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The Economics of High Arctic Gas Development: Expanded Sensitivity Analysis

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Executive Summary

This report provides a re-assessment of the economic feasibility of producing and delivering gas from the High Arctic, as described in a previous CERI report.[1] It includes a re-evaluation of the assumptions of the previous study and additional sensitivity analyses.

The motivation for this study remains the same as for the previous analysis. The North American natural gas marketplace is currently experiencing a tightness of supply and strong demand, with the consequence of much higher than historical norms for natural gas prices. As a result, many incremental sources of supply are being re-examined, including natural gas from the North Slope of Alaska, the Mackenzie Valley Corridor, the Mackenzie Delta, and the Beaufort Sea, as well as LNG from other areas of the world, many of which are more distant and less politically stable.

The existence of large accumulations of natural gas in the Canadian High Arctic has already been established. The Arctic Pilot Project Application of 1981 estimated recoverable and marketable reserves of natural gas at almost 9 Tcf for the discoveries made at Hecla and Drake Point on Melville Island. This report evaluates Melville Island resource development and delivery options as an example of the potential in the High Arctic.

Alternative Development Schemes

This report examines the same three development options—LNG to eastern Canada, GTL to eastern Canada, and CNG to the Mackenzie Delta—as in the previous report, with the addition of a variation on the LNG delivery option that includes transshipment to regular LNG tankers in West Greenland.

- Delivery as LNG directly to North America's northeastern seaboard
  The configuration of this project includes a barge mounted liquefaction facility, LNG storage barges, a dock and loading facility and a fleet of icebreaking LNG tankers. LNG is delivered to third-party regasification facilities in Nova Scotia or New Brunswick.

- Delivery as LNG, with transshipment in West Greenland
  This project is identical to the previous one except for transshipment from icebreaking tankers to conventional vessels, at a storage facility located in West Greenland. This scheme is intended to minimize capital expenditures for vessels and to provide more flexibility in choice of markets.

[1] Mortensen, P. *Economics of High Arctic Gas Development*. Canadian Energy Research Institute, March 2004.

- Delivery as CNG to a Mackenzie Corridor pipeline
  This avoids the large capital costs of liquefaction facilities of the LNG schemes. CNG vessels have much lower capacities than LNG tankers—about one-third—and are therefore better suited to short-haul routes, making transportation from Melville Island to the Mackenzie Delta feasible commercially.

- Delivery as GTL to North America's northeastern seaboard
  Several GTL options are available, but they are all relatively inefficient, consuming about 35 percent of the input energy in the conversion process—1 Bcf/d of natural gas feedstock into 100,000 barrels per day of liquids. Delivery is by tanker to Saint John, where the synthetic crude is used to produce ultra clean lubes, jet fuel, diesel and olefins.

Assumptions and Sensitivities

The three most important assumptions in the analysis are project start-up dates, commodity prices, and capital and operating costs. CERI analyzed production start-up years of 2009, 2014, and 2019.

CERI used two separate near-term baseline Henry Hub prices of $5.85 (Canadian) or $4.50 (U.S.) and $7.37 (Canadian) or $5.70 (U.S.) per MMBTU for the 2005-2015 period, in 2005 constant dollars. Each of these was extended using three price lines for the 2015-2040 period—a low case that is flat to declining, a middle case that mimics the industry-accepted Sproule and GLJ forecasts, and a high case.

- Price line A - flat at $5.85 (Canadian) to 2015, increasing to $13.89 (Canadian) in 2040
- Price line B - flat at $5.85 (Canadian) to 2015, increasing to $10.23 (Canadian) in 2040
- Price line C - flat at $5.85 (Canadian) to 2015, increasing to $7.55 (Canadian) in 2040
- Price line A' - flat at $7.37 (Canadian) to 2015, increasing to $13.89 (Canadian) in 2040
- Price line B' - flat at $7.37 (Canadian) to 2015, increasing to $10.23 (Canadian) in 2040
- Price line C' - flat at $7.37 (Canadian) to 2015, increasing to $7.55 (Canadian) in 2040

The overall capital and operating costs of the various schemes vary by less than 30 percent. Capital costs range from $4.9 billion for the LNG option to $6.3 billion for GTL, in 2005 constant Canadian dollars. Similarly, total operating costs for the period to 2040 range from $432 million to $600 million, 2005 constant Canadian dollars.

CERI varied the facility, vessel, and drilling capital costs and their operations and maintenance costs by ±25 percent for each of the variables independently. Monte Carlo simulations were performed assuming variations of as much as ±50 percent simultaneously in each of the key variables.

Results

All four of the scenarios are economically feasible (have a positive net present value) under certain price levels, namely Price Forecasts A, A', B', and C'. Price Forecasts B and C have negative, or barely positive, net present values.

In the case of Price Forecast B, the only option that provided positive net present values (NPV's) is CNG, and only for a production start of 2019. Using the B' Forecast—with its higher initial base—all the development options provide positive NPV's with production start years of 2014 and 2019 relatively the same.

The net present value of the CNG option is estimated at $24 million and $416 million for a start year of 2019 under Price Forecasts B and B', respectively.

The sensitivity analysis shows that although the initial calculation showed that the CNG project is the most favourable under Price Forecasts A' and B', for all production start years, the range of NPV's between input parameter changes of –25 percent and +25 percent is greater than the range of NPV for the corresponding cases for both of the LNG scenarios and the GTL scenario.

In addition, the Monte Carlo analysis shows that the range of NPV's between the 5^{th} and 95^{th} percentiles is greater than the range of NPV's for the corresponding cases for both of the LNG scenarios and the GTL scenario.

Additional Possible Implications

In addition to monetization of stranded reserves, North American development of incremental sources of supply, with its required infrastructure, provides security of supply to North American consumers.

Socio-economic and environmental issues will be critical considerations for any proposed development in the High Arctic. Important issues such as comparative risk assessments of these and other delivery options, the appropriate discount rate(s) and the appropriate project life or lives will also need to be examined. Delivery of GTL versus LNG or natural gas likely conveys greater economic costs and benefits than are captured in the present analysis. Besides reduced emissions of GTL compared to diesel, the GTL option has the potential benefit of providing a home grown substitute for the volumes of diesel that must currently be imported into remote northern communities of the High Arctic. Finally, the optionality of the transshipment scenario likely has a risk mitigation effect that may be better considered using other analytical techniques.

1.0 Introduction

The purpose of this report is to re-assess the economic feasibility of producing and delivering natural gas from the High Arctic as described in CERI's March 2004 study entitled, *Economics of High Arctic Gas Development*. Updated cost and timing estimates, justification for assumptions, and a sensitivity analysis are also provided in this report.

This study should be considered as an update to the March 2004 study of the capital and operating costs of three scenarios for Arctic gas development, LNG, CNG, and GTL. This study also examines a fourth case, LNG delivery with transshipment through Greenland. Sensitivity and Monte Carlo analysis were performed for each of the four cases to give an indication of the impact of changes to the key parameters affecting net present value.

This report is based on information that has been provided by others, including the client(s). CERI has utilized such information without verification unless specifically noted otherwise. CERI accepts no liability for errors or inaccuracies in information provided by others.

CERI conducted this analysis and prepared this report utilizing reasonable care and skill in applying methods of analysis consistent with normal industry practice. All results are based on information available at the time of review. Changes in factors upon which the review is based could affect the results. Forecasts are inherently uncertain because of events or combinations of events that cannot reasonably be foreseen including the actions of government, individuals, third parties and competitors. NO IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE SHALL APPLY.

2.0 Background

The tight supply/demand balance and prices higher than historical norms in North American natural gas markets have led to renewed interest in incremental sources of supply, including natural gas from the North Slope of Alaska, the Mackenzie Valley Corridor, the Mackenzie Delta, and the Beaufort Sea, as well as LNG from other areas of the world, many of which are more distant and less politically stable.

The existence of large accumulations of natural gas in the Canadian High Arctic has already been established. The Arctic Pilot Project Application of 1981 estimated recoverable and marketable reserves of natural gas at almost 9 Tcf for the discoveries made at Hecla and Drake Point on Melville Island.

Because of the absence of current detailed designs for High Arctic gas production and delivery concepts, cost estimates are preliminary in nature. This report examines the impact of various changes to cost estimates and timing on the economic feasibility of several development schemes.

The same three options examined previously are included in this study: LNG, CNG, and GTL. An additional scenario has been added for this study: LNG delivery to the Northeast via a transshipment terminal in Greenland. Several of the scenarios are illustrated on the map of Figure 2.1. Because of the projection employed, distances are "stretched" more near the North Pole.

Figure 2.1: Overview of High Arctic Natural Gas Development Schemes

Deliveries to other ports have also been discussed in this study. The technical challenges and routing alternatives associated with a dedicated pipeline from the Arctic warrant treatment in a separate study.

The March 2004 study concluded that production and ship-borne transportation from Melville Island is economically feasible with any of the three development schemes (LNG, CNG, and GTL) examined. Under the Base case assumptions, each of the technologies provided more than the 15 percent minimum rate of return. The CNG project provided the greatest economic value by a significant margin over the GTL and LNG alternatives. The sensitivity analysis concluded that the CNG project remains viable and clearly superior to the two alternatives even under conditions of lower market prices and higher project costs. However, the CNG project involves significant risks regarding the provision of suitable docking facilities for CNG carriers in the Mackenzie Delta region and the corresponding distance that the landed gas must be transported before entering the Mackenzie Valley Pipeline.

As before, this analysis focuses exclusively on Melville Island gas development as an example of what may be possible for other areas of the High Arctic.

3.0 Assumptions and Methodology

CERI's March 2004 study entitled, *Economics of High Arctic Gas Development*, was used as the starting point for this study. Both rely on information provided by proponents of the Polar Gas Project and the Arctic Pilot Project.

The Polar Gas Project proposed to construct a pipeline from the High Arctic to Southern Ontario. It submitted an application to the National Energy Board (NEB) in December 1977. The project consisted of a 3,763 km pipeline from Melville Island to Longlac, Ontario. At Longlac, the pipeline was to connect to the existing TransCanada pipeline system. The project planned to deliver 2.1 Bcf/d through a 42 inch diameter pipeline. With added compression, the project was expected to expand to deliveries of 3.0 Bcf/d. The application included a detailed description of facilities as well as socio-economic and environmental studies. Cost estimates and information on gas supply and cost estimates were never filed and the application was never completed.

The absence of supply information is unfortunate because the planned throughput appears far higher than could be sustained from the Melville Island gas deposits alone. Consequently, there must have been plans to tie in additional discoveries.

The Arctic Pilot Project proposed to ship gas as liquefied natural gas (LNG) in ice-breaking tankers to delivery points in Nova Scotia and Quebec. It filed an application with the NEB in November 1981. This project is of significant interest to the current analysis because it proposed a design for delivering LNG from Melville Island to Quebec and Nova Scotia using icebreaking LNG carriers. The application provides information on facilities, gas supply and cost estimates.

The project was configured to deliver 320 MMcf/d of gas from the Borden Island Main pool of the Drake Point Field to a barge-mounted liquefaction facility at Bridport Inlet. The liquefaction facility would provide 2.2 million tonnes of LNG per year. Two Arctic Class 7 LNG carriers with 140,000 cubic metre LNG capacity would transport the LNG over 4,600 km to regasification terminals in Nova Scotia and Quebec.

A description of a phased expansion to the project was included with the application. The second phase would increase throughput to 550 MMcf/d and require a total of 4 LNG carriers. A third phase, requiring production from the Hecla field, would see throughput rise to 1.375 Bcf/d and require 9 LNG carriers.

The over-abundance of gas in North America in the latter half of the 1980s (the "gas bubble") and corresponding drop in North American gas prices were likely primary factors in the projects' failure to proceed.

The general assumptions for the economic analysis are as follows:

3.1 Reserves and Resources Assessments

- As indicated in Table 3.1, the Arctic Pilot Project estimated marketable gas reserves of 5.1 Tcf and 3.6 Tcf in the Drake Point and Hecla fields, respectively.[2] The Canadian Gas Potential Committee (CGPC) and the Geological Survey of Canada (GSC) developed resource estimates that were below the Arctic Pilot Project's estimates. The CGPC estimates the Drake Point field at 5.982 Tcf of initial gas-in-place and 4.9 Tcf of initial marketable gas and the Hecla field at 4.199 Tcf of initial gas-in-place and 3.5 Tcf of initial marketable gas, giving a total of 10.181 Tcf of initial gas-in-place and 8.4 Tcf of initial marketable gas.[3] The GSC indicates a lower estimate of 6.495 Tcf of marketable gas from both fields.[4] In comparison, the Alberta Energy and Utilities Board estimates Alberta's remaining established reserves at 40 Tcf.[5] To simplify the analysis and capitalize on economy of scale benefits, this analysis assumes a target production level of 1,000 MMcf/d over a twenty year production period.

Table 3.1: Marketable Gas Reserves[6]

Field	Pool	Reserves (Tcf)
Drake Point	Borden Island Main	4.6
	Borden Island I-55	0.4
	Schei Point	0.1
	Sub-total	5.1
Hecla	Mould Bay	0.02
	Borden Island Main	3.1
	Borden Island C-32	0.05
	Schei Point	0.4
	Sub-total	3.6
Total		8.7

- The energy content of the gas produced on Melville Island is estimated at 1,000 BTU/ft^3. Gas analyses supplied for the Arctic Pilot Project Application indicates that the natural gas is predominantly methane (over 97 percent), sweet, and essentially free of heavy ends.

[2] *Arctic Pilot Project Application (GH-3-81) Volume 2 – Gas Supply and Markets.*

[3] Nominal marketable estimates calculated from raw gas-in-place numbers using ratios indicated in Canadian Gas Potential Committee, *Natural Gas Potential in Canada – 2001*, Ch. 12, Pg. 17.

[4] Geological Survey of Canada, *Paper 83-31.*

[5] Alberta Energy and Utilities Board. *Statistical Series (ST) 2004-98: Alberta's Reserves 2003 and Supply Demand Outlook 2004-2013*.

[6] *Arctic Pilot Project Application (GH-3-81) Volume 2 – Gas Supply and Markets.*

3.2 Start-up

- In the previous study, production was assumed to begin in 2009. Feedback suggested a less optimistic timeframe so this study examines the impact of a delay in the start of production to 2014 and to 2019.
- Preparation of the regulatory filing, regulatory proceedings, design and construction occur over a 4 year period prior to production. The estimated cost of the project design and regulatory phases of the project is $210 million (2005 Canadian dollars).

3.3 Operation

- The project is expected to operate 345 days of the year. The remaining 20 days represent downtime associated with the ships in dry dock for annual inspections and service. Delays associated with weather, repairs and scheduled and unscheduled equipment maintenance represent another 10 days per year when individual ships are unavailable over the course of the year. This is consistent with the estimate provided in the Arctic Pilot Project Application.
- The design raw gas production rate of 1000 MMcf/d requires simultaneous flows from both the Drake Point and Hecla fields, on the east and west sides of the island, respectively.

3.4 Discounted Cash Flow Analysis

- The net present value (NPV) of each project assumes a 15 percent (after royalty and tax) discount rate.
- The initial analysis assumes 75 percent equity financing.
- Full Flow Through Analysis is assumed. This allows any losses to be applied to other activities of the project developers. This removes the need to carry losses forward to apply against revenues later in the project.
- Corporate income tax is included. The federal tax rate includes the adjustments made in the August 2003 budget. These changes include a reduction in the corporate income rate to 21 percent minus the Crown royalty by 2007. Changes to taxation include elimination of the 25 percent resource allowance by 2007. The Northwest Territories and Nunavut corporate tax rates are assigned at 4 percent.
- All costs are in 2005 Canadian dollars unless otherwise indicated.
- Mobilization and demobilization costs are incorporated into the capital costs of the project components.
- Drilling costs are separated from other project capital costs. Drilling costs qualify for declining balance depreciation at 30 percent per year.
- All non-drilling facility capital costs qualify for declining balance depreciation at 25 percent per year.

- Capital costs associated with the vessels qualify for declining balance depreciation at 15 percent per year.
- The Crown royalty ranges from 1 to 5 percent per month until payout. After payout, the Crown royalty is the greater of 30 percent of net revenue or 5 percent of gross revenue.

3.5 Price Forecasts

- Prices are determined at the delivery point by means of a netback calculation from the nearest recognized city gate. For LNG deliveries, the delivery point is assumed to be the Strait of Canso, Nova Scotia. CNG deliveries are made to the inlet of the Mackenzie Valley pipeline at the Mackenzie Delta. The GTL project economics assume delivery of synthetic crude to the refinery at Saint John, New Brunswick.
- The natural gas price forecasts are developed from forecasts of Henry Hub prices. Oil prices in dollars per barrel, for the GTL option, are six times the natural gas price in dollars per thousand cubic feet. This assumes that the 6:1 energy equivalency applies and that the factors that impact pricing do so equally to both oil and natural gas.[7]
- Throughput calculations are made on a volumetric basis using Canadian dollars per Mcf.

Conversion factors to assist with the relationships between natural gas and LNG are provided as Appendix A.

Price forecasts were developed using several standard price lines. These price forecasts were combined into six forecasts: A, B, C, A', B', and C'.

A sensitivity analysis was performed for each of the models to give an indication of the specific variables that have the greatest impact on the net present value (NPV) of the projects. Each of the four technological scenarios were run under each of the six forecasts. The key variables were changed +25 percent and –25 percent, one parameter at a time. Then a Monte Carlo simulation was performed with uniform +50 percent and –50 percent distributions to show the impact of simultaneous changes in cost estimates.

Sensitivities were performed for facility capital expenditures, drilling capital expenditures, vessel capital expenditures, facility operations and maintenance, and vessel operations and maintenance.

[7] There appears to be a shift in the relative value of natural gas to oil. This relationship may be the topic of a future study; however, the simplification is appropriate for the size, scope and purpose of the current study.

4.0 Field Development and Pipelines

The Arctic Pilot Project Application called for only the Borden Island Main pool in the Drake Point Field to be produced. This amounts to 322 MMcf/d over the 20 year project period. Achieving this level of production called for 10 wells to be drilled from 3 onshore pads into the offshore pool. Subsequent expansions to the Arctic Pilot Project were expected to increase throughput to 550 MMcf/d and eventually 1.375 Bcf/d. The third expansion required production from the Hecla field. The staged development was intended to allow project designs and operations to be refined as experience was gained with operating in the North.

To simplify the analysis and capitalize on economy of scale benefits, this analysis has adopted a target production level of 1,000 MMcf/d over the twenty year production period. This level of throughput would require simultaneous production from both the Drake Point and Hecla fields. It is assumed that developing both fields will double the drilling requirements to six onshore pads and a total of 20 wells. The Drake Point field is in Nunavut and the Hecla field is in the Northwest Territories.

The gas is sweet and contains virtually no natural gas liquids as indicated in the gas composition estimate in Table 4.1 that was provided in the Arctic Pilot Project application. With this composition, only dehydration of the raw gas stream would be required.

Table 4.1: Natural Gas Composition – Drake Point Field

Constituent	Mole Percent
Methane	98.71
Ethane	0.67
Nitrogen	0.60
Propane	0.02

For the purpose of estimating Crown production royalties, an estimate of the previously incurred costs of exploration must be included. The analysis adopts typical industry practice and consider these costs as “sunk”, which are disregarded for project economics and are instead recovered through the use of a higher rate of return than in other industries.

Field development to bring the Drake Point and Hecla fields into production is estimated to require 20 new development wells at an average cost of $17.5 million (2005 Canadian dollars) each. These costs are based on extended reach drilling in both the Wytch Farm development in Southern England[8] and in the Schrader Bluff development[9] in Alaska. Another $18 million is

[8] Allen, F. et al. “Extended-Reach Drilling: Breaking the 10-km Barrier”, *Oilfield Review*, Winter, 1997. Fourteen wells at a cost of $150 million (1991 U.S. dollars = $240 million 2003 Canadian dollars).

allocated to 30 km of flow lines to bring the gas to a central facility. The capital cost of a 1000 MMcf/d dehydration facility is estimated at $90 million.

Field development costs for flow lines and the dehydration facility were estimated through the application of adjustment factors to development costs in Alberta. The adjustment factors reflect the higher costs associated with mobilization and demobilization in the north, weather delays, labor premiums, and higher costs to transport materials to the site.

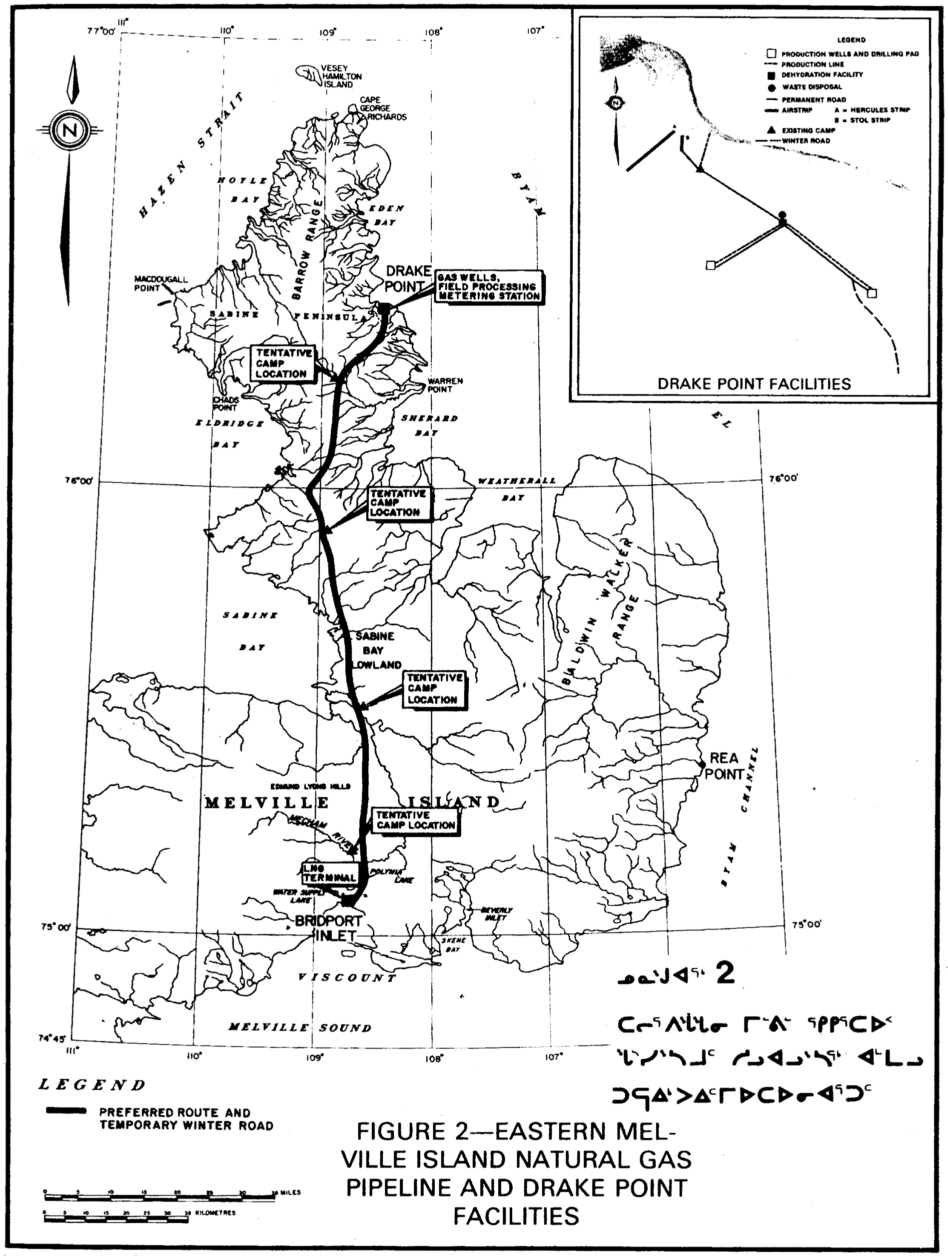
Costs (2005 Canadian dollars):

- Estimated drilling capital cost = 20 wells x $17.5 million/well = $350 million
- Flowlines = $18 million
- 22 km x 20 inch diameter = $15.9 million
- 8 km x 8 inch diameter = $2.8 million
- Dehydration Plant (1000 MMcf/d throughput) = $90 million
- Total field capital cost = $458 million
- Annual field operating cost = $33 million

A 161 km pipeline to link the Drake Point field to the southern coast of Melville Island at Bridport Inlet was designed for the Arctic Pilot Project Application, as shown in Figure 4.1.

[9] Williams, B. "Alaska Update: Operators unlocking North Slope's viscous oil commerciality", *Oil and Gas Journal*, Volume 99, Issue 32, Aug. 6, 2001, p. 36. Fourteen oil producing wells and 20 water injectors for $175 million (2001 U.S. dollars = $247 million 2005 Canadian dollars).

Figure 4.1: Melville Island Pipeline[10]



To accommodate the higher throughput volume of 1000 MMcf/d, the pipeline diameter is increased from the 22 inches in the original design to 36 inches. An additional 36 inch diameter lateral approximately 45 km long is required to link the Hecla field to the pipeline. An estimated 22,000 horsepower compression station will be required to handle the increase in flow.

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[10] *Arctic Pilot Project (Northern Component), Report of the Environmental Assessment Panel.* October 1980.

By modifying and updating the estimates contained in the Arctic Pilot Project Application, the estimated capital cost of the pipeline would be $338 million with an annual operating cost of $4.4 million (2005 Canadian dollars). This corresponds to an approximate 60 percent northern premium applied to typical Alberta pipeline and compression costs.[11]

The supply configuration and costs described in this section are common to all of the project configurations.

5.0 Description of Price Forecasts

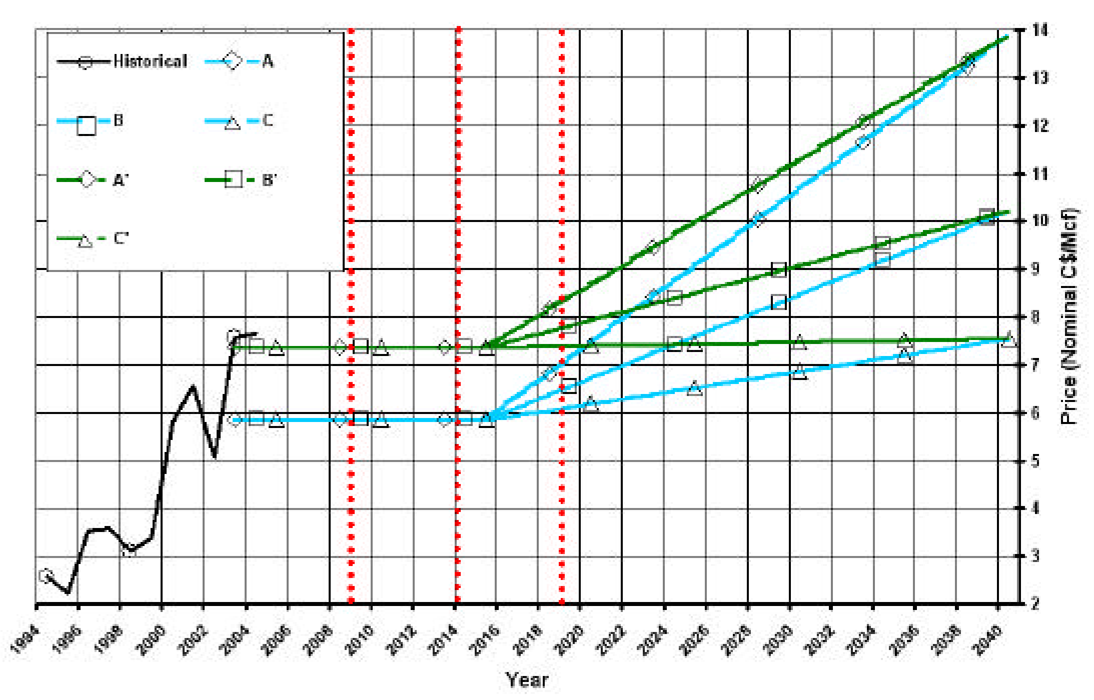
In the Base Case forecast of the March 2004 study, the natural gas price at Henry Hub rises to $11.91 per Mcf (current Canadian dollars) in 2030. The Low Case of that study estimates the Henry Hub price at $9.60 per Mcf (current Canadian dollars) in 2030. The Low Case was based on CERI's Base Case and the Low Oil Price case of the Energy Information Administration's Annual Energy Outlook 2004.[12]

The six price forecasts in this current study were formulated to encompass the forecasts of the previous study and to better reflect current thinking about future prices, as shown in Figure 5.1.

[11] Typical Alberta costs are in the range of $912,000 per km for 36 inch diameter pipeline and $1,150 per hp for compression (20,000 hp). These costs were compiled from Nova Gas Transmission Ltd. Annual Reports. According to the "Special Report - Pipeline Economics", *Oil and Gas Journal*, September 8, 2003, pipeline costs in the U.S. in 2003 ranged from $972,000 to $3 million per km (2005 Canadian dollars) and compression from $1,580 to $1,900 per hp (20,000 hp). The wide range in costs is partially due to the difference in right-of-way costs that depend largely on the density of development in the areas a pipeline traverses.

[12] The Energy Information Administration released in December 2004 the *Annual Energy Outlook 2005 (Early Release)*. Because of the date and version of the release, it has not been incorporated into this study.

Figure 5.1: Henry Hub Natural Gas Prices for Various Forecasts



5.1 Forecasts A and A'

Forecasts A and A' are based on an extension of CERI's Base Case forecast to 2030 provided as part of the March 2004 study. Between 2031 and 2040, a growth rate of 1.5 percent per annum was applied to the Base Case natural gas price in current dollars per Mcf at Henry Hub. The extended Base Case forecast gives a natural gas price of $13.82 per Mcf (current Canadian dollars) in 2040. Prices for other locations were calculated at fixed differentials from the Henry Hub price. The fixed differentials were $2.30 per Mcf between Henry Hub and the start of the Mackenzie Valley Pipeline and $1.37 per Mcf between Henry Hub and the Strait of Canso. For oil, a 6:1 oil to gas ratio was assumed. Forecast A stays constant at $5.85 per Mcf at Henry Hub until 2015 and increases starting in 2016 to reach $13.89 per Mcf in 2040. Forecast A' reaches the same level in 2040 but from a price that stays constant at $7.37 per Mcf until 2015. Forecasts A and A' achieve about the same price level as the extended Base Case forecast.

5.2 Forecasts B and B'

Forecasts B and B' are based on estimates obtained through the websites of Gilbert Laustsen Jung Petroleum Consultants (GLJ) and Sproule Associates Limited. In its forecast revised September 23, 2004, GLJ forecasts the Henry Hub natural gas price to decrease from $8.15 per Mcf in 2004 to $6.49 per Mcf in 2010. Then the price is forecast to increase to $6.69 per Mcf in 2014 and then to increase at 1.5 percent per annum for 2015 and beyond.[13]

[13] The GLJ forecast is expressed in current U.S. dollars per MMBTU.

The Sproule forecast of October 31, 2004 predicts a Henry Hub price of $8.00 per Mcf in 2004, increasing to $9.13 per Mcf in 2005, before dropping to $6.43 per Mcf in 2009. It increases to $6.93 in 2014 and at 1.5 percent per annum for 2015 and beyond.[14]

Like Forecasts A and A', Forecasts B and B' stay constant at $5.85 per Mcf and $7.37 per Mcf, respectively, at Henry Hub until 2015 and increases, starting in 2016. Forecasts B and B' reach $10.23 per Mcf in 2040, slightly higher than the $9.85 and $10.19 per Mcf given by extensions to 2040 of the GLJ and Sproule forecasts, respectively. As a point of reference, if the Low Case forecast of the previous study was extended at a growth rate of 1.5 percent per annum to 2040, the Henry Hub price would reach $10.88 per Mcf. Prices for other locations were derived from the Henry Hub price using the same fixed differentials as previously described. The oil price assumes a 6:1 oil to gas ratio until 2015 and then increases linearly, starting in 2016, to the price given by the Sproule forecast extended to 2040.

5.3 Forecasts C and C'

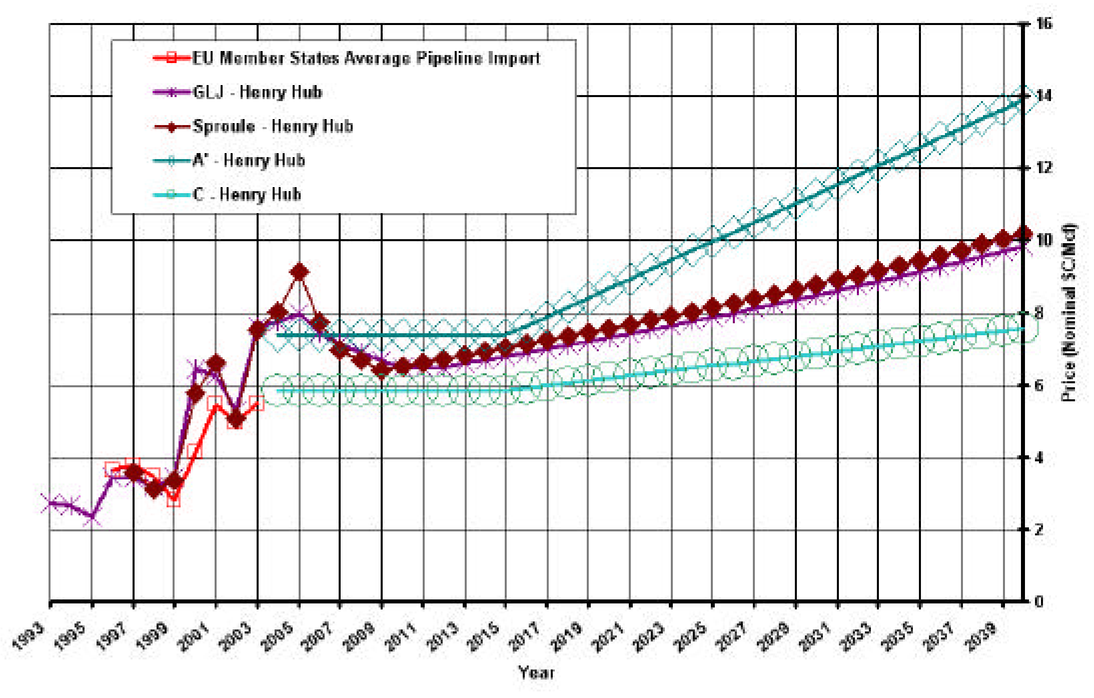
Forecasts C and C' are based on the National Energy Board's report issued January 2003 and entitled, *Canada's Energy Future: Scenarios for Supply and Demand to 2025*. The report forecasts Henry Hub natural gas prices to 2025 for two scenarios: Supply Push and Techno-Vert. The Supply Push forecast gives a Henry Hub natural gas price that increases from $5.34 per Mcf in 2004 to $6.33 per Mcf in 2018 before declining to $6.03 per Mcf in 2025. The Techno-Vert forecast gives a Henry Hub natural gas price that increases from $5.65 per Mcf in 2004 to $7.20 per Mcf in 2018 before declining to $6.85 per Mcf in 2025.[15] Beyond 2025, prices are assumed to increase at 1.5 percent per annum, which happen to be consistent with the assumptions of GLJ and Sproule for 2015 and beyond. Extending the forecasts in this manner gives a price of $7.54 per Mcf and $8.56 per Mcf in 2040 for the Supply Push and Techno-Vert forecasts, respectively.

Forecasts C and C' stay constant at $5.85 per Mcf and $7.37 per Mcf, respectively, at Henry Hub until 2015 and increases, starting in 2016. They reach $7.55 per Mcf in 2040, marginally higher than the extended NEB forecasts. Prices for other locations were derived from the Henry Hub price using the same fixed differentials as previously described. The oil price assumes a 6:1 oil to gas ratio until 2015 and then increases linearly, starting in 2016, to the price given by the Supply Push forecast extended to 2040.

Figure 5.2 shows the relationship between the Henry Hub natural gas price and European prices as measured by the EU Member States Average Pipeline Import Price given by the International Energy Agency (IEA) in its quarterly statistical report.[16]

[14] The Sproule forecast is expressed in current U.S. dollars per MMBTU.
[15] The NEB forecasts are expressed in year 2001 U.S. dollars per MMBTU.
[16] International Energy Agency. *Energy Prices and Taxes: Quarterly Statistics, Third Quarter 2004*. The data are expressed in year 2003 U.S. dollars per million BTU.

Figure 5.2: Henry Hub Natural Gas Price relative to European Pipeline Import Price



Deliveries to European ports would require additional carriers. While the optionality provided by alternative delivery points is considered valuable, quantification of this advantage is not examined within the scope of this study. Furthermore, with additional transportation, it is hypothesized that delivery of Arctic gas to European markets would not be competitive with the sources of gas currently serving those markets.

6.0 Liquefied Natural Gas (LNG) Option

This study adopts all of the liquefied natural gas assumptions used in the March 2004 study, except for a re-assessment of the number of required icebreaking LNG tankers. The basic configuration of the LNG option is based on the design from the Arctic Pilot Project Application. This includes a barge-mounted liquefaction facility, LNG storage barges, construction of a dock and loading facilities, and provision of a fleet of icebreaking LNG tankers. The Application assumes that the LNG is delivered to new third-party regasification facilities located in Nova Scotia along the Strait of Canso.

The estimated capital cost of the project to the point where the LNG can be loaded onto ships is $2,807 million (2005 Canadian dollars). This consists of $458 million for field development, $338 million for the pipeline and $2,011 for the liquefaction facilities. At a production rate of 6.0 million tonnes of LNG per year, the total unit capital cost of $468 per tonne per year (2005 Canadian dollars) to the liquefaction stage falls at the upper end of the range of recent projects.

Table 6.1: Unit Capital Costs Through the Liquefaction Stage[17]

Location	Capacity (MMt/y)	Cost (2005 Canadian dollars/t/y)
Arctic Project – LNG Scenario	6.0	468
Atlantic LNG, Trinidad – Train 1	2.9	274
Atlantic LNG, Trinidad – Trains 2 and 3	6.8	227
OLNG, Oman	6.9	274
NLNG, Nigeria	6.1	412
RasGas, Qatar	6.4	549
QatarGas, Qatar	4.8	309

6.1 Liquefaction

A major difference from the initial Arctic Pilot Phase I design is the scale of the facility. The original design called for a 2.2 million tonne per year (MMt/y) single train liquefaction plant handling a raw gas stream of 322 MMcf/d. For this analysis, the 1000 MMcf/d inlet gas stream will enter a two-train facility with each train sized at 3.3 MMt/y.

Reductions in modern LNG liquefaction costs are estimated to be roughly 20 percent below those of the 1980s plants. Some of the reduction is due to technological progress, but a much larger portion is due to economies of scale as plant trains have become larger.[18]

Capital and operating costs of the LNG liquefaction plant are shown below in Canadian 2005 dollars.

Costs (2005 Canadian dollars):

- Project Development = $9 million
- Site Development = $955 million
- LNG Liquefaction Plant = $657 million
- Barge for LNG Plant = $77 million
- LNG Storage Barges (2 @ 100,000 m^3 of LNG each) = $283 million
- Barge Tow-in Costs = $29 million
- Total capital costs = $2,011 million
- Annual operating costs = $84 million

[17] Unit capital costs converted from U.S. to Canadian dollars at an exchange rate of $0.75 U.S. dollars per $1.00 Canadian dollar. Unit capital costs for Trinidad from University of Houston Institute for Energy, Law and Enterprise, “Overview of the U.S. LNG Industry”, 2003. Unit capital costs for Oman, Qatar and Nigeria from Shell Global Solutions, “Benchmarking LNG plant costs”, as supplied for publication in *Oil and Gas Journal*, April 2003.

[18] “Eventual Union for Qatari LNG Projects?”, *World Gas Intelligence*, December 17, 2003, p. 5. In Qatar, increasing the capacity of LNG liquefaction plant from 3.3 MMt/y to 4.7 MMt/y reduces unit costs by 13%, and from 4.7 MMt/y to 5 MMt/y by 7%.

Site development represents the largest single capital cost item for the facility. Roughly half of the costs for site development are related to construction of the dock, with the remainder split between onshore site preparation, piping and mechanical equipment, utilities and communications, and accommodation and site buildings. The site development cost estimate was prepared by escalating the 1980 estimate for the Arctic Pilot Project.

Annual operating costs are estimated at $84 million. The operating cost estimate was prepared by escalating the original costs from the Arctic Pilot Project Application and fine-tuning these with a comparison to estimated operating costs of a modern LNG facility proposed for Newfoundland.[19]

6.2 Shipping

The proposed LNG carriers have the capacity to take roughly 143,000 m^3 of LNG on board at Bridport Inlet. Natural and induced LNG "boil-off" occurs over the course of the trip as the LNG warms. The boil-off is used as the primary fuel to power the LNG carrier. The boil-off means that only about 133,000 m^3 of LNG is available for delivery at the end of the roughly 9300 km round-trip voyage.

The Arctic Pilot Project Application called for 345 days of operations per year, allowing 20 days for each LNG carrier to be taken into dry dock for annual inspection and maintenance and 10 days over the course of the year for each LNG carrier to be out of service for scheduled and unscheduled maintenance or weather delays.

LNG carrier speeds are expected to average almost 16 knots in open water and just over 9 knots when in ice. The duration of a round-trip voyage will vary considerably depending on the amount of ice encountered in each season. Gas wells and the liquefaction facility are most efficient if operated at a constant rate. Moreover, it was believed in the previous study that liquefaction plant throughput and storage capacity should be based on the longest transit times to avoid having to flare gas. In that study, the required number of ships was based on the longest traverse duration of 28 days, experienced in March and April of a typical year.[20] This gives an average speed of 7.5 knots, considerably less than the average speed of 9 knots through ice.

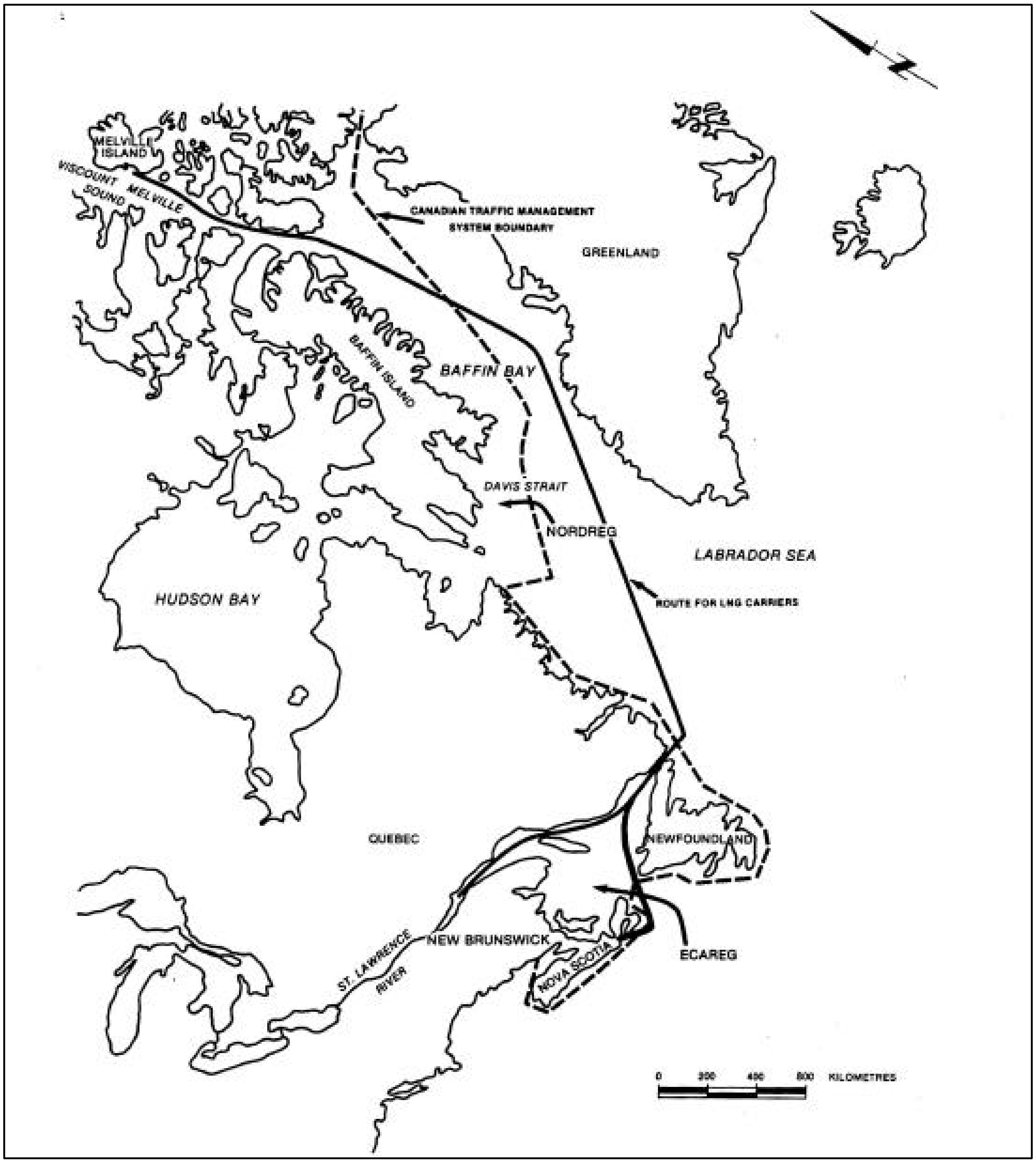
This study uses the year-round average of 21.6 days. In this way, the number of tankers is reduced from 9 to 7, with an average speed of 9.7 knots and a total of 109 trips accomplished over a year.

[19] Worley International Inc. and Worley Engineers for Newfoundland Ocean Industries Association, *Natural Gas Development Based on Non-Pipeline Options – Offshore Newfoundland – Technical Feasibility Analysis*, Dec. 7, 2000.

[20] The Arctic Pilot Project Application estimated that the minimum round-trip duration of 14 days occurs during September.

The proposed shipping route through the Parry Channel is shown in Figure 6.1. The most severe ice along this route is encountered within 500 km of Melville Island, designated as Ice Zone 6 in Figure 6.2.

Figure 6.1: Proposed LNG Shipping Route[21]



[21] *Arctic Pilot Project Application (GH-3-81)*.

Figure 6.2: Ice Management Zones[22]

Arctic Class 7 ships are required for year round use through the Parry Channel to Melville Island in accordance with Schedule VIII of the *Arctic Waters Pollution Prevention Act* (AWPPA), as shown in Table 6.2.

[22] *Arctic Waters Pollution Protection Act*. Retrieved December 31, 2004 from <http://www.tc.gc.ca/acts-regulations/FILES/zips/file_folder/awppa/awppa.zip>.

Table 6.2: Arctic Navigation Zones and Time Periods (Arctic Water Pollution Protection Act)

AWPPA 1

SCHEDULE VIII

(ss. 6 and 26)

TABLE

	Col. I	Col. II	Col. III	Col. IV	Col. V	Col. VI	Col. VII	Col. VIII	Col. IX	Col. X	Col. XI	Col. XII	Col. XIII	Col. XIV	Col. XV	Col. XVI	Col. XVII
Item	Category	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	Zone 11	Zone 12	Zone 13	Zone 14	Zone 15	Zone 16
1.	Arctic Class 10	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year
2.	Arctic Class 8	July 1 to Oct. 15	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year
3.	Arctic Class 7	Aug. 1 to Sept. 30	Aug. 1 to Nov. 30	July 1 to Dec. 31	July 1 to Dec. 15	July 1 to Dec. 15	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year	All Year
4.	Arctic Class 6	Aug. 15 to Sept. 15	Aug. 1 to Oct. 31	July 15 to Nov. 30	July 15 to Nov. 30	Aug. 1 to Oct. 15	July 15 to Feb. 28	July 1 to Mar. 31	July 1 to Mar. 31	All Year	All Year	July 1 to Mar. 31	All Year	All Year	All Year	All Year	All Year
5.	Arctic Class 4	Aug. 15 to Sept. 15	Aug. 15 to Oct. 15	July 15 to Oct. 31	July 15 to Nov. 15	Aug. 15 to Sept. 30	July 20 to Dec. 31	July 15 to Jan. 15	July 15 to Jan. 15	July 10 to Mar. 31	July 10 to Feb. 28	July 5 to Jan. 15	June 1 to Jan. 31	June 1 to Feb. 15	June 15 to Feb. 15	June 15 to Mar. 15	June 1 to Feb. 15
6.	Arctic Class 3	Aug. 20 to Sept. 15	Aug. 20 to Sept. 30	July 25 to Oct. 15	July 20 to Nov. 5	Aug. 20 to Sept. 25	Aug. 1 to Nov. 30	July 20 to Dec. 15	July 20 to Dec. 31	July 20 to Jan. 20	July 15 to Jan. 25	July 5 to Dec. 15	June 10 to Dec. 31	June 10 to Dec. 31	June 20 to Jan. 10	June 20 to Jan. 31	June 5 to Jan. 10
7.	Arctic Class 2	No Entry	No Entry	Aug. 15 to Sept. 30	Aug. 1 to Oct. 31	No Entry	Aug. 15 to Nov. 20	Aug. 1 to Nov. 20	Aug. 1 to Nov. 30	Aug. 1 to Dec. 20	July 25 to Dec. 20	July 10 to Nov. 20	June 15 to Dec. 5	June 25 to Nov. 22	June 25 to Dec. 10	June 25 to Dec. 20	June 10 to Dec. 10
8.	Arctic Class 1A	No Entry	No Entry	Aug. 20 to Sept. 15	Aug. 20 to Sept. 30	No Entry	Aug. 25 to Oct. 31	Aug. 10 to Nov. 5	Aug. 10 to Nov. 20	Aug. 10 to Dec. 10	Aug. 1 to Dec. 10	July 15 to Nov. 10	July 1 to Nov. 10	July 15 to Oct. 31	July 1 to Nov. 30	July 1 to Dec. 10	June 20 to Nov. 30
9.	Arctic Class 1	No Entry	No Entry	No Entry	No Entry	No Entry	Aug. 25 to Sept. 30	Aug. 10 to Oct. 15	Aug. 10 to Oct. 31	Aug. 10 to Oct. 31	Aug. 1 to Oct. 31	July 15 to Oct. 20	July 1 to Oct. 31	July 15 to Oct. 15	July 1 to Nov. 30	July 1 to Nov. 30	June 20 to Nov. 15
10.	Type A	No Entry	No Entry	Aug. 20 to Sept. 10	Aug. 20 to Sept. 20	No Entry	Aug. 15 to Oct. 15	Aug. 1 to Oct. 25	Aug. 1 to Nov. 10	Aug. 1 to Nov. 20	July 25 to Nov. 20	July 10 to Oct. 31	June 15 to Nov. 10	June 25 to Oct. 22	June 25 to Nov. 30	June 25 to Dec. 5	June 20 to Nov. 20
11.	Type B	No Entry	No Entry	Aug. 20 to Sept. 5	Aug. 20 to Sept. 15	No Entry	Aug. 25 to Sept. 30	Aug. 10 to Oct. 15	Aug. 10 to Oct. 31	Aug. 10 to Oct. 31	Aug. 1 to Oct. 31	July 15 to Oct. 20	July 1 to Oct. 25	July 15 to Oct. 15	July 1 to Nov. 30	July 1 to Nov. 30	June 20 to Nov. 10
12.	Type C	No Entry	No Entry	No Entry	No Entry	No Entry	Aug. 25 to Sept. 25	Aug. 10 to Oct. 10	Aug. 10 to Oct. 25	Aug. 10 to Oct. 25	Aug. 1 to Oct. 25	July 15 to Oct. 15	July 1 to Oct. 25	July 15 to Oct. 10	July 1 to Nov. 25	July 1 to Nov. 25	June 20 to Nov. 10
13.	Type D	No Entry	No Entry	No Entry	No Entry	No Entry	No Entry	Aug. 10 to Oct. 5	Aug. 15 to Oct. 20	Aug. 15 to Oct. 20	Aug. 5 to Oct. 20	July 15 to Oct. 10	July 1 to Oct. 20	July 30 to Sept. 30	July 10 to Nov. 10	July 5 to Nov. 10	July 1 to Oct. 31
14.	Type E	No Entry	No Entry	No Entry	No Entry	No Entry	No Entry	Aug. 10 to Sept. 30	Aug. 20 to Oct. 20	Aug. 20 to Oct. 15	Aug. 10 to Oct. 20	July 15 to Sept. 30	July 1 to Oct. 20	Aug. 15 to Sept. 20	July 20 to Oct. 31	July 20 to Nov. 5	July 1 to Oct. 31

Climate change in the Arctic is reportedly reducing ice conditions in the North. According to the Third Assessment Report of the Intergovernmental Panel on Climate Change, there has been a reduction of the extent of Arctic sea-ice extent by 2.9% per decade over the 1978-1996 period, sea ice has thinned, and there are now more melt days per summer.[23] The Arctic Climate Impact Assessment (ACIA) in 2004 noted that reduced sea ice may permit increased offshore extraction of oil and gas but increased ice movement may also make shipping initially more difficult.[24] However, the Arctic Water Pollution Protection Act (AWPPA) has not yet been modified to reduce the required Arctic Class 7 rating required for the proposed route. While the ship construction standards have not been reduced, less severe ice conditions resulting from climate change may allow consideration of increased ship speeds and therefore the possibility of reducing the number of ships required for the project. Due to the absence of information from which to make this judgement, the effects of climate change on ship speeds has not been considered in this analysis.

The original design of the icebreaking LNG carriers for the Arctic Pilot Project Application called for Arctic Class 7 capability. No LNG carrier with icebreaking capability has ever been constructed, so the unique design of the proposed LNG carriers from the Arctic Pilot Project Application remains the primary source of information for capability and costs. Moving to an Arctic Class 7 hull in the 1980 estimate increased the capital cost of the standard LNG carrier by roughly $62 million in equivalent 2005 Canadian dollars. Since new-build standard LNG carriers have declined in price to roughly $206 million (2005 Canadian dollars), the estimated cost of a modern Arctic Class 7 version is estimated at $268 million (2005 Canadian dollars).

Costs (2005 Canadian dollars) for the LNG carriers:

- Capital cost per ship = $268 million
- Annual operating cost per ship = $44 million

For seven (7) ships:

- Capital cost = $1,875 million
- Annual operating cost = $310 million

Cost estimates for standard LNG carriers have been verified with reports from several sources. The Energy Information Administration's report, *U.S. LNG Markets and Uses: June 2004 Update*, states that a 130,000 m^3 tanker costs about $160 million U.S. or roughly $210 million Canadian. In addition, equity research of Bear, Stearns & Co. estimates a 135,000 m^3 tanker at $160 million

[23] Intergovernmental Panel on Climate Change, *IPCC Third Assessment Report - Climate Change 2001*. Chapter 16 Polar Regions (Arctic and Antarctic), Executive Summary retrieved December 31, 2004 from <http://www.grida.no/climate/ipcc_tar/wg2/pdf/wg2TARchap16.pdf>.

[24] Arctic Monitoring and Assessment Programme (AMAP). *Arctic Climate Impact Assessment* retrieved December 31, 2004 from <http://amap.no/acia/>.

U.S.[25] JP Morgan Chase & Co. estimates a 210,000 m^3 tanker at $200 million U.S. or $260 million Canadian.[26]

6.3 Regasification

Regasification facilities in Nova Scotia are assumed to be developed by third parties. There is a range in views regarding potential regasification costs. The minimum cost is estimated at roughly $0.34 per Mcf (2005 Canadian dollars) to represent regasification in fully depreciated capacity in the four existing U.S. import terminals.[27] Estimates for new terminals range from $0.44 to $0.69 per Mcf (2005 Canadian dollars).[28] The U.S. Energy Information Administration estimates regasification to add $0.41 per Mcf (2005 Canadian dollars) to the price of imported LNG.[29] For this analysis, an estimate of $0.60 per Mcf was selected.

Alternatives exist for regasification of the LNG if the Canadian facilities do not proceed. The four existing terminals in the U.S. at Everett, MA, Cove Point, MD, Elba Island, GA and Lake Charles, LA are unlikely to accept regular shipments from Canada's North since they are already fully contracted for periods of up to 20 years. Many new regasification projects are proposed for various locations along the coasts of North America but estimates suggest that less than five of these projects are likely to enter service over the next ten years.[30]

Proposed North American regasification terminals that provide the shortest shipping distances for an Arctic LNG project are indicated in Table 6.3.

[25] Dudas, M. S. and Zeppelin, S. M. *LNG to Save the Day? Outlook for Global LNG Engineering and Construction Opportunities.* Bear, Stearns & Co., August 2003,

[26] Pak, J. M. and Kan, M. *South Korea Shipbuilding. LNG Carrier Orders Keep Coming.* JP Morgan Chase & Co., September 14, 2004.

[27] "LNG costs and markets have both changed in recent years." *Petroleum News*, Volume 6, Number 3, March 28, 2001.

[28] "LNG and its Role in a 30 Tcf Market", El Paso Global LNG, May 14, 2002. "Overview of the U.S. LNG Industry", University of Houston Institute for Energy, Law and Enterprise, 2003.

[29] Energy Information Administration, *The Global Liquefied Natural Gas Market: Status & Outlook.* December 2003.

[30] "Natural Gas Market Issues and Outlook." CERI, December 13, 2003.

Table 6.3: Proposed LNG Regasification Projects in the Northeast[31]

Project	Location	Proponents	Sendout Capacity (Bcf/d)
Bear Head	Point Tupper, NS	Anadarko	1.0 – 1.5
Cacouna Energy	Gros Cacouna, PQ	TransCanada, Petro-Canada	0.5
Canaport	Saint John, NB	Irving Oil, Repsol	1.0
Keltic LNG	Goldboro, NS	Keltic Petrochemicals	0.5 – 1.9
Point Tupper	Point Tupper, NS	Statia Terminals Canada	0.5
Rabaska	Ville Guay/Beaumont, PQ	Gaz Metropolitain, Enbridge, Gaz de France	0.5
Brayton Point LNG	Somerset, MA	Somerset LNG	0.65
Crown Landing	Logan Township, NJ	BP	1.2
Northeast Gateway	offshore Gloucester, MA	Excelerate Energy LLC	0.8
Providence LNG	Providence, RI	Keyspan, BG Group	0.5
Quoddy Bay	Pleasant Point, ME	Passamaquoddy/Sipayik Reservation	0.5 – 1.0
Weaver's Cove	Fall River, MA	Poten & Partners, Amerada Hess	0.4 – 0.8

It is assumed that sufficient regasification terminal capacity will exist for LNG delivery to Atlantic Canada.

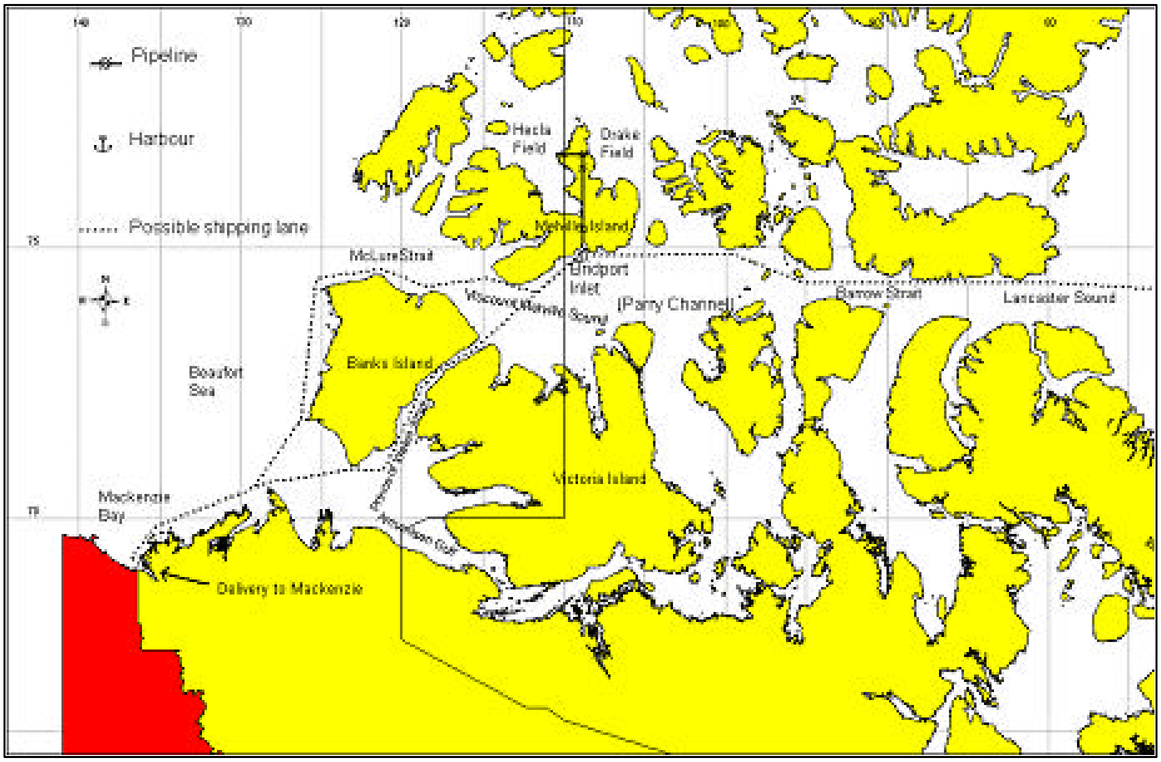
7.0 Compressed Natural Gas (CNG) Option

A compressed natural gas project avoids the high capital costs of both the liquefaction plant and regasification terminal in a LNG project. In a CNG project, standard compression facilities are used to compress gas up to 3000 psig. This gas is transported in specially designed pressure vessels or line-pipe that have been placed in the hold of a ship.

The main drawback of CNG compared to LNG is that CNG carriers can, at best, deliver roughly 34 percent of the capacity of LNG carriers (1000 MMcf vs. 2900 MMcf of natural gas). As a result, CNG projects tend to be better suited to shorter shipping distances than LNG projects. The shorter haul available to a CNG project from Melville Island would be to deliver gas to the Mackenzie Delta for shipment on the Mackenzie Valley Pipeline. This shortens the round trip distance to roughly 2,600 km compared to the 9,300 km for LNG going to Nova Scotia.

[31] Intelligence Press. "North American LNG Import Terminals" retrieved December 13, 2004 from <http://intelligencepress.com/features/lng/terminals/lng_terminals.html>.

Figure 7.1: Delivery of CNG to the Mackenzie Valley Pipeline



7.1 Compression and Loading/Unloading Facilities

The field development and pipeline system on Melville Island for the CNG project is identical to that for the LNG project. The site development at Bridport Inlet to provide the berthing facilities for the CNG carriers are also the same. However, the CNG project requires only a standard compression facility with minimal storage capacity since the daily throughput corresponds to the daily loading capacity of the CNG carriers.

Costs (2005 Canadian dollars):

- Project Development = $9 million
- Site Development = $955 million
- Berthing facilities (unload) and pipeline connection – Mackenzie Delta = $60 million
- Compression = $165 million
- Total capital costs = $1,189 million
- Annual operating costs = $10 million

The estimate of $60 million for the unloading facilities in the Mackenzie Delta and a pipeline to the inlet of the Mackenzie Valley Pipeline presume that basic harbour facilities will have been developed at that location in support of the construction of the Mackenzie Valley Pipeline. The CNG project would then just have to construct berthing facilities for the CNG carriers. If no basic harbour facilities exist, site development costs as much as the $955 million at Bridport Inlet may potentially be required.

7.2 Shipping

Each CNG carrier is assumed to carry one day's gas production of 1000 MMcf. This represents the upper end of the capacity of current designs. The capacity of CNG carriers is limited by the weight associated with the pressure vessels carried in the holds. The lightship draft associated with this size of carrier is at the upper limit for the vessel to be dry docked for annual inspection and maintenance.

There are currently five designs of tankers and barges:

- Cran & Stenning Technology Inc. invented the coselle system in 1996. This system consists of about 11 miles of 6 inch diameter steel pipe wrapped around a single spool in a steel girder.
- The Pressurized Natural Gas concept was developed by Knutsen O.A.S. Shipping AS, German pipe manufacturer EUROPIPE GmbH and Det Norske Veritas AS, a Norwegian risk management group. It utilizes vertically stacked 42 inch diameter steel pipes.
- Gas Transport Modules, or GTM's, are promoted by TransCanada and use horizontally stacked 42 inch diameter composite reinforced line pipe to boost strength and reduce weight.
- EnerSea Transport's technology, Volume Optimized Transport and Storage (VOTRANS) chills the gas to –30 degrees Celsius and stores it at between 1,500 and 1,800 psig, far lower than the other technologies which store gas at between 3,000 and 3,600 psig. The technology consists of vertically stacked 42 inch diameter steel pressure vessels.
- Trans Ocean has developed a concept that entails vertically stacked 44 inch diameter glass-fibre reinforced plastic pressure vessels.

The proponents of these transportation concepts are currently seeking approval from the maritime classification societies, Det Norske Veritas AS, the American Bureau of Shipping, and Lloyd's Register of Shipping, among others.

The maximum round-trip duration is estimated at 10.5 days, giving an average speed of 5.6 knots. As a result, the CNG project requires a minimum of 11 carriers to ensure that a ship is available to load during each day of gas production. A total of 351 round trips are required per year, resulting in an average of roughly 32 trips for each carrier in a year.

In Arctic waters, the hulls of CNG carriers will need to be Arctic Class 7 if using the Parry Channel and Arctic Class 8 if shipping through the Prince of Wales Strait to the Mackenzie Delta. If the Prince of Wales Strait is not navigable during the winter months, an alternative route to the north and west of Banks Island would encounter even harsher ice conditions. This alternative route would require an Arctic Class 10 ship.

The cost of a standard CNG carrier is estimated to be roughly $72 million higher than a standard LNG carrier ($278 million[32] vs. $206 million Canadian dollars). Moving to an Arctic Class 7 hull increased the capital cost of the standard LNG carrier by roughly $62 million ($268 million vs. $206 million). Adding the ice strengthening to the CNG carrier to achieve Arctic Class 7 standards might therefore increase its cost to $278 + $62 = $340 million. A further rough cost increment of $21 million is assumed necessary to bring the CNG carrier up to Arctic Class 8 or 10 standards. The total for the CNG carrier is therefore estimated at $361 million.

Costs (2005 Canadian dollars) for the CNG carriers:
- Capital cost per ship = $361 million
- Annual operating cost per ship = $44 million

For eleven (11) ships:
- Capital cost = $3,972 million
- Annual operating cost = $484 million

8.0 Gas-To-Liquids (GTL) Option

Three alternative processes could be considered for a GTL project – methanol, methanol to gasoline, and Fischer-Tropsch (F-T). These processes produce methanol, ultra-clean gasoline or synthetic crude oil, respectively. Each process extracts a heavy price in terms of conversion efficiency, with roughly 35 percent of the input energy consumed in the process. As an example, a typical F-T process creates 100,000 barrels of synthetic crude oil for every 1000 MMcf of inlet gas into the plant.

8.1 GTL Plant

The F-T process was selected for a demonstration plant constructed by BP on the Kenai Peninsula in Alaska. The demonstration plant began operations in July 2003 and provides a good source of data for a modern facility built in a northern location. The technology used at the demonstration plant involves a revised process that includes a compact reformer. BP indicates that the revised process reduces the capital cost to $28,000 (2005 Canadian dollars) per daily barrel from a previous standard of $34,000 (2005 Canadian dollars).[33]

Assuming a Fischer-Tropsch process would be employed, the GTL plant would convert the 1000 MMcf/d gas feed into 100,000 barrels per day of synthetic crude oil. This plant size is larger than

[32] Cost premium is based on cost estimates in Worley International Inc. and Worley Engineers for Newfoundland Ocean Industries Association, *Natural Gas Development Based on Non-Pipeline Options – Offshore Newfoundland – Technical Feasibility Analysis*, Dec. 7, 2000.

[33] "BP's GTL Plant Meets its Objectives." *Petroleum News*, Volume 8, Number 52, December 28, 2003.

most of the existing and soon-to-be-completed GTL plants but smaller than many that are under development in Qatar.[34]

Upon delivery to a refinery in an East Coast market, synthetic crude from the GTL project is used to produce ultra clean lubes, jet fuel, diesel and naphtha (olefins).

Local markets for GTL, as a cleaner substitute for diesel, in Canada's North is an additional benefit of this technology. For example, both SasolChevron's GTL fuel and Syntroleum's S-2 Synthetic Diesel state their products produce lower emissions than diesel.[35] While fixed costs for the production of GTL are still relatively high, a potential reduction in CO_2 emissions for the Kyoto Protocol makes GTL promotion more attractive.

In Canada, it appears the market provides, "without cost" to the consumer, additives in diesel when the temperature begins to fall to ensure that automobile fuel does not freeze. SasolChevron states that its process balances the high cetane numbers given by linear paraffins in the diesel boiling range and better cold flow properties offered by branched paraffins. It claims its fuel has a cetane number in excess of 70, while retaining good cold flow properties (CFPP lower than -20°C).[36] Syntroleum's S-2 contains a high percentage of iso-paraffins, such that no additives are required to improve low-temperature properties. The cloud point of a fuel is also affected by its distillation characteristics. Testing has demonstrated that the cloud point (CP), pour point, and cold filter plugging point (CFPP) all surpass the specifications set forth in ASTM D-975 and EN 590.[37]

The capital cost of the GTL facilities on Melville Island and in Bridport Inlet involves all of the same siting elements as the LNG project. However, much higher capital costs are associated with the GTL plant than with the LNG project's liquefaction plant.

Costs (2005 Canadian dollars):

- Project Development = $9 million
- GTL Plant = $2,780[38] million
- Barge for GTL Plant = $77 million
- GTL Storage Barges (2) = $283 million
- Site Development = $955 million
- Barge Tow-in Costs = $29 million

[34] California Energy Commission. *GTL Working Group Analysis, October 12, 2004* retrieved December 21, 2004 from <http://www.energy.ca.gov/afvs/documents/2004-10-12_GTL_ANALYSIS.PDF>.

[35] Other parties involved in the development of GTL technologies or projects include: ConocoPhillips, ExxonMobil, Marathon, Petro SA, Rentech, Statoil, Shell, Qatar Petroleum, among others.

[36] "Physical and chemical properties." Sasol Chevron. Retrieved December 1, 2004 from <http://www.sasolchevron.com/physical_chemical_properties.htm>.

[37] "Syntroleum S-2 Synthetic Diesel." Syntroleum. Retrieved December 1, 2004 from <http://www.syntroleum.com/media/syntroleum_s2.pdf>.

[38] Reducing the high capital costs of the GTL plant is the primary goal of ongoing GTL research. One alternative, proposed by Syntroleum, includes plans for a packaged barge-mounted GTL plant (20,000 bpd/barge at a cost of $412 million per barge). This system would reduce costs to $21,000 per daily barrel.

- Total capital costs = $4,135 million
- Annual operating costs = $262[39] million

8.2 Shipping

Tankers will still need to be Arctic Class 7 to transit the Parry Channel. The major difference is that the higher energy content of the synthetic crude significantly reduces the volume of the energy product to be transported. As a result, considerably fewer ships are required to transport the converted product than is the case for LNG or CNG.

The proposed GTL carrier will be an ice-strengthened Suezmax tanker that displaces under 200,000 deadweight tons (DWT) and has a cargo capacity of 1 million barrels of synthetic crude. A previous example of this type of ice-strengthened tanker was the S.S. Manhattan (155,000 DWT) which traversed the Northwest Passage on a test voyage in 1969.

The capacity of the tanker corresponds to 10 days of natural gas production. As a result, just 3 tankers are required for the project, taking 31 days per round trip at an average speed of 6.7 knots.[40]

Costs (2005 Canadian dollars) for the GTL carriers:

- Capital cost per ship = $381 million
- Annual operating cost per ship = $44 million

For three (3) ships:

- Capital cost = $1,144 million
- Annual operating cost = $133 million

9.0 LNG Option with Greenland Transshipment

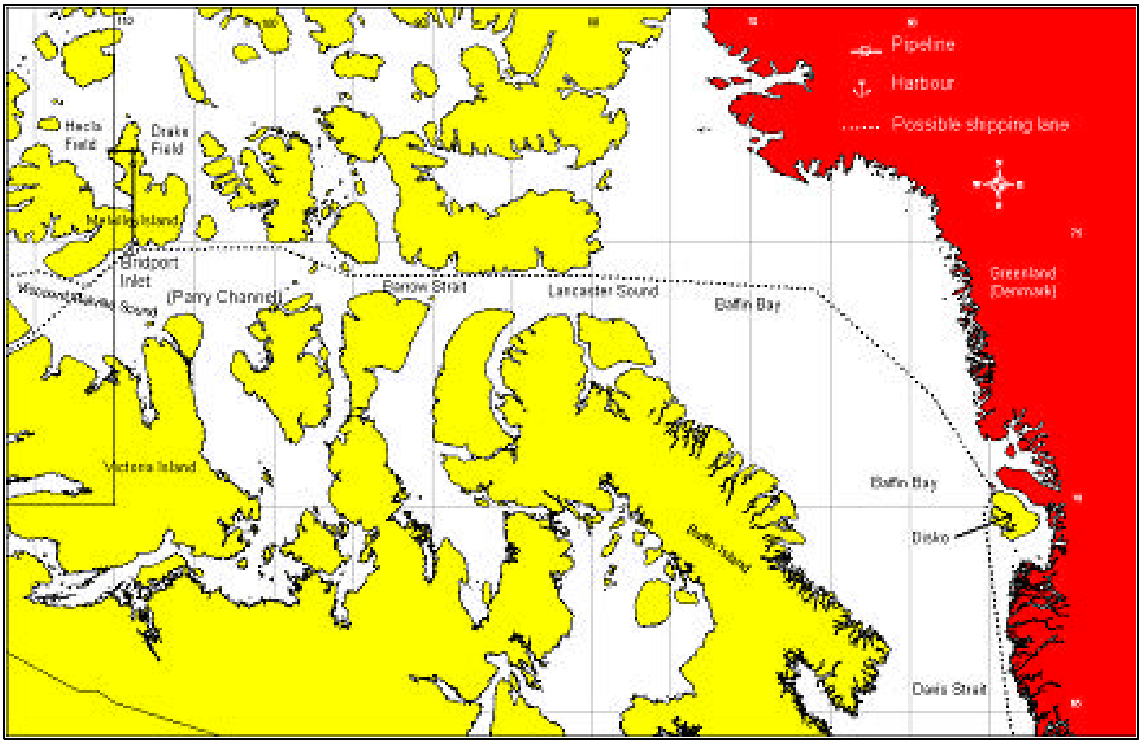
An option to use a transshipment facility on the west coast of Greenland[41] was formulated to reduce the required number of Arctic Class 7 tankers. However, development of storage facilities would be required for this option. The number of ships and the amount of storage required depends on the delivery to the Strait of Canso of the same volume as the case without transshipment. Delivery to other ports, such as to Europe, would require additional tankers and may result in the establishment of a hub for Atlantic LNG trade.

[39] Based on an estimate of $5.50 per barrel from Energy Information Administration, *International Energy Outlook 2000*, pg. 59.

[40] The maximum round trip duration assumes delivery of the synthetic crude to the refinery at Saint John, NB.

[41] Greenland has a home rule arrangement with Denmark, which is a member of the European Union.

Figure 9.1: Delivery of LNG to the Strait of Canso via Greenland



9.1 Liquefaction

As in the case without transshipment, capital and operating costs of the LNG liquefaction plant are reiterated below in Canadian 2005 dollars.

Costs (2005 Canadian dollars):

- Project Development = $9 million
- Site Development = $955 million
- LNG Liquefaction Plant = $657 million
- Barge for LNG Plant = $77 million
- LNG Storage Barges (2 @ 100,000 m^3 of LNG each) = $283 million
- Barge Tow-in Costs = $29 million
- Total capital costs = $2,011 million
- Annual operating costs = $84 million

9.2 Shipping

The proposed LNG carriers would load LNG at Bridport Inlet for delivery to Goldhavn, Disko Island off the coast of Greenland for a round-trip distance of 3500 km. Tankers travelling between Disko Island and the Strait of Canso have a round-trip distance of 6000 km, for a total of almost 10,000 km. It is assumed that the tankers in the first leg of the journey would be

Arctic Class 7 with a capacity of 143,000 m^3 of LNG. The second leg would utilize standard LNG tankers that have a capacity of 200,000 m^3, the tanker size currently under development.

For the first leg , five (5) Arctic Class 7 tankers would be needed, travelling at an average speed of 6.2 knots, with 14 days required per round-trip. For the second leg, two (2) standard tankers would travel at an average speed of 15.8 knots and would require 9 days per round-trip.

The estimated cost of a modern Arctic Class 7 version is $268 million while the standard tankers are estimated at $206 million. Operating costs for the standard LNG tanker are assumed to be 75 percent of those for Arctic Class 7 tankers.

Costs (million 2005 Canadian dollars) for the LNG carriers:

- Capital cost per ship = $268 million for Arctic Class 7 and $206 million for standard
- Annual operating cost per ship = $44 million for Arctic Class 7 and $33 million for standard

For five (5) Arctic Class 7 and two (2) standard ships:

- Capital cost = $1,339 million for Arctic Class 7 and $412 million for standard = $1,751 million
- Annual operating cost = $221 million for Arctic Class 7 and $66 million for standard = $287 million

9.3 Storage

In addition to those LNG facilities required for the option without transshipment, facilities for aboveground storage were added. One source to CERI advises that for 160,000 cubic metres, the cost is approximately $150 million (U.S.), which amounts to about $940 (U.S.) per cubic metre or $1,270 per cubic metre in 2005 Canadian dollars. This differs from the costs from a research report by Bear, Stearns & Co. of approximately $165 million (U.S.) for 300,000 cubic metres or $550 (U.S.) per cubic metre for full containment storage tanks[42] and $200 (U.S.) per cubic meter for single containment tanks. It is also lower than Arup Energy's estimate of $300 to $350 (U.S.) per cubic metre. The estimate provided to CERI is extrapolated to $381 million (2005 Canadian dollars) for a volume of over approximately 6 Bcf of natural gas (or 300,000 cubic metres of LNG) for this study. For comparison, the storage and sendout capacities of existing regasification terminals is provided in Table 9.1.

[42] Full containment storage tanks, the current LNG industry standard, involve two integrated storage tanks: a free-standing alloy steel inner tank which contains the stored liquid, and an outer tank which provides security in the event of any loss of containment from the inner tank.

Table 9.1: Existing LNG Regasification Terminals in North America[43]

Project	Location	Owner(s)	Sendout Capacity (Bcf/d)	Storage Capacity (Bcf)
Cove Point LNG	Lusby, MD	Dominion	1.0	5
Elba Island	Elba Island, GA	El Paso	0.44	4
Everett LNG	Everett, MA	Distrigas of Massachusetts Corp., Tractebel LNG/Suez	0.725	3.4
Trunkline LNG	Lake Charles, LA	Panhandle Energy (Southern Union)	0.63	6.3

Salt cavern storage of LNG as a dense phase, such as in Conversion Gas Imports' Bishop Process, would likely reduce the storage capital cost but is not included in this study.[44]

Additional operating expenditures are assumed to add about $5 million per year to the $84 million annual liquefaction expenditure.

9.4 Regasification

As in the LNG case without transshipment, an estimated cost of $0.60 per Mcf was assumed for regasification.

Including all of the elements of the value chain of the LNG options without and with transshipment shows that transshipment requires a capital expenditure that is an estimated $257 million more and operating expenditures that are $17 million per year less.

10.0 Risk Factors

As described in the previous study, there is technological and economic uncertainty related to the production and delivery of natural gas from the Arctic.

The analysis has relied heavily on the Arctic Pilot Project Application. The reliability of the information and its applicability to current technological, construction and shipping conditions represents a significant risk for the analysis.

An initial risk to be considered is the reliability of the resource information. The resource could turn out to be smaller than anticipated, or producing conditions could cause the life of the wells to be reduced. If deliveries from the gas fields are interrupted by harsh conditions, facilities and

[43] Intelligence Press. "North American LNG Import Terminals" retrieved December 13, 2004 from <http://intelligencepress.com/features/lng/terminals/lng_terminals.html>.

[44] McCall, M. M. "Field Test and Full Scale Design of Critical Components of a Salt Cavern Based LNG Receiving Terminal," a presentation to U.S. Energy Economists, March 18, 2004 retrieved from <http://www.conversiongas.com/USAEE-CGI_-_March_18_2004.pdf>.

ships could be idled. A reduction of the supply would lead to under-utilization of the capital assets and cause unit costs to rise.

For the March 2004 analysis, the Arctic project was assumed to begin operations in 2009 following a four year period to obtain regulatory approvals and financing and to construct facilities and ships. However, development of Arctic resources will likely not occur by 2009. These uncertainties have been examined in this study as delays in production start-up from 2009 to 2014 and to 2019.

Obtaining the required regulatory approvals represents another risk to the project. The cost of the original Arctic Pilot Project Application was close to $100 million in 1980, and it is unknown how much, if any, of the original filing could be re-used. The time to prepare an updated filing and complete the regulatory process could be longer than anticipated and delay the overall project. For this analysis, a cost of $206 million was assigned to cover project design and obtaining regulatory approvals.

Efforts have been made to update the costs indicated in the original Arctic Pilot Project Application by referring to costs from more current projects wherever possible. Where more current examples do not exist, the analysis was forced to escalate the costs from the Arctic Pilot Project Application. The sensitivity and Monte Carlo analysis performed in this study should identify and quantify some of this uncertainty. In addition, northern premiums associated with the length of the construction season and the costs of providing labor, equipment and materials to the site may differ from those assumed.

Shipping costs represent another large component of the project expenditures and involve major risks. If ice conditions cause transit times to be slower than anticipated, additional ships will be required. If ships become stuck in the ice, the costs of dedicated icebreakers may be required. Damage to ships and corresponding downtime for repairs could reduce deliveries.

This analysis assumes the project will be undertaken in a single phase although the original concept called for a phased development that would allow subsequent expansions to benefit from the experience gained in earlier phases. This was particularly expected to benefit ship design since the icebreaking carrier is an untried concept. Experience gained through actual operations in the north could be incorporated into the design of subsequent carriers. As a result, the construction of the entire project in a single phase carries some additional risk of lower efficiency than a multi-stage approach.

The effect of market price uncertainty has been examined using six price forecasts in this study. A ratio of 6:1 for the oil-to-gas price was assumed to avoid bias. If prices turn out to be significantly lower than expected, the economic viability of the project could be jeopardized, as indicated by Forecasts C and C'. Conditions that could result in low prices include:

- Large amounts of LNG are developed worldwide and enter the North American market.

- Pipelines from the north bringing large amounts of natural gas into the North American market.
- High levels of gas demand being irreversibly lost due to previous periods of high prices.

The proposed CNG design examined in this study incurs additional risks associated with the Mackenzie Valley Pipeline. Foremost is that the pipeline must be built. Second is that there must be sufficient available capacity on the pipeline to accommodate the production from the Arctic. Depending on the design of the original pipeline, providing the required capacity may involve additional compression or pipeline looping. Another risk associated with the CNG design is the need for berthing facilities at the Mackenzie Delta. For this analysis it was assumed that harbor facilities would have been constructed as part of the Mackenzie Valley Pipeline project and that these would be available to the CNG project. If this turns out to not be the case, it may be necessary to add almost $1 billion to the capital cost estimate of the CNG project for construction of new docking facilities.

The availability of sufficient import capacity represents a potential risk to the proposed LNG project. All of the existing U.S. terminals are fully subscribed to other LNG sources for periods of up to 20 years. As a result, new LNG regasification capacity would be required to accept supplies of gas from the Arctic. While large numbers of new LNG import terminals have been proposed, several have already been rejected due to local opposition. If it becomes increasingly difficult or costly to site LNG regasification terminals, the LNG option may incur additional costs.

11.0 Results

The models were run with the initial capital and operating cost estimates and other economic assumptions described previously. The inputs and the results are presented in Table 11.1.

The results indicate that:

- All four of the scenarios are economically favourable (have a positive net present value) under certain price levels, namely Price Forecasts A, A', B', and C'.
- Price Forecasts B and C have negative, or barely positive, NPV's.
- Delays in the start of production increases the NPV for the scenarios under Price Forecasts A and A', has no impact on NPV for the scenarios under Price Forecasts B and B', and reduces the NPV for the scenarios under Price Forecasts C and C'.
- For the price forecasts that start at $5.85 (Canadian) per Mcf at Henry Hub, Price Forecast A is the most favourable, followed by Price Forecasts B and C. The price forecasts that start at the higher price level, $7.37 (Canadian) per Mcf at Henry Hub, Price Forecasts A', B', and C', are more favourable than the corresponding lower Price Forecasts, A, B, and C.
- The CNG project is the most favourable under Price Forecasts A' and B' for all start years. It is also the most favourable under Price Forecast A for start years of 2014 and 2019 and under Price Forecast C' for start years of 2009 and 2014. The CNG project has the second highest capital cost but the second lowest operating cost. Also, despite lower prices at the start of the Mackenzie Valley Pipeline relative to the Strait of Canso, the volume of natural

gas delivered to the start of the Mackenzie Valley Pipeline is greater than the volume of natural gas delivered to the Strait of Canso in both of the LNG projects.

- The LNG case without transshipment is marginally more favourable than the LNG case with transshipment.
- One of the results of the March 2004 study, that all of the three scenarios examined at that time resulted in a positive NPV under the Base Case price forecast, is replicated here by the results under Price Forecast A' for a production start date of 2009.

Table 11.1: Summary of Initial Cost Estimates and Results

	LNG	CNG	GTL	LNG Transshipment
Capital Costs (million 2005 Canadian dollars)				
Project Development	206	206	206	206
Development Drilling	350	350	350	350
Producing Fields and Dehydration	108	108	108	108
Melville Island Pipeline	338	338	338	338
Facilities	2,011	1,189	4,135	2,392
Vessels	1,875	3,966	1,144	1,751
Total Capital Costs	4,888	6,158	6,281	5,145
Annual Operating Costs (million 2005 Canadian dollars)				
Gas Production and Processing	33	33	33	33
Melville Island Pipeline	4	4	4	4
Facilities	84	10	262	89
Vessels	310	487	133	288
Regasification	168	0	0	166
Total Operating Costs	600	535	432	581
NPV @ 15% for Price Track A (million 2005 Canadian dollars)				
Production Start 2009	(163)	(30)	47	(191)
Production Start 2014	29	190	155	2
Production Start 2019	439	606	380	409
NPV @ 15% for Price Track B (million 2005 Canadian dollars)				
Production Start 2009	(266)	(152)	(43)	(295)
Production Start 2014	(235)	(100)	(61)	(261)
Production Start 2019	(92)	24	(31)	(119)
NPV @ 15% for Price Track C (million 2005 Canadian dollars)				
Production Start 2009	(343)	(240)	(89)	(372)
Production Start 2014	(427)	(296)	(170)	(451)
Production Start 2019	(461)	(330)	(223)	(483)
NPV @ 15% for Price Track A' (million 2005 Canadian dollars)				
Production Start 2009	513	626	467	475
Production Start 2014	570	725	487	535
Production Start 2019	846	1044	637	817
NPV @ 15% for Price Track B' (million 2005 Canadian dollars)				
Production Start 2009	412	502	377	374
Production Start 2014	300	406	259	266
Production Start 2019	300	416	194	267
NPV @ 15% for Price Track C' (million 2005 Canadian dollars)				
Production Start 2009	338	412	332	299
Production Start 2014	105	175	141	70
Production Start 2019	(98)	(29)	(25)	(128)

11.1 Sensitivity Analysis

A simple sensitivity analysis[45] was performed to vary by ±25 percent each of the most important variables, one variable at a time. These parameters are: facility, vessel, and drilling capital expenditures, and facility and vessel annual O&M. The discount rate has the greatest impact on net present value (NPV) but is kept at 15 percent for this analysis.

The following figures illustrate the results of this sensitivity analysis. The results indicate that:

- A change of 25 percent in any of the four parameters can change NPV by about $300 million.
- In all of the cases, NPV is least sensitive to changes in drilling capital expenditures. Drilling, as estimated, comprises a small proportion of the total project cost.
- In all of the scenarios of LNG without transshipment, facility capital expenditures and vessel annual O&M have the greatest impact on NPV.
- In all of the CNG scenarios, vessel O&M has the greatest impact on NPV, followed by vessel capital expenditures.
- In all of the GTL scenarios, facility capital expenditures has the greatest impact on NPV.
- In most of the scenarios of LNG with transshipment, facility capital expenditures and vessel annual O&M have the greatest impact on NPV. This result is the same as that for LNG without transshipment.
- Although the initial calculation showed that the CNG project is the most favourable under Price Forecasts A' and B', for all production start years, the range of NPV between changes of –25 percent and +25 percent is greater than the range of NPV for the corresponding cases for both of the LNG scenarios and the GTL scenario.

Note that the scenarios differ in the relative technological uncertainty which is not precisely reflected in the arbitrary ±25 percent applied to each of the parameters for each of the scenarios. In addition, particularly for vessel capital expenditures and vessel O&M, learning can take place over time that makes phasing-in of a project more favourable than illustrated here.

[45] This uncertainty analysis focuses on parameter uncertainty, not model uncertainty.

Figure 11.1: LNG Scenario – NPV (billion 2005 Canadian dollars) with ±25% Change in Each Parameter – Initial Low Price

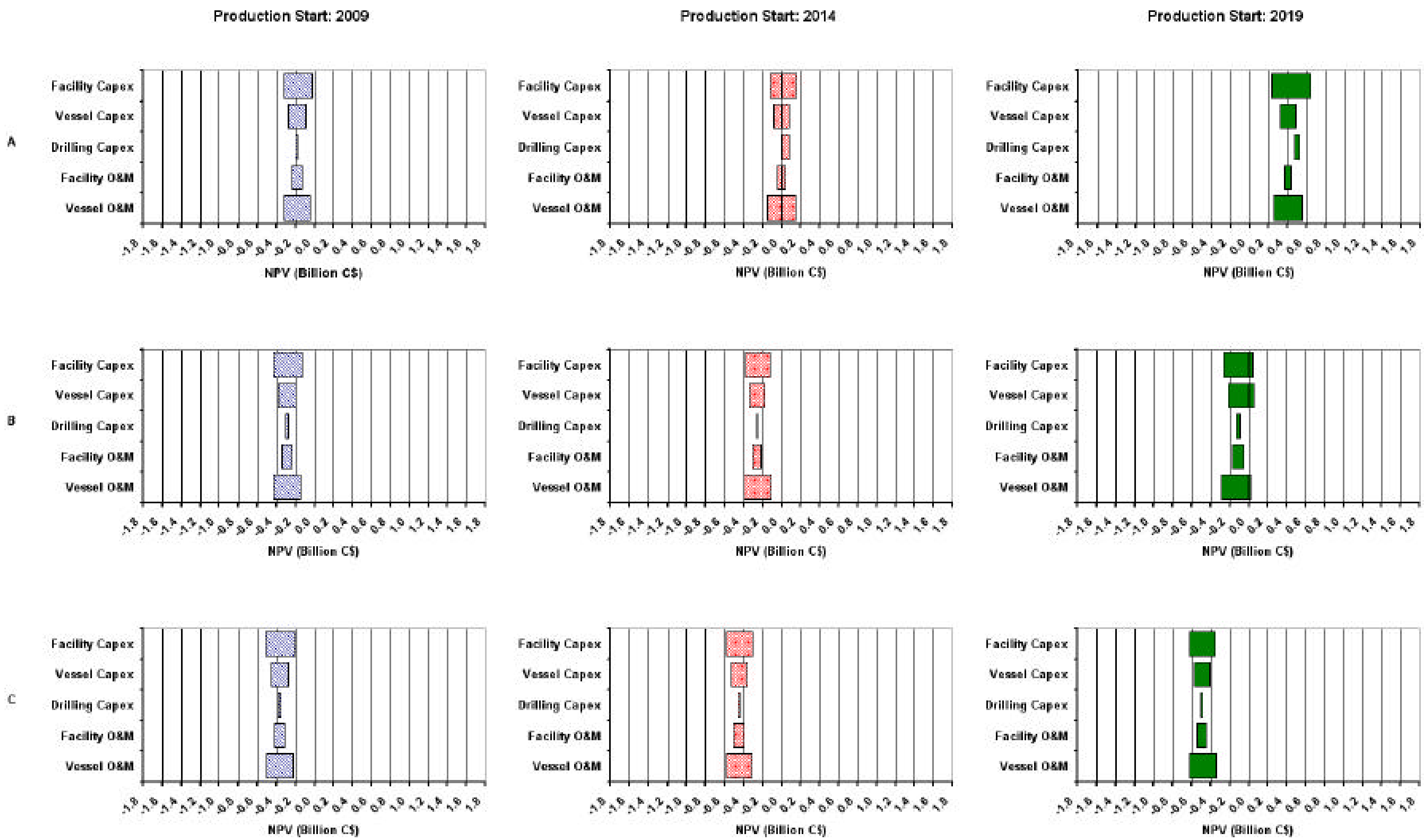


Figure 11.2: LNG Scenario – NPV (billion 2005 Canadian dollars) with ±25% Change in Each Parameter – Initial High Price

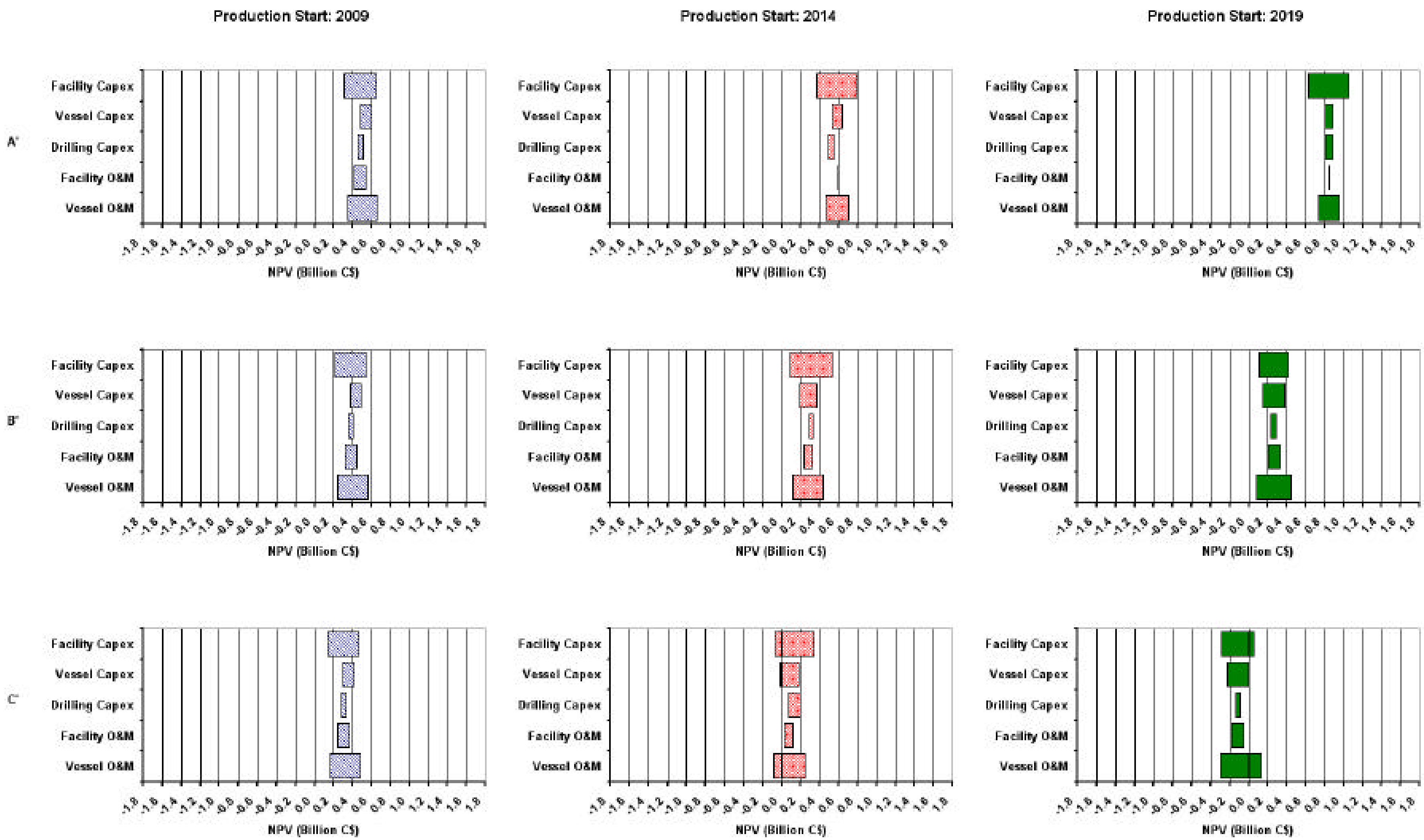


Figure 11.3: CNG Scenario – NPV (billion 2005 Canadian dollars) with ±25% Change in Each Parameter – Initial Low Price

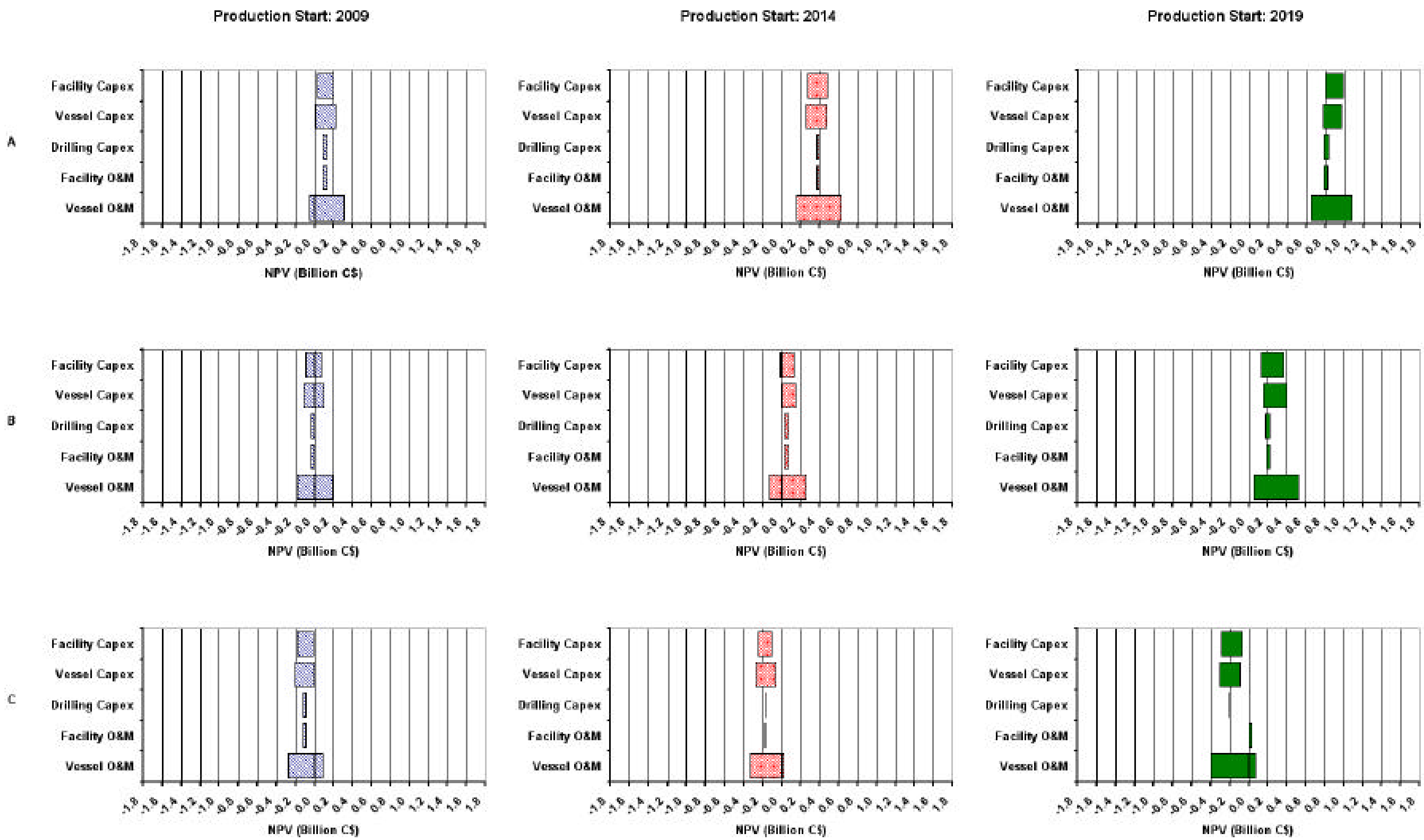


Figure 11.4: CNG Scenario – NPV (billion 2005 Canadian dollars) with ±25% Change in Each Parameter – Initial High Price

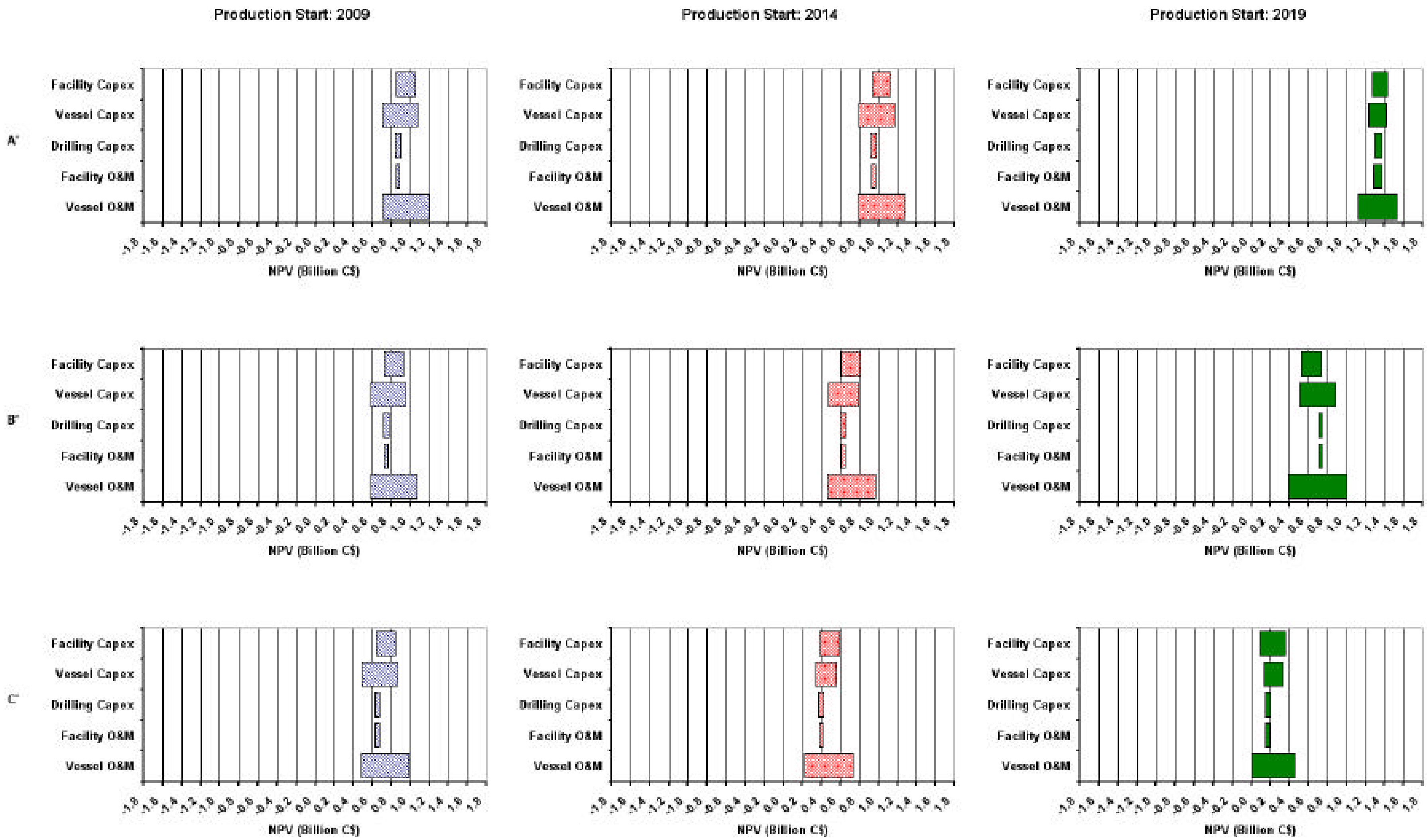


Figure 11.5: GTL Scenario – NPV (billion 2005 Canadian dollars) with ±25% Change in Each Parameter – Initial Low Price

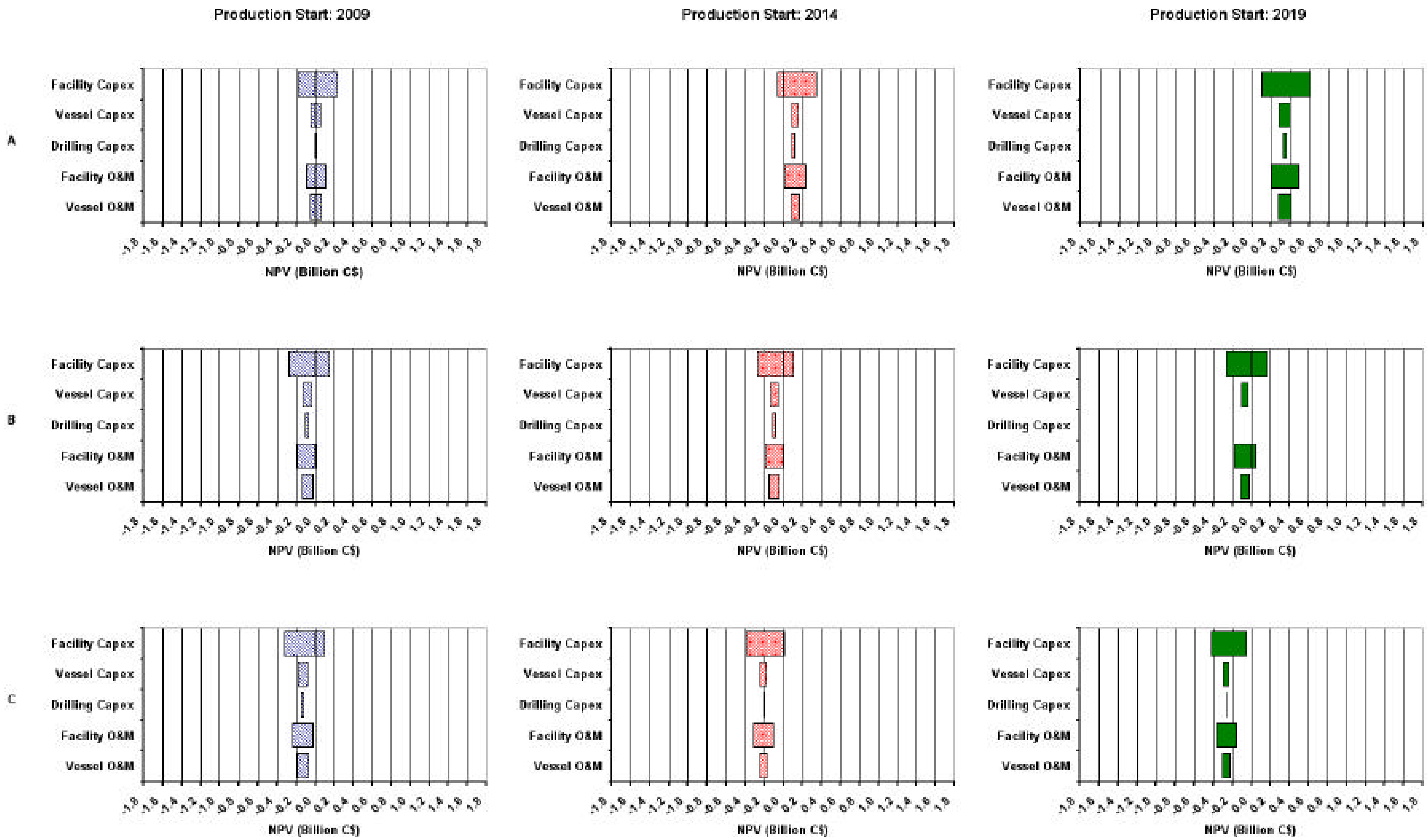


Figure 11.6: GTL Scenario – NPV (billion 2005 Canadian dollars) with ±25% Change in Each Parameter – Initial High Price

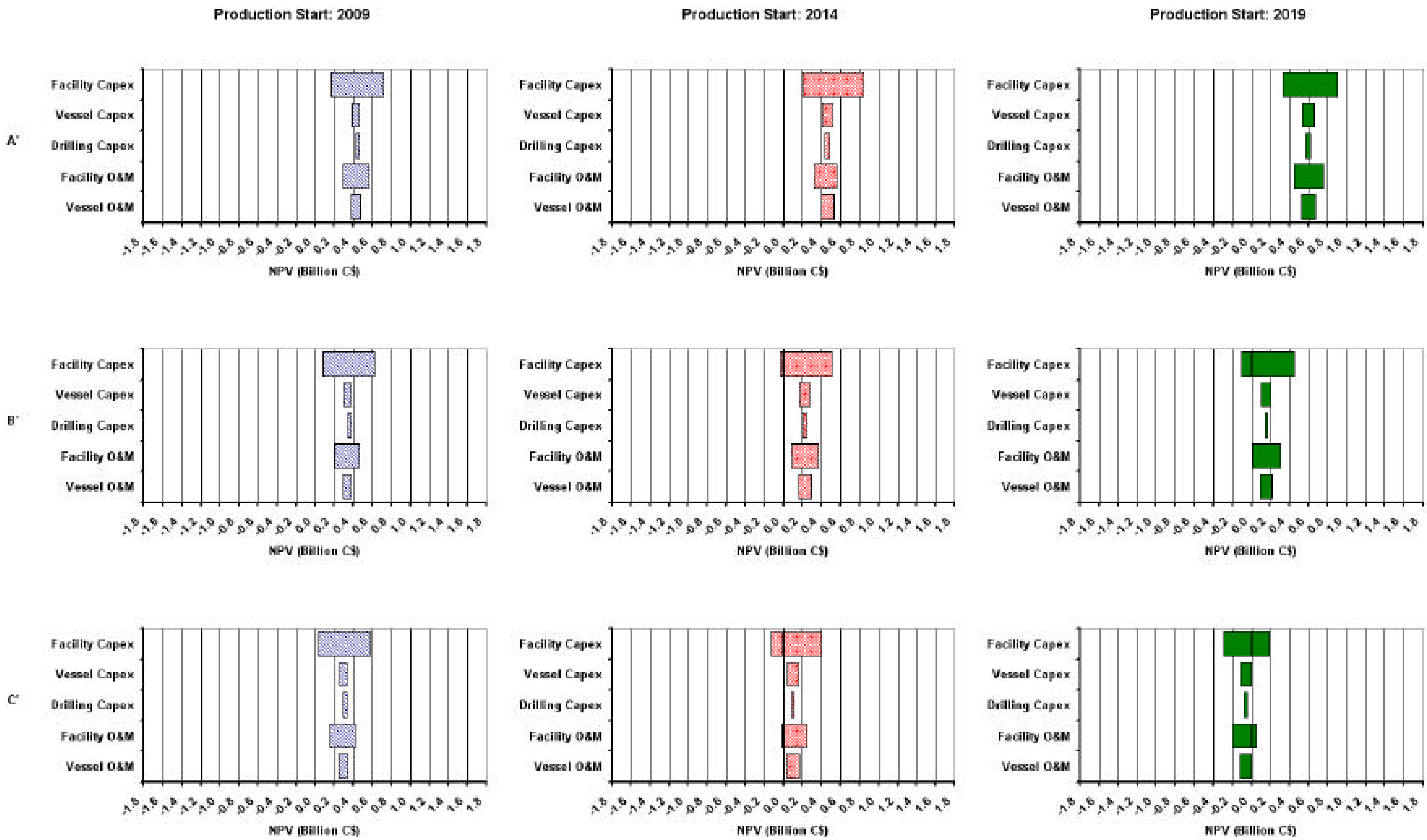


Figure 11.7: LNG Transshipment Scenario – NPV (billion 2005 Canadian dollars) with ±25% Change in Each Parameter – Initial Low Price

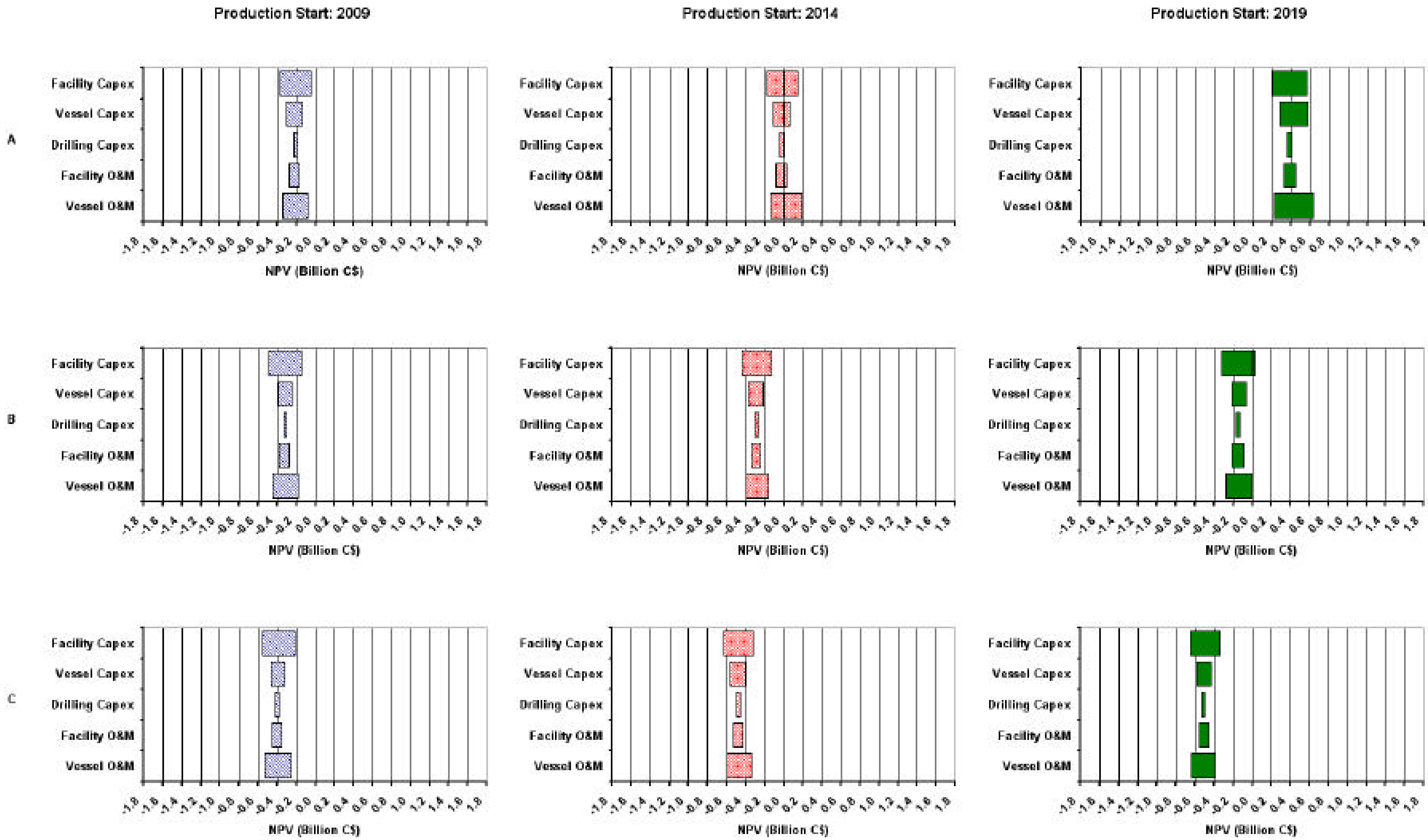
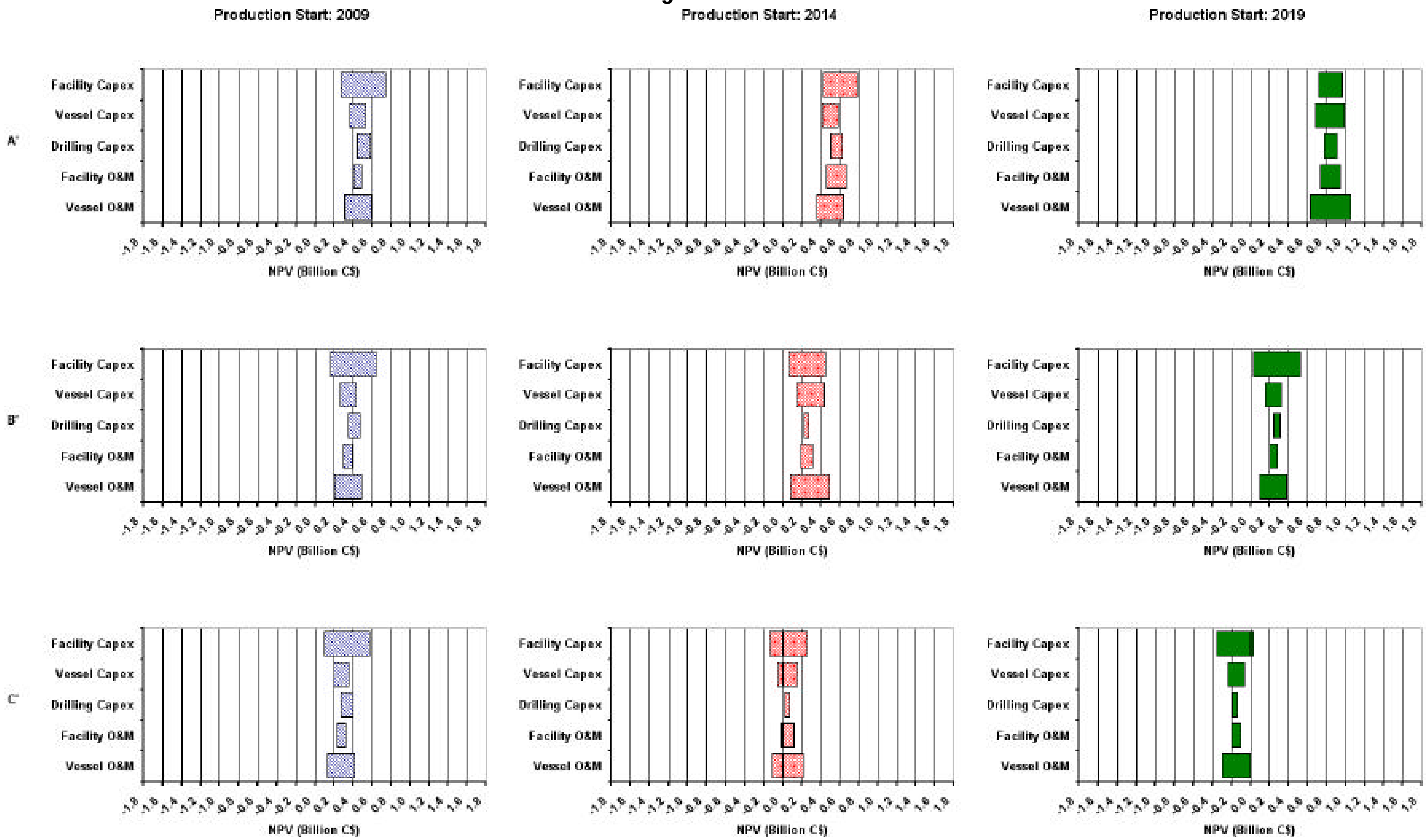


Figure 11.8: LNG Transshipment Scenario – NPV (billion 2005 Canadian dollars) with ±25% Change in Each Parameter – Initial High Price



11.2 Monte Carlo Analysis

A Monte Carlo analysis examined the impact of the overall uncertainty of each of the projects. In this analysis, each of the most important variables was varied simultaneously.

Consistent with common practice, a uniform distribution is specified since the uncertainty is assumed to be less than a factor of 10 for each variable and there is no knowledge about a midpoint to assign a triangular distribution. When the range of uncertainty exceeds a factor of 10, either a log-uniform or log-triangular distribution are often assumed. Applications of other distributions such as normal, lognormal, gamma, beta, Poisson, and Weibull depend on the availability of relevant data.

The same five variables as in the sensitivity analysis were assigned uniform distributions of ± 50 percent and 5000 iterations were performed for each case.

The following figures illustrate the results of this analysis. Note that all values shown in the NPV distributions are in thousand Canadian 2005 dollars.

The results are consistent with the mean NPV values shown in the Table 11.1. In addition, the results indicate that:

- The probability distribution of the NPV for each case appears to be normal.
- Depending on the case considered, the NPV can range by about $1.8 billion between the highest and lowest NPV.
- Although the initial calculation showed that the CNG project is the most favourable under Price Forecasts A' and B', for all production start years, the range of NPV between the 5th and 95th percentile is greater than the range of NPV for the corresponding cases for both of the LNG scenarios and the GTL scenario.
- The LNG case without transshipment has NPV distributions similar in shape and range as the LNG case with transshipment.
- The positive skew of some of the NPV distributions are especially notable for the CNG and GTL scenarios. In a positively skewed distribution, there are a small number of very large values and the median value is less than the mean.

Application of normal or triangular input distributions and reduced ranges for the input parameters would reduce the range or standard deviation of the NPV distributions. Phasing in of these projects may improve input parameter estimation and provide additional option value that is hidden in a traditional discounted cash flow analysis.

Figure 11.9: LNG Scenario – NPV Distribution (billion 2005 Canadian dollars) with ±50% Uniform Distributions – Initial Low Price

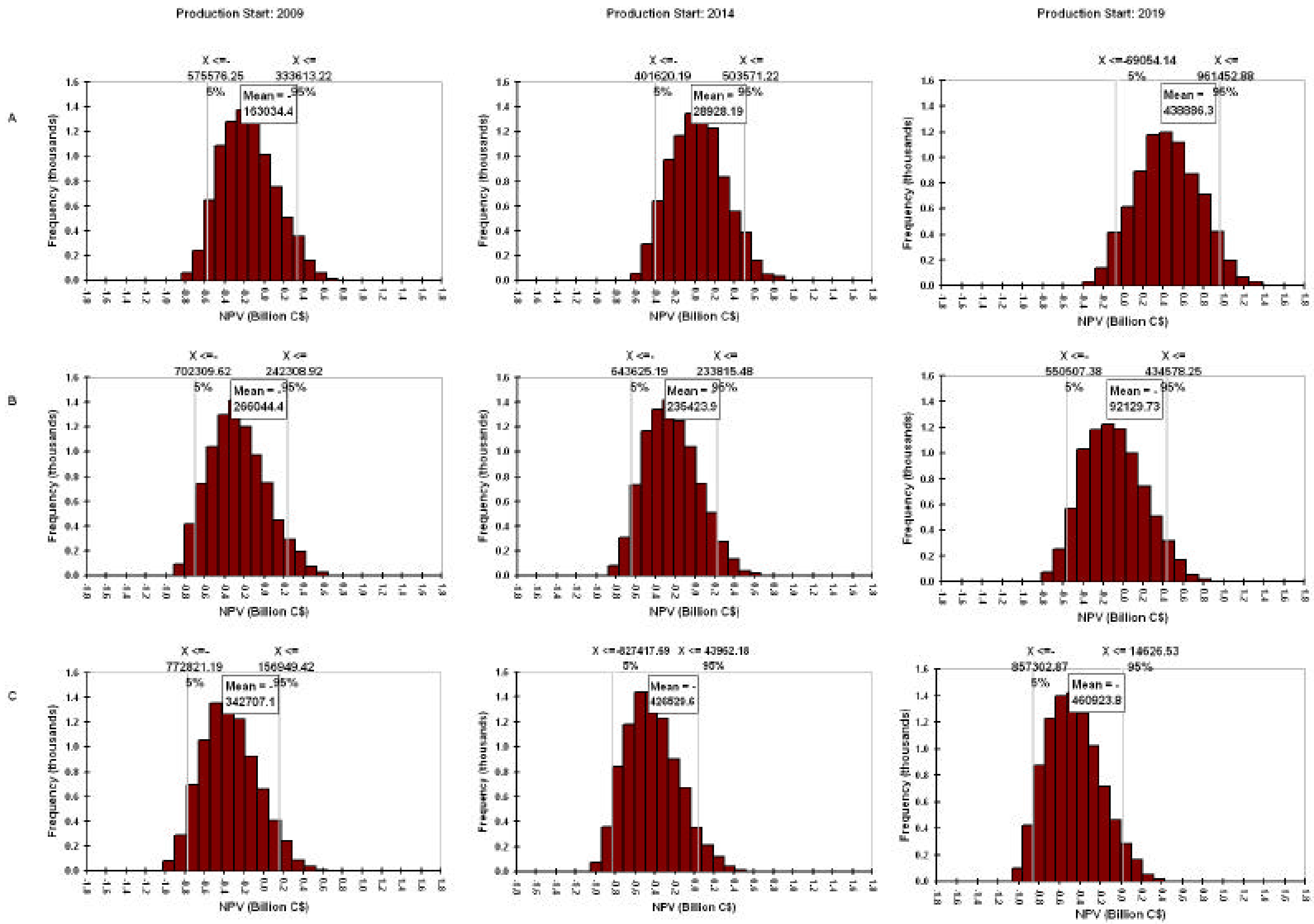


Figure 11.10: LNG Scenario – NPV Distribution (billion 2005 Canadian dollars) with ±50% Uniform Distributions – Initial High Price

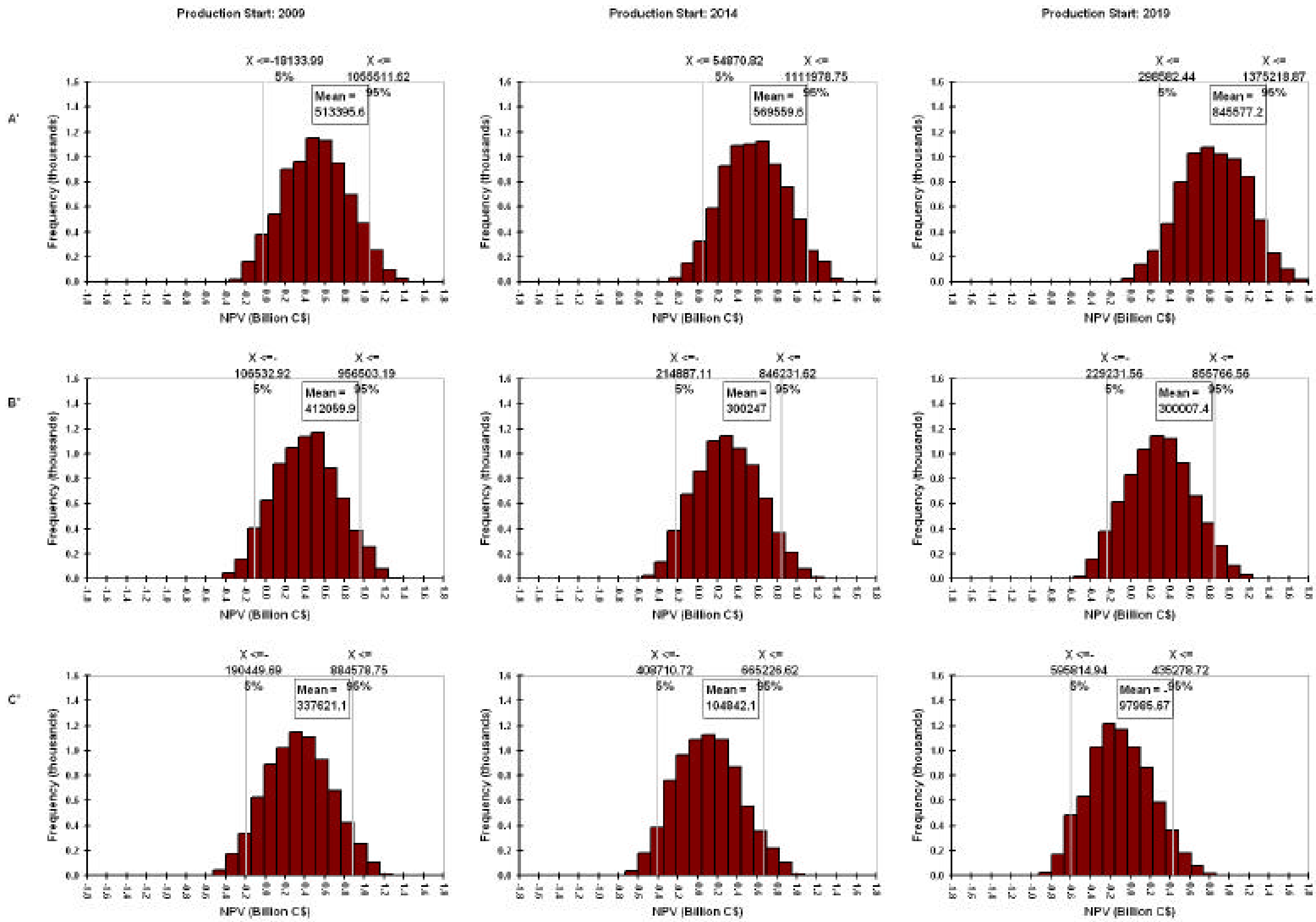


Figure 11.11: CNG Scenario – NPV Distribution (billion 2005 Canadian dollars) with ±50% Uniform Distributions – Initial Low Price

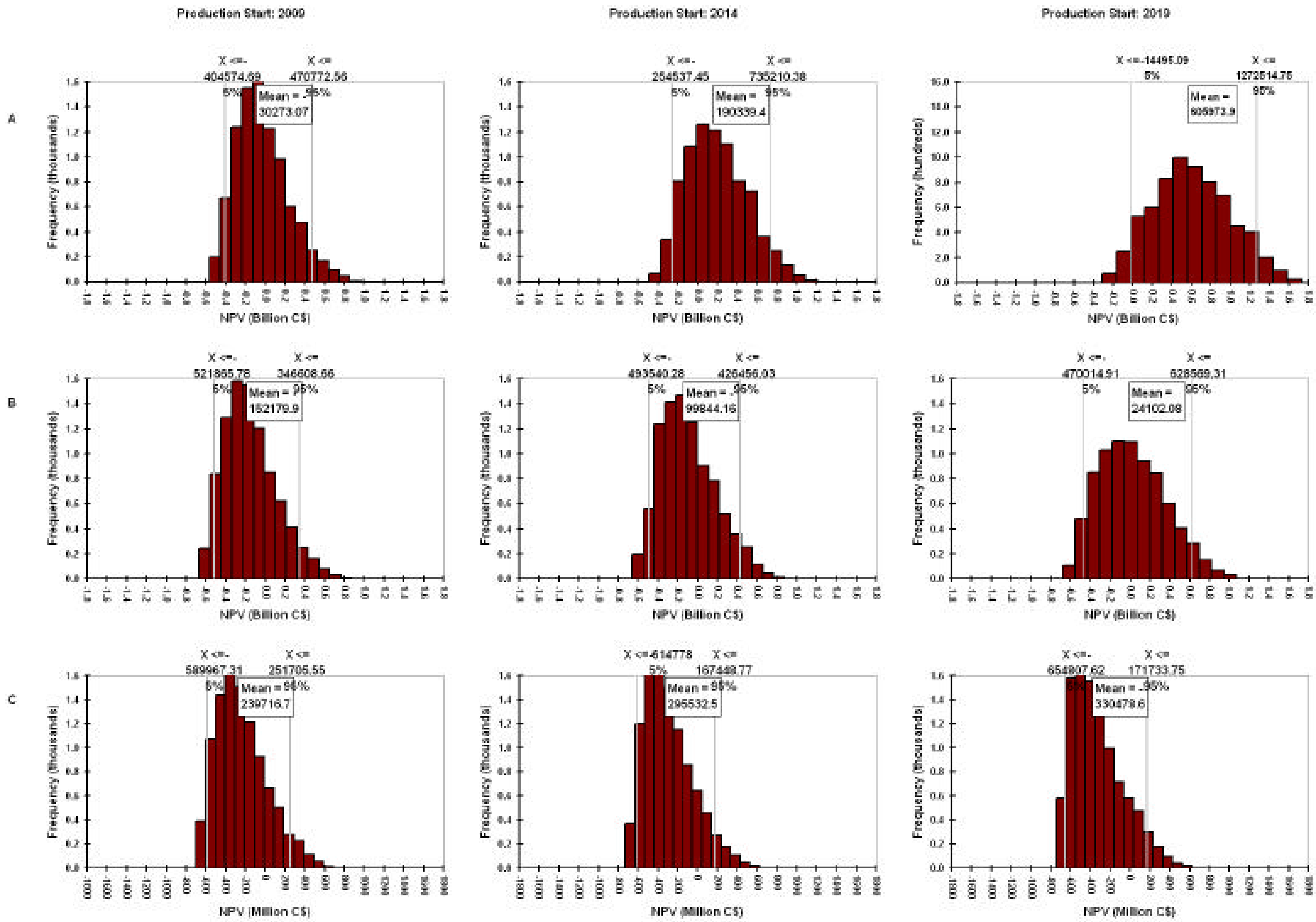


Figure 11.12: CNG Scenario – NPV Distribution (billion 2005 Canadian dollars) with ±50% Uniform Distributions – Initial High Price

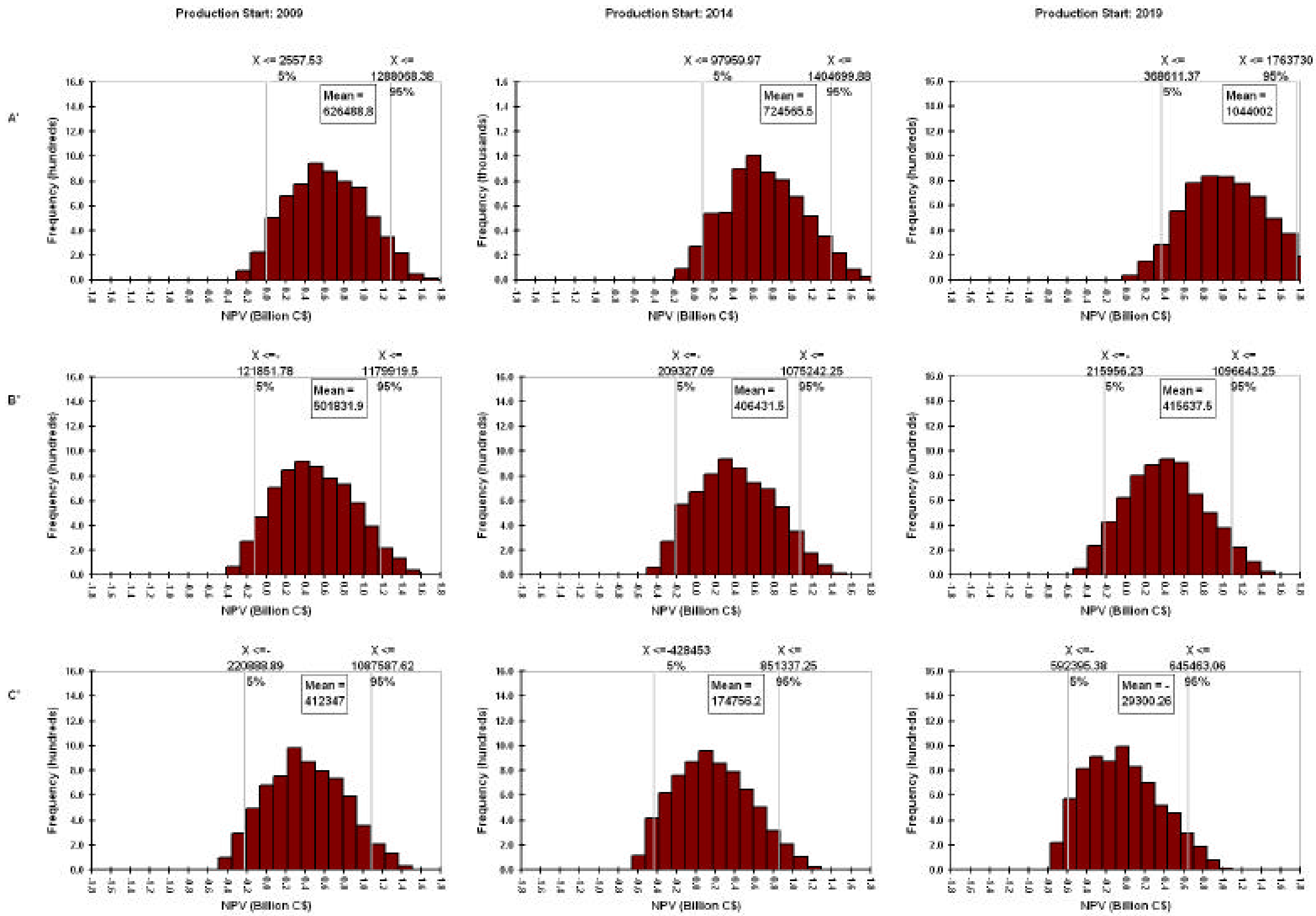


Figure 11.13: GTL Scenario – NPV Distribution (billion 2005 Canadian dollars) with ±50% Uniform Distributions – Initial Low Price

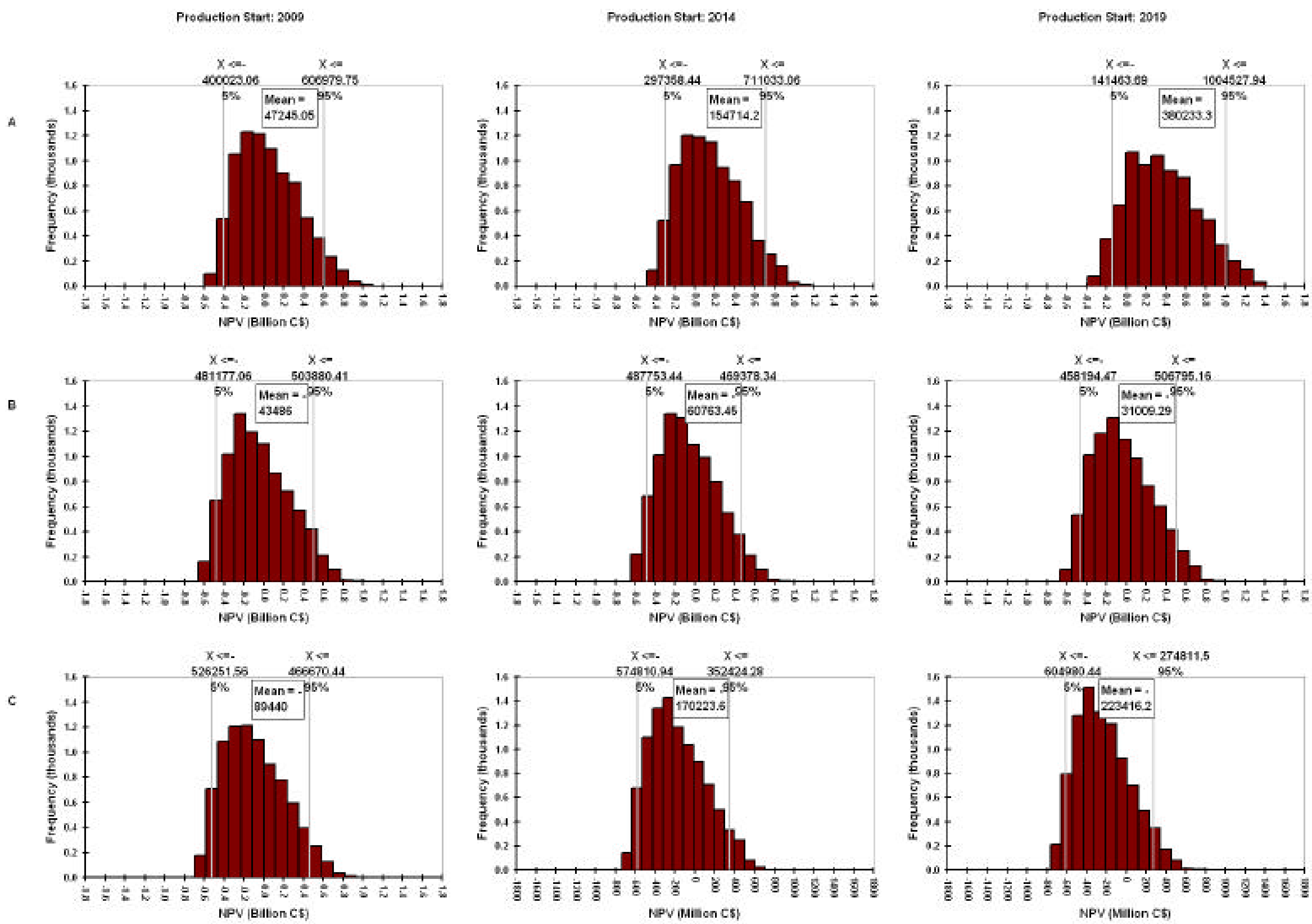


Figure 11.14: GTL Scenario – NPV Distribution (billion 2005 Canadian dollars) with ±50% Uniform Distributions – Initial High Price

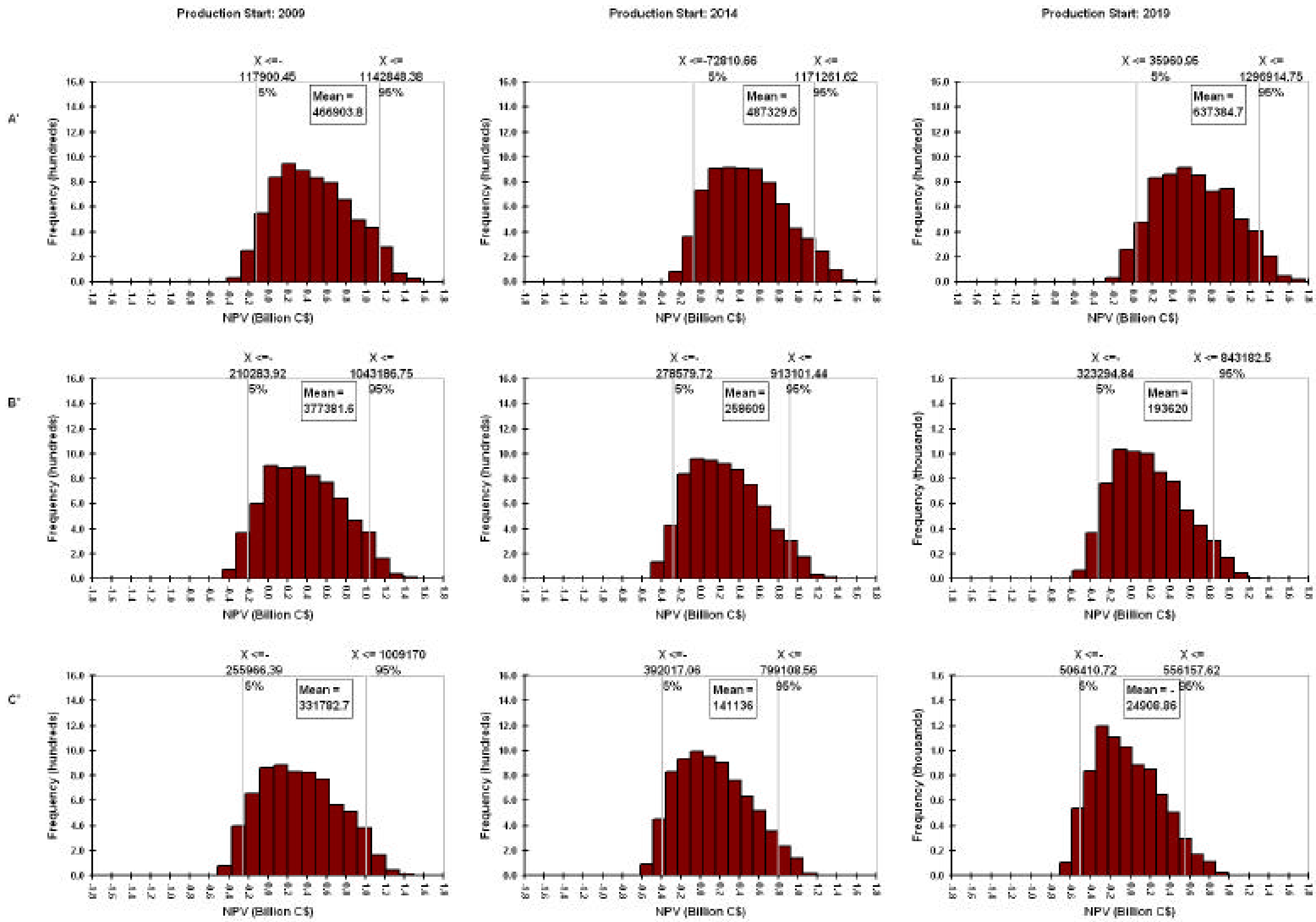


Figure 11.15: LNG Transshipment Scenario – NPV Distribution (billion 2005 Canadian dollars) with ±50% Uniform Distributions – Initial Low Price

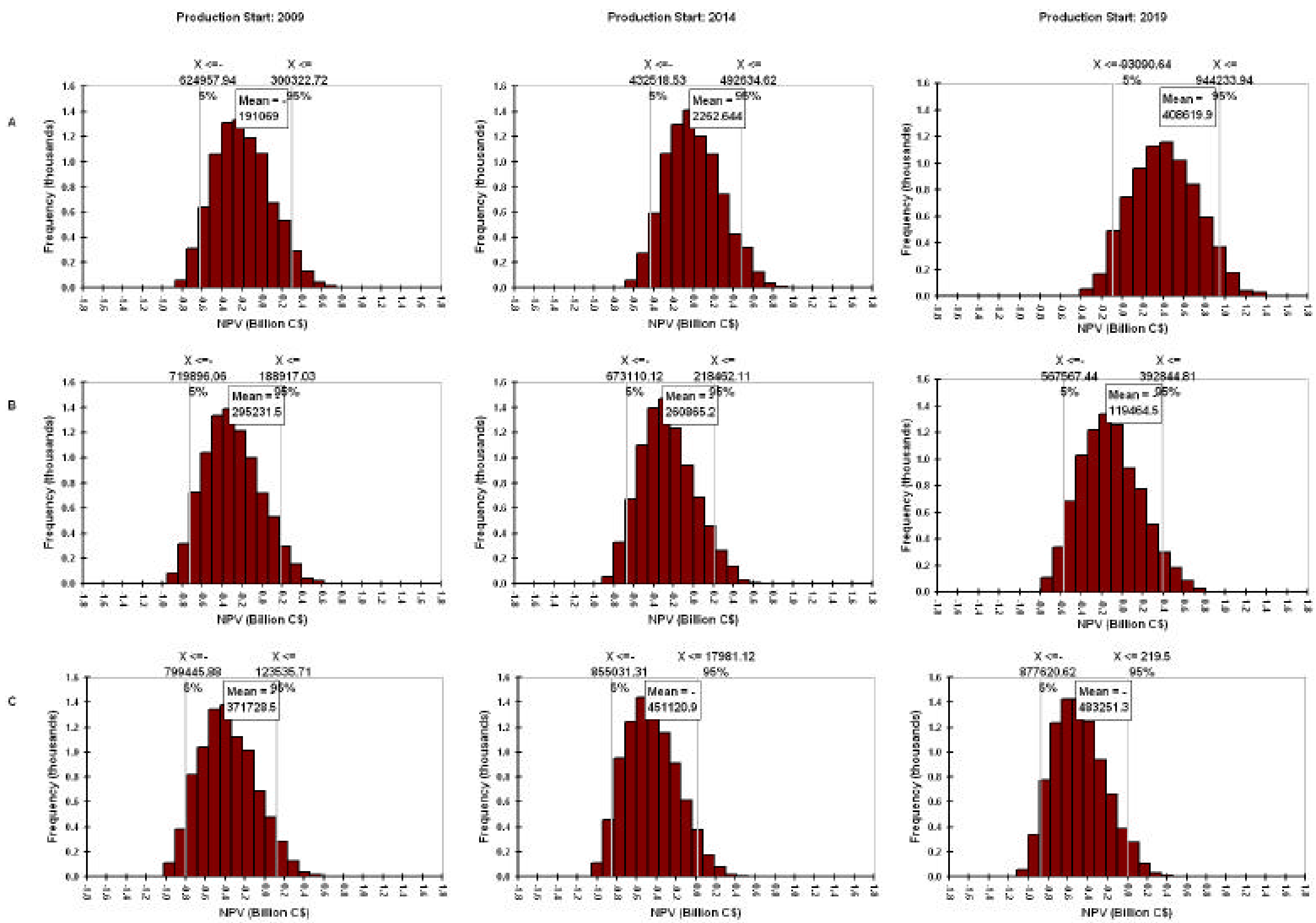
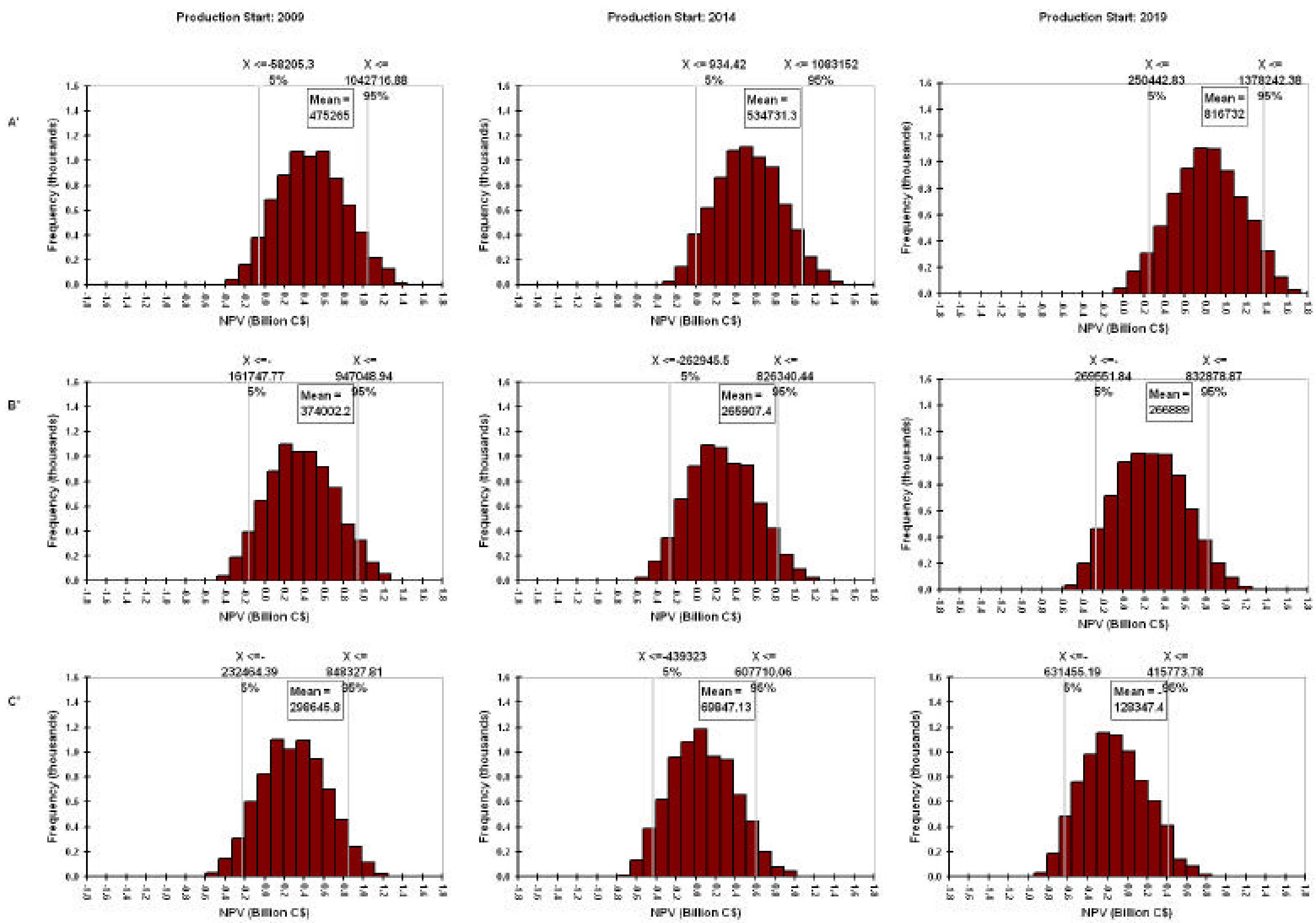


Figure 11.16: LNG Transshipment Scenario – NPV Distribution (billion 2005 Canadian dollars) with ±50% Uniform Distributions – Initial High Price



12.0 Conclusions and Recommendations

This preliminary analysis suggests that production and ship-borne transportation of natural gas from Melville Island is economically feasible (have a positive net present value) for all four of the scenarios under certain price levels, namely Price Forecasts A, A', B', and C'. Price Forecasts B and C have negative, or barely positive, net present values.

In the case of Price Forecast B, the only option that provided positive net present values (NPV's) is CNG, and only for a production start of 2019. Using the B' Forecast—with its higher initial base—all the development options provide positive NPV's with production start years of 2014 and 2019 relatively the same.

The net present value of the CNG option is estimated at $24 million and $416 million for a start year of 2019 under Price Forecasts B and B', respectively.

While the CNG project provides the greatest economic value when point estimates are used, the results of the sensitivity analysis suggest that parameter uncertainty of as little as 25 percent can change the NPV such that another project may appear more favourable. The Monte Carlo analysis also makes the uncertainty for the projects apparent. Skewness of the NPV distributions for some of the price forecasts under the CNG scenario suggests further work is required in model validation and parameter estimation.

The CNG project involves significant risks regarding the provision of suitable docking facilities for CNG carriers in the Mackenzie Delta region and the corresponding distance that the landed gas must be piped before entering the Mackenzie Valley Pipeline.

In addition to monetization of stranded reserves, North American development of incremental sources of supply, with its required infrastructure, provides security of supply to North American consumers.

Socio-economic and environmental issues will be critical considerations for any proposed development in the High Arctic. Important issues such as comparative risk assessments of these and other delivery options, the appropriate discount rate(s) and the appropriate project life or lives will also need to be examined. Delivery of GTL versus LNG or natural gas likely conveys greater economic costs and benefits than are captured in the present analysis. Besides reduced emissions of GTL compared to diesel, the GTL option has the potential benefit of providing a home grown substitute for the volumes of diesel that must currently be imported into remote northern communities of the High Arctic. Finally, the optionality of the transshipment scenario likely has a risk mitigation effect that may be better considered using other analytical techniques.

It is important to recognize that the results of this analysis provide only a preliminary indication of the general economic viability of the concepts examined. Further analysis at considerably more detailed levels will be required for any of these concepts to move ahead.

Appendix A
Abbreviations and Conversions

Tcf = trillion cubic feet
Bcf = billion cubic feet
MMcf = million cubic feet
Mcf = thousand cubic feet
MMt = million tonnes of LNG
Bcm = billion cubic metres
BTU = British Thermal Unit
psig = pounds per square inch (gauge)

49 Bcf of gas = 1 MMt LNG
1.38 Bcm gas = 1 MMt LNG

Liquefaction reduces gas volume by 584 times (gas at atmospheric): (584 Bcm gas = 1 Bcm LNG)

GTL: 1 Bcf gas = 100,000 barrels of synthetic crude oil

Gas consumed as fuel:

LNG

- Liquefaction = 11 percent
- Boil off during transit to Nova Scotia = 7.4 percent
- Regasification = 1.7 percent

CNG

- Compression = 2 percent

Appendix B
Presentation at the Calgary Petroleum Club

CERI

The Economics of High Arctic Gas Development: Expanded Sensitivity Analysis

Luke Chan, Senior Economist lchan@ceri.ca
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George Eynon, Senior Director, Research geynon@ceri.ca

January 13, 2005

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Agenda

CERI

- Background
- Assumptions and Methodology
- Price Forecasts
- Development Schemes
  - LNG / LNG with Greenland transshipment
  - CNG
  - GTL
- Sensitivity and Monte Carlo Analysis
- Conclusions and Recommendations

2

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Background

- Tight supply/demand balance and prices higher than historical norms.
- Renewed interest in incremental sources of supply.
- Large accumulations of natural gas in the Canadian High Arctic.
- LNG with/without transshipment, CNG, and GTL.

3

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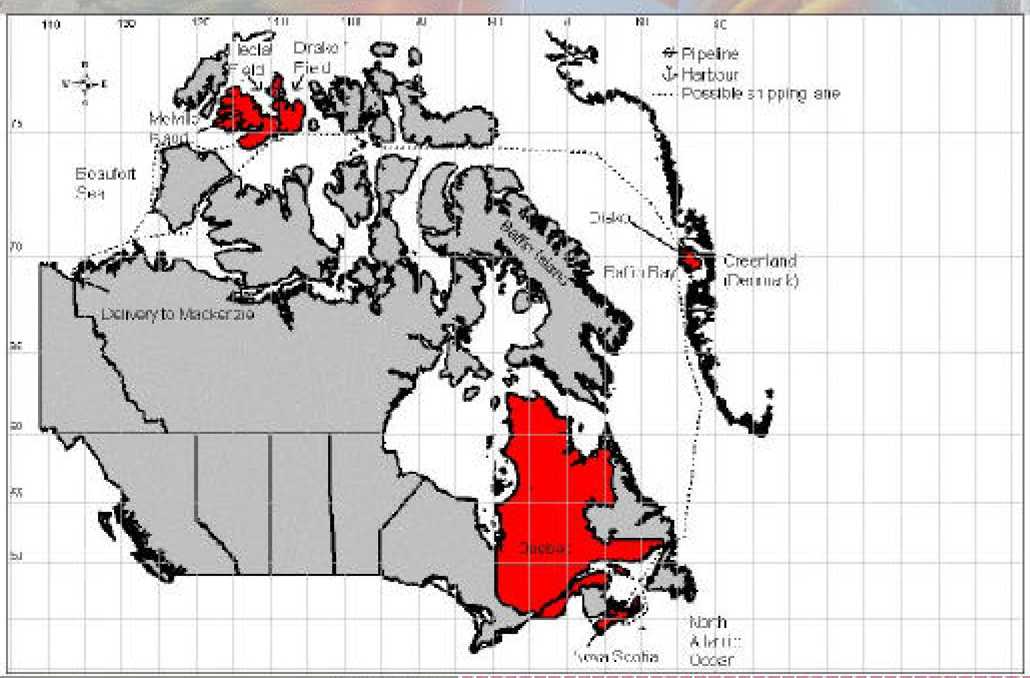
Map of Development Schemes



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Previous Work

- March 2004 study, *Economics of High Arctic Gas Development*.
- Production and ship-borne transportation from Melville Island economically feasible with any of LNG, CNG, and GTL.
- The CNG project greatest economic value.
- Sensitivity analysis: CNG project remains viable and clearly superior to the two alternatives even under conditions of lower market prices and higher project costs.
- CNG project involves significant risks.

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Arctic Pilot Project & Polar Gas Project

- Polar Gas Project, 1977
  - 3763 km 42" pipeline from Melville Island to Longlac, Ontario.
  - 2.1 Bcf/d; 3.0 Bcf/d with added compression.
- Arctic Pilot Project, 1981
  - Melville Island to Nova Scotia and Quebec.
  - 320 MMcf/d from Drake Point to Bridport Inlet.
  - 2.2 million tonnes of LNG per year; 2 Arctic Class 7 LNG carriers
  - Second phase: 550 MMcf/d; 4 carriers.
  - Third phase: 1.375 Bcf/d (Hecla) ; 9 carriers.

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Resource Estimates

- Arctic Pilot Project: marketable gas reserves of 5.1 Tcf & 3.6 Tcf in the Drake Point and Hecla fields.
- CGPC 2001: 10.2 Tcf of initial gas-in-place (about 8.4 Tcf of initial marketable gas).
- GSC 1983: 6.495 Tcf of marketable gas from both fields.
- Alberta: ST 2004-98 - Remaining Est. Reserves of 40 Tcf

	Endowment (Tcf) (CGPC 2001)		
Region	In-Place	Nom. Marketable	Nom. Remaining
WCSB	423	249	142
Mackenzie	54	35	35
Arctic	31	26	26
Nova Scotia	27	11	11
Nfld/Labrador	39	17	17
All	592	342	233

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Methodology

- Data gathering for scenarios
- Price forecasts
- Model building
  - Royalties and taxes
- Discounted cash flow
  - 15% discount rate (real)
- 3 parts of analysis:
  - Point estimate DCF
  - ±25% sensitivity
  - Monte Carlo simulation

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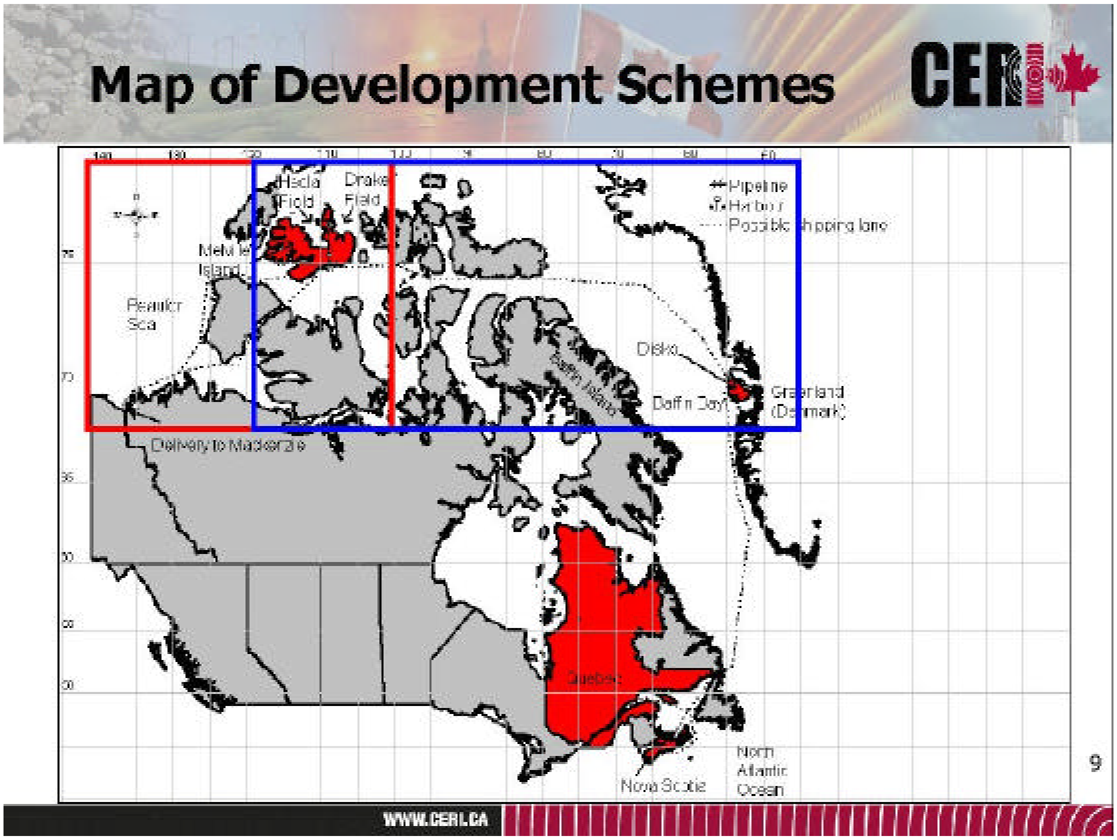
Map of Development Schemes
CERI
Hecla Field
Drake Field
Melville Island
Beaufort Sea
Pipeline
Harbour
Possible shipping lane
Disko
Baffin Island
Baffin Bay
Greenland (Denmark)
Delivery to Mackenzie
Quebec
Nova Scotia
North Atlantic Ocean
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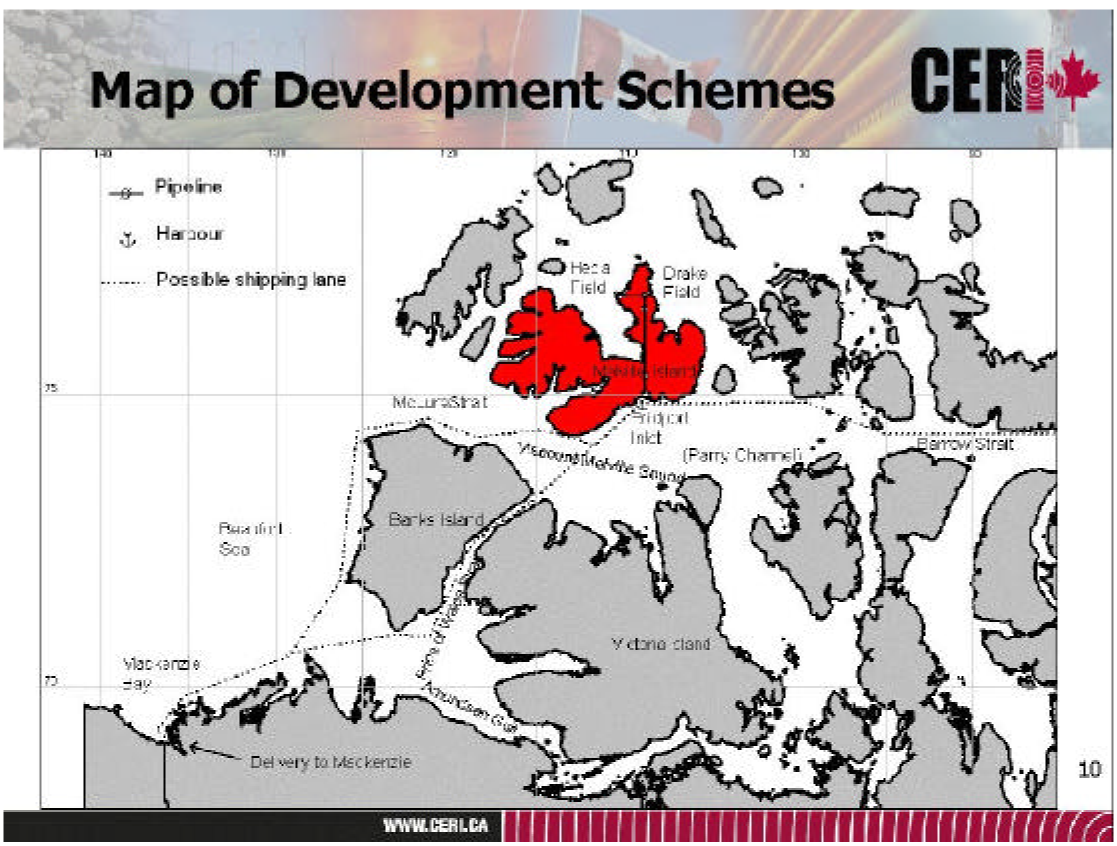
Map of Development Schemes
CERI
Pipeline
Harbour
Possible shipping lane
Hecla Field
Drake Field
Melville Island
McClure Strait
Bridport Inlet
(Parry Channel)
Viscount Melville Sound
Barrow Strait
Banks Island
Beaufort Sea
Victoria Island
Mackenzie Bay
Amundsen Gulf
Delivery to Mackenzie
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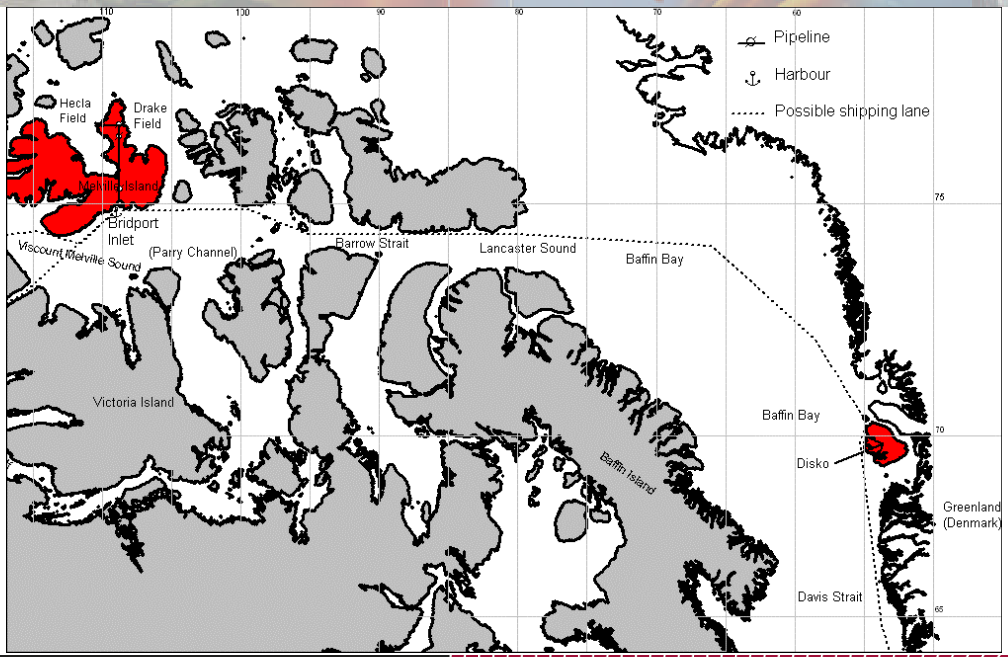
Map of Development Schemes



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Assumptions

- 1,000 MMcf/d over 20 years starting in 2009, 2014 and 2019.
- 4-year preparation of the regulatory filing, proceedings, design and construction for $210 million.
- Operate 345 days of the year.
- 15% (after royalty and tax) discount rate and 75% equity financing.
- August 2003 budget: reduction in corporate income rate to 21% minus the Crown royalty by 2007 and elimination of the 25% resource allowance by 2007.
- Declining Balance Depreciation:
  - Drilling 30%; non-drilling facility 25%; vessels 15%.
- Crown royalty ranges from 1% to 5% per month until payout. After payout, the Crown royalty is the greater of 30% of net revenue or 5% of gross revenue.

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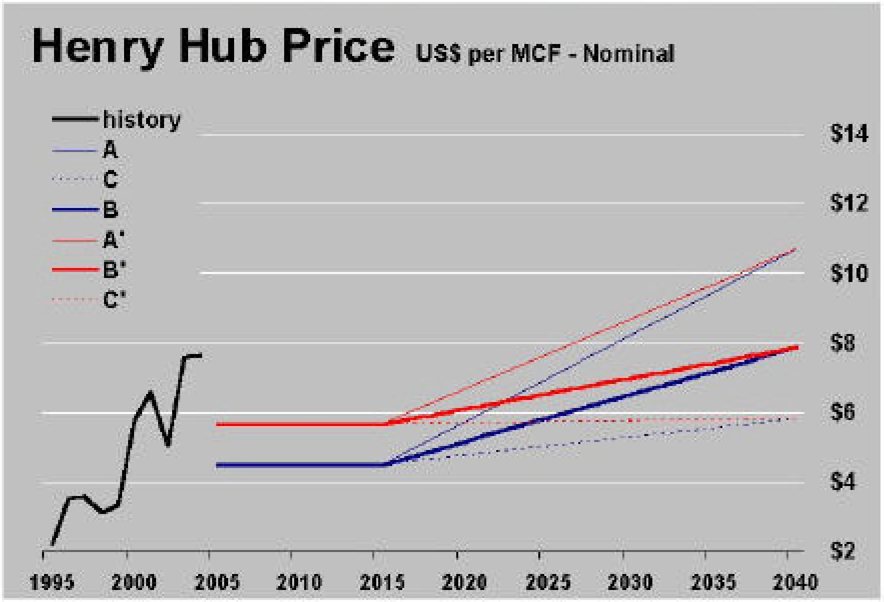
Price Forecasts



Source: CERI and others

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Melville Island Development

- 20 new wells x $17.5 MM =$350 MM.
- $18 MM for 30 km of flow lines.
- 1000 MMcf/d dehydration facility for $90 MM.
- 161 km 36″ from Drake Point to Bridpoint Inlet and 45 km 36″ lateral from Hecla. One 22,000 horsepower compression station.
- Total capital cost = $800 MM.
- Annual operating cost = $40 MM.

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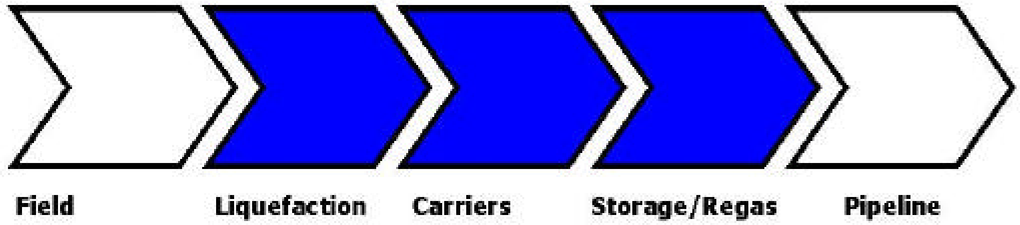
Liquefied Natural Gas (LNG) Option



- Liquefaction: capital = $2 B; operating = $80 MM
- Carriers:
  - Unit capital = $268 MM; unit operating = $44 MM
  - 7 ships: capital = $1.9 B; operating = $310 MM
- Regasification: estimate $0.60 per Mcf

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LNG with Transshipment Option

- Liquefaction and Regasification: as before
- Carriers and storage:
  - Unit capital = $268 MM & $206 MM; unit operating = $44 MM & $33 MM
  - 5 Arctic Class 7 and 2 standard ships: capital = $1.8 B; operating = $290 MM
  - $380 MM for a volume of 300,000 cubic metres

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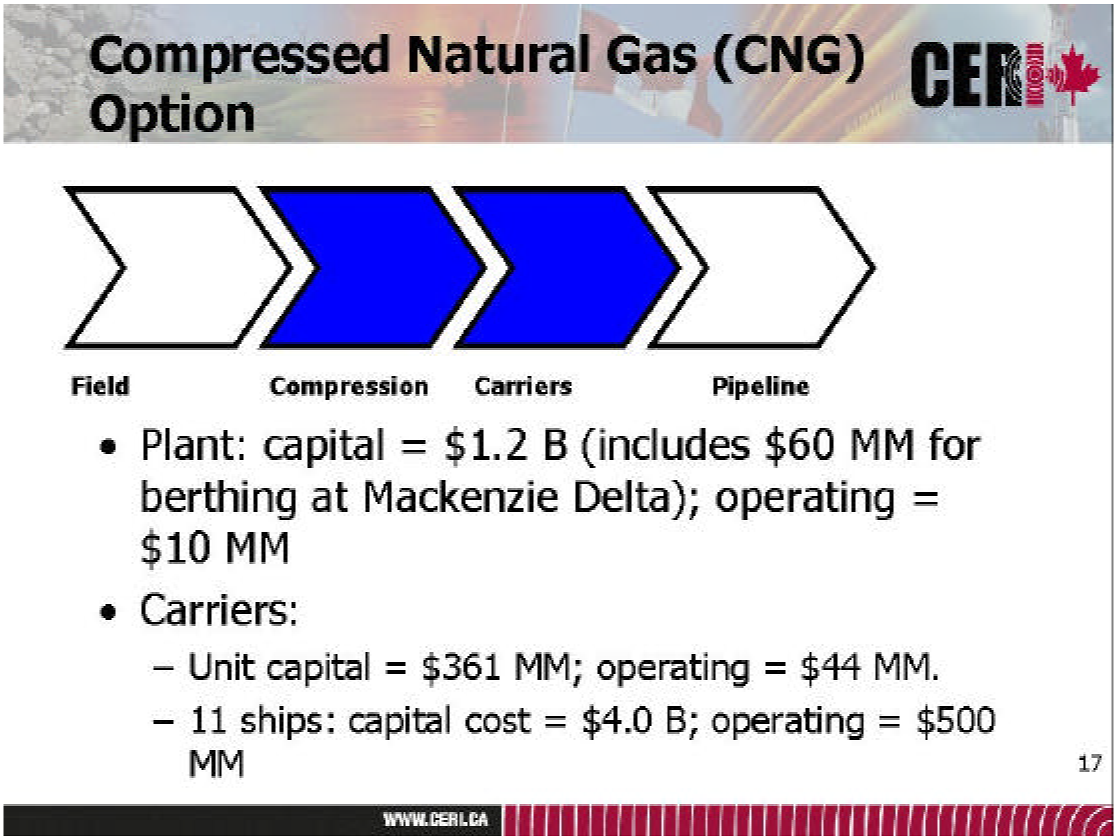
Compressed Natural Gas (CNG) Option
CERI
Field
Compression
Carriers
Pipeline
• Plant: capital = $1.2 B (includes $60 MM for berthing at Mackenzie Delta); operating = $10 MM
• Carriers:
– Unit capital = $361 MM; operating = $44 MM.
– 11 ships: capital cost = $4.0 B; operating = $500 MM
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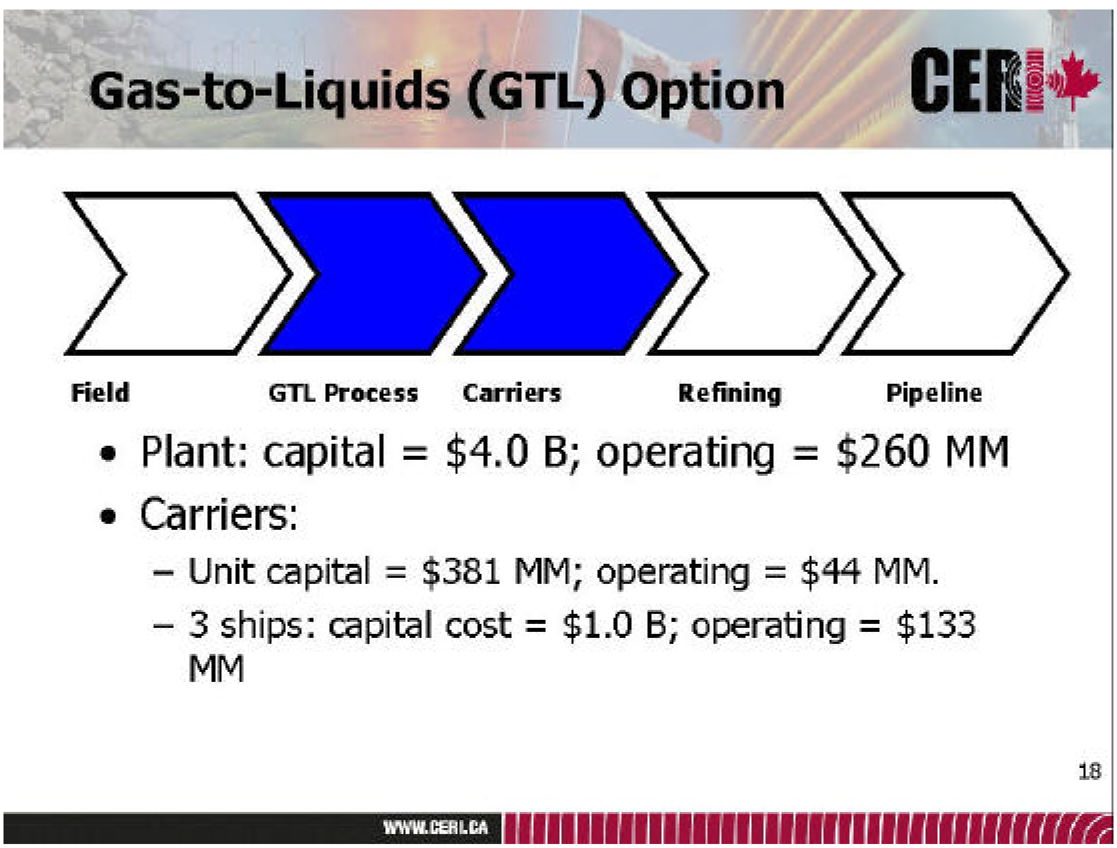
Gas-to-Liquids (GTL) Option
CERI
Field
GTL Process
Carriers
Refining
Pipeline
• Plant: capital = $4.0 B; operating = $260 MM
• Carriers:
– Unit capital = $381 MM; operating = $44 MM.
– 3 ships: capital cost = $1.0 B; operating = $133 MM
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Capital and Operating Costs

	2005 Million Canadian Dollars			
	LNG	LNG Transshipment	CNG	GTL
Capital Costs (Over 4 years)				
Melville	1000	1000	1000	1000
Facilities	2000	2400	1200	4100
Vessels	1900	1800	4000	1100
Total	4900	5100	6200	6300
Annual Operating Costs				
Melville	40	40	40	40
Facilities	80	90	10	260
Vessels	310	290	490	130
Total	430	420	540	430

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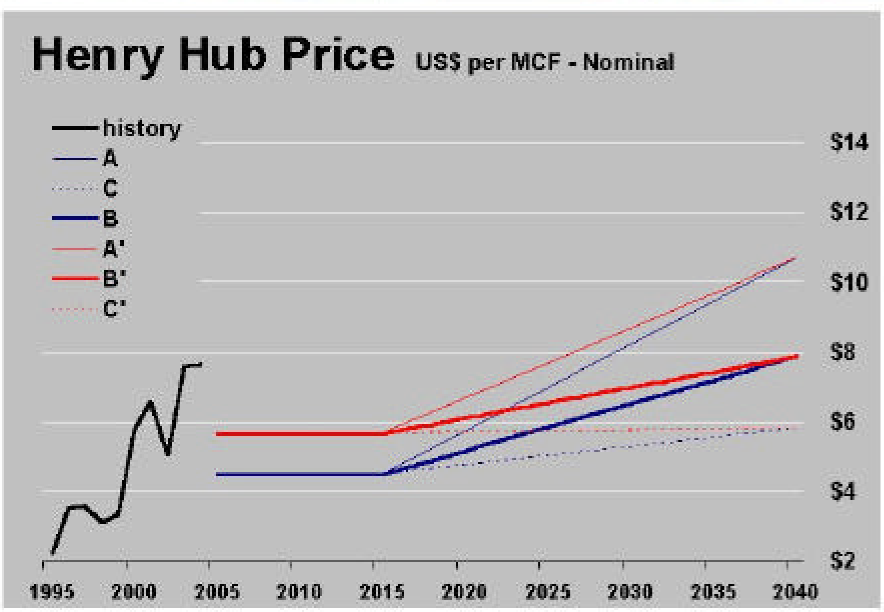
Price Forecasts



Source: CERI and others

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Sample Results of DCF Analysis

	NPV at 15% (2005 Million Canadian Dollars)			
	LNG	LNG Transshipment	CNG	GTL
Price Forecast B				
Start 2009	(270)	(300)	(150)	(40)
Start 2014	(240)	(260)	(100)	(60)
Start 2019	(90)	(120)	20	(30)
Price Forecast B'				
Start 2009	410	370	500	380
Start 2014	300	270	410	260
Start 2019	300	270	420	200

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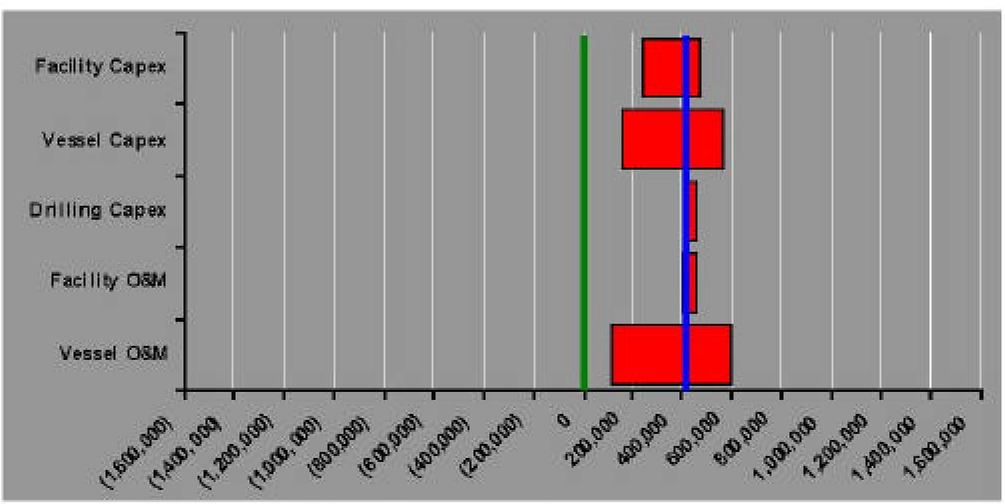
Sample Sensitivity Analysis



- X-axis: NPV in thousands.
- CNG, Forecast B′, Start 2014.

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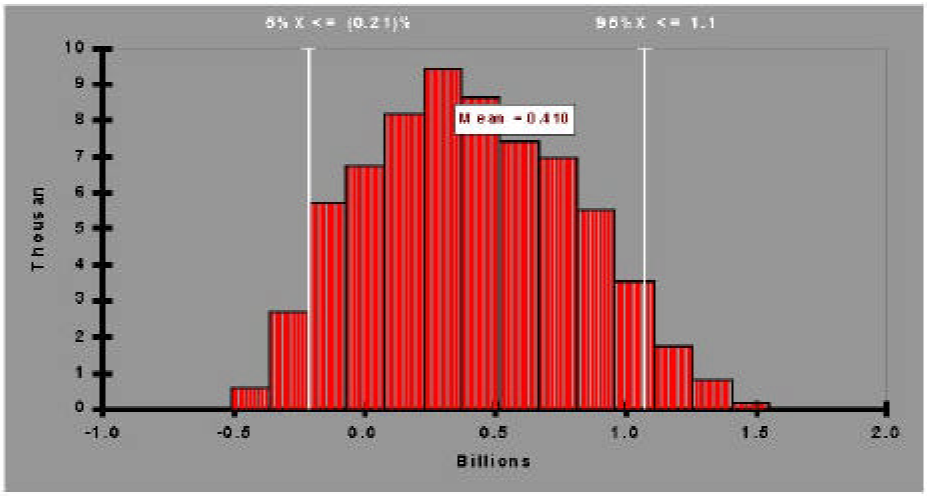
Sample
Monte Carlo Analysis



- X-axis: NPV in billions.
- CNG, Forecast B′, Start 2014.

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Conclusions and
Recommendations (1)

- Economically feasible for all 4 of the scenarios examined under certain price forecasts, specifically, under the higher price levels of A, A′, B′, and C′.
- Reserve size makes scenarios mutually exclusive.
- Delay: A and A′ improves expected NPV; B and B′ little impact; C and C′ reduces NPV.
- The CNG project is the most favourable under price forecasts A' and B', for all start years.
- The CNG project is the most favourable under A for start years of 2014 and 2019.
- The CNG project is the most favourable under C′ for start years of 2009 and 2014.

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Conclusions and Recommendations (2)

- The LNG case without transshipment is marginally more favourable than the LNG case with transshipment.
- A change of 25 percent in any of the five parameters can change NPV by as much as $300 million.
- In most cases, the probability distribution of the NPV is normal.
- In order to reduce the range or standard deviations of the NPV distributions, ranges for the input parameters can be reduced through learning such as in a phased project.

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Risk Factors

- Only a preliminary indication of the general economic viability of the concepts examined.
- Reliability and applicability of the Arctic Pilot Project Application.
- Reliability of the resource information.
- Northern premiums.
- Shipping costs.
- Single phase.
- Sufficient available capacity on the MVP to accommodate production from the Arctic. Need for berthing facilities at the Mackenzie Delta.
- Regasification capacity.

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Implications

- North American development of incremental sources of supply in relatively close proximity, with its required infrastructure, provides security of supply to North American consumers.
- Socio-economic and environmental issues critical.
- Comparative risk assessments of field development and these and other delivery options, the appropriate discount rate(s) and project life need to be examined.
- Externalities:
  - Delivery of GTL versus LNG or natural gas
  - Transshipment scenario risk mitigation

High Arctic Gas: Low Cost LNG Source?

US$ per MCF

source	destination	distance	gas supply		liqui-faction		shipping $0.00016		re-gas		total costs
Trinidad	Everett, MS	2,330	$	1.00	$	1.00	$	0.37	$	0.30	$2.67
Trinidad	Elba Is, GA	2,030	$	1.00	$	1.09	$	0.33	$	0.30	$2.72
Trinidad	Cove Point, MD	2,180	$	1.00	$	1.09	$	0.35	$	0.30	$2.74
Trinidad	Lake Charles, LA	2,640	$	1.00	$	1.09	$	0.42	$	0.30	$2.81
Algeria	Cove Point, MD	4,380	$	1.00	$	1.09	$	0.70	$	0.30	$3.09
Norway	Cove Point, MD	4,710	$	1.00	$	1.09	$	0.75	$	0.30	$3.14
Canada High Arctic	**NS-NB-PQ**	**3,250**	**$**	**1.00**	**$**	**1.20**	**$**	**0.65**	**$**	**0.30**	**$3.15**
Algeria	Lake Charles, LA	5,790	$	1.00	$	1.09	$	0.93	$	0.30	$3.32
Nigeria	Lake Charles, LA	7,400	$	1.00	$	1.09	$	1.19	$	0.30	$3.58
Qatar/Ras Laffan	Lake Charles, LA	9,738	$	1.00	$	1.09	$	1.56	$	0.30	$3.95
Australia NW shelf	Lake Charles, LA	11,290	$	1.00	$	1.09	$	1.81	$	0.30	$4.20

- Capex+opex = US$4.5 billion; development, pipeline, liquefaction plant
- Supply costs actually = US$0.45; 10 TCF discovered; development costs only
- Distance = 3,250 miles; closer to market than some current supplies
- Shipping = US$0.65 ($0.0002 per mile); +25% for Arctic Class-7 vessels

Appendix C
CERI Energy Insight

CANADIAN ENERGY RESEARCH INSTITUTE

Issue No. 4
January 2005

CERI Energy Insight

CERI Energy Insights are a new series of short commentaries on current energy issues in Canada and North America. Through these insights, we hope you will gain a broader and deeper understanding of different energy issues and how they inter-relate.

Daniel Czamanski, Senior Vice President
Please send your comments and feedback to dczamanski@ceri.ca.

About CERI
The Canadian Energy Research Institute (CERI) is a cooperative research organization established through an initiative of government, academia and industry in 1975. The Institute's mission is to provide relevant, independent, objective economic research and education in energy and related environmental issues. Related objectives include reviewing emerging energy issues and policies as well as developing expertise in the analysis of questions related to energy and the environment.

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The Economic Viability of Natural Gas in Canada's High Arctic

By Luke Chan, George Eynon and David McColl

Introduction

North American natural gas markets are in tight supply/demand balance. Prices are significantly higher than historical norms. This has created renewed interest in various sources of incremental gas supply such as the North Slope of Alaska, Mackenzie Valley Corridor, Mackenzie Delta, and Beaufort Sea, and liquefied natural gas (LNG) from other areas of the world. Many of these sources are more distant and in less politically stable regions.

This renewed interest motivated CERI to conduct a re-assessment of development and delivery options and the economic feasibility of natural gas from Canada's High Arctic.[1]

CERI has produced scoping economics for a range of schemes including LNG, gas-to-liquids (GTL) and compressed natural gas (CNG) development, varying prices, capital and operating costs, and timing.

CERI used two sets of prices—the most significant element in the analysis—for 2005-2015, each with three (low-, mid- and high-) case extrapolations to 2040 (see figure, page 3). The capital and operating costs of all the projects vary by less than 30 percent; CERI examined cost variations for each of the elements of plus-or-minus 25 percent. The time-delays examined were for start-up dates in 2009, 2014 and 2019.

All of the development schemes are expected to be economically feasible, depending on the specific combinations of these variables.

[1] Canada's Arctic Islands.

Building on Previous work

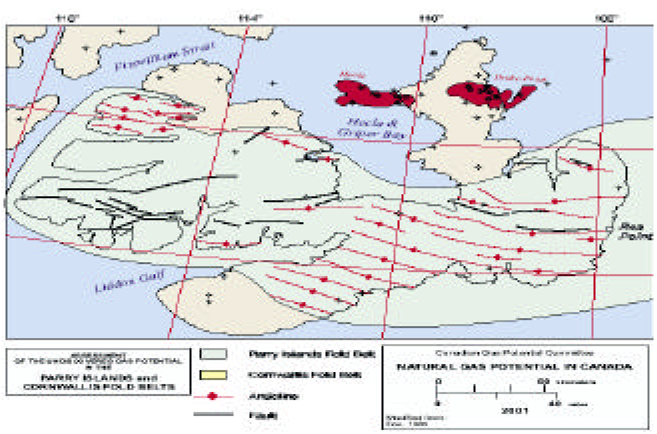
In a previous study,[2] CERI concluded that production and ship-borne transportation from Melville Island in Canada's Arctic is economically feasible with any of three development schemes—LNG, CNG, GTL—examined. In that study, under the base-case assumptions, each of the schemes provided more than the required 15 percent minimum rate of return. The CNG project provided the greatest economic value by a significant margin over the GTL and LNG alternatives.

CERI has completed an expanded sensitivity analysis on this study. As before, this analysis focuses exclusively on Melville Island gas development as an example of what may be possible for other areas of the High Arctic.

Resource Base and Reserves

In its 1997 report, the Canadian Gas Potential Committee (CGPC) predicted the Canadian frontier basins, including the Mackenzie Valley, Beaufort Basin, Sverdrup Basin and the Sable Sub-Basin, contain 107 Tcf of potential marketable gas. The CGPC also noted that high-risk conceptual plays are probable in remote frontier basins, but that exploration programs are required to confirm their existence.

Two fields have been discovered on the Sabine Peninsula of Melville Island, Drake Point and Hecla, with gas resources of 5.982 Tcf and 4.199 Tcf gas-in-place, respectively, according to the CGPC's 2001 report. The fields can be developed together in a single onshore/offshore project.



Source: Canadian Gas Potential Committee, Natural Gas Potential in Canada 2001, Figure 12.11, 2001.

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[2] Mortensen, P. *Economics of High Arctic Gas Development*, Canadian Energy Research Institute, March 2004.

Background

The Arctic Pilot Project Application (1981) estimated recoverable and marketable reserves of natural gas at almost 9 Tcf for the discoveries made at Hecla and Drake Point on Melville Island. The application proposed a design for delivering from Melville Island to Quebec and Nova Scotia using icebreaking LNG carriers. The project was configured to deliver 320 MMCFPD of natural gas, from the Borden Island Main pool of the Drake Point field, to a barge-mounted liquefaction facility at Bridport Inlet. The 2.2 million tonnes per year plant was intended to deliver LNG—via two 140,000 cubic metre capacity Arctic Class 7 vessels—to regasification terminals in Quebec and Nova Scotia, some 5,200 kilometres away.

The Application proposed a second phase to increase throughput to 550 MMCFPD with 4 LNG carriers, and a third phase to increase throughput, with development of the Hecla field, to 1375 MMCFPD and 9 LNG carriers.

The Economics of Coalbed Methane ...

CERI is conducting a study to assess the potential supply of natural gas from the coal seams of western Canada over the next twenty years. The project takes as its starting point the various estimates of coalbed methane resource potential, in particular that of the Canadian Gas Potential Committee (CGPC). Available technologies for natural gas production and produced water handling will be investigated, and the environmental issues associated with production of natural gas from coal seams examined.

The research will provide an indicative 20-year projection of natural gas supply from WCSB coal seams under representative North American gas demand and price conditions, with a determination of how much of the potential resource is economic at various price levels.

This multi-client study will be of particular interest to:

- Natural gas E&P companies
- Drilling and service sector companies
- Gathering system and midstream operators
- Natural gas pipeline companies
- Western Canadian provincial governments
- Large natural gas end-users, and
- Financial institutions

If you would like to sponsor this research or have any questions, please contact Peter Howard (phoward@ceri.ca).

Development Schemes

The same three options examined in the CERI March 2004 study are included in the present study: liquefied natural gas (LNG) to eastern Canada, compressed natural gas (CNG) to the Mackenzie Delta, and gas-to-liquids (GTL) to eastern Canada. An additional scenario has been added: LNG delivery to eastern Canada with transshipment to conventional vessels at a storage terminal in Greenland.

LNG directly to the Northeastern Seaboard - the configuration of this project includes a barge mounted liquefaction facility, LNG storage barges, a dock and loading facility and a fleet of icebreaking LNG tankers. LNG is delivered to third party regasification facilities in Nova Scotia or New Brunswick.

LNG with transshipment in West Greenland - this project is identical to the previous one except for transshipment from icebreaking tankers to conventional vessels, at a storage facility located in West Greenland. This scheme is intended to minimize capital expenditures for vessels and to provide more flexibility in choice of markets.

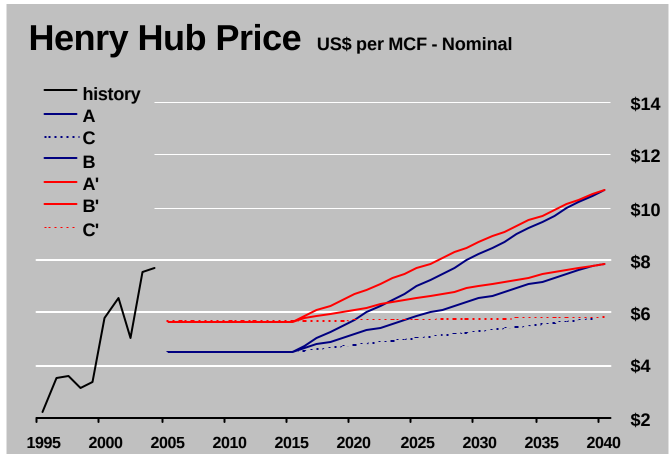
CNG to a Mackenzie Corridor pipeline - this avoids the large capital costs of liquefaction facilities of the LNG schemes. CNG vessels have much lower capacities than LNG tankers—about one-third—and are therefore better suited to short-haul routes, making transportation from Melville Island to the Mackenzie Delta feasible commercially.

GTL to the Northeastern Seaboard - several GTL options are available, but they are all relatively inefficient, consuming about 35 percent of the input energy in the conversion process—1 BCFPD of natural gas feedstock into 100 MBOPD of liquids. Delivery is by tanker to US East Coast refineries, where the synthetic crude is used to produce ultra clean lubes, jet fuel, diesel, and olefins.

Assumptions and Sensitivities

The three most important assumptions in the analysis are project start-up dates, commodity prices, and capital and operating costs. CERI analyzed production start-up years of 2009, 2014 and 2019.

CERI used two separate near-term baseline Henry Hub prices of C$5.85 (US$4.50) and C$7.37 (US$5.67) per MCF for the 2005-2015 period. Each of these was extended using three price lines for the 2015-2040 period—a low case that is flat to modestly increasing nominally, a middle modestly-increasing case that mimics the industry-accepted Sproule and GLJ forecasts, and a higher case.



Fixed differentials were applied to the Henry Hub price to derive prices at the Strait of Canso for the LNG options, the Mackenzie Delta for the CNG option, and Saint John for the GTL option. In the latter case, an oil price is formulated using a 6:1 oil price to natural gas price.

The overall capital and operating costs of the various schemes vary by less than 30 percent. Capital costs range from $4.888 billion for the LNG option to $6.281 billion for GTL, in 2005 constant Canadian dollars. Similarly, total operating costs for the period to 2040 range from $415 million to $535 million.

CERI varied the facility, vessel, and drilling capital costs, as well as their operations and maintenance costs, by plus-or-minus 25 percent for each of the variables independently. Monte Carlo simulations were performed assuming variations of as much as plus-or-minus 50 percent simultaneously in each of the key variables.

Results

This preliminary analysis suggests that production and ship-borne transportation of natural gas from Melville Island is economically feasible (positive NPV) for all 4 of the scenarios examined under certain price forecasts, specifically, under the higher price levels of A, A’, B’, and C’. However, the reserve size makes the scenarios mutually exclusive.

For price forecasts A and A’, delaying the start of production improves expected NPV. A delay has very little impact for forecasts B and B’ and reduces NPV for forecasts C and C’.

The CNG project is the most favourable under price forecasts A’ and B’, for all start years, under A for start years of 2014 and 2019, and under C’ for start years of 2009 and 2014.

The LNG case without transshipment is marginally more favourable than the LNG case with transshipment.

A change of 25 percent in any of the five parameters can change NPV by as much as $300 million. In most cases, the probability distribution of the NPV is normal.

Monte Carlo simulations show that while the CNG project is the most favourable under price forecasts A' and B', for all production start years, the range of NPVs between the 5th and 95th percentile is greater than the range of NPVs for the corresponding cases for both of the LNG scenarios and the GTL scenario.

Note that reducing the range or standard deviation of the NPV distributions requires reduced ranges for the input parameters that can be gained through learning such as in a phased project.

Additional Possible Implications

Development of Melville Island natural gas with its shipping option for the production stream, might well be seen as more environmentally sensitive than conventional offshore exploration and development of Beaufort Sea resource potential, and could well have an impact on the timing of that activity.

North American development of incremental sources of supply, with its required infrastructure, provides security of supply to North American consumers.

Socio-economic and environmental issues will be critical considerations for any proposed development in the High Arctic. Important issues such as comparative risk assessments of field development and these and other delivery options, the appropriate discount rate(s) and the appropriate project life will also need to be examined. For example, delivery of GTL versus LNG or natural gas likely conveys greater potential benefits than are captured in the present analysis. In addition, the GTL option has the potential benefit of providing a home-grown substitute for the volumes of diesel that must currently be imported into Nunavut communities, of improving economic conditions in the north, and of reducing greenhouse gases. Finally, the optionality inherent with carrier transportation alternatives and especially in the transshipment scenario likely has a risk mitigation effect that may be better considered with other analytical techniques.

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