Final Report

Economic Overview of Oil and Gas Resources Found in the Queen Charlotte Basin

Prepared for:

Natural Resources Canada (NRCan)

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Section 1.0 Introduction

1.1 Objectives

This report, prepared for Natural Resources Canada (NRCan) by Wade Locke Economic Consulting, Strategic Concepts, Inc. and Jacques Whitford, provides the Government of Canada with expert analysis of the potential economic value that could be associated with the development of the oil and gas resources within the Queen Charlotte Basin (QCB) region of British Columbia. Specifically, the objectives of the study are:

- to determine what portion of the oil and gas resources, found in the QCB, may be economic to produce using currently available technology;
- to make an assessment of the economic value of the oil and gas reserves in the QCB; and
- to evaluate the strategic value of these offshore resources in various contexts.

1.2 Report Rationale

This report was commissioned by NRCan to provide information regarding the potential economic value of oil and gas resources in the Queen Charlotte Basin (QCB). The information contained in this report will be used by the federal government as part of the decision making process for establishing future Marine Protected Areas (MPAs). The Government of Canada is currently in the process of establishing a network of MPAs to protect marine plants, animals and ecosystems. Within these areas, human activities may be restricted in certain ways. Therefore, it is important to determine the economic impact of restricting the development of resources such as oil and gas in order that this information is taken into consideration when determining whether or not to establish an MPA. Conducting socio-economic assessments are also part of the *National Framework for Establishing and Managing Marine Protected Areas (1999).* These assessments include an evaluation of hydrocarbon resource potential and how the establishment of an MPA may affect economic uses of oil and gas.

The QCB is an area deemed to have high oil and gas potential and therefore it is crucial to determine the economic value of this potential. For this reason NRCan requested the research team to develop an economic overlay of oil and gas resources in the QCB. This information can then be used to assist in the decision making process for establishing MPAs.

1.3 Report Structure

This report contains four sections. Section One introduces the report, its objectives and its rationale, and provides a brief description of past petroleum activity in the QCB and an overview of the resource evaluations undertaken for it. The technological environment for exploration and development options in the context of the potential future development of these resources is outlined in Section Two, while Section Three presents the methodology and findings of the economic valuation. The summary and conclusion, which includes an assessment of the strategic value of the resources, are contained in Section Four.

1.4 Background

The Queen Charlotte Basin is located between mainland British Columbia and the Queen Charlotte Islands. To the north, the basin is connected to Pacific Ocean through the Dixon Entrance and to the south, through Queen Charlotte Sound at the north end of Vancouver Island.

Oil and gas exploration was first undertaken in the area in 1913, when a well was drilled on the west side of Graham Island. Eight additional wells were drilled from Graham Island between 1949 and 1971. There was offshore activity during the early 1960s, in the form of two dimensional (2-D) seismic surveys. The results from these surveys led to the drilling of an additional eight offshore wells by Shell Canada in the late 1960s. Although these wells and seismic surveys did not result in commercial discoveries, the information they generated formed the basis for the hydrocarbon resource estimates used in this study. Figure 1 illustrates the QCB region and the location of the wells drilled to date[1].

Figure 1: Queen Charlotte Basin - Location of Wells Drilled

A moratorium on offshore drilling was established in 1972 and there has been no further exploration activity in the region with the exception of one onshore well on Graham Island in 1984 and periodic seismic work, including an extensive survey undertaken in 1998 by the Geological Survey of Canada (GSC). This lack of activity is a result of the federal moratorium on issuing new exploration permits and the suspension of work under existing permits. While the moratorium remains in place, both levels of government are considering options for future offshore activity.

[1] Diagram obtained directly from Peter Hannigan, Natural Resources Canada.

1.5 Estimates of Hydrocarbon Potential of the Queen Charlotte Basin

A number of studies and resource assessments have been undertaken for the hydrocarbon resources of the QCB, confirming that it has significant oil and gas potential. While the 18 wells drilled to date have not resulted in commercial discoveries, they have provided information that allows assessments of the overall oil and gas potential of the area.[2]

In a study undertaken for the Geological Survey of Canada, Hannigan et al. (2001) provide estimates of the hydrocarbon potential of the basin. In this assessment, three regional-scale conceptual plays were considered: Miocene, Cretaceous and Pliocene. Using previously published reports, including unpublished seismic and well-history data, Hannigan and his team modeled the potential of the basin using the Petroleum Exploration and Resource Evaluation System (PETRIMES) model to develop a lognormal probability distribution of both oil and gas fields in each of the three conceptual plays. The estimates of the oil in place and gas in place they developed are summarized in Table 1 and form the basis for the analysis undertaken in this report.

Table 1: Estimated Oil in Place and Gas in Place for the Queen Charlotte Basin

Conceptual Play	Expected Number of Fields	Median Play Potential (in place) (million m^3)	Mean Play Potential (in place) (million m^3)	Median of Largest Field Size (in place) (million m^3)
Conceptual Oil Plays				
Cretaceous	62	392	478	96
Miocene	28	574	668	165
Pliocene	13	398	652	233
Total Oil	**103**	**1,560**		
Conceptual Gas Plays				
Cretaceous	50	75,435	94,336	20,675
Miocene	40	285,710	317,080	71,190
Pliocene	30	321,750	389,710	95,774
Total Gas	**120**	**733,760**		

Source: Hannigan et al. (2001, Table 4)

As Table 1 indicates, there is a median potential of 1.56 million cubic metres (9.8 billion barrels) of oil in place and 733.76 billion cubic metres (25.9 trillion cubic feet) of gas in place within the QCB. In their study, Hannigan et al. make no estimates of the quantum of recoverable resources that may exist. Rather, their analysis was confined to estimating the amount of hydrocarbons in place and the distribution of field/pool sizes in each play. While the latter was not reported in their study, this information was obtained from Peter Hannigan for use in this report. The distributions of fields/pools by size by oil in place or natural gas in place for the three conceptual plays are illustrated in Figures 2 to 7. The complete raw dataset for the expected field distribution in the QCB as generated by the PETRIMES model is provided in Appendix A. Appendix A also contains the corresponding distributions of recoverable oil and gas reserves utilized in this study.

[2] Strong et al (2002, p.7) reports that 10 wells were drilled on Graham Island and 8 offshore in the QCB.

Figure 2: Distribution of Oil in Place by Size of Mean and Median Oil Pools Queen Charlotte Basin: Miocene Play

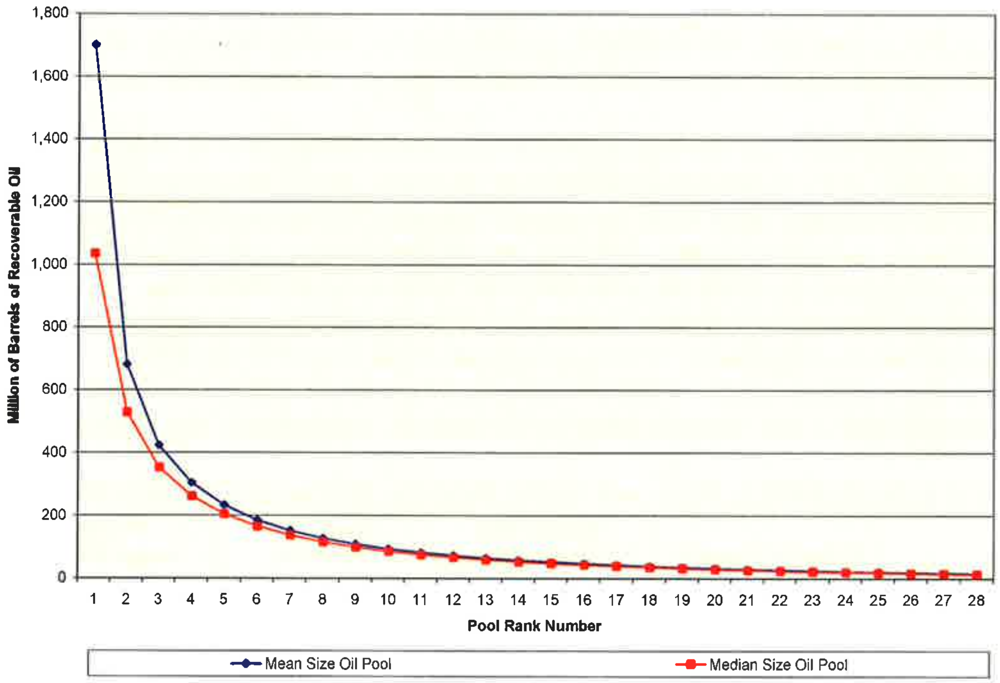


Figure 3: Distribution of Oil in Place by Size of Mean and Median Oil Pools Queen Charlotte Basin: Cretaceous Play

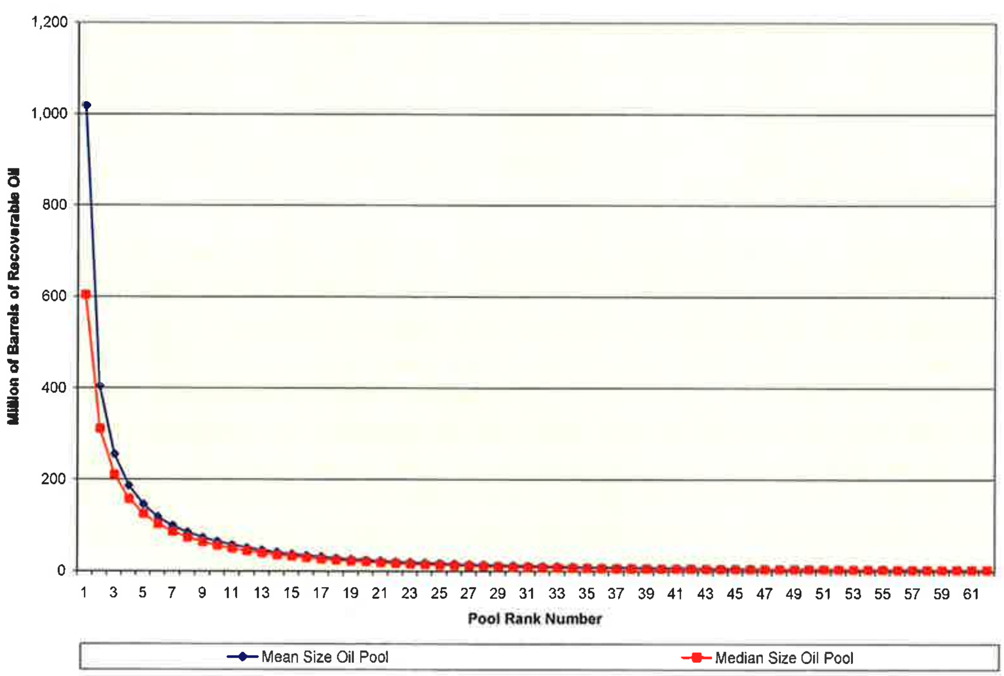


Figure 4: Distribution of Oil in Place by Size of Mean and Median Oil Pools Queen Charlotte Basin: Pliocene Play

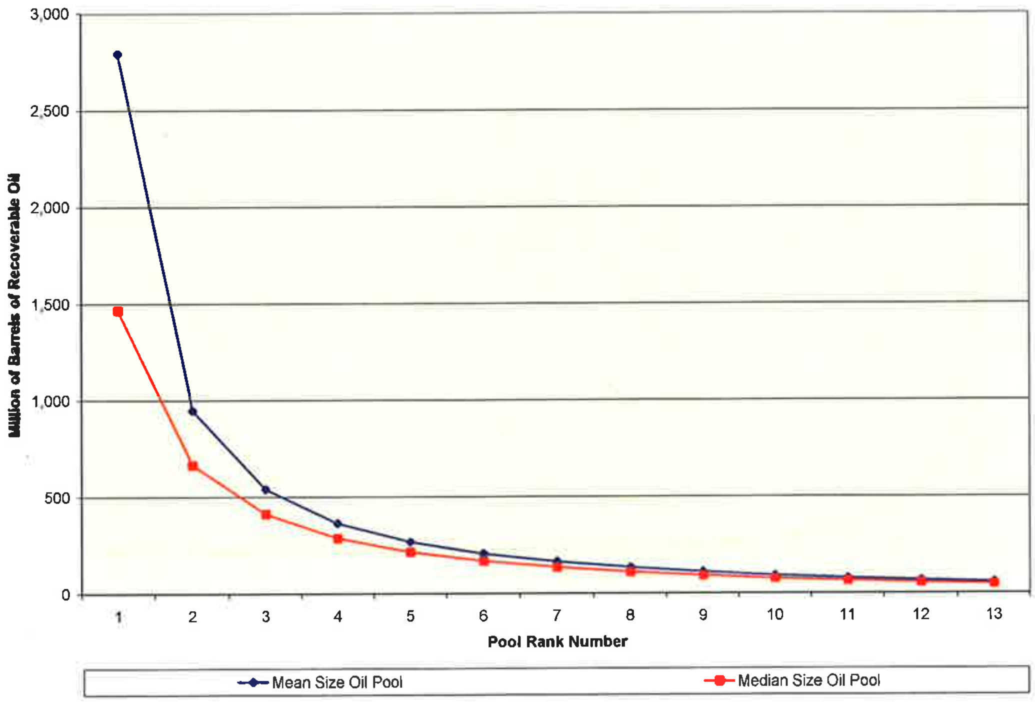


Figure 5: Distribution of Gas in Place by Size of Mean and Median Gas Pools Queen Charlotte Basin: Miocene Play

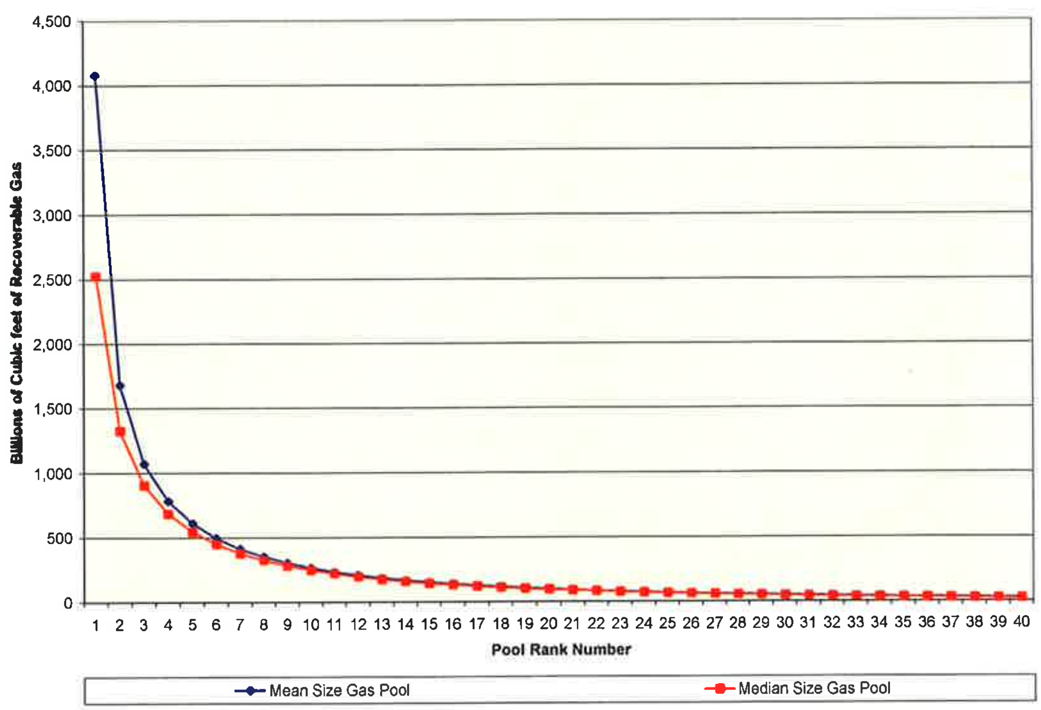


Figure 6: Distribution of Gas in Place by Size of Mean and Median Gas Pools Queen Charlotte Basin: Cretaceous Play

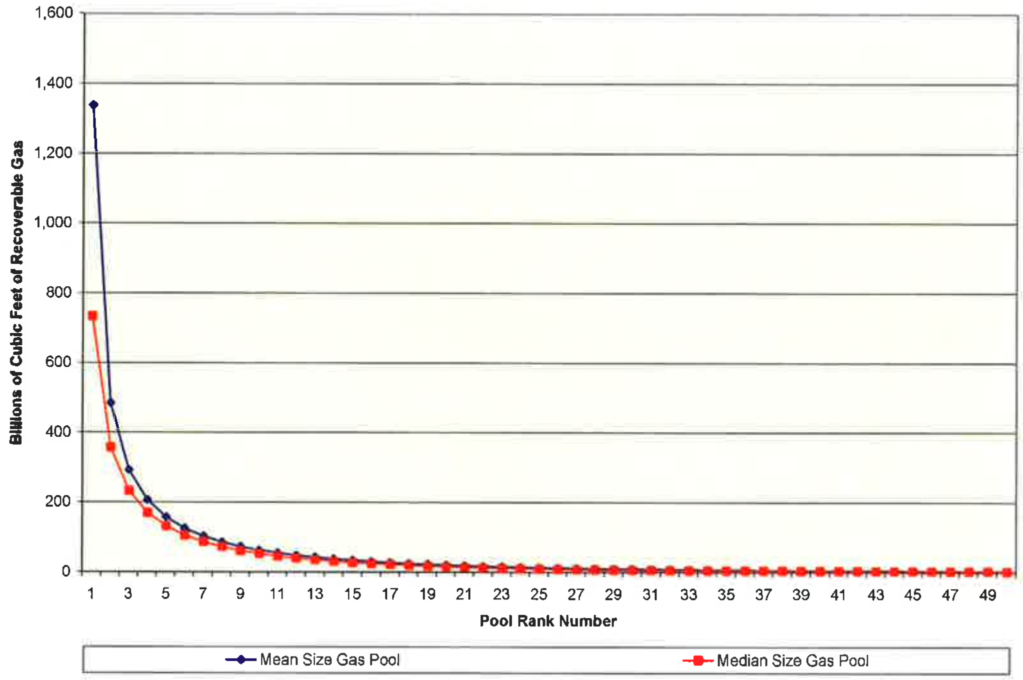
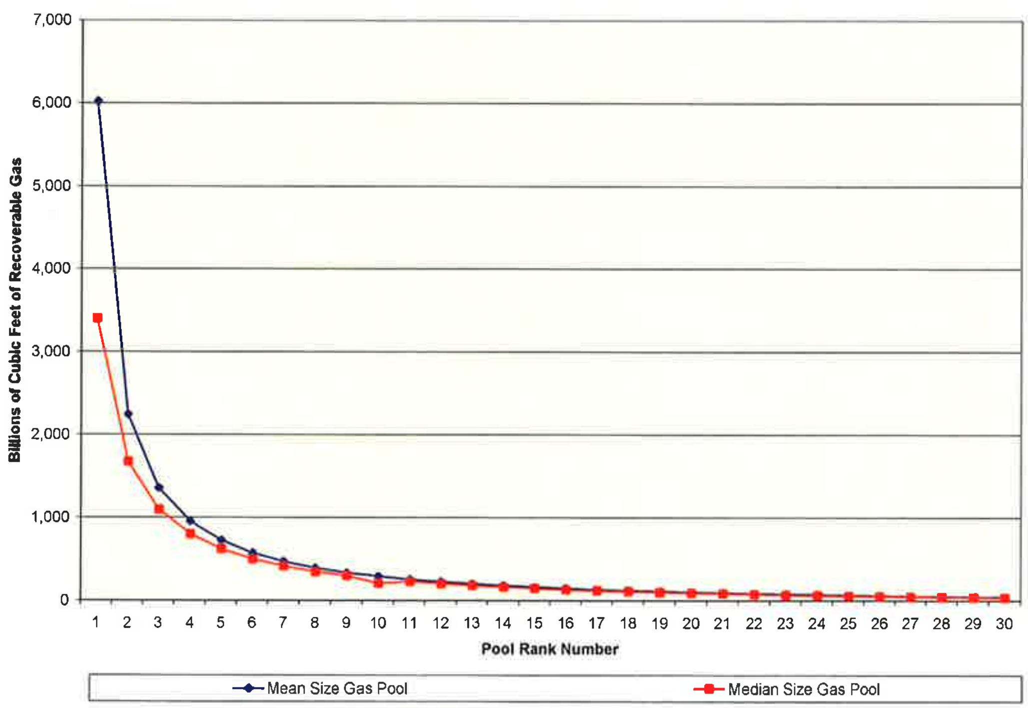


Figure 7: Distribution of Gas in Place by Size of Mean and Median Gas Pools Queen Charlotte Basin: Pliocene Play



1.5.1 Recoverable Resource Estimates

The next step in the current analysis is to determine the potential recoverable reserves that may follow from the estimates of oil in place and gas in place contained in Hannigan et al. (2001). This requires the estimation of a recovery factor to be applied to pools in the conceptual oil and gas plays. Unfortunately, the type and quality of information that is required for a precise estimation of recovery factors will not be available until more extensive drilling and testing are undertaken in the QCB. This problem was overcome by examining the literature and through discussions with individuals knowledgeable about the oil and gas plays in the basin. For the purpose of the present analysis, two recovery factors were assumed for the oil fields and two for the natural gas fields, in the QCB. The recoverable oil reserves were estimated by applying either a 25% or 34% recovery factor.[3] The recoverable natural gas, on the other hand, was estimated utilizing either a 75% or a 60% recovery factor.[4]

The detailed distribution of recoverable reserves for oil and gas in each conceptual play is provided in Appendix A. For illustrative purposes, Tables 2 and 3 provide the distribution of the top-five pools by size in each play.

Table 2: Distribution of Expected Recoverable Reserves of Oil by Size of Pool and Recovery Factor – Queen Charlotte Basin (mean pool size; millions of bbls)

		Recoverable Oil Reserves	
Pool #	**Oil in Place**	**25% Recovery Factor**	**34% Recovery Factor**
	Miocene Oil Play		
1	1,700.1	425.0	578.0
2	681.9	170.5	231.9
3	425.2	106.3	144.6
4	304.3	76.1	103.5
5	233.1	58.3	79.3
Subtotal	**4,199.6**	**1,049.9**	**1,427.9**
	Cretaceous Oil Play		
1	1,018.8	254.7	346.4
2	404.1	101.0	137.4
3	255.5	63.9	86.9
4	186.2	46.5	63.3
5	145.5	36.4	49.5
Subtotal	**3,018.7**	**754.7**	**1,026.4**
	Pliocene Oil Play		
1	2,793.2	698.3	949.7
2	948.6	237.1	322.5
3	541.9	135.5	184.3
4	365.3	91.3	124.2
5	267.9	67.0	91.1
Subtotal	**4,103.5**	**1,025.9**	**1,395.2**
Total Oil	**11,322**	**2,831**	**3,850**

[3] The 25% recovery factor was reported in the Royal Society of Canada Experts Report (2004, p. 14), while the 34% recovery factor was suggested by Ron Smyth, Government of British Columbia.
[4] The 75% figure was also taken from the Royal Society of Canada Experts Report (2004, p. 14) and the 60% estimate was suggested by Ron Smyth.

Table 3: Distribution of Expected Recoverable Reserves of Gas by Size of Pool and Recovery Factor – Queen Charlotte Basin (mean pool size; billions of ft^3)

		Recoverable Gas Reserves	
Pool #	**Gas in Place**	**60% Recovery Factor**	**75% Recovery Factor**
Miocene Gas Play			
1	4,082.9	2,449.7	3,062.1
2	1,682.6	1,009.5	1,261.9
3	1,072.3	643.4	804.3
4	782.5	469.5	586.9
5	610.5	366.3	457.8
Subtotal	**8,932,900.9**	**5,359,740.6**	**6,699,675.7**
Cretaceous Gas Play			
1	1,337.6	802.6	802.6
2	484.5	290.7	290.7
3	293.1	175.9	175.9
4	207.1	124.2	124.2
5	157.8	94.7	94.7
Subtotal	**2,657,222.6**	**1,594,333.6**	**1,594,333.6**
Pliocene Gas Play			
1	6,023.6	3,614.2	4,517.7
2	2,241.0	1,344.6	1,680.7
3	1,355.9	813.6	1,016.9
4	953.5	572.1	715.1
5	722.6	433.6	542.0
Subtotal	**10,978,240.0**	**6,586,944.0**	**8,233,680.0**
Total Oil	**22,568,364**	**13,541,018**	**16,527,689**

Tables 2 and 3 indicate that between 2.8 to 3.9 billion barrels of oil and 13.5 and 16.5 tcf of natural gas could technically be recovered from the top five pools in each play within the QCB. However, this does not represent the amount of oil and natural gas that would be economic to develop and extract. That is a much smaller amount, the size of which depends on technology, costs and output prices. The economically recoverable reserves are estimated in the economic analysis section of this paper.

Section 2.0 Technological Overview

This section of the report provides an overview of technological trends in the offshore oil and gas industry, particularly with respect to exploration and development activity and their implications for potential future development of the hydrocarbon resources in the QCB. This information, in turn, was used to develop the capital and operating cost estimates used in the economic value analysis in Section Three.

2.1 Offshore Exploration and Drilling Technology

Literature reviews undertaken as part of this study indicate that the continued success of the offshore oil and gas industry can be attributed in part to technological advances in exploration, drilling and production techniques.[5] Today's technologies are more benign

[5] Energy Information Administration, Natural Gas 1998: Issues and Trends, p 175.
American Petroleum Institute, Environmental Commitment, http://api-ec.api.org

and result in little damage to the environment. In addition to identifying better drill targets, the industry has also improved the actual drilling itself, which is less intrusive and more precise with a focus on minimizing disturbances to land, vegetation, water, air, natural habitats, and surrounding communities.

2.1.1 Seismic Survey Technology

Seismic surveys are used for exploration, development and reservoir characterization. In the offshore, data are collected from streamers towed behind seismic vessels. Since the mid 1990s, most offshore drill targets are first identified using 3-D seismology, which uses imaging technology that bounces acoustic and/or electrical vibrations off underground surfaces, generating data that produce multidimensional representations of those surfaces. These data are then plotted on detailed virtual maps that allow companies to identify areas where commercial quantities of oil and natural gas may have accumulated. After careful analysis, exploratory drill targets are identified, and wells are drilled in the locations offering the greatest chance for success.

By using seismic imaging, as well as other available technologies, such as satellite-derived gravity and bathymetry, global positioning systems, and geographical information systems, today's oil and natural gas explorers find much more while disturbing far less of the natural environment."[6]

Seismic surveys can be very expensive, depending on the type of survey (2-D vs. 3-D), the size of the area being surveyed and the overall global demand for seismic vessels. In the current environment, there is considerable demand for seismic vessels and therefore current costs are considerable. Seismic programs can run anywhere from $2 million to over $20 million. Costs for 3-D seismic surveys range from US$5,000 to US$25,000 per square kilometre.

2.1.2 Drilling Technology

Drilling is a critical component of oil and gas development. While seismic technology is used to identify targets, it is only through drilling into the targets that the presence of oil and gas resources can be verified. In the past, wells were drilled vertically to a pre-determined depth ranging from a few thousand feet to as much as five miles. New drilling techniques, including **directional drilling, horizontal drilling** and **extended-reach drilling** have improved drilling results by penetrating multiple targets along different planes. For oil and natural gas producers, this facilitates reaching reservoirs that are not located directly beneath the drilling rig, and avoiding sensitive surface and subsurface environmental features.

As a result of these new drilling technologies, exploration has become more efficient, less environmentally intrusive and has a higher propensity for success. All of these features

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Society of Petroleum Engineers, Horizontal and Multilaterial Wells, http://www.spe.org
Petroleum Technology Transfer Council, 3-D Seismic Technology: An Overview, http://
[6] American Petroleum Institute, Environmental Commitment, http://api-ec.api.org

are important to future hydrocarbon potential in the QCB as they provide benefits to all stakeholders.

The costs of drilling an offshore well are currently quite high. Depending on water depth, depth of drill target (below the surface) of the seafloor, and overall global demand for drilling rigs, offshore wells can run as high as $75 US million each. As with the demand for seismic ships, the global demand for offshore drilling rigs is currently outstripping supply. The result is long lead times for booking rigs and higher costs than have prevailed in recent years. Clearly, the exploration for offshore oil and gas resources is a very cost-prohibitive and risky activity.

2.2 Production and Development Technology

New technology is also changing in the development and production of offshore oil and gas fields. Since the first offshore production platform was installed in the Gulf of Mexico in the 1930s, much has changed in the offshore production industry. There are now many types of production systems in use for offshore oil and gas developments. Each of them is available in a myriad of configurations and scales, and adapted to the environmental challenges of the producing region.

Table 4 summarizes some of the basic types of production facilities used in the offshore oil and gas industry.

Table 4: Offshore Production Technologies

Production System	Description/Features
Fixed Platform	- A jacket (vertical section made of structural steel) is fixed to the seafloor. - On the deck, a platform is installed which houses the drilling rigs, production facilities and living quarters. - Designed for long term use - Good for water depths up to 1,700 feet.
Compliant Towers	- Narrow, flexible towers fixed to a piled foundation supporting a deck for drilling and production operations. - Designed to sustain significant lateral deflections and forces - Typically used in water depths ranging from 1,500 and 3,000 feet.
Semi-submersible platforms	- Platforms with legs that are buoyant enough to allow the structure to float, but with sufficient weight to keep the structure upright. - Can be moved from place to place - Flexible in that they can be lowered or raised by altering the amount of flooding in buoyancy tanks - Usually anchored by cable anchors during drilling operations - Used in depths from 600 to 6,000 feet.
Jack-up Platforms	- Jack-ups can be jacked up above the sea using legs than can be lowered like jacks. - Used in relatively low depths - Designed to move from place to place.

Production System	Description/Features

Floating Production Systems	- Large ships equipped with processing facilities on the deck
	- Moored to a location for use over a long period, however, they can be redeployed at other fields.
	- Drilling is conducted from a separate drilling rig.
	- Extensive use of subsea production facilities.
	- Types of floating production systems include:
	  - FPSO (floating production, storage, and offloading system)
	  - FSO (floating storage and offloading system)
	  - FSU (floating storage unit).

Tension Leg Platform (TLP)	- TLPs consist of floating rigs tethered to the seabed to eliminate most vertical movement of the structure. - Used in water depths up to about 6,000 feet. - Seastars are small TLPs used in depths between 600 and 3,500 feet
Subsea tieback	- All drilling and wellhead facilities are located on the seafloor. - Pipelines are tied back to either existing platforms or to the shore where production facilities are located. - Less intrusive on the surface of the ocean and less costly without having to construct offshore platforms. - Used extensively in mature offshore producing regions and allows for the economic development of smaller fields that "tie-in" to existing platforms.

2.3 Implications for Potential QCB Development

Given the rapid advances in technologies, it is impossible to predict the specific production techniques that would be used for the potential discoveries in the QCB. Because there are no known commercial discoveries, even a basic data points such as the location and water depth of potential developments cannot be accurately determined. Furthermore, given the extended period (a minimum of 10-15 years) between today and any actual development activities, it is impossible to predict with any certainty what technologies will be best suited for use in the QCB.

To provide an illustration of some current offshore oil, gas and oil and gas project technologies, Table 5 below has been compiled from information on the www.rigzone.com website, which has a project database of ongoing projects.

As Table 5 illustrates, the scale of offshore oil and gas projects varies considerably, both in terms of size and technological complexity as well as costs. The few examples listed in this table indicate a range of development costs from US$40 million to US$700 million and reserves ranging from 25 to 250 million barrels of oil and from 117 to 900 bcf of natural gas. These examples serve to illustrate the difficulty in making accurate assessments of development costs and hence, assessing economic viability of the undiscovered QCB hydrocarbon resources.

Table 5: Selected Offshore Oil and Gas Project Summaries

Project/ Operator/ Location	Oil/ Gas	Production Facility	Dev Cost ($M US)	Production	Reserves	Production Life	Water Depth	Start-up	Notes
Vixen ConocoPhillips UK North Sea	G	Subsea tieback	$40	120 mmcf/d	117 bcf	6 years; up to 13	32 m	Oct/00	- 135 km offshore - 18 months from discovery to production - Single-well field through discovery well - 8.6 km tieback to existing platform
Leadon Kerr-McGee UK North Sea	O	FPSO	$700	10,700 bpd	170 M bbl		113 m	Jan/02	- Discovered in 1979 - 166 km from shore - 3 fields, including Leadon
Alvheim Marathon Norway	O	FPSO; conversion of existing tanker	$350	80,000 bpd	250 M bbl	25 years	125 m	Mar/07	- Discovered in 1998 - 3 fields
Glitne Statoil Norway	O	FPSO	$90	40,000 bpd	25 M bbl		110 m	Aug/01	- Discovered in 1955 - $90M dev cost included 4 production wells and engineering - FPSO vessel leased; not purpose-built for this project - FPSO vessel is the Petrojarl I, which has serviced 10 fields since 1986
Sigyn Esso Norway	G	Subsea tieback	$525	120 mmcf/d	187 bcf	10 years	70 m	Dec/02	- Discovered in June 1982 - Tied back to Sleipner platform - 3 wells through subsea template
Canyon Express TotalFina US GOM	G	Subsea tieback	$600	500 mmcf/d	900 bcf		2,200 m	Sept/02	- 3 separate gas fields - 88 km of pipelines from fields to platform - Tied back to fixed-leg Canyon - Station platform for processing; platform in 90 m of water - 10 wells - One of the most advanced subsea tiebacks undertaken
Goldeneye Shell UK North Sea	G	Fixed Platform	$560	300 mmcf/d	135 M boe	7-10 years	120 m	Oct/04	- 105 km of pipelines - Unmanned platform - Gas processed at existing onshore plant
Curlew Field Shell UK North Sea	O/G	FPSO (conversion)	$300	45,000 bpd 100 mmcf/d	71 M bbl 244 bcf		92 m		- 220 km offshore - Subsea facilities tied back to FPSO

Section 3.0 Economic Value Analysis

This section of the report brings together the information regarding resource potential and development options into an economic analysis. It uses cost information from various sources to develop an illustrative model that tests the threshold for economic viability for oil and gas fields in the QCB. Using this model, economic cut-off field sizes are identified and compared to the field size estimates generated by Hannigan et al. (2001).

3.1 Methodology

The framework used in this analysis assumes that only those resources which can be profitably exploited will contribute to the estimated value of resources in the QCB. Moreover, it also assumes that any field which is profitable to develop will be developed, which implies that none of the profitable fields are located within restricted areas such as MPAs. To the extent some of the Pools identified in Hannigan et al (2001) are located within restricted areas, the value of the oil and gas resources reported in this report will be an overestimate of the true value of offshore resources that can be exploited.

In the context of the analysis undertaken in this report, it is assumed that no field will be developed unless the after-tax rate of return for the full cycle economics is at least 12%.[7] In other words, it is assumed that no field will be developed unless industry can recoup its full capital and operating costs, its taxes paid, and receive sufficient income to compensate it for the opportunity cost of its capital. This is similar to the approach used by the United States Geological Survey.[8]

The first step in the analysis was to estimate the technically recoverable reserves in the QCB (see Section 1.5.1). This is achieved by applying recovery factors to the estimated distribution of oil or gas in place by field/pool size derived by Hannigan et al. (2001). The recovery factors utilized, as was noted above, are 25% and 34% for oil and 60% and 75% for natural gas. The application of these factors yields a distribution of the technically recoverable oil and gas by field size for each of the conceptual plays.

The next step is to utilize a cash flow analysis model to determine the minimum-size field that can be profitably exploited in the QCB, given the development technology available, the costs associated with developing and operating these fields, the cost of transporting the product to the market, the taxes and royalties for which the project operators will be liable, and the price that the company can expected to receive for its product. Furthermore, it is important to recognize that none of this information is currently available. Moreover, it is not even known with precision in which part of the QCB development will occur. This is important because the water depths within the QCB

[7] Since zero inflation has been assumed for this analysis, the 12% ROR is both real and nominal in the context of the analysis performed in this report. Moreover, all prices and costs are in 2006 dollars and are undiscounted unless specifically indicated otherwise.
[8] See, for example, Attanasi (2005, p.11) which indicates projects with a positive discounted cash flow at 12% are considered to be developed.

vary[9] and, as such, some shallow water technologies will not be feasible at some locations in the QCB.

However, for the purpose of this analysis, it is assumed that a semi-submersible rig will be used for oil field development and production.[10] Information on the capital and operation costs and production profiles are taken from the Terra Nova Development Plan and updated for inflation and currency changes that have occurred since the development plan was submitted. As well, the offshore royalty regime utilized in this analysis is modeled on the generic offshore oil royalty regime currently in place in Newfoundland and Labrador. The specifics of this scenario are described in Appendix B.

The natural gas development is modeled on the Sable Offshore Energy Project. Nova Scotia's generic offshore natural gas royalty is employed to calculate the royalty liabilities associated with each economic natural gas development. The specifics of this scenario are provided in Appendix C.

In addition, to illustrate the sensitivity of the estimates of the economic value of recoverable oil, a second technology assumption is analyzed. It assumes a similar small-scale tie-back development and production profile utilized in 2004 study for the Royal Roads University.[11] The specifics of this technology are also described in Appendix B and C for the oil and gas scenarios, respectively.

Given these development scenarios, it is possible to calculate the minimum size oil and natural gas fields that can generate a 12% after-tax rate of return for the operators of the project under various pricing assumptions. Fields below this size are excluded from further analysis. All remaining fields on or above the economic cutoff have been analyzed further to determine the value of the resource, the discounted net cash flow to the operators, the value of corporation taxes and royalties to the provincial government and the corresponding value of provincial GDP that will be associated with these potential developments.

3.2 Results

3.2.a The Economic Value of Recoverable Oil

Table 6 and Figure 8 present the results of the analysis of the minimum size field that is economic to develop under various prices, for both the semi-submersible and the small-

[9] Royal Society of Canada (2004, p. xi) indicates that water depth in the QCB are greater than 100 metres for most of the basin, with maximum depths of more than 400 metres.
[10] Ibid. (p. 18-22) noted that for the water depths of the QCB, the exploration rigs used would probably be jack-up types (for shallow water), semi-submersibles for deeper water and drill ships for deep water…and that the production platforms in QCB would probably be either seabed-founded platforms or FPSOs.
[11] Bridges and Associates (2004) assumed developments characterized primarily smaller platforms with by subsea pipeline to shore. They also assumed that the oil project would have a capital cost of $650 million and an annual operating cost of $19 million while the natural gas project would have a capital cost of $607 million and an annual operating cost of $23 million.

scale tie-back technologies. At low prices ($20 US/bbl), the semi-submersible technology would require a field of at least 535 million barrels of recoverable oil to be economic to develop. As prices increase, the threshold minimum size of field decreases. For instance, with prices in the $45 US/bbl range, fields with 226 million barrels become economic, while if current prices[12] persist, it would commercially viable to exploit fields as small as 155 million barrels with the semi-submersible technology.

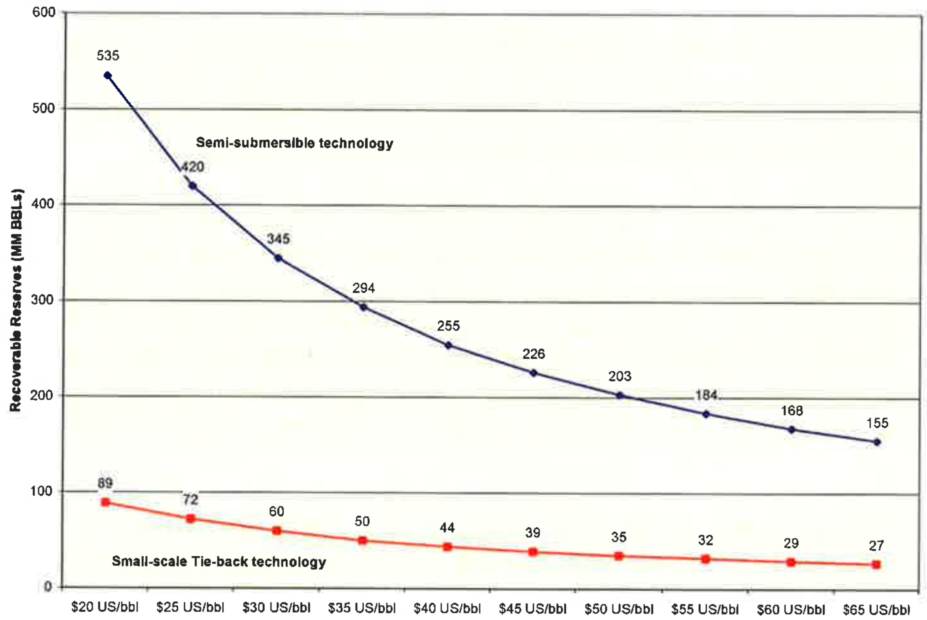
Since there is no way of knowing exactly where within the QCB the oil resources will be exploited, and hence what production technology will be used, Table 6 also indicates the minimum size field that can be economic to exploit if the assumptions utilized in the Royal Roads study apply, which in our study is referred to as the small-scale tie-back scenario. Clearly, it is profitable to exploit much smaller fields if this small-scale tie-back technology proves feasible. For example, fields as small as 40 million barrels of recoverable reserves become profitable at oil prices in the range of $45 US/bbl.

Table 6: Minimum Size of Oil Field Required in the QCB to Generate an After-tax Rate of Return of 12% for Different Oil Prices under Different Technologies (Millions of Barrels of Recoverable Oil)

Oil Price Scenarios	Semi-Submersible Technology	Small-Scale Tie-Back Technology
$20 US/bbl	535 M bbl	89 M bbl
$25 US/bbl	420 M bbl	72 M bbl
$30 US/bbl	345 M bbl	60 M bbl
$35 US/bbl	294 M bbl	50 M bbl
$40 US/bbl	255 M bbl	44 M bbl
$45 US/bbl	226 M bbl	39 M bbl
$50 US/bbl	203 M bbl	35 M bbl
$55 US/bbl	184 M bbl	32 M bbl
$60 US/bbl	168 M bbl	29 M bbl
$65 US/bbl	155 M bbl	27 M bbl

[12] According to www.bloomberg.com/energy/, the spot price for West Texas Intermediate at Cushing Oklahoma was $69.32 US/bbl on April 13, 2006.

Figure 8: Minimum-Sized Oil Field Profitable to Exploit in Queen Charlotte Basin



The estimates of the value of the recoverable oil resources in the QCB, using the semi-submersible technology, are presented in Tables 7 and 8 and Figures 9 and 10. The results derived with the small-scale tie-back technology are provided in Appendix Table A13 for comparison.

With higher prices, the value of economically recoverable oil increases because more fields are profitable to develop and each barrel of oil produced is worth more. For the 34% recovery factor, as indicated in Table 7 and Figure 9, the value of oil in the QCB ranges from nearly $30 billion US (at $20 US/bbl) to slightly more than $160 billion US (at $65 US/bbl). Given that long-term oil prices are expected to be in the $40 US to $50 US range, it might be best to focus on this price scenario.[13] At $45 US/bbl, 2.4 billion barrels of oil, with a value of over $100 billion US, could be commercially exploited. If the ultimate recovery of oil from the QCB turns out to be closer to 25% than 34%, then the value of recoverable oil at $45 US/bbl and using semi-submersible technology is approximately $70 billion US, associated with the production of 1.6 billion barrels.

Table 7 also reports information on the amount of provincial corporation income taxes and royalties that are estimated for each scenario. Obviously, as the price rises, the amount of revenue flowing to the provincial treasury also increases. For example, the Government of British Columbia can expect to receive $7 billion US at $20 US/bbl, which increases to $51 billion US at $65 US/bbl. The mid-range estimate ($45 US/bbl) yields $31 billion US in provincial corporation income taxes and royalties to the treasury.

[13] GLJ Petroleum Consultants, in the their April 1, 2006 forecast, http://www.gljpc.com/pdfs/pricing.pdf, forecast that the real price of WTI at Cushing Oklahoma after 2010 will remain at $45 US bbl, which they also inflate at 2% per annum to derive a nominal estimate.

In addition, provincial GDP[14] associated with developing the potential oil fields in the QCB increases with prices. Specifically, the impact on provincial GDP range from $11.4 billion US ($20 US/bbl and 25% recovery) to $152.6 billion US ($65 US/bbl and 34% recovery). At $45 US/bbl, the estimates of provincial GDP are $96.1 billion US and $63.4 billion US for 34% and 25% recovery assumptions, respectively.

Likewise, profits that accrue to the developers of the oil deposits also grow with increases in oil prices. Oil profits,[15] for instance, range from $120 million US at $20 US/bbl to $1.5 billion US at $65 US/bbl.

Finally, as indicated in Table A13, if the small-scale tie-back technology can be utilized, then the recoverable oil at $45 US/bbl increases to 3.9 billion barrels, given a 34% recovery factor and 2.7 billion, given a 25% recovery factor. The corresponding economic values are $165 billion US and almost $115 billion US, respectively.

Table 7: Value of Recoverable Oil Resource in the QCB for Various Prices and Assuming a 34% Recovery Factor and a Semi-Submersible Production Technology

	Recoverable Reserves (Millions of bbls)	Undiscounted Total Revenue (Millions of $ US)	After Tax Discounted NCF @12% (Millions of $ US)	Undiscounted Provincial CIT & Royalty Revenue (Millions of $ US)	Undiscounted Provincial GDP (Millions of $ US)
Scenario: $20 US/bbl					
	949.7	$18,044	$109	$4,806	$15,821
	578.0	$10,982	$12	$2,246	$9,307
Sum	**1,528**	**$29,026**	**$121**	**$7,052**	**$25,128**
Scenario: $25 US/bbl					
	949.7	$22,555	$174	$6,575	$20,332
	578.0	$13,728	$53	$3,308	$12,052
Sum	**1,528**	**$36,283**	**$227**	**$9,883**	**$32,384**
Scenario: $30 US/bbl					
	949.7	$27,066	$240	$8,349	$24,843
	578.0	$16,473	$94	$4,385	$14,798
	346.4	$9,872	$0	$1,928	$8,539
Sum	**1,874**	**$53,411**	**$334**	**$14,662**	**$48,180**
Scenario: $35 US/bbl					
	949.7	$31,578	$305	$10,127	$29,354
	578.0	$19,219	$134	$5,468	$17,543
	346.4	$11,518	$25	$2,568	$10,185
	322.5	$10,723	$14	$2,270	$9,425
Sum	**2,197**	**$73,038**	**$478**	**$20,433**	**$66,507**
Scenario: $40 US/bbl					

[14] Provincial GDP is estimated as the value of output less the import content of the inputs that were used to produce it on an annual basis. Based upon the experience in Newfoundland and Labrador (See Locke et al (2004, p.ii)), it is assumed that 50% of the operating expenditures will come from sources outside of British Columbia.

[15] It important to realize that the profits reported for oil developers in this scenario are expressed in present value terms and account for all explicit costs and taxes and include an implicit return to compensate the developer for the opportunity cost of their capital invested in these projects.

	Recoverable Reserves (Millions of bbls)	Undiscounted Total Revenue (Millions of $ US)	After Tax Discounted NCF @12% (Millions of $ US)	Undiscounted Provincial CIT & Royalty Revenue (Millions of $ US)	Undiscounted Provincial GDP (Millions of $ US)
	949.7	$36,089	$370	$11,905	$33,865
	578.0	$21,964	$174	$6,552	$20,289
	346.4	$13,163	$50	$3,212	$11,830
	322.5	$12,255	$37	$2,869	$10,957
Sum	**2,197**	**$83,471**	**$631**	**$24,538**	**$76,941**
Scenario: $45 US/bbl					
	949.7	$40,600	$436	$13,683	$38,376
	578.0	$24,710	$213	$7,635	$23,034
	346.4	$14,809	$75	$3,469	$13,475
	322.5	$13,787	$60	$3,469	$12,489
	231.9	$9,914	$4	$2,004	$8,749
Sum	**2,428**	**$103,820**	**$788**	**$30,649**	**$96,123**
Scenario: $50 US/bbl					
	949.7	$45,111	$501	$15,461	$42,887
	578.0	$27,455	$253	$8,717	$25,780
	346.4	$16,454	$99	$4,504	$15,121
	322.5	$15,319	$83	$4,070	$14,021
	231.9	$11,015	$20	$2,433	$9,851
Sum	**2,428**	**$115,354**	**$956**	**$35,185**	**$107,660**
Scenario: $55 US/bbl					
	949.7	$49,622	$565	$17,254	$47,398
	578.0	$30,201	$293	$9,800	$28,525
	346.4	$18,099	$123	$5,154	$16,766
	322.5	$16,857	$105	$4,673	$15,553
	231.9	$12,117	$37	$2,865	$10,952
	184.3	$9,630	$0	$1,921	$8,536
Sum	**2,613**	**$136,526**	**$1,123**	**$41,667**	**$127,730**
Scenario: $60 US/bbl					
	949.7	$54,133	$631	$19,028	$51,909
	578.0	$32,946	$333	$10,882	$31,271
	346.4	$19,745	$146	$5,805	$18,412
	322.5	$18,383	$127	$5,279	$17,084
	231.9	$13,218	$53	$3,298	$12,054
	184.3	$10,505	$14	$2,261	$9,411
Sum	**2,613**	**$143,765**	**$1,304**	**$46,553**	**$140,141**
Scenario: $65 US/bbl					
	949.7	$58,644	$696	$20,802	$56,420
	578.0	$35,692	$372	$11,965	$34,016
	346.4	$21,390	$170	$6,455	$20,057
	322.5	$19,914	$149	$5,885	$18,616
	231.9	$14,320	$70	$3,731	$13,156
	184.3	$11,381	$27	$2,604	$10,286
Sum	**2,613**	**$161,341**	**$1,484**	**$51,442**	**$152,551**

Table 8: Value of Recoverable Oil Resource in the QCB for Various Prices and Assuming a 25% Recovery Factor and a Semi-Submersible Production Technology

	Recoverable Reserves (Millions of bbls)	Undiscounted Total Revenue (Millions of $ US)	After Tax Discounted NCF @12% (Millions of $ US)	Undiscounted Provincial CIT & Royalty Revenue (Millions of $ US)	Undiscounted Provincial GDP (Millions of $ US)
Scenario: $20 US/bbl					
	698.3	$13,268	$44	$3,071	$11,415
Sum	**698**	**$13,268**	**$44**	**$3,071**	**$11,415**
Scenario: $25 US/bbl					
	698.3	$16,585	$93	$4,370	$14,732
	425.0	$10,094	$2	$1,979	$8,644
Sum	**1,123**	**$26,679**	**$95**	**$6,349**	**$23,376**
Scenario: $30 US/bbl					
	698.3	$19,902	$141	$5,671	$18,049
	425.0	$12,113	$33	$2,758	$10,663
Sum	**1,123**	**$32,015**	**$174**	**$8,429**	**$28,712**
Scenario: $35 US/bbl					
	698.3	$23,218	$189	$6,977	$21,366
	425.0	$14,131	$63	$3,550	$12,682
Sum	**1,123**	**$37,349**	**$252**	**$10,527**	**$34,048**
Scenario: $40 US/bbl					
	698.3	$26,535	$237	$8,285	$24,683
	425.0	$16,150	$93	$4,342	$14,701
	254.7	$9,679	$0	$1,901	$8,481
Sum	**1,378**	**$52,364**	**$330**	**$14,528**	**$47,865**
Scenario: $45 US/bbl					
	698.3	$29,852	$285	$9,593	$28,000
	425.0	$18,169	$122	$5,139	$16,719
	254.7	$10,888	$18	$2,371	$9,690
	237.1	$10,136	$7	$2,086	$8,964
Sum	**1,615**	**$69,045**	**$432**	**$19,189**	**$63,373**
Scenario: $50 US/bbl					
	698.3	$33,169	$333	$10,900	$31,317
	425.0	$20,188	$151	$5,937	$18,738
	254.7	$12,098	$36	$2,845	$10,900
	237.1	$11,262	$24	$2,527	$10,090
Sum	**1,615**	**$76,717**	**$544**	**$22,209**	**$71,045**
Scenario: $55 US/bbl					
	698.3	$36,486	$381	$12,208	$34,634
	425.0	$22,206	$180	$6,734	$20,757
	254.7	$13,308	$54	$3,320	$12,110
	237.1	$12,388	$41	$2,969	$11,217
Sum	**1,615**	**$84,388**	**$656**	**$25,582**	**$79,618**
Scenario: $60 US/bbl					
	698.3	$39,803	$429	$13,515	$37,950
	425.0	$24,225	$210	$7,531	$22,776
	254.7	$14,518	$72	$3,795	$13,320
	237.1	$13,515	$58	$3,412	$12,343

	Recoverable Reserves (Millions of bbls)	Undiscounted Total Revenue (Millions of $ US)	After Tax Discounted NCF @12% (Millions of $ US)	Undiscounted Provincial CIT & Royalty Revenue (Millions of $ US)	Undiscounted Provincial GDP (Millions of $ US)
	170.5	$9,719	$2	$1,963	$8,645
Sum	**1,786**	**$101,780**	**$771**	**$30,216**	**$95,034**
Scenario: $65 US/bbl					
	698.3	$43,120	$477	$14,823	$41,267
	425.0	$26,244	$239	$8,327	$24,794
	254.7	$15,728	$90	$4,270	$14,530
	237.1	$14,641	$74	$3,854	$13,469
	170.5	$10,528	$14	$2,278	$9,455
Sum	**1,786**	**$110,261**	**$894**	**$33,552**	**$103,515**

Figure 9: Value of Recoverable Oil and Size of Reserves in the Queen Charlotte Basin by Price Assuming a 34% Recovery Factor and a Semi-Submersible Production Technology

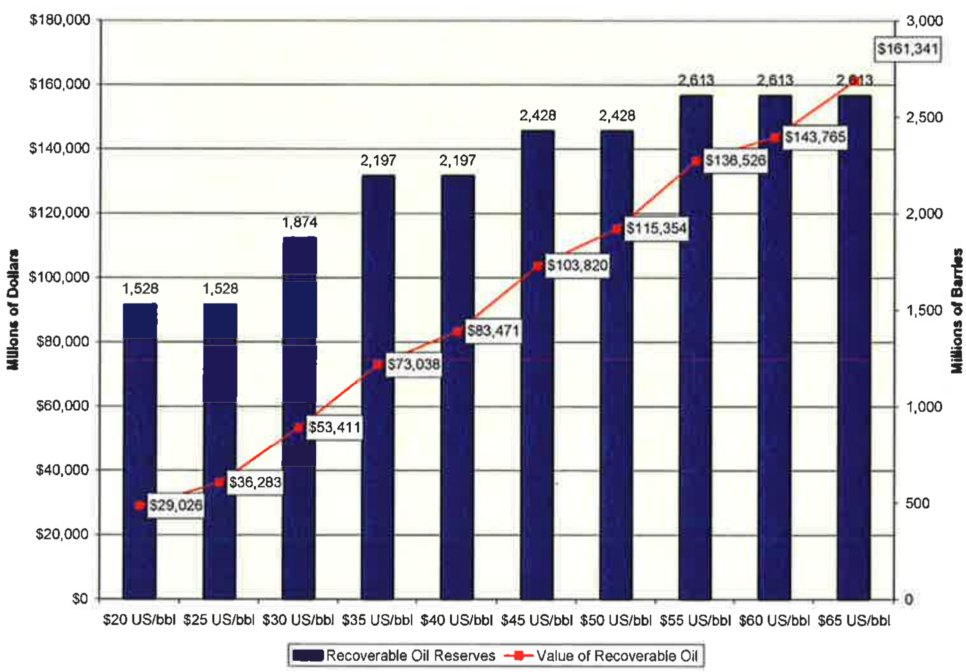
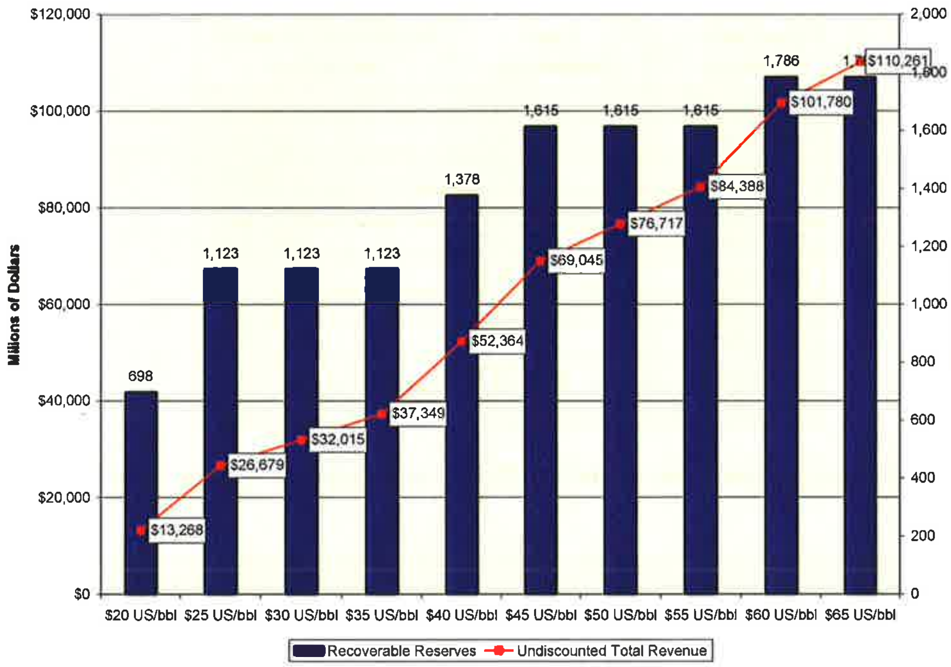


Figure 10: Value of Recoverable Oil and Size of Reserves in the Queen Charlotte Basin by Price Assuming a 25% Recovery Factor and a Semi-Submersible Production Technology



3.2.b The Economic Value of Recoverable Gas

Table 9 and Figure 11 present the results of the analysis of the minimum size field that is economic to develop under various prices for both the Sable technology and the small-scale tie-back technology. At low prices, for example $2 US/MCF, a field of at least 4.3 tcf of recoverable gas would be required for it to be economic to develop using Sable technology. As prices increase, the minimum-sized field again decreases. For instance, with natural gas prices in the $6 US/MCF, fields with 1.43 tcf become economic to exploit. If current prices[16] persist, it would commercially viable to exploit fields as small as 1.23 tcf employing the Sable technology.

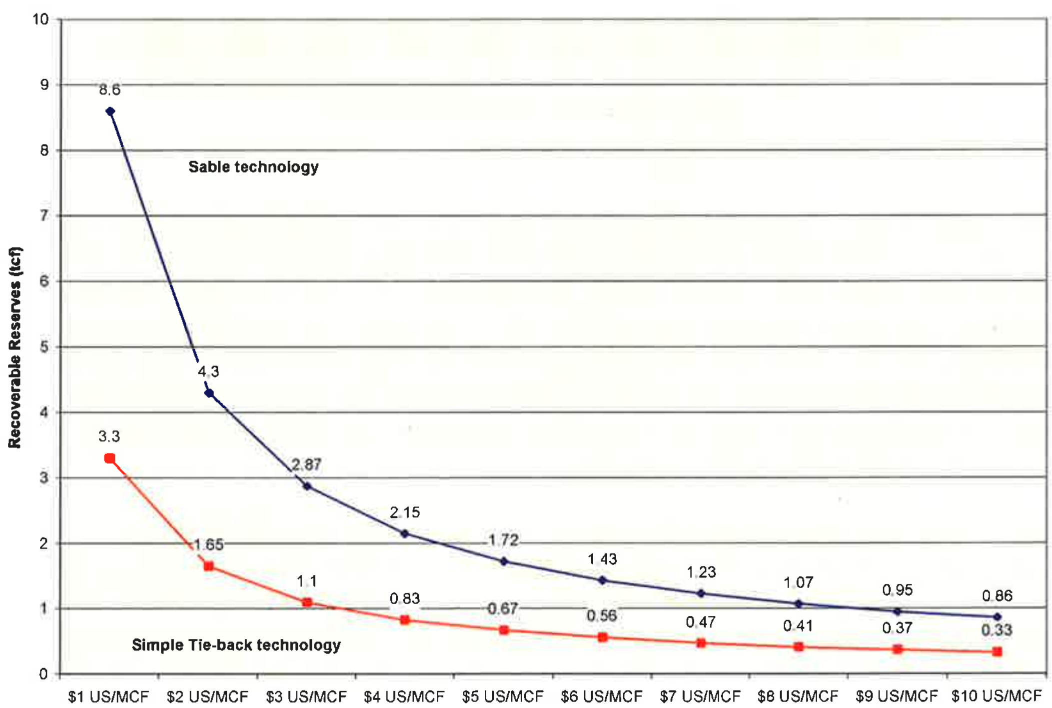
Because there is no way of knowing exactly from where within the QCB the gas resources will be exploited, Table 9 also indicates the minimum size field that can be economic to exploit if the cost and technology assumptions utilized in the Royal Roads study are valid. Clearly, much smaller fields become profitable under these assumptions. For example, fields as small as 0.6 tcf of recoverable gas become profitable to develop at natural gas prices in the range of $6 US/MCF.

[16] According to the US Energy Information Administration, http://tonto.eia.doe.gov/oog/info/ngw/ngupdate.asp, the spot price for natural gas at Henry Hub on April 12, 2006 was $6.79 US/MMBTU, which using an average heat conversion of 1,207 Btu per cubic foot corresponds to $6.97 US/MCF.

Table 9: Minimum Size of Gas Field Required in the QCB to Generate an After-tax Rate of Return of 12% for Different Gas Prices under Different Technologies (Trillions of ft^3 of Recoverable Natural Gas)

Gas Price Scenarios	Sable Technology	Small-Scale Tie-Back Technology
$1 US/MCF	8.60 TCF	3.30 TCF
$2 US/MCF	4.30 TCF	1.65 TCF
$3 US/MCF	2.87 TCF	1.10 TCF
$4 US/MCF	2.15 TCF	0.83 TCF
$5 US/MCF	1.72 TCF	0.67 TCF
$6 US/MCF	1.43 TCF	0.56 TCF
$7 US/MCF	1.23 TCF	0.47 TCF
$8 US/MCF	1.07 TCF	0.41 TCF
$9 US/MCF	0.95 TCF	0.37 TCF
$10 US/MCF	0.86 TCF	0.33 TCF

Figure 11: Minimum-Sized Gas Field Profitable to Exploit in Queen Charlotte Basin



The estimates of the value of the recoverable gas resources in the QCB with the Sable technology are presented in Tables 10 and 11 and Figures 13 and 14. The results for the small-scale tie-back technology are provided in Appendix Table A14 for comparison.

For higher prices, the value of economically recoverable gas increases because more fields are profitable to develop and each cubic foot of natural gas is worth more. For the 75% recovery factor, the value of gas ranges from $8 billion US at $2 US/MCF to nearly $113 billion US at $10US/MCF. Given that long-term gas prices are expected to range in the $6 US/MCF to $7 US/MCF range, it might be best to focus on this price scenario.[17] With $6 US/MCF, 9.3 tcf of natural gas, with a value of over $50 billion US, could be commercially exploited from the QCB. If it turns out that the ultimate recovery of oil from the QCB is closer to 60% than 75%, then the value of recoverable gas at $6 US/MCF and using Sable technology is $33 billion US associated with 6.1 tcf of gas.

Table 10 also reports information on the amount of provincial corporation income taxes and royalties that are estimated for each scenario. Again, higher prices result in more revenue flowing to the BC treasury. For example, the Government of British Columbia can expect to receive $2 billion US at $3US/MCF, which increases to $25 billion US at $10 US/MCF. The mid-range estimate ($6 US/MCF) yields $11 billion US in provincial corporation income taxes and royalties to the treasury.

In addition, provincial GDP[18] associated with developing the potential gas fields in the QCB increases as prices rise. Specifically, the impact on provincial GDP range from nothing (below $2 US/MCF and 60% or 75% recovery) to $107.8 billion US ($10 US/MCF and 75% recovery. At $6 US/MCF, the estimates of provincial GDP are $31.0 billion US and $47.5 billion US for 60% and 75% recovery assumptions, respectively.

Likewise, profits that accrue to the developers of the gas deposits also increase at higher natural gas prices. Natural gas profits, for instance, range from $22 million US at $3 US/MCF to $0.5 billion US at $10 US/MCF.

Finally, as indicated in Table A14, if the small-scale tie-back technology could be successfully utilized in the QCB, then the recoverable gas at $6 US/MCF increased to 11.3 tcf under a 60% recovery factor and 14.7 tcf under a 75% recovery factor. The corresponding economic values are $61 billion US and $79 billion US.

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[17] GLJ Petroleum Consultants, in the their April 1, 2006 forecast available at http://www.gljpc.com/pdfs/pricing.pdf, forecast that the real spot price of at the Alberta plant gate after 2010 is estimated to fall in the $6 US/mmbtu to $7 US/mmbtu, which they also inflate at 2% per annum to derive a nominal estimate.

[18] Provincial GDP is estimated as the value of output less the import content of the inputs that were used to produce it on an annual basis. Based upon the experience in Newfoundland and Labrador (See Locke et al (2004, p.ii)), it is assumed that 50% of the operating expenditures will come from sources outside of British Columbia.

Table 10: Value of Recoverable Gas Resource in the QCB for Various Prices and Assuming a 60% Recovery Factor for Gas and a Sable Production Technology

	Recoverable Reserves (TCF)	Undiscounted Total Revenue (Millions of $ US)	After Tax Discounted NCF @12% (Millions of $ US)	Undiscounted Provincial CIT & Royalty Revenue (Millions of $ US)	Undiscounted Provincial GDP (Millions of $ US)
Scenario: $1 US/MCF					
Sum	**0**	**$0**	**$0**	**$0**	**$0**
Scenario: $2 US/MCF					
Sum	**0**	**$0**	**$0**	**$0**	**$0**
Scenario: $3 US/MCF					
	3.61	$9,747	$22	$2,224	$8,897
Sum	**3.61**	**$9,747**	**$22**	**$2,224**	**$8,897**
Scenario: $4 US/MCF					
	3.61	$12,996	$55	$3,761	$12,146
	2.45	$8,820	$12	$1,728	$7,970
Sum	**6.1**	**$21,816**	**$67**	**$5,489**	**$20,116**
Scenario: $5 US/MCF					
	3.61	$16,245	$90	$5,153	$15,395
	2.45	$11,025	$36	$2,805	$10,175
Sum	**6.1**	**$27,270**	**$126**	**$7,958**	**$25,570**
Scenario: $6 US/MCF					
	3.61	$19,494	$121	$6,692	$18,644
	2.45	$13,230	$58	$3,845	$12,380
Sum	**6.1**	**$32,724**	**$179**	**$10,537**	**$31,024**
Scenario: $7 US/MCF					
	3.61	$22,743	$154	$8,116	$21,893
	2.45	$15,435	$80	$4,849	$14,585
	1.34	$8,442	$9	$1,500	$7,592
Sum	**7.41**	**$46,620**	**$243**	**$14,465**	**$44,070**
Scenario: $8 US/MCF					
	3.61	$25,992	$184	$9,644	$25,142
	2.45	$17,640	$103	$5,838	$16,790
	1.34	$9,648	$20	$2,194	$8,798
Sum	**7.41**	**$53,280**	**$307**	**$17,676**	**$50,773**
Scenario: $9 US/MCF					
	3.61	$29,241	$219	$10,991	$28,391
	2.45	$19,845	$122	$6,944	$18,995
	1.34	$10,854	$35	$2,668	$10,004
	1.01	$8,181	$5	$1,385	$7,331
Sum	**8.42**	**$68,121**	**$381**	**$21,988**	**$64,721**
Scenario: $10 US/MCF					
	3.61	$32,490	$248	$12,530	$31,640
	2.45	$22,050	$146	$7,836	$21,200
	1.34	$12,060	$48	$3,239	$11,210
	1.01	$9,090	$15	$1,888	$8,240
Sum	**8.42**	**$75,690**	**$457**	**$25,493**	**$72,290**

Table 11: Value of Recoverable Gas Resource in the QCB for Various Prices and Assuming a 75% Recovery Factor for Gas and a Sable Production Technology

	Recoverable Reserves (TCF)	Undiscounted Total Revenue (Millions of $ US)	After Tax Discounted NCF @12% (Millions of $ US)	Undiscounted Provincial CIT & Royalty Revenue (Millions of $ US)	Undiscounted Provincial GDP (Millions of $ US)
Scenario: $1 US/MCF					
Sum	**0**	**$0**	**$0**	**$0**	**$0**
Scenario: $2 US/MCF					
	4.52	$8,136	$4	$1,373	$7,286
Sum	**4.52**	**$8,136**	**$4**	**$1,373**	**$7,286**
Scenario: $3 US/MCF					
	4.52	$12,204	$49	$3,287	$11,354
	3.06	$8,262	$6	$1,453	$7,412
Sum	**7.58**	**$20,466**	**$55**	**$4,740**	**$18,766**
Scenario: $4 US/MCF					
	4.52	$16,272	$90	$5,164	$15,422
	3.06	$11,016	$35	$2,802	$10,166
Sum	**7.58**	**$27,288**	**$125**	**$7,966**	**$25,588**
Scenario: $5 US/MCF					
	4.52	$20,340	$127	$7,144	$19,490
	3.06	$13,770	$65	$4,037	$12,920
Sum	**7.58**	**$34,110**	**$192**	**$11,181**	**$32,410**
Scenario: $6 US/MCF					
	4.52	$24,408	$173	$8,789	$23,558
	3.06	$16,524	$90	$5,406	$15,674
	1.68	$9,072	$15	$1,883	$8,222
Sum	**9.26**	**$50,004**	**$278**	**$16,078**	**$47,454**
Scenario: $7 US/MCF					
	4.52	$28,476	$211	$10,674	$27,626
	3.06	$19,278	$118	$6,607	$18,428
	1.68	$10,584	$31	$2,582	$9,734
	1.26	$7,938	$3	$1,233	$7,088
Sum	**10.52**	**$66,276**	**$363**	**$21,096**	**$67,876**
Scenario: $8 US/MCF					
	4.52	$32,544	$249	$12,553	$31,694
	3.06	$22,032	$146	$7,828	$21,246
	1.68	$12,096	$48	$3,251	$11,246
	1.26	$9,072	$15	$1,883	$8,222
Sum	**10.52**	**$75,744**	**$458**	**$25,515**	**$72,408**
Scenario: $9 US/MCF					
	4.52	$36,612	$292	$14,266	$35,762
	3.06	$24,786	$176	$8,974	$23,936
	1.68	$13,608	$63	$3,980	$12,758
	1.26	$10,206	$28	$2,365	$9,356
	1.02	$8,262	$6	$1,453	$7,412
	1.00	$8,100	$4	$1,364	$7,250
Sum	**12.54**	**$101,574**	**$569**	**$32,402**	**$96,384**
Scenario: $10 US/MCF					

	Recoverable Reserves (TCF)	Undiscounted Total Revenue (Millions of $ US)	After Tax Discounted NCF @12% (Millions of $ US)	Undiscounted Provincial CIT & Royalty Revenue (Millions of $ US)	Undiscounted Provincial GDP (Millions of $ US)
	4.52	$40,680	$327	$16,224	$39,830
	3.06	$27,540	$201	$10,286	$26,690
	1.68	$15,120	$79	$4,641	$14,270
	1.26	$11,340	$38	$2,997	$10,490
	1.02	$9,180	$16	$1,914	$8,330
	1.00	$9,000	$14	$1,794	$8,150
Sum	**12.54**	**$112,860**	**$675**	**$37,856**	**$107,760**

Figure 12: Value of Recoverable Gas and Size of Reserves in the Queen Charlotte Basin by Price Assuming a 60% Recovery Factor and a Sable Production Technology

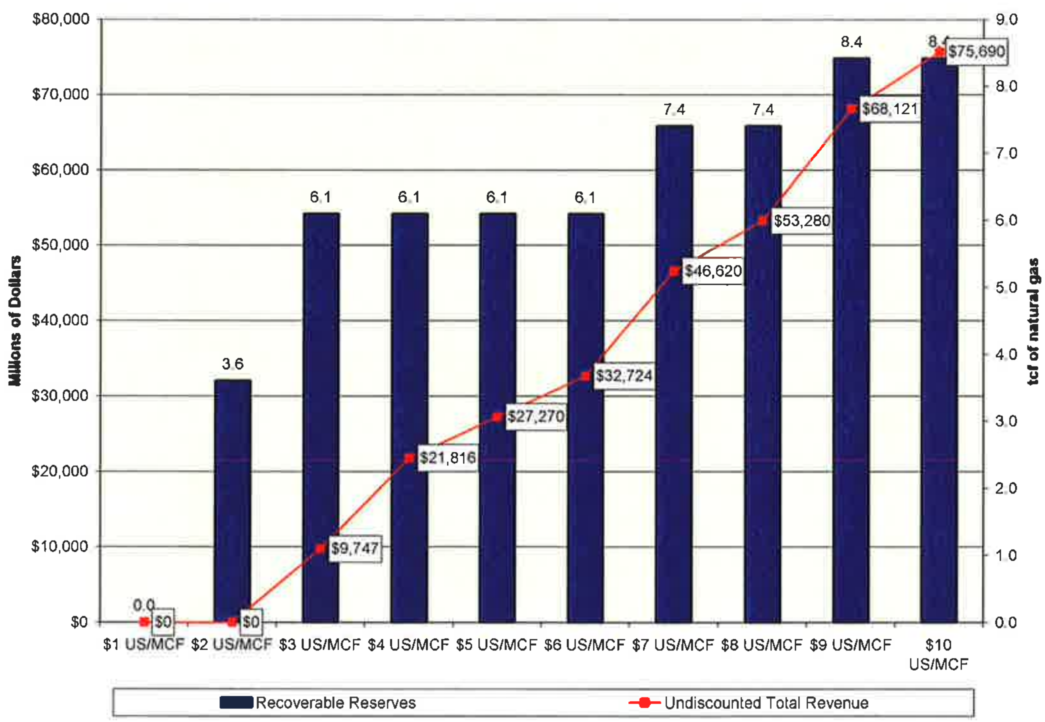
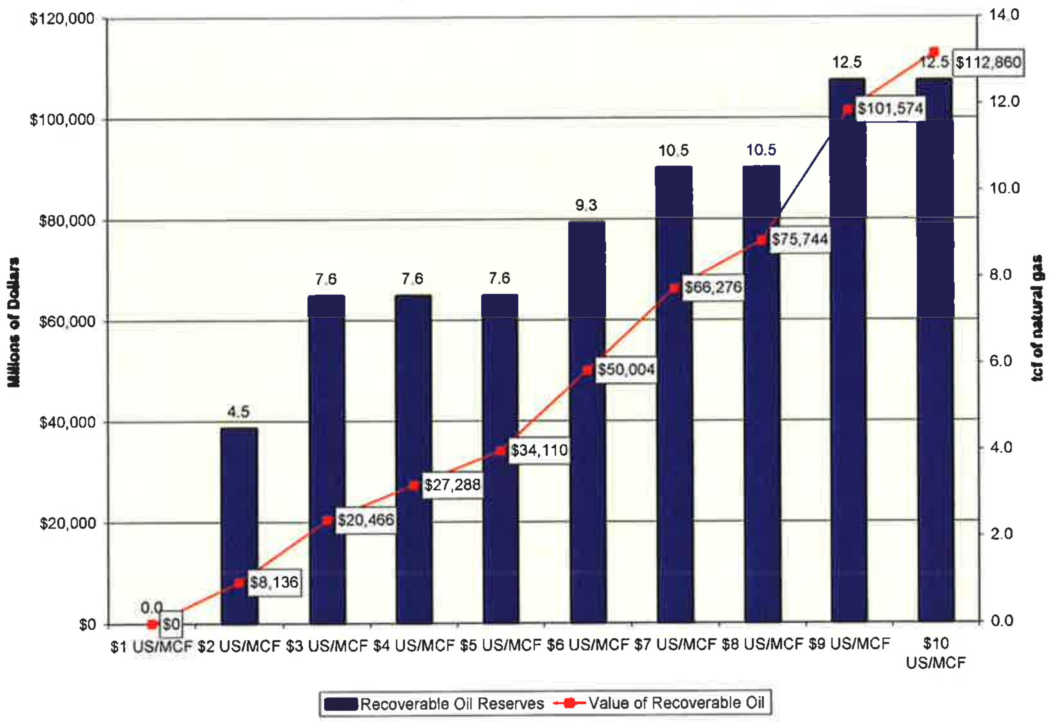


Figure 13: Value of Recoverable Gas and Size of Reserves in the Queen Charlotte Basin by Price Assuming a 75% Recovery Factor and a Sable Production Technology



Section 4 Summary and Conclusion

This section of the report summarizes the major findings and conclusions of the study.

4.1 Economic Value

Based on the analysis used above, the value of economically recoverable oil in the QCB, assuming a 34% recovery factor, is between $29 billion US or $34 billion Cdn at a price of $20 US/bbl and $161 billion US or $189 billion Cdn at a price of $65 US/bbl. A mid-range estimate is $104 billion US or $122 billion Cdn at $45 US/bbl oil price. This corresponds to a range of potentially recoverable oil between 1.5 billion barrels to 2.8 billion, with 2.4 billion being economically recoverable with $45 US/bbl. If only 25% of oil resources are recoverable, then the value of oil resources ranges from $13 billion US or $15 billion Cdn at a price of $20 US/bbl to $110 billion US or $129 billion Cdn at a price of $65 US/bbl.

The estimated values of economically recoverable natural gas, assuming a 60% recovery factor, ranges from zero at low prices ($1 US/MCF) to $76 billion US or $89 billion at high prices ($10 US/MCF). The mid-range range estimate, assuming $6 US/MCF, is $33 billion US or $39 billion Cdn, which represent 6.1 tcf of recoverable natural gas. If the recovery factor is 75%, then the estimated value of natural gas also increases; for example, the mid-range estimate increases to $50 billion US or $59 billion Cdn.

At this point, it is interesting to compare this estimate to other estimates. This information is presented in Table 12.

Table 12: Comparison with Other Estimates Values for oil and Gas in the QCB

Source	Product	Assumed Price[1]	Recoverable Reserves	Value	Adjusted Value[2]
Royal Society (2004, p.xii)	Oil	$30-$40 US/bbl	1.3 billion barrels	$ 50 B Cdn	$ 42 B Cdn
	Gas	$6 - $7 US/MCF	9.8 tcf	$60 B Cdn	$51 B Cdn
Our comparable estimates	Oil	$35 US/bbl	1.1 billion barrels	$37 B US	$44 B Cdn
	Gas	$6 US/MCF	9.3 tcf	$50 B US	$59 B Cdn
Johnson Hildebrand (2001, p.3)	Oil	$30 US/bbl		$55 B US	$65 B Cdn
	Gas	$5 US/MCF		$40 B US	$47 B Cdn
Our comparable estimates	Oil	$30 US/bbl	1.1 billion barrels	$32 B US	$38 B Cdn
	Gas	$6 US/MCF	9.3 tcf	$50 B US	$59 B Cdn

1. *The prices for WTI that prevailed at the time of the Royal Society estimates were $31.07 US/bbl in 2003 and $41.38 US/bbl in 2004 for WTI, while the Alberta Plant Gate spot price of natural gas was$6.49 US/mmbtu in 2003 and $6.70 US/mmbtu in 2004. The corresponding prices that prevailed in 2000 for the Johnson and Hildebrand estimates were $30.22 US/bbl and $5.67 US/mmbtu. This information was taken from GLJ Petroleum Consultants April 1, 2006 forecast (http://www.gljpc.com/)*

2. *Adjusted value takes into account that the exchange rates in 2006 are different than those in existence at the times the other estimates were calculated. The exchange used in our calculations was $0.85 US/Cdn. The corresponding exchanges in effect for the Royal Society and Johnson and Hildebrand estimates were $0.72 US/Cdn and $0.673US/Cdn, respectively.*

As Table 12 illustrates, when comparable prices are utilized, the estimates for the value of oil and gas calculated for the QCB are similar to those derived by the Royal Society (2004) - $42 billion Cdn. versus $44 billion Cdn. for oil and $51 billion Cdn. versus $59 billion Cdn. for natural gas. However, our estimates are less close to those derived by Johnson and Hildebrand (2001) - $65 billion Cdn. versus $38 billion for oil and $47 billion Cdn. versus $59 billion for natural gas.

4.2 Strategic Value

One of the study's objectives was to provide commentary on the strategic value of the resources from a national, regional and local perspective.

4.2.1 National, Regional and Local Significance

Nationally, the potential resources of the QCB are important for a number of reasons.

The primary source of strategic value of BC's offshore oil and gas resources is that it represents another source of conventional oil that will reduce Canada's reliance on the Western Canada Sedimentary Basin (WCSB) and Eastern Canada's offshore as the main sources of conventional crude. From a global perspective, the addition of reserves in stable countries such as Canada is very important because the world's demand for oil continues to grow while supplies of conventional oil are not keeping pace. For example, as Table 13 below illustrates, of Canada's 4.4 billion m^3 of undiscovered recoverable resources, over one-third or 1.5 billion are expected to come from frontier basins, including the QCB. From a national energy security perspective, it is more important than ever to ensure the orderly development of Canada's frontier oil and gas resources.

Canada ranks second in the world in recoverable oil and bitumen resources. The vast majority of Canada's resources are contained within the Alberta oil sands deposits, which account for over 84% of Canada's estimated 58 billion m^3 of recoverable oil resources. Conventional oil resources are declining as the WCSB has reached maturity and production continues offshore Newfoundland and Labrador. Table 7 below lists Canada's crude oil and bitumen resources at the end of 2001.

Table 13: Crude Oil and Bitumen Resources at Year End 2001
(million cubic metres)

	Discovered Recoverable Resources						
Source	**Cumulative Production**	**Remaining Established Reserves**	**Future Improved Recovery**	**Total**	**Undiscovered Recoverable Resources**	**Ultimate Recoverable Resources**	**Original Oil in Place**
Light Crude							
BC	98	26	18	**142**	42	184	512
AB	2,033	206	267	**2,506**	501	3,007	9,199
SK	200	44	121	**365**	22	387	1,437
MB	34	4	2	**40**	6	46	235
ON	12	2	0	**14**	0	14	62
Frontier Crude							
NS Offshore	7	0	3	**10**	83	93	493
NL Offshore	27	178	80	**285**	464	749	3,365
Mainland NWT & YK	33	10	2	**45**	50	95	315
Mackenzie Delta & Beaufort Sea	0	0	161	**161**	905	1,066	3,610
Arctic Islands	0	0	65	**65**	686	751	2,785
Other Frontier[1]	0	0	0	**0**	1,500	1,500	5,800
Total Frontier	**67**	**188**	**311**	**566**	**3,688**	**4,254**	**16,368**
Heavy Oil							
AB	272	72	138	**482**	33	515	2,873
SK	398	149	235	**782**	94	876	5,054
Total Heavy Oil	**670**	**221**	**373**	**1,264**	**127**	**1,391**	**7,927**
Total Conventional	**3,114**	**691**	**1,092**	**4,897**	**4,386**	**9,283**	**35,740**
Oil Sands							
Mining	395	5,195	4,410	**10,000**	0	10,000	24,100
In-situ	165	22,575	16,260	**39,000**	0	39,000	375,900
Total Oil Sands	**560**	**27,770**	**20,670**	**49,000**	**0**	**49,000**	**400,000**

1 Other Frontier includes QCB
Source: National Energy Board, "Canada's Energy Future: Scenarios for Supply and Demand to 2025".

From a local and regional perspective, exploiting these QCB resources will provide a source of diversification for the BC economy and provide significant resource rents to the provincial treasury. It will provide BC workers and businesses with opportunities to create work and business in the exploration and delineation phases, through to the development and production phases. With technological advances occurring throughout the industry, particularly in the areas of subsea production and advanced drilling techniques, the development of an industry in BC will allow local workers and businesses to develop expertise in new technologies and apply them to the unique BC offshore environment, with the possibility of also developing export potential.

The development of these resources is also important from a national Aboriginal perspective. The development of large resource projects often serves as the impetus to resolving long-standing land claims and other issues related to Aboriginal Canadians. By moving forward with the development of BC's offshore hydrocarbon resources, the resolution of land claims issues may be expedited and BC's Aboriginals may then have access to significant resource rents.

4.3 Conclusion

There is significant potential economic value that could be extracted from the orderly development of the hydrocarbon resources in the Queen Charlotte Basin. The analysis presented in this report demonstrates that at mid-price ranges ($45 US/bbl for oil and $6/MCF for natural gas), the economic value of the oil and gas resources found in the Queen Charlotte basin range between $80 and $120 billion Cdn for oil and between $40 and $60 billion Cdn. for gas. These impacts would provide positive economic impacts to all stakeholders, namely the Government of British Columbia, the local labour force, the business community, the Government of Canada and BC's Aboriginals. In fact, the associated estimates for the corporation income tax revenue and royalties that should flow to the provincial treasury are: $20 to $40 billion Cdn for oil and $10 to $20 billion Cdn for natural gas. As well, economic activity, GDP, will increase. The corresponding increases in GDP are estimated at: $70 to $110 billion Cdn for oil and $40 to $60 billion Cdn. for gas.

Should this area become part of an established MPA, the potential economic value would be placed in jeopardy. As policy makers within the various federal government departments weigh the costs and benefits of establishing an MPA in the Queen Charlotte Basin, the economic impacts as identified in this report should be considered and weighed against any qualitative benefits that may be generated through the establishment of the MPA in the Queen Charlotte Basin.

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Appendices

Appendix A – Data Appendix

Table A-1: Distribution of Oil in Place by Size of Pool – Queen Charlotte Basin: Miocene Oil Play

Pool #	Mean Pool Size (Million M^3)	Median Pool Size (Million M^3)	Mean Pool Size (Millions of Barrels)	Median Pool Size (Millions of Barrels)
1	270.3	164.7	1,700.1	1,036.1
2	108.4	84.2	681.9	529.3
3	67.6	56.3	425.2	353.9
4	48.4	41.7	304.3	262.0
5	37.1	32.6	233.1	204.9
6	29.6	26.4	186.1	165.9
7	24.3	21.9	152.8	137.6
8	20.4	18.5	128.1	116.2
9	17.4	15.8	109.2	99.5
10	15.0	13.7	94.3	86.3
11	13.1	12.0	82.4	75.6
12	11.6	10.6	72.7	66.8
13	10.3	9.5	64.6	59.5
14	9.2	8.5	57.9	53.2
15	8.3	7.6	52.0	47.8
16	7.5	6.9	47.0	43.2
17	6.8	6.2	42.6	39.1
18	6.2	5.6	38.7	35.4
19	5.6	5.1	35.3	32.2
20	5.1	4.7	32.2	29.3
21	4.7	4.2	29.4	26.7
22	4.3	3.9	26.9	24.3
23	3.9	3.5	24.6	22.1
24	3.6	3.2	22.5	20.2
25	3.3	2.9	20.6	18.4
26	3.0	2.7	18.9	16.8
27	2.8	2.4	17.3	15.3
28	2.5	2.2	15.9	13.9
Combined	**667.7**	**574.0**	**4,199.6**	**3,610.4**

Source: Distribution by pool size obtained directly from Peter Hannigan. Median expected play potential taken directly from Hannigan et al. (2001, Table 4). Mean expected play potential derived as the product of 27.98 pools (expected number of fields from log-normal distribution for the play provided by Hannigan) and 23.863 million of cubic meters (the mean of the log-normal distribution for the play). The conversion factor utilized is 0.158987 barrels per cubic metre.

Table A2: Distribution of Oil in Place by Size of Pool – Queen Charlotte Basin: Cretaceous Oil Play

Pool #	Mean Pool Size (Million M^3)	Median Pool Size (Million M^3)	Mean Pool Size (Millions of Barrels)	Median Pool Size (Millions of Barrels)
1	162.0	96.1	1,018.8	604.3
2	64.2	49.5	404.1	311.3
3	40.6	33.5	255.5	210.8
4	29.6	25.2	186.2	158.2
5	23.1	20.0	145.5	125.5
6	18.8	16.4	118.5	103.1
7	15.8	13.8	99.3	86.7
8	13.5	11.8	84.9	74.3
9	11.7	10.2	73.6	64.4
10	10.3	9.0	64.6	56.5
11	9.1	7.9	57.3	49.9
12	8.1	7.1	51.1	44.4
13	7.3	6.3	46.0	39.8
14	6.6	5.7	41.5	35.8
15	6.0	5.1	37.7	32.3
16	5.5	4.7	34.4	29.3
17	5.0	4.2	31.4	26.6
18	4.6	3.9	28.9	24.3
19	4.2	3.5	26.5	22.2
20	3.9	3.2	24.5	20.4
21	3.6	3.0	22.6	18.7
22	3.3	2.7	21.0	17.2
23	3.1	2.5	19.4	15.8
24	2.9	2.3	18.1	14.6
25	2.7	2.1	16.8	13.5
26	2.5	2.0	15.7	12.5
27	2.3	1.8	14.7	11.5
28	2.2	1.7	13.7	10.7
29	2.0	1.6	12.9	9.9
30	1.9	1.5	12.1	9.3
31	1.8	1.4	11.4	8.6
32	1.7	1.3	10.7	8.1
33	1.6	1.2	10.1	7.6
34	1.5	1.1	9.6	7.1
35	1.4	1.1	9.1	6.8
36	1.4	1.0	8.7	6.4
37	1.3	1.0	8.3	6.1
38	1.3	0.9	7.9	5.8
39	1.2	0.9	7.6	5.6
40	1.2	0.9	7.3	5.4
41	1.1	0.8	7.0	5.2
42	1.1	0.8	6.7	5.1
43	1.0	0.8	6.5	4.9

Pool #	Mean Pool Size (Million M^3)	Median Pool Size (Million M^3)	Mean Pool Size (Millions of Barrels)	Median Pool Size (Millions of Barrels)
44	1.0	0.8	6.2	4.8
45	1.0	0.7	6.0	4.7
46	0.9	0.7	5.8	4.6
47	0.9	0.7	5.7	4.5
48	0.9	0.7	5.5	4.4
49	0.8	0.7	5.3	4.3
50	0.8	0.7	5.2	4.2
51	0.8	0.7	5.0	4.2
52	0.8	0.6	4.9	4.1
53	0.8	0.6	4.7	4.0
54	0.7	0.6	4.6	3.9
55	0.7	0.6	4.5	3.8
56	0.7	0.6	4.3	3.7
57	0.7	0.6	4.2	3.6
58	0.6	0.6	4.1	3.5
59	0.6	0.5	3.9	3.4
60	0.6	0.5	3.8	3.3
61	0.6	0.5	3.7	3.2
62	0.6	0.5	3.6	3.1
Combined	479.9	392.0	3,018.7	2,465.6

Source: Distribution by pool size obtained directly from Peter Hannigan. Median expected play potential taken directly from Hannigan et al. (2001, Table 4). Mean expected play potential derived as the product of 61.89 pools (expected number of fields from log-normal distribution for the play provided by Hannigan) and 7.7546 million of cubic meters (the mean of the log-normal distribution for the play). The conversion factor utilized is 0.158987 barrels per cubic metre.

Table A3: Distribution of Oil in Place by Size of Pool – Queen Charlotte Basin: Pliocene Oil Play

Pool #	Mean Pool Size (Million M^3)	Median Pool Size (Million M^3)	Mean Pool Size (Millions of Barrels)	Median Pool Size (Millions of Barrels)
1	444.1	233.1	2,793.2	1,466.0
2	150.8	106.1	948.6	667.3
3	86.2	65.7	541.9	413.4
4	58.1	46.0	365.3	289.1
5	42.6	34.4	267.9	216.3
6	32.9	26.9	206.8	169.0
7	26.3	21.6	165.1	135.9
8	21.5	17.7	135.0	111.6
9	17.8	14.8	112.2	92.9
10	15.0	12.4	94.5	78.2
11	12.8	10.5	80.3	66.3
12	10.9	9.0	68.8	56.6
13	9.4	7.7	59.2	48.5
Combined	652.4	398.0	4,103.5	2,503.3

Source: Distribution by pool size obtained directly from Peter Hannigan. Median expected play potential was taken directly from Hannigan et al. (2001, Table 4). Mean expected play potential derived as the product of 13.03 pools (expected number of fields from log-normal distribution for the play provided by Hannigan) and 50.069 million of cubic meters (the mean of the log-normal distribution for the play). The conversion factor utilized is 0.158987 barrels per cubic metre.

Table A4: Distribution of Gas in Place by Size of Pool – Queen Charlotte Basin: Miocene Gas Play

Pool #	Mean Pool Size (Million M^3)	Median Pool Size (Million M^3)	Mean Pool Size (Billions of ft^3)	Median Pool Size (Billions of ft^3)
1	115,010.0	71,188.0	4,082.9	2,527.2
2	47,396.0	37,343.0	1,682.6	1,325.7
3	30,207.0	25,516.0	1,072.3	905.8
4	22,043.0	19,273.0	782.5	684.2
5	17,196.0	15,361.0	610.5	545.3
6	13,962.0	12,662.0	495.7	449.5
7	11,644.0	10,680.0	413.4	379.1
8	9,899.3	9,162.1	351.4	325.3
9	8,539.9	7,962.1	303.2	282.7
10	7,453.4	6,991.2	264.6	248.2
11	6,568.4	6,191.8	233.2	219.8
12	5,837.0	5,524.6	207.2	196.1
13	5,225.5	4,961.3	185.5	176.1
14	4,709.1	4,481.2	167.2	159.1
15	4,269.2	4,068.9	151.6	144.4
16	3,890.9	3,712.3	138.1	131.8
17	3,562.7	3,402.0	126.5	120.8
18	3,275.2	3,129.5	116.3	111.1
19	3,021.3	2,888.2	107.3	102.5
20	2,795.0	2,672.1	99.2	94.9
21	2,592.0	2,477.0	92.0	87.9
22	2,408.5	2,299.7	85.5	81.6
23	2,241.9	2,137.9	79.6	75.9
24	2,089.7	1,989.7	74.2	70.6
25	1,950.3	1,853.6	69.2	65.8
26	1,822.0	1,728.1	64.7	61.3
27	1,703.6	1,612.2	60.5	57.2
28	1,594.0	1,504.8	56.6	53.4
29	1,492.3	1,405.0	53.0	49.9
30	1,397.7	1,312.3	49.6	46.6
31	1,309.6	1,226.1	46.5	43.5
32	1,227.4	1,145.5	43.6	40.7
33	1,150.6	1,070.6	40.8	38.0
34	1,078.6	1,000.7	38.3	35.5
35	1,011.2	934.9	35.9	33.2
36	947.9	872.9	33.7	31.0
37	888.5	814.6	31.5	28.9
38	832.5	759.7	29.6	27.0
39	779.9	708.3	27.7	25.1
40	730.4	660.1	25.9	23.4
Combined	317,118.0	285,710.0	8,932,900.9	8,048,169.0

Source: Distribution by pool size obtained directly from Peter Hannigan. Median expected play potential was taken directly from Hannigan et al. (2001, Table 4). Mean expected play potential derived as the product of 39.97 pools (expected number of fields from log-normal distribution for the play provided by Hannigan) and 7,933.9 million of cubic meters (the mean of the log-normal distribution for the play). The conversion factor utilized is 0.0355 millions of cubic metres to billions of cubic feet.

Table A5: Distribution of Gas in Place by Size of Pool – Queen Charlotte Basin: Cretaceous Gas Play

Pool #	Mean Pool Size (Million M^3)	Median Pool Size (Million M^3)	Mean Pool Size (Billions of ft^3)	Median Pool Size (Billions of ft^3)
1	37,679.0	20,675.0	1,337.6	734.0
2	13,649.0	10,080.0	484.5	357.8
3	8,257.2	6,585.7	293.1	233.8
4	5,833.2	4,807.1	207.1	170.7
5	4,444.9	3,723.2	157.8	132.2
6	3,543.4	2,992.7	125.8	106.2
7	2,911.2	2,467.6	103.3	87.6
8	2,443.8	2,072.8	86.8	73.6
9	2,084.9	1,765.8	74.0	62.7
10	1,801.2	1,520.9	63.9	54.0
11	1,571.9	1,321.5	55.8	46.9
12	1,383.0	1,156.4	49.1	41.1
13	1,225.2	1,017.8	43.5	36.1
14	1,091.7	900.3	38.8	32.0
15	977.5	799.8	34.7	28.4
16	879.0	713.1	31.2	25.3
17	793.4	637.9	28.2	22.6
18	718.5	572.3	25.5	20.3
19	652.8	514.8	23.2	18.3
20	594.9	464.3	21.1	16.5
21	543.7	419.8	19.3	14.9
22	498.4	380.5	17.7	13.5
23	458.2	345.9	16.3	12.3
24	422.6	315.5	15.0	11.2
25	391.0	288.9	13.9	10.3
26	363.0	265.7	12.9	9.4
27	338.1	245.5	12.0	8.7
28	315.9	228.0	11.2	8.1
29	296.2	212.9	10.5	7.6
30	278.6	199.9	9.9	7.1
31	262.8	188.7	9.3	6.7
32	248.7	179.1	8.8	6.4
33	235.9	170.9	8.4	6.1
34	224.3	163.8	8.0	5.8
35	213.8	157.6	7.6	5.6
36	204.2	152.2	7.2	5.4
37	195.4	147.4	6.9	5.2
38	187.2	143.0	6.6	5.1
39	179.6	139.0	6.4	4.9
40	172.4	135.1	6.1	4.8
41	165.7	131.4	5.9	4.7
42	159.3	127.7	5.7	4.5
43	153.2	124.1	5.4	4.4

Pool #	Mean Pool Size (Million M^3)	Median Pool Size (Million M^3)	Mean Pool Size (Billions of ft^3)	Median Pool Size (Billions of ft^3)
44	147.3	120.4	5.2	4.3
45	141.7	116.6	5.0	4.1
46	136.1	112.8	4.8	4.0
47	130.8	108.9	4.6	3.9
48	125.5	104.9	4.5	3.7
49	120.4	100.9	4.3	3.6
50	115.3	97.0	4.1	3.4
Combined	94,331.4	75,435.0	2,657,222.6	2,124,929.6

Source: Distribution by pool size obtained directly from Peter Hannigan. Median expected play potential was taken directly from Hannigan et al. (2001, Table 4). Mean expected play potential derived as the product of 49.51 pools (expected number of fields from log-normal distribution for the play provided by Hannigan) and 1,905.3 million of cubic meters (the mean of the log-normal distribution for the play). The conversion factor utilized is 0.0355 millions of cubic metres to billions of cubic feet.

Table A6: Distribution of Gas in Place by Size of Pool – Queen Charlotte Basin: Pliocene Gas Play

Pool #	Mean Pool Size (Million M^3)	Median Pool Size (Million M^3)	Mean Pool Size (Billions of ft^3)	Median Pool Size (Billions of ft^3)
1	169,680.0	95,780.0	6,023.6	3,400.2
2	63,126.0	47,108.0	2,241.0	1,672.3
3	38,195.0	30,878.0	1,355.9	1,096.2
4	26,859.0	22,580.0	953.5	801.6
5	20,355.0	17,519.0	722.6	621.9
6	16,155.0	14,122.0	573.5	501.3
7	13,239.0	11,700.0	470.0	415.4
8	11,110.0	9,895.6	394.4	351.3
9	9,495.5	8,505.9	337.1	302.0
10	8,231.2	5,875.0	292.2	208.6
11	7,214.7	6,509.2	256.1	231.1
12	6,379.3	5,767.2	226.5	204.7
13	5,680.6	5,141.5	201.7	182.5
14	5,087.8	4,606.7	180.6	163.5
15	4,579.0	4,145.3	162.6	147.2
16	4,138.0	3,744.2	146.9	132.9
17	3,752.6	3,392.4	133.2	120.4
18	3,413.4	3,082.3	121.2	109.4
19	3,112.9	2,806.7	110.5	99.6
20	2,845.2	2,560.1	101.0	90.9
21	2,605.4	2,338.6	92.5	83.0
22	2,389.7	2,139.2	84.8	75.9
23	2,194.7	1,958.8	77.9	69.5
24	2,017.9	1,795.0	71.6	63.7
25	1,857.0	1,645.6	65.9	58.4
26	1,710.0	1,509.0	60.7	53.6
27	1,575.5	1,384.0	55.9	49.1
28	1,452.1	1,269.5	51.5	45.1
29	1,338.8	1,164.6	47.5	41.3
30	1,234.6	1,068.4	43.8	37.9
Combined	389,727.5	389,710.0	10,978,240.0	10,977,746.5

Source: Distribution by pool size obtained directly from Peter Hannigan. Median expected play potential was taken directly from Hannigan et al. (2001, Table 4). Mean expected play potential derived as the product of 30.16 pools (expected number of fields from log-normal distribution for the play provided by Hannigan) and 12,922 million of cubic meters (the mean of the log-normal distribution for the play) . The conversion factor utilized is 0.0355 millions of cubic metres to billions of cubic feet.

Table A7: Distribution of Expected Recoverable Reserves of Oil by Size of Pool and Recovery Factor – Queen Charlotte Basin: Miocene Oil Play

Pool #	Oil-in-Place Mean Pool Size (Million M^3)	Oil-in-Place Mean Pool Size (Millions of Barrels)	Recoverable Oil Reserves Assuming 25% Recovery Factor[1] Mean Pool Size (Millions of Barrels)	Recoverable Oil Reserves Assuming 34% Recovery Factor[1] Mean Pool Size (Millions of Barrels)
1	270.3	1,700.1	425.0	578.0
2	108.4	681.9	170.5	231.9
3	67.6	425.2	106.3	144.6
4	48.4	304.3	76.1	103.5
5	37.1	233.1	58.3	79.3
6	29.6	186.1	46.5	63.3
7	24.3	152.8	38.2	51.9
8	20.4	128.1	32.0	43.5
9	17.4	109.2	27.3	37.1
10	15.0	94.3	23.6	32.1
11	13.1	82.4	20.6	28.0
12	11.6	72.7	18.2	24.7
13	10.3	64.6	16.2	22.0
14	9.2	57.9	14.5	19.7
15	8.3	52.0	13.0	17.7
16	7.5	47.0	11.8	16.0
17	6.8	42.6	10.7	14.5
18	6.2	38.7	9.7	13.2
19	5.6	35.3	8.8	12.0
20	5.1	32.2	8.0	10.9
21	4.7	29.4	7.3	10.0
22	4.3	26.9	6.7	9.1
23	3.9	24.6	6.2	8.4
24	3.6	22.5	5.6	7.7
25	3.3	20.6	5.2	7.0
26	3.0	18.9	4.7	6.4
27	2.8	17.3	4.3	5.9
28	2.5	15.9	4.0	5.4
Combined	667.7	4,199.6	1,049.9	1,427.9

1. The 25% recovery factor was reported in the Royal Society of Canada report (2004, p.14) and was attributed to Peter Hannigan. The 34% recovery factor was suggested by Ron Smyth, Government of British Columbia.

Table A8: Distribution of Expected Recoverable Reserves of Oil by Size of Pool and Recovery Factor – Queen Charlotte Basin: Cretaceous Oil Play

Pool #	Oil-in-Place Mean Pool Size (Million M^3)	Oil-in-Place Mean Pool Size (Millions of Barrels)	Recoverable Oil Reserves Assuming 25% Recovery Factor[1] Mean Pool Size (Millions of Barrels)	Recoverable Oil Reserves Assuming 34% Recovery Factor[1] Mean Pool Size (Millions of Barrels)
1	162.0	1,018.8	254.7	346.4
2	64.2	404.1	101.0	137.4
3	40.6	255.5	63.9	86.9
4	29.6	186.2	46.5	63.3
5	23.1	145.5	36.4	49.5
6	18.8	118.5	29.6	40.3
7	15.8	99.3	24.8	33.8
8	13.5	84.9	21.2	28.9
9	11.7	73.6	18.4	25.0
10	10.3	64.6	16.2	22.0
11	9.1	57.3	14.3	19.5
12	8.1	51.1	12.8	17.4
13	7.3	46.0	11.5	15.6
14	6.6	41.5	10.4	14.1
15	6.0	37.7	9.4	12.8
16	5.5	34.4	8.6	11.7
17	5.0	31.4	7.9	10.7
18	4.6	28.9	7.2	9.8
19	4.2	26.5	6.6	9.0
20	3.9	24.5	6.1	8.3
21	3.6	22.6	5.7	7.7
22	3.3	21.0	5.2	7.1
23	3.1	19.4	4.9	6.6
24	2.9	18.1	4.5	6.1
25	2.7	16.8	4.2	5.7
26	2.5	15.7	3.9	5.3
27	2.3	14.7	3.7	5.0
28	2.2	13.7	3.4	4.7
29	2.0	12.9	3.2	4.4
30	1.9	12.1	3.0	4.1
31	1.8	11.4	2.8	3.9
32	1.7	10.7	2.7	3.6
33	1.6	10.1	2.5	3.4
34	1.5	9.6	2.4	3.3
35	1.4	9.1	2.3	3.1
36	1.4	8.7	2.2	2.9
37	1.3	8.3	2.1	2.8
38	1.3	7.9	2.0	2.7
39	1.2	7.6	1.9	2.6
40	1.2	7.3	1.8	2.5

Pool #	Oil-in-Place Mean Pool Size (Million M^3)	Oil-in-Place Mean Pool Size (Millions of Barrels)	Recoverable Oil Reserves Assuming 25% Recovery Factor[1] Mean Pool Size (Millions of Barrels)	Recoverable Oil Reserves Assuming 34% Recovery Factor[1] Mean Pool Size (Millions of Barrels)
41	1.1	7.0	1.7	2.4
42	1.1	6.7	1.7	2.3
43	1.0	6.5	1.6	2.2
44	1.0	6.2	1.6	2.1
45	1.0	6.0	1.5	2.1
46	0.9	5.8	1.5	2.0
47	0.9	5.7	1.4	1.9
48	0.9	5.5	1.4	1.9
49	0.8	5.3	1.3	1.8
50	0.8	5.2	1.3	1.8
51	0.8	5.0	1.3	1.7
52	0.8	4.9	1.2	1.7
53	0.8	4.7	1.2	1.6
54	0.7	4.6	1.1	1.6
55	0.7	4.5	1.1	1.5
56	0.7	4.3	1.1	1.5
57	0.7	4.2	1.0	1.4
58	0.6	4.1	1.0	1.4
59	0.6	3.9	1.0	1.3
60	0.6	3.8	1.0	1.3
61	0.6	3.7	0.9	1.3
62	0.6	3.6	0.9	1.2
Combined	479.9	3,018.7	754.7	1,026.4

1. The 25% recovery factor was reported in the Royal Society of Canada report (2004, p.14) and was attributed to Peter Hannigan. The 34% recovery factor was suggested by Ron Smyth, Government of British Columbia.

Table A9: Distribution of Expected Recoverable Reserves of Oil by Size of Pool and Recovery Factor – Queen Charlotte Basin: Pliocene Oil Play

Pool #	Oil-in-Place Mean Pool Size (Million M^3)	Oil-in-Place Mean Pool Size (Millions of Barrels)	Recoverable Oil Reserves Assuming 25% Recovery Factor[1] Mean Pool Size (Millions of Barrels)	Recoverable Oil Reserves Assuming 34% Recovery Factor[1] Mean Pool Size (Millions of Barrels)
1	444.1	2,793.2	698.3	949.7
2	150.8	948.6	237.1	322.5
3	86.2	541.9	135.5	184.3
4	58.1	365.3	91.3	124.2
5	42.6	267.9	67.0	91.1
6	32.9	206.8	51.7	70.3
7	26.3	165.1	41.3	56.1
8	21.5	135.0	33.7	45.9
9	17.8	112.2	28.1	38.2
10	15.0	94.5	23.6	32.1
11	12.8	80.3	20.1	27.3
12	10.9	68.8	17.2	23.4
13	9.4	59.2	14.8	20.1
Combined	652.4	4,103.5	1,025.9	1,395.2

1. The 25% recovery factor was reported in the Royal Society of Canada report (2004, p.14) and was attributed to Peter Hannigan. The 34% recovery factor was suggested by Ron Smyth, Government of British Columbia.

Table A10: Distribution of Expected Recoverable Reserves of Gas by Size of Pool and Recovery Factor – Queen Charlotte Basin: Miocene Gas Play

Pool #	Gas-in-Place Mean Pool Size (Million M^3)	Gas-in-Place Mean Pool Size (Billions of ft^3)	Recoverable Gas Reserves Assuming 60% Recovery Factor[1] Mean Pool Size (Billions of ft^3)	Recoverable Gas Reserves Assuming 75% Recovery Factor[1] Mean Pool Size (Billions of ft^3)
1	115,010.0	4,082.9	2,449.7	3,062.1
2	47,396.0	1,682.6	1,009.5	1,261.9
3	30,207.0	1,072.3	643.4	804.3
4	22,043.0	782.5	469.5	586.9
5	17,196.0	610.5	366.3	457.8
6	13,962.0	495.7	297.4	371.7
7	11,644.0	413.4	248.0	310.0
8	9,899.3	351.4	210.9	263.6
9	8,539.9	303.2	181.9	227.4
10	7,453.4	264.6	158.8	198.4
11	6,568.4	233.2	139.9	174.9
12	5,837.0	207.2	124.3	155.4
13	5,225.5	185.5	111.3	139.1
14	4,709.1	167.2	100.3	125.4
15	4,269.2	151.6	90.9	113.7
16	3,890.9	138.1	82.9	103.6
17	3,562.7	126.5	75.9	94.9
18	3,275.2	116.3	69.8	87.2
19	3,021.3	107.3	64.4	80.4
20	2,795.0	99.2	59.5	74.4
21	2,592.0	92.0	55.2	69.0
22	2,408.5	85.5	51.3	64.1
23	2,241.9	79.6	47.8	59.7
24	2,089.7	74.2	44.5	55.6
25	1,950.3	69.2	41.5	51.9
26	1,822.0	64.7	38.8	48.5
27	1,703.6	60.5	36.3	45.4
28	1,594.0	56.6	34.0	42.4
29	1,492.3	53.0	31.8	39.7
30	1,397.7	49.6	29.8	37.2
31	1,309.6	46.5	27.9	34.9
32	1,227.4	43.6	26.1	32.7
33	1,150.6	40.8	24.5	30.6
34	1,078.6	38.3	23.0	28.7
35	1,011.2	35.9	21.5	26.9
36	947.9	33.7	20.2	25.2
37	888.5	31.5	18.9	23.7
38	832.5	29.6	17.7	22.2
39	779.9	27.7	16.6	20.8
40	730.4	25.9	15.6	19.4
Combined	317,118.0	8,932,900.9	5,359,740.6	6,699,675.7

1. The 75% recovery factor was reported in the Royal Society of Canada report (2004, p.14) and was attributed to Peter Hannigan. The60% recovery factor was suggested by Ron Smyth, Government of British Columbia.

Table A11: Distribution of Expected Recoverable Reserves of Gas by Size of Pool and Recovery Factor – Queen Charlotte Basin: Cretaceous Gas Play

Pool #	Gas-in-Place Mean Pool Size (Million M^3)	Gas-in-Place Mean Pool Size (Billions of ft^3)	Recoverable Gas Reserves Assuming 60% Recovery Factor[1] Mean Pool Size (Billions of ft^3)	Recoverable Gas Reserves Assuming 75% Recovery Factor[1] Mean Pool Size (Billions of ft^3)
1	37,679.0	1,337.6	802.6	802.6
2	13,649.0	484.5	290.7	290.7
3	8,257.2	293.1	175.9	175.9
4	5,833.2	207.1	124.2	124.2
5	4,444.9	157.8	94.7	94.7
6	3,543.4	125.8	75.5	75.5
7	2,911.2	103.3	62.0	62.0
8	2,443.8	86.8	52.1	52.1
9	2,084.9	74.0	44.4	44.4
10	1,801.2	63.9	38.4	38.4
11	1,571.9	55.8	33.5	33.5
12	1,383.0	49.1	29.5	29.5
13	1,225.2	43.5	26.1	26.1
14	1,091.7	38.8	23.3	23.3
15	977.5	34.7	20.8	20.8
16	879.0	31.2	18.7	18.7
17	793.4	28.2	16.9	16.9
18	718.5	25.5	15.3	15.3
19	652.8	23.2	13.9	13.9
20	594.9	21.1	12.7	12.7
21	543.7	19.3	11.6	11.6
22	498.4	17.7	10.6	10.6
23	458.2	16.3	9.8	9.8
24	422.6	15.0	9.0	9.0
25	391.0	13.9	8.3	8.3
26	363.0	12.9	7.7	7.7
27	338.1	12.0	7.2	7.2
28	315.9	11.2	6.7	6.7
29	296.2	10.5	6.3	6.3
30	278.6	9.9	5.9	5.9
31	262.8	9.3	5.6	5.6
32	248.7	8.8	5.3	5.3
33	235.9	8.4	5.0	5.0
34	224.3	8.0	4.8	4.8
35	213.8	7.6	4.6	4.6
36	204.2	7.2	4.3	4.3
37	195.4	6.9	4.2	4.2
38	187.2	6.6	4.0	4.0
39	179.6	6.4	3.8	3.8
40	172.4	6.1	3.7	3.7

Pool #	Gas-in-Place Mean Pool Size (Million M^3)	Gas-in-Place Mean Pool Size (Billions of ft^3)	Recoverable Gas Reserves Assuming 60% Recovery Factor[1] Mean Pool Size (Billions of ft^3)	Recoverable Gas Reserves Assuming 75% Recovery Factor[1] Mean Pool Size (Billions of ft^3)
41	165.7	5.9	3.5	3.5
42	159.3	5.7	3.4	3.4
43	153.2	5.4	3.3	3.3
44	147.3	5.2	3.1	3.1
45	141.7	5.0	3.0	3.0
46	136.1	4.8	2.9	2.9
47	130.8	4.6	2.8	2.8
48	125.5	4.5	2.7	2.7
49	120.4	4.3	2.6	2.6
50	115.3	4.1	2.5	2.5
Combined	94,331.4	2,657,222.6	1,594,333.6	1,594,333.6

1. The 75% recovery factor was reported in the Royal Society of Canada report (2004, p.14) and was attributed to Peter Hannigan. The60% recovery factor was suggested by Ron Smyth, Government of British Columbia.

Table A12: Distribution of Expected Recoverable Reserves of Gas by Size of Pool and Recovery Factor – Queen Charlotte Basin: Pliocene Gas Play

Pool #	Gas-in-Place Mean Pool Size (Million M^3)	Gas-in-Place Mean Pool Size (Billions of ft^3)	Recoverable Gas Reserves Assuming 60% Recovery Factor[1] Mean Pool Size (Billions of ft^3)	Recoverable Gas Reserves Assuming 75% Recovery Factor[1] Mean Pool Size (Billions of ft^3).
1	169,680.0	6,023.6	3,614.2	4,517.7
2	63,126.0	2,241.0	1,344.6	1,680.7
3	38,195.0	1,355.9	813.6	1,016.9
4	26,859.0	953.5	572.1	715.1
5	20,355.0	722.6	433.6	542.0
6	16,155.0	573.5	344.1	430.1
7	13,239.0	470.0	282.0	352.5
8	11,110.0	394.4	236.6	295.8
9	9,495.5	337.1	202.3	252.8
10	8,231.2	292.2	175.3	219.2
11	7,214.7	256.1	153.7	192.1
12	6,379.3	226.5	135.9	169.8
13	5,680.6	201.7	121.0	151.2
14	5,087.8	180.6	108.4	135.5
15	4,579.0	162.6	97.5	121.9
16	4,138.0	146.9	88.1	110.2
17	3,752.6	133.2	79.9	99.9
18	3,413.4	121.2	72.7	90.9
19	3,112.9	110.5	66.3	82.9
20	2,845.2	101.0	60.6	75.8
21	2,605.4	92.5	55.5	69.4
22	2,389.7	84.8	50.9	63.6
23	2,194.7	77.9	46.7	58.4
24	2,017.9	71.6	43.0	53.7
25	1,857.0	65.9	39.6	49.4
26	1,710.0	60.7	36.4	45.5
27	1,575.5	55.9	33.6	41.9
28	1,452.1	51.5	30.9	38.7
29	1,338.8	47.5	28.5	35.6
30	1,234.6	43.8	26.3	32.9
Combined	389,727.5	10,978,240.0	6,586,944.0	8,233,680.0

1. The 75% recovery factor was reported in the Royal Society of Canada report (2004, p.14) and was attributed to Peter Hannigan. The60% recovery factor was suggested by Ron Smyth, Government of British Columbia.

Table A13: Comparison of the Economic Value of Oil Resources in the Queen Charlotte Basin for the Semi-Submersible and Small-Scale Tie-Back Technologies

Oil Price ($/bbl)	Minimum Size Field to Yield 12% After-Tax ROR Simple Tie-Back Technology (Millions of Barrels)	Potential Recoverable Reserves 34% Recovery Factor (Millions of Barrels)	Value of Recoverable Reserves 34% Recovery Factor (Millions of US Dollars)	Potential Recoverable Reserves 25% Recovery Factor (Millions of Barrels)	Value of Recoverable Reserves 25% Recovery Factor (Millions of US Dollars)
Semi-Submersible Technology					
$20 US	535	1,528	$29,026	698	$13,268
$25 US	420	1,528	$36,283	1,123	$26,679
$30 US	345	1,874	$53,411	1,123	$32,015
$35 US	294	2,197	$73,038	1,123	$37,349
$40 US	255	2,197	$83,471	1,378	$52,364
$45 US	226	2,428	$103,820	1,615	$69,045
$50 US	203	2,428	$115,354	1,615	$76,717
$55 US	184	2,613	$136,526	1,615	$84,288
$60 US	168	2,613	$143,765	1,786	$101,780
$65 US	155	2,757	$167,341	1,786	$110,261
Small-Scale Tie-Back Technology					
$20 US	89	3,300	$61,055	2,220	$42,176
$25 US	72	3,450	$80,264	2,296	$54,527
$30 US	60	3,576	$101,929	2,485	$69,161
$35 US	50	3,734	$122,511	2,537	$84,344
$40 US	44	3,823	$143,636	2,630	$99,930
$45 US	39	3,939	$165,175	2,709	$114,186
$50 US	35	3,973	$187,103	2,779	$130,416
$55 US	32	4,037	$210,931	2,811	$146,893
$60 US	29	4,094	$230,107	2,869	$161,936
$65 US	27	4,121	$254,480	2,896	$178,848

Table A14: Comparison of the Economic Value of Gas Resources in the Queen Charlotte Basin for the Sable and Small-Scale Tie-Back Technologies

Gas Price ($/MCF)	Minimum Size Field to Yield 12% After-Tax ROR (TCF)	Potential Recoverable Reserves 60% Recovery Factor (TCF)	Value of Recoverable Reserves 60% Recovery Factor (Millions of US Dollars)	Potential Recoverable Reserves 75% Recovery Factor (TCF)	Value of Recoverable Reserves 75% Recovery Factor (Millions of US Dollars)
Sable Technology					
$1 US	8.60	0.0	$0	0.0	$0
$2 US	4.30	3.6	$0	4.5	$8,136
$3 US	2.87	6.1	$9,747	7.6	$20,466
$4 US	2.15	6.1	$21,816	7.6	$27,288
$5 US	1.72	6.1	$27,270	7.6	$34,110
$6 US	1.43	6.1	$32,724	9.3	$50,004
$7 US	1.23	7.4	$46,620	10.5	$66,276
$8 US	1.07	7.4	$53,280	10.5	$75,744
$9 US	0.95	8.4	$68,121	12.5	$101,574
$10 US	0.86	8.4	$75,690	12.5	$112,860
Small-Scale Tie-Back Technology					
$1 US	3.30	3.6	$3,253	4.5	$4,066
$2 US	1.65	6.1	$10,915	9.3	$16,669
$3 US	1.10	7.4	$19,992	10.5	$28,411
$4 US	0.83	8.4	$30,305	12.5	$45,154
$5 US	0.67	10.0	$45,154	14.1	$63,279
$6 US	0.56	11.3	$60,748	14.7	$79,104
$7 US	0.47	11.7	$73,831	15.2	$95,703
$8 US	0.41	12.2	$84,500	15.7	$112,671
$9 US	0.37	12.2	$98,437	16.5	$133,250
$10 US	0.33	12.9	$115,768	17.1	$154,498

Appendix B – Oil Scenarios

Semi-Submersible Oil Scenario

The information used in developing the semi-submersible scenario was based on the information submitted by Petro-Canada as part of its development plan application for the Terra Nova project. The financial data was updated to 2006 prices and current exchange rates. The key parameters utilized in this scenario were:

- capital costs = $2.5 US billion
- operating costs = $120 US million/yr plus $1.50 US/bbl
- exploration cost = $400 million
- transportation cost = $1.5 US/bbl
- quality adjustment = 5%
- costs of capital – 12%
- inflation = 0%
- royalty regime = Newfoundland and Labrador offshore generic

Table B1: An Illustrative Cost Profile for 500 Million Barrels of Oil

Year	Exploration ($ M US)	Capex ($ M US)	Production (M Bbls)	Opex ($ M US)	Transportation ($ M US)
1	$100				
2	$100				
3	$100				
4	$100				
5		$5			
6		$11			
7		$21			
8		$32			
9		$278		$5	
10		$557		$16	
11		$820	16.1	$63	$24
12		$131	62.1	$213	$93
13		$100	62.1	$213	$93
14		$205	62.1	$213	$93
15		$89	62.1	$213	$93
16		$110	53.5	$200	$80
17		$95	42.8	$184	$64
18		$58	34.3	$171	$51
19		$0	27.8	$162	$42
20		$0	22.5	$154	$34
21		$0	18.2	$147	$27
22		$0	15.0	$142	$22
23		$0	11.8	$138	$18
24		$0	9.6	$134	$14
Sum	**$400**	**$2,511**	**500**	**$2,370**	**$750**

Small-Scale Tie-Back Oil Scenario

The information used in developing the simple tie-back scenario was based on the Royal Rhodes study, Bridges et al. (2004). The key parameters utilized in this scenario are:

- capital costs = $0.6 US billion
- operating costs = $10 US million/yr plus $1.00 US/bbl
- exploration cost = $50 million
- transportation cost = $0.75 US/bbl
- quality adjustment = 5%
- costs of capital – 12%
- inflation = 0%
- royalty regime = Newfoundland and Labrador offshore generic

Table B2: An Illustrative Cost Profile for 100 Million Barrels of Oil

Year	Exploration ($ M US)	Capex ($ M US)	Production (M Bbls)	Opex ($ M US)	Transportation ($ M US)
1	$25				
2	$25				
3		$1			
4		$3			
5		$5			
6		$8			
7		$67			
8		$133			
9		$196	3.2	$13	$2
10		$31	12.4	$22	$9
11		$24	12.4	$22	$9
12		$49	12.4	$22	$9
13		$21	12.4	$22	$9
14		$26	10.7	$21	$8
15		$23	8.6	$19	$6
16		$14	6.9	$17	$5
17		$0	5.6	$16	$4
18		$0	4.5	$14	$3
19		$0	3.6	$14	$3
20		$0	3.0	$13	$2
21		$0	2.4	$12	$2
22		$0	1.9	$12	$1
Sum	**$50**	**$600**	**100**	**$240**	**$75**

Appendix C: Gas scenarios

Sable Scenario Gas Scenario

The information used in developing the semi-submersible scenario was based on the information from the Sable project. The key parameters utilized in this scenario were:

- capital costs = $1.6 US billion
- operating costs = $68 US million/yr
- exploration cost = $400 million
- ratio of produced to marketed gas = 90%
- costs of capital – 12%
- inflation = 0%
- royalty regime = Nova Scotia offshore generic

Table C1: An Illustrative Cost Profile for 2 TCF of Natural Gas

Year	Exploration ($ M US)	Capex ($ M US)	Production (BCF)	Opex ($ M US)
1	$100			
2	$100			
3	$100			
4	$100			
5		$539		
6		$522		
7		$0	66.6	$68
8		$0	96.9	$68
9		$261	133.3	$68
10		$156	133.3	$68
11		$104	133.3	$68
12		$0	133.3	$68
13		$0	133.3	$68
14		$0	133.3	$68
15		$0	133.3	$68
16		$0	133.3	$68
17		$0	133.3	$68
18		$0	133.3	$68
19		$0	106.6	$68
20		$0	85.3	$68
21		$0	68.2	$68
22		$0	54.6	$68
23		$0	43.7	$68
24		$0	34.9	$68
25		$0	27.9	$68
26		$0	22.4	$68
27		$0	17.9	$68
28		$0	14.3	$68
29		$0	11.4	$68
30		$0	9.2	$68
31		$0	7.3	$68
Sum	**$400**	**$1,582**	**2,000**	**$1,700**

Small-Scale Tie-Back Gas Scenario

The information used in developing the simple tie-back scenario was based on the Royal Rhodes study, Bridges et al. (2004). The key parameters utilized in this scenario were:

- capital costs = $0.6 US billion
- operating costs = $25 US million
- exploration cost = $200 million
- ratio of produced to marketed gas = 90%
- costs of capital – 12%
- inflation = 0%
- royalty regime = Nova Scotia offshore generic

Table C2: An Illustrative Cost Profile for 500 BCF of Natural Gas

Year	Exploration ($ M US)	Capex ($ M US)	Production (BCF)	Opex ($ M US)
1	$50			
2	$50			
3	$50			
4	$50			
5		$179		
6		$174		
7		$0	16.7	$25
8		$0	24.2	$25
9		$87	33.3	$25
10		$52	33.3	$25
11		$35	33.3	$25
12		$0	33.3	$25
13		$0	33.3	$25
14		$0	33.3	$25
15		$0	33.3	$25
16		$0	33.3	$25
17		$0	33.3	$25
18		$0	33.3	$25
19		$0	26.7	$25
20		$0	21.3	$25
21		$0	17.1	$25
22		$0	13.6	$25
23		$0	10.9	$25
24		$0	8.7	$25
25		$0	7.0	$25
26		$0	5.6	$25
27		$0	4.5	$25
28		$0	3.6	$25
29		$0	2.9	$25
30		$0	2.3	$25
31		$0	1.8	$25
Sum	**$200**	**$527**	**500**	**$625**