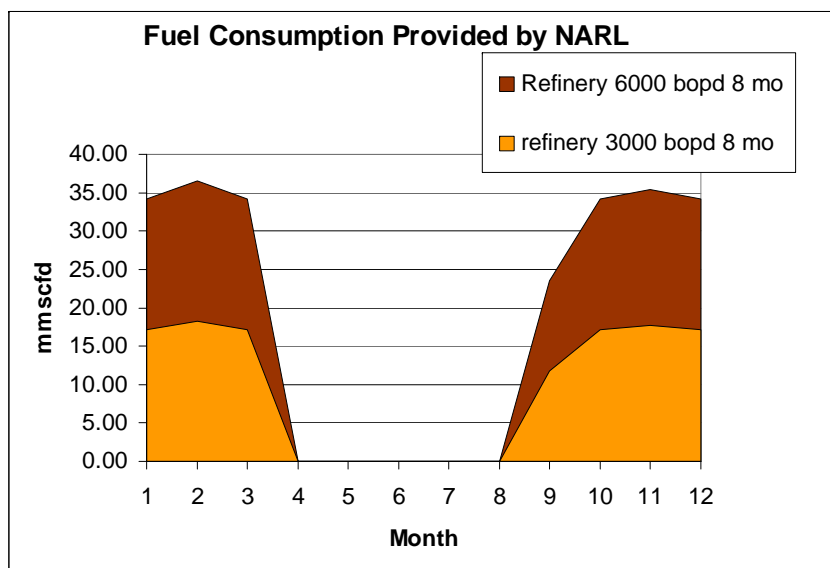
# On Island Market and Seasonal Variability

## On Island Demand Profile

Other minor conversions possible\*

- Heavy Fuel Oil to Natural Gas
- May be supplied by trucking LNG or by pipeline

\*\*\* Does not include demand growth opportunities from INCO, refineries, pulp and paper other



Figures are circa 2000-2001 Provided by indicated source





## Where is this leading?

*Revisiting the economic model used previously we have the following revised assumptions:*

Maximum platform modification and lost oil costs	\$200 million USD
Daily average throughput in 2010 dropped to	80 mmscf/d
Pipeline costs left (high) at	\$300 million USD
Producers netback at platform left at	\$2.0 USD/mscfd
Power plant costs left at 0.8 USD per Watt (turnkey)	\$400 million USD
Infrastructure rate of return on equity pre tax	10%
All OPEX costs remain intact as presented for 22 year life of project	

RESULT:

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***Cost of electricity at the Holyrood gate                      6 cents US / KWh***

***Though this model is simplistic and may be considered indicative only – it does indicate that the economics are realistic and compelling when compared to the costs of the alternatives, in particular, foreign crude.***





## **So, why isn't it done? . . . Because prior conditions were adverse:**

1. Simplicity of oil-only developments was more attractive, less risky, for investment in this environmentally challenging region considered “frontier” for oil and “immature” for gas.
2. Gas resources were deemed insufficient to warrant producer-owned infrastructure linking Grand Banks to continental markets.
3. Early development options for gas pipelines were third-party initiatives that were viewed as meddling in the affairs of producers who were putting up the cash for the oil developments, and, threatened downstream control of resource flow and future profit taking.
4. Prior gas initiatives were based on the presumption that political and regulatory will could be captured. However, Governments were unwilling to risk scuttling oil developments or oil royalty talks on the technical and economic risks that producers stated would result from incorporating gas play. In addition, the regulator was too inexperienced or without the mandate to object.

## So Why Now? What has changed?

1. NFLD Oil industry is maturing. Producers have conquered the risks of operating offshore Newfoundland through demonstrating fantastic profitability, safety and security through existing oil developments.
2. On the Island we can capture new power investments on a go-forward basis because very few new electric energy projects are on the books or committed to and policy review is ongoing
3. Acting now will reduce electrical price uncertainty from crude and improve availability to existing and new customers such as Abitibi, INCO, new refineries, etc
4. Acting now will give us access to our offshore gas resources prior to it becoming available to others at a higher price, ie, we must secure a recall quantity of the resource that satisfies domestic thermal needs before its value escalates to North American market prices

## **So Why Now? What has changed?**

### ***New conditions Continued . .***

1. Commodity prices are very high now, relief may be in sight but vulnerability and uncertainty prevail. True cost of our oil dependency will be felt as our crude inventories are re-supplied and rate stabilization takes place through the PUB.
2. The permanent loss of associated gas produced offshore occurs daily – and the losses are greater than our total requirements if we replaced oil at Holyrood with Grand Banks gas. Emissions would be curtailed by ½ million tons per annum immediately.
3. Government has expressed a willingness and desire to move on new energy initiatives that are particularly strategic and aligned with the Province's best long-term interests.



## **Premier Danny Williams in 2005**

. . . Williams said. “I’d like to see us have a stake in gas, whether that’s through equity, or, a pipeline that comes in here . . .”

*Reference: The Telegram, Fall 2005  
St. John’s, Newfoundland*





## What can be done to advance this concept

Go and get unbiased, objective opinions from experts but we **MUST**

### ***Ask the right questions!***

- “Do we have the right to access this resource right now given the current rate of reinjection losses and our current domestic energy needs”?
- “If there is no royalty regime in place for gas then who owns the resource if it is an unused byproduct with zero book value to producers”?
- “What are the producers actual refit costs for a small export line”?
- “Can the unused natural gas resources available 300 km offshore be competitive with alternate foreign supply sources for Newfoundland”?



**Lets ask these questions and see what we get. . .**



## **END OF PRESENTATION**

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**Many thanks for your attention on this and I look forward to your questions**



**Steve Bruneau**  
**Memorial University of Newfoundland**  
**Faculty of Engineering and Applied Science**