POTENTIAL BENEFITS

OF

OFFSHORE OIL AND GAS DEVELOPMENT

IN

QUEEN CHARLOTTE BASIN, BRITISH COLUMBIA

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EXECUTIVE SUMMARY

1. Introduction

This report evaluates the potential benefits from offshore oil and gas development in Queen Charlotte Basin (QCB), British Columbia for an assumed single stand-alone oil field and a single stand-alone field of wet or dry natural gas. Separate categories of benefit are identified as:

- net resource revenue (or economic rent) that accrues from offshore operations to the federal government as corporation income tax, to the provincial government as royalties and corporation income tax, and to the private sector as after-tax profit;
- incremental output, GDP, household income, employment and government revenues arising directly and indirectly at provincial and regional levels from expenditures incurred at the different stages of offshore activity (expenditure benefits); and
- transformative changes to provincial and regional economies resulting from offshore development that contribute to long-term growth over and above economic rent and expenditure benefits.

The report, the first in-depth review of the economic impacts of offshore activity conducted for the provincial government, supplements the more limited estimation of economic benefits in earlier studies, and adds to the knowledge base regarding the potential economic pay-off from offshore activity. While the report does not measure the negative impacts that could accompany offshore activity, it can be used to inform the process of weighing the benefits of offshore activity against the possible risks.

Since the quantitative components of the analysis are necessarily based on many assumptions, results should be seen as illustrative orders of magnitude rather than firm predictions. Moreover, conservative assumptions are utilized to avoid overstating the estimated numerical benefits and, along with sensitivity analysis on key parameters, as a way of addressing the many uncertainties surrounding the estimation of benefits.

Key Finding: Substantial potential gains from offshore energy development are possible, even in the context of the single oil and gas field developments assumed in the analysis.

While the report evaluates the potential benefits of single fields of oil and gas, it can be reasonably expected that additional commercial fields will be subsequently discovered and developed. Thus, the commercial life of QCB might follow the kind of trajectory seen in other offshore basins such as Cook Inlet, Alaska and Jeanne d’Arc Basin off Newfoundland and Labrador. Cook Inlet has been producing for over 50 years, and there are now seven producing oil fields and seventeen producing gas fields. Three fields have been developed off Newfoundland and Labrador and a fourth is expected to be in production within the next ten years.

2. Activity Scenarios

The analyses of economic rent and expenditure impact are based on expenditure profiles associated with assumed activity scenarios that, in turn, are developed from an assessment of the resource potential of QCB.

Resource Potential

Estimates by the Geological Survey of Canada indicate a median potential of 1.56 billion cubic metres (9.8 billion barrels (bbls)) of oil distributed in 103 fields and 733.76 billion cubic metres (25.9 trillion cubic feet (tcf)) of natural gas in place distributed in 120 fields in QCB. Assuming that the second largest fields will be discovered and developed first, and assuming conservative recovery factors of 34% for oil and 67% for gas, the cost, rent and expenditure impact analyses of the study are based upon 578 million bbls of recoverable oil and 2.736 tcf of recoverable natural gas.

Probable locations for commercial oil and gas pools are in Hecate Strait and western Queen Charlotte Sound along a fairway running northwest to southeast roughly parallel to the axis of Hecate Strait.

Scenario Framework

Oil and gas developments are assumed to be stand-alone developments. That is, the oil development does not have associated gas and the natural gas development does not produce any commercial quantities of oil. Data from a drilling program in the 1960s suggest that the natural gas stream could contain commercial quantities of natural gas liquids (NGLs). Separate scenarios are therefore developed for wet gas containing commercial quantities of NGLs and for dry gas. Also, given uncertainty concerning the exact location of the resource pools, separate scenarios are developed for pools relatively close to where the resources might be brought ashore (Kitimat, Prince Rupert or Port Hardy) and for pools further away.

Specifically, the following activity scenarios provide the framework for cost, rent and expenditure impact analyses:

- **Short Pipeline Oil Scenario (SPOS)**: This scenario assumes that the produced oil is initially transported to a shore-based transshipment terminal by an underwater pipeline that is 150 km in length before being shipped by tanker to market.
- **Long Pipeline Oil Scenario (LPOS)**: This scenario assumes that the produced oil is initially transported to a shore-based transshipment terminal by an underwater pipeline that is 300 km in length before being shipped by tanker to market.
- **Short Pipeline Wet Gas Scenario (SPWGS)**: This scenario assumes that the produced gas containing NGLs is initially transported to a shore-based natural gas and fractionation plant for further processing by an underwater pipeline that is

150 km in length. The processed natural gas is then fed into the land-based provincial pipeline system and the NGLs are transported to market by rail or road.

- **Long Pipeline Wet Gas Scenario (LPWGS)**: This scenario assumes that the produced gas containing NGLs is initially transported to a shore-based natural gas and fractionation plant for further processing by an underwater pipeline that is 300 km in length. The processed natural gas is then fed into the land-based provincial pipeline system and the NGLs are transported to market by rail or road.
- **Short Pipeline Dry Gas Scenario (SPDGS)**: This scenario assumes that produced gas does not contain NGLs. The gas is initially processed on the production platform and is then transported to shore by an underwater pipeline that is 150 km in length before being fed into the land-based provincial pipeline system for transportation to market.
- **Long Pipeline Dry Gas Scenario (LPDGS)**: This scenario assumes that produced gas does not contain NGLs. The gas is initially processed on the production platform and is then transported to shore by an underwater pipeline that is 300 km in length before being fed into the land-based provincial pipeline system for transportation to market.

Exploration, Development and Production Activities

Exploration activities are assumed identical for each of the six scenarios. At the development stage, each of the scenarios assumes that the oil or gas field is developed using a steel semi-submersible production technology. Development drilling costs depend upon the number of wells required to fully exploit the field (36 wells for oil; 20 wells for gas). The analyses assume a 28-inch underwater pipeline for oil and a 24-inch underwater pipeline for gas. Dry gas is processed on the production platform; on-shore fractionation and NGL plants are required for the wet gas developments.

At the production stage, peak production of oil occurs in the second year of production at 150 thousand bbls/day and continues at this level for four years, declining geometrically at 7.8%/year thereafter. For the estimated field size of 578 million bbls of recoverable oil, this gives a productive life of 14 years. For gas, peak production is 473 mmcf/day beginning in the second year of production and lasting for 12 years with a geometric decline after peak production of 25%/year. For the estimated field size of 2.736 tcf of recoverable gas, this gives a productive life of 25 years. For each mmcf of raw gas in the wet gas scenario, 4.7 bbls of condensate, 11.9 bbls of butane and 11.2 bbls of propane are produced. Ethane is assumed to be left in the natural gas stream and sold jointly with the methane.

Costs are assumed to escalate at 2%/year and are shown separately in 2006 and actual as-spent dollars. Economic rent and expenditure impact analyses are conducted in 2006 dollars.

3. Economic Rent Benefits

Financial viability analyses indicate the scenarios that are capable of generating a 10% real, after-tax rate of return when all of a project's 2006 costs and revenues are considered over its entire life cycle. Surplus (or economic rent) arising from operations is then estimated in the form of royalty and corporation income tax revenue for the provincial government, corporation income tax for the federal government and after-tax profit for petroleum companies.

In testing the robustness of the financial viability analyses and in estimating economic rent, 2006 oil prices are utilized in increments of $5 US/bbl, from $20 to $100 US/bbl for West Texas Intermediate crude (WTI). The corresponding 2006 natural gas prices range from $2 to $10 US/mmbtu in increments of $1/mmbtu.[1] If there is interest in evaluating economic rent at prices not included in the analysis, estimates can be generated from equations in Appendix 3H.

Key Finding: Projects are estimated to be viable (in the sense of yielding positive net revenue in present value terms) at prices at and above $35 US/bbl for oil, $5 US/mmbtu for wet gas, and $6 US/mmbtu for dry gas.

Estimates of economic rent over the full ranges of energy prices are laid out in Section 3 of the report. These estimates are summarized in Section 6 for expected long-term price ranges of $70-80 US/bbl for oil and $6-7 US/mmbtu for natural gas.

Key Finding: All projects are profitable and generate economic rent benefits for stakeholders, even at the lower bounds of expected long-run price ranges.

At the conservative lower bounds of expected long-term price ranges, economic rent estimates for each of the stakeholders are as follows (all results in 2006 Canadian dollars):

- **Provincial government**: approximately $11 billion over the productive life of the single assumed oil field in QCB, approximately $4.5-4.8 billion over the life of the single assumed wet gas field, and approximately $3.5-3.8 billion over the life of the single dry gas field. Specific returns depend on the length of the underwater pipeline needed to carry the resource to shore. In discounted present value terms, these results are respectively just over $2 billion, $0.6-0.7 billion and approximately $0.5 billion.
- **Federal government**: approximately $5.1 billion from the oil field, $2.1 billion from the wet gas field and $1.8 billion from the dry gas field (respectively $1.1 billion, $0.4 billion and $0.3 billion in present value terms).
- **Companies**: approximately $14.5 billion from the oil field, approximately $5.9 billion from the wet gas field and $5.0 billion from the dry gas field (in present value terms, approximately $2.3 billion from oil, $0.3-0.4 billion from wet gas and approximately $0.2 billion from dry gas).

[1] In the absence of a BC offshore royalty regime, the Newfoundland and Labrador generic offshore regime is utilized for calculating royalties associated with the oil developments. The Nova Scotia offshore regime for natural gas is used for calculating the royalties associated with the natural gas developments. As well, the analyses abstract from the impact of direct corporation income taxes and royalty payments on provincial equalization entitlements.

Key Finding: Depending on the length of the pipeline, the provincial government gains additional revenue of approximately $221 million ($44 million in present value terms) for every dollar increase in the price of oil. The federal government gains additional revenue of approximately $88 million. ($19 million in present value terms) and the companies gain additional net revenue of $262-263 million (approximately $58 million in present value terms). For every dollar increase in the price of natural gas, the provincial government gains $1.2-1.3 billion in revenue ($192-209 million in present value terms) depending not only on the length of the pipeline but also on whether the gas is wet or dry, the federal government gains $445-463 million ($82-83 million in present value terms) and the companies gain $1.3-1.5 billion ($263-303 million in present value terms).

Key Finding: At the lower bounds of the expected long-run price ranges, estimated shares of rent are as follows:

- **Provincial government**: approximately 36% (oil), 36-37% (wet gas) and 34-36% (dry gas) based on 2006 dollar estimates, or 39% (oil), around 48% (wet gas) and 50-52% (dry gas) based on discounted dollar estimates.
- **Federal government**: approximately 17% (oil), 17% (wet gas) and 17-18% (dry gas) based on 2006 dollar estimates, or 19-20% (oil), 25-28% (wet gas) and 28-32% (dry gas) based on discounted dollar estimates.
- **Companies**: approximately 47% (oil), 46-47% (wet gas) and 47-48% (dry gas) based on 2006 dollar estimates, or approximately 42% (oil), 24-27% (wet gas) and 16-22% (dry gas) based on discounted dollar estimates.

Key Finding: As price rises over expected ranges, the share of nominal rent increases for the provincial government and falls for the federal government and companies. In terms of discounted rent, as price increases the share accruing to the provincial government rises marginally for oil projects but falls for gas projects, while the federal government share falls for both oil and gas projects and the private sector share increases for all projects.

4. Expenditure Benefits

The analysis of benefits resulting from expenditures incurred in exploration, development and production activities shows impacts of the expenditure on output, GDP, employment, household income and tax revenues as the expenditure creates demand for production of additional goods and services. The analysis is conducted from the perspectives of (a) the province as a whole and (b) two regions of the province (the QCB region surrounding the assumed area of offshore activity, and the rest of the province). Benefits are defined according to the scenario framework outlined above; and to the extent that the analytical models allow, benefits include indirect and induced impacts arising from the multiplier process as well as direct expenditure effects.[2] Impacts are also defined in both aggregate

[2] Indirect effects occur as the energy industry purchases inputs from other sectors creating additional output, employment, income and tax payments in those sectors which, in turn, purchase additional inputs,

dollar terms and as impacts per million dollars of expenditure. Aggregate impacts are based on the scale of expenditures assumed for the rental analysis.

Expenditure impact estimates assume that energy prices are sufficiently high to ensure viability of projects.

Provincial Impacts

Key Finding: The single fields of oil and gas assumed in the study are estimated to yield at each stage of activity the following expenditure benefits for the province as a whole (results in 2006 Canadian dollars):

- **Exploration**: increased output of $430 million; GDP of $170 million; 2,500 annual jobs; household income of $131million; and tax revenue of $59 million.[3] Provincial government tax revenue is $33 million, or 56%, of total tax revenue.
- **Development**: increased output of around $4.0 billion (oil) and $2.8-3.2 billion (gas); GDP of around $1.4 billion (oil) and $1.0-1.1 billion (gas); some 24,000 annual jobs (oil) and 16-19,000 annual jobs (gas); household income of approximately $1.1 billion (oil) and $770-900 million (gas); and tax revenue of $440-460 million (oil) and $290-330 million (gas). Provincial government tax revenue is $239-249 million (oil) and $158-176 million (gas), around 55% of total tax revenue.
- **Production**: increased output of $6.1 billion (oil) and $4.4 billion (gas); GDP of $2.0 billion (oil) and $1.4 billion (gas); 28,000 annual jobs (oil) and 21,000 annual jobs (gas); household income of $1.5 billion (oil) and $1.1 billion (gas); and tax revenue of $366 million (oil) and $265 million (gas). Provincial government tax revenue is $157 million (oil) and $113 million (gas), or 43% of total tax revenue.

Key Finding: Highest gains in output, GDP, employment and household income occur at the production stage and lowest gains are at the exploration stage. By contrast, the development stage yields higher tax revenue than the production stage. Oil development yields greater expenditure benefits than gas development, and wet gas development yields marginally higher benefits than dry gas development. Oil production yields higher expenditure benefits than gas production.

Key Finding: Among levels of government, the provincial government is the major beneficiary in terms of tax revenue at exploration and development stages while the federal government becomes the leading beneficiary at the production stage.

Key Finding: In terms of benefits per million dollars of expenditure, estimates are as follows (results in 2006 Canadian dollars):

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and so on through multiple rounds of spending. Induced effects arise as still further spending occurs from increased incomes generated in the spending process.

[3] In the context of expenditure benefits, tax revenue includes corporation income taxes, personal income taxes and commodity taxes.

- **Exploration**: increased output of $690,000, GDP of $270,000, 4 annual jobs, household income of $210,000 and tax revenue of $95,000.
- **Development**: increased output of $810-840,000 depending on the whether the product is oil or gas and where exactly it is discovered; GDP of around $280-300,000; 5 annual jobs; household income of $220-240,000; and tax revenue of $85-88,000.
- **Production**: increased output of $2.1 million; GDP of $670,000; approximately 10 annual jobs; household income of $500,000; and tax revenue of $125,000 (2006).

Key Finding: In terms of impacts per million dollars of expenditure, highest gains are at the production stage and lowest gains at the exploration stage, except in terms of federal and provincial tax revenues arising in the province. Federal and provincial tax revenues per million dollars of expenditure are highest at the production stage and lowest at the development stage.

Regional Impacts[4]

Key Finding: Estimated benefits (in 2006 Canadian dollars) in the QCB region at each stage of activity are as follows (proportionate shares of provincial benefits in parentheses):[5]

- **Exploration** increased output of $12-24 million (3.1-6.4% of increased provincial output); GDP of $8-20 million (5.2-13.5% of increased provincial GDP); 111-292 annual jobs (5.1-13.4%); household income of $7-19 million (6.3-17.3%); and local tax revenue of $23,000 (1.6%).
- **Development**:, increased output of $111-242 million (oil) (3.1-6.4% of increased provincial output) and $77-186 million (gas) (3.1-6.5%); GDP of $68-196 million (oil) (5.6-15.3% of increased provincial GDP) and $46-151million (gas) (5.5-15.7%); some 1,200-3,600 annual jobs (oil) (5.6-16.0%) and 800-2,800 annual jobs (gas) (5.5-16.3%); household income of $62-190 million (oil) (6.6-9.2%) and $42-146 million (gas) (6.5-19.6%) ; and local tax revenue of $287-304,000 (oil) and $205-232,000 (gas) (1.7% in both cases).
- **Production**: increased output of $143-245 million (oil) and $104-177 million (gas) (2.8-4.8% of increased provincial output in both cases); GDP of $79-181 million (oil) and $57-131 million (gas) (4.6-10.5%);1,006-2,335 annual jobs (oil) and 728-1690 annual jobs (gas)(4.7-10.8%); household income of $68-170 million (oil) and $49-123 million (gas)(6.6-16.4%); and local tax revenue of $419,000 (oil) and $303,000 (gas)(1.8% in both cases).

[4] Due to the specification of the regional impact model used in the analysis, total regional benefits do not include induced effects. However, regional benefits estimated in the regional impact model can be roughly adjusted for induced effects by applying regional shares of provincial totals estimated in the regional model to provincial totals estimated in the Provincial Expenditure Benefits section of the report.
[5] Benefits for the rest of the province are not shown separately in this summary (for details see Section 4.2 of the report).

Key Finding: In terms of benefits per million dollars of expenditure in the QCB region, estimates are as follows (results in 2006 Canadian dollars):

- **Exploration**: increased output of $19-38,000, GDP of $12-32,000, 0.2-0.5 annual jobs, household income of $11-31,000 and local tax revenue of as little as $4.
- **Development**: increased output of $22-46,000 (oil) and $23-49,000 (gas); GDP of $14-38,000 (oil) and $14-40,000 (gas); 0.2-0.7 annual jobs (oil) and 0.3-0.7 jobs (gas); household income of $13-36,000 (oil) and $12-39,000 (gas); and local tax revenue of around $6.
- **Production**: increased output of $49-84,000; GDP of $27-62,000; 0.4-0.8 annual jobs; household income of $23-58,000; and local tax revenue of $140.

In light of estimates of QCB benefits, it may be necessary to consider ways of directing to the QCB region a reasonable amount of the provincial financial revenue (economic rent) gained from offshore activity if communities in the region are to be assured that they are receiving a fair share of the benefits from the offshore resource. Options could include revenue-sharing arrangements with local governments and/or First Nations, cost-sharing agreements, or the provision of targeted grants for such purposes as investment in community infrastructure, local service needs and/or training required for jobs in the industry.

5. Transformative Economic Changes

Key Finding: Based on experience from elsewhere (primarily Norway, the UK, Atlantic Canada and Cook Inlet, Alaska), the industry can be expected to stimulate structural changes in provincial and regional economies that offer the potential for long-term sustainable growth in output, income and employment beyond the benefits outlined in Sections 3 and 4 of the report.

According to economic growth theory, the determinants of long-term growth are increases in the quantity and quality (or productivity) of factor inputs to the production process. On the basis of this framework, evidence from elsewhere shows the positive influence of offshore oil and gas activity on the following supply-side drivers of long-term growth:

- investments in infrastructure, education and training, and research and development;
- economic diversification;
- entrepreneurship, self-confidence and ambition in the business community; and
- population change.

Key Finding: Traditional sectors of the provincial and regional economies such as fisheries and tourism could experience benefits from offshore activity, despite possible risks. The fisheries, for example, could benefit from improved weather forecasting and search and rescue operations resulting from the presence of the petroleum industry. Local tourism could benefit from improved air links and hotel facilities, corporate tourism and even petroleum industry-related tourist attractions. Also, responding to the stimulus of population increase, other sectors such as retail, real estate and public services are likely to show renewed development.

SECTION 1

INTRODUCTION

1.1 Background to the Study

The offshore area of BC includes four sedimentary basins: Queen Charlotte, Tofino, Georgia and Winona basins (see Figure 1.1). Of the four basins, attention has been directed at Queen Charlotte Basin (QCB) as the most prospective. Based on recent estimates (Royal Society of Canada 2004, Locke et al 2006), Queen Charlotte Basin comprising Hecate Strait and Queen Charlotte Sound could contain as much as 1.1-1.3 billion barrels (bbls) of recoverable oil and 9.3-9.8 trillion cubic feet (tcf) of recoverable gas.

These figures place the potential of QCB on the same scale as the mature oil and gas fields in Cook Inlet, Alaska and the developed and developing fields of the Jeanne d'Arc Basin off Newfoundland (Royal Society of Canada 2004, p. xii). Put another way, the gas potential of QCB is around half the size of the known in-place reserves of northeast BC and the oil potential is about four times greater (Strong et al. 2002, Appendix 6, Table 2).

Figure 1.1: Generalized Map of Sedimentary Basin, Offshore BC

Source: http://www.offshoreoilandgas.gov.bc.ca

Oil and gas exploration was first undertaken on shore in the area as early as 1913. In the period 1949-71 seismic surveys and further drilling occurred, including eight offshore wells by Shell Canada in the late 1960s (see Figure 1.1). In 1972 the federal government imposed a moratorium on offshore exploration in QCB. Following the Exxon Valdez tanker accident in Prince William Sound, Alaska in 1989, the provincial government announced its own moratorium.

In the late 1990s, and more vigorously in the years following the 2001 election in BC, governments began to re-examine the merits of the moratoria and to investigate the potential for offshore development in light of serious economic decline in the resource-dependent communities of coastal BC.

At the provincial level, a series of reports were commissioned to review the state of knowledge concerning the engineering, science and socio-economic aspects of offshore activity (AGRA, Earth and Environmental Ltd 1998, Jacques Whitford Environment Ltd 2001, Strong et al 2002, Offshore Oil and Gas Task Force 2002). The general conclusion from the reviews was that there was no fundamental deficiency in science or technology that would preclude offshore development, given an effective regulatory framework to address concerns relating to impact on the environment, First Nations communities, and fishing and tourism industries.

The province also funded research initiatives to generate new knowledge on scientific, technical and socio-economic issues of relevance to offshore activity. The largest of these initiatives was the Northern Coastal Information and Research Program at the University of Northern British Columbia (2002-04), a program that produced a series of reports dealing with: highly-valued marine and shoreline resources in QCB; the health of marine and estuarine ecosystems in QCB; education and training needs for the oil and gas sector; an information dissemination system for QCB communities; and the effects of offshore activity on QCB communities.

Meanwhile, the federal government announced a three-phase approach to reviewing its moratorium that included the establishment of:

- a scientific panel to identify science gaps concerning the offshore, to consider whether the moratorium should be lifted for selected areas and to consult with First Nations;
- a review panel to conduct community consultations regarding the federal moratorium (the Priddle inquiry); and
- a separate process to engage First Nations in consideration of the issue.

The scientific panel concluded that, ‘provided an adequate regulatory regime is put in place, there are no science gaps that need to be filled before lifting the moratoria’ (Royal Society of Canada, 2004, p. xix). The reports of both the Priddle enquiry (Public Review Panel 2004) and the First Nations consultation process (Brooks 2004) revealed public reservations about the prospect of lifting the moratorium. These reservations were based on risks to the environment, First Nations’ cultures and livelihoods, and other sectors of the economy such as the fisheries and tourism.

Through Western Economic Diversification the federal government also funded a research program on selected social and economic issues involved in offshore development, including estimates of possible resource revenues and expenditure benefits based on two illustrative development scenarios, one for oil, the other for gas (Royal Roads University 2004).

Other quantitative economic studies on potential offshore activity to date are:

- a brief estimate of provincial resource revenues and expenditure benefits prepared for the BC Coast Information Team (BriMar Consultants Ltd 2003);
- an analysis prepared for Natural Resources Canada of the economic value of the energy resources of QCB, including implications for provincial resource revenues and GDP (Locke et al 2006); and
- a brief analysis prepared for the Canada/British Columbia Oceans Coordinating Committee of the value of potential production in QCB and of expenditure benefits from construction and operation phases of oil and gas development, one of several ocean sectors examined (Gislason et al 2007).

1.2 Purpose of the Current Report

This report, the first in-depth review of the economic impacts of offshore activity conducted for the provincial government, supplements the estimation of economic benefits developed in earlier studies, and adds to the knowledge base regarding the potential economic pay-off from offshore activity. As such, it is designed to help inform the process of weighing the economic benefits of exploiting the offshore resource against the perceived risks that have received attention in the public discourse.

As the BC Progress Board advised: ‘The federal and provincial government (sic) should provide more detailed information to the public on the potential for BC’s offshore oil and gas industry and make analysis of this potential a priority….’(BC Progress Board 2005 p.15).

This report distinguishes the following categories of benefit for assumed separate single fields of oil and natural gas:

- net resource revenue (or economic rent) as this accrues from offshore operations to the federal government as corporation income tax, the provincial government as royalties and corporation income tax, and the private sector as after-tax profit;
- incremental output, GDP, employment, household income and government revenues at both provincial and regional levels arising directly and indirectly from expenditures incurred at the different stages of offshore activity (expenditure benefits); and
- transformative changes to provincial and regional economies that contribute to long-term sustainable growth over and above the impacts measured as economic rent and expenditure benefits.

While the report covers a broader spectrum of impacts than those addressed in other BC offshore economic studies, it is restricted to estimation of potential benefits. It does not measure possible negative impacts from offshore activity that, if they were to materialize, would have to be weighed against the measured benefits discussed in the report.

Thus the current study is neither the comprehensive cost-benefit analysis nor the multi-criteria evaluation of the offshore issue of the sort ambitiously called for in one commentary (OOGRG 2004, pp.70, 114). The purpose of the report is to throw light on the main beneficial aspects of a complex, multi-dimensional topic with other aspects of the topic being left for others to address.

The quantitative parts of the analyses are necessarily based on many assumptions, especially given the absence of an existing offshore industry. Results should therefore be seen as illustrative orders of magnitude rather than firm predictions. At the same time, it is important to appreciate that the report adopts conservative assumptions in order not to inflate possible benefits and, together with sensitivity analysis on key parameters, as a way of dealing with the many uncertainties surrounding estimation of benefits.

1.3 Organization of the Report

This introductory section (Section 1) is followed in Section 2 by an outline of the activity scenarios that underpin the subsequent benefit analyses. Section 2 reviews the geological assessments that form the basis for several of the assumptions developed for costing the exploration (seismic work and exploratory drilling), development (facilities construction) and production scenarios from which benefit estimates are generated. Section 2 also describes the costing exercises for each of these activities.

Section 3 contains the analysis of net resource revenue (or economic rent) resulting from oil and gas production as this will be shared by the private sector and provincial and federal governments.

Section 4 includes the analyses of output, gross domestic product (GDP), employment, household income and government revenue impacts resulting from expenditures incurred by the industry at each stage of activity. Expenditures on exploration, development and production create not only direct benefits in the forms of extra output, GDP, jobs and household incomes for those who work in the industry as well as tax revenues for governments, but also indirect and so-called induced output, jobs, incomes and associated government revenues in both energy and other sectors. Output, GDP, employment and household income benefits are estimated separately for the province as a whole and for both the region around the QCB and for the rest of BC. Government revenues are analyzed from provincial, federal and municipal perspectives.

Expenditure impact estimates in Section 4 are based on well-established economic models that take the structure of provincial and regional economies as given. Based on long-term economic growth theory, Section 5 explores further likely benefits that emergence of an offshore industry would be expected to create. These relate to structural changes in the provincial and regional economies that can contribute to sustained development over the longer term. Likely structural changes include population growth resulting from offshore activity, infrastructure development, industrial diversification, increased research and development activity, acquisition of new skills/knowledge (through formal training and 'learning by doing'), and new attitudes and confidence in the business community.

A summary of findings and conclusions appears in Section 6.

SECTION 2

ACTIVITY SCENARIOS

This section outlines the scenarios on which economic rent and expenditure impact analyses are based. The scenarios are developed in light of an assessment of the resource potential of the QCB and are described in terms of their cost implications.

2.1 QCB Resource Assessment

A great deal of uncertainty is attached to oil and gas exploration and development. How much will be discovered? Will developments be profitable? How quickly can fields be put in production? Scenarios are conceptual views of future oil and gas resource developments and are based on the best available information at the time. Scenarios are routinely used by resource managers for project evaluation and also as a source of information for the public about potential future developments in an area. The more geological and engineering data there are available, the more reliable the scenario and the effects that flow from it. A considerable amount of pertinent geological data is available for QCB for scenario development, primarily from the first round of offshore exploration by Shell and Chevron in the 1960s and 1970s, and from a multiyear investigation of onshore and offshore parts of the basin by the Geological Survey of Canada (GSC) in the 1980s (Woodsworth 1991).

Petroleum resource assessments are routinely prepared by the GSC for all of Canada's prospective sedimentary basins. The discovery and development scenarios presented in this report are founded on the results of a comprehensive study of the probabilistic assessment of the oil and gas resources in QCB by the GSC (GSC 2001). There are several different methods for calculating the undiscovered petroleum resources in a basin. The GSC method uses a play analysis.[6]

An oil and gas resource assessment of a basin typically involves two steps:

Step 1 is to develop estimates of the total, undiscovered resources in place, regardless of any economic constraint. The focus is a calculation of the volume of in-place oil and gas resources that might be contained in the basin based on geological factors only.

Step 2 is to determine how much of the total oil and gas endowment would be economic to produce under varying engineering or economic conditions. This first requires a conversion of the in-place resources into what might be technically recoverable based on pool size and engineering conditions.

The resource assessment model does not predict precisely where the individual pools will be discovered. However, a recent basin analysis of the prospective Tertiary stratigraphic

[6] A play analysis is based on the analysis of a set of geological factors that can lead to the formation of recoverable deposits of oil and gas in the subsurface.

section of QCB concluded that 36-38% of the basin is prospective for oil and gas generation (Whiticar et al 2004) and lies in a northwest-southeast trending fairway roughly parallel to the axis of Hecate Strait. In the current report it is assumed that the commercial pools will be discovered in this fairway.

2.1.1 Geological Assessment

Geological factors that are evaluated in a play analysis involve the following questions:

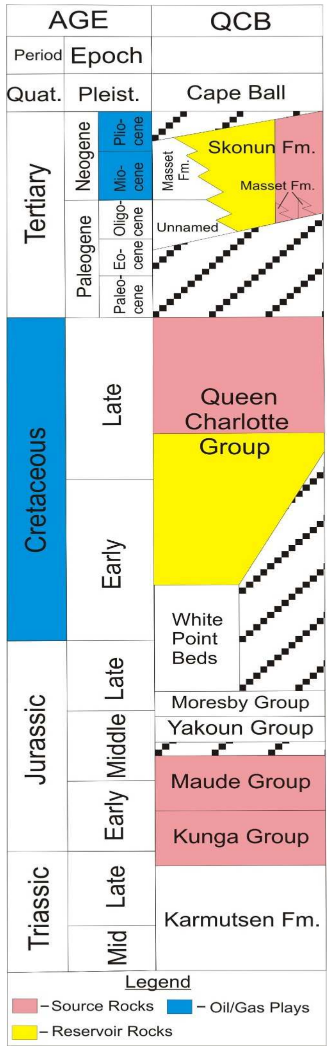
- Are there source rocks present to form hydrocarbons?
- Are reservoir rocks present and do they have adequate quality?
- Are cap rocks and structures present that can form traps for petroleum?
- Is the thermal history of the basin favourable for oil and/or gas generation?
- Have hydrocarbons migrated into the reservoir rock after the traps formed?

When geologists establish that a set of these circumstances are present in a basin they can determine that a play exists for petroleum to have been generated. In the GSC assessment, the play is the primary assessment unit. A play is composed of pools having a common history of hydrocarbon generation, migration, reservoir development and trap configuration. A pool is an accumulation of oil or gas within a particular play that is hydraulically separated from any other hydrocarbon accumulation.

The degree of reliability of an estimate of the petroleum potential of a play depends upon the amount of geological knowledge about the basin, its so-called 'exploration maturity'. The more there is known about a basin, the more reliable the estimate of its petroleum potential. The GSC geologists had access to Shell 1960s seismic data, which covered all of the company's offshore licenses in QCB, and to more targeted seismic data by Chevron shot in the 1970s. Data from the eight offshore wells drilled by Shell in the 1960s were also available. In addition, 1,000 km of modern seismic data were shot by the GSC in 1988, plus the GSC had recently concluded a three-year multidisciplinary program of geological investigations of the geology of Haida Gwaii (the Queen Charlotte Islands), where source rocks and reservoir rocks are exposed and available for study and over 70 oil seeps are known.

A simplified stratigraphic column for QCB is shown in Figure 2.1 below. Petroleum source rocks (red) occur in the Upper Kunga-lower Maude Groups, Upper Queen Charlotte Group, and the lower Skonun Formation. Potential reservoir strata (yellow) occur and in the lower part of the Queen Charlotte Group (Cretaceous) and in the Skonun Formation (Miocene and Pliocene).

Figure 2.1. Simplified Stratigraphic Column for QCB



Source: modified from Hannigan et al. 2001

The GSC identified three plays in the Queen Charlotte Basin: a Cretaceous Play, a Miocene Play and a Pliocene Play. For each play, the GSC estimated the number of possible fields (a field consists of one or more oil and/or gas pools within a single structure or trap) that may exist. For each field the GSC calculated the volume of oil and gas that it may contain at different levels of probability using a statistical computer method (PETRIMES) developed by the GSC.[7]

The predicted volume of oil and gas for each play was not reported by the GSC (GSC 2001). However, these data are available on request from the GSC and are given in

[7] PETRIMES is an internationally recognised assessment method that has been adopted by other Geological Surveys, such as by the US Geological Survey (USGS).

Appendix 2A of the report. The results for each play are aggregated using statistical methods in the PETRIMES model and presented as probability distributions for the total volume of oil and the total volume of gas in place in the play at any value of probability from 0% to 100% (see Appendix 2B). The number normally chosen to describe the amount of petroleum resources in a play is at the median value of probability, representing the volume of resources in place at a cumulative probability of 50%.

Results for QCB are shown in Table 2.1.

Table 2.1: Estimated Oil in Place and Gas in Place for QCB

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)
Oil Plays				
Cretaceous Play	62	392	478	96
Miocene Play	28	574	668	165
Pliocene Play	13	398	652	233
Total Oil	**103**	**1,560**		
Gas Plays				
Cretaceous Play	50	75,435	94,336	20,675
Miocene Play	40	285,710	317,080	71,190
Pliocene Play	30	321,750	389,710	95,774
Total Gas	**120**	**733,760**		

Source: Hannigan et al. 2001, Table 4.

The GSC estimated the total oil and gas in place for QCB to be 9.8 billion bbls of oil, and 25.9 tcf of gas at the median value of probabilistic assessment.

2.1.2 Economic Assessment

The next step is to predict the fields identified in the PETRIMES model that could be developed. Variables include engineering (e.g. pool size, recovery factor) and economics (e.g. exploration, development and production costs, and commodity price). This type of analysis was not undertaken by the GSC. It should be noted that the United States Geological Survey undertakes an economic analysis of frontier basins employing a second computer program named PRESTO (Mineral Management Service 96-003).

Without access to an economic computer model such as PRESTO, geologists often resort to using analogues with other similar basins to make predictions about recoveries and future oil and gas production. Geological comparisons have been drawn between the QCB and the producing Cook Inlet Basin in Alaska (e.g. Thompson et al 1990, Whiticar et al 2002, Royal Society of Canada Expert Panel 2004). The Cook Inlet Basin is about 380 km long and about 80 km wide, has over 240 wells, and has been producing oil and gas for almost 50 years. Comparatively, QCB is about 470 km long and about 100 km wide.

There are at present seven producing oil fields and 17 producing gas fields in Cook Inlet. There are 15 platforms tapping the offshore fields and these are linked by pipelines to onshore facilities. To date, over 1.5 billion bbls of oil reserves have been discovered in Cook Inlet (ADNR 2003). Given the similarities in geology and size between Cook Inlet and QCB, the successful development of Cook Inlet confirms the likelihood of commercial potential in QCB.

Expected Pool Sizes

An analysis of the discovery record in the world's petroleum basins by the French Petroleum Institute (Laherrere 1996) revealed that, with great regularity, within about five years of exploring a new basin, explorers find the "queen" first, which is the second largest field. The "king", or the largest field, is usually discovered within the next five years. Over the next decade the next eight to ten "lords" are discovered. Once the royal family has been found, the rest of the fields discovered in a basin are basically "pawns" in size, and many of these are not large enough to be commercially developed.

Recent advances in exploration technology, such as 3-D seismic, have resulted in improved success rates and now the largest field is often the first field to be discovered. For example, the Hibernia field was the first discovery in the virgin Jeanne d'Arc Basin, offshore Newfoundland and Labrador, and to date it has proved to be the largest field.

However, in order to be relatively conservative, the assumed basis for the cost analysis in Section 2.2 is that the second largest fields identified by the PETRIMES model will be discovered and developed first in line with the FPI finding noted above. These are the pools in the Miocene play shown in Tables 2.2 and 2.3 below.

Table 2.2: Largest Predicted Gas Fields by Play in QCB

Gas Plays	Mean Gas in Place	Marketable Gas (Bcf)
	(Bcf)	Assumed 67% Recovery Factor
Cretaceous Gas Play (C53C9608)		
Pool Rank 1	1338	896
Pool Rank 2	485	325
Pool Rank 3	293	196
Miocene Gas Plays (C53A9608)		
Pool Rank 1	4083	2736
Pool Rank 2	1683	1128
Pool Rank 3	1072	718
Pliocene Gas Plays (C5389608)		
Pool Rank 1	6023	4035
Pool Rank 2	2241	1501
Pool Rank 3	1356	909

*Mean in-place volumes from Hannigan et al. 2001
** Pool used in economic analyses: rank 1 Miocene play

Table 2.3: Largest Predicted Oil Fields by Play in QCB

Oil Plays	Mean Oil in Place	Marketable Oil (Mbbl)
	(Mbbl)	Assumed 34% Recovery Factor
Cretaceous Oil Play (C53B9608)		
Pool Rank 1	1018.8	346.4
Pool Rank 2	404.1	137.4
Pool Rank 3	255.5	86.9
Miocene Oil Play (C5399608)		
Pool Rank 1	1700.3	578.2
Pool Rank 2	682.0	231.9
Pool Rank 3	425.2	144.6
Pliocene Oil Play (C5379608)		
Pool Rank 1	2793.2	949.7
Pool Rank 2	948.6	322.5
Pool Rank 3	541.9	184.3

*Mean in-place volumes from Hannigan et al. 2001.
** Pool used in economic analyses: rank 1 Miocene play

Recovery Factors

The recovery factor for oil and gas is an estimate of the total volume of hydrocarbons that can be recovered from a field expressed as a percentage of the total hydrocarbons originally in place in a field.

Uncertainty is attached to both of these estimated volumes. Oil occupies minute pores in the rock forming the reservoir. To be able to produce the oil, the oil that is in the pores must be displaced by something else. This can be achieved by natural seepage of water when pressure drops, or by expansion of an associated gas cap. Generally water or gas must be injected into the reservoir to achieve maximum recovery. But even when good displacement is present, some oil will remain in the pores.

A general rule of thumb in the industry used to be that 1/3 of the oil and 2/3 of the gas in a field is recoverable. Recent engineering advances, such as horizontal drilling and re-injection of produced gas and water, have led to improved recoveries in many fields. Moreover, based on almost 50 years of exploration and production data, recovery factors in Cook Inlet are higher than traditional factors.[8] Even so, in order to be conservative, the traditional recovery factors are used in this study, giving quantities of marketable resources as shown in Tables 2.2 and 2.3 above.

2.1.3 Pool Locations

It is impossible to predict exactly where commercial pools will be discovered in QCB. However, sufficient well, seismic and gravity data are available to make a reasonable assessment of the distribution of maturity zones in the younger Miocene and Pliocene sedimentary package for petroleum formation (Figures 2.3 and 2.4 below). The Whiticar et al (2003) assessment does not address migration or trapping histories and makes no prediction about potential reservoir locations. Because there are a number of basement highs throughout the basin it is considered reasonable to assume that hydrocarbons did not migrate from one depocenter to another across a basement high.

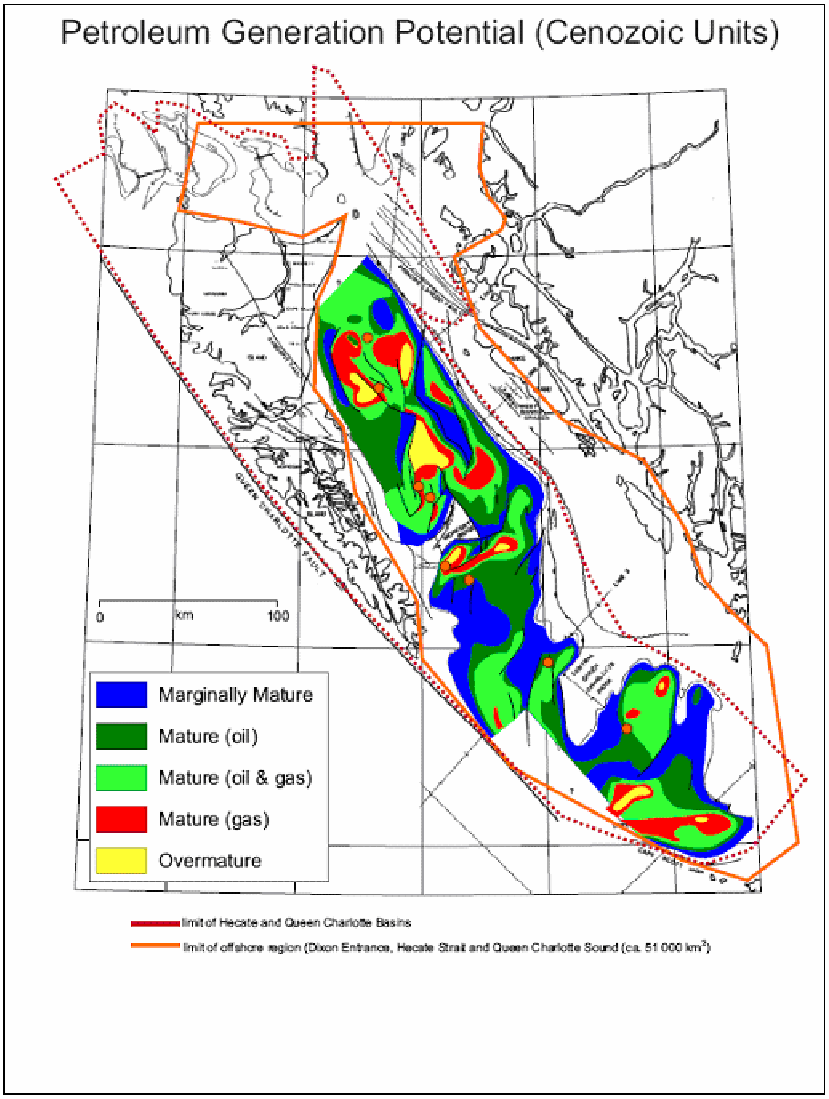
Whiticar et al outline two areas where the Tertiary Skonun Formation was buried the deepest and might therefore have yielded the largest amount of hydrocarbons (Figure 2.3).

The distribution of the older Mesozoic oil-prone source rocks in the offshore regions is speculative as none of the Shell wells was drilled to deep enough depths to intersect them. Recently Haggart (2003) and Lyatsky (2006) suggested that the Mesozoic oil-

[8] Cook Inlet recovery factors for offshore fields are in the order of 36% for oil (Advanced Resources International 2005) and 80-90% for gas (Hartz 2006, Thomas et al 2004). It should be noted, however, that the gas fields discovered to date occur at shallow depths and close to shore in Cook Inlet (Thomas et al 2004). By contrast, the prospective parts of QCB lie further from shore. Also, there are two additional potential sources for QCB gas: the stratigraphically deeper Mesozoic strata and the shallower Tertiary Skonun Formation. Gas from the Mesozoic source could be trapped at depths greater than the Cook Inlet fields, which would also lead to lower recovery. For these reasons the conservative recovery factor of 67% seems reasonable.

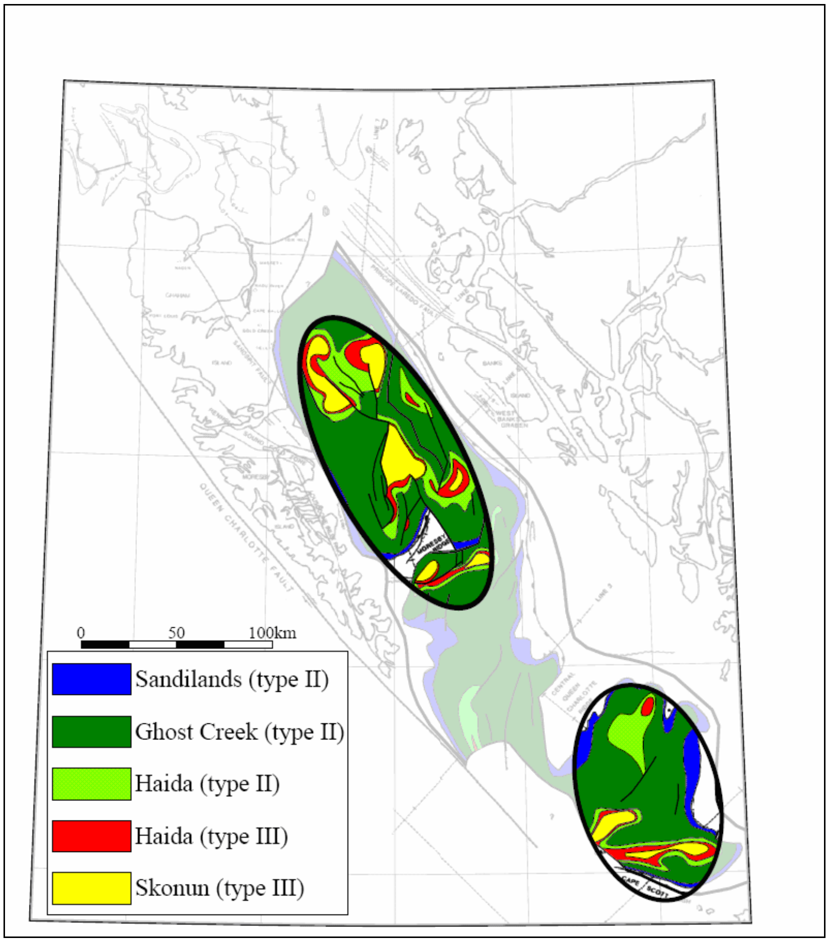
prone source rocks extend in a southeast direction from Haida Gwaii beneath western Queen Charlotte Sound and that this region may be a prime oil exploration area (Figure 2.4).

Figure 2.2: Analysis of Petroleum Potential in QCB



Source: Whiticar et al. 2003.

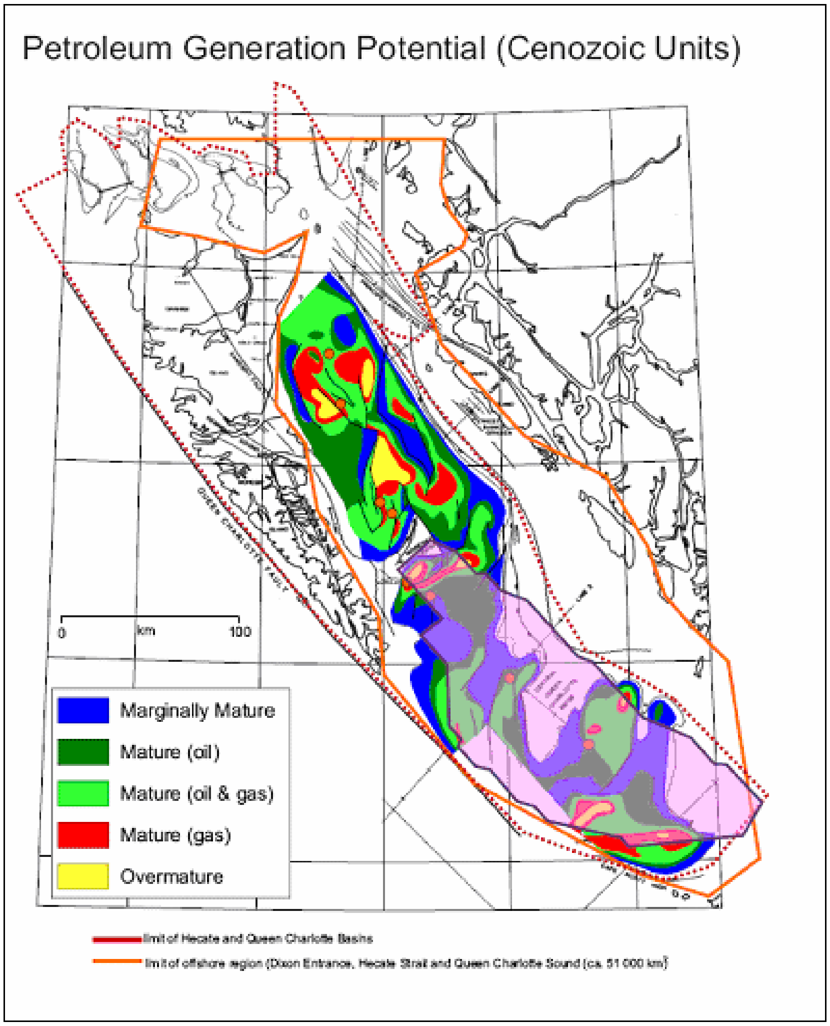
Figure 2.3: Areas of Highest Potential Hydrocarbon Generation in QCB



Colour coding shows areas where kerogen in the assumed source rock beds below Hecate Strait and Queen Charlotte Sound is predicted to be transformed into hydrocarbon by more than 50%. In the two encircled zones the Skonun Formation is buried the deepest and might have therefore generated the largest amount of hydrocarbon. Distribution of Mesozoic source rocks is highly unknown, but likely at least in Queen Charlotte Sound. The southern encircled area therefore bears extra potential based on the Mesozoic petroleum system.

Source: Whiticar et al. 2003.

Figure 2.4: Analysis of Petroleum Potential in QCB (with the outline of an area considered to be prospective for oil exploration)



Sources: Whiticar et al. 2003; Lyatsky 2006.

The highlighted area in Figure 2.4 indicates the area considered by Lyatsky (2006) to be the most prospective for oil exploration.

2.1.4 Summary of QCB Resource Assessment

The estimates used in this report of the oil and gas in place in QCB are based on the probabilistic assessment of the basin completed by the GSC using the statistical model PETRIMES (Hannigan et al. 2001). The in-place resource numbers were converted to marketable resources by applying recovery factors of 34% for oil and 67% for gas. These assumed recoveries are conservative when compared to historical production data from Cook Inlet.

The most likely locations where these oil and gas fields will be discovered are considered to lie in the prospective fairway that lies close to the axis of Hecate Strait and extends southwards into Queen Charlotte Sound.

2.2 Cost Analyses[9]

Utilizing the results from the resource assessment analysis undertaken in Section 2.1, the cost assessments are performed under the assumption that the top ranked pools for oil and for gas in the Miocene play will be found and developed. These pools represent the second largest fields identified in the resource assessment of QCB. Hence, the cost, rent and expenditure impact analyses that follow are based upon 578 million bbls of recoverable oil and 2.736 tcf of natural gas. These developments are assumed to be stand-alone developments. That is, the oil development does not have associated gas and the natural gas development does not produce any commercial quantities of oil.[10]

However, based on a chemical analysis of earlier drilling results,[11] it is possible, but not certain, that the natural gas stream may contain natural gas liquids (NGLs). Accordingly, two separate gas scenarios were undertaken — a "wet gas" scenario that allows for NGLs to be contained in the raw gas produced and a "dry gas" scenario that assumes NGLs are absent from the gas stream. Specifically, the chemical analysis reproduced in Appendix 2C of the report (Table 2C.1), indicates that for each million cubic foot of raw natural gas production, one should expect to obtain, as well, 4.7 bbls of condensate, 11.9 bbls of butane and 11.2 bbls of propane. For the analysis considered in this study, the ethane is assumed to be left in the natural gas stream and sold jointly with the methane.

Finally, since it is not possible to know specifically where in QCB the developments will occur, it was decided to consider two possible variants on each of the scenarios.[12] Consistent with the Whiticar analysis referred to in Section 2.1 (Whiticar et al 2003), the variants allow for the oil or gas fields to be found either relatively close to shore

[9] In interpreting the assumptions utilized in the cost and rent analysis, it is important to appreciate that every effort has been made to ensure that the assumption utilized were reasonable. However, it is possible that other analysts might favour some assumptions other than those utilized in this study. Given this possibility, the assumptions employed in this analysis were reviewed for their reasonableness by experts who were familiar with both the oil and gas industry and British Columbia's offshore.

[10] This assumption, identical to that invoked by Bridges and Associates (2004a) in their analysis of British Columbia offshore oil and gas projects, is one of convenience. By separating the oil analysis from the gas analysis, it allows one to focus on the capital and cost profiles associated with either the oil or gas development separately. Whether oil and natural gas will be found together will depend upon characteristics of the areas explored. The East Coast of Canada, for example, has projects that are only natural gas (Sable), only oil (Terra Nova and Hebron) and a combination of oil and gas (Hibernia and White Rose).

[11] The chemical analysis was based on the Sockeye B-10 well drilled by Shell in the 1960s. See Appendix 2C, Table 2C.1 for the results of the chemical analysis utilized in this study.

[12] The use of play analysis to evaluate the economic potential of undiscovered resources is a common approach used by the US Geological Survey. See, for example, Attanasi (2003, 2005), Attanasi and Freeman (2005) and Mineral Management Services (2003). As the Mineral Management Services (2003, V2) suggests: "The economic model does not predict precisely when or where individual pools will be discovered as the discovery and development rates are entirely dependent on industry effort."

(requiring an underwater pipeline of 150 km in length) or further away from shore (requiring an underwater pipeline of 300 km in length).[13]

Given the scenarios considered in this study, cost, rent and expenditure impact analyses were developed for the following scenarios:

1. **Short Pipeline Oil Scenario (SPOS)**: This scenario assumes that the produced oil is initially transported to a shore-based transshipment terminal by an underwater pipeline that is 150 km in length before being shipped by tanker to market.
2. **Long Pipeline Oil Scenario (LPOS)**: This scenario assumes that the produced oil is initially transported to a shore-based transshipment terminal by an underwater pipeline that is 300 km in length before being shipped by tanker to market.
3. **Short Pipeline Wet Gas Scenario (SPWGS)**: This scenario assumes that the produced gas containing NGLs is initially transported to a shore-based natural gas and fractionation plant for further processing by an underwater pipeline that is 150 km in length. The processed natural gas is then fed into the land-based provincial pipeline system and the NGLs are transported to market by rail or road.
4. **Long Pipeline Wet Gas Scenario (LPWGS)**: This scenario assumes that the produced gas containing NGLs is initially transported to a shore-based natural gas and fractionation plant for further processing by an underwater pipeline that is 300 km in length. The processed natural gas is then fed into the land-based provincial pipeline system and the NGLs are transported to market by rail or road.
5. **Short Pipeline Dry Gas Scenario (SPDGS)**: This scenario assumes that produced gas does not contain NGLs. The gas is initially processed on the production platform and is then transported to shore by an underwater pipeline that is 150 km in length before being fed into the land-based provincial pipeline system for transportation to market.
6. **Long Pipeline Dry Gas Scenario (LPDGS)**: This scenario assumes that produced gas does not contain NGLs. The gas is initially processed on the production platform and is then transported to shore by an underwater pipeline that is 300 km in length before being fed into the land-based provincial pipeline system for transportation to market.

The exchange rate assumed throughout this analysis is $0.85 US/Cdn and the annual rate of inflation is 2%, which applies to both prices and input costs.[14] It is assumed further

[13] While it is possible that the oil or gas fields can be found either closer to shore or further away, this range appears to be reasonable given the area that is being considered in this analysis.

[14] The 2% figure is common in Canadian forecasts of oil prices. For example, GLJ Petroleum Consultants Ltd assumes a 2% inflation for both their oil and gas price forecasts issued on October 1, 2006 (http://www.gljpc.com/pdfs/pricing.pdf); AMJ Petroleum Consultants assume a 2% annual rate of inflation for their September 30, 2006 forecast (http://www.ajma.net/price/price_2006_09.htm) and Sproule assumed 2% inflation in their November 30, 2006 forecast (http://www.sproule.com/prices/oil_escalated.htm). The longer term assumptions for exchange rates are: GLJ - $0.89 US/Cdn., AMJ - $0.88 US/Cdn. and Sproule - $0.90 US/Cdn. As well, the target inflation rate for the Bank of Canada remains at 2% (http://www.bankofcanada.ca/en/press/background_nov06.pdf). Imperial (1998, pp. 6-4) assumed that all costs and prices escalated at 3% per year in their analysis of a pipeline development of natural gas from the

that no field will be developed unless the real, after-tax rate of return for the full-cycle economics is at least 10%. 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.[15]

2.2.1 Exploration

For each of the six development scenarios considered, the assumptions about exploration activities are identical. It is assumed that each exploration program consists of a 2006 Canadian dollar expenditure of $80 million on seismic activity spread equally over two years.[16] This will be followed by a drilling program that will utilize a semi-submersible drilling rig that will be available at a rig rental rate of $450,000 (2006) US per day[17] and will have to be mobilized from Asia.[18] The mobilization costs for the rig will be $19 (2006) million Cdn.; it will cost $5.0 (2006) million Cdn. to ensure that the rig meets all Canadian standards while operating in Canadian waters; and the exploration program will have to cover another $19.0 (2006) million Cdn. in demobilization cost once the exploration program has been completed.[19] The assumed drilling cost for an exploration/delineation well is $71.3 (2006) million Cdn.[20] Finally, it is assumed that seven exploration/delineation wells will be drilled before production can commence from the field.[21] This implies that the exploration program for each scenario will cost $622 (2006) million Cdn. before considering the effects of inflation.

Grand Banks of Newfoundland and Labrador. Van Meurs (2006 p. 26) assumed 2% inflation per year in his analysis of the government-take with the proposed changes to the Alaska fiscal regime.

[15] Attanasi (2005, p.11), Attanasi and Freeman (2005), National Energy Technology Laboratory (2006, p. 27) and Locke et al. (2006, p.13) adopt a similar approach, but assume that projects with less than 12% after-tax rate of return will not be developed. Chan et al. (2005, p.8), on the other hand, assumed an after-tax discount rate of 15%. A 10% figure is used in this analysis because the project assumes that they are 100% equity financed. However, allowing debt finance would improve the return to shareholders above 10% as long as the private sector consortium can borrow funds at less than 10%.

[16] When this study wishes to signify that expenditures are adjusted for inflation relative to 2006, it does this by incorporating 2006 in parenthesis following the price figure or expenditure estimate.

[17] Canadian Association of Petroleum Producers (2006) noted that rig rates currently exceed $600,000 US/day; all-in rig drilling day rates are approximately $1 million US/day; and well costs are exceeding $100 million US. As well, a review of the rig rental rates currently being charged by Transocean, as reflected in their Fleet Update Report, indicates that the $450,000 day rate is a reasonable assumption (http://library.corporate-ir.net/library/11/113/113031/items/223168/RIGFLT-Dec01-2006-web2.pdf).

[18] Mineral Management Service (2003 V2, p.B7) also assumes in their analysis of oil and gas development in the offshore area of Cook Inlet that a rig from Asia would be towed into the area. However, in that analysis, the rig was assumed to serve as both an exploration and (if successful) a production platform. Chan et al. (2005, p. 8) also incorporated mobilization and demobilization costs into the capital estimate utilized in their analysis.

[19] The mobilization cost is based on the assumed rig rental day rate of $450,000 US/day, an average towing speed of between 5 and 7 nautical mile per hour and an assumed distance of between 4,000 and 5,000 nautical miles. The cost of bringing rigs up to Canadian standards is based on the experience on the east coast of Canada.

[20] Based on the experience in Atlantic Canada, this assumes that the rig rental cost is approximately 50% of the all-in drilling costs. In addition, the total cost per well is estimated based on the number of days expected to drill a well in offshore BC, which, in turn, is related to the historical averages observed in offshore BC with adjustment for testing and completions.

[21] While it is not possible to know precisely the number of exploration/delineation wells that will be required for success, an assumption of seven wells is consistent with assumptions used in other studies. For

2.2.2 Development and Production

Each of the development scenarios assumes that a steel semi-submersible production technology is utilized. This is a conservative assumption that relies on the assessment of Strong et al. (2002, p.16), which indicated that most of the waters of Hecate Strait, Queen Charlotte Sound and the Dixon Entrance are between 200 and 400 metres in depth. [22] For deeper waters, a floating system, perhaps tied to subsea wells, may provide the best development alternative. Since it is not possible to know in advance the water depths that will exist where these fields are found, it was decided to go with the more conservative assumption that a semi-submersible technology would be utilized. Others have been faced with similar decisions and have opted for technologies that are more appropriate for shallow-water developments.[23] However, these assumptions are no more valid than the conservative assumption employed in this analysis.

As in Locke et al. (2006, p.14), information on the non-drilling capital and operation costs for the steel semi-submersible production platform are taken from the Terra Nova Development Plan and updated for inflation and currency changes that have occurred since that development plan was submitted. For the gas developments, the topsides and gas processing facilities and operating costs were based on information taken from the Sable project, but the substructure for the steel semi-submersible was based on the same information as was used for the oil production platform. For both the oil and gas development scenarios, the drilling costs were estimated separately and depended upon the number of wells required to fully exploit the field.

Oil: Short Pipeline Scenario (SPOS)

The oil field will be developed utilizing a semi-submersible production technology. The assumed 2006 Canadian dollar cost for the production facility is $2.1 billion, which consists of the substructure ($600 million), topsides ($900 million), project management ($170 million) and subsea technology ($420 million).[24] The remainder of the capital cost is accounted for by development drilling. Given the size of the field, it is assumed that

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example, Mineral Management Service (2003 V1, p.ES 2) assumed, in constructing hypothetical development scenarios for land sales in Cook Inlet Alaska, 4 exploration wells and 3 delineation wells. Van Meurs (2006, p. 24) assumed an exploration program that had a 1:4 success ratio and Bridges and Associates (2004a, Table 4-1) indicates that their oil development scenario had 4 exploration wells.

[22] As well, the 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.

[23] For example, Mineral Management Service (2003 V2, p. B7) notes that the water depths in OCS areas of Cook Inlet range from 60 feet to nearly 600 feet (18-180 metres). They assume that the commercial discovery would be in the northern, shallower portions of lower Cook Inlet, and, as such, assume that the development platform would be a bottom-founded design, either with legs or a monotower. Bridges and Associates (2004) also assumed that development would occur in shallow water and, as such, smaller jack-up rigs could be utilized.

[24] The original Terra Nova development plan's estimate of the capital cost associated with the steel semi-submersible production facility and development drilling was $2.4 billion (1995) Cdn. Adjusting for inflation using a 1.22 adjustment factor (127.3 CPI 2006/104.2 CPI 1995) and removing development drilling (30% of capital expenditure) from this estimate yields $2.07 billion (2006) Cdn.

36 development (production/injection) wells will be needed to fully exploit this field.[25] The cost per development well is assumed to be $59.2 (2006) million Cdn.[26] This adds another $2.1 (2006) billion Cdn. to the assumed capital costs.

The cost of the underwater pipeline to shore is assumed to be $75,000 (2006) Cdn. per km-inch and it is assumed that a 28-inch pipeline will be needed for this oil development.[27] Hence, it is assumed that the capital cost for the underwater pipeline to transport the oil to a transshipment point onshore is $315 (2006) million Cdn. Another $100 (2006) million Cdn. has been added to the capital cost to allow for abandonment and decommissioning of the production facility at the end of its productive life. Finally, the transshipment facility is assumed to cost $300 million Cdn.[28] Therefore, the assumed capital costs for the short pipeline oil development is $4.9 (2006) billion Cdn or the total finding and development cost for this scenario is $5.6 (2006) billion Cdn.[29]

Peak production from this field is assumed to be 150,000 bbls per day, which represents approximately 9.5% annually of the total recoverable reserves.[30] The peak is expected to

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[25] In this kind of analysis, the information required to determine well productivities and drainage areas is not available and, as such, the requisite information to calculate the number of wells and determine their spacing is absent. Consequently, it is necessary to estimate the number of wells required from experiences elsewhere. For comparison purposes, consider that Van Meurs (2006, p. 24) undertook his analysis under two assumptions for the number of wells required to develop a 500 million bbls oil field – a high productivity assumption requiring 28 wells and a low productivity assumption requiring 52 wells. The Terra Nova project has plans for 44 wells to develop its 440 million bbls field; White Rose has planned for 21 wells for its 250 million bbls field and Hibernia has planned 80 wells for its 1.2 billion bbls field. On the other hand, Attanasi (2003, Table A3, p. 51) indicates a well productivity of approximately 3.7 million bbls per well for fields of comparable size developed in Alaska. In any event, 36 well should be sufficient to fully exploit a 578 million bbls oil field, especially with enhanced recovery techniques and horizontal drilling technology available currently.

[26] It is not uncommon to assume that exploration wells cost more to drill than development wells. See, for example, Attanasi (2003, p. 21) and Thomas et al. (2004, p. 160-1).

[27] Bridges and Associates (2004b, p. 18) assumed that oil in British Columbia's offshore would be transported to shore using a 16-inch, 130-km pipeline that would cost $111 million. This works out to $53,365 per km-inch. While the cost per km-inch for oil pipelines in the North Sea is considerably higher (approximately $100,000 per km-inch, see Appendix 2D), it was decided to be reasonably conservative and to utilize an average of these two estimates.

[28] This estimate is based on the cost of a similar facility in Newfoundland and Labrador.

[29] To give some perspective to this estimate, consider that Canadian finding development costs for oil in the last 10 years have varied between $12 and $14 Cdn. per bbl (Canadian Association of Petroleum Producers (2004)). The corresponding estimate for finding and development costs utilized in the current analysis is $9.69 Cdn. per bbl ($5.6 billion/578 million bbl). According to Canadian Association of Petroleum Producers (2006), the capital cost for the east coast oil projects were: Hibernia field - $5.8 billion, Terra Nova - $2.8 billion and White Rose - $2.3 billion. The Thunder Horse field in the Gulf of Mexico is being developed with semi-submersible technology that is estimated to cost $5 billion US (www.worldnetdaily.com/news/artiles.asp?ARTICLE_ID=47336). The Kristen project, utilizing semi-submersible technology in the North Sea, is estimated to cost $2.6 billion US to develop (www.rigzone.com/data/projects/project_detail.asp?project_id=2). The Na Kika oil and gas project, utilizing semi-submersible technology in the Gulf of Mexico, is estimated to cost $1.4 billion US to develop (http://www.rigzone.com/data/projects/project_detail.asp?project_id=99).

[30] To put this in perspective, Van Meurs (2006, p. 24) assumed 110,000 bbls per day for his 500 million bbls field analysis, the Terra Nova project was estimated to have a peak production rate of 125,000 bbls per day for its 440 million bbls field (www.offshore–technology.com/projects/terra_nova/), the White Rose project was estimated to have a peak production rate of 110,000 bbls per day its 250 million bbls field

occur in the second year of production and to last for four year before declining geometrically at 7.8% per year thereafter. Under these assumptions, the field will produce 578 million bbls over its 14 year operating life.

The assumed operating costs for this oil development consists of $120 (2006) million US in fixed operating costs and $1.50 US/bbl in variable operating cost.[31] Based on the assumed production of 578 million bbls and an operating life of 14 years, the operating cost over the life of the project is $2.9 (2006) billion Cdn. In addition, it has been assumed that the oil will be shipped by marine tankers from the transshipment point to market and that this will cost $1.00 (2006) Cdn. per bbl or the marine transportation costs will be $578 (2006) million Cdn.[32]

The relevant 2006 and as-spent-dollars data for the SPOS are provided in Appendix 2E, Tables 2E.1 and 2E.2.

Oil: Long Pipeline Scenario (LPOS)

Everything in this scenario is identical to that described for the SPOS except that the length of the underwater pipeline is assumed to be 300 km. Hence, the capital costs for the pipeline increases from $315 (2006) million Cdn. to $630 (2006) million Cdn and the capital costs assumed for the LPOS is $5.3 (2006) billion Cdn. The corresponding finding and development cost increases to $5.9 (2006) billion Cdn. The operating and marine transportation costs and the production profile are unaltered by changing the assumed length of the pipeline.

The relevant 2006 and as-spent-dollars data for the LPOS are provided in Appendix 2E, Tables 2E.3 and 2E.4.

(www.huskyenergy.ca/operations/canada/eastcoast/projects/whiterose.asp) for and the Hibernia field was expected to have a peak production of 200,000 bbls per day (Canada Association of Petroleum Producers, 2006). Mineral Management Service (2003 V2, Table B2) assumed a peak production that was equivalent to 13% of total recoverable reserves. This peak was estimated to be achieved in year two and to last for 3 years before declining at 17.5% annually. Attanasi (2003, p. 45-5 and p. 53) indicates that the peak rate of production for an oil field greater than 500 million bbls was equivalent to 10% of recoverable reserves would last for four years before declining at a rate of 12% per year.

[31] These are the operating costs that are consistent with the steel semi-submersible production rig outlined in the Terra Nova development plan. As well, at peak production, this yields an annual operating cost of $230 million (2006) Cdn., which is consistent with the experience of fields currently operating on the Grand Banks. In addition, this operating cost includes approximately $15 million per annum to operate the transshipment terminal, which corresponds to the cost to operate the Newfoundland and Labrador facility net of debt servicing charges.

[32] Bridges and Associates (2004b, p. 8) assumed that the marine cost of transporting oil from British Columbia to the United States was $0.70 US per bbl. Craig (1996) assumed $1.45 US per bbl for the cost of shipping oil from Alaska to southwestern US markets via marine tankers. Given the exchange rate utilized in this study and the difference in distances to market, $1.00 Cdn. per bbl is comparable to the estimates employed in these other studies.

Wet Gas: Short Pipeline Scenario (SPWGS)

The natural gas field for the wet gas scenario will be developed utilizing a semi-submersible production technology, with gas processing and separation facilities located onshore. The assumed 2006 cost for the production facility, subsea technology, onshore gas and onshore NGL plant is $1.8 (2006) billion Cdn.[33] The remainder of the capital cost will consist of development drilling. Given the size of the field, it is assumed that 20 development (production/injection) wells will be needed to fully exploit this field.[34] The real cost per well is assumed to be $59.2 (2006) million Cdn. This adds another $1.2 (2006) billion Cdn. to the assumed capital costs. The cost of the underwater pipeline to shore is assumed to be $100,000 Cdn per km-inch and it is assumed that a 24 inch pipeline will be needed for this gas development.[35] Hence, it is assumed that the capital cost for the underwater pipeline to transport the gas to the gas plant onshore is $360 (2006) million Cdn. Another $100 (2006) million Cdn. has been added to the capital cost to allow for abandonment and decommissioning of the production facility at the end of its productive life. Therefore, the assumed capital cost for the short pipeline wet gas development is $3.5 (2006) billion Cdn.[36] The corresponding finding and development costs are $4.1 (2006) billion Cdn. or $1.50 (2006) Cdn./mcf .[37]

[33] As noted above, the topsides and gas processing facilities are based on the Sable offshore energy project.

[34] Without knowing the specifics of the discovered natural gas field, it is not possible to predict with any precision the number of wells needed to fully develop the field. The 20-well assumption is a reasonable assumption given the information that currently exists and given the experience of other comparable fields. For example, for its six development fields and approximately the same amount of natural gas initially assumed present, the Sable project used 28 development wells, (www.cnsopb.ns.ca/genera;info/descriptions.html). Encana (2006) assumed 9 wells were needed to fully exploit Deep Panuke's one tcf of gas. Chan (2005 p10) assumed 10 wells were required to produce 550 mmcfd for 20 years and 20 wells were needed for 1000 mmcfd. Imperial (1998, p6-6 Tables 6.4 & 6-5) assumed that for a new gas facility on the Grand Banks to produce 1.4 tcf of gas, it would require 10 development wells. Thomas et al. (2004, p.176) reports that the Kenai River field had produced 2.235 tcf as of the end of 2003 from approximately 37 wells. As well, Thomas et al. (2004, p158 Table 4.4) lists the fields operating in Cook Inlet in 2003 and the number of completed producing wells associated with each field. There were 7 identifiable fields which accounted of 93 producing wells. This implies that there was an average of 13.3 wells per field. The range of producing wells per field went from 4 for Swanson River to 37 for Kenai. Mineral Management Services (2003, V2 Table B2) had 6 production wells for their hypothetical Alaska project.

[35] The Sable Offshore Energy project also assumed a 24-in 225 km pipeline to shore (ExxonMobil Sable DPA (www.soep.com/cgi-bin/getpage?pageid=1/5/0&dpa=1/3/1/4). The proposed Encana development of the Deep Panuke project includes a 22 inch pipeline that will run 176 km and will cost $200 million or $51, 563 per km-inch. The Imperial Venture Corp. (1998, p. 5-15) assumed a 24-inch pipeline for a gas transportation system that was need to transport 500 mmcf/d. The pipeline is assumed to be 310 miles long (p. 5-12). This works out to slightly more than $60,000 US/km-inch for the pipeline scenario considered. Bridges and Associates (2004a, p.14) assumed that natural gas was transported to shore through a 12-inch, 70 km pipeline. Thomas (2004, p.180) assumed a 24-inch, 300-km pipeline for a 330 mmscf/d development. On the other hand, comparable underwater natural gas lines in the North Sea had an average cost of $152, 252 Cdn. per km-inch. As such, the $100,000 Cdn. per km-inch used in this study is the midpoint of the Canadian and North sea estimates and is meant to be a relatively conservative estimate.

[36] The development cost for the Sable project was $3 billion (http://www.gov.ns.ca/energy/AbsPage.aspx?id=1380&siteid=1&lang=1).

[37] This finding and development for natural gas compares well to recent estimates for Canada. Canadian Association of Petroleum Producers (2004) indicates that the finding and development cost in Canada in 2000 was $1.50 Cdn/mcf.

Given that 2.7 tcf of natural gas and 73 million bbls of NGLs (10 million bbls of condensate, 33 million bbls of butane and 31 million bbls of propane) are to be produced, it is assumed that peak raw gas production is 473 mmcf/d (6.3% annually of total recoverable reserves), the peak will last for 12 years, with a one year ramp up in production and the geometric decline after peak production is 25%. The production is assumed to last for 25 years. In addition, given the extraction of NGLs from the raw gas stream, a 3.9% shrinkage factor was applied. Based on a chemical analysis of the drilling results associated with the earlier Sockeye well, it is assumed that from each mmcf of raw gas, 4.7 bbls of condensate, 11.9 bbls of butane and 11.2 bbls of propane will be produced. Further, 3% of the produced gas is assumed to be consumed for field use and, as such, peak sales gas production is 441 mmcf/d.[38] Finally, natural gas and NGLs are further processed and separated at onshore gas and fractionation plants.

The assumed operating costs for this gas development consists of $60 (2006) million US in fixed operating costs and $0.10 (2006) million US/mcf in variable operating cost, which requires $91(2006) million at peak production.[39] Based on the assumed production of 2.7 tcf of natural gas, 73 million bbls of NGLs and an operating life of 25 years, the uninflated operating cost over the life of the project is $2.1 (2006) billion Cdn. In addition, it has been assumed that the natural gas will be shipped by domestic pipelines to market and the toll will be $1.00 Cdn/mcf of natural gas shipped, which will cost $2.6 (2006) billion Cdn. over the life of the project.[40]

The relevant 2006 and as-spent-dollars data for the SPWGS are provided in Appendix 2E, Tables 2E.5 and 2E.6.

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[38] For comparison purposes, compare this production profile to the Sable project. For example, Gardiner-Pinfold (2002, pp.10 & 36) indicated that at the time of their study, Sable contained 2.6 tcf of gas, was producing 550 mmcfd of gas, selling 460 mmcfd and 20,000 bbls of NGLs per day. Imperial (1998, pp. 6-5, Table 6.3) assumed that with a new facility on the Grand Banks and a total field size of 1.4 tcf, peak production would be 140 bcf (or 10% of total reserves); would last for 6 years and decline at 8.5% per year. Bridges and Associates (2004b) assumed a peak production of 78 mmcf/d. Mineral Management Services (2003, V2 Table B2) assumed a gas production 190 BCF, a peak production of 10% of eventual sales gas produced, an eight year peak, a two year ramp up for gas and a decline rate of 50% decline rate. Thomas et al. (2004, p.139-143) assumed an exponential decline between 20 and 22%. As well, Thomas et al. (2004, p.145) reported that Beluga River had 4 years at peak, where the peak was 11.7% of total production and for North Cook Inlet, peak was 5 years and peak was 9.6% of total production for gas. Thomas et al. (2004 p. 159) assumed that the average lease usage of all dry gas fields in the Cook Inlet is 3.3%. Mineral Management Service (2003, p. B6) assumed that field consumption (test flaring, power generation and other platform uses) used 0.5 billion cubic feet annually through the productive life of the platform. This corresponds to 2.7% of raw gas produced. Attanasi and Freeman (2005, p. 13) assumed that their gas project would remain at peak until 75 to 80 of the field’s original reserves were produced and then decline at 24 percent per year.
[39] The operating costs for the Sable project, according to Gardner-Pinfold (2002, p. 40), was $133 million. Note, the fixed operating cost in the current study is approximately 4% of facilities costs. This corresponds to 5% used by CERI and 6.2% used by Imperial (1998). As well, this operating cost estimate includes the operating costs associated with the gas plant and the fractionation plant.
[40] While the current domestic toll is approximately $0.50 Cdn/mcf, it was decided to add another $0.50 to this toll to allow for the possibility that additional capacity might be required in the domestic system and, as such, this capacity addition would be recovered from the users of the domestic pipeline.

Wet Gas: Long Pipeline Scenario (LPWGS)

Everything is identical to that described for the Short Pipeline Scenario except the length of the underwater pipeline is assumed to 300 km. This implies that the capital costs for the pipeline increases from $360 (2006) million Cdn. to $720 (2006) million Cdn. Consequently, the capital costs assumed for the long pipeline oil scenario is $3.8 (2006) billion Cdn. while total finding and development costs are $4.4 (2006) billion Cdn. The operating costs and the domestic pipeline transportation costs are unaltered by this assumption.

The relevant 2006 and as-spent-dollars data for the LPWGS are provided in Appendix 2E, Tables 2E.7 and 2E.8.

Dry Gas: Short Pipeline Scenario (SPDGS)

The natural gas field for the dry gas scenario will be developed utilizing a semi-submersible production technology. The assumed 2006 cost for the production facility, gas processing equipment and subsea technology is $1.7 billion Cdn. The remainder of the capital cost will consist of development drilling. Given the size of the field, it is assumed that 20 development (production/injection) wells will be needed to fully exploit this field. The cost per well is assumed to be $59.2 (2006) million Cdn. This adds another $1.2 (2006) billion Cdn. to the assumed capital costs. The cost of the underwater pipeline to shore is assumed to be $100,000 Cdn per km-inch and it is assumed that a 24 inch pipeline will be needed for this gas development. Hence, it is assumed that the capital cost for the underwater pipeline to transport the gas to the gas plant onshore is $360 (2006) million Cdn. Another $100 (2006) million Cdn. has been added to the capital cost to allow for abandonment and decommissioning of the production facility at the end of its productive life. Therefore, the assumed capital costs for the short pipeline wet gas development is $3.4 billion Cdn. and total finding and development costs are $4.0 (2006) billion Cdn..

The assumed operating costs for this oil development consists of $60 (2006) million US in fixed operating costs and $0.10 (2006) million US/mcf in variable operating cost. Based on the assumed production of 2.7 tcf of natural gas and an operating life of 25 years, the operating cost over the life of the project is $2.1 (2006) billion Cdn. In addition, it has been assumed that the natural gas will be shipped by domestic pipelines to market and the toll will be $1.00 Cdn/mcf of natural gas shipped, which will cost $2.7 (2006) billion Cdn. over the life of the project.

Given that 2.7 tcf of natural gas are to be produced, it is assumed that peak raw gas production is 473 mmcf/d (6.3% annually of total recoverable reserves), the peak will last for 12 years, with a one-year ramp up in production and the geometric decline after peak production is 25%. The production is assumed to last for 25 years. In addition, 3% of the produced gas is assumed to be consumed for field use and, as such, peak sales gas production is 459 mmcf/d. Finally, natural gas is processed on the production facility.

The relevant 2006 and as-spent-dollars data for the SPDGS are provided in Appendix 2E, Tables 2E.9 and 2E.10.

Dry Gas: Long Pipeline Scenario (LPDGS)

Everything is identical to that described for the Short Pipeline Scenario except the length of the underwater pipeline is assumed to be 300 km. This implies that the capital costs for the pipeline increases from $180 (2006) million Cdn. to $360 (2006) million Cdn. Consequently, the capital costs assumed for the long pipeline oil scenario is $3.7 billion Cdn. and total finding and development costs are $4.3 (2006) billion Cdn. The operating costs and the domestic pipeline transportation costs are unaltered by this assumption.

The relevant 2006 and as-spent-dollars data for the LPDGS are provided in Appendix 2E, Tables 2E.11 and 2E.12.

SECTION 3

ECONOMIC RENT BENEFITS

Based on the assumed cost and production profiles for each scenario described in Section 2.2 and a series of assumptions about output prices, financial viability analyses were undertaken for each scenario to determine for each the before-tax surplus (economic rent) and its distribution between private and public sectors.

In undertaking these analyses, a number of additional assumptions were needed. First, the financial viability analysis for each option was performed utilizing a ring-fenced assumption.[41] Other assumptions utilized in the analysis were:

- exploration expenses are fully expensed for the purposes of calculating corporation income tax liabilities;
- development wells can be written off on a 30% declining balance basis;
- all other development capital can be written off on a 25% declining balance basis;
- provincial royalties are deductible for the purpose of calculating corporation income tax liabilities;
- projects are 100% equity financed;
- the price received for British Columbia crude will be 84% of the West Texas Intermediate (WTI) price to reflect quality differences between the medium crude expected in QCB and Texas light sweet crude;[42]
- the assumed prices, net of transportation cost, received for NGLs are: $48.10 US/bbl (2006) for condensate, $34.52 US/bbl (2006) butane and $29.83 US/bbl (2006) for propane;[43]
- project viability is assessed over the full assumed life of a field;[44]

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[41] A ring-fenced assumption means that the investment costs incurred early in the project's life must be carried forward and written off against income earned from the project only. Effectively, this means that we are assuming that this project is being developed by entities that have no other profitable developments within Canada that can use the losses on the British Columbia projects to reduce their profitability and tax liabilities immediately. Without knowing who might look for or find the oil and gas fields in British Columbia's offshore, this seems reasonable. However, if the consortium involved can use losses on the British Columbia projects to defray tax liabilities on profitable projects elsewhere in Canada, then the projects analyzed in this study will show greater viability than reflected in the analysis utilized here.

[42] According to GLJ Petroleum Consultants January 1, 2007 forecast, the long-term price (expressed in 2007 dollars) for WTI is estimated to be $52 US/bbl, while the corresponding long-term price for medium crude oil was $51.25 Cdn/bbl or $43.56 US/bbl (expressed in 2007 dollars), or medium crude is expected to sell for approximately 84% of the WTI price.

[43] The estimated NGL prices is based upon the long term prices reported in GLJ Petroleum Consultants January 1, 2007 forecast and assuming $1 US/bbl for transportation costs. The Canadian price figures in the GLP forecast were converted to 2006 dollar prices by assuming a 2% annual inflation rate and were converted into US dollars by assuming an exchange rate of $0.85 US/Cdn.

[44] This means that if the discounted cash flow turns negative in any given year during the life of a project, production does not cease. This assumption is consistent with the principle of conservatism adopted in the report.

- the Newfoundland and Labrador generic offshore oil royalty regime is utilized for calculating royalties associated with the oil developments;[45]
- the Nova Scotia offshore regime for natural gas is used for calculating the royalties associated with the natural gas developments;[46] and
- the impact of direct corporation income taxes and royalty payments from the oil and gas developments on provincial equalization entitlements are not analyzed.[47]

These financial viability analyses demonstrate whether, given the assumptions utilized, any of the development options can be developed at a profit. That is, these analyses indicate which of the scenarios are capable of generating a 10% real, after-tax rate of return when all of the project's costs and revenues are considered over its entire life cycle. The 2006 oil prices utilized in these financial viability analyses for both the short and long pipeline oil scenarios range, in increments of $5 US/bbl, from $20 to $100 US/bbl for WTI. The corresponding 2006 natural gas prices utilized in both the short and long pipeline versions of the dry and wet gas scenarios range from $2 to $10 US/mmbtu, in increments of $1/mmbtu.

To illustrate the reasonableness of the price assumptions utilized in this analysis, Figures 3.1 and 3.2 provide publicly-available, Canadian-based forecasts for oil and natural gas prices[48]. Tracking prices forward from 2010, it is reasonable to put the long-term price for WTI crude oil in 2006 dollars between $70 and $80 US/bbl. The corresponding long-term price forecast for natural gas is between $6 and $7 US/mmbtu. Clearly, the range of prices employed in this analysis lies on both sides of the forecast price band illustrated in Figures 3.1 and 3.2.

It is apparent that these price forecasts look conservative in the context of recent developments in oil and natural gas prices. However, their use is consistent with the principle of conservatism employed in the study. Moreover, as outlined below, the report provides data for estimating economic rent at resource prices outside the range of prices used in the analysis if such estimates are of interest.

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[45] The royalty for oil is the Newfoundland and Labrador generic royalty and is described in Appendix 3A.
[46] The royalty for natural gas is Nova Scotia's generic royalty–base regime and is also described in Appendix 3A.
[47] At the time of this analysis, there had been no decision as to how the equalization program will be amended. Whether non-renewable natural resources will be wholly or partially removed from the equalization formula remains a possibility.
[48] The forecast were converted into a common year and currency. The forecasts assume that all prices are in 2006 prices. This information was derived from GLJ Petroleum Consultants' January 1, 2008 forecast (http://www.gljpc.com/); Sproule Associated Limited's February 29, 2008 forecast (http://www.sproule.com/prices/defaultprices.htm); AMJ Petroleum's Consultants' December 31, 2007 forecast (http://www.ajma.net/price/price_2006_09.htm) and the US Energy Information Agency's 2008 Energy Outlook (www.eia.doe.gov/oiaf/aeo/excel/yearbyyear.xls).

Figure 3.1: Select Price Forecasts for Crude Oil
($US/bbl – Constant 2006 Prices)

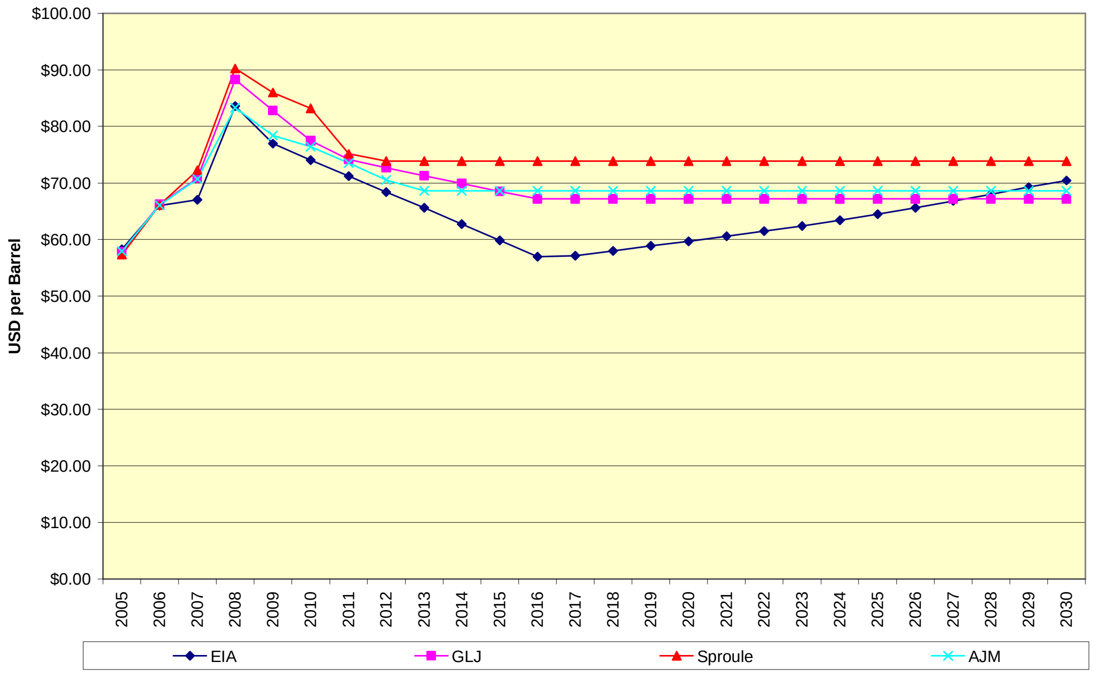
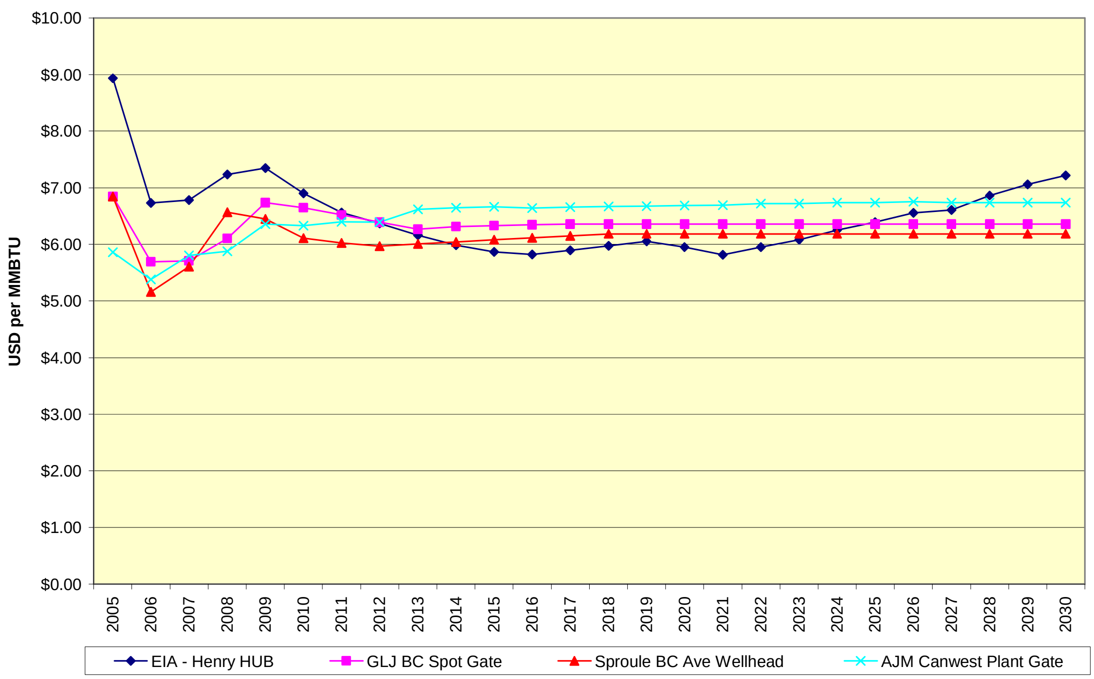


Figure 3.2: Select Price Forecasts for Natural Gas ($ Cdn/mmbtu – Constant 2006 Prices)



For each of the development scenarios, the summary financial viability analyses are presented below. The statistics for the detailed financial viability analyses are attached in Appendices 3B-3G.

If there is interest in estimating net revenue (economic rent) and shares of rent for each stakeholder (the provincial government, the federal government and the consortium of companies that undertakes the activity) at oil and gas prices not used in the analysis, it is possible to extrapolate from the least squares relationships between prices and revenue estimated by simple regression analysis using data in the tables in this section. Estimated linear trends showing the change in revenue for each stakeholder with respect to a dollar change in the price of the resource are presented as equations in Appendix 3H. Estimates of revenue can be calculated from these equations by inserting price as variable ‘x’ to generate values for revenue (variable ‘y’). Shares of rent can then be calculated directly from revenue estimates for each stakeholder.

All financial viability and economic rent estimates are in 2006 prices.

3.1 Financial Viability Analysis: Short Pipeline Oil Scenario (SPOS)

Table 3.1 and Figures 3.3 and 3.4 below summarize the key statistics from the financial viability analysis that was undertaken for the short pipeline oil scenario. The detailed financial viability statistics are provided in Appendix 3B, Tables 3B.1 to 3B.17. From Table 3.1 below, the short pipeline oil development described in this study will be profitable to develop for all prices above $30 US/bbl. Since the long-term price is expected to range between $70 and $80 US/bbl, there is a high probability that this type of oil development can be profitably exploited in offshore British Columbia should that opportunity become available in the future.

Since $70 US/bbl is at the lower range of the long-term price forecasts, the detailed discussion that follows for the financial viability of the short pipeline oil scenario will focus primarily on this price scenario. Based on the $70 US/bbl price scenario and the Newfoundland and Labrador generic offshore royalty, the British Columbia government can expect to receive $11.2 billion (2006) in corporation income taxes and royalties over the life of this development. This is equivalent to $2.1 billion in present value terms, given that a 10% real discount rate is utilized.[49] The federal government can expect to receive approximately $5.1 billion (2006) in direct corporation income taxes or a discounted value of $1.1 billion.[50] The corresponding revenue flow, net of explicit

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[49] Corporations operating in more than one province may pay corporate tax in one or more of those provinces. Corporate taxable income is allocated among the provinces in which the corporation has a permanent establishment (office, mine, well, etc.) based on factors including the ratios of (i) wages and salaries in the province, and (ii) gross revenues in the province, to those for Canadian operations. Depending upon the location of the corporation's employees (particularly head office staff) and sales activity, the actual corporate taxes may be higher or lower than those that would be received if it were a stand-alone activity operating only in British Columbia.

[50] There has been no adjustment for the equalization implications of this increase in oil revenue flowing to the provincial treasury.

costs,[51] to the private consortium of companies[52] that will develop this project is $14.6 billion (2006) or $2.3 billion in discounted present value terms. This translates into a real, after-tax internal rate of return on total capital of 22.9%.

As oil prices rise, the rent going to each stakeholder increases. For every dollar increase in the price of a barrel of oil, the provincial government gains approximately $222 million (2006) in undiscounted revenue ($44 million in discounted present value terms), the federal government gains approximately $88 million (2006) ($19 million in discounted terms), and the companies gain approximately $262 million (2006) ($58 million in discounted terms). For details, see the coefficients on the price variable ('x') in the SPOS equations in Appendix 3H.

Figures 3.3 and 3.4 illustrate how the discounted and undiscounted shares of pre-tax net cash flow vary with price. The share of undiscounted revenues that accrues to the provincial government increases from 28.8% to 37.3% as prices rise from $35 to $100 US/bbl. On the other hand, the share of discounted revenues going to the provincial government declines from 43.5% to 38.8% over the same price range. The undiscounted effects are explained by the fact that at low prices, the profit-sensitive components of royalties and corporation income taxes are less effective and the revenue results are being driven more by the ad valorem royalties. As such, even though profitability is low, these ad valorem royalties tend to extract a higher share of the net cash flow from the project. However, price increases have less of an impact on discounted shares because profit-sensitive royalties do not kick in significantly until later years and are therefore heavily discounted.

The federal government share decreases as prices rise because of the increasing importance of provincial government royalties. This increase in the importance of provincial royalties has two effects: (1) royalties act as a separate revenue source for the provincial government that is not directly available to the federal government and (2) since royalties are deductible from the corporation income tax base, the high royalty rate reduces the effective tax rate for corporation income taxes, which, in turn, implies that the federal share will be smaller, everything else equal.

The share of undiscounted revenues going to the private companies developing this oil field decreases at higher prices. This simply reflects the fact that at lower prices, the consortium requires a longer period of time to recoup its expenditure through tax and royalty write-offs. As well, for the same reason, the discounted share going to the consortium increases with prices. In other words, the tax and royalty write-off are used up more quickly, implying that the consortium is in a taxable position earlier.

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[51] Explicit costs are actual expenditures. They do not include the opportunity costs of the funds invested. Instead, opportunity costs are reflected in the discount rate used in the NPV analysis.

[52] While this analysis assumes that any offshore oil or gas development in British Columbia will be developed through the private sector only, this does not rule out the possibility that the provincial government may form a crown corporation that will assume a working interest in such a development. However, there is currently no such entity.

The relative discounted shares at $70 US/bbl are: 38.7% for the provincial government, 19.2% for the federal government and 42.0% for the consortium that develops the oil field. This translates into the equivalent of $2.1 billion in present value terms for the provincial treasury, $1.1 billion for the federal treasury and $2.3 billion for the members of the consortium. Obviously, at $70 US/bbl, this project is profitable, generates significant benefits to all stakeholders and would be developed if this opportunity became available.

Table 3.1: Summary of Financial Viability Analysis – Short Pipeline Oil Scenario (monetary values in millions 2006 dollars Cdn)

Case	Prov. Rev. Nominal	Fed. Rev. Nominal	After-Tax NCF Nominal	IRR Nominal	Prov. Rev. Discounted (@10% Real)	Fed. Rev. Discounted (@10% Real)	After-Tax NCF Discounted (@10% Real)	IRR Real
$20 US/bbl	$942	$522	$904	4.7%	$166	$76	($749)	2.6%
$25 US/bbl	$1,432	$1,106	$2,685	9.0%	$260	$188	($352)	6.9%
$30 US/bbl	$2,284	$1,606	$4,191	12.2%	$405	$297	($2)	10.0%
$35 US/bbl	$3,145	$2,106	$5,687	14.8%	$566	$404	$333	12.5%
$40 US/bbl	$3,986	$2,611	$7,195	17.0%	$732	$512	$662	14.7%
$45 US/bbl	$5,003	$3,073	$8,573	18.9%	$919	$616	$975	16.6%
$50 US/bbl	$6,447	$3,427	$9,631	20.4%	$1,179	$701	$1,233	18.1%
$55 US/bbl	$7,694	$3,832	$10,836	21.8%	$1,424	$790	$1,501	19.4%
$60 US/bbl	$8,880	$4,251	$12,087	23.1%	$1,663	$881	$1,774	20.7%
$65 US/bbl	$10,045	$4,676	$13,354	24.3%	$1,904	$971	$2,046	21.8%
$70 US/bbl	$11,186	$5,106	$14,638	25.4%	$2,140	$1,062	$2,322	22.9%
$75 US/bbl	$12,324	$5,538	$15,925	26.4%	$2,377	$1,153	$2,597	23.9%
$80 US/bbl	$13,453	$5,971	$17,218	27.4%	$2,612	$1,245	$2,873	24.9%
$85 US/bbl	$14,571	$6,408	$18,520	28.3%	$2,844	$1,337	$3,152	25.8%
$90 US/bbl	$15,680	$6,847	$19,829	29.2%	$3,074	$1,430	$3,432	26.7%
$95 US/bbl	$16,802	$7,283	$21,128	30.0%	$3,311	$1,522	$3,707	27.4%
$100 US/bbl	$17,924	$7,719	$22,425	30.7%	$3,548	$1,614	$3,980	28.2%

Table 3.1: Summary of Financial Viability Analysis – Short Pipeline Oil Scenario (Continued)

Case	Undiscounted Share of Pre-Tax NCF Prov. Gov.	Undiscounted Share of Pre-Tax NCF Fed. Gov.	Undiscounted Share of Pre-Tax NCF Proponent	Discounted Share of Pre-Tax NCF Prov. Gov.	Discounted Share of Pre-Tax NCF Fed. Gov.	Discounted Share of Pre-Tax NCF Proponent
$20 US/bbl	**No Project**					
$25 US/bbl	**No Project**					
$30 US/bbl	**No Project**					
$35 US/bbl	28.8%	19.3%	52.0%	43.5%	31.0%	25.5%
$40 US/bbl	28.9%	18.9%	52.2%	38.4%	26.9%	34.7%
$45 US/bbl	30.1%	18.5%	51.5%	36.6%	24.5%	38.8%
$50 US/bbl	33.1%	17.6%	49.4%	37.9%	22.5%	39.6%
$55 US/bbl	34.4%	17.1%	48.5%	38.3%	21.3%	40.4%
$60 US/bbl	35.2%	16.9%	47.9%	38.5%	20.4%	41.1%
$65 US/bbl	35.8%	16.7%	47.6%	38.7%	19.7%	41.6%
$70 US/bbl	36.2%	16.5%	47.3%	38.7%	19.2%	42.0%
$75 US/bbl	36.5%	16.4%	47.1%	38.8%	18.8%	42.4%
$80 US/bbl	36.7%	16.3%	47.0%	38.8%	18.5%	42.7%
$85 US/bbl	36.9%	16.2%	46.9%	38.8%	18.2%	43.0%
$90 US/bbl	37.0%	16.2%	46.8%	38.7%	18.0%	43.2%
$95 US/bbl	37.2%	16.1%	46.7%	38.8%	17.8%	43.4%
$100 US/bbl	37.3%	16.1%	46.7%	38.8%	17.7%	43.5%

Figure 3.3: Undiscounted Share of Pre-Tax Net Cash Flow – Short Pipeline Oil Scenario: Various Prices

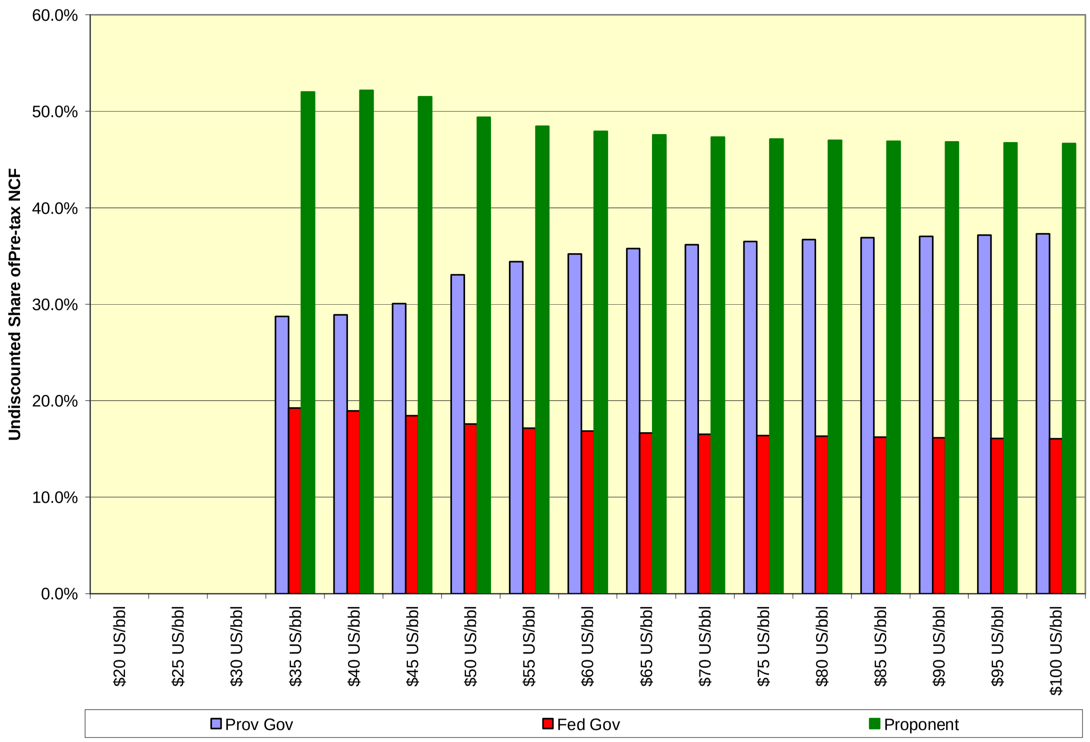
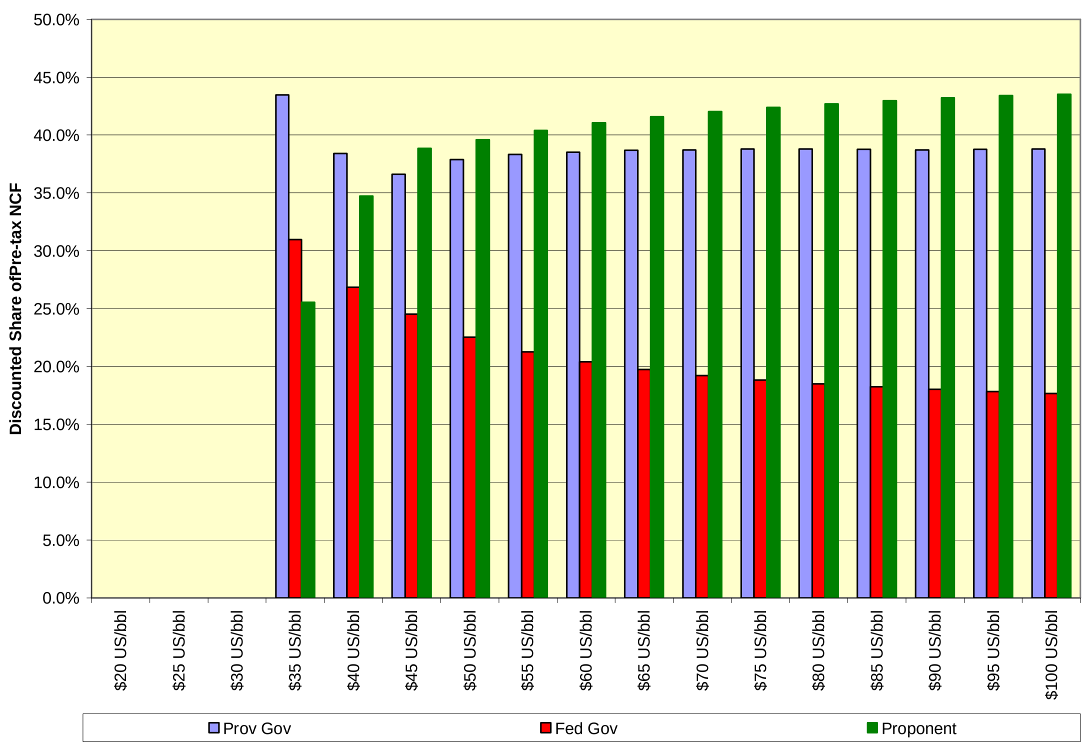


Figure 3.4: Discounted Share of Pre-Tax Net Cash Flow – Short Pipeline Oil Scenario: Various Prices



3.2 Financial Viability Analysis: Long Pipeline Oil Scenario (LPOS)

Table 3.2 and Figures 3.5 and 3.6 summarize the key statistics from the financial viability analysis that was undertaken for the long pipeline oil scenario. The more detailed statistics are provided in Appendix 3C, Tables 3C.1 to 3C.17. The results of this financial viability analysis are similar to those derived for the short pipeline oil scenario.

With an oil price of $70 US/bbl, the British Columbia government is estimated to receive $11.0 billion (2006) in undiscounted corporation income taxes and royalties from this project. This is equivalent to $2.1 billion in discounted present value terms. As well, the federal government can expect to receive approximately $5.1 billion (2006) in undiscounted corporation income taxes, which is $1.1 billion in discounted terms. The corresponding revenue flow, net of explicit costs, to the consortium of companies that will develop this project is $14.5 billion (2006) or $2.3 billion in present value terms. This corresponds to a real, after-tax internal rate of return to total capital of 22.2%.

Based on least squares estimates from data in table 3.2, for every dollar increase in the price of a barrel of oil, the provincial government gains approximately $221 (2006) million in undiscounted revenue ($44 million in discounted present value terms), the federal government gains approximately $88 million (2006) ($19 million in discounted terms), and the companies gain approximately $263 million (2006) ($58 million in discounted terms) (see Appendix 3H).

As in the short pipeline case, one observes that the share of undiscounted revenue going to the provincial government increases as prices rise from $35 to $100 US/bbl. Specifically, it goes from 28.6% to 37.1% (see Figures 3.5 and 3.6). Yet, in discounted terms, the share going to the provincial government decreases from 46.4% to approximately 38.8% over the same price range.

The federal government share decreases with prices because of the increasing importance of provincial government royalties. The federal government's share of undiscounted revenues falls from 19.4% to 16.1% as prices rise from $35 to $100 US/bbl. Over the same price range, the federal share of discounted revenues declines from 33.5% to 17.8%.

The share of undiscounted revenues being derived by the consortium developing this oil field decreases at higher prices. For instance, the undiscounted revenue share decreases from 52.0% to 46.7% as prices rise from $35 to $100 US/bbl. The discounted revenue share rises from 20.1% to 43.4% over the same price range.

The relative shares of discounted revenue at $70 US/bbl are: 38.7% for the provincial government, 19.6% for the federal government and 41.7% for the private sector consortium. This is equivalent to $2.1 billion in discounted dollars for the provincial treasury, $1.1 billion for the federal treasury and $2.2 billion for the members of the consortium.

Table 3.2: Summary of Financial Viability Analysis – Long Pipeline Oil Scenario (monetary values in millions 2006 dollars Cdn)

Case	Prov. Rev. Nominal	Fed. Rev. Nominal	After-Tax NCF Nominal	IRR Nominal	Prov. Rev. Discounted (@10% Real)	Fed. Rev. Discounted (@10% Real)	After-Tax NCF Discounted (@10% Real)	IRR Real
$20 US/bbl	$910	$464	$679	3.9%	$160	$65	($866)	1.9%
$25 US/bbl	$1,399	$1,045	$2,464	8.2%	$252	$174	($463)	6.1%
$30 US/bbl	$2,147	$1,570	$4,048	11.4%	$381	$284	($99)	9.2%
$35 US/bbl	$3,036	$2,063	$5,523	14.0%	$543	$391	$235	11.7%
$40 US/bbl	$3,879	$2,567	$7,032	16.2%	$706	$498	$567	13.9%
$45 US/bbl	$4,719	$3,073	$8,542	18.1%	$874	$607	$894	15.8%
$50 US/bbl	$6,130	$3,436	$9,624	19.7%	$1,115	$697	$1,166	17.4%
$55 US/bbl	$7,441	$3,824	$10,781	21.1%	$1,366	$785	$1,430	18.7%
$60 US/bbl	$8,659	$4,236	$12,009	22.4%	$1,610	$874	$1,700	20.0%
$65 US/bbl	$9,829	$4,659	$13,272	23.6%	$1,847	$965	$1,975	21.1%
$70 US/bbl	$10,990	$5,085	$14,541	24.7%	$2,088	$1,055	$2,247	22.2%
$75 US/bbl	$12,126	$5,517	$15,829	25.7%	$2,322	$1,147	$2,524	23.2%
$80 US/bbl	$13,266	$5,948	$17,115	26.7%	$2,560	$1,238	$2,798	24.2%
$85 US/bbl	$14,393	$6,382	$18,409	27.6%	$2,795	$1,330	$3,075	25.1%
$90 US/bbl	$15,510	$6,818	$19,712	28.5%	$3,027	$1,422	$3,353	26.0%
$95 US/bbl	$16,620	$7,257	$21,020	29.3%	$3,257	$1,515	$3,633	26.8%
$100 US/bbl	$17,739	$7,694	$22,320	30.1%	$3,492	$1,607	$3,909	27.5%

Table 3.2: Summary of Financial Viability Analysis – Long Pipeline Oil Scenario (Continued)

Case	Undiscounted Share of Pre-Tax NCF Prov. Gov.	Undiscounted Share of Pre-Tax NCF Fed. Gov.	Undiscounted Share of Pre-Tax NCF Proponent	Discounted Share of Pre-Tax NCF Prov. Gov.	Discounted Share of Pre-Tax NCF Fed. Gov.	Discounted Share of Pre-Tax NCF Proponent
$20 US/bbl	**No Project**					
$25 US/bbl	**No Project**					
$30 US/bbl	**No Project**					
$35 US/bbl	28.6%	19.4%	52.0%	46.4%	33.5%	20.1%
$40 US/bbl	28.8%	19.0%	52.2%	39.8%	28.1%	32.0%
$45 US/bbl	28.9%	18.8%	52.3%	36.8%	25.6%	37.7%
$50 US/bbl	31.9%	17.9%	50.2%	37.4%	23.4%	39.2%
$55 US/bbl	33.8%	17.3%	48.9%	38.2%	21.9%	39.9%
$60 US/bbl	34.8%	17.0%	48.2%	38.5%	20.9%	40.6%
$65 US/bbl	35.4%	16.8%	47.8%	38.6%	20.2%	41.3%
$70 US/bbl	35.9%	16.6%	47.5%	38.7%	19.6%	41.7%
$75 US/bbl	36.2%	16.5%	47.3%	38.7%	19.1%	42.1%
$80 US/bbl	36.5%	16.4%	47.1%	38.8%	18.8%	42.4%
$85 US/bbl	36.7%	16.3%	47.0%	38.8%	18.5%	42.7%
$90 US/bbl	36.9%	16.2%	46.9%	38.8%	18.2%	43.0%
$95 US/bbl	37.0%	16.2%	46.8%	38.7%	18.0%	43.2%
$100 US/bbl	37.1%	16.1%	46.7%	38.8%	17.8%	43.4%

Figure 3.5: Undiscounted Share of Pre-Tax Net Cash Flow – Long Pipeline Oil Scenario: Various Prices

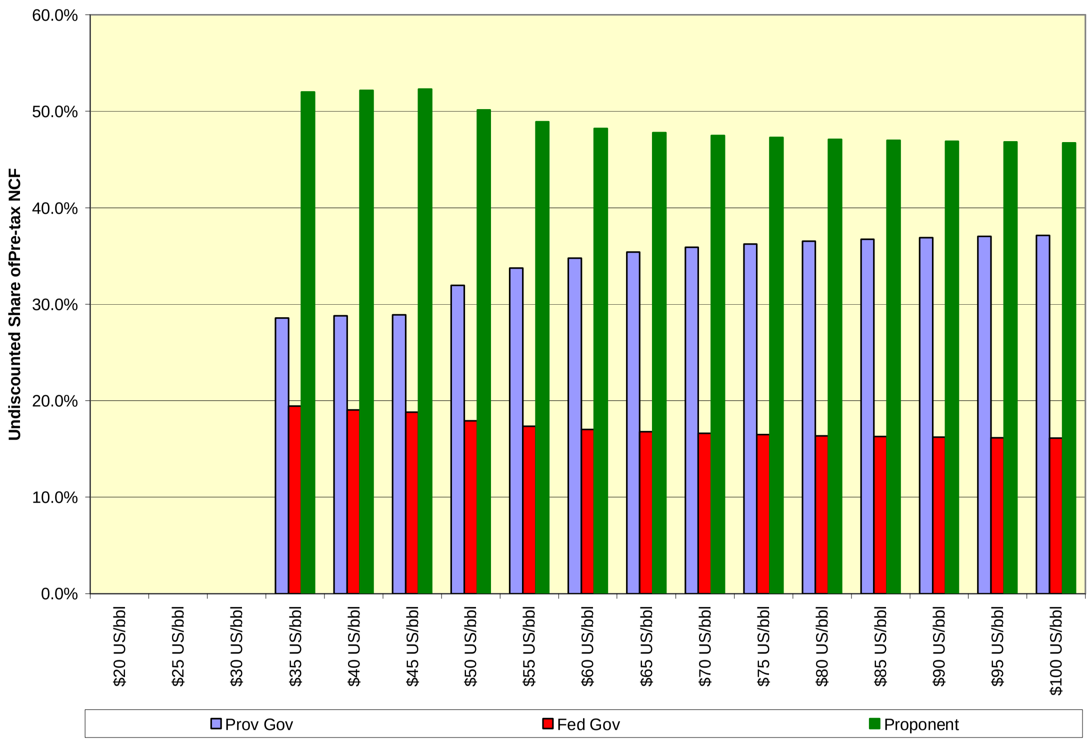
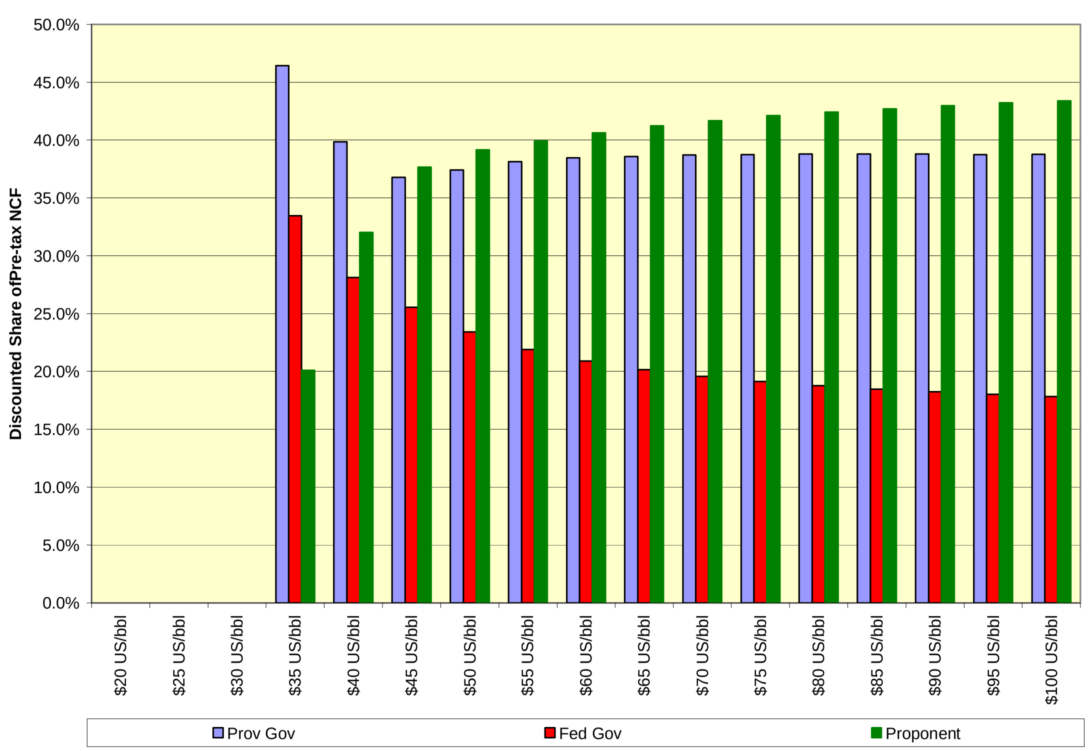


Figure 3.6: Discounted Share of Pre-Tax Net Cash Flow – Long Pipeline Oil Scenario: Various Prices



3.3 Financial Viability Analysis: Short Pipeline Wet Gas Scenario (SPWGS)

Table 3.3 and Figures 3.7 and 3.8 summarize the results of the financial viability analysis of the short pipeline wet gas scenario. The detailed financial viability statistics are provided in Appendix 3D, Tables 3D.1 to 3D.9. From Table 3.3, the wet gas development described in this study will be profitable to undertake for all prices above $4 US/mmbtu. Since the long-term price is expected to be in the range $6 to $7 US/mmbtu, then one can assume that this type of gas development can be profitably exploited in offshore British Columbia.

Based on the minimum price required for viability of $5 US/mmbtu and the Nova Scotia offshore natural gas royalty regime, the British Columbia government can expect to receive $3.3 billion (2006) in undiscounted corporation income taxes and royalties from this project. This becomes $460 million in present value terms when a 10% real discount rate is utilized. In addition, the federal government is estimated to receive approximately $1.7 billion (2006) in corporation income taxes or $280 million in present value terms. The corresponding undiscounted revenue flow, net of explicit costs, to the consortium of companies that developed this project is approximately $4.7 billion (2006) or $150 million in present value terms. This yields a real, after-tax internal rate of return to total capital of 11.3%. As well, if prices are in the $6 to $7 US/mmbtu range over the long term, then the revenue going to each stakeholder will increase. For example, the discounted revenue to the provincial treasury is between approximately $700 and $950 million if prices are in the range $6 to $7 US/mmbtu.

Based on least squares estimates from data in table 3.3, for every dollar increase in the price of a million British thermal units of gas, the provincial government gains approximately $1.3 billion (2006) in undiscounted revenue ($209 million in discounted present value terms), the federal government gains approximately $445 million (2006) ($82 million in discounted terms), and the companies gain approximately $1.3 billion ($263 million in discounted terms) (see Appendix 3H).

Figures 3.7 and 3.8 illustrate how the shares of discounted and undiscounted pre-tax net cash flow change with price. The share of undiscounted revenues that accrues to the provincial government increases from 34.2% to 40.9% as prices rise from $5 to $10 US/mmbtu. The share of discounted revenues going to the provincial government decreases from 51.6% to 44.8% over the same price range.

The federal government share decreases with prices. Specifically, the federal share of undiscounted revenues decreases from 17.7% at $5 US/mmbtu to 15.4% at $10 US/mmbtu and the share of discounted revenues falls from 31.8% to 18.6% over this price range. The corresponding changes in the share of undiscounted and discounted revenues to the private sector consortium are, respectively, 48.1% to 43.8% and 16.6% to 36.6%.

The relative shares of discounted revenues at $5 US/mmbtu are: 51.6% for the provincial government, 31.8% for the federal government and 16.6% for the consortium developing the wet gas field. This is equivalent to $460 million in present value terms for the provincial treasury, $280 million for the federal treasury and $150 million for the members of the consortium.

Table 3.3: Summary of Financial Viability Analysis – Short Pipeline Wet Gas Scenario (monetary values in millions 2006 dollars Cdn)

Case	Prov. Rev. Nominal	Fed. Rev. Nominal	After-Tax NCF Nominal	IRR Nominal	Prov. Rev. Discounted (@10% Real)	Fed. Rev. Discounted (@10% Real)	After-Tax NCF Discounted (@10% Real)	IRR Real
$2 US/mmbtu	$252	$218	($41)	1.8%	$37	$25	($832)	-0.2%
$3 US/mmbtu	$766	$828	$1,937	7.7%	$108	$113	($437)	5.6%
$4 US/mmbtu	$1,885	$1,314	$3,435	11.1%	$256	$202	($120)	8.9%
$5 US/mmbtu	$3,329	$1,725	$4,683	13.5%	$460	$284	$148	11.3%
$6 US/mmbtu	$4,792	$2,133	$5,914	15.5%	$695	$360	$391	13.2%
$7 US/mmbtu	$6,309	$2,532	$7,100	17.1%	$953	$434	$613	14.8%
$8 US/mmbtu	$7,576	$2,998	$8,469	18.7%	$1,160	$522	$871	16.4%
$9 US/mmbtu	$8,898	$3,451	$9,796	20.1%	$1,390	$605	$1,114	17.8%
$10 US/mmbtu	$10,320	$3,879	$11,049	21.3%	$1,641	$682	$1,339	18.9%

Table 3.3: Summary of Financial Viability Analysis – Short Pipeline Wet Gas Scenario (Continued)

Case	Undiscounted Share of Pre-Tax NCF Prov. Gov.	Undiscounted Share of Pre-Tax NCF Fed. Gov.	Undiscounted Share of Pre-Tax NCF Proponent	Discounted Share of Pre-Tax NCF Prov. Gov.	Discounted Share of Pre-Tax NCF Fed. Gov.	Discounted Share of Pre-Tax NCF Proponent
$2 US/mmbtu	No Project					
$3 US/mmbtu	No Project					
$4 US/mmbtu	No Project					
$5 US/mmbtu	34.2%	17.7%	48.1%	51.6%	31.8%	16.6%
$6 US/mmbtu	37.3%	16.6%	46.1%	48.1%	24.9%	27.0%
$7 US/mmbtu	39.6%	15.9%	44.5%	47.6%	21.7%	30.6%
$8 US/mmbtu	39.8%	15.7%	44.5%	45.4%	20.4%	34.1%
$9 US/mmbtu	40.2%	15.6%	44.2%	44.7%	19.5%	35.8%
$10 US/mmbtu	40.9%	15.4%	43.8%	44.8%	18.6%	36.6%

Figure 3.7: Undiscounted Share of Pre-Tax Net Cash Flow – Short Pipeline Wet Gas Scenario: Various Prices

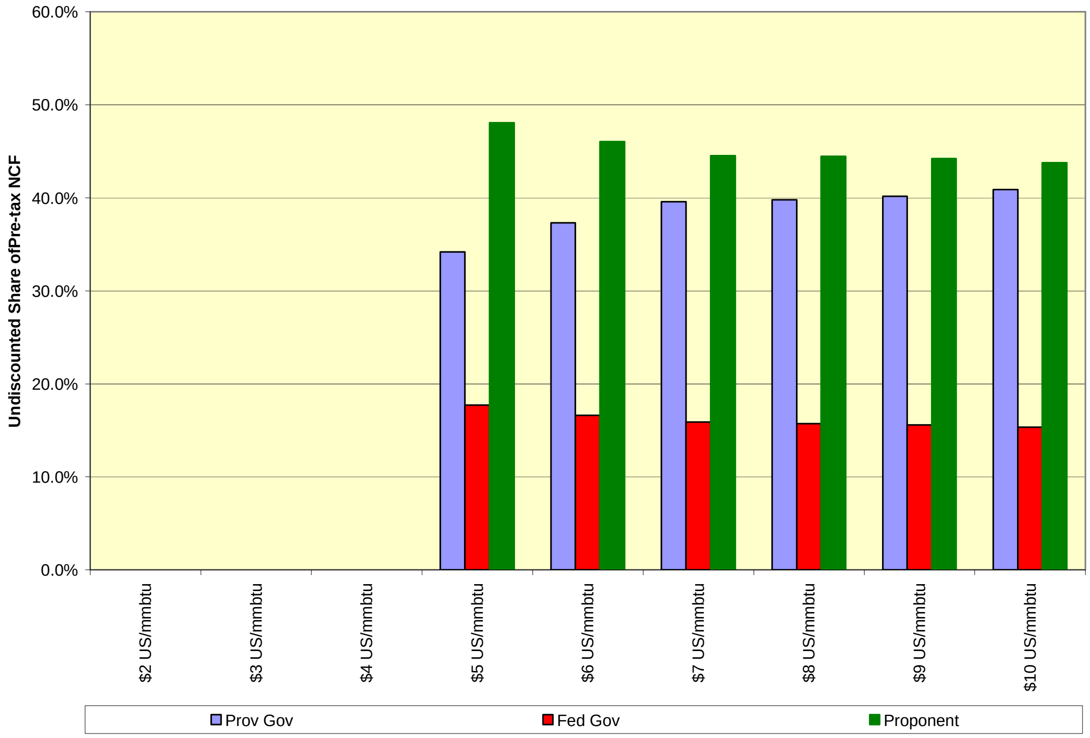
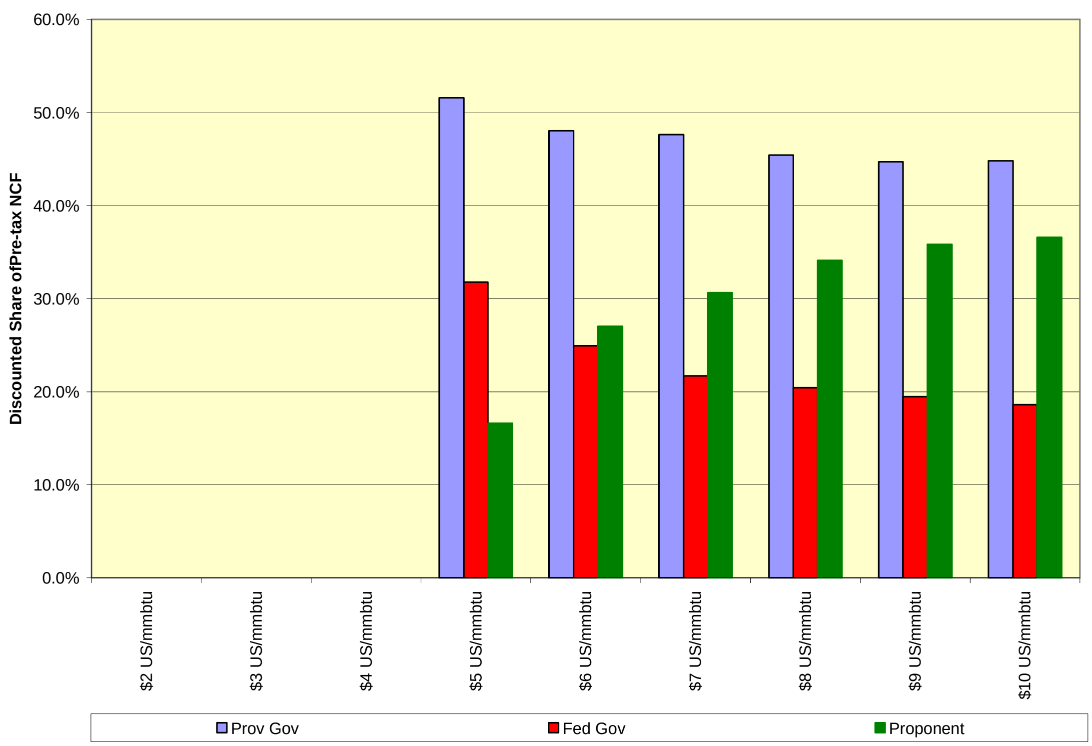


Figure 3.8: Discounted Share of Pre-Tax Net Cash Flow – Short Pipeline Wet Gas Scenario: Various Prices



3.4 Financial Viability Analysis: Long Pipeline Wet Gas Scenario (LPWGS)

Table 3.4 and Figures 3.9 and 3.10 summarize the key statistics from the financial viability analysis that was undertaken for the long pipeline wet gas scenario. The detailed statistics are provided in Appendix 3E, Tables 3E.1 to 3E.9. The results are very similar to those obtained from the short pipeline wet gas scenario. In particular, a price of $5 US/mmbtu or higher is required in order to profitably develop this resource.

Based on the $5 US/mmbtu price scenario, the government of British Columbia can expect to receive approximately $2.9 billion (2006) in corporation income taxes and royalties from this development, which is equivalent to $400 million in present value terms. The federal government can expect to receive approximately $1.7 billion (2006) in corporation income taxes or $280 million in present value terms. The corresponding revenue flow, net of explicit costs, to the consortium of private sector companies that will develop this project is approximately $4.7 billion (2006) or $60 million in discounted terms. This is equivalent to a real, after-tax internal rate of return on total capital of 10.5%. As well, if prices are in the $6 to $7 US/mmbtu range in the long term, then the revenue going to each stakeholder increases. In particular, the discounted revenue to the provincial treasury is between $630 million and $860 million for prices in the range of $6 to $7 US/mmbtu.

Based on least squares estimates from data in table 3.4, for every dollar increase in the price of a million British thermal units of gas, the provincial government gains approximately $1.3 billion (2006) in undiscounted revenue ($201 million in discounted present value terms), the federal government gains approximately $450 million ($82 million in discounted terms), and the companies gain approximately $1.4 billion ($271 million in discounted terms) (see Appendix 3H).

Figures 3.9 and 3.10 show how the shares of discounted and undiscounted pre-tax net cash flow change with price. The share of undiscounted revenues going to the provincial government increases from 31.4% to nearly 40.1% as prices rise from $5 to $10 US/mmbtu. The share of discounted revenues going to the provincial government decreases from 53.9% to 44.4% over the same price range.

The federal government share of undiscounted revenues decreases from 18.6% to 15.6% over the price range $5 to $10 US/mmbtu. The corresponding change in the share of discounted federal revenues is from 37.7% to 19.3%.

The share of undiscounted revenues going to the consortium developing this gas field decreases from 50.1% to 44.3% over the range of prices analyzed in this study. The share of discounted revenues going to the consortium increases from 8.5% to 36.3% over this same range of prices.

The relative shares of discounted revenues at $5 US/mmbtu are: 53.9% for the provincial government, 37.7% for the federal government and 8.5% for the consortium developing the wet gas field. This translates into the equivalent of $400 million in present value terms for the provincial treasury, $280 million for the federal treasury and $60 million for the members of the consortium.

Table 3.4: Summary of Financial Viability Analysis – Long Pipeline Wet Gas Scenario (monetary values in millions 2006 dollars Cdn)

Case	Prov. Rev. Nominal	Fed. Rev. Nominal	After-Tax NCF Nominal	IRR Nominal	Prov. Rev. Discounted (@10% Real)	Fed. Rev. Discounted (@10% Real)	After-Tax NCF Discounted (@10% Real)	IRR Real
$2 US/mmbtu	$219	$156	($306)	0.9%	$33	$17	($972)	-1.1%
$3 US/mmbtu	$696	$769	$1,706	6.7%	$96	$101	($567)	4.6%
$4 US/mmbtu	$1,558	$1,317	$3,400	10.2%	$213	$194	($222)	8.1%
$5 US/mmbtu	$2,941	$1,742	$4,693	12.7%	$398	$279	$63	10.5%
$6 US/mmbtu	$4,457	$2,136	$5,886	14.7%	$627	$356	$310	12.4%
$7 US/mmbtu	$5,910	$2,547	$7,124	16.4%	$862	$433	$552	14.1%
$8 US/mmbtu	$7,349	$2,970	$8,364	17.8%	$1,109	$511	$781	15.5%
$9 US/mmbtu	$8,642	$3,430	$9,714	19.3%	$1,322	$598	$1,035	17.0%
$10 US/mmbtu	$9,990	$3,876	$11,022	20.5%	$1,558	$679	$1,272	18.2%

Table 3.4: Summary of Financial Viability Analysis – Long Pipeline Wet Gas Scenario (Continued)

Case	Undiscounted Share of Pre-Tax NCF Prov. Gov.	Undiscounted Share of Pre-Tax NCF Fed. Gov.	Undiscounted Share of Pre-Tax NCF Proponent	Discounted Share of Pre-Tax NCF Prov. Gov.	Discounted Share of Pre-Tax NCF Fed. Gov.	Discounted Share of Pre-Tax NCF Proponent
$2 US/mmbtu	**No Project**					
$3 US/mmbtu	**No Project**					
$4 US/mmbtu	**No Project**					
$5 US/mmbtu	31.4%	18.6%	50.1%	53.9%	37.7%	8.5%
$6 US/mmbtu	35.7%	17.1%	47.2%	48.5%	27.5%	24.0%
$7 US/mmbtu	37.9%	16.3%	45.7%	46.7%	23.5%	29.9%
$8 US/mmbtu	39.3%	15.9%	44.8%	46.2%	21.3%	32.5%
$9 US/mmbtu	39.7%	15.7%	44.6%	44.7%	20.2%	35.0%
$10 US/mmbtu	40.1%	15.6%	44.3%	44.4%	19.3%	36.3%

Figure 3.9: Undiscounted Share of Pre-Tax Net Cash Flow – Long Pipeline Wet Gas Scenario: Various Prices

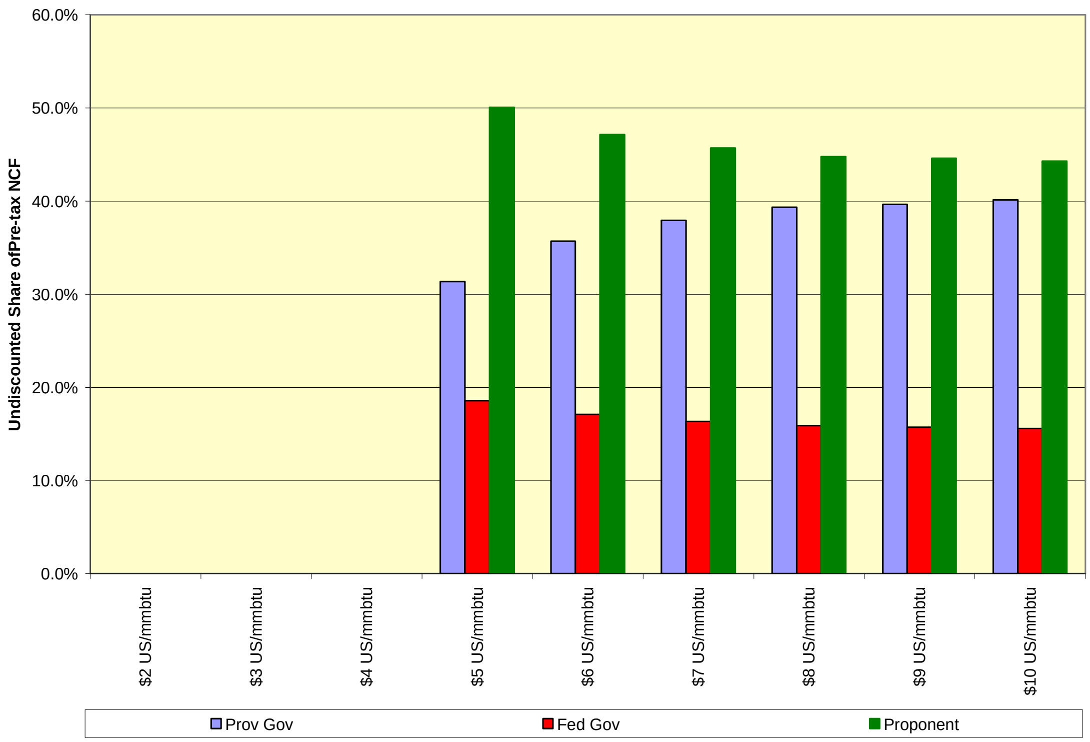
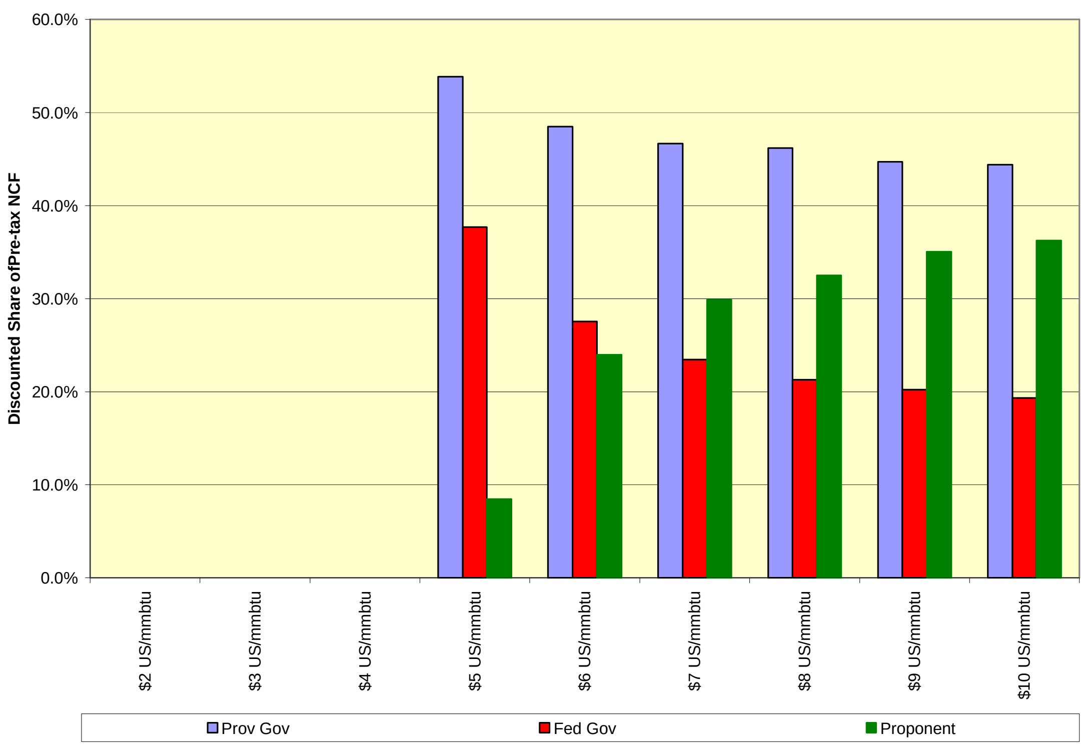


Figure 3.10: Discounted Share of Pre-Tax Net Cash Flow – Long Pipeline Wet Gas Scenario: Various Prices



3.5 Financial Viability Analysis: Short Pipeline Dry Gas Scenario (SPDGS)

Table 3.5 and Figures 3.11 and 3.12 summarize the key statistics from the financial viability analysis that was undertaken for the short pipeline dry gas scenario. The detailed statistics are provided in Appendix 3F, Tables 3F.1 to 3F.9. From Table 3.5, the dry gas development described in this study will be profitable to undertake for all prices above $5 US/mmbtu.

Based on the minimum price required for viability of $6 US/mmbtu price scenario, the British Columbia government can expect to receive approximately $3.8 billion (2006) in corporation income taxes and royalties from this project. This is equivalent to $540 million in present value terms. The federal government can expect to receive approximately $1.8 billion (2006) in corporation income taxes or $310 million in present value terms. The corresponding revenue flow, net of explicit costs, to the consortium of companies that develop this project is approximately $5.0 billion (2006) or $240 million in present value terms. This translates into a real, after-tax internal rate of return to total capital of 12.1%. As well, if prices are in the range of $6-7 US/mmbtu over the long term, then the revenue going to each stakeholder increases. For example, in discounted terms, the revenue to the provincial treasury falls between approximately $540 million and $770 million.

Based on least squares estimates from data in table 3.5, for every dollar increase in the price of a million British thermal units of gas, the provincial government gains approximately $1.3 billion (2006) in undiscounted revenue ($201 million in discounted present value terms), the federal government gains approximately $462 million ($83 million in discounted terms), and the companies gain approximately $1.5 billion ($293 million in discounted terms) (see Appendix 3H).

Figures 3.11 and 3.12 illustrate how the shares of discounted and undiscounted pre-tax net cash flow change with price. The share of undiscounted revenues going to the provincial government increases from 35.8% to 41.0% as prices rise from $6 to $10 US/mmbtu. The share of discounted revenues going to the provincial government decreases from 49.7% to 45.4% over the same price range.

The federal government share of undiscounted revenues decreases from 17.2% to 15.3% as prices rise from $6 to $10 US/mmbtu and the discounted share decreases from 28.3% to 18.8% over the same price range. The corresponding share going to the private consortium changes from 47.0% to 43.6% for the undiscounted series to 22.0% to 35.8% for the discounted series.

The relative shares of discounted revenues at $6 US/mmbtu are: 49.7% for the provincial government, 28.3% for the federal government and 22.0% for the consortium developing the dry gas field. In present value terms, this translates into the equivalent of $540 million for the provincial treasury, $310 million for the federal treasury and $240 million for the members of the consortium.

Table 3.5: Summary of Financial Viability Analysis – Short Pipeline Dry Gas Scenario (monetary values in millions 2006 dollars Cdn)

Case	Prov. Rev. (2006 $ M Cdn.)	Fed. Rev. (2006 $ M Cdn.)	After-Tax NCF (2006 $ M Cdn.)	IRR Nominal	Prov. Rev. Discounted (@10% Real) ($ M Cdn.)	Fed. Rev. Discounted (@10% Real) ($ M Cdn.)	After-Tax NCF Discounted (@10% Real) ($ M Cdn.)	IRR Real
$2 US/mmbtu	$38	($70)	($2,261)		$12	($3)	($1,224)	
$3 US/mmbtu	$316	$323	$296	3.2%	$47	$41	($728)	1.1%
$4 US/mmbtu	$974	$933	$2,256	8.7%	$137	$137	($336)	6.6%
$5 US/mmbtu	$2,348	$1,387	$3,656	11.9%	$324	$224	($34)	9.7%
$6 US/mmbtu	$3,798	$1,829	$4,993	14.3%	$542	$309	$239	12.1%
$7 US/mmbtu	$5,231	$2,277	$6,340	16.4%	$772	$393	$502	14.1%
$8 US/mmbtu	$6,675	$2,731	$7,671	18.1%	$1,018	$477	$749	15.7%
$9 US/mmbtu	$8,198	$3,162	$8,944	19.4%	$1,288	$555	$977	17.1%
$10 US/mmbtu	$9,649	$3,612	$10,271	20.8%	$1,542	$637	$1,217	18.4%

Table 3.5: Summary of Financial Viability Analysis – Short Pipeline Dry Gas Scenario (Continued)

Case	Undiscounted Share of Pre-Tax NCF Prov. Gov.	Undiscounted Share of Pre-Tax NCF Fed. Gov.	Undiscounted Share of Pre-Tax NCF Proponent	Discounted Share of Pre-Tax NCF Prov. Gov.	Discounted Share of Pre-Tax NCF Fed. Gov.	Discounted Share of Pre-Tax NCF Proponent
$2 US/mmbtu	**No Project**					
$3 US/mmbtu	**No Project**					
$4 US/mmbtu	**No Project**					
$5 US/mmbtu	**No Project**					
$6 US/mmbtu	35.8%	17.2%	47.0%	49.7%	28.3%	22.0%
$7 US/mmbtu	37.8%	16.4%	45.8%	46.3%	23.6%	30.1%
$8 US/mmbtu	39.1%	16.0%	44.9%	45.4%	21.3%	33.4%
$9 US/mmbtu	40.4%	15.6%	44.1%	45.7%	19.7%	34.7%
$10 US/mmbtu	41.0%	15.3%	43.6%	45.4%	18.8%	35.8%

Figure 3.11: Undiscounted Share of Pre-Tax Net Cash Flow – Short Pipeline Dry Gas Scenario: Various Prices

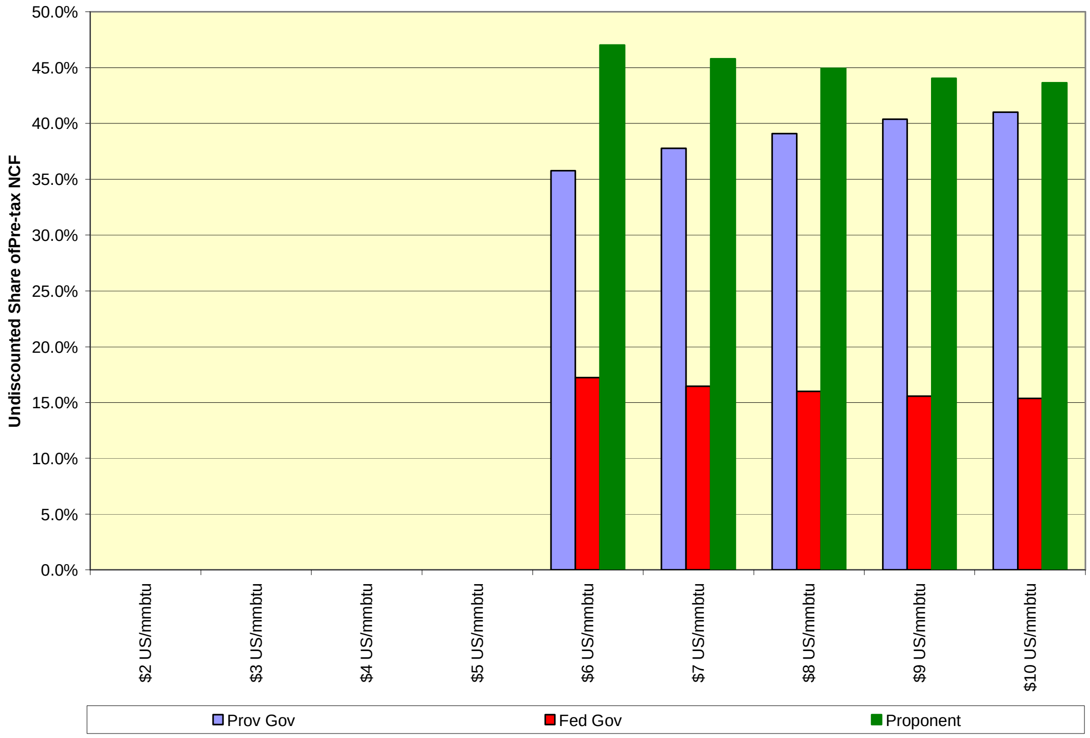
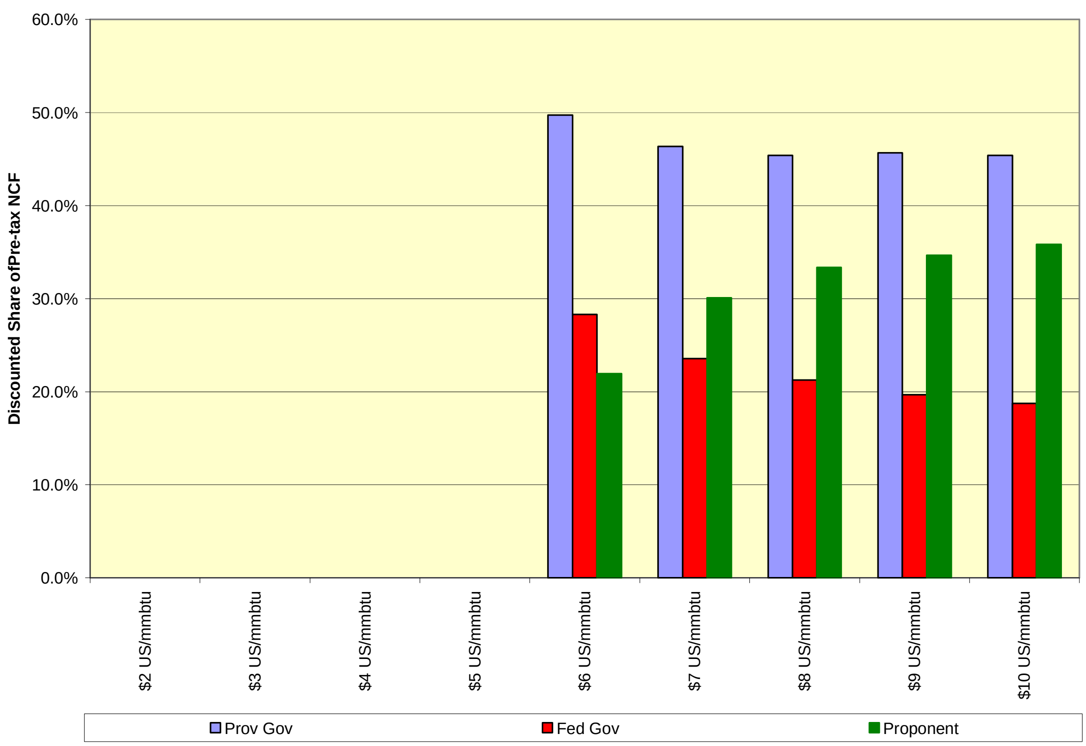


Figure 3.12: Discounted Share of Pre-Tax Net Cash Flow – Short Pipeline Dry Gas Scenario: Various Prices



3.6 Financial Viability Analysis: Long Pipeline Dry Gas Scenario (LPDGS)

Table 3.6 and Figures 3.13 and 3.14 summarize the key statistics from the financial viability analysis that was undertaken for the long pipeline dry gas scenario. The detailed financial viability statistics are provided in Appendix 3G, Tables 3G.1 to 3G.9. From Table 3.6, the dry gas development described in this study will be profitable to undertake for all prices above $5 US/mmbtu.

Since $6 US/mmbtu is the lowest price that will yield at least a 10% real, after-tax rate of return over the life of the project, the detailed discussion of the financial viability analysis will focus on this price scenario. Based on the $6 US/mmbtu price scenario, the government of British Columbia can expect to receive approximately $3.5 billion (2006) in corporation income taxes and royalties from this project. This is equivalent to approximately $490 million in present value terms. The federal government can expect to receive approximately $1.8 billion (2006) in corporation income taxes or $300 million in present value terms. The corresponding revenue flow, net of explicit costs, to the consortium of companies that develop this project is $4.9 billion (2006) or $150 million in present value terms. This translates into a real internal rate of return of 11.2%. As well, if prices are at $6-7 US/mmbtu over the long term, then the revenue going to each stakeholder increases. For example, in discounted terms, the revenue to the provincial treasury will range between $490 million and $710 million.

Based on least squares estimates from data in table 3.6, for every dollar increase in the price of a million British thermal units of gas, the provincial government gains approximately $1.2 billion (2006) in undiscounted revenue ($192 million in discounted present value terms), the federal government gains approximately $463 million ($82 million in discounted terms), and the companies gain approximately $1.5 billion ($303 million in discounted terms) (see Appendix 3H).

Figures 3.13 and 3.14 illustrate how the shares of discounted and undiscounted pre-tax net cash flow change with price. The share of undiscounted revenues going to the provincial government increases from 34.2% to 40.3% as prices rise from $6 to $10 US/mmbtu. The discounted share going to the provincial government decreases from 52.2% to 45.1%.

The federal government share of undiscounted revenues decreases from 17.7% to 15.6% and its share of discounted revenues decreases from 32.1% to 19.5% over this price range. The corresponding ranges of shares for the development consortium are 48.0% to 44.2% (undiscounted) and 15.7% to 35.4% (discounted).

The relative shares of discounted revenues at $6 US/mmbtu are: 52.2% for the provincial government, 32.1% for the federal government and 15.7% for the consortium developing the wet gas field. This translates to the equivalent of $490 million in present value terms for the provincial treasury, $300 million for the federal treasury and almost $150 million for the members of the consortium.

Table 3.6: Summary of Financial Viability Analysis – Long Pipeline Dry Gas Scenario (monetary values in millions 2006 dollars Cdn)

Case	Prov. Rev. Nominal	Fed. Rev. Nominal	After-Tax NCF Nominal	IRR Nominal	Prov. Rev. Discounted (@10% Real)	Fed. Rev. Discounted (@10% Real)	After-Tax NCF Discounted (@10% Real)	IRR Real
$2 US/mmbtu	$38	($70)	($2,621)		$12	($3)	($1,377)	
$3 US/mmbtu	$282	$259	$34	2.1%	$42	$32	($866)	0.1%
$4 US/mmbtu	$825	$893	$2,085	7.8%	$118	$125	($459)	5.7%
$5 US/mmbtu	$1,894	$1,421	$3,716	11.1%	$260	$220	($119)	9.0%
$6 US/mmbtu	$3,511	$1,819	$4,928	13.4%	$489	$301	$147	11.2%
$7 US/mmbtu	$4,909	$2,276	$6,303	15.5%	$706	$388	$420	13.2%
$8 US/mmbtu	$6,471	$2,696	$7,549	17.1%	$967	$466	$657	14.8%
$9 US/mmbtu	$7,956	$3,137	$8,850	18.6%	$1,223	$547	$896	16.2%
$10 US/mmbtu	$9,335	$3,605	$10,232	19.9%	$1,463	$633	$1,147	17.6%

Table 3.6: Summary of Financial Viability Analysis – Long Pipeline Dry Scenario (Continued)

Case	Undiscounted Share of Pre-Tax NCF Prov. Gov.	Undiscounted Share of Pre-Tax NCF Fed. Gov.	Undiscounted Share of Pre-Tax NCF Proponent	Discounted Share of Pre-Tax NCF Prov. Gov.	Discounted Share of Pre-Tax NCF Fed. Gov.	Discounted Share of Pre-Tax NCF Proponent
$2 US/mmbtu	**No Project**					
$3 US/mmbtu	**No Project**					
$4 US/mmbtu	**No Project**					
$5 US/mmbtu	**No Project**					
$6 US/mmbtu	34.2%	17.7%	48.0%	52.2%	32.1%	15.7%
$7 US/mmbtu	36.4%	16.9%	46.7%	46.7%	25.6%	27.7%
$8 US/mmbtu	38.7%	16.1%	45.2%	46.3%	22.3%	31.4%
$9 US/mmbtu	39.9%	15.7%	44.4%	45.9%	20.5%	33.6%
$10 US/mmbtu	40.3%	15.6%	44.2%	45.1%	19.5%	35.4%

Figure 3.13: Undiscounted Share of Pre-Tax Net Cash Flow – Long Pipeline Dry Gas Scenario: Various Prices

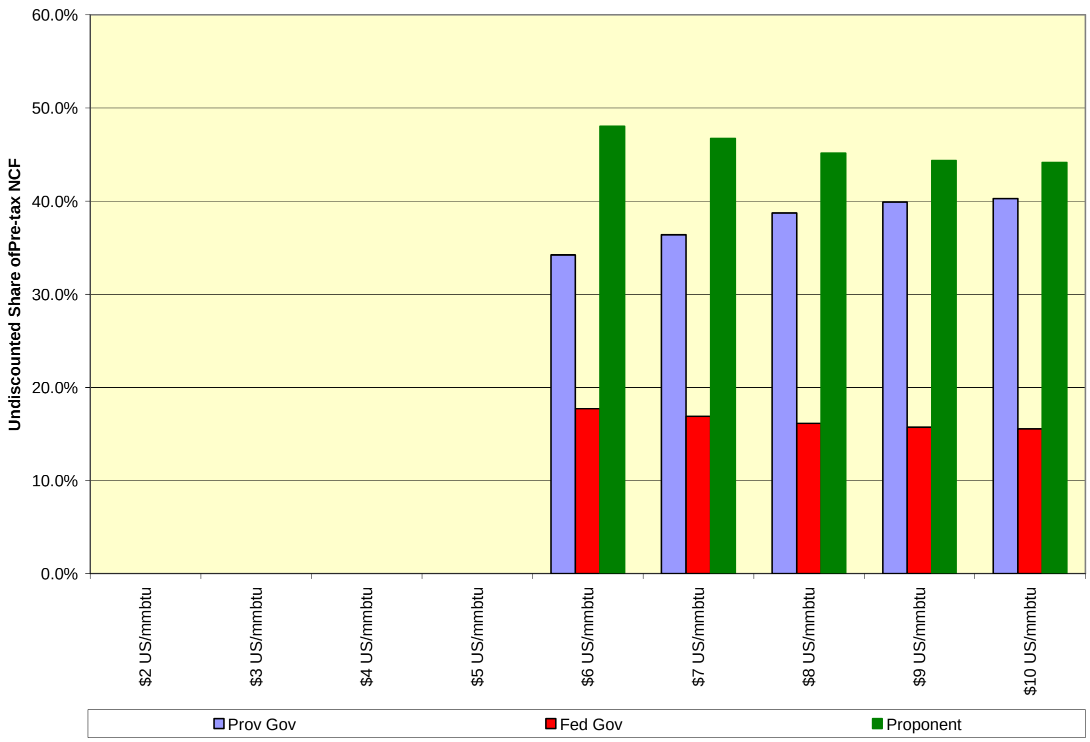
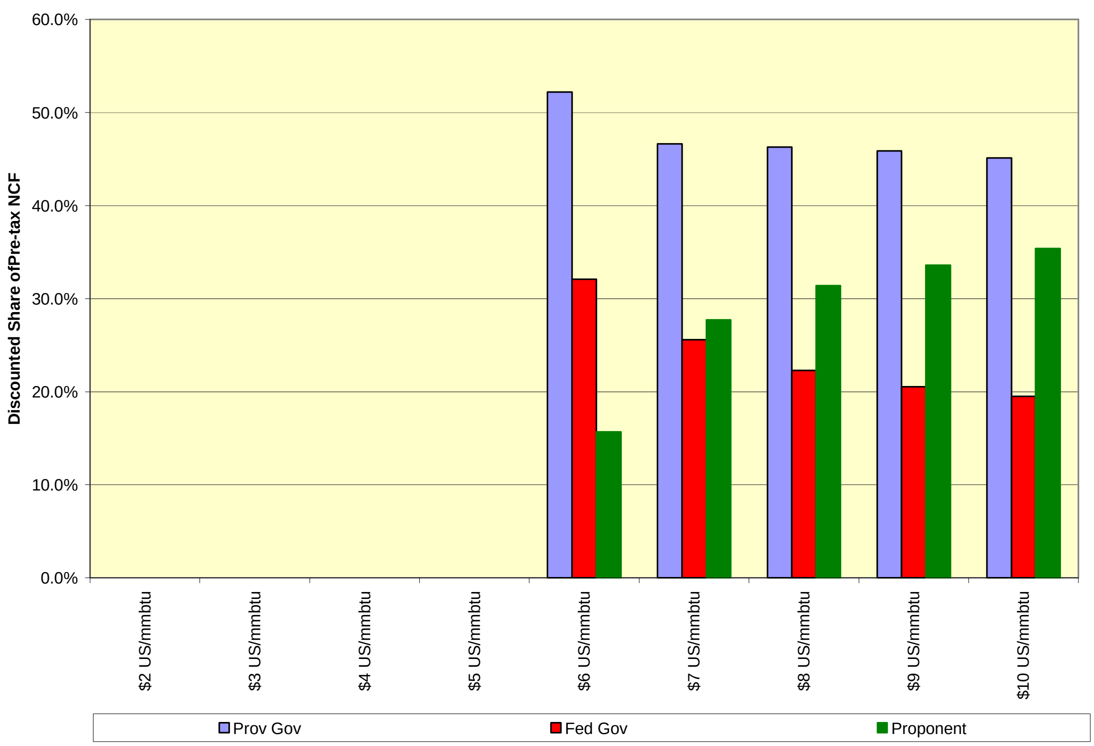


Figure 3.14: Discounted Share of Pre-Tax Net Cash Flow – Long Pipeline Dry Gas Scenario: Various Prices



3.7 Conclusions: Financial Viability Analyses

In interpreting the results from the rent analysis, it is important to appreciate that many conservative assumptions were employed in the analysis. To the extent that these assumptions are relaxed, this will enhance the implied viability of the scenarios considered.

Because they can be profitably developed at the lower bounds of the long-term price forecasts, it is reasonable to conclude that both of the oil scenarios and all of the gas scenarios would in all likelihood be developed should those opportunities become available.

SECTION 4

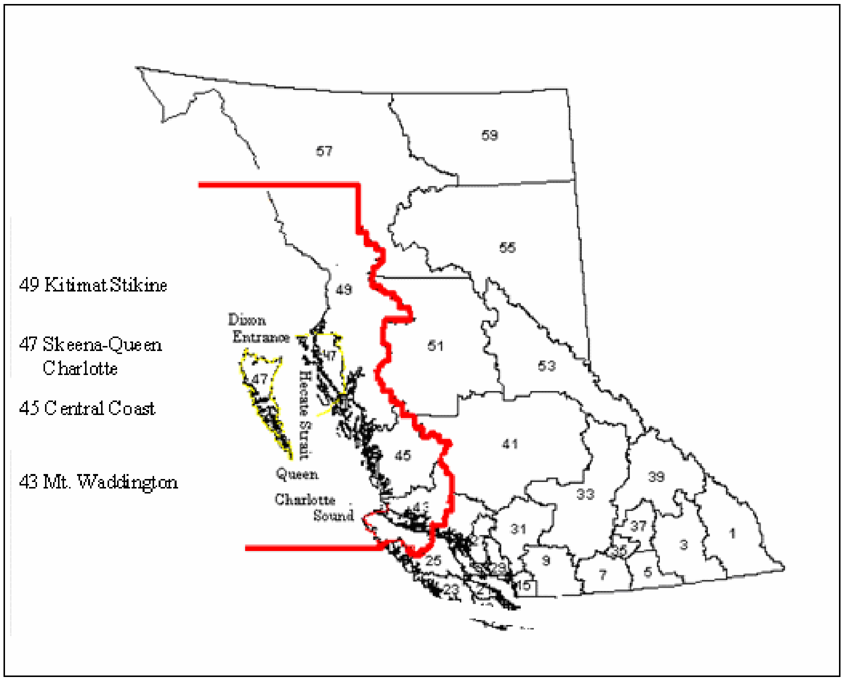
EXPENDITURE BENEFITS

Expenditure inputs for the analysis of expenditure benefits are 2006 dollar cost estimates for each scenario as outlined in Appendix 2E, Tables 2E.1, 2E.3, 2E.5, 2E.7, 2E.9 and 2E.11. Results are shown separately for exploration, short and long pipeline development (oil, wet gas, dry gas) and production.

Results show direct, indirect and where possible induced impacts on output, GDP at factor cost, employment, household income and government tax revenue (federal, provincial and municipal).[53] Results have provincial and regional dimensions, showing impacts separately for (i) the province as a whole and (ii) the Queen Charlotte Basin (QCB) region of the province and (iii) the rest of BC. The QCB region comprises the regional districts of Mount Waddington, Central Coast, Skeena-Queen Charlotte and Kitimat-Stikine (see Figure 4.1 below).

[53] GDP at factor cost is a measure of the value of final goods and services produced within a jurisdiction in a given period of time. It is defined as the sum of value added at each stage of production, where value added is the income accruing to, or the cost of, the factors of production (labour, capital and land) used at each stage of production. GDP at factor cost, as it measures the value of **final** commodities produced, is distinguished from 'output', a measure of **all** commodities produced at every stage of production, including intermediate inputs into later stages of production. Household income includes wages and salaries, benefits and mixed income (net income of farm operators and non-farm unincorporated businesses). Federal and provincial tax revenues include personal and corporation income taxes, GST, PST and other commodity taxes such as gas taxes, liquor and lottery taxes and profits, air transportation taxes, duties and excise taxes. For purposes of this analysis, municipal tax revenues, while primarily property taxes, include only such other taxes as amusement and accommodation taxes because the estimating model (the BC input-output model) does not include property taxes.

Figure 4.1 Queen Charlotte Basin Region of BC



Results are presented as aggregate impacts based on the scale of activity assumed in the scenarios outlined in Section 2 of the report. Results are also presented in terms of impacts per million dollars of expenditure at each stage of activity. The former results show what the size of impacts would be if the scale of activity assumed in the activity scenarios materializes. The latter results can be used to estimate the size of impacts for any scale of activity, assuming no economies or diseconomies of scale in exploration, development or production.

As in the case of the financial viability analyses in Section 3 of the report, results are to be interpreted as illustrative of possible economic potential rather than firm predictions. More precise estimates will come from detailed engineering studies that would be undertaken if moratoria are lifted and companies show genuine interest in the offshore resource. Even then, the standard estimating models used cannot provide more than round orders of magnitude, given the assumptions on which they are based.

Expenditure impact estimates assume that energy prices are sufficiently high to ensure viability of projects.

4.1 Provincial Expenditure Benefits

Provincial results are generated from the BC input-output model (BCIOM) operated by BC Statistics. Results are based on 2003 BCIOM data, with employment estimates based on average annual labour compensation by industry in 2006.[54] Results show cumulative totals over the period of activity assumed in each activity scenario.

Three steps were involved in preparing the expenditure estimates in Appendix 2E for inputting to the BCIOM:

(i) Disaggregation of expenditures into sub-components

Allocation of broad expenditure categories across appropriate sub-categories of inputs was necessary to allow the BCIOM to trace the input-output relationships of the provincial economy on a commodity basis, including leakages of input expenditures into inter-provincial and international imports. Expenditure data from Appendix 2E are summarized in Appendix 4A with cost categories broken down into sub-categories of cost. Sub-category disaggregations are approximations based on information taken from Newfoundland and Labrador oil projects (Hibernia, Terra Nova, White Rose, Hebron) and the Sable offshore gas project in Nova Scotia.

(ii) Allocation of expenditures to BCIOM commodities

Where expenditure items did not match the commodity groupings used in the BCIOM, expenditures were allocated to commodities based on BCIOM information from related industries, available studies and best judgement.

(iii) Adjustment for BC leakage rates on direct expenditures

A proportion of expenditures at each stage of activity will leak out of the provincial economy immediately and therefore play no role in creating provincial impacts. A proportion of expenditure on labour will accrue to labour that is non-resident in BC; a proportion of goods and services inputs will be purchased from suppliers outside the province. Summary estimates of BC leakage rates are shown in Appendix 4B (Tables 4B.1 and 4B.2).[55]

Leakage rates for labour were estimated line by line on the basis of experience elsewhere and key informant advice.[56] BC leakage rates for labour are estimated to be 42% at the exploration stage, 32-36% at the development stage and 30% at the production stage.[57]

[54] Employment is therefore measured as yearly jobs, full-time or part-time. Industries used in the calculation were support activities for mining and oil and gas extraction (exploration), oil and gas engineering construction (development) and oil and gas extraction (production).

[55] Rates are conservative to the extent that they do not provide for likely increases over time in local capacity to serve the labour and commodity needs of projects.

[56] It may not have been unreasonable to draw on experience in Atlantic Canada, even though east coast economies differ in structure from the BC economy. On the one hand, the BC economy is more diversified and could offer lower local leakage rates than in the Atlantic provinces. On the other hand, BC is not expected to impose local benefit requirements for labour and procurement, at least to the extent required under the Atlantic Accords.

[57] These development stage rates are comparable to the development stage capture rates (the obverse of leakage rates) for labour from east coast offshore projects reported in the range 57-66% for the Atlantic provinces as a group (Locke and Strategic Concepts 2004, Table 2). Other estimated or assumed labour

Leakages of initial expenditures into goods and services imported into BC were estimated on the basis of the provincial import ratios in the BCIOM, except where specific estimates were used for expenditure categories not included in the BCIOM, or where the circumstances of the BC offshore warranted reliance on expert judgment and/or experience elsewhere. Expenditure items for which BCIOM ratios were not used were the following:

- various equipment rentals for drilling, including rental of drilling rigs and supply vessels at exploration and development stages (it was assumed that rigs would be rented from abroad and supply vessels would be 75% chartered from abroad);
- vessels and equipment for seismic surveys (assumed to be 80% supplied abroad);[58]
- installation and commissioning of undersea pipelines (assumed to be 65% undertaken by international contractors, a proportion based on SOEP (ExxonMobil nd, Table 8.4-6)); and
- construction of the production facility sub-structure (assumed to be built abroad).

Based on the above procedures, the BC leakage rates for materials and services are estimated to be 72% at the exploration stage, 67-68% at the development stage and 22% at the production stage (see Appendix 4B, Tables 4B.1 and 4B.2).[59]

Removal of immediate leakages from initial expenditures on labour and goods and services leaves the net expenditure infusion of offshore activity to the provincial economy, or project expenditure in BC.

All dollar figures reported below are in 2006 prices.[60]

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capture rates are as follows. Provincial capture rates in the range 51-56% are estimated for seismic work and drilling on projects in north east BC (Bhargava et al 2004, figures 9.3 and 9.4). Development stage rates of 50% for BC (Gislason 2007, exhibit K.1) and 53% for Nova Scotia from SOEP (ExxonMobil nd, Table 8.4-26) are assumed. A labour capture rate of 54% for SOEP is estimated by Gardner-Pinfold (2002, Table 5.1). At the production stage, Gislason assumes 80% for BC (Gislason 2007, exhibit K.1).

[58] The finding for local content for seismic work in Atlantic Canada was 21% (Locke and Strategic Concepts 2004, Table 4).

[59] These rates are generally in line with findings and assumptions made elsewhere for exploration and development, and are somewhat lower for production. Bhargava et al (2004, figures 9.3 and 9.4) show BC capture rates for goods and services in seismic and drilling activity in northeast BC in the range 25-36%. Locke and Strategic Concepts (2004, Table 2) find commodity capture rates for the Atlantic provinces from Newfoundland projects in the range 27-47% at the development stage and 48-54% at the production stage. Commodity capture rates for Nova Scotia are estimated at 37% for development and 39% for production on the Cohasset-Panuke project (Gardner-Pinfold 2002, Table 5.1). Capture rates for SOEP at the development stage are 33% (Gardner-Pinfold 2002, Table 5.1) and 28% (ExxonMobil nd, Table 8.3-1); 39% (Gardner-Pinfold 2002, Table 5.1) and 64% (ExxonMobil nd, Table 8.3-3) at the production stage. Gislason assumes 30% for exploration and development and 60% for production in BC (Gislason 2007, exhibit K.1). BriMar Consultants (2003) use 28% and 64% respectively for BC, based on east coast evidence.

[60] Municipal tax revenues are understated to the extent that the BCIOM does not include property taxes (see footnote 53).

4.1.1 Exploration

Estimates of impact for the scale of exploration expenditure assumed in sections 2 and 3 of the report are shown in Table 4.1. For assumed exploration expenditure of $622 million, $206 million is estimated to be project expenditure in BC after adjusting for initial leakages from the BC economy, of which $116 million is spent on commodities and the remainder on factor incomes (GDP at factor cost) and commodity taxes less subsidies (net commodity taxes).

Taking into account indirect and induced effects as well as direct effects, results show total incremental output in BC of $430 million, GDP of $170 million, 2,463 yearly jobs and household income of $131 million over two years of seismic surveying, three years of mobilization and exploratory drilling activity, and one year of demobilization. Incremental tax revenues generated in BC are shown to be approximately $24 million for the federal government, $33 million for the provincial government and $2 million for municipal governments. Results apply to both oil and gas exploration.

Table 4.1: Provincial Expenditure Impacts: Exploration ($2006)

	Direct	Indirect	Induced	Total
Output ($M)	206	180	44	430
GDP at factor cost ($M)	62	84	25	170
Employment (#)	909	1,174	380	2,463
Household Income ($M)	61	55	16	131
Tax Revenue ($M)	39	13	8	59
Federal Government	14	7	3	24
Provincial Government	24	5	4	33
Municipal Government	0	1	1	2

Minor differences due to rounding.

Estimated impacts in terms of provincial output, GDP, employment, household income and tax revenue per million dollars of exploration expenditure are shown in Table 4.2.

Table 4.2: Provincial Expenditure Impacts Per $Million Expenditure: Exploration ($2006)

	Direct	Indirect	Induced	Total
Output ($M)	0.332	0.290	0.070	0.693
GDP at factor cost ($M)	0.099	0.134	0.040	0.273
Employment (#)	1.462	1.890	0.612	3.963
Household Income ($M)	0.098	0.089	0.025	0.211
Tax Revenue ($000)	62.261	20.210	12.865	95.336
Federal Government	23.030	10.535	5.523	39.087
Provincial Government	39.231	8.274	6.042	53.548
Municipal Government	0.000	1.401	1.300	2.701

Minor differences due to rounding.

Estimates in Table 4.2 suggest that, taking into account indirect and induced effects, a million dollars of expenditure on exploration activity could create $693,000 in increased output, $273,000 in GDP, 4 year-long jobs and $211,000 in household income in BC. In terms of tax revenues, a million dollars of exploration activity is estimated to generate tax revenue of around $39,000 for the federal government, $54,000 for the provincial government and $3,000 for municipal governments.

Sectors of the provincial economy most positively impacted in terms of spin-off activity as a result of exploration are in order of scale of impact: finance, insurance and real estate; mining and oil and gas extraction itself; transportation and warehousing; manufacturing; operating, office, cafeteria and laboratory supplies; professional, scientific and technical services; and wholesale trade.[61]

4.1.2 Oil Development

Table 4.3 shows the impacts of developing the infrastructure for oil production (short and long pipelines) based on levels of expenditure assumed in sections 2 and 3 of the report. For outlays of $4,937 million (short pipeline) and $5,252 million (long pipeline) on development drilling, pipeline and transshipment terminal construction, and production rig construction and installation, direct expenditure in BC is estimated to be $1,756 million (short pipeline) and $1,863 million (long pipeline). These levels of direct expenditure generate in BC $3,987-$4,239 million of incremental output, $1,409-1,489 million of GDP, around 24,000 yearly jobs and $1,108-1,174 million of household income. Incremental tax revenues are shown to be approximately $180-189 million for the federal government, $239-249 million for the provincial government and $17-18 million for municipal governments. Impacts are higher for the long pipeline case due to higher expenditure than in the short pipeline case.

These effects are achieved over 13 years of development activity plus decommissioning of the production facility in the final year of oil production.

Table 4.3: Provincial Expenditure Impacts: Oil Development ($2006)

	SHORT PIPELINE				LONG PIPELINE			
	Direct	**Indirect**	**Induced**	**Total**	**Direct**	**Indirect**	**Induced**	**Total**
Output ($M)	1,756	1,881	349	3,987	1,863	2,007	370	4,239
GDP at factor cost ($M)	336	875	198	1,409	355	925	210	1,489
Employment (#)	6,340	14,052	3,041	23,433	6,697	14,886	3,223	24,807
Household Income ($M)	336	647	124	1,108	355	687	132	1,174
Tax Revenue ($M)	233	138	64	436	242	147	68	456
Federal Government	83	70	27	180	86	74	29	189
Provincial Government	151	58	30	239	156	61	32	249
Municipal Government	0	11	6	17	0	11	7	18

Minor differences due to rounding.

[61] Full details by sector and measure of impact can be supplied on request.

Impacts per million dollars of expenditure from developing the infrastructure for oil production (short and long pipelines) are shown in Table 4.4.

Table 4.4: Provincial Expenditure Impacts Per $Million Expenditure: Oil Development ($2006)

	SHORT PIPELINE				LONG PIPELINE			
	Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total
Output ($M)	0.356	0.381	0.071	0.808	0.355	0.382	0.070	0.807
GDP at factor cost ($M)	0.068	0.177	0.040	0.285	0.068	0.176	0.040	0.284
Employment (#)	1.284	2.846	0.616	4.746	1.275	2.834	0.614	4.723
Household Income ($M)	0.068	0.131	0.025	0.224	0.068	0.131	0.025	0.224
Tax Revenue ($000)	47.268	27.989	12.952	88.209	46.082	27.904	12.904	86.890
Federal Government	16.725	14.080	5.560	36.365	16.368	14.017	5.539	35.924
Provincial Government	30.543	11.715	6.083	48.340	29.714	11.703	6.060	47.477
Municipal Government	0.000	2.194	1.309	3.503	0.000	2.184	1.304	3.488

Minor differences due to rounding.

Sectors experiencing the major spin-off impacts of oil development expenditures are: finance, insurance and real estate; professional, scientific and professional services; manufacturing; construction; wholesale trade; operating, office, cafeteria and laboratory supplies; and mining and oil and gas extraction itself.

The scale of expenditure and hence aggregate impacts is much greater for development than for exploration. Output, GDP, employment and household income impacts per million dollars of expenditure are also higher at the development stage. This is because leakage rates on non-resident labour and imported commodities are lower at the development stage (see Appendix 4B, Table 4B.1). Tax revenues per million dollars of expenditure, however, are higher at the exploration stage because income taxes are higher relative to commodity taxes at the exploration stage.

4.1.3 Wet Gas Development

Table 4.5 shows the impacts of expenditure on developing the infrastructure for wet gas production, based on levels of expenditure assumed in sections 2 and 3 of the report. These expenditures are incurred on development drilling, pipeline construction, construction of onshore gas separation and processing plants, and construction and installation of the production rig. For outlays of $3,462 million (short pipeline) and $3,822 million (long pipeline), direct expenditures in BC are estimated to be $1,271 million and $1,392 million respectively. These levels of direct expenditure generate in BC $2,894-3,183 million of incremental output, $1,030-1,123 million of GDP, approximately 17-19,000 yearly jobs and $819-895 million of household income. Incremental tax revenues are shown to be approximately $127-137 million for the federal government, $163-176 million for the provincial government and $13-14 million for municipal governments.

These effects are achieved over 14 years of development drilling and nine years of facilities construction, plus decommissioning of the production facility in the final year of gas production.

Table 4.5: Provincial Expenditure Impacts: Wet Gas Development ($2006)

	SHORT PIPELINE				LONG PIPELINE			
	Direct	**Indirect**	**Induced**	**Total**	**Direct**	**Indirect**	**Induced**	**Total**
Output ($M)	1,271	1,366	257	2,894	1,392	1,509	281	3,183
GDP at factor cost ($M)	252	632	146	1,030	274	689	159	1,123
Employment (#)	4,761	10,343	2,243	17,347	5,169	11,297	2,451	18,917
Household Income ($M)	252	475	92	819	274	521	100	895
Tax Revenue ($M)	155	100	47	303	165	110	52	327
Federal Government	56	50	20	127	60	55	22	137
Provincial Government	99	42	22	163	105	46	24	176
Municipal Government	0	8	5	13	0	9	5	14

Minor differences due to rounding.

Impacts per million dollars of expenditure from developing the infrastructure for wet gas production (short and long pipelines) are shown in Table 4.6.

Table 4.6: Provincial Expenditure Impacts Per $Million Expenditure: Wet Gas Development ($2006)

	SHORT PIPELINE				LONG PIPELINE			
	Direct	**Indirect**	**Induced**	**Total**	**Direct**	**Indirect**	**Induced**	**Total**
Output ($M)	0.367	0.395	0.074	0.836	0.364	0.395	0.074	0.833
GDP at factor cost ($M)	0.073	0.183	0.042	0.298	0.072	0.180	0.042	0.294
Employment (#)	1.375	2.988	0.648	5.011	1.352	2.956	0.641	4.950
Household Income ($M)	0.073	0.137	0.027	0.237	0.072	0.136	0.026	0.234
Tax Revenue ($000)	44.877	29.003	13.624	87.504	43.239	28.774	13.485	85.499
Federal Government	16.302	14.531	5.849	36.682	15.781	14.389	5.789	35.959
Provincial Government	28.575	12.193	6.399	47.167	27.458	12.131	6.333	45.922
Municipal Government	0.000	2.279	1.377	3.656	0.000	2.255	1.363	3.618

Minor differences due to rounding.

Sectors experiencing the major positive spin-off impacts of wet gas development expenditures are in order of impact: professional, scientific and technical services; finance, insurance and real estate; manufacturing; construction; wholesale trade; operating, office, cafeteria and laboratory supplies; and mining and oil and gas extraction.

Aggregate wet gas development impacts are not as great as oil development impacts due to lower development costs for wet gas. Fewer wells are drilled for gas, the pipeline is narrower and the extra costs of constructing onshore facilities are offset by lower production facility and other capital costs (see Appendix 4A, Tables 4A.2 and 4A.3). By contrast, except for tax revenue, impacts per million dollars of expenditure are slightly greater for wet gas than for oil because leakage rates are lower for gas (Appendix 4B, Tables 4B.1 and 4B.2).

4.1.4 Dry Gas Development

Table 4.7 shows the impacts of expenditure on developing the infrastructure for dry gas production (short and long pipelines), based on levels of dry gas development expenditure assumed in sections 2 and 3 of the report. In this scenario, gas is processed on the platform and the gas does not contain NGLs. Therefore, there is no onshore processing plant nor an NGL plant. Expenditures are incurred on development drilling, pipeline construction, and construction and installation of the production facility. For outlays of $3,362 million (short pipeline) and $3,722 million (long pipeline), direct expenditures in BC are estimated to be $1,215 million and $1,336 million respectively. These levels of direct expenditure generate in BC $2,787-$3,075 million of incremental output, $977-1,069 million of GDP, approximately 16-18,000 yearly jobs and $772-$848 million of household income. Incremental tax revenues are shown to be approximately $121-132 million for the federal government, $158-170 million for the provincial government and $12-13 million for municipal governments.

As for wet gas development, these effects are achieved over 14 years of development drilling and nine years of facilities construction, plus decommissioning of the production facility in the final year of gas production.

Table 4.7: Provincial Expenditure Impacts: Dry Gas Development (2006)

	SHORT PIPELINE				LONG PIPELINE			
	Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total
Output ($M)	1,215	1,328	244	2,787	1,336	1,471	268	3,075
GDP at factor cost ($M)	225	613	138	977	247	670	152	1,069
Employment (#)	4,252	9,962	2,124	16,338	4,659	10,916	2,332	17,907
Household Income ($M)	225	460	87	772	247	506	95	848
Tax Revenue ($M)	149	98	45	291	159	107	49	315
Federal Government	53	49	19	121	57	54	21	132
Provincial Government	96	41	21	158	102	45	23	170
Municipal Government	0	8	5	12	0	8	5	13

Minor differences due to rounding.

Impacts per million dollars of expenditure from developing the infrastructure for wet gas production (short and long pipelines) are shown in Table 4.8.

Table 4.8: Provincial Expenditure Impacts Per $Million Expenditure: Dry Gas Development ($2006)

	SHORT PIPELINE				LONG PIPELINE			
	Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total
Output ($M)	0.361	0.395	0.073	0.829	0.359	0.395	0.072	0.826
GDP at factor cost ($M)	0.067	0.182	0.041	0.291	0.066	0.180	0.041	0.287
Employment (#)	1.265	2.963	0.632	4.860	1.252	2.933	0.627	4.811
Household Income ($M)	0.067	0.137	0.026	0.230	0.066	0.136	0.026	0.228
Tax Revenue ($000)	44.275	29.012	13.286	86.573	42.652	28.776	13.176	84.604
Federal Government	15.833	14.557	5.704	36.094	15.344	14.409	5.656	35.409
Provincial Government	28.442	12.173	6.240	46.854	27.308	12.110	6.188	45.606
Municipal Government	0.000	2.282	1.343	3.625	0.000	2.257	1.332	3.589

Minor differences due to rounding.

Sectors impacted significantly by dry gas development are the same as for wet gas development, namely: professional, scientific and technical services; finance, insurance and real estate; manufacturing; construction; wholesale trade; operating, office, cafeteria and laboratory supplies; and mining and oil and gas extraction.

Aggregate impacts are marginally lower for dry gas than for wet gas because an NGL plant is not required for dry gas. Impacts per million dollars of expenditure are also slightly lower for dry gas.

4.1.5 Production

Table 4.9 shows the impacts of operating expenditures assumed in sections 2 and 3 of the report for production of oil and natural gas (short and long pipelines) over the assumed operating lives of the projects (14 years for the oil project and 25years for the gas project).[62]

For outlays of $2,918 million (oil) and $2,111 million (wet or dry gas), direct expenditures in BC are estimated to be $2,244 million (oil) and $1,624 million (gas). These levels of direct expenditure generate in BC $4,431-$6,124 million of incremental output, $1,412-$1,952 million of GDP, approximately 20-28,000 yearly jobs and $1,062-1.468 million of household income. Incremental tax revenues are shown to be approximately $134-186 million for the federal government, $113-157million for the provincial government and $17-23 million for municipal governments.

Table 4.9: Provincial Expenditure Impacts: Production ($2006)

	OIL				GAS			
	Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total
Output ($M)	2,244	3,335	544	6,124	1,624	2,413	394	4,431
GDP at factor cost ($M)	204	1,440	308	1,952	148	1,042	223	1,412
Employment (#)	2,659	20,922	4,741	28,321	1,924	15,138	3,430	20,492
Household Income ($M)	204	1,069	194	1,468	148	774	140	1,062
Tax Revenue ($M)	66	200	100	366	48	145	72	265
Federal Government	33	110	43	186	24	80	31	134
Provincial Government	34	76	47	157	24	55	34	113
Municipal Government	0	13	10	23	0	9	7	17

Minor differences due to rounding.

Impacts per million dollars of operating expenditure are shown in Table 4.10. These are the same for oil and gas.

[62] No distinction is drawn between impacts of wet gas and dry gas at the production stage. This is because operating expenditures for wet and dry gas are assumed to be the same (Appendix 4A, Table 4A.4). Without detailed engineering estimates, the rent and expenditure analyses assume for convenience that higher offshore processing costs just offset onshore NGL production costs.

Table 4.10: Provincial Expenditure Impacts Per $Million Expenditure: Production ($2006)

	Direct	Indirect	Induced	Total
Output ($M)	0.769	1.143	0.186	2.099
GDP at factor cost ($M)	0.070	0.493	0.106	0.669
Employment (#)	0.911	7.170	1.625	9.706
Household Income ($M)	0.070	0.366	0.066	0.503
Tax Revenue ($000)	22.728	68.449	34.160	125.337
Federal Government	11.181	37.846	14.665	63.692
Provincial Government	11.546	26.108	16.043	53.697
Municipal Government	0.000	4.495	3.452	7.947

Minor differences due to rounding.

Sectors experiencing the major positive impact of spending on production activity are in order of impact for both oil and natural gas production: transportation and warehousing; mining and oil and gas extraction; finance, insurance and real estate; professional, scientific and professional services; operating, office, cafeteria and laboratory supplies; manufacturing; wholesale trade; and retail trade.

Aggregate impacts of expenditure at the production stage are higher than impacts at the development stage, except in terms of tax revenue, even though aggregate expenditures are lower at the production stage. This is primarily because expenditure leakages on imported goods and services are significantly lower at the production stage (Appendix 4B, Tables 4B.1 and 4B.2). So far as tax revenue is concerned, results reflect the mix of goods and services used as inputs at each stage, differential commodity tax margins, and the balance of income tax and commodity tax in revenue estimates.

Impacts per million dollars of expenditure are greater at the production stage than the development stage, reflecting differences in input-output relations between scenarios.

4.1.6 Conclusions: Provincial Expenditure Benefits

While estimated expenditure impacts are not to be interpreted as firm predictions of the effects of offshore activity, they illustrate the substantial orders of magnitude that are possible at the provincial level. To the extent that assumptions of the analysis are conservative, results understate the scale of possible impact.

Reflecting relative expenditures in BC at each stage, highest gains in output, GDP, employment and household income occur at the production stage and lowest gains are at the exploration stage. By contrast, the development stage yields higher tax revenue than the production stage. Oil development yields greater benefits than gas development, and wet gas development yields marginally higher benefits than dry gas development. Oil production yields higher benefits than gas production due to higher expenditure in BC on oil production.

Among levels of government, the provincial government is the major beneficiary in terms of tax revenues at exploration and development stages while the federal government becomes the leading beneficiary at the production stage. These findings are a reflection of the balance of income tax and commodity tax in tax revenue at each stage and the tax rates associated with the different types of commodities used as inputs at each stage.[63]

In terms of impacts per million dollars of expenditure, highest gains are at the production stage and lowest gains at the exploration stage, except in terms of federal and provincial tax revenue where benefits per million dollars of expenditure are lowest at the development stage. Differences at the development stage between wet gas, dry gas and oil may not be material.

4.2 Regional Expenditure Benefits

Regional results are generated from a prototype bi-regional economic impact model for BC (Sandhu and Schofield 2007) calibrated to 2003 BCIOM data. The model distinguishes between the QCB region of BC as defined at the beginning of Section 4 (see Figure 4.1) and the rest of the province.

The model generates estimates of direct and indirect, but not induced, impacts. Therefore, estimates of total regional expenditure benefits are understated. However, results are reconciled to provincial results in terms of direct and indirect effects shown in Section 4.1.[64] Also, results give a clear indication of approximate shares of provincial benefit accruing to the QCB region and the rest of the province.

Direct project expenditures on commodities in BC are allocated to the QCB region and the rest of the province on the basis of coefficients in the regional impact model. The regional allocation of direct non-commodity project expenditures in BC (payments to factors of production (largely labour) with an adjustment for commodity taxation) is estimated according to assumed ranges as follows: non-commodity expenditures in the QCB region at the exploration stage (10-30%), at the development stage (15-50%) and at the production stage (25-75%). At the exploration stage, for example, if 10% of direct non-commodity expenditures in BC occur in the QCB region, then 90% of direct non-commodity expenditures in BC occur in the rest of the province. If the QCB proportion for exploration is 30%, the proportion for the rest of BC is 70%.

In presenting results, the regional sourcing of provincial and federal tax revenues is suppressed on the presumption that it is not of significant interest from a policy-making

[63] Provincial input taxes are in general larger than federal input taxes because companies receive a rebate on commodities used in production and the GST is passed on to consumers.

[64] Provincial direct and indirect effects computed for each scenario from the bi-regional model are not identical to provincial direct and indirect effects from the BCIOM shown in Section 4.1. This is due to differences between models in the levels of commodity and sectoral aggregation used. The bi-regional model uses 50 commodities and 26 sectors (the so-called ‘small’ level of aggregation expanded to highlight seafood processing and wood products in the manufacturing sector) while the BCIOM has 720 commodities and 304 sectors (the ‘working’ level of aggregation).

perspective. On the other hand, municipal tax revenues are shown by region.[65] All results are in 2006 dollars.

The abbreviations Lb and Ub in the tables of results refer respectively to the lower and upper bounds of assumed ranges for non-commodity expenditures in the QCB region.

4.2.1 Exploration

Table 4.11 shows estimated direct, indirect and total impacts of exploration expenditures by region and for the province as a whole. Table 4.12 shows the percentage shares of total provincial impacts in each region. Direct impacts appear as range estimates based on the assumed range of 10-30% of total direct BC non-commodity expenditure being in the QCB region.

Results show that at the exploration stage, excluding induced effects, an estimated $12-24 million of new output is produced in the QCB region compared with an estimated $351-363 million in the rest of the province (RBC). The share of incremental provincial output produced in the QCB region is approximately 3-6% while the share produced in the rest of the province is 94-97%.

GDP of $8-20 million (5-14% of the provincial total), employment of 111-292 jobs (5-14%), household income of $7-19 million (6-17 %) and municipal tax revenue of $23,000 (less than 2%) is estimated to occur in the QCB region. GDP of $128-140 million (86-95% of the provincial total), employment of approximately 2,000 jobs (87-95%), household income of $92-104 million (83-94 %) and municipal tax revenue of $1.4 million (over 98%) is estimated to occur in the rest of the province.

Estimated regional impacts per million dollars of exploration expenditure are shown in Table 4.13. Estimates indicate that, abstracting from induced effects, the QCB region secures $19-38,000 of output, $12-32,000 of GDP, less than one job, $11-31,000 of household income and under $1,000 of municipal revenue for every million dollars of expenditure on exploration activity. In the rest of the province, output increases by $565-584,000 and GDP by $206-226,000, around 3 jobs are added, household income increases by $148-167,000 and municipal tax revenue by $2,300.

[65] As indicated earlier (footnotes 53 and 60), municipal tax revenues (local taxes) are understated to the extent that the BCIOM does not include property taxes.

Table 4.11: Regional Expenditure Impacts: Exploration ($2006)

	Direct					Indirect			Total				
	QCB		RBC		BC	QCB	RBC	BC	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB					Lb	Ub	Lb QCB	Ub QCB	
Output ($M)	9	21	198	186	206	3	165	168	12	24	363	351	375
GDP at factor cost ($M)	6	18	55	43	62	2	85	86	8	20	140	128	148
Employment (#)	91	273	818	636	909	20	1262	1281	111	292	2080	1898	2190
Household Income ($M)	6	18	55	42	61	1	49	50	7	19	104	92	111
Local taxes ($000)	0	0	0	0	0	23	1,404	1,427	23	23	1,404	1,404	1,427

Table 4.12: Regional Shares of Provincial Expenditure Impacts: Exploration (%)

	Total				
	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB	
Output	3.07	6.37	96.93	93.63	100.00
GDP at factor cost	5.19	13.52	94.81	86.48	100.00
Employment	5.05	13.35	94.95	86.65	100.00
Household Income	6.30	17.25	93.70	82.75	100.00
Local taxes	1.59	1.59	98.41	98.41	100.00

Table 4.13: Regional Expenditure Impacts Per $Million Expenditure: Exploration ($2006)

	Direct					Indirect			Total				
	QCB		RBC		BC	QCB	RBC	BC	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB					Lb	Ub	Lb QCB	Ub QCB	
Output ($M)	0.014	0.034	0.318	0.298	0.332	0.005	0.266	0.271	0.019	0.038	0.584	0.565	0.603
GDP at factor cost ($M)	0.010	0.030	0.089	0.069	0.099	0.002	0.137	0.139	0.012	0.032	0.226	0.206	0.238
Employment (#)	0.146	0.439	1.316	1.024	1.463	0.032	2.030	2.062	0.178	0.471	3.346	3.054	3.524
Household Income ($M)	0.010	0.029	0.088	0.068	0.098	0.001	0.079	0.081	0.011	0.031	0.167	0.148	0.178
Local taxes ($000)	0.000	0.000	0.000	0.000	0.000	0.037	2.260	2.296	0.037	0.037	2.260	2.260	2.296

4.2.2 Oil Development

Tables 4.14 and 4.17 show estimated total impacts of oil development expenditures by region for short and long pipeline cases. Tables 4.15 and 4.18 show percentage shares of provincial impacts in each region.

Abstracting from induced effects and depending on the length of the underwater pipeline, increased output from oil development of $111-242 million (3.1-6.4% of the provincial total) is estimated to occur in the QCB region. Increased GDP of $68-196 million (5.6-15.3% of the provincial total), 1189-3602 jobs (5.9-16.0%), household income of $62-190 million (6.6-19.1%) and municipal tax revenue of $287-304,000 (around 2%) also occur in the QCB region. Increased output of $3.4-3.7 billion (94-97% of the provincial total), GDP of $1.0-1.2 billion (85-94%), approximately 18-21,00 jobs (84-94%), household income of $758-928 million (81-94%) and municipal tax revenue of $16,700-17,500 (around 98%) is estimated to occur in the rest of the province.

Tables 4.16 and 4.19 show impacts per million dollars of expenditure by region and length of pipeline. Output of $22-46,000, GDP of $14-38,000, 0.2-0.7 jobs, household income of $12-36,000 and less than one thousand dollars of municipal tax revenue is estimated to occur in the QCB region for every million dollars of expenditure on oil development. Output of $679-703,000, GDP of $207-232,000, 3.6-4.1 jobs, household income of $153-177,000 and municipal tax revenue of approximately $3,000 is estimated to occur in the rest of the province.

Table 4.14: Regional Expenditure Impacts: Oil Development Short Pipeline ($2006)

	Direct					Indirect			Total				
	QCB		RBC		BC	QCB	RBC	BC	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB					Lb	Ub	Lb QCB	Ub QCB	
Output ($M)	75	193	1681	1564	1756	36	1791	1826	111	228	3472	3355	3583
GDP at factor cost ($M)	50	168	286	168	336	17	859	876	68	185	1145	1027	1212
Employment (#)	951	3170	5389	3170	6340	238	14738	14975	1189	3408	20127	17908	21315
Household Income ($M)	50	168	286	168	336	12	590	601	62	180	875	758	937
Local taxes ($000)	0	0	0	0	0	287	16,726	17,014	287	287	16,726	16,726	17,014

Table 4.15: Regional Shares of Provincial Expenditure Impacts: Oil Development Short Pipeline (%)

	Total				
	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB	
Output	3.09	6.37	96.91	93.63	100.00
GDP at factor cost	5.58	15.28	94.42	84.72	100.00
Employment	5.58	15.99	94.42	84.01	100.00
Household Income	6.62	19.16	93.38	80.84	100.00
Local taxes	1.69	1.69	98.31	98.31	100.00

Table 4.16: Regional Expenditure Impacts Per $Million Expenditure: Oil Development Short Pipeline ($2006)

	Direct					Indirect			Total				
	QCB		RBC		BC	QCB	RBC	BC	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB					Lb	Ub	Lb QCB	Ub QCB	
Output ($M)	0.015	0.039	0.341	0.317	0.356	0.007	0.363	0.370	0.022	0.046	0.703	0.679	0.726
GDP at factor cost ($M)	0.010	0.034	0.058	0.034	0.068	0.004	0.174	0.177	0.014	0.038	0.232	0.208	0.246
Employment (#)	0.193	0.642	1.092	0.642	1.284	0.048	2.985	3.033	0.241	0.690	4.077	3.627	4.317
Household Income ($M)	0.010	0.034	0.058	0.034	0.068	0.002	0.119	0.122	0.013	0.036	0.177	0.153	0.190
Local taxes ($000)	0.000	0.000	0.000	0.000	0.000	0.058	3.388	3.446	0.058	0.058	3.388	3.388	3.446

Table 4.17: Regional Expenditure Impacts: Oil Development Long Pipeline ($2006)

	Direct					Indirect			Total				
	QCB		RBC		BC	QCB	RBC	BC	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB					Lb	Ub	Lb QCB	Ub QCB	
Output ($M)	80	204	1783	1659	1863	38	1910	1948	118	242	3693	3569	3811
GDP(FC)	53	177	302	177	355	18	908	926	72	196	1209	1085	1281
Employment (#)	1005	3349	5692	3349	6697	253	15627	15880	1258	3602	21320	18976	22577
Household Income ($M)	53	177	302	177	355	12	626	638	66	190	928	803	993
Local taxes ($000)	0	0	0	0	0	304	17,545	17,849	304	304	17,545	17,545	17,849

Table 4.18: Regional Shares of Provincial Expenditure Impacts: Oil Development Long Pipeline (%)

	Total				
	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB	
Output	3.09	6.35	96.91	93.65	100.00
GDP at factor cost	5.59	15.29	94.41	84.71	100.00
Employment	5.57	15.95	94.43	84.05	100.00
Household Income	6.61	19.11	93.39	80.89	100.00
Local taxes	1.70	1.70	98.30	98.30	100.00

Table 4.19: Regional Expenditure Impacts Per $Million Expenditure: Oil Development Long Pipeline ($2006)

	Direct					Indirect			Total				
		QCB		RBC	BC	QCB	RBC	BC		QCB		RBC	BC
	Lb	Ub	Lb QCB	Ub QCB					Lb	Ub	Lb QCB	Ub QCB	
Output ($M)	0.015	0.039	0.339	0.316	0.355	0.007	0.364	0.371	0.022	0.046	0.703	0.680	0.726
GDP at factor cost ($M)	0.010	0.034	0.057	0.034	0.068	0.003	0.173	0.176	0.014	0.037	0.230	0.207	0.244
Employment (#)	0.191	0.638	1.084	0.638	1.275	0.048	2.975	3.024	0.239	0.686	4.059	3.613	4.299
Household Income ($M)	0.010	0.034	0.057	0.034	0.068	0.002	0.119	0.122	0.012	0.036	0.177	0.153	0.189
Local taxes ($000)	0.000	0.000	0.000	0.000	0.000	0.058	3.341	3.398	0.058	0.058	3.341	3.341	3.398

4.2.3 Wet Gas Development

Tables 4.20 and 4.23 show estimated total impacts of wet gas development expenditures by region for short and long pipeline cases. Tables 4.21 and 4.24 show percentage shares of provincial impacts in each region.

Again abstracting from induced effects and depending on the length of the underwater pipeline, increased output of $82-186 million (3.2-6.6% of the provincial total) is estimated to occur in the QCB region. Increased GDP of $51-151 million (5.7-15.7% of the provincial total), approximately 900-2,800 jobs (5.7-16.3%), household income of $46-146 million (6.7-19.6%) and municipal tax revenue of $213-232,000 (around 2%) also occur in the QCB region. Increased output of $2.4-2.8 billion, GDP of $744-906 million, approximately 13-16,000 jobs, household income of $554-702 million and municipal tax revenue of approximately $12-13,000 is estimated to occur in the rest of the province, with percentage shares of the provincial total equal to (100-QCB share) for each type of impact.

Tables 4.22 and 4.25 show impacts per million dollars of expenditure by region and length of pipeline. Output of $24-49,000, GDP of $14-40,000, 0.3-0.7 jobs, household income of $13-39,000 and less than one thousand dollars of municipal tax revenue is estimated to occur in the QCB region for every million dollars of expenditure on wet gas development. Output of $700-728,000, GDP of $212-240,000, 3.7-4.2 jobs, household income of $159-186,000 and municipal tax revenue of $3-4,000 is estimated to occur in the rest of the province.

Table 4.20: Regional Expenditure Impacts: Wet Gas Development Short Pipeline ($2006)

	Direct					Indirect			Total				
	QCB		RBC		BC	QCB	RBC	BC	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB					Lb	Ub	Lb QCB	Ub QCB	
Output ($M)	56	144	1215	1126	1271	26	1305	1331	82	171	2519	2431	2602
GDP at factor cost ($M)	38	126	214	126	252	13	618	631	51	139	832	744	883
Employment (#)	714	2381	4047	2381	4761	176	10718	10894	890	2557	14764	13098	15655
Household Income ($M)	38	126	214	126	252	9	428	437	46	135	642	554	689
Local taxes ($000)	0	0	0	0	0	213	12,157	12,370	213	213	12,157	12,157	12,370

Table 4.21: Regional Shares of Provincial Expenditure Impacts: Wet Gas Development Short Pipeline (%)

	Total				
	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB	
Output	3.16	6.56	96.84	93.44	100.00
GDP at factor cost	5.73	15.73	94.27	84.27	100.00
Employment	5.69	16.33	94.31	83.67	100.00
Household Income	6.74	19.56	93.26	80.44	100.00
Local taxes	1.73	1.73	98.27	98.27	100.00

Table 4.22: Regional Expenditure Impacts Per $Million Expenditure: Wet Gas Development Short Pipeline ($2006)

	Direct					Indirect			Total				
	QCB		RBC		BC	QCB	RBC	BC	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB					Lb	Ub	Lb QCB	Ub QCB	
Output ($M)	0.016	0.042	0.351	0.325	0.367	0.008	0.377	0.384	0.024	0.049	0.728	0.702	0.752
GDP at factor cost ($M)	0.011	0.036	0.062	0.036	0.073	0.004	0.179	0.182	0.015	0.040	0.240	0.215	0.255
Employment (#)	0.206	0.688	1.169	0.688	1.375	0.051	3.096	3.147	0.257	0.739	4.265	3.784	4.522
Household Income ($M)	0.011	0.036	0.062	0.036	0.073	0.002	0.124	0.126	0.013	0.039	0.186	0.160	0.199
Local taxes ($000)	0.000	0.000	0.000	0.000	0.000	0.062	3.512	3.573	0.062	0.062	3.512	3.512	3.573

Table 4.23: Regional Expenditure Impacts: Wet Gas Development Long Pipeline ($2006)

	Direct					Indirect			Total				
	QCB		RBC		BC	QCB	RBC	BC	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB					Lb	Ub	Lb QCB	Ub QCB	
Output ($M)	61	157	1331	1235	1392	29	1441	1470	90	186	2772	2676	2862
GDP at factor cost ($M)	41	137	233	137	274	14	673	687	55	151	906	810	961
Employment (#)	775	2585	4394	2585	5169	194	11734	11928	969	2778	16128	14319	17097
Household Income ($M)	41	137	233	137	274	9	469	479	51	146	702	606	753
Local taxes ($000)	0	0	0	0	0	232	13,093	13,325	232	232	13,093	13,093	13,325

Table 4.24: Regional Shares of Provincial Expenditure Impacts: Wet Gas Development Long Pipeline (%)

	Total				
	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB	
Output	3.16	6.51	96.84	93.49	100.00
GDP at factor cost	5.73	15.70	94.27	84.30	100.00
Employment	5.67	16.25	94.33	83.75	100.00
Household Income	6.72	19.45	93.28	80.55	100.00
Local taxes	1.74	1.74	98.26	98.26	100.00

Table 4.25: Regional Expenditure Impacts Per $Million Expenditure: Wet Gas Development Long Pipeline ($2006)

	Direct					Indirect			Total				
	QCB		RBC		BC	QCB	RBC	BC	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB					Lb	Ub	Lb QCB	Ub QCB	
Output ($M)	0.016	0.041	0.348	0.323	0.364	0.008	0.377	0.385	0.024	0.049	0.725	0.700	0.749
GDP at factor cost ($M)	0.011	0.036	0.061	0.036	0.072	0.004	0.176	0.180	0.014	0.039	0.237	0.212	0.252
Employment (#)	0.203	0.676	1.150	0.676	1.352	0.051	3.070	3.121	0.254	0.727	4.220	3.747	4.474
Household Income ($M)	0.011	0.036	0.061	0.036	0.072	0.002	0.123	0.125	0.013	0.038	0.184	0.159	0.197
Local taxes ($000)	0.000	0.000	0.000	0.000	0.000	0.061	3.426	3.486	0.061	0.061	3.426	3.426	3.486

4.2.4 Dry Gas Development

Tables 4.26 and 4.29 show estimated total impacts of dry gas development expenditures by region for short and long pipeline cases. Tables 4.27 and 4.30 show percentage shares of provincial impacts in each region.

Abstracting from induced effects and depending on the length of the underwater pipeline, increased output of $77-171 million (3.1-6.2% of the provincial total), increased GDP of $46-137 million (5.5-14.9%), approximately 800-2,500 jobs (5.5-15.5%), household income of $42-133 million (6.5-18.6%) and municipal tax revenue of $205-223,000 (around 2%) is estimated to occur in the QCB region. Increased output of $2.4-2.7 billion, GDP of $714-866 million, approximately 12-15,000 jobs, household income of $529-668 million and municipal tax revenue of approximately $12-13,000 is estimated to occur in the rest of the province, with percentage shares of the provincial total equal to (100-QCB share) for each type of impact.

Tables 4.28 and 4.31 show impacts per million dollars of expenditure by region and length of pipeline. Output of $23-46,000, GDP of $14-37,000, 0.2-0.7 jobs, household income of $12-36,000 and less than one thousand dollars of municipal tax revenue is estimated to occur in the QCB region for every million dollars of expenditure on dry gas development. Output of $700-723,000, GDP of $210-236,000, 3.7-4.2 jobs, household income of $156-181,000 and municipal tax revenue of approximately $3,500 is estimated to occur in the rest of the province.

Table 4.26: Regional Expenditure Impacts: Dry Gas Development Short Pipeline ($2006)

	Direct					Indirect			Total				
	QCB		RBC		BC	QCB	RBC	BC	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB					Lb	Ub	Lb QCB	Ub QCB	
Output ($M)	51	130	1163	1085	1215	25	1267	1292	77	156	2430	2351	2507
GDP at factor cost ($M)	34	113	192	113	225	12	601	613	46	125	793	714	839
Employment (#)	638	2126	3614	2126	4252	169	10366	10535	807	2295	13981	12492	14787
Household Income ($M)	34	113	192	113	225	8	416	425	42	121	608	529	650
Local taxes ($000)	0	0	0	0	0	205	11,750	11,955	205	205	11,750	11,750	11,955

Table 4.27: Regional Shares of Provincial Expenditure Impacts: Dry Gas Development Short Pipeline (%)

	Total				
	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB	
Output	3.06	6.21	96.94	93.79	100.00
GDP at factor cost	5.50	14.90	94.50	85.10	100.00
Employment	5.46	15.52	94.54	84.48	100.00
Household Income	6.48	18.61	93.52	81.39	100.00
Local taxes	1.71	1.71	98.29	98.29	100.00

Table 4.28: Regional Expenditure Impacts Per $Million Expenditure: Dry Gas Development Short Pipeline ($2006)

	Direct					Indirect			Total				
	QCB		RBC		BC	QCB	RBC	BC	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB					Lb	Ub	Lb QCB	Ub QCB	
Output ($M)	0.015	0.039	0.346	0.323	0.361	0.008	0.377	0.384	0.023	0.046	0.723	0.699	0.746
GDP at factor cost ($M)	0.010	0.034	0.057	0.034	0.067	0.004	0.179	0.182	0.014	0.037	0.236	0.212	0.249
Employment (#)	0.190	0.632	1.075	0.632	1.265	0.050	3.084	3.134	0.240	0.683	4.159	3.716	4.399
Household Income ($M)	0.010	0.034	0.057	0.034	0.067	0.002	0.124	0.126	0.013	0.036	0.181	0.157	0.193
Local taxes ($000)	0.000	0.000	0.000	0.000	0.000	0.061	3.495	3.556	0.061	0.061	3.495	3.495	3.556

Table 4.29: Regional Expenditure Impacts: Dry Gas Development Long Pipeline ($2006)

	Direct					Indirect			Total				
	QCB		RBC		BC	QCB	RBC	BC	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB					Lb	Ub	Lb QCB	Ub QCB	
Output ($M)	56	143	1280	1194	1336	28	1403	1431	85	171	2683	2596	2768
GDP at factor cost ($M)	37	123	210	123	247	14	656	670	51	137	866	780	917
Employment (#)	699	2330	3960	2330	4659	186	11383	11570	885	2516	15343	13713	16229
Household Income ($M)	37	123	210	123	247	9	458	467	46	133	668	581	714
Local taxes ($000)	0	0	0	0	0	223	12,686	12,909	223	223	12,686	12,686	12,909

Table 4.30: Regional Shares of Provincial Expenditure Impacts: Dry Gas Development Long Pipeline (%)

	Total				
	QCB		RBC		BC
	Lb	Ub	Lb QCB	Lb QCB	
Output	3.06	6.19	96.94	93.81	100.00
GDP at factor cost	5.51	14.94	94.49	85.06	100.00
Employment	5.45	15.50	94.55	84.50	100.00
Household Income	6.47	18.58	93.53	81.42	100.00
Local taxes	1.73	1.73	98.27	98.27	100.00

Table 4.31: Regional Expenditure Impacts Per $Million Expenditure: Dry Gas Development Long Pipeline ($2006)

	Direct					Indirect			Total				
	QCB		RBC		BC	QCB	RBC	BC	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB					Lb	Ub	Lb QCB	Ub QCB	
Output ($M)	0.015	0.038	0.344	0.321	0.359	0.008	0.377	0.385	0.023	0.046	0.721	0.698	0.744
GDP at factor cost ($M)	0.010	0.033	0.056	0.033	0.066	0.004	0.176	0.180	0.014	0.037	0.233	0.210	0.246
Employment (#)	0.188	0.626	1.064	0.626	1.252	0.050	3.059	3.109	0.238	0.676	4.123	3.684	4.360
Household Income ($M)	0.010	0.033	0.056	0.033	0.066	0.002	0.123	0.125	0.012	0.036	0.179	0.156	0.192
Local taxes ($000)	0.000	0.000	0.000	0.000	0.000	0.060	3.409	3.468	0.060	0.060	3.409	3.409	3.468

4.2.5 Production

Tables 4.32 and 4.35 show estimated total impacts of production expenditures by region for oil and gas scenarios. Tables 4.33 and 4.36 show percentage shares of provincial impacts in each region.

Abstracting from induced effects, increased output of $104-245 million (2.8-4.8% of the provincial total), increased GDP of $57-181 million (4.6-10.5%), 728-2,335 jobs (4.5-10.8%), household income of $49-170 million (6.6-16.4%) and municipal tax revenue of $303-419,000 (around 2%) is estimated to occur in the QCB region, depending on whether the product is oil or gas. Increased output of $3.5-5.0 billion, GDP of $1.1-1.7 billion, approximately 14-21,000 jobs, household income of $626-967 million and municipal tax revenue of approximately $17-23 million is estimated to occur in the rest of the province, with percentage shares of the provincial total equal to (100-QCB share) for each type of impact.

Tables 4.34 and 4.37 show impacts per million dollars of expenditure by region and product produced. Output of $49-84,000, GDP of $27-62,000, 0.4-0.8 jobs, household income of $23-58,000 and less than one thousand dollars of municipal tax revenue is estimated to occur in the QCB region for every million dollars of expenditure on dry gas development. Output of approximately $1.7 billion, GDP of $530-565,000, 6.6-7.1 jobs, household income of $296-331,000 and municipal tax revenue of approximately $8,000 is estimated to occur in the rest of the province.

Table 4.32: Regional Expenditure Impacts: Oil Production ($2006)

	Direct					Indirect			Total				
	QCB		RBC		BC	QCB	RBC	BC	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB					Lb	Ub	Lb QCB	Ub QCB	
Output ($M)	88	190	2156	2054	2244	55	2842	2897	143	245	4998	4896	5141
GDP at factor cost ($M)	51	153	153	51	204	28	1496	1524	79	181	1650	1547	1729
Employment (#)	665	1994	1994	665	2659	341	18647	18988	1006	2335	20642	19312	21647
Household Income ($M)	51	153	153	51	204	17	814	831	68	170	967	865	1035
Local taxes ($000)	0	0	0	0	0	419	23,222	23,641	419	419	23,222	23,222	23,641

Table 4.33: Regional Shares of Provincial Expenditure Impacts: Oil Production (%)

	Total				
	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB	
Output	2.78	4.77	97.22	95.23	100.00
GDP at factor cost	4.58	10.49	95.42	89.51	100.00
Employment	4.65	10.79	95.35	89.21	100.00
Household Income	6.55	16.42	93.45	83.58	100.00
Local taxes	1.77	1.77	98.23	98.23	100.00

Table 4.34: Regional Expenditure Impacts Per $Million Expenditure: Oil Production ($2006)

	Direct					Indirect			Total				
	QCB		RBC		BC	QCB	RBC	BC	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB					Lb	Ub	Lb QCB	Ub QCB	
Output ($M)	0.030	0.065	0.739	0.704	0.769	0.019	0.974	0.993	0.049	0.084	1.713	1.678	1.762
GDP at factor cost ($M)	0.018	0.053	0.053	0.018	0.070	0.010	0.513	0.522	0.027	0.062	0.565	0.530	0.592
Employment (#)	0.228	0.683	0.683	0.228	0.911	0.117	6.391	6.508	0.345	0.800	7.074	6.619	7.419
Household Income ($M)	0.018	0.053	0.053	0.018	0.070	0.006	0.279	0.285	0.023	0.058	0.331	0.296	0.355
Local taxes ($000)	0.000	0.000	0.000	0.000	0.000	0.144	7.958	8.102	0.144	0.144	7.958	7.958	8.102

Table 4.35: Regional Expenditure Impacts: Gas Production ($2006)

	Direct					Indirect			Total				
	QCB		RBC		BC	QCB	RBC	BC	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB					Lb	Ub	Lb QCB	Ub QCB	
Output ($M)	64	138	1560	1486	1624	40	2056	2096	104	177	3617	3543	3720
GDP at factor cost ($M)	37	111	111	37	148	20	1083	1103	57	131	1194	1120	1251
Employment (#)	481	1443	1443	481	1924	247	13493	13739	728	1690	14936	13974	15663
Household Income ($M)	37	111	111	37	148	12	589	601	49	123	700	626	749
Local taxes ($000)	0	0	0	0	0	303	16,803	17,106	303	303	16,803	16,803	17,106

Table 4.36: Regional Shares of Provincial Expenditure Impacts: Gas Production (%)

	Total				
	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB	
Output	2.78	4.77	97.22	95.23	100.00
GDP at factor cost	4.58	10.49	95.42	89.51	100.00
Employment	4.65	10.79	95.35	89.21	100.00
Household Income	6.55	16.42	93.45	83.58	100.00
Local taxes	1.77	1.77	98.23	98.23	100.00

Table 4.37: Regional Expenditure Impacts Per $Million Expenditure: Gas Production ($2006)

	Direct					Indirect			Total				
	QCB		RBC		BC	QCB	RBC	BC	QCB		RBC		BC
	Lb	Ub	Lb QCB	Ub QCB					Lb	Ub	Lb QCB	Ub QCB	
Output ($M)	0.030	0.065	0.739	0.704	0.769	0.019	0.974	0.993	0.049	0.084	1.713	1.678	1.762
GDP at factor cost ($M)	0.018	0.052	0.052	0.018	0.070	0.010	0.513	0.522	0.027	0.062	0.565	0.530	0.592
Employment (#)	0.228	0.683	0.683	0.228	0.911	0.117	6.391	6.508	0.345	0.800	7.074	6.619	7.419
Household Income ($M)	0.018	0.052	0.052	0.018	0.070	0.006	0.279	0.285	0.023	0.058	0.331	0.296	0.355
Local taxes ($000)	0.000	0.000	0.000	0.000	0.000	0.000	0.008	0.008	0.144	0.144	7.958	7.958	8.102

4.2.6 Conclusions: Regional Expenditure Benefits

To the extent that results do not include induced effects and local taxes do not include property taxes, regional impact estimates in total and in terms of per million dollars of expenditure, are understated. At the same time, application of estimated percentage regional shares to provincial benefit aggregates in section 4.1 will give some idea of the orders of magnitude of regional impacts inclusive of induced effects.

It is apparent that the QCB region, which stands to bear the bulk of the risks associated with offshore oil and gas activity, is likely to share a relatively small proportion of provincial expenditure benefits. This is because, in the absence of the sort of structural changes discussed in section 5 of the report, the region lacks the capacity to supply many of the inputs required directly for offshore activity and to meet the demands created by the indirect and induced effects of that activity.

However, in so far as the QCB region does benefit from structural improvements to the local economy as a result of offshore activity, there will be positive impacts on the region that are not measured by the expenditure impact analysis in this section (for detailed examples of likely structural changes, see section 5). Even so, the analysis suggests that if communities in the QCB region are to view the prospect of offshore development as providing a fair share for them of the substantial provincial benefits anticipated from offshore activity, then it will be necessary to consider ways of directing to the region a reasonable amount of the provincial financial revenue (economic rent) gained from offshore activity. Options could include, for example, negotiated revenue-sharing arrangements with local governments and/or First Nations, cost-sharing agreements, or the provision of targeted grants for such purposes as investment in community infrastructure, local service needs and/or training required for jobs in the industry.

SECTION 5

TRANSFORMATIVE ECONOMIC CHANGES

"While the main beneficial effects of oil developments upon [Aberdeen] firms have been in the form of increased demand, there have also been benefits on the supply side, allowing firms to produce more efficiently. They are difficult to quantify but include better technological facilities, improved telecommunications, and more extensive transport links, nationally and internationally." (Harris, Lloyd and Newlands 1988, pp. 38-39).

This section of the study of potential economic benefits from offshore oil and gas activity explores the further benefits that may result through offshore industry-related structural changes to the British Columbia and QCB economies. These include the effects of offshore petroleum activity on infrastructure development, education and training, and research and development (R&D), and the ways in which these and other developments may increase the entrepreneurship and competitiveness of local individuals and companies, diversify the economy, result in population increase, and in general affect traditional industries.

The discussion is primarily based on experience in Norway, the United Kingdom, and Atlantic Canada. Use is also made of information on experience at Cook Inlet, Alaska, which some argue represents a close analogue in terms of basin size, ecosystem and geology. However, much of the literature on Alaska is principally concerned with the North Slope, pipelines and the state-wide fiscal impacts, with it being difficult to separate out experience directly related to activity in Cook Inlet.

The section is grounded in the theory of long-run economic growth (e.g. Solow 1956, 1957, Romer 1986, 1990). The theory defines the long-run rate of growth of output (and hence income) as a function of growth in the quantity and quality (or productivity) of factor inputs to the production process. Over the long run, in other words, growth is dependent on expansion of the capacity of the economy to produce goods and services.[66]

According to the theory, drivers of long-run, sustainable growth include increases in the size of the labour force, the size of the stock of physical capital (including public sector infrastructure) and the quantum of natural resources available in an economy, with an important source of labour force growth being population increase. Other key drivers are influences on the productivity of labour, capital and natural resource endowments. These include: investments in human capital (education and training, health); research and development (R&D) activities that promote technical progress; organizational improvements in both individual companies and the economy at large, including diversification of the industrial base of the economy, such that labour and capital are put to more productive use and the capacity to produce goods and services is broadened; and attitudinal developments in the work force (greater entrepreneurial spirit, greater motivation).

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[66] In the original version of the theory (Solow 1956, 1957), the determinants of growth were taken to be exogenously given; in later versions termed 'endogenous growth theory' (Romer 1986, 1990), the determinants of growth are explained within the model.

It should be noted that the impacts discussed in this section are greatly influenced by such factors as the local context and government policies and initiatives. In the former case, the potential for local companies benefiting from offshore activity is influenced by the pre-existing economy, including the types, capabilities and strengths of existing companies and business groups. The potential for education, training and R&D is similarly affected by the strength and maturity of the college system.[67]

The delivery of offshore petroleum activity-related economic development initiatives is also greatly affected by government policies and initiatives. These will reflect the approach adopted by governments, their ability to fund them, and, critically, what levels of government have jurisdiction over such matters, and the regulatory mechanisms available to them. None of these are currently clear with respect to British Columbia offshore activity.

5.1 Impacts on Infrastructure, Education and Training, and R&D

The petroleum industry makes major infrastructure, education and training, and R&D investments in order to support its activities. Other private sector interests and governments also invest in these areas as part of corporate social responsibility or economic development initiatives. In the latter case, this may be part of industrial benefits planning designed to leverage the local benefits from petroleum industry investment and to contribute to sustainable economic development.

This section provides a review of the infrastructure, education and training, and R&D, primarily as experienced in Norway, the United Kingdom and Atlantic Canada.

5.1.1 Infrastructure

Especially during the development and operations phases, offshore petroleum activity commonly results in, or contributes to, the development of construction, fabrication, supply, service, education, training and R&D infrastructure. For example, in Newfoundland and Labrador, the industrial facilities that have resulted from the offshore oil and gas sector include:

- Bull Arm Construction Yard.
- Marystown / Cow Head Fabrication Facility.
- Newfoundland Transshipment Terminal.
- Penney Energy Marine Terminal.
- NEWDOCK Fabrication Facility.
- Cougar Helicopter Terminal.
- Hibernia Training Simulator.
- Harvey and Company Offshore Supply Base.
- Schlumberger Canada Service Facility.
- ASCO Warehouse Complex.

[67] It can be argued that British Columbia is relatively well-positioned in some of these matters, relative to some other jurisdictions, given the existing strength and maturity of its engineering, marine and environmental sectors (BC Innovation Council 2004), and its universities and colleges. It will also benefit from capabilities developed relative to onshore activity in NE BC. However, there may be important regional variations, and hence constraints.

- Halliburton Operations Centre.
- Baker Hughes Canada Service Facility.
- East Coast Tubulars Goods Facility.

The capital cost of these and other smaller facilities built between 1985 and 2004 was over $1.2 billion. This provided a major boost to the local construction sector, generating demands for materials and equipment, as well as engineering, project management and construction services. Using a rule of thumb that labour comprises 20% of all construction costs, work on this infrastructure resulted in expenditures of approximately $240 million in construction labour.

The availability of such infrastructure is important to petroleum companies considering further projects in any region. It reduces the cost, and hence increases the likelihood, of such projects. It likely also increases the local participation in them, by increasing the ability of local companies and individuals to be involved in construction, fabrication and operations activities.

The development of an offshore petroleum industry is also frequently accompanied by the development or enhancement of education, training, R&D facilities, and associated equipment. These have made a major contribution to petroleum-related and other education and training and R&D. Some examples from Newfoundland and Labrador include:

Memorial University:

- Centre for Earth Resources Research.
- Centre for Cold Ocean Resources Engineering (C-CORE).
- Centre for Marine Compressed Natural Gas.
- Oil and Gas Development Partnership and associated facilities.
- Computer-Aided Design Facility, Engineering.
- C-CORE Geotechnical Modeling Centrifuge.
- Centre for Offshore and Remote Medicine and Telemedicine..
- Visualization Laboratory.
- Institute for Marine Dynamics Wave Generating System.

Marine Institute:

- Centre for Marine Simulation.
- Offshore Safety and Survival Centre.
- Southside Marine Base.

College of the North Atlantic:

- Petroleum Technology Training Program Equipment.
- Petroleum Production Training Enhancement Project.
- Drill Rig Operator Training Equipment.
- Safety and Emergency Response Training Centre.

The new infrastructure developed to meet direct or multiplier offshore petroleum activity-related requirements commonly also includes new industrial parks, office buildings, hotels and housing.

The offshore petroleum industry also requires high-quality air transportation infrastructure and services. All areas experiencing offshore petroleum activity see the construction or expansion of new aviation infrastructure, to cater to the needs of industry personnel to access offshore workplaces from their homes, and of executives, regulators, consultants and others to fly to, from and between such centres of industry activity as Stavanger, Aberdeen, St. John's, Halifax, Calgary and Houston. In specific examples:

- MacKay and Mackay (1975, pp. 120-121) noted as early as 1975 that "the number of scheduled air services to and from [Aberdeen] airport have doubled in the last two years." Major terminal and other expansions have been completed and are planned, and will allow non-stop links with North America and the Middle East (BAA Aberdeen, 2005, p.13; Ewen 2005). Kemp and Smith (2002) note that the industry has also had an impact on the travel patterns of airport users. "In 1992, 26.6 of all terminal passengers leaving Aberdeen airport were destined for oil platforms and rigs. Over 50% of air transport movements from Aberdeen airport had the same destinations."
- Similarly, while Stavanger was relatively isolated in the 1960s, by 1994 its airport had flights to Oslo and Bergen every 30 minutes during the workday, to London four times a day, to Amsterdam three times a day, and to Paris once a day (Måsvær 2002).
- Continental Airlines introduced non-stop flights between St. John's and New York in 2004, in order to provide 'the host of oil and energy companies doing business in St. John's [with] better access to Houston, the US oil and energy capital' (Continental 2004).

Some of the new infrastructure described above is specifically and solely used by the offshore petroleum industry. This is the case, for example, with most marine supply bases, transshipment terminals and supply yards and warehouses. However, some offshore petroleum infrastructure can have value to other industries. For example, improved aviation infrastructure and services are beneficial to tourism and a wide range of other industries, and while the construction yard at Bull Arm, Newfoundland, was developed to build offshore platforms and topsides, it has subsequently fabricated components for a major mine and mill in Labrador.

Alaskan.com (n.d.) and Kenai Peninsula Economic Development District (n.d.) both imply that oil discoveries in Cook Inlet led to subsequent infrastructure development in the region. Unfortunately, detailed information is hard to come by; the Cook Inlet industry is older and smaller than Prudhoe Bay's, and thus is passed over in many studies on the impacts of the industry.

However, Cook Inlet is notable for the development of a number of petroleum-related industrial facilities, most of them built in the late 1960s. They have seen fluctuating levels of activity and include a fertilizer plant, a refinery, and a liquefied natural gas (LNG) plant:

- The Collier Chemical Plant, later sold to UNOCAL and then Agrium, was constructed over the period 1968-1969 (Cook Inlet Oil and Gas 2004). In 1975, it began exporting fertilizer to Portland, Oregon (Alaska Department of Labor 1975), a side benefit of which was that returning barges could bring cargo into Cook Inlet. The plant closed in 2007 because there was insufficient Cook Inlet gas to generate electricity, provide domestic heating and make fertilizer, resulting in the loss of about 300 jobs. (Anchorage Daily News 2007).

- The Tesoro-Alaska Refinery Corporation facility in Nikiski was constructed in 1969. In 1975 Tesoro began producing multiple grades of gasoline, and in 1995 it 'began producing more value-added products'. It now consumes all of the Inlet's oil production, and now imports oil and gas from outside (Cook Inlet Oil and Gas 2005, p 2), employing 180 direct employees and a 'significant contract workforce' (p. 8).
- The ConocoPhillips LNG plant in Nikiski was built in 1969 and claims to be "the first commercially successful LNG export facility in the world." A joint venture with Marathon, it employed over 40 full-time employees and a 'modest contract workforce' in 2005. It is one of the smallest operational LNG export facilities in the world, producing approximately 1.7 million tons of LNG annually. As of 2005, it served two customers in Japan. Its federal export license for the LNG plant expires in the first quarter of 2009, and no plans for renewing this license, or to seek other customers, have been announced. (Cook Inlet Oil and Gas 2005, p. 9).

In addition to these large industrial facilities, several oil industry-related companies operate in the Kenai Peninsula (McDowell Group & Information Insights 2001). The Alaska Petroleum Contractors and Natchiq Inc. run a Nikiski facility for building oil field modules. The scale of activity has fluctuated, but in 1998 320 people were employed building a module there (p. 27). Andarko Petroleum Corporation, Cross Timbers, and Forcenergy all employed local residents in exploration and production, and in Kenai/Soldotna the Unocal, Peak Oilfield Service Company, Alaska Petroleum Contractors, Tesoro Alaska, and Baker Hughes Oil Services were among the top ten employers in 1998.

5.1.2 Education and Training

The offshore petroleum industry requires a wide range of skills. Some will likely be related to existing activity in coastal regions, such as construction, stevedoring and seafaring. There are also other much more specialized requirements, in such areas as welding, drilling, reservoir engineering and subsea activity. Governments and industry may put training in place so as to increase the local share of offshore petroleum-related employment. This may have wide benefits for the jurisdiction, to the degree that new skills have applications in other industries, that training can be provided to non-residents, or that those providing the training contribute to a range of local R&D efforts such as were described above.

Norway

Norway has long had programs to allow local residents' involvements in the industry. The OLF (2005) lists some recent programs targeted at education for the petroleum industry. These include Hammerfest Upper Secondary School's establishing curriculum in chemical and process subjects (in response to the Snøhvit development), and a bachelor program in resource management, including petroleum activity, at the University College of Finnmark. New safety education is being provided by the Norwegian University of Science and Technology, while the University of

Stavanger has developed a national security course focusing on government planning and management.

According to the OLF (2004), “many of the oil companies have cooperation agreements with the university and college sector concerning financial and technical support. These measures include rotation of technical personnel between the university and college sector and the petroleum industry. The objective is to strengthen education, learning and development of expertise in subjects that have particular relevance for the oil and gas cluster” (p. 36).

Mikkelsen, Jøsendal, Steineke and Rapmund (nd) indicate that every year about 200 master’s level students and 10 to 20 PhDs in petroleum technology fields graduate from Norwegian universities (p. 19). This includes about 100 MSc students from the Gas Technology Center at the Norwegian University of Science and Technology. The courses and programs available there include MSc and PhD degrees in Petroleum Engineering and in Petroleum Geoscience (Gas Technology Center, nd). Måsvær (2002) notes that few Stavanger residents pursued university-level education before the start of offshore oil activity, but that the city now has its own college. It achieved university status in 2003.

United Kingdom

Petroleum-related education and training initiatives were introduced early in the United Kingdom. As early as 1977, Clark noted that “the training and education of lower-level rig personnel is currently met for North Sea operations by on-the-job training supplemented by short courses offered by the Petroleum Industry Training Board and also by a system of correspondence courses organized by the International Association of Drilling Contractors. Pioneering development in low and medium level training for oil drilling technology in the United Kingdom was started by the South Eastern Drilling Company. SEDCO set up its own training centre in Aberdeen to help meet its own needs to rapidly increase its offshore drilling activities. A National Centre for Drilling Technology is now being established at Livingston, near Edinburgh, by the Petroleum Industry Training Board” (p. 213).

Clark also mentions post-graduate and “post-experience” university courses in offshore engineering, petroleum geology, coastal dynamics and civil engineering; degree programs for engineering and geology-related majors with options in ocean or offshore focuses; and several short courses, craft courses, and a diploma program (p. 214).

Arnold (1978) elaborates on the training offered by Robert Gordon’s Institute of Technology (RGIT) in the l970s. It added offshore drilling and oil drilling technology courses to its Higher National Diploma in Engineering (p. 223) early on, and began offering short courses for oil company personnel and graduates in 1972. It further added a one-year post-graduate course in offshore engineering and provided several other courses for oil companies. It also had a program in which students were allocated projects based on research requested by industry.

Training and education are still high priorities in the United Kingdom. The Offshore Petroleum Industry Training Organization (OPITO) is an industry-owned organization based in Aberdeen that provides training services to oil industry employers. It is not only a major source of industry-supported training activity, but also – because non-local companies obtain training in Aberdeen – a source of economic benefits for the region (OPITO 2006).

One of OPITO's programs trains 100 new technicians per year for the offshore petroleum industry (United Kingdom Offshore Operators Association, nd). Trainees received 18 months to two years of practical learning and then approximately two years of on-the-job training, leading to the attainment of a National or Scottish Vocational Qualification. Such training has been provided in Central and NE Scotland, NE England and East Anglia, with support from Offshore Contractors Association, the UKOOA, Cogent and the Engineering and Construction Industry Training Board.

Scotland's universities continue to be strongly involved in offshore petroleum industry-related training. For example, the Robert Gordon University (previously RGIT) offers several courses related to the offshore oil and gas industry. These include an undergraduate Mechanical and Offshore Engineering Beng (Hons)/Meng program, and post-graduate courses include Asset Management, Drilling and Well Engineering, Oil and Gas Engineering, Oil and Gas Law, Oilfield Chemicals: Instrumental Analytical Sciences, and Petroleum Production Engineering. Several petroleum companies offer scholarships at the Robert Gordon University (Robert Gordon University 2006).

In another university example, Heriot-Watt University offers masters-level courses through its Institute of Petroleum Engineering at its campuses in Edinburgh, Orkney and Dubai. These courses are Masters of Science in Petroleum Engineering, Petroleum Engineering with Project Management, Reservoir Evaluation and Management, Geoscience of Subsurface Exploration Appraisal and Development, Renewable Energy, and Marine Resource Management. It also offers distance learning courses, the opportunity to study at the Institute for an MPhil or PhD, and various short courses, and performs research in several petroleum-related areas of expertise (Heriot-Watt University 2006).

Atlantic Canada

Individuals and companies in Newfoundland and Labrador have also benefited from education and training resulting from the petroleum industry. The industry is working at the technological frontier, in a harsh environment and increasingly deep waters, using wells of record lengths and production systems of great complexity. This has required the development of new education and training programs and facilities at Memorial University, the Marine Institute, the College of the North Atlantic (CNA), and private training institutions. There has also been a rapid growth in cooperative education, scholarships and awards, and on-the-job training. This has produced a skilled local workforce, able to design, maintain and operate offshore systems in a safe and environmentally responsible manner.

Specific programs that provide education and training related to the offshore petroleum and related industries include (Petroleum Industry Human Resource Committee 2001):

Undergraduate and/or graduate degree programs at Memorial University[68]:

- Engineering (Civil, Electrical, Computer, Mechanical, Ocean and Naval Architectural, and Offshore Oil and Gas).
- Earth Sciences.
- Oil and Gas Studies.
- Physics and Physical Oceanography.
- Marine Biology.
- Maritime Studies
- Technology

Diploma programs at the Marine Institute:

- Technology Programs (e.g., nautical science, naval architecture, marine engineering systems design, and marine environmental).
- Trades Programs (e.g., marine diesel mechanic, offshore structural steel/plate fitter, deckhand).
- Training Courses (e.g., safety and survival training, radio operators, firefighting and recruitment, marine first-aid).

Diploma programs at the CNA:

- Technology Programs (e.g., petroleum, civil, electrical, electronics, geomatics, industrial, and mechanical engineering, environmental technology).
- Industrial Trades Programs (e.g., heavy equipment operation, metal fabrication, welding, pipe-fitting; electrical).

In several cases, oil companies and their contractors have formed partnerships with educational institutions to develop local training programs and curriculum that meet their specific requirements.

Education and training developments since 2003 have included the following:

- Memorial University's Oil and Gas Development Partnership launched a Master of Oil and Gas Studies executive development program designed for personnel destined for senior positions in the oil industry, service and supply companies and government agencies and departments.
- Memorial's Department of Earth Sciences added undergraduate programming in the petroleum and sedimentary basin area, and increased its capacity for graduate study in petroleum geology and sedimentology, and exploration seismology.
- The Faculty of Engineering introduced Oil and Gas as an undergraduate option for all discipline streams, and greatly increased its capacity for petroleum-related graduate research.

[68] A number of these and other education programs are being coordinated and facilitated by Memorial University's Oil and Gas Development Partnership (see Section 5.1.1).

- The teaching capabilities of Memorial University were further strengthened by the appointment of new faculty, who will also be active in R&D (see below).
- The Marine Institute was contracted to develop, manage and deliver 4,500 training days for personnel on the White Rose FPSO. This included the administration and logistical coordination of subcontracted training partners, facilities, equipment and other resources.
- The Burin Campus of CNA undertook a large pipe welding contract for Kiewit Offshore Services and introduced a new nine-month Industrial Instrument Mechanic pre-employment program.

The petroleum industry provides co-operative education places to large numbers of Memorial University and CNA students. Thanks to the national and international nature of many of the companies involved, this includes placements in such places as Calgary, Houston and Aberdeen. For example, during 2002, 289 Memorial University Faculty of Engineering and Applied Science students and 59 Faculty of Business students, for a total of 348 students, received placements with companies undertaking petroleum-related work. Of these, 217 (62%) worked in Newfoundland and Labrador, 32 (9%) elsewhere in Canada and 99 (28%) outside Canada (Community Resource Services Ltd 2003).

The breadth of experience received is indicated by the identity of some of the companies involved. For example, Faculty of Business students had placements with Exxon-Mobil in Halifax, Chevron in Calgary, Aker Oil and Gas Technology, London Offshore Consultants and XL Technology in the UK, Kongsberg Offshore and Kongsberg-Simrad in Norway, Siemens Demag Delaval and the Association of Suppliers in the Offshore Industry in the Netherlands, and Coflexip Stena Offshore in France.

The CNA similarly places large numbers of cooperative students in the petroleum industry. For example, in 2001 this included students studying Applied Business Information Technology (2 placements), Electrical Engineering (13), Electronics Engineering (2), Environmental Technology (6), Geomatics Engineering (13), Industrial Engineering (12), Mechanical (Manufacturing) Engineering (3), Petroleum Engineering (26) and Programmer Analyst (11). This included 19 placements in Alberta, 5 in the US and 4 in Scotland, with such companies as Exxon-Mobil, Schlumberger, Halliburton, Baker Hughes and Veritas.

In addition to the operators themselves, a number of local firms that provide services to the offshore petroleum industry recruit a large portion of their workforce from local educational institutions, as well as supporting the development and implementation of a range of related training programs and initiatives. Cougar Helicopters, for example, is an important supporter of the CNA's aviation training program in Gander (Community Resource Services Ltd. 2003).

In Nova Scotia, SOEI spent almost $15.6 million on training and education between 1998 and 2000 (Gardner-Pinfold Economic Consultants 2002, p. 57). Another training program in NS, sponsored by the Guysborough County Regional Development Authority, sought to train fishermen for work on offshore supply and service vessels (p. 70). The Nova Scotia government also invested in education and training through the Offshore Development Fund (pp. 76-77).

Cook Inlet

Kenai Peninsula College (2005) offers an Associate degree in Industrial Process Instrumentation, which prepares students for instrument technician positions in oil-related facilities. It also offers a one-year certificate in petroleum technology that "provides the student with specific training in petroleum and chemical plant operations or instrumentation (p. 2)."

In addition, the Kenai Peninsula College system includes the Mining and Petroleum Training Service, established in 1979 by the University of Alaska "to deliver training, development and consulting services to the resource industries of Alaska." It has trained over 50,000 people, including clients in Russia and Aruba. The college in 2005 had 100 positions for industry field trips and 50 annual internships in areas including Process Operations and Instrumentation. (University of Alaska Fairbanks, 2006).

5.1.3 Research and Development

Offshore petroleum activity involves the use of various advanced and evolving technologies. Governments and industry often seek to increase the benefits from such activity through local R&D, some of which may result in the development of products and expertise that have export potential. This expansion of local R&D efforts and capabilities may have benefits within and beyond the offshore petroleum industry. Scotland, Norway and Atlantic Canada have all actively sought petroleum industry R&D activity, using a wide range of different funding and regulatory approaches. This section provides an overview of this experience of local involvement in R&D.

Norway

Norway appears to have invested large amounts in pursuing offshore petroleum-related R&D activity. The government has focused on developing high technology in specialized areas, allowing them to improve the economies of domestic extraction and to access the global market for support services (Locke and Strategic Concepts Inc, 2004 p. 38). Much of the funding of R&D activity in Norway is public (BC Innovation Council 2004, pp. 15-16), which may be a net benefit to the region containing the R&D firms and lead to higher international competitiveness of local firms and higher extraction rates. Total R&D expenditures increased from just over NOK 5000 million in 1983 to about NOK 25000 million in 2001. This period saw the government's contribution shrink relative to that of the private sector (p. 11), although it has been fairly stable in nominal terms since the late 1980s.

Research Council of Norway figures indicate that the industry spent NOK 1297 million on R&D in Norway in 2002 (OLF 2004). This included substantial spending by some service companies; for example, Schlumberger, a global oil service company, has invested 500 million NOK on R&D in Stavanger alone (OLF 2005, p. 22).

These R&D efforts have contributed to local discovery and productivity rates. For example, the Statfjord Late Phase project extended the expected life of that field from 2009 to 2020 (OLF 2005, p. 22). The OLF claims that, generally, discovery rates are as high as 40% in the Norwegian offshore, and that recovery rates for the five largest fields increased from 35% to

53% over the 1990s (p 25). Overall, “the anticipated average recovery rate for oil grew by ten percent from 1991 to 1997 (OLF 2004, p. 34).” The high rates are in part attributed to R&D and especially the Reservoir Utilization through advanced Technological Help (RUTH) program.

Undertaken as a joint initiative of the Norwegian government, several research institutions, and 18 oil companies, the RUTH program increased recovery rates substantially. In operation from 1991 until 1996, it was a co-operative initiative between the Norwegian Research Council, the Norwegian Petroleum Directorate and several oil companies and public research institutes. It produced several significant results in a short period, attracting industry attention and new business participants (Karlsen et al. 2000).

Mikkelsen, Jøsendal, Steineke, and Rapmund discuss a number of other Norwegian R&D programs. One, Offshore 2010, focuses on applied R&D by local supply and services companies. It is funded by the NRC (30%) and the petroleum industry (70%). By the end of 2001, 316.3 million NOK had been allocated to the program. The main R&D institutions involved have been NTNU, IFE, SINTEF, Rogaland Research and Christian Michelsen Research (NRC 2001). By the end of 2001, 60 companies, including a significant number of small and medium-sized enterprises, had participated in Offshore 2010 projects. The main technological covered are subsea production, drilling and well/fluid transportation (Mikkelsen, Jøsendal, Steineke and Rapmund nd).

Another program, DEMO 2000, was initiated in 1999 with the aim of developing new fields on the Norwegian Continental Shelf through the use of new technology and improved security of execution within budget and planning, and developing new industry products for the global market. In addition to public funding that currently stands at a total of some 250 million NOK, the program leveraged twice as much support from the private sector and R&D institutions. Current DEMO 2000 partners include the Ministry of Oil and Energy, four public R&D institutes, six oil companies and some specialist oil and gas suppliers. (Mikkelsen, Jøsendal, Steineke and Rapmund nd, pp. 13-14).[69]

The Gas Technology Center is an important focus of Norwegian R&D activity. It operates out of the Norwegian University of Science and Technology with assistance from the Foundation for Scientific and Industrial Research. It has 53 professors, 133 PhD candidates, and 16 post-doctoral researchers, and performs research out of the faculties of Engineering Science and Technology; Natural Sciences and Technology; Information Technology, Mathematics, and Electrical Engineering; Social Sciences and Technology Management; and Arts. Between 80 and 90% of the research is externally funded, mainly by the Research Council of Norway and Norwegian industry.

[69] Some other R&D programs have been less successful. For example, the FORCE program was initiated by the Norwegian Petroleum Directorate and several major oil companies as a complement to the RUTH program. It receives no public funding and is aimed at stimulating increased co-operation between the oil companies. Its overall impact has been modest, as the main activities taking place have been experience transfer and general knowledge diffusion in the context of industry seminars and informal meetings. (Mikkelsen, Jøsendal, Steineke and Rapmund nd)

Norwegian R&D initiatives have also developed technology with export potential. For example, the OLF (2005) indicates that Gazprom has been working with Norsk Hydro on the Stokman field in Russia because it wants to use the techniques and experience Hydro developed in Norway (p. 8).

United Kingdom

As is the case in Norway, and with education and training, R&D initiatives started early in the United Kingdom. According to Clark (1977), Heriot-Watt University was providing consulting and research services in mechanical, chemical, civil, electrical, and electronic engineering as early as the mid-1970s. Robert Gordon's Institute of Technology also provided consulting and research services for mechanical, electrical, and electronic engineering, while Strathclyde University provided them for metallurgy and Glasgow University for naval architecture (p. 215).

Many of the United Kingdom R&D initiatives have sought to respond to local environmental challenges, and in a number of cases this has led to the development of new niche technologies with potential in other regions of the world. As early as 1974, Baxendell was discussing several issues associated with the extreme environment of the North Sea that required technical solutions (deep water, extreme weather conditions, distance from shore). These included special heavy-lift crane barges that could operate in rough weather, and special construction techniques. The new technologies developed related to saturation diving techniques (p. 31) and floating landing platforms to deal with local weather conditions (p. 25).

Some companies operating in the North Sea developed "automated seabed systems directed by remote control," and were developing "a new class of underwater vehicle which can weld, inspect or wrap pipe automatically." (Arnold 1978, p. 97) Heriot Watt University soon "became the leader in underwater and petroleum engineering. Research being developed in a number of centres covers such problems as fatigue crack growth in steel, measuring currents and their effects, new diving equipment, marine fouling, wave slam on rigs." (pp. 97-98) Advances were also made in land-to-sea telecommunications, leading to possible opportunities elsewhere (p. 211). Arnold (1978) also refers to oil companies establishing specialised wave forecasting systems in the North Sea (p. 95).

More recently, Robert Gordon University has undertaken R&D related to the remote monitoring for petroleum operations and miniature remotely operated vehicles. It also has a Centre for Process Integration and Membrane Technology, that pursues research in acid gas removal from natural gas streams, and a well engineering research group, and it has received several 'proof of concept awards' for R&D in the offshore petroleum sector (Robert Gordon University 2006).

The United Kingdom is actively seeking to identify further R&D opportunities. For example, the Industry Technology Facilitator (ITF) was launched in 1999 in response to a recommendation of the Oil and Gas Industry Task Force. The Task Force, comprised of representatives of government, industry and academe, aimed to develop an understanding of key future petroleum industry issues. It concluded that technology leadership and cooperation were essential to the industry's future competitiveness and recommended a cross-industry body be established to stimulate technology development. The ITF is governed by a board made up of oil and service company representatives and supported by the UK Department of Trade and Industry. It facilitates major advances by connecting technology developers with end users and sources of funding. During 2003, ITF established 18 new projects representing an industry investment of about $10 million. (Industry Technology Facilitator 2004).

Atlantic Canada

Considerable amounts of petroleum-industry-related R&D work have been done in Newfoundland and Labrador. Operators, contractors, government agencies, industry groups and research organizations support or participate in work in such areas as engineering and design (e.g., vessel design, mooring options), operational studies (e.g., seismic survey techniques, vessel offloading, safety equipment and procedures, ice detection and response) and environmental investigations (e.g., wave and current studies, fish habitat compensation). This work, primarily undertaken at Memorial University, the Marine Institute and the Institute for Marine Dynamics, has helped sustain and further build the local R&D community, assisting it in serving local interests in the petroleum and other industries. It has also helped make the province a center of excellence in such topics as cold oceans engineering, hull testing and marine science.

The last few years have seen a consolidation and growth in local offshore petroleum-related R&D capabilities. For example:

- Memorial University has further developed its expertise related to various aspects of offshore petroleum activity, including appointments in sedimentology, reservoir quality, reservoir seismology, reservoir engineering, control systems, underwater vehicles, asset integrity, safety engineering, chemical engineering and gas processing.
- New R&D infrastructure put in place at Memorial University includes the $20 million Landmark Graphics Visualization Centre, which is the first of its kind at a university. It provides a theatre setting in which researchers can view and analyze images of large volumes of data and conduct detailed simulations.
- EnerSea Canada, in partnership with Memorial University, established the Centre for Marine Compressed Natural Gas. Its partners include technology providers, shipping companies, offshore technology companies, petroleum companies, research organizations and the governments of Newfoundland and Labrador and Nova Scotia. The Centre addresses the technical challenges of developing CNG transportation systems for global application, including in harsh offshore environments such as in Atlantic Canada.
- The Marine Institute launched a $9 million R&D program dealing with the modeling and simulation of harsh environments, allowing a further expansion in the activities and capabilities of the Centre for Marine Simulation.
- The Centre for Cold Ocean Resources Engineering (C-CORE), on the campus of Memorial University, commissioned Canada’s only geotechnical centrifuge facility with earthquake modeling capabilities. It is of particular value for understanding the risks of earthquakes for such offshore petroleum facilities as deepwater platforms and pipelines.

In Nova Scotia, Sable Offshore Energy Incorporated (SOEI) spent $17.4 million on R&D over the 1995-2000 period, largely to solve problems with developing that project. It also invested about $9 million in technology transfer, in the form of “transfer of equipment, skills and training (p 57).” These may simply be costs of the project; benefits other than those directly following from the project itself are not discussed by this report. The government also spent approximately $46 million of its Offshore Development Fund on R&D. (Gardner Pinfold Consulting Economists 2002, p. 57).

Cook Inlet

Again, there is limited information on Alaskan R&D initiatives that can be explicitly linked to Cook Inlet activity. However, British Petroleum opened a gas-to-liquids research facility in Nikiski, Cook Inlet, in 2002, to “test new technologies designed to produce ‘white crude’ or ‘white diesel’ fuels from natural gas.” The plant employed 20 full-time employees, and a “modest contract workforce” but was scheduled for closure in 2007 (Cook Inlet Oil and Gas 2005, pp. 9-10).

5.2 Economic Diversification

The offshore petroleum industry can clearly have substantial positive impacts on infrastructure, education and training and R&D, and thereby may strengthen other existing industries. It may also deliver economic diversification through:

- the export of offshore petroleum expertise, goods and services to other markets;
- the sale of this expertise and these goods and services, or developments thereof, to other industries, locally, nationally and internationally; and
- opportunities for established companies to diversify into oil and gas work.

This section discusses each of these potential impacts.

5.2.1 Exporting Petroleum Expertise

“Demanding customers in the oil industry constitute an important and comprehensive upgrade mechanism for the supplier industry and related industries. Through the oil and gas industry’s need for new solutions, the quality of the suppliers’ technology, expertise, and processes is upgraded” (OLF 2005, p. 9).

The petroleum industry is very demanding in terms of such matters as bidding, quality assurance, quality control, document control, accounting, equipment and training. Companies that wish to compete for petroleum industry work may have to expend considerable time and money upgrading. However, while the industry is very demanding, there are considerable rewards for local companies that succeed in it. The required changes make such firms highly competitive, and thereby also change their business cultures, attitudes, morale and ambition. Furthermore, links with the petroleum industry locally can provide companies with an invaluable means of marketing themselves nationally and internationally.

These factors have helped companies to find work on other petroleum projects in Atlantic Canada and around the world. For example, while the industry did not exist in Norway prior to the 1970s, its petroleum supply industry was estimated to employ 90,000 people in 2001 (Locke and Strategic Concepts Incorporated 2004, p. 37). This is made up of “world-class companies specializing in subsea development, platform construction, and mechanical engineering.” As an example, FMC Kongsberg Subsea participates in projects in several countries on all continents, with over half of its employees working outside Norway (Steenstrup 2002). Norsk Hydro has similarly expanded into international markets, with operations in Newfoundland and Labrador, the Gulf of Mexico, Russia, Angola, Libya and Iran, in addition to Norway (Beyer 2002).

Scottish companies have benefited in similar ways. Cumbers (2000) has noted that Aberdeen “has transcended its earlier role as a glorified supply base and branch plant economy to become an important centre of expertise and knowledge… within the international oil industry. It has in particular been a centre for ‘learning-by-doing’ and ‘learning-by-using’ in the sense that products, services, and processes first developed and tested in the North Sea have found new markets overseas. A positive aspect of this is the high number of indigenous firms that have become successful exporters” (p. 380).

Best (2000) has described how, further south, offshore petroleum activity has allowed companies in Yarmouth, England to develop exportable expertise (pp. 3-4). He refers to such firms as AMEC, which has found overseas markets for expertise developed in the domestic offshore industry.

In Newfoundland and Labrador, a survey of 65 St. John’s area companies involved in the oil industry found that slightly more than a quarter of them exported products or services outside the Province in the 2001 to 2003 period (City of St. John’s.2004). Examples of local successes include:

- NEWDOCK, which developed subsea assemblies fabrication capabilities through Terra Nova project contracts, now exports them to the Gulf of Mexico.
- C-CORE, an engineering R&D corporation, now conducts over 40% of its business in more than ten countries worldwide.
- Oceanic Consulting Company, founded in 1997 out of an earlier initiative to use R&D facilities in St. John’s, has been involved in such projects as the design of spar production platforms in the Gulf of Mexico, FPSOs for use in West Africa, and supply and service vessels for use in Kazakhstan.

Gardner-Pinfold Consulting Economists (2002, pp. 77-79) provides similar success stories among Nova Scotia companies working in the offshore petroleum industry, including:

- Jacques Whitford, which has grown and expanded its capabilities through joint ventures, largely through work with the petroleum industry. It was awarded the 2006 Nova Scotia Export Achievement Award for Export Growth through Partnership, for the success of its Middle East offices.
- Secunda Marine, founded in Halifax in 1983, which owned 17 vessels, employed 600 and had offices in Newfoundland and Barbados as well as Nova Scotia, by 2000. It operates globally, including in the North Sea and Pakistan, and has a diversified operation including cable-laying telecommunications.

Such successes have reduced the degree to which these companies, and the economy as a whole, are dependent on the fortunes of local offshore petroleum activity.

5.2.2 Diversifying from Petroleum Expertise

Having been successful in the petroleum industry, many companies have also been able apply their capabilities in, or adapt them to, other industries. This has happened in local, national and international markets.

MacKay and Mackay (1975, pp. 120-121) note that "an interesting and encouraging aspect of this influx of new activity [to Scotland] has been the appearance of companies and bodies largely unconnected with the oil and gas industries. These are over and above the normal indirect, spin-off activities associated with increases in income, employment, and population. The most notable has been the establishment in Aberdeen of merchant banks and finance houses (Edward Bates, Bank of Nova Scotia, Finance for Industry, etc.). Similarly, there has been an enormous expansion in office developments in the city: in June 1974 existing office space totaled 140,000 m^2; an additional 95,000 m^2 had received full planning permission and were under construction; and another 80,000 m^2 were at various stages of the planning application process." MacKay and Mackay characterize this as "self-generating growth."

In Norway, "the oil industry has another function that is not very recognized in the Norwegian debate on business development. The engineering workshop and service companies are not just significant suppliers to the oil and gas industry. They deliver production equipment, tools, machines, motors, valves and other products to many industrial clusters, including to the production of electricity, wind and wave power, the maritime sector, as well as the seafood and food cluster. As such, the firms that supply goods and services to the oil industry – also on an equal basis with ICT and finance – are a key part of the infrastructure in developing more industries." (OLF 2005, p. 9) At a local level, Måsvær (2002) notes that the offshore petroleum industry internationalized companies in Stavanger and changed it from a small fishing port to a globally-oriented business centre.

As in Scotland, the offshore petroleum industry has had impacts on the Norwegian financial sector, with local banks becoming "world leaders on payment transfers, not least due to major assignments in handling a very considerable cash flow from the petroleum industry" (OLF 2005, p. 23).

Research for the Hibernia Management and Development Company (Community Resource Services Ltd. 1996 and 1999) and Petroleum Research Atlantic Canada (Community Resource Services Ltd. 2003) has identified a number of examples of Atlantic Canadian companies that have successfully sold expertise and goods and services developed for the petroleum industry, or further developments thereof, to other industries, locally, nationally and internationally. They include:

- Stratos Global, which first developed its communications and information capabilities in the offshore petroleum industry, now also serves military, shipping, fishing, broadcasting,

aviation, mining, cruise-ship and other requirements out of its operations in St. John's, Maryland, Louisiana and Scotland.
- Oceanic Consulting Company, which has expanded beyond the petroleum industry into tug and barge testing, modelling the hull form of patrol boats, investigating thruster options on ferries, studying the interactions between marine structures and ice and, most notably, undertaking hull model testing for a winning America's Cup yacht.
- C-CORE, which has undertaken work for the European Space Agency, European space companies and Australian mining companies.

As is indicated by the example of Oceanic Consulting, investments in R&D infrastructure for the petroleum industry have also supported work for other industries, and thereby furthered economic diversification.

5.2.3 Diversifying into Petroleum Industry Work

The oil and gas industry in Aberdeen provided many local companies with an opportunity to diversify into oil related work, particularly for companies engaged in fishing and fish processing. Kemp and Smith (2002) identified the Wood Group as one example of this. Building on a core business in the fishing and fish processing industry, the company moved first into supply base facilities and continued to diversify, moving into areas such as offshore engineering. This growth resulted in the Wood Group employing over 1,000 people and achieving a turnover of approximately £40 million by the late 1970s. The Richard Irvin group, another company with a base in fishing and fish processing, diversified into the oil and gas industry by acquiring offshore engineering and electrical interests. As established by Kemp and Smith, entry into the offshore was often facilitated by a synergy with existing activities in related sectors.

5.3 Increased Entrepreneurship, Self-confidence and Ambition

In all of the above jurisdictions, success in the offshore petroleum industry and subsequently other sectors, has produced a new cadre of confident and ambitious business leaders who are role models to the business community as a whole. Their success and that of their companies has encouraged or (through the competition they pose) required that other firms become more competitive. Examples taken from a study of the effects of offshore oil industry activity on businesses in Newfoundland and Labrador (Community Resource Services Ltd 2003) are as follows:

- While senior Murray Industrial personnel were initially intimidated by the size and complexity of the industry, trade shows and seminars in Norway, Scotland and the United States gave them the opportunity to learn more about its realities and overcome their reticence. Over time, according to its President, David Murray, "the offshore industry has got to know us and we have proven what we can do for them."
- According to Fred Cahill, President of G.J. Cahill, his company "took its lumps, but learned from these" while developing an understanding of the petroleum industry and its requirements. The company's managers are now very confident of their ability to compete in this and other industrial sectors.

- John Brake, President and CEO of M&M Offshore, indicated company managers were initially intimidated and apprehensive, perhaps as a result of the ‘insularity’ of the Newfoundland and Labrador business community. With time though, not least as a result of learning from experience, they came to understand how the industry works and became confident that they can deliver what it requires.
- The President of P.F. Collins, Bernard Collins, noted that, like many other Newfoundland-based businesses, his company has developed a ‘can-do’ attitude when dealing with the oil industry. This has increased its ability to compete with national brokerage firms.

5.4 Population Growth

The above discussion has focused on the direct effects of offshore petroleum activity on the private sector and economy. However, offshore petroleum activity can also result in in-migration and reduced out-migration, increasing the size of the local labour, housing and retail markets, and thereby expanding the economy and business opportunities.

In some cases, the industry has served to reverse historic demographic patterns. For example, Harris, Lloyd and Newlands (1988, p. 6) note that while the Grampian region of Scotland had Britain’s highest out-migration rate in the 1960s, this was reversed in the 1970s with the arrival of the petroleum industry, and the area then experienced rapid population growth (p. 21). In the decades prior to the development of the oil and gas industry, the population in the Grampian region fell from 468,200 in 1951 to 436,000 in 1971. The population than began to recover throughout the 1970s, reaching 453,000 in 1976. This growth continued throughout the 1980s and 1990s, reaching 533,000 in 1995 (Kemp and Smith 2002). Scotland as a whole and Norway have experienced similar patterns (Gaskin and MacKay 1978, p. 29, and Måsvær 2002).

Newfoundland and Labrador’s population is similarly larger than it would have been without the petroleum industry, because increased economic activity and employment generally reduces out-migration and increases in-migration. Net migration is largely a function of the difference in average wages and employment rates between the Province and the rest of Canada. Both these differences were smaller than they would have been in the absence of the petroleum industry, resulting in a provincial population that was approximately 16,000 (1.7%) larger than it would otherwise have been in 2004 (PRAC 2005).

5.5 Impacts on Traditional Industries

Offshore petroleum activity can have a range of other impacts, some of them admittedly negative, on the local economy. For example, Galenson (1986) argues that Norway’s performance in curbing inflation was less than it might have been without oil revenues, and that they allowed the government to pursue policies that harmed manufacturing: “Oil money was used to preserve the existing pattern of industry. The restructuring necessary to meet changing market demands was slowed, if not stopped. New initiatives were not encouraged” (pp. 78-79). Mallakh, Noreng and Poulson (1984, pp. 87-89) and Noreng (1980, pp. 190-193) argue that one of the problems was that Norwegian government policy prevented labour from moving to more productive firms and sectors. It was not only prevented from moving to and from manufacturing, but from less to more productive uses within manufacturing.

In Scotland, while Harris, Lloyd and Newlands (1988) found many benefits from the petroleum industry in Aberdeen, they also described its 'displacement and deterrence effects' on traditional industries (pp 42-52). Displacement sees existing activity being crowded out by new activity, while deterrence sees new activity preventing other activity by making a region unattractive for it. The offshore petroleum industry generated upward pressure on wages[70] and increased the price of housing and office space, although industrial property shortages were avoided due to an increase in warehouse and factory space. The high housing prices deterred outside workers from entering the region for employment.

As a result of these forces, several industries had local growth rates below their national averages, while ones that were already declining saw that decline accelerate. Industries that declined faster than average in the 1970s included fishing, food and drink, clothing and footwear, building materials, and timber and furniture (pp. 45-47). Harris, Lloyd and Newlands conclude that "for every 100 jobs created by the oil industry in Aberdeen, at least eight jobs have been lost in traditional industries. By 1981, displaced and deterred employment amounted to more than 3,000 jobs. Of this, only about 25 per cent has been absorbed by the oil sector."

The relatively modest profitability of some traditional industries when compared to the oil and gas industry limited their ability to compete with the sector for employees. Additionally, some traditional industries were negatively affected by the upward pressure on the sterling exchange rate, which hindered competitiveness of some sectors and created difficulties for exporters (Kemp and Smith 2002).

This decline of other industries resulted in a higher dependence on the oil industry. Newlands (2000) estimates that, in 1985, 40% of Aberdeen's workforce relied upon oil (p. 135). He also notes that, in the 1960s, "most businesses in Aberdeen were locally owned and controlled with only a few examples of external ownership [but] a survey conducted in 1984 suggested that the figure had fallen to as low as 11 per cent" (p. 142).

By contrast with the possibility of negative impacts on traditional sectors of the economy, there may also be benefits. Harris, Lloyd and Newlands (1988), note that "better communications… benefit individuals as well as firms. Indeed, they are just one example of the improvement in the range and quality of services available to people in Aberdeen which has taken place in recent years. There has been a marked increase in the number, variety, and quality of shops and restaurants. There are more entertainment spots such as wine bars, discos and nightclubs. These developments cannot be attributed wholly to the establishment of the oil industry in Aberdeen, but oil developments have undoubtedly influenced the extent and pace of change. Furthermore,the increase in income and population has almost certainly prevented the disappearance of more of these traditional forms of entertainment" (pp. 38-39).

[70] The growth of the oil and gas industry had a significant impact on incomes in the Grampian Region. In 1972, average male earnings were 88% of the British national average. By 1977 both males and females exceeded it, and by 1984 male earnings in the region were 117% of the British average (Kemp and Smith 2002).

Similar changes have had significant positive consequences for local tourism in Aberdeen, Stavanger, St. John's and other offshore petroleum activity centres. Various studies have shown the industry making a major contribution to local tourism through improved air links, meetings, conferences, trade shows, corporate hospitality and the personal expenditures of petroleum industry personnel.[71] Newlands (2000) notes that eight new hotels opened, and others expanded, in Aberdeen in the 1970s. This increased the number of hotel rooms by 27% between 1970 and 1975 and by 58% between 1975 and 1980. The number of restaurants rose from 17 to 36 (pp. 134-135). A similar expansion and 'cosmopolitanization' of the hospitality, accommodations and, hence, tourism has been seen in St. John's (Shrimpton 2002).

Industrial infrastructure projects may themselves be of interest to some visitors. For example, tours of the Hibernia offshore platform construction were an important attraction in Newfoundland. Stavanger's Norsk Oljemuseum, the Aberdeen Maritime Museum and the Johnson Geo Centre in St. John's provide other examples of popular and informative petroleum industry-related tourist attractions.

There can be petroleum activity-related pressures on the availability and price of hotel space and air transportation, but where this has occurred it has generally been of short duration. Furthermore, there may be the opportunity to use anticipated demands as a way of leveraging change anyway required if tourism is to increase. Thus, for example, the Falkland Islands government sought to ensure that the accommodations and transportation demands associated with a six-well offshore exploration program contributed to long-term improvements in hotel space and scheduled air services.[72]

Despite risks to the fisheries from possible petroleum industry accidents, sea-bed debris and loss of access to fishing grounds, there is evidence from the east coast of Canada that debris, access and other issues can be worked through on the basis of mutual respect and understanding between the two industries (Canning 2000). A stringent regulatory regime is also required. At the same time, the fisheries appear to have benefited from improved weather forecasting and search and rescue operations resulting from development of an offshore petroleum industry (Community Resource Services Ltd 2003).

The benefits from offshore petroleum activity need not be limited to the private sector. Harris, Lloyd and Newlands note that "the maintenance or improvement of services applies also to the public sector. There are better hospital facilities and a larger and more comprehensive

[71] While it is often difficult to quantify these effects, a Hibernia construction project expenditure study found employees spent about $22 million a year in restaurants and bars, and $2.7 million a year on tourism, in Newfoundland and Labrador. Such personal and corporate expenditures have secondary effects on the amount, range and quality of accommodations, restaurants, transportation services, and recreation and entertainment facilities.

[72] A common, but less tangible, concern is that oil and gas activity will undermine the image and desirability of frontier regions as tourism destinations. However, management strategies have limited the negative effects of such activity, and notwithstanding these concerns, places like Norway, the Shetland Islands, the Falkland Islands, Nova Scotia and Newfoundland and Labrador continue to experience rapid growth in tourism, including eco-tourism and adventure tourism.

educational system than would have been the case had oil developments not reversed the trend of economic decline and emigration from Aberdeen" (1988, pp. 38-39).

5.6 Conclusions: Transformative Economic Changes

There is growing interest, globally, nationally and locally, in creating sustainable economic development. Notwithstanding the fact that offshore petroleum industry activity involves large technologically-complex projects and the exploitation of a non-renewable resource, the information presented above indicates that it has been the engine for significant and sustainable economic development in a number of jurisdictions on both sides of the Atlantic. This is partly because it can make a major contribution to output, income, employment and government finances as discussed in earlier sections of this report. Such activity has often also had a transformative effect, by helping to enhance the productive capacity of the economy by stimulating growth in the quantity and quality of factor inputs to the production process, thereby contributing to sustainable long-term economic development.

In particular, offshore petroleum activity has had significant, and sometimes dramatic, effects on infrastructure development, education and training, and R&D in Norway, the United Kingdom, Atlantic Canada and, to a lesser degree, around Cook Inlet, Alaska. Industry activity has also increased the entrepreneurship and competitiveness of local individuals and companies, and generated population growth, commonly reversing previous demographic trends. The impacts on traditional industries have generally been positive, although there can be negative effects, especially if there is an already tight market for labour, office space or housing.

SECTION 6

SUMMARY AND CONCLUSIONS

The analyses in this report show that substantial economic benefits are possible from a single field of oil and a single field of either wet or dry gas in QCB, even making conservative assumptions. The benefits will materialize in the forms of:

- net resource revenue (or economic rent) that accrues from offshore operations to the federal government as corporation income tax, to the provincial government as royalties and corporation income tax, and to the private sector as after-tax profit;
- incremental output, GDP, household income, employment and government revenues arising directly and indirectly at provincial and regional levels from expenditures incurred at the different stages of offshore activity (expenditure benefits); and
- long-term economic growth based on structural changes to the economy resulting from offshore activity; these changes can be expected to enhance the capacity of provincial and regional economies to generate output, income, employment and tax revenues over and above the amounts generated as economic rent and expenditure benefits.

6.1 Economic Rent Benefits

A necessary condition for the generation of economic rent is that projects are viable from the point of view of the private sector. If projects are not viable and do not proceed, no rent is earned by any party. Projects are estimated to be viable (in the sense of yielding positive net revenue in present value terms) at prices at and above $35 US/bbl for oil, $5 US/mmbtu for wet gas, and $6 US/mmbtu for dry gas.

Estimates of economic rent for each scenario measured in undiscounted 2006 dollars and in discounted present value terms using a real discount rate of 10% are shown in Table 6.1 below. The table shows estimates of rent accruing to the provincial government (in the form of royalties and corporation income tax), the federal government (as corporation income tax) and companies (as after-tax profit) over the lives of the assumed projects in the single fields of oil and gas predicated in the study.

In order to simplify the presentation of results that were calculated over broad ranges of oil and gas prices, Table 6.1 displays estimates of economic rent for prices at the lower and upper bounds only of the expected long-term price ranges of $70-80 US/bbl for oil and $6-7 US/mmbtu for natural gas. Details at all prices used in the analysis are available in Section 3 of the report.

Table 6.1: Estimates of Economic Rent at $70-80 US/bbl (Oil) and $6-7 US/mmbtu (Gas) ($2006 Billion Cdn)

Scenario	BC Government Nominal $	Federal Government Nominal $	Companies Nominal $	BC Government Discounted $	Federal Government Discounted $	Companies Discounted $
SPOS	11.19 - 13.45	5.11 - 5.97	14.64 -17.22	2.14 - 2.61	1.06 - 1.25	2.32 - 2.87
LPOS	10.99 - 13.27	5.09 - 5.95	14.54 -17.11	2.09 - 2.56	1.06 - 1.24	2.25 - 2.80
SPWGS	4.79 - 6.31	2.13 - 2.53	5.91 - 7.10	0.70 - 0.95	0.36 - 0.43	0.39 - 0.61
LPWGS	4.46 - 5.91	2.14 - 2.55	5.89 - 7.12	0.63- 0.86	0.36 - 0.43	0.31 - 0.55
SPDGS	3.80 – 5.23	1.83 - 2.28	4.99 - 6.34	0.54 - 0.77	0.31 - 0.39	0.24 - 0.50
LPDGS	3.51 - 4.91	1.82 - 2.28	4.93 -6.30	0.49 - 0.71	0.30 - 0.39	0.15 - 0.42

At the lower bounds of the expected long-run price ranges, Table 6.1 shows estimated rent in 2006 prices for the different stakeholders as follows:[73]

- **Provincial government**: approximately $11 billion (2006) over the productive life of the single assumed oil field in QCB, approximately $4.5-4.8 billion (2006) over the life of the single assumed wet gas field, and approximately $3.5-3.8 billion (2006) over the life of the single dry gas field. Specific returns depend on the length of the underwater pipeline needed to carry the resource to shore. In discounted present value terms, these results are respectively just over $2 billion, $0.6-0.7 billion and approximately $0.5 billion.
- **Federal government**: approximately $5.1 billion (2006) from the oil field, $2.1 billion (2006) from the wet gas field and $1.8 billion (2006) from the dry gas field (respectively $1.1 billion, $0.4 billion and $0.3 billion in present value terms).
- **Companies**: approximately $14.5 billion (2006) from the oil field, approximately $5.9 billion (2006) from the wet gas field and $5.0 billion (2006) from the dry gas field (in present value terms, approximately $2.3 billion from oil, $0.3-0.4 billion from wet gas and approximately $0.2 billion from dry gas).

Projects are therefore profitable and generate benefits for stakeholders even at the lower bound of expected price ranges. At higher prices, all projects yield larger benefits.

If there is interest in evaluating economic rent for the different stakeholders at prices of oil and gas not included in the analysis, estimates of rent can be generated from the equations in Appendix 3H. Table 6.2 summarizes the changes in economic rent for a one dollar change in the 2006 price of the resource. These changes are the coefficients on the price variable (‘x’) in the equations in Appendix 3H.

[73] For the purpose of illustrating results in a succinct manner, the lower bound of expected long-run price ranges is chosen on the principle of conservatism. For results at other oil or gas prices included in the analysis, refer to Table 6.1 and tables in Section 3 of the report.

Table 6.2: Changes in Economic Rent per $US Change in Oil and Gas Prices ($2006 Million Cdn)

Scenario	BC Government Nominal $	Federal Government Nominal $	Companies Nominal $	BC Government Discounted $	Federal Government Discounted $	Companies Discounted$
SPOS	221.87	87.65	261.74	44.17	18.90	57.54
LPOS	220.60	87.94	262.72	43.63	18.98	57.99
SPWGS	1,317.17	444.80	1,340.37	209.38	81.57	263.07
LPWGS	1,291.22	449.57	1,361.58	200.57	82.12	271.28
SPDGS	1,272.92	462.18	1,493.10	200.88	82.52	293.08
LPDGS	1,241.95	463.25	1,522.92	191.52	82.32	302.55

Table 6.3 shows percentage shares of estimated rent measured in nominal and discounted present value terms over expected long-run price ranges. As price rises over expected ranges, the share of nominal rent increases for the provincial government and falls for the federal government and companies. In terms of discounted rent, as price increases the share accruing to the provincial government rises marginally for oil projects but falls for gas projects, while the federal government share falls for both oil and gas projects and the private sector share increases for all projects.

Table 6.3: Shares of Economic Rent at $70-80 US/bbl (Oil) and $6-7 US/mmbtu (Gas)

Scenario	BC Government Nominal $	Federal Government Nominal $	Companies Nominal $	BC Government Discounted $	Federal Government Discounted $	Companies Discounted$
SPOS	36.2-36.7%	16.5-16.3%	47.3-47.0%	38.7-38.8%	19.2-18.5%	42.0-42.7%
LPOS	35.9-36.5%	16.6-16.4%	47.5-47.1%	38.7-38.8%	19.6-18.8%	41.7-42.4%
SPWGS	37.3-39.6%	16.6-15.9%	46.1-44.5%	48.1-47.6%	24.9-21.7%	27.0-30.6%
LPWGS	35.7-37.9%	17.1-16.3%	47.2-45.7%	48.5-46.7%	27.5-23.5%	24.0-29.9%
SPDGS	35.8-37.8%	17.2-16.4%	47.0-45.8%	49.7-46.3%	28.3-23.6%	22.0-30.1%
LPDGS	34.2-36.4%	17.7-16.9%	48.0-46.7%	52.2-46.7%	32.1-25.6%	15.7-27.7%

These results indicate that at the lower bounds of the expected long-run price ranges, estimated shares of rent are as follows:

- **Provincial government**: approximately 36% (oil), 36-37% (wet gas) and 34-36% (dry gas) based on 2006 dollar estimates, or 39% (oil), around 48% (wet gas) and 50-52% (dry gas) based on discounted dollar estimates.
- **Federal government**: approximately 17% (oil), 17% (wet gas) and 17-18% (dry gas) based on 2006 dollar estimates, or 19-20% (oil), 25-28% (wet gas) and 28-32% (dry gas) based on discounted dollar estimates.
- **Companies**: approximately 47% (oil), 46-47% (wet gas) and 47-48% (dry gas) based on 2006 dollar estimates, or approximately 42% (oil), 24-27% (wet gas) and 16-22% (dry gas) based on discounted dollar estimates.

In order to estimate shares at prices of oil and gas not used in the analysis, it is possible to compute shares from revenue estimates generated from the equations in Appendix 3H

6.2 Provincial Expenditure Benefits

Total (direct plus indirect plus induced) expenditure benefits in the province as a whole are summarized in aggregate dollar terms in Table 6.4.[74] Values shown for development scenarios are range estimates for short and long pipeline cases, with the low end of ranges representing the short pipeline case.[75]

Table 6.4: Provincial Expenditure Impacts ($2006)

	Exploration	Development			Production	
		Oil	Wet Gas	Dry Gas	Oil	Gas
Output ($M)	430	3987-4239	2894-3183	2787-3075	6124	4431
GDP at factor cost ($M)	170	1409-1489	1030-1123	977-1069	1952	1412
Employment (000)	2.5	23.4-24.8	17.3-18.9	16.3-17.9	28.3	20.5
Household income ($M)	131	1108-1174	819-895	772-848	1468	1062
Tax revenue ($M)	59	436-456	303-327	291-315	366	265
Federal Government	24	180-189	127-137	121-132	186	134
Provincial Government	33	239-249	163-176	158-170	157	113
Municipal Government	2	17-18	13-14	12-13	23	17

The results show that highest gains in output, GDP, employment and household income occur at the production stage and lowest gains are at the exploration stage. By contrast, the development stage yields higher tax revenue than the production stage. Oil development yields greater expenditure benefits than gas development, and wet gas development yields marginally higher benefits than dry gas development. Production-stage expenditure benefits are higher for oil than for gas.

Among levels of government, the provincial government is the major beneficiary in terms of tax revenue at exploration and development stages while the federal government becomes the leading beneficiary at the production stage.

Specifically, the single fields of oil and gas assumed in the study are estimated on conservative assumptions to yield at each stage of activity the following expenditure benefits (in 2006 prices) for the province as a whole over the lives of the assumed projects:

- **Exploration**: increased output of $430 million; GDP of $170 million; 2,500 annual jobs; household income of $131 million; and tax revenue of $59 million. Provincial government tax revenue is $33 million, or 56%, of total tax revenue.
- **Development**: increased output of around $4.0 billion (oil) and $2.8-3.2 billion (gas); GDP of around $1.4 billion (oil) and $1.0-1.1 billion (gas); some 24,000 annual jobs (oil)

[74] Expenditure benefit estimates assume that energy prices are sufficiently high to ensure project viability.
[75] There is no distinction at the production stage for impacts of wet and dry gas because operating expenditures are assumed to be the same in the two cases.

and 16-19,000 annual jobs (gas); household income of approximately $1.1 billion (oil) and $770-900 million (gas); and tax revenue of $440-460 million (oil) and $290-330 million (gas). Provincial government tax revenue is $239-249 million (oil) and $158-176 million (gas), around 55% of total tax revenue.

- **Production**: increased output of $6.1 billion (oil) and $4.4 billion (gas); GDP of $2.0 billion (oil) and $1.4 billion (gas); 28,000 annual jobs (oil) and 21,000 annual jobs (gas); household income of $1.5 billion (oil) and $1.1 billion (gas); and tax revenue of $366 million (oil) and $265 million (gas). provincial government tax revenue is $157 million (oil) and $113 million (gas), or 43% of total tax revenue.

Expenditure benefits per million dollars of expenditure for each stage of activity are shown in Table 6.5.

Table 6.5: Provincial Expenditure Impacts Per $Million Expenditure ($2006)

	Exploration	Development			Production
		Oil	Wet Gas	Dry Gas	
Output ($M)	0.69	0.81-0.81	0.84-0.83	0.83-0.83	2.10
GDP at factor cost ($M)	0.27	0.29-0.28	0.30-0.29	0.29-0.29	0.67
Employment (#)	3.96	4.75-4.72	5.01-4.95	4.86-4.81	9.71
Household income ($M)	0.21	0.22-0.22	0.24-0.23	0.23-0.23	0.50
Tax revenue ($000)	95.34	88.21-86.89	87.50-85.50	86.57-84.60	125.34
Federal Government	39.09	36.37-35.92	36.68-35.96	36.09-35.41	63.69
Provincial Government	53.55	48.34-47.48	47.17-45.92	46.85-45.61	53.70
Municipal Government	2.70	3.50-3.49	3.66-3.62	3.63-3.59	7.95

These results indicate that highest gains are again at the production stage and lowest gains are at the exploration stage, except in respect of federal and provincial tax revenue where benefits per million dollars of expenditure are lowest at the development stage. Differences at the development stage between wet gas, dry gas and oil may not be material.

Assuming no economies or diseconomies of scale, results indicate that for every million dollars spent on exploration, development or production activities before provincial expenditure leakages, provincial benefits at 2006 prices are as follows:

- **Exploration**: increased output of $690,000, GDP of $270,000, 4 annual jobs, household income of $210,000 and tax revenue of $95,000.
- **Development**: increased output of $810-840,000 depending on the whether the product is oil or gas and where it is discovered; GDP of around $280-300,000; 5 annual jobs; household income of $220-240,000; and tax revenue of $85-88,000.
- **Production**: increased output of $2.1million; GDP of $670,000; approximately 10 annual jobs; household income of $500,000; and tax revenue of $125,000.

6.3 Regional Expenditure Benefits

Total (direct plus indirect) expenditure benefits in the QCB region and rest of the province (RBC) are summarized in aggregate dollar terms in Table 6.6. The table also shows percentage shares of provincial impacts in each region of the province.

Table 6.6: Regional Expenditure Impacts ($2006)

		Exploration	Development			Production	
QCB Region			**Oil**	**Wet Gas**	**Dry Gas**	**Oil**	**Gas**
Output ($M)	Total	12-24	111-242	82-186	77-171	143-245	104-177
	%BC	3.1-6.4	3.1-6.4	3.2-6.5	3.1-6.2	2.8-4.8	2.8-4.8
GDP at factor cost ($M)	Total	8-20	68-196	51-151	46-137	79-181	57-131
	%BC	5.2-13.5	5.6-15.3	5.7-15.7	5.5-14.9	4.6-10.5	4.6-10.5
Employment (#)	Total	111-292	1189-3602	890-2778	807-2516	1006-2335	728-1690
	%BC	5.1-13.4	5.6-16.0	5.7-16.3	5.5-15.5	4.7-10.8	4.7-10.8
Household income ($M)	Total	7-19	62-190	46-146	42-133	68-170	49-123
	%BC	6.3-17.3	6.6-19.2	6.7-19.6	6.5-18.6	6.6-16.4	6.6-16.4
Local taxes ($000)	Total	23-23	287-304	213-232	205-223	419-419	303-303
	%BC	1.6-1.6	1.7-1.7	1.7-1.7	1.7-1.7	1.8-1.8	1.8-1.8
RBC Region							
Output ($M)	Total	351-363	3355-3693	2431-2772	2351-2683	4896-4998	3543-3617
	%BC	93.6-96.9	93.6-96.9	93.4-96.8	93.8-96.9	95.2-97.2	95.2-97.2
GDP at factor cost ($M)	Total	128-140	1027-1209	744-906	714-866	1547-1650	1120-1194
	%BC	86.5-94.8	84.7-94.4	84.3-94.3	85.1-94.5	89.5-95.4	89.5-95.4
Employment (000)	Total	1.9-2.1	17.9-21.3	13.1-16.1	12.5-15.3	19.3-20.6	14.0-14.9
	%BC	86.7-95.0	84.0-94.4	83.7-94.3	84.5-94.6	89.2-95.4	89.2-95.4
Household income ($M)	Total	92-104	62-190	554-702	529-668	865-967	626-700
	%BC	82.8-93.7	80.8-93.4	80.4-93.3	81.4-93.5	83.6-93.5	83.6-93.5
Local taxes ($M)	Total	1.4-1.4	16.7-17.5	12.2-13.1	11.8-12.7	23.2-23.2	16.8-16.8
	%BC	98.4-98.4	98.3-98.3	98.3-98.3	98.3-98.3	98.2-98.2	98.2-98.2

Range values in the table reflect lower and upper bound assumptions concerning QCB region proportions of direct non-commodity project expenditures in BC. In the development scenarios, range values also reflect short and long pipeline cases.

Focusing on the QCB region that surrounds the area of assumed offshore activity, the results in Table 6.6 show the following estimated benefits in the QCB region, excluding induced effects:

- **Exploration**: depending on whether 10% or 30% of direct non-commodity expenditure on exploration in BC occurs in the QCB region, increased output of $12-24 million (3.1-6.4% of increased provincial output);GDP of $8-20 million (5.2-13.5% of increased provincial GDP); 111-292 annual jobs (5.1-13.4% of the provincial total); household income of $7-19 million (6.3-17.3%); and local tax revenue of $23,000 (1.6%).
- **Development**: depending on whether 15% or 50% of direct non-commodity expenditure on development in BC occurs in the QCB region, and depending on the length of the pipeline, increased output of $111-242 million (oil) (3.1-6.4% of increased provincial output) and, depending also on whether gas is wet or dry, $77-186 million (gas) (3.1-6.5% of increased provincial output); GDP of $68-196 million (oil) (5.6-15.3% of increased provincial GDP) and $46-151 million (gas) (5.5-15.7%); some 1,200-3,600 annual jobs (oil) (5.6-16.0% of the provincial total) and 800-2,800 annual jobs (gas) (5.5-16.3%); household income of $62-190 million (oil) (6.6-19.2%)and $42-146 million (gas) (6.5-19.6%) ; and local tax revenue of $287-304,000 (oil) and $205-232,000 (gas) (1.7% in both cases).
- **Production**: depending on whether 25% or 75% of direct non-commodity expenditure in BC at the production stage occurs in the QCB region, increased output in the QCB region of $143-245 million (oil) and $104-177 million (gas) (2.8-4.8% of provincial output in both cases); GDP of $79-181 million (oil) and $57-131 million (gas) (4.6-10.5%);1,006-2,335 annual jobs (oil) and 728-1690 annual jobs (gas)(4.7-10.8%); household income of $68-170 million (oil) and $49-123 million (gas)(6.6-16.4%); and local tax revenue of $419,000 (oil) and $303,000 (gas)(1.8%).

Table 6.7 shows regional impacts per million dollars of expenditure for each stage of activity.

Table 6.7: Regional Expenditure Impacts Per $Million Expenditure ($2006)

	Exploration	**Development**			**Production**
QCB Region		**Oil**	**Wet Gas**	**Dry Gas**	
Output ($000)	19-38	22-46	24-49	23-46	49-84
GDP at factor cost ($000)	12-32	14-38	14-40	14-37	27-62
Employment (#)	0.18-0.47	0.24-0.69	0.25-0.74	0.24-0.68	0.35-0.80
Household income ($000)	11-31	13-36	13-39	12-36	23-58
Local taxes ($000)	0.04-0.04	0.06-0.06	0.06-0.06	0.06-0.06	0.14-0.14
RBC Region					
Output ($000)	565-584	680-703	700-728	698-723	1678-1713
GDP at factor cost ($000)	206-226	207-232	212-240	210-236	530-592
Employment (#)	3.1-3.3	3.6-4.1	3.7-4.3	3.7-4.2	6.6-7.1
Household income ($000)	148-167	153-177	159-186	156-181	296-331
Local taxes ($000)	2.26-2.26	3.34-3.39	3.43-3.51	3.41-3.50	7.96-7.96

Assuming no economies or diseconomies of scale, results indicate that for every million dollars spent on exploration, development or production activities before provincial expenditure leakages, benefits at 2006 prices in the QCB region are as follows:

- **Exploration**: increased output of $19-38,000; GDP of $12-32,000; 0.2-0.5 annual jobs;, household income of $11-31,000 and local tax revenue of as little as $4..
- **Development**: increased output of $22-46,000 (oil) and $23-49,000 (gas); GDP of $14-38,000 (oil) and $14-40,000 (gas); 0.2-0.7 annual jobs (oil) and 0.3-0.7 jobs (gas); household income of $13-36,000 (oil) and $12-39,000 (gas); and local tax revenue of around $6.
- **Production**: increased output of $49-84,000; GDP of $27-62,000; 0.4-0.8 annual jobs; household income of $23-58,000; and local tax revenue of $140.

The evidence from tables 6.6 and 6.7 is that the benefits to the QCB region can be expected to be quite small in absolute and relative terms. Even in the most positive light at the upper end of estimated bounds, the QCB region is estimated to capture no more than 6.5% of incremental provincial output, approximately 16% of incremental GDP and employment, approximately 19.5% of household income and 1.8% of local tax revenue. Therefore, communities in the QCB region that will mainly bear the risks of offshore activity are unlikely to benefit substantially from that activity in terms of expenditure impacts. In truth, their situation is likely to be improved when structural changes to the local and provincial economies, as discussed in Section 5 of the report, are taken into account. Nevertheless, an implication of the analysis is that it may be necessary to find ways of directing to the QCB region a reasonable amount of the provincial financial revenue (economic rent) gained from offshore activity if communities in the region are to be assured that they are receiving a fair share of the benefits from the offshore resource. Options could include revenue-sharing arrangements with local governments and/or First Nations, cost-sharing agreements, or the provision of targeted grants for such purposes as investment in community infrastructure, local service needs and/or training required for jobs in the industry.[76]

6.4 Transformative Economic Changes

In addition to benefits in the form of economic rent and expenditures impacts, a new oil and gas sector can be expected to stimulate further growth in output, income, employment and government finances. This is because the new sector is likely to stimulate changes in provincial and regional economies that represent either increases in the quantity of inputs to the productive process or improvements to the quality (productivity) of inputs, thereby enhancing the capacity of economies to produce goods and services. This has been the experience in other offshore settings such as the North Sea, Atlantic Canada and Cook Inlet, Alaska.

Examples of input quantity and/or quality enhancement in these other geographic settings include:

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[76] The importance of directing a fair share of offshore rent to communities in the QCB region is particularly relevant in respect of the smaller communities in the region. While the larger centres of Prince Rupert and/or Kitimat and/or Port Hardy could benefit as supply centres for the offshore industry, it is unlikely that the smaller communities elsewhere in the region will benefit to the same degree.

- new investments in infrastructure, education and training programs, and research and development activities;
- economic diversification;
- increased entrepreneurship, self-confidence and ambition in the business community; and
- population increase.

The review also considers the possible impacts on traditional sectors of the provincial and regional economies such as fisheries and tourism, and concludes that, despite possible risks, these sectors can experience marked benefits.

6.5 Final Observations

Features of the analyses that should not be overlooked relate to: the data and models on which the findings rest; the focus of the report on solely the benefit side of offshore activity; and the conservative approach to the estimation of benefits in the quantitative sections of the report.

Data and Models

In terms of data, the major challenge for any study of a hypothetical situation such as offshore energy resource development in BC is that there are no historical data that pertain to the particular situation under analysis. That said, however, the geological data in Section 2.1 of the report are based on the latest probability estimations of the Geological Survey of Canada, experience in Cook Inlet, an area of similar geological character to the QCB, and recent academic studies. Expenditure estimates in Section 2.2 and used in Sections 3 and 4 of the report are derived from experience in other offshore locations, primarily off the Canadian east coast, and expert advice. The evidence for structural change in Section 5 comes from the record in comparable offshore locations elsewhere.

Moreover, the models employed in Sections 3 and 4 of the report are of a type commonly used for estimating economic rent and expenditure benefits, and observations on the potential for sustainable growth in Section 5 are based on the framework of established long-term growth theory.

In the cases of the provincial input-output and regional impact models used in Section 4, it is necessary to explain that when a ‘shock’ to the economic system (for example, introducing a new industry such as offshore oil and gas) occurs, the models assume:

- adjustments through input-output relationships elsewhere in the economy happen immediately;
- relative prices of goods and services are not disturbed;
- inputs into production processes continue to be used in the same proportions irrespective of the level of output of a commodity; and
- there are no constraints on supply so that an increase in demand for a commodity leads to a proportional increase in its output.

Given the issues around data availability and model assumptions, the results should be seen as illustrative orders of magnitude rather than precise predictions. Where feasible, results are presented as range estimates to avoid any false impression of precision. Also, working assumptions for the analyses err in general on the conservative side (see below) so as not to overstate estimated benefits and, together with sensitivity analysis on key parameters, as a way of addressing the many uncertainties involved in estimating benefits.

Benefit-Side Focus

The analyses focus on benefit estimation and are not designed to measure the possible risks of offshore activity. This feature of the study leads to two observations. First, concerns around the risks of activity point to the importance of developing a stringent regulatory regime to protect the marine and coastal ecosystem, quite aside from the estimated magnitude of possible benefits. Second, while the study is not intended to be a risk assessment analysis, the detailed evaluation of benefits that it provides could help to inform such an analysis. That is to say, the estimates of benefit in the report could be weighed against possible risks in the process of considering policy direction.

Conservative Estimation Procedures

It is important to repeat that all quantitative results in the report are conservative to the extent that many of the assumptions that underlie the estimates are conservative.

Conservative aspects of the resource assessment on which the quantitative analyses are based include initial discovery and development of the "queen" field rather than the "king" field, even though the latter has been discovered and developed first in some areas in recent times due to advances in exploration technology. Likewise, traditional recovery factors of 1/3 for oil and 2/3 for gas are used, despite engineering advances that have led to higher recoveries in many fields, including fields in Cook Inlet, Alaska.

Key conservative assumptions built into computations of financial viability and economic rent are as follows. First, exploration activities, development drilling, construction and operation of the production platform are not shared between oil and gas projects (i.e. each project stands alone). This means that there are no economies of scope in terms of exploration, development and production activities. Second, companies cannot use losses on British Columbia projects to defray tax liabilities on profitable projects elsewhere in Canada. Third, investment outlays are fully expensed for corporation income tax purposes. Fourth, projects are assumed to be 100% equity financed. Also, estimates relating to expected long-term prices and the exchange rate for the Canadian dollar appear conservative in the context of current energy prices and exchange rates.

In the estimation of expenditure benefits, substantial expenditures on equipment for surveying and drilling, and on pipeline installation and construction of the production facility sub-structure, are assumed to leak out of the provincial economy as imported goods and services that generate no expenditure benefits in BC. At the same time, leakage rates at both provincial and QCB-region levels are in general conservative to the extent that they do not provide for likely increases over time in local capacity to serve the labour and commodity needs of projects. Also, municipal tax revenues estimated in the BC input-output model exclude property taxes, and estimates of regional benefits exclude induced effects.

Finally, the study assumes activity in just single fields of oil and gas. Based on precedent from offshore operations elsewhere, it can be reasonably expected, however, that other commercial fields will come on stream in QCB subsequent to the discovery and development of the single fields assumed in the analyses. In this sense, the estimates of the study can be interpreted as measures of merely the initial benefits of developing the QCB resource.

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APPENDICES

Appendices Section 2

Appendix 2A: Distribution of Resources in Place by Size of Pool

Table 2A.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 Bbls)	Median Pool Size (Millions of Bbls)
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 bbl per cubic meter.

Table 2A.2: 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 Bbls)	Median Pool Size (Millions of Bbls)
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 Bbls)	Median Pool Size (Millions of Bbls)
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 bbl per cubic meter.

Table 2A.3: Distribution of Oil in Place by Size of Pool – QCB: Pliocene Oil Play

Pool #	Mean Pool Size (Million M^3)	Median Pool Size (Million M^3)	Mean Pool Size (Millions of Bbls)	Median Pool Size (Millions of Bbls)
1	444.1	233.1	2,739.2	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: Distributed 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 13.03 pools (expected number of fields from log-normal distribution for the play). The conversion factor utilized is 0.158987 bbl per cubic meter.

Table 2A.4: Distribution of Gas in Place by Size of Pool – QCB: 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	25,616.0	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	2,137.8	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**	**8,932,300.9**	**8,048,169.0**

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 39.97 pools (expected number of fields from log-normal distribution for the play provided by Hannigan) and 7,933.9 million cubic meters (the mean of the log-normal distribution for the play). The conversion factor utilized is 0.0355 millions of cubic meters to billions of cubic feet.

Table 2A.5: Distribution of Gas in Place by Size of Pool – QCB: 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
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 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 2A.6: 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 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.

Appendix 2B: Estimated In-Place Resource Potential

Fig.2B.1 Estimated in-place oil potential of the Cretaceous play in the QCB. Median value of probabilistic assessment is 392 x $10^6 m^3$ of in-place oil distributed in 62 fields (Hannigan et al. 2001)

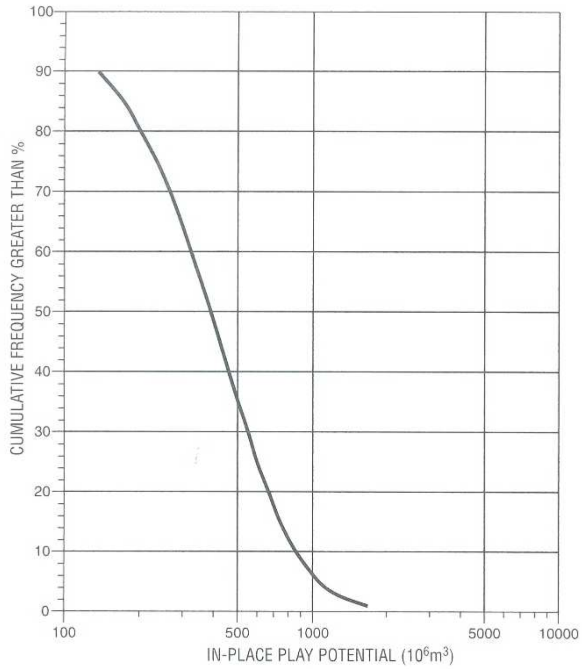

Fig. 2B.2 Estimated in-place gas potential of the Cretaceous play in the QCB. Median value of probabilistic assessment is 75 x $10^9 m^3$ of in-place oil distributed in 50 fields (Hannigan et al. 2001)

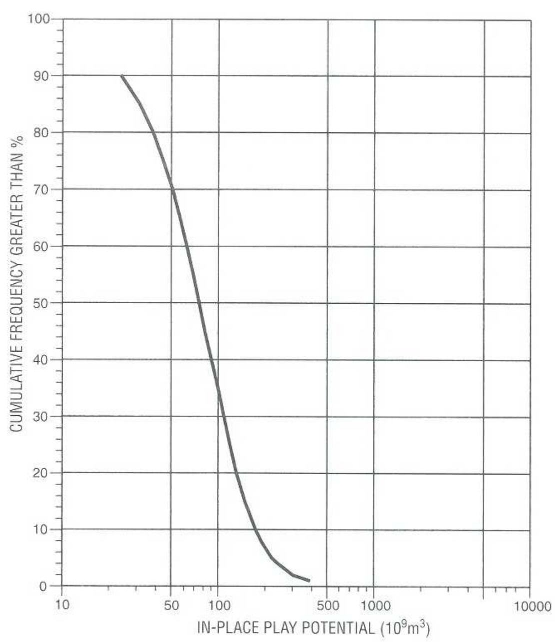

Fig. 2B.3 Estimated in-place oil potential of the Miocene play in the QCB. Median value of probabilistic assessment is 574 x $10^6 m^3$ of in-place oil distributed in 28 fields (Hannigan et al. 2001).

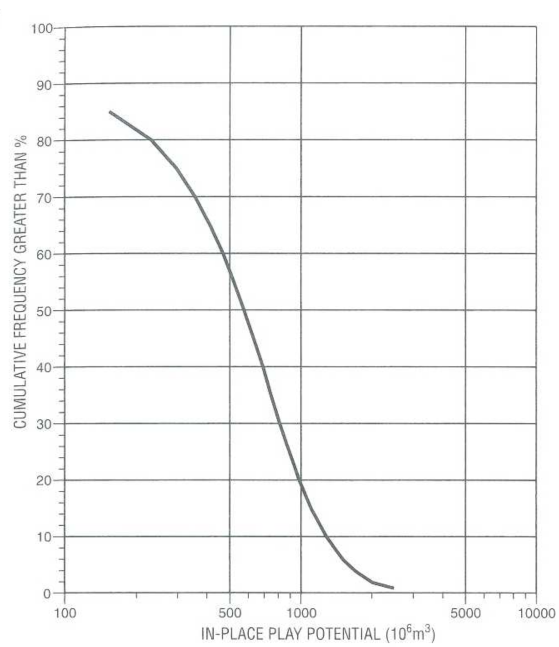

Fig. 2B.4 Estimated in-place gas potential of the Miocene play in the QCB. Median value of probabilistic assessment is 286 x $10^9 m^3$ of in-place oil distributed in 40 fields (Hannigan et al. 2001).

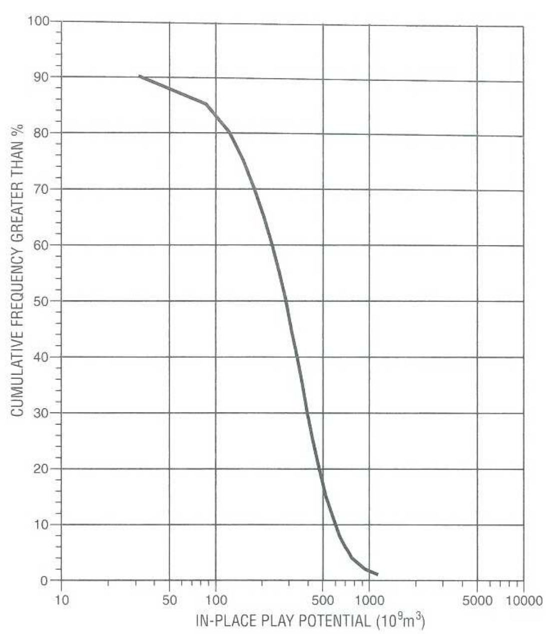

Fig. 2B.5 Estimated in-place oil potential of the Pliocene play in the QCB. Median value of probabilistic assessment is 398 x $10^6 m^3$ of in-place oil distributed in 13 fields (Hannigan et al. 2001)

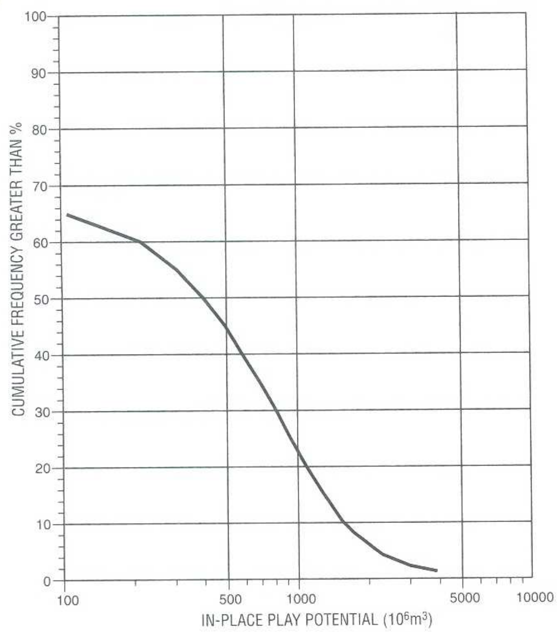

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Fig. 2B.6 Estimated in-place gas potential of the Pliocene play in the QCB. Median value of probabilistic assessment is 322 x $10^9 m^3$ of in-place oil distributed in 30 fields (Hannigan et al. 2001).

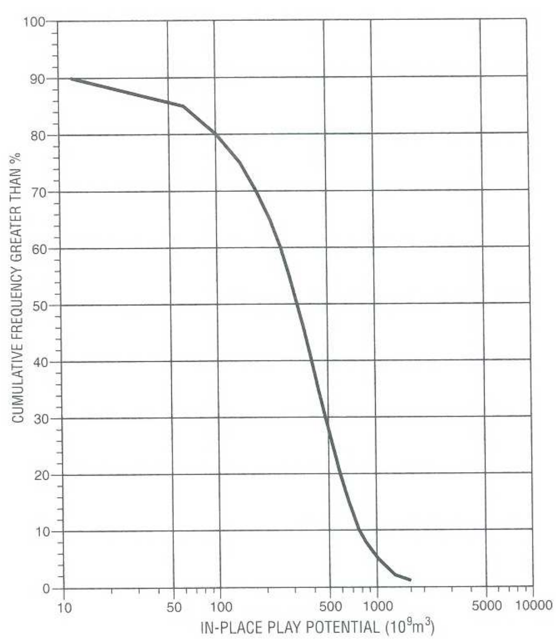


Fig. 2B.7 Estimate of total oil potential for the QCB region. Median value of probabilistic assessment is 1.6 x $10^9 m^3$ of in-place oil (Hannigan et al. 2001).

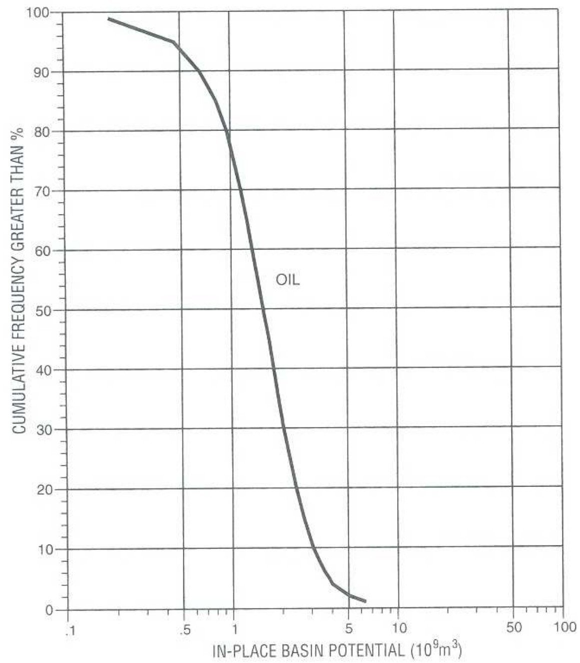
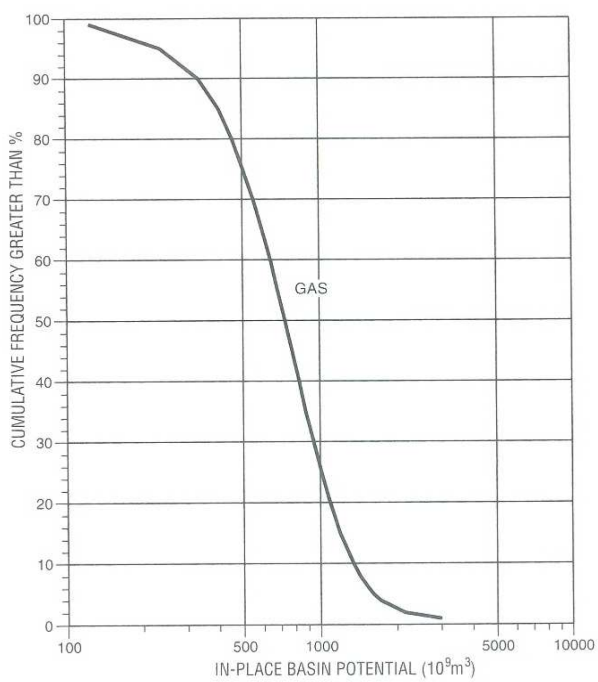


Fig. 2B.8 Estimate of total gas potential for the QCB region. Median value of probabilistic assessment is 734 x $10^9 m^3$ of in-place oil (Hannigan et al. 2001).



Appendix 2C: Gas Composition Analysis

Table 2C.1: Queen Charlotte Basin: Sockeye B-10 Gas Analysis and Liquids Extraction Summary (Plant recovery Temperature -20°F

Component	Mole % Separator Gas	Gas Plant Recovery %	Mole % Sales Gas
H2	0.00	0.00	0.00
He	0.00	0.00	0.00
N2	2.48	0.00	2.58
CO2	0.08	100.00	0.00
H2S	0.00	100.00	0.00
C1	77.72	0.00	80.84
C2	12.23	0.00	12.72
C3	4.89	35.00	3.31
i C4	1.11	75.00	0.29
n C4	0.97	75.00	0.25
i C5	0.29	97.00	0.01
n C5	0.13	97.00	0.00
C6	0.06	100.00	0.00
C7	0.04	100.00	0.00
C8	0.00	100.00	0.00
C9	0.00	100.00	0.00
C10+	0.00	100.00	0.00
Total :	**100.00**		**100.00**
Molecular Weight	20.653		19.299
Specific Gravity	0.7129		0.6662
Critical Temperature, °R	392.5		379.3
Critical Pressure , psia	662.5		666.0
Net Calorific Value, BTU/scf	1,100.4		1,034.0
Shrinkage (excluding Fuel) %			3.9
PLANT PRODUCTS Based on 1.0 MMscf of			
	Units	***Raw Gas***	***Sales Gas***
Sulphur	Long Ton	0.0	0.0
Condensate	stb	4.7	4.9
Butane	stb	11.9	12.4
Propane	stb	11.2	11.6
Ethane	stb	0.0	0.0
Total		**27.8**	**28.9**

Based on: Chemical & Geological Laboratories Ltd., Laboratory Report Number: E68-7070, gas analysis performed on the Sockeye B-10 well for Shell Canada, Ltd., June 24, 1968.

Appendix 2D: Pipeline Costs in the North Sea

Table 2D.1: Costs of Oil Pipelines in the North Sea

Name of Pipeline	Size (Inches)	Distance (km)	Capacity (bbls/d)	Investment Cost 2006 NOK Billion	Investment Cost 2006 Cdn. Million *(0.182871 $/NOK)*	Cost per in-km (Cdn. Dollars)
Grane Oil Pipeline	29	220	213,854	1.60	$293	$45,861
Troll Oil Pipeline I	16	85	267,317	1.12	$205	$150,600
Troll Oil Pipeline II	20	80	251,592	1.00	$183	$114,294
Average						**$103,585**

Source: Ministry of Petroleum and Energy and the Norwegian Petroleum Directorate, Facts: The Norwegian Petroleum Sector- 2006

Table 2D.2: Costs of Gas Pipelines in the North Sea

Name of Pipeline	Size (Inches)	Distance (km)	Capacity (bbls/d)	Investment Cost 2006 NOK Billion	Investment Cost 2006 Cdn. Million *(0.182871 $/NOK)*	Cost per in-km (Cdn. Dollars)
Draugen Gas Export	16	78	194	1.1	$201	$161,184
Grane Gas Pipeline	18	50	348	0.3	$55	$60,957
Heidrun Gas Export	16	37	387	0.9	$165	$278,013
Norne Gas Transport	16	126	348	1.2	$219	$108,852
Average						**$152,252**

Source: Ministry of Petroleum and Energy and the Norwegian Petroleum Directorate, Facts: The Norwegian Petroleum Sector- 2006

Appendix 2E: Basic Scenario Data ($CAN)

Table 2E.1: Select Statistics for Short Pipeline Oil Scenario – (2006 Prices)

Year	Seismic Surveys ($ M)	Mobilization Demobilization Cost ($ M)	Exploration & Delineation Wells Cost ($ M)	Development Drilling Cost ($ M)	Shorter Pipeline Capital Cost ($ M)	Transship. Facility Capital Cost ($ M)	Production Facility & Other Capital Cost ($ M)	Total Finding & Development Cost ($ M)	Operating Cost ($ M)	Marine Transport Cost ($ M)	Annual Production (mm bbls)
1	$40.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$40.0	$0.0	$0.0	0.0
2	$40.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$40.0	$0.0	$0.0	0.0
3	$0.0	$23.9	$142.6	$0.0	$0.0	$0.0	$0.0	$166.5	$0.0	$0.0	0.0
4	$0.0	$0.0	$142.6	$0.0	$0.0	$0.0	$0.0	$142.6	$0.0	$0.0	0.0
5	$0.0	$0.0	$213.9	$0.0	$0.0	$0.0	$0.0	$213.9	$0.0	$0.0	0.0
6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$6.2	$6.2	$0.0	$0.0	0.0
7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$12.4	$12.4	$0.0	$0.0	0.0
8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$24.7	$24.7	$0.0	$0.0	0.0
9	$0.0	$0.0	$0.0	$0.0	$105.0	$100.0	$37.1	$242.1	$0.0	$0.0	0.0
10	$0.0	$0.0	$0.0	$355.2	$105.0	$100.0	$402.0	$962.3	$5.9	$0.0	0.0
11	$0.0	$0.0	$0.0	$355.2	$105.0	$100.0	$674.1	$1,234.3	$18.8	$0.0	0.0
12	$0.0	$0.0	$0.0	$236.8	$0.0	$0.0	$821.3	$1,058.1	$70.5	$18.6	18.6
13	$0.0	$0.0	$0.0	$236.8	$0.0	$0.0	$60.0	$296.8	$237.8	$54.7	54.7
14	$0.0	$0.0	$0.0	$177.6	$0.0	$0.0	$55.0	$232.6	$237.8	$54.7	54.7
15	$0.0	$0.0	$0.0	$177.6	$0.0	$0.0	$0.0	$177.6	$237.8	$54.7	54.7
16	$0.0	$0.0	$0.0	$177.6	$0.0	$0.0	$0.0	$177.6	$237.8	$54.7	54.7
17	$0.0	$0.0	$0.0	$177.6	$0.0	$0.0	$0.0	$177.6	$230.5	$50.6	50.6
18	$0.0	$0.0	$0.0	$118.4	$0.0	$0.0	$0.0	$118.4	$223.8	$46.8	46.8
19	$0.0	$18.9	$0.0	$118.4	$0.0	$0.0	$0.0	$137.3	$217.6	$43.3	43.3
20	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$211.9	$40.1	40.1
21	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$206.6	$37.1	37.1
22	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$201.7	$34.3	34.3
23	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$197.2	$31.7	31.7
24	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$193.0	$29.3	29.3
25	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$100.0	$100.0	$189.1	$27.1	27.1
Total	**$80.0**	**$42.8**	**$499.2**	**$2,131.5**	**$315.0**	**$300.0**	**$2,192.8**	**$5,561.3**	**$2,917.9**	**$578.1**	**578.1**

Table 2E.2: Select Statistics for Short Pipeline Oil Scenario – (As-Spent-Dollar Prices)

Year	Seismic Surveys ($ M)	Mobilization Demobilization Cost ($ M)	Exploration & Delineation Wells Cost ($ M)	Development Drilling Cost ($ M)	Shorter Pipeline Capital Cost ($ M)	Transship. Facility Capital Cost ($ M)	Production Facility & Other Capital Cost ($ M)	Total Finding & Development Cost ($ M)	Operating Cost ($ M)	Marine Transport Cost ($ M)	Annual Production (mm bbls)
1	$40.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$40.0	$0.0	$0.0	0.0
2	$40.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$40.8	$0.0	$0.0	0.0
3	$0.0	$24.9	$148.4	$0.0	$0.0	$0.0	$0.0	$173.3	$0.0	$0.0	0.0
4	$0.0	$0.0	$151.3	$0.0	$0.0	$0.0	$0.0	$151.3	$0.0	$0.0	0.0
5	$0.0	$0.0	$231.6	$0.0	$0.0	$0.0	$0.0	$231.6	$0.0	$0.0	0.0
6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$6.8	$6.8	$0.0	$0.0	0.0
7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$13.9	$13.9	$0.0	$0.0	0.0
8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$28.4	$28.4	$0.0	$0.0	0.0
9	$0.0	$0.0	$0.0	$0.0	$123.0	$117.2	$43.4	$283.6	$0.0	$0.0	0.0
10	$0.0	$0.0	$0.0	$424.6	$125.5	$119.5	$480.5	$1,150.0	$7.0	$0.0	0.0
11	$0.0	$0.0	$0.0	$433.0	$128.0	$121.9	$821.7	$1,504.7	$22.9	$0.0	0.0
12	$0.0	$0.0	$0.0	$294.5	$0.0	$0.0	$1,021.2	$1,315.7	$87.7	$23.1	18.6
13	$0.0	$0.0	$0.0	$300.4	$0.0	$0.0	$76.1	$376.5	$301.6	$69.4	54.7
14	$0.0	$0.0	$0.0	$229.8	$0.0	$0.0	$71.1	$300.9	$307.6	$70.8	54.7
15	$0.0	$0.0	$0.0	$234.4	$0.0	$0.0	$0.0	$234.4	$313.8	$72.2	54.7
16	$0.0	$0.0	$0.0	$239.1	$0.0	$0.0	$0.0	$239.1	$320.0	$73.7	54.7
17	$0.0	$0.0	$0.0	$243.8	$0.0	$0.0	$0.0	$243.8	$316.5	$69.5	50.6
18	$0.0	$0.0	$0.0	$165.8	$0.0	$0.0	$0.0	$165.8	$313.4	$65.6	46.8
19	$0.0	$27.0	$0.0	$169.1	$0.0	$0.0	$0.0	$196.1	$310.8	$61.9	43.3
20	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$308.7	$58.4	40.1
21	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$307.0	$55.1	37.1
22	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$305.7	$52.0	34.3
23	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$304.8	$49.0	31.7
24	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$304.3	$46.3	29.3
25	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$160.8	$160.8	$304.1	$43.7	27.1
Total	**$80.8**	**$51.9**	**$531.3**	**$2,734.4**	**$376.5**	**$358.6**	**$2,724.1**	**$6,857.5**	**$4,136.1**	**$810.7**	**578.1**

Table 2E.3: Select Statistics for Long Pipeline Oil Scenario – (2006 Prices)

Year	Seismic Surveys ($ M)	Mobilization Demobilization Cost ($ M)	Exploration & Delineation Wells Cost ($ M)	Development Drilling Cost ($ M)	Longer Pipeline Capital Cost ($ M)	Transship. Facility Capital Cost ($ M)	Production Facility & Other Capital Cost ($ M)	Total Finding & Development Cost ($ M)	Operating Cost ($ M)	Marine Transport Cost ($ M)	Annual Production (mm bbls)
1	$40.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$40.0	$0.0	$0.0	0.0
2	$40.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$40.0	$0.0	$0.0	0.0
3	$0.0	$23.9	$142.6	$0.0	$0.0	$0.0	$0.0	$166.5	$0.0	$0.0	0.0
4	$0.0	$0.0	$142.6	$0.0	$0.0	$0.0	$0.0	$142.6	$0.0	$0.0	0.0
5	$0.0	$0.0	$213.9	$0.0	$0.0	$0.0	$0.0	$213.9	$0.0	$0.0	0.0
6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$6.2	$6.2	$0.0	$0.0	0.0
7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$12.4	$12.4	$0.0	$0.0	0.0
8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$24.7	$24.7	$0.0	$0.0	0.0
9	$0.0	$0.0	$0.0	$0.0	$210.0	$100.0	$37.1	$347.1	$0.0	$0.0	0.0
10	$0.0	$0.0	$0.0	$355.2	$210.0	$100.0	$402.0	$1,067.3	$5.9	$0.0	0.0
11	$0.0	$0.0	$0.0	$355.2	$210.0	$100.0	$674.1	$1,339.3	$18.8	$0.0	0.0
12	$0.0	$0.0	$0.0	$236.8	$0.0	$0.0	$821.3	$1,058.1	$70.5	$18.6	18.6
13	$0.0	$0.0	$0.0	$236.8	$0.0	$0.0	$60.0	$296.8	$237.8	$54.7	54.7
14	$0.0	$0.0	$0.0	$177.6	$0.0	$0.0	$55.0	$232.6	$237.8	$54.7	54.7
15	$0.0	$0.0	$0.0	$177.6	$0.0	$0.0	$0.0	$177.6	$237.8	$54.7	54.7
16	$0.0	$0.0	$0.0	$177.6	$0.0	$0.0	$0.0	$177.6	$237.8	$54.7	54.7
17	$0.0	$0.0	$0.0	$177.6	$0.0	$0.0	$0.0	$177.6	$230.5	$50.6	50.6
18	$0.0	$0.0	$0.0	$118.4	$0.0	$0.0	$0.0	$118.4	$223.8	$46.8	46.8
19	$0.0	$18.9	$0.0	$118.4	$0.0	$0.0	$0.0	$137.3	$217.6	$43.3	43.3
20	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$211.9	$40.1	40.1
21	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$206.6	$37.1	37.1
22	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$201.7	$34.3	34.3
23	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$197.2	$31.7	31.7
24	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$193.0	$29.3	29.3
25	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$100.0	$100.0	$189.1	$27.1	27.1
Total	**$80.0**	**$42.8**	**$499.2**	**$2,131.5**	**$630.0**	**$300.0**	**$2,192.8**	**$5,876.3**	**$2,917.9**	**$578.1**	**578.1**

Table 2E.4: Select Statistics for Long Pipeline Oil Scenario – (As-Spent-Dollar Prices)

Year	Seismic Surveys ($ M)	Mobilization Demobilization Cost ($ M)	Exploration & Delineation Wells Cost ($ M)	Development Drilling Cost ($ M)	Longer Pipeline Capital Cost ($ M)	Transship. Facility Capital Cost ($ M)	Production Facility & Other Capital Cost ($ M)	Total Finding & Development Cost ($ M)	Operating Cost ($ M)	Marine Transport Cost ($ M)	Annual Production (mm bbls)
1	$40.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$40.0	$0.0	$0.0	0.0
2	$40.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$40.8	$0.0	$0.0	0.0
3	$0.0	$24.9	$148.4	$0.0	$0.0	$0.0	$0.0	$173.3	$0.0	$0.0	0.0
4	$0.0	$0.0	$151.3	$0.0	$0.0	$0.0	$0.0	$151.3	$0.0	$0.0	0.0
5	$0.0	$0.0	$231.6	$0.0	$0.0	$0.0	$0.0	$231.6	$0.0	$0.0	0.0
6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$6.8	$6.8	$0.0	$0.0	0.0
7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$13.9	$13.9	$0.0	$0.0	0.0
8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$28.4	$28.4	$0.0	$0.0	0.0
9	$0.0	$0.0	$0.0	$0.0	$246.0	$117.2	$43.4	$406.7	$0.0	$0.0	0.0
10	$0.0	$0.0	$0.0	$424.6	$251.0	$119.5	$480.5	$1,275.5	$7.0	$0.0	0.0
11	$0.0	$0.0	$0.0	$433.0	$256.0	$121.9	$821.7	$1,632.7	$22.9	$0.0	0.0
12	$0.0	$0.0	$0.0	$294.5	$0.0	$0.0	$1,021.2	$1,315.7	$87.7	$23.1	18.6
13	$0.0	$0.0	$0.0	$300.4	$0.0	$0.0	$76.1	$376.5	$301.6	$69.4	54.7
14	$0.0	$0.0	$0.0	$229.8	$0.0	$0.0	$71.1	$300.9	$307.6	$70.8	54.7
15	$0.0	$0.0	$0.0	$234.4	$0.0	$0.0	$0.0	$234.4	$313.8	$72.2	54.7
16	$0.0	$0.0	$0.0	$239.1	$0.0	$0.0	$0.0	$239.1	$320.0	$73.7	54.7
17	$0.0	$0.0	$0.0	$243.8	$0.0	$0.0	$0.0	$243.8	$316.5	$69.5	50.6
18	$0.0	$0.0	$0.0	$165.8	$0.0	$0.0	$0.0	$165.8	$313.4	$65.6	46.8
19	$0.0	$27.0	$0.0	$169.1	$0.0	$0.0	$0.0	$196.1	$310.8	$61.9	43.3
20	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$308.7	$58.4	40.1
21	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$307.0	$55.1	37.1
22	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$305.7	$52.0	34.3
23	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$304.8	$49.0	31.7
24	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$304.3	$46.3	29.3
25	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$160.8	$160.8	$304.1	$43.7	27.1
Total	**$80.8**	**$51.9**	**$531.3**	**$2,734.4**	**$753.0**	**$358.6**	**$2,724.1**	**$7,234.0**	**$4,136.1**	**$810.7**	**578.1**

Table 2E.5: Select Statistics for Short Pipeline Wet Gas Scenario – (2006 Prices)

Year	Seismic Surveys Cost ($ M)	Mobilization Demobilization Cost $M)	Exploration & Delineation Wells Cost ($ M)	Development Drilling Cost ($ M)	Shorter Pipeline Capital Cost ($ M)	Onshore Gas Plant Capital Cost ($ M)	Onshore NGL Plant Capital Cost ($ M)	Production Facility & Other Capital Cost ($ M)	Total Finding & Development Cost ($ M)
1	$40.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$40.0
2	$40.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$40.0
3	$0.0	$23.9	$142.6	$0.0	$0.0	$0.0	$0.0	$0.0	$166.5
4	$0.0	$0.0	$142.6	$0.0	$0.0	$0.0	$0.0	$0.0	$142.6
5	$0.0	$0.0	$213.9	$0.0	$0.0	$0.0	$0.0	$0.0	$213.9
6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$5.2	$5.2
7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$10.4	$10.4
8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$15.3	$15.3
9	$0.0	$0.0	$0.0	$0.0	$120.0	$0.0	$0.0	$25.7	$145.7
10	$0.0	$0.0	$0.0	$236.8	$120.0	$0.0	$0.0	$232.0	$588.8
11	$0.0	$0.0	$0.0	$236.8	$120.0	$75.0	$25.0	$499.2	$956.0
12	$0.0	$0.0	$0.0	$0.0	$0.0	$150.0	$75.0	$629.0	$854.0
13	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$40.2	$99.4
14	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$36.9	$96.1
15	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
16	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$0.0	$59.2
17	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$0.0	$59.2
18	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
19	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$0.0	$59.2
20	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$0.0	$59.2
21	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
22	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$0.0	$59.2
23	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$0.0	$59.2
24	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
25	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$0.0	$59.2
26	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$0.0	$59.2
27	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
28	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$0.0	$59.2

29	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
30	$0.0	$18.9	$0.0	$59.2	$0.0	$0.0	$0.0	$0.0	$78.1
31	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
32	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
33	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
34	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
35	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
36	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$100.0	$100.0
Total	**$80.0**	**$42.8**	**$499.2**	**$1,184.2**	**$360.0**	**$225.0**	**$100.0**	**$1,593.8**	**$4,085.0**

Table 2E.5: Select Statistics for Short Pipeline Wet Gas Scenario – (2006 Prices) (Continued)

Year	Operating Cost ($ M)	Domestic Pipeline Transport Cost ($ M)	Daily Production Raw Natural Gas (mmcf)	Daily Production Sales Natural Gas (mmcf)	Annual Production Condensate (mm bbls)	Annual Production Butane (mm bbls)	Annual Production Propane (mm bbls)
1	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
2	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
3	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
4	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
5	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
6	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
7	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
8	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
9	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
10	$5.9	$0.0	0.0	0.0	0.00	0.00	0.00
11	$18.8	$0.0	0.0	0.0	0.00	0.00	0.00
12	$80.7	$80.5	236.5	220.4	0.41	1.03	0.97
13	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
14	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
15	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
16	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
17	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
18	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
19	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
20	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
21	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
22	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
23	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
24	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
25	$86.4	$125.3	368.4	343.4	0.41	1.60	1.51
26	$82.9	$97.6	287.0	267.5	0.41	1.25	1.17
27	$80.2	$76.1	223.6	208.4	0.41	0.97	0.91
28	$78.1	$59.3	174.2	162.3	0.41	0.76	0.71

29	$76.4	$46.2	135.7	126.5	0.41	0.59	0.55
30	$75.1	$36.0	105.7	98.5	0.41	0.46	0.43
31	$74.1	$28.0	82.3	76.7	0.41	0.36	0.34
32	$73.3	$21.8	64.1	59.8	0.41	0.28	0.26
33	$72.7	$17.0	50.0	46.6	0.41	0.22	0.20
34	$72.3	$13.2	38.9	36.3	0.41	0.17	0.16
35	$71.9	$10.3	30.3	28.3	0.41	0.13	0.12
36	$71.6	$8.0	23.6	22.0	0.41	0.10	0.10
Total	**$2,111.3**	**$2,550.0**	**2,736**	**2,550**	**10.1**	**32.6**	**30.6**

*Gas production totals = production over life of field.

Table 2E.6: Select Statistics for Short Pipeline Wet Gas Scenario (As-Spent-Dollar Prices)

Year	Seismic Surveys Cost ($ M)	Mobilization Demobilization Cost $M)	Exploration & Delineation Wells Cost ($ M)	Development Drilling Cost ($ M)	Shorter Pipeline Capital Cost ($ M)	Onshore Gas Plant Capital Cost ($ M)	Onshore NGL Plant Capital Cost ($ M)	Production Facility & Other Capital Cost ($ M)	Total Finding & Development Cost ($ M)
1	$40.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$40.0
2	$40.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$40.8
3	$0.0	$24.9	$148.4	$0.0	$0.0	$0.0	$0.0	$0.0	$173.3
4	$0.0	$0.0	$151.3	$0.0	$0.0	$0.0	$0.0	$0.0	$151.3
5	$0.0	$0.0	$231.6	$0.0	$0.0	$0.0	$0.0	$0.0	$231.6
6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$5.7	$5.7
7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$11.7	$11.7
8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$17.6	$17.6
9	$0.0	$0.0	$0.0	$0.0	$140.6	$0.0	$0.0	$30.1	$170.7
10	$0.0	$0.0	$0.0	$283.0	$143.4	$0.0	$0.0	$277.3	$703.7
11	$0.0	$0.0	$0.0	$288.7	$146.3	$91.4	$30.5	$608.5	$1,165.4
12	$0.0	$0.0	$0.0	$0.0	$0.0	$186.5	$93.3	$782.1	$1,061.9
13	$0.0	$0.0	$0.0	$75.1	$0.0	$0.0	$0.0	$51.0	$126.1
14	$0.0	$0.0	$0.0	$76.6	$0.0	$0.0	$0.0	$47.7	$124.3
15	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
16	$0.0	$0.0	$0.0	$79.7	$0.0	$0.0	$0.0	$0.0	$79.7
17	$0.0	$0.0	$0.0	$81.3	$0.0	$0.0	$0.0	$0.0	$81.3
18	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
19	$0.0	$0.0	$0.0	$84.6	$0.0	$0.0	$0.0	$0.0	$84.6
20	$0.0	$0.0	$0.0	$86.3	$0.0	$0.0	$0.0	$0.0	$86.3
21	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
22	$0.0	$0.0	$0.0	$89.7	$0.0	$0.0	$0.0	$0.0	$89.7
23	$0.0	$0.0	$0.0	$91.5	$0.0	$0.0	$0.0	$0.0	$91.5
24	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
25	$0.0	$0.0	$0.0	$95.2	$0.0	$0.0	$0.0	$0.0	$95.2
26	$0.0	$0.0	$0.0	$97.1	$0.0	$0.0	$0.0	$0.0	$97.1
27	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

28	$0.0	$0.0	$0.0	$101.1	$0.0	$0.0	$0.0	$0.0	$101.1
29	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
30	$0.0	$33.6	$0.0	$105.1	$0.0	$0.0	$0.0	$0.0	$138.7
31	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
32	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
33	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
34	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
35	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
36	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$200.0	$200.0
Total	**$80.8**	**$58.5**	**$531.3**	**$1,635.0**	**$430.3**	**$277.9**	**$123.7**	**$2,031.6**	**$5,169.2**

Table 2E.6: Select Statistics for Short Pipeline Wet Gas Scenario (As-Spent-Dollar Prices) (Continued)

Year	Operating Cost ($ M)	Domestic Pipeline Transport Cost ($ M)	Daily Production Raw Natural Gas (mmcf)	Daily Production Sales Natural Gas (mmcf)	Annual Production Condensate (mm bbls)	Annual Production Butane (mm bbls)	Annual Production Propane (mm bbls)
1	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
2	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
3	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
4	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
5	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
6	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
7	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
8	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
9	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
10	$7.0	$0.0	0.0	0.0	0.00	0.00	0.00
11	$22.9	$0.0	0.0	0.0	0.00	0.00	0.00
12	$100.4	$100.0	236.5	220.4	0.41	1.03	0.97
13	$115.3	$204.1	472.9	440.8	0.41	2.05	1.93
14	$117.6	$208.2	472.9	440.8	0.41	2.05	1.93
15	$119.9	$212.3	472.9	440.8	0.41	2.05	1.93
16	$122.3	$216.6	472.9	440.8	0.41	2.05	1.93
17	$124.8	$220.9	472.9	440.8	0.41	2.05	1.93
18	$127.3	$225.3	472.9	440.8	0.41	2.05	1.93
19	$129.8	$229.8	472.9	440.8	0.41	2.05	1.93
20	$132.4	$234.4	472.9	440.8	0.41	2.05	1.93
21	$135.1	$239.1	472.9	440.8	0.41	2.05	1.93
22	$137.8	$243.9	472.9	440.8	0.41	2.05	1.93
23	$140.5	$248.8	472.9	440.8	0.41	2.05	1.93
24	$143.3	$253.7	472.9	440.8	0.41	2.05	1.93
25	$139.0	$201.6	368.4	343.4	0.41	1.60	1.51
26	$136.0	$160.2	287.0	267.5	0.41	1.25	1.17
27	$134.2	$127.3	223.6	208.4	0.41	0.97	0.91

28	$133.3	$101.1	174.2	162.3	0.41	0.76	0.71
29	$133.0	$80.4	135.7	126.5	0.41	0.59	0.55
30	$133.4	$63.9	105.7	98.5	0.41	0.46	0.43
31	$134.3	$50.7	82.3	76.7	0.41	0.36	0.34
32	$135.5	$40.3	64.1	59.8	0.41	0.28	0.26
33	$137.1	$32.0	50.0	46.6	0.41	0.22	0.20
34	$138.9	$25.5	38.9	36.3	0.41	0.17	0.16
35	$141.0	$20.2	30.3	28.3	0.41	0.13	0.12
36	$143.2	$16.1	23.6	22.0	0.41	0.10	0.10
Total	**$3,315.3**	**$3,756.0**	**2,736**	**2,550**	**10.1**	**32.6**	**30.6**

*Gas production totals = production over life of field.

Table 2E.7: Select Statistics for Long Pipeline Wet Gas Scenario – (2006 Prices)

Year	Seismic Surveys Cost ($ M)	Mobilization Demobilization Cost $M)	Exploration & Delineation Wells Cost ($ M)	Development Drilling Cost ($ M)	Longer Pipeline Capital Cost ($ M)	Onshore Gas Plant Capital Cost ($ M)	Onshore NGL Plant Capital Cost ($ M)	Production Facility & Other Capital Cost ($ M)	Total Finding & Development Cost ($ M)
1	$40.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$40.0
2	$40.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$40.0
3	$0.0	$23.9	$142.6	$0.0	$0.0	$0.0	$0.0	$0.0	$166.5
4	$0.0	$0.0	$142.6	$0.0	$0.0	$0.0	$0.0	$0.0	$142.6
5	$0.0	$0.0	$213.9	$0.0	$0.0	$0.0	$0.0	$0.0	$213.9
6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$5.2	$5.2
7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$10.4	$10.4
8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$15.3	$15.3
9	$0.0	$0.0	$0.0	$0.0	$240.0	$0.0	$0.0	$25.7	$265.7
10	$0.0	$0.0	$0.0	$236.8	$240.0	$0.0	$0.0	$232.0	$708.8
11	$0.0	$0.0	$0.0	$236.8	$240.0	$75.0	$25.0	$499.2	$1,076.0
12	$0.0	$0.0	$0.0	$0.0	$0.0	$150.0	$75.0	$629.0	$854.0
13	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$40.2	$99.4
14	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$36.9	$96.1
15	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
16	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$0.0	$59.2
17	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$0.0	$59.2
18	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
19	$0.0	$18.9	$0.0	$59.2	$0.0	$0.0	$0.0	$0.0	$59.2
20	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$0.0	$59.2
21	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
22	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$0.0	$59.2
23	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$0.0	$59.2
24	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
25	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$0.0	$59.2
26	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$0.0	$59.2
27	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
28	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$0.0	$59.2

29	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
30	$0.0	$0.0	$0.0	$59.2	$0.0	$0.0	$0.0	$0.0	$78.1
31	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
32	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
33	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
34	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
35	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
36	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$100.0	$100.0
Total	**$80.0**	**$42.8**	**$499.2**	**$1,184.2**	**$720.0**	**$225.0**	**$100.0**	**$1,593.8**	**$4,445.0**

Table 2E.7: Select Statistics for Long Pipeline Wet Gas Scenario – (2006 Prices) (Continued)

Year	Operating Cost ($ M)	Domestic Pipeline Transport Cost ($ M)	Daily Production Raw Natural Gas (mmcf)	Daily Production Sales Natural Gas (mmcf)	Annual Production Condensate (mm bbls)	Annual Production Butane (mm bbls)	Annual Production Propane (mm bbls)
1	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
2	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
3	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
4	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
5	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
6	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
7	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
8	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
9	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
10	$5.9	$0.0	0.0	0.0	0.00	0.00	0.00
11	$18.8	$0.0	0.0	0.0	0.00	0.00	0.00
12	$80.7	$80.5	236.5	220.4	0.41	1.03	0.97
13	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
14	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
15	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
16	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
17	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
18	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
19	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
20	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
21	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
22	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
23	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
24	$90.9	$160.9	472.9	440.8	0.41	2.05	1.93
25	$86.4	$125.3	368.4	343.4	0.41	1.60	1.51
26	$82.9	$97.6	287.0	267.5	0.41	1.25	1.17
27	$80.2	$76.1	223.6	208.4	0.41	0.97	0.91
28	$78.1	$59.3	174.2	162.3	0.41	0.76	0.71

29	$76.4	$46.2	135.7	126.5	0.41	0.59	0.55
30	$75.1	$36.0	105.7	98.5	0.41	0.46	0.43
31	$74.1	$28.0	82.3	76.7	0.41	0.36	0.34
32	$73.3	$21.8	64.1	59.8	0.41	0.28	0.26
33	$72.7	$17.0	50.0	46.6	0.41	0.22	0.20
34	$72.3	$13.2	38.9	36.3	0.41	0.17	0.16
35	$71.9	$10.3	30.3	28.3	0.41	0.13	0.12
36	$71.6	$8.0	23.6	22.0	0.41	0.10	0.10
Total	**$2,111.3**	**$2,550.0**	**2,736**	**2,550**	**10.1**	**32.6**	**30.6**

*Gas production totals = production over life of field.

Table 2E.8: Select Statistics for Long Pipeline Wet Gas Scenario (As-Spent-Dollar Prices)

Year	Seismic Surveys Cost ($ M)	Mobilization Demobilization Cost $M)	Exploration & Delineation Wells Cost ($ M)	Development Drilling Cost ($ M)	Longer Pipeline Capital Cost ($ M)	Onshore Gas Plant Capital Cost ($ M)	Onshore NGL Plant Capital Cost ($ M)	Production Facility & Other Capital Cost ($ M)	Total Finding & Development Cost ($ M)
1	$40.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$40.0
2	$40.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$40.8
3	$0.0	$24.9	$148.4	$0.0	$0.0	$0.0	$0.0	$0.0	$173.3
4	$0.0	$0.0	$151.3	$0.0	$0.0	$0.0	$0.0	$0.0	$151.3
5	$0.0	$0.0	$231.6	$0.0	$0.0	$0.0	$0.0	$0.0	$231.6
6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$5.7	$5.7
7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$11.7	$11.7
8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$17.6	$17.6
9	$0.0	$0.0	$0.0	$0.0	$281.2	$0.0	$0.0	$30.1	$311.3
10	$0.0	$0.0	$0.0	$283.0	$286.8	$0.0	$0.0	$277.3	$847.1
11	$0.0	$0.0	$0.0	$288.7	$292.6	$91.4	$30.5	$608.5	$1,311.7
12	$0.0	$0.0	$0.0	$0.0	$0.0	$186.5	$93.3	$782.1	$1,061.9
13	$0.0	$0.0	$0.0	$75.1	$0.0	$0.0	$0.0	$51.0	$126.1
14	$0.0	$0.0	$0.0	$76.6	$0.0	$0.0	$0.0	$47.7	$124.3
15	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
16	$0.0	$0.0	$0.0	$79.7	$0.0	$0.0	$0.0	$0.0	$79.7
17	$0.0	$0.0	$0.0	$81.3	$0.0	$0.0	$0.0	$0.0	$81.3
18	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
19	$0.0	$0.0	$0.0	$84.6	$0.0	$0.0	$0.0	$0.0	$84.6
20	$0.0	$0.0	$0.0	$86.3	$0.0	$0.0	$0.0	$0.0	$86.3
21	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
22	$0.0	$0.0	$0.0	$89.7	$0.0	$0.0	$0.0	$0.0	$89.7
23	$0.0	$0.0	$0.0	$91.5	$0.0	$0.0	$0.0	$0.0	$91.5
24	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
25	$0.0	$0.0	$0.0	$95.2	$0.0	$0.0	$0.0	$0.0	$95.2
26	$0.0	$0.0	$0.0	$97.1	$0.0	$0.0	$0.0	$0.0	$97.1
27	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

28	$0.0	$0.0	$0.0	$101.1	$0.0	$0.0	$0.0	$0.0	$101.1
29	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
30	$0.0	$33.6	$0.0	$105.1	$0.0	$0.0	$0.0	$0.0	$138.7
31	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
32	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
33	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
34	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
35	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
36	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$200.0	$200.0
Total	**$80.8**	**$58.5**	**$531.3**	**$1,635.0**	**$860.6**	**$277.9**	**$123.7**	**$2,031.6**	**$5,599.4**

Table 2E.8: Select Statistics for Long Pipeline Wet Gas Scenario (As-Spent-Dollar Prices) (Continued)

Year	Operating Cost ($ M)	Domestic Pipeline Transport Cost ($ M)	Daily Production Raw Natural Gas (mmcf)	Daily Production Sales Natural Gas (mmcf)	Annual Production Condensate (mm bbls)	Annual Production Butane (mm bbls)	Annual Production Propane (mm bbls)
1	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
2	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
3	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
4	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
5	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
6	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
7	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
8	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
9	$0.0	$0.0	0.0	0.0	0.00	0.00	0.00
10	$7.0	$0.0	0.0	0.0	0.00	0.00	0.00
11	$22.9	$0.0	0.0	0.0	0.00	0.00	0.00
12	$100.4	$100.0	236.5	220.4	0.41	1.03	0.97
13	$115.3	$204.1	472.9	440.8	0.41	2.05	1.93
14	$117.6	$208.2	472.9	440.8	0.41	2.05	1.93
15	$119.9	$212.3	472.9	440.8	0.41	2.05	1.93
16	$122.3	$216.6	472.9	440.8	0.41	2.05	1.93
17	$124.8	$220.9	472.9	440.8	0.41	2.05	1.93
18	$127.3	$225.3	472.9	440.8	0.41	2.05	1.93
19	$129.8	$229.8	472.9	440.8	0.41	2.05	1.93
20	$132.4	$234.4	472.9	440.8	0.41	2.05	1.93
21	$135.1	$239.1	472.9	440.8	0.41	2.05	1.93
22	$137.8	$243.9	472.9	440.8	0.41	2.05	1.93
23	$140.5	$248.8	472.9	440.8	0.41	2.05	1.93
24	$143.3	$253.7	472.9	440.8	0.41	2.05	1.93
25	$139.0	$201.6	368.4	343.4	0.41	1.60	1.51
26	$136.0	$160.2	287.0	267.5	0.41	1.25	1.17
27	$134.2	$127.3	223.6	208.4	0.41	0.97	0.91

28	$133.3	$101.1	174.2	162.3	0.41	0.76	0.71
29	$133.0	$80.4	135.7	126.5	0.41	0.59	0.55
30	$133.4	$63.9	105.7	98.5	0.41	0.46	0.43
31	$134.3	$50.7	82.3	76.7	0.41	0.36	0.34
32	$135.5	$40.3	64.1	59.8	0.41	0.28	0.26
33	$137.1	$32.0	50.0	46.6	0.41	0.22	0.20
34	$138.9	$25.5	38.9	36.3	0.41	0.17	0.16
35	$141.0	$20.2	30.3	28.3	0.41	0.13	0.12
36	$143.2	$16.1	23.6	22.0	0.41	0.10	0.10
Total	**$3,315.3**	**$3,756.0**	**2,736**	**2,550**	**10.1**	**32.6**	**30.6**

*Gas production totals = production over life of field.

Table 2E.9: Select Statistics for Short Pipeline Dry Gas Scenario – (2006 Prices)

Year	Seismic Surveys Cost ($ M)	Mobilization Demobilization Cost $M)	Exploration & Delineation Wells Cost ($ M)	Development Drilling Cost ($ M)	Shorter Pipeline Capital Cost ($ M)	Onshore Gas Plant Capital Cost ($ M)	Onshore NGL Plant Capital Cost ($ M)	Production Facility & Other Capital Cost ($ M)	Total Finding & Development Cost ($ M)
1	$40.0	$0.0	$0.0	$0.0	$0.0			$0.0	$40.0
2	$40.0	$0.0	$0.0	$0.0	$0.0			$0.0	$40.0
3	$0.0	$23.9	$142.6	$0.0	$0.0			$0.0	$166.5
4	$0.0	$0.0	$142.6	$0.0	$0.0			$0.0	$142.6
5	$0.0	$0.0	$213.9	$0.0	$0.0			$0.0	$213.9
6	$0.0	$0.0	$0.0	$0.0	$0.0			$5.2	$5.2
7	$0.0	$0.0	$0.0	$0.0	$0.0			$10.4	$10.4
8	$0.0	$0.0	$0.0	$0.0	$0.0			$15.3	$15.3
9	$0.0	$0.0	$0.0	$0.0	$120.0			$25.7	$145.7
10	$0.0	$0.0	$0.0	$236.8	$120.0			$232.0	$588.8
11	$0.0	$0.0	$0.0	$236.8	$120.0			$574.2	$931.0
12	$0.0	$0.0	$0.0	$0.0	$0.0			$779.0	$779.0
13	$0.0	$0.0	$0.0	$59.2	$0.0			$40.2	$99.4
14	$0.0	$0.0	$0.0	$59.2	$0.0			$36.9	$96.1
15	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
16	$0.0	$0.0	$0.0	$59.2	$0.0			$0.0	$59.2
17	$0.0	$0.0	$0.0	$59.2	$0.0			$0.0	$59.2
18	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
19	$0.0	$18.9	$0.0	$59.2	$0.0			$0.0	$59.2
20	$0.0	$0.0	$0.0	$59.2	$0.0			$0.0	$59.2
21	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
22	$0.0	$0.0	$0.0	$59.2	$0.0			$0.0	$59.2
23	$0.0	$0.0	$0.0	$59.2	$0.0			$0.0	$59.2
24	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
25	$0.0	$0.0	$0.0	$59.2	$0.0			$0.0	$59.2
26	$0.0	$0.0	$0.0	$59.2	$0.0			$0.0	$59.2
27	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
28	$0.0	$0.0	$0.0	$59.2	$0.0			$0.0	$59.2

29	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
30	$0.0	$0.0	$0.0	$59.2	$0.0			$0.0	$78.1
31	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
32	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
33	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
34	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
35	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
36	$0.0	$0.0	$0.0	$0.0	$0.0			$100.0	$100.0
Total	**$80.0**	**$42.8**	**$499.2**	**$1,184.2**	**$360.0**			**$1,818.8**	**$3,985.0**

Table 2E.9: Select Statistics for Short Pipeline Dry Gas Scenario – (2006 Prices) (Continued)

Year	Operating Cost ($ M)	Domestic Pipeline Transport Cost ($ M)	Daily Production Raw Natural Gas (mmcf)	Daily Production Sales Natural Gas (mmcf)	Annual Production Condensate (mm bbls)	Annual Production Butane (mm bbls)	Annual Production Propane (mm bbls)
1	$0.0	$0.0	0.0	0.0			
2	$0.0	$0.0	0.0	0.0			
3	$0.0	$0.0	0.0	0.0			
4	$0.0	$0.0	0.0	0.0			
5	$0.0	$0.0	0.0	0.0			
6	$0.0	$0.0	0.0	0.0			
7	$0.0	$0.0	0.0	0.0			
8	$0.0	$0.0	0.0	0.0			
9	$0.0	$0.0	0.0	0.0			
10	$5.9	$0.0	0.0	0.0			
11	$18.8	$0.0	0.0	0.0			
12	$80.7	$83.7	236.5	229.4			
13	$90.9	$167.4	472.9	458.7			
14	$90.9	$167.4	472.9	458.7			
15	$90.9	$167.4	472.9	458.7			
16	$90.9	$167.4	472.9	458.7			
17	$90.9	$167.4	472.9	458.7			
18	$90.9	$167.4	472.9	458.7			
19	$90.9	$167.4	472.9	458.7			
20	$90.9	$167.4	472.9	458.7			
21	$90.9	$167.4	472.9	458.7			
22	$90.9	$167.4	472.9	458.7			
23	$90.9	$167.4	472.9	458.7			
24	$90.9	$167.4	472.9	458.7			
25	$86.4	$130.4	368.4	357.4			
26	$82.9	$101.6	287.0	278.4			
27	$80.2	$79.2	223.6	216.9			
28	$78.1	$61.7	174.2	168.9			

29	$76.4	$48.0	135.7	131.6			
30	$75.1	$37.4	105.7	102.5			
31	$74.1	$29.1	82.3	79.9			
32	$73.3	$22.7	64.1	62.2			
33	$72.7	$17.7	50.0	48.5			
34	$72.3	$13.8	38.9	37.8			
35	$71.9	$10.7	30.3	29.4			
36	$71.6	$8.4	23.6	22.9			
Total	**$2,111.3**	**$2,653.7**	**2,736**	**2,654**			

*Gas production totals = production over life of field.

Table 2E.10: Select Statistics for Short Pipeline Dry Gas Scenario (As-Spent-Dollar Prices)

Year	Seismic Surveys Cost ($ M)	Mobilization Demobilization Cost $M)	Exploration & Delineation Wells Cost ($ M)	Development Drilling Cost ($ M)	Shorter Pipeline Capital Cost ($ M)	Onshore Gas Plant Capital Cost ($ M)	Onshore NGL Plant Capital Cost ($ M)	Production Facility & Other Capital Cost ($ M)	Total Finding & Development Cost ($ M)
1	$40.0	$0.0	$0.0	$0.0	$0.0			$0.0	$40.0
2	$40.8	$0.0	$0.0	$0.0	$0.0			$0.0	$40.8
3	$0.0	$24.9	$148.4	$0.0	$0.0			$0.0	$173.3
4	$0.0	$0.0	$151.3	$0.0	$0.0			$0.0	$151.3
5	$0.0	$0.0	$231.6	$0.0	$0.0			$0.0	$231.6
6	$0.0	$0.0	$0.0	$0.0	$0.0			$5.7	$5.7
7	$0.0	$0.0	$0.0	$0.0	$0.0			$11.7	$11.7
8	$0.0	$0.0	$0.0	$0.0	$0.0			$17.6	$17.6
9	$0.0	$0.0	$0.0	$0.0	$140.6			$30.1	$170.7
10	$0.0	$0.0	$0.0	$283.0	$143.4			$277.3	$703.7
11	$0.0	$0.0	$0.0	$288.7	$146.3			$700.0	$1,134.9
12	$0.0	$0.0	$0.0	$0.0	$0.0			$968.6	$968.6
13	$0.0	$0.0	$0.0	$75.1	$0.0			$51.0	$126.1
14	$0.0	$0.0	$0.0	$76.6	$0.0			$47.7	$124.3
15	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
16	$0.0	$0.0	$0.0	$79.7	$0.0			$0.0	$79.7
17	$0.0	$0.0	$0.0	$81.3	$0.0			$0.0	$81.3
18	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
19	$0.0	$0.0	$0.0	$84.6	$0.0			$0.0	$84.6
20	$0.0	$0.0	$0.0	$86.3	$0.0			$0.0	$86.3
21	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
22	$0.0	$0.0	$0.0	$89.7	$0.0			$0.0	$89.7
23	$0.0	$0.0	$0.0	$91.5	$0.0			$0.0	$91.5
24	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
25	$0.0	$0.0	$0.0	$95.2	$0.0			$0.0	$95.2
26	$0.0	$0.0	$0.0	$97.1	$0.0			$0.0	$97.1
27	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0

28	$0.0	$0.0	$0.0	$101.1	$0.0			$0.0	$101.1
29	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
30	$0.0	$33.6	$0.0	$105.1	$0.0			$0.0	$138.7
31	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
32	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
33	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
34	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
35	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
36	$0.0	$0.0	$0.0	$0.0	$0.0			$200.0	$200.0
Total	**$80.8**	**$58.5**	**$531.3**	**$1,635.0**	**$430.3**			**$2,309.6**	**$5,045.4**

Table 2E.10: Select Statistics for Short Pipeline Dry Gas Scenario (As-Spent-Dollar Prices) (Continued)

Year	Operating Cost ($ M)	Domestic Pipeline Transport Cost ($ M)	Daily Production Raw Natural Gas (mmcf)	Daily Production Sales Natural Gas (mmcf)	Annual Production Condensate (mm bbls)	Annual Production Butane (mm bbls)	Annual Production Propane (mm bbls)
1	$0.0	$0.0	0.0	0.0			
2	$0.0	$0.0	0.0	0.0			
3	$0.0	$0.0	0.0	0.0			
4	$0.0	$0.0	0.0	0.0			
5	$0.0	$0.0	0.0	0.0			
6	$0.0	$0.0	0.0	0.0			
7	$0.0	$0.0	0.0	0.0			
8	$0.0	$0.0	0.0	0.0			
9	$0.0	$0.0	0.0	0.0			
10	$7.0	$0.0	0.0	0.0			
11	$22.9	$0.0	0.0	0.0			
12	$100.4	$104.1	236.5	229.4			
13	$115.3	$212.4	472.9	458.7			
14	$117.6	$216.6	472.9	458.7			
15	$119.9	$220.9	472.9	458.7			
16	$122.3	$225.4	472.9	458.7			
17	$124.8	$229.9	472.9	458.7			
18	$127.3	$234.5	472.9	458.7			
19	$129.8	$239.1	472.9	458.7			
20	$132.4	$243.9	472.9	458.7			
21	$135.1	$248.8	472.9	458.7			
22	$137.8	$253.8	472.9	458.7			
23	$140.5	$258.9	472.9	458.7			
24	$143.3	$264.0	472.9	458.7			
25	$139.0	$209.8	368.4	357.4			
26	$136.0	$166.7	287.0	278.4			
27	$134.2	$132.5	223.6	216.9			

28	$133.3	$105.2	174.2	168.9			
29	$133.0	$83.6	135.7	131.6			
30	$133.4	$66.4	105.7	102.5			
31	$134.3	$52.8	82.3	79.9			
32	$135.5	$42.0	64.1	62.2			
33	$137.1	$33.3	50.0	48.5			
34	$138.9	$26.5	38.9	37.8			
35	$141.0	$21.0	30.3	29.4			
36	$143.2	$16.7	23.6	22.9			
Total	**$3,315.3**	**$3,908.8**	**2,736**	**2,654**			

*Gas production totals = production over life of field.

Table 2E.11: Select Statistics for Long Pipeline Dry Gas Scenario – (2006 Prices)

Year	Seismic Surveys Cost ($ M)	Mobilization Demobilization Cost $M)	Exploration & Delineation Wells Cost ($ M)	Development Drilling Cost ($ M)	Longer Pipeline Capital Cost ($ M)	Onshore Gas Plant Capital Cost ($ M)	Onshore NGL Plant Capital Cost ($ M)	Production Facility & Other Capital Cost ($ M)	Total Finding & Development Cost ($ M)
1	$40.0	$0.0	$0.0	$0.0	$0.0			$0.0	$40.0
2	$40.0	$0.0	$0.0	$0.0	$0.0			$0.0	$40.0
3	$0.0	$23.9	$142.6	$0.0	$0.0			$0.0	$166.5
4	$0.0	$0.0	$142.6	$0.0	$0.0			$0.0	$142.6
5	$0.0	$0.0	$213.9	$0.0	$0.0			$0.0	$213.9
6	$0.0	$0.0	$0.0	$0.0	$0.0			$5.2	$5.2
7	$0.0	$0.0	$0.0	$0.0	$0.0			$10.4	$10.4
8	$0.0	$0.0	$0.0	$0.0	$0.0			$15.3	$15.3
9	$0.0	$0.0	$0.0	$0.0	$240.0			$25.7	$265.7
10	$0.0	$0.0	$0.0	$236.8	$240.0			$232.0	$708.8
11	$0.0	$0.0	$0.0	$236.8	$240.0			$574.2	$1,051.0
12	$0.0	$0.0	$0.0	$0.0	$0.0			$779.0	$779.0
13	$0.0	$0.0	$0.0	$59.2	$0.0			$40.2	$99.4
14	$0.0	$0.0	$0.0	$59.2	$0.0			$36.9	$96.1
15	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
16	$0.0	$0.0	$0.0	$59.2	$0.0			$0.0	$59.2
17	$0.0	$0.0	$0.0	$59.2	$0.0			$0.0	$59.2
18	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
19	$0.0	$0.0	$0.0	$59.2	$0.0			$0.0	$59.2
20	$0.0	$0.0	$0.0	$59.2	$0.0			$0.0	$59.2
21	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
22	$0.0	$0.0	$0.0	$59.2	$0.0			$0.0	$59.2
23	$0.0	$0.0	$0.0	$59.2	$0.0			$0.0	$59.2
24	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
25	$0.0	$0.0	$0.0	$59.2	$0.0			$0.0	$59.2
26	$0.0	$0.0	$0.0	$59.2	$0.0			$0.0	$59.2
27	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
28	$0.0	$0.0	$0.0	$59.2	$0.0			$0.0	$59.2

29	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
30	$0.0	$18.9	$0.0	$59.2	$0.0			$0.0	$78.1
31	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
32	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
33	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
34	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
35	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
36	$0.0	$0.0	$0.0	$0.0	$0.0			$100.0	$100.0
Total	**$80.0**	**$42.8**	**$499.2**	**$1,184.2**	**$720.0**			**$1,818.8**	**$4,345.0**

Table 2E.11: Select Statistics for Long Pipeline Dry Gas Scenario – (2006 Prices) (Continued)

Year	Operating Cost ($ M)	Domestic Pipeline Transport Cost ($ M)	Daily Production Raw Natural Gas (mmcf)	Daily Production Sales Natural Gas (mmcf)	Annual Production Condensate (mm bbls)	Annual Production Butane (mm bbls)	Annual Production Propane (mm bbls)
1	$0.0	$0.0	0.0	0.0			
2	$0.0	$0.0	0.0	0.0			
3	$0.0	$0.0	0.0	0.0			
4	$0.0	$0.0	0.0	0.0			
5	$0.0	$0.0	0.0	0.0			
6	$0.0	$0.0	0.0	0.0			
7	$0.0	$0.0	0.0	0.0			
8	$0.0	$0.0	0.0	0.0			
9	$0.0	$0.0	0.0	0.0			
10	$5.9	$0.0	0.0	0.0			
11	$18.8	$0.0	0.0	0.0			
12	$80.7	$83.7	236.5	229.4			
13	$90.9	$167.4	472.9	458.7			
14	$90.9	$167.4	472.9	458.7			
15	$90.9	$167.4	472.9	458.7			
16	$90.9	$167.4	472.9	458.7			
17	$90.9	$167.4	472.9	458.7			
18	$90.9	$167.4	472.9	458.7			
19	$90.9	$167.4	472.9	458.7			
20	$90.9	$167.4	472.9	458.7			
21	$90.9	$167.4	472.9	458.7			
22	$90.9	$167.4	472.9	458.7			
23	$90.9	$167.4	472.9	458.7			
24	$90.9	$167.4	472.9	458.7			
25	$86.4	$130.4	368.4	357.4			
26	$82.9	$101.6	287.0	278.4			
27	$80.2	$79.2	223.6	216.9			
28	$78.1	$61.7	174.2	168.9			

29	$76.4	$48.0	135.7	131.6			
30	$75.1	$37.4	105.7	102.5			
31	$74.1	$29.1	82.3	79.9			
32	$73.3	$22.7	64.1	62.2			
33	$72.7	$17.7	50.0	48.5			
34	$72.3	$13.8	38.9	37.8			
35	$71.9	$10.7	30.3	29.4			
36	$71.6	$8.4	23.6	22.9			
Total	**$2,111.3**	**$2,653.7**	**2,736**	**2,654**			

*Gas production totals = production over life of field.

Table 2E.12: Select Statistics for Long Pipeline Dry Gas Scenario (As-Spent-Dollar Prices)

Year	Seismic Surveys Cost ($ M)	Mobilization Demobilization Cost $M)	Exploration & Delineation Wells Cost ($ M)	Development Drilling Cost ($ M)	Longer Pipeline Capital Cost ($ M)	Onshore Gas Plant Capital Cost ($ M)	Onshore NGL Plant Capital Cost ($ M)	Production Facility & Other Capital Cost ($ M)	Total Finding & Development Cost ($ M)
1	$40.0	$0.0	$0.0	$0.0	$0.0			$0.0	$40.0
2	$40.8	$0.0	$0.0	$0.0	$0.0			$0.0	$40.8
3	$0.0	$24.9	$148.4	$0.0	$0.0			$0.0	$173.3
4	$0.0	$0.0	$151.3	$0.0	$0.0			$0.0	$151.3
5	$0.0	$0.0	$231.6	$0.0	$0.0			$0.0	$231.6
6	$0.0	$0.0	$0.0	$0.0	$0.0			$5.7	$5.7
7	$0.0	$0.0	$0.0	$0.0	$0.0			$11.7	$11.7
8	$0.0	$0.0	$0.0	$0.0	$0.0			$17.6	$17.6
9	$0.0	$0.0	$0.0	$0.0	$281.2			$30.1	$311.3
10	$0.0	$0.0	$0.0	$283.0	$286.8			$277.3	$847.1
11	$0.0	$0.0	$0.0	$288.7	$292.6			$700.0	$1,281.2
12	$0.0	$0.0	$0.0	$0.0	$0.0			$968.6	$968.6
13	$0.0	$0.0	$0.0	$75.1	$0.0			$51.0	$126.1
14	$0.0	$0.0	$0.0	$76.6	$0.0			$47.7	$124.3
15	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
16	$0.0	$0.0	$0.0	$79.7	$0.0			$0.0	$79.7
17	$0.0	$0.0	$0.0	$81.3	$0.0			$0.0	$81.3
18	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
19	$0.0	$0.0	$0.0	$84.6	$0.0			$0.0	$84.6
20	$0.0	$0.0	$0.0	$86.3	$0.0			$0.0	$86.3
21	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
22	$0.0	$0.0	$0.0	$89.7	$0.0			$0.0	$89.7
23	$0.0	$0.0	$0.0	$91.5	$0.0			$0.0	$91.5
24	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
25	$0.0	$0.0	$0.0	$95.2	$0.0			$0.0	$95.2
26	$0.0	$0.0	$0.0	$97.1	$0.0			$0.0	$97.1
27	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
28	$0.0	$0.0	$0.0	$101.1	$0.0			$0.0	$101.1

29	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
30	$0.0	$33.6	$0.0	$105.1	$0.0			$0.0	$138.7
31	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
32	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
33	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
34	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
35	$0.0	$0.0	$0.0	$0.0	$0.0			$0.0	$0.0
36	$0.0	$0.0	$0.0	$0.0	$0.0			$200.0	$200.0
Total	**$80.8**	**$58.5**	**$531.3**	**$1,635.0**	**$860.6**			**$2,309.6**	**$5,475.7**

Table 2E.12: Select Statistics for Long Pipeline Dry Gas Scenario (As-Spent-Dollar Prices) (Continued)

Year	Operating Cost ($ M)	Domestic Pipeline Transport Cost ($ M)	Daily Production Raw Natural Gas (mmcf)	Daily Production Sales Natural Gas (mmcf)	Annual Production Condensate (mm bbls)	Annual Production Butane (mm bbls)	Annual Production Propane (mm bbls)
1	$0.0	$0.0	0.0	0.0			
2	$0.0	$0.0	0.0	0.0			
3	$0.0	$0.0	0.0	0.0			
4	$0.0	$0.0	0.0	0.0			
5	$0.0	$0.0	0.0	0.0			
6	$0.0	$0.0	0.0	0.0			
7	$0.0	$0.0	0.0	0.0			
8	$0.0	$0.0	0.0	0.0			
9	$0.0	$0.0	0.0	0.0			
10	$7.0	$0.0	0.0	0.0			
11	$22.9	$0.0	0.0	0.0			
12	$100.4	$104.1	236.5	229.4			
13	$115.3	$212.4	472.9	458.7			
14	$117.6	$216.6	472.9	458.7			
15	$119.9	$220.9	472.9	458.7			
16	$122.3	$225.4	472.9	458.7			
17	$124.8	$229.9	472.9	458.7			
18	$127.3	$234.5	472.9	458.7			
19	$129.8	$239.1	472.9	458.7			
20	$132.4	$243.9	472.9	458.7			
21	$135.1	$248.8	472.9	458.7			
22	$137.8	$253.8	472.9	458.7			
23	$140.5	$258.9	472.9	458.7			
24	$143.3	$264.0	472.9	458.7			
25	$139.0	$209.8	368.4	357.4			
26	$136.0	$166.7	287.0	278.4			
27	$134.2	$132.5	223.6	216.9			

28	$133.3	$105.2	174.2	168.9			
29	$133.0	$83.6	135.7	131.6			
30	$133.4	$66.4	105.7	102.5			
31	$134.3	$52.8	82.3	79.9			
32	$135.5	$42.0	64.1	62.2			
33	$137.1	$33.3	50.0	48.5			
34	$138.9	$26.5	38.9	37.8			
35	$141.0	$21.0	30.3	29.4			
36	$143.2	$16.7	23.6	22.9			
Total	**$3,315.3**	**$3,908.8**	**2,736**	**2,654**			

*Gas production totals = production over life of field.

Appendices Section 3

Appendix 3A: Generic Offshore Royalties

Newfoundland and Labrador's Generic Offshore Oil Royalty

The generic offshore royalty defines two royalty bases – one for calculating basic royalties and one for calculating net royalties. Basic royalties are calculated as a percent of gross revenue, where gross revenue is equal to gross sales revenue less eligible transportation costs to the point of sale. Net royalties are calculated as a percent of net revenue after net royalty payout occurs. Net revenue is gross revenue less eligible costs. Net royalty payout occurs when the costs related to a particular project are recovered plus a specified return allowance on those costs. There are two tiers to the net royalty payout and each one has a different return allowance.

The royalty structure is illustrated by the following table.

Generic Offshore Oil Royalty Structure	
Basic Royalty	
Until the earliest of: (i) 20% of reserves (ii) 50 million bbl (iii) Simple payout	1.0%
Until the earliest of: (i) 100 million bbls of cumulative production (ii) Simple payout	2.5%
Next 100 million bbls	5.0%
Thereafter	7.5%
Net Royalty	
Tier I Rate Return Allowance	 20% 5% + Long Term Government Bond Rate
Tier II Rate Return Allowance	 10% 15% + Long Term Government Bond Rate

A more detailed explanation can be found at the Government of Newfoundland and Labrador's website (http://www.nr.gov.nl.ca/mines&en/exploration/offshore.pdf).

Nova Scotia's Offshore Natural Gas Generic Royalty – Base Regime

Nova Scotia's generic royalty has two revenue bases – (1) gross revenue (GR), which is the value of the petroleum leaving the boundary of an offshore project and (2) net revenue (NR) , which is the gross revenue of the project less the cost associated with getting the petroleum to the project boundary. It also has a return allowance which is a percentage of unrecovered project costs and it utilizes the long term Government of Canada bond rate (10 years) (LTBR). Once simple payout is achieved, the return allowance ceases to be calculated.

The royalty structure is given by the following table.

Generic Royalty Structure – Base Regime	
Gross Revenue Royalty	
Tier 1	2% GR, until simple payout + RA based on 5% plus LTBR
Tier 2	5% GR, until simple payout + RA based on 20% plus LTBR
Net Revenue Royalty	
Tier 3	20% NR, until simple payout + RA based on 45% plus LTBR (minimum of 5% of GR payable)
Tier 4	35% NR (minimum of 5% of GR payable)

A more detailed explanation can be found on the Government of Nova Scotia's website (http://www.gov.ns.ca:80/energy/AbsPage.aspx?siteid=1&lang=1&id=1585).

Appendix 3B: Results of Economic and Rent Analysis – Short Pipeline Oil Scenario ($2006)

Table 3B.1: Selected Statistics for Economic and Rent Analysis of Short Pipeline Oil Scenario - $20 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$242.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$242.1	-$112.9	$0.0	$0.0
10	$0.0	$962.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$968.2	-$410.6	$0.0	$0.0
11	$0.0	$1,234.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,253.2	-$483.2	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$367.1	$3.5	$0.0	$3.5	$0.0	-$783.7	-$274.7	$1.2	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$1,082.1	$16.8	$0.0	$16.8	$0.0	$475.9	$151.6	$5.4	$0.0
14	$0.0	$232.6	$237.8	$54.7	54.7	$1,082.1	$38.9	$0.0	$38.9	$0.0	$518.1	$150.1	$11.3	$0.0
15	$0.0	$177.6	$237.8	$54.7	54.7	$1,082.1	$51.4	$0.0	$51.4	$0.0	$560.6	$147.6	$13.5	$0.0
16	$0.0	$177.6	$237.8	$54.7	54.7	$1,082.1	$69.0	$0.0	$69.0	$0.0	$543.0	$130.0	$16.5	$0.0
17	$0.0	$177.6	$230.5	$50.6	50.6	$1,001.0	$71.3	$0.0	$71.3	$0.0	$470.9	$102.5	$15.5	$0.0
18	$0.0	$118.4	$223.8	$46.8	46.8	$925.9	$65.9	$35.3	$101.2	$65.1	$370.4	$73.3	$20.0	$12.9
19	$18.9	$118.4	$217.6	$43.3	43.3	$856.4	$61.0	$34.6	$95.6	$63.8	$298.7	$53.7	$17.2	$11.5
20	$0.0	$0.0	$211.9	$40.1	40.1	$792.2	$56.4	$38.9	$95.3	$71.7	$373.3	$61.0	$15.6	$11.7
21	$0.0	$0.0	$206.6	$37.1	37.1	$732.8	$52.2	$38.9	$91.1	$71.7	$326.3	$48.5	$13.5	$10.7
22	$0.0	$0.0	$201.7	$34.3	34.3	$677.8	$48.3	$37.7	$85.9	$69.5	$286.4	$38.7	$11.6	$9.4
23	$0.0	$0.0	$197.2	$31.7	31.7	$627.0	$44.6	$35.7	$80.3	$65.7	$252.1	$31.0	$9.9	$8.1
24	$0.0	$0.0	$193.0	$29.3	29.3	$580.0	$41.3	$33.2	$74.5	$61.2	$222.0	$24.8	$8.3	$6.8
25	$0.0	$100.0	$189.1	$27.1	27.1	$536.5	$38.2	$29.0	$67.2	$53.4	$99.7	$10.1	$6.8	$5.4
Total	**$622.0**	**$4,939.3**	**$2,917.9**	**$578.1**	**578.1**	**$11,425.1**	**$658.7**	**$283.2**	**$941.9**	**$522.1**	**$903.9**	**-$749.2**	**$166.4**	**$76.5**
											Nom IRR	**4.7%**		
											Real IRR	**2.6%**		

*****Totals do not always equal column sums due to rounding.

Table 3B.2: Selected Statistics for Economic and Rent Analysis of Short Pipeline Oil Scenario - $25 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$242.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$242.1	-$112.9	$0.0	$0.0
10	$0.0	$962.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$968.2	-$410.6	$0.0	$0.0
11	$0.0	$1,234.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,253.2	-$483.2	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$458.8	$4.4	$0.0	$4.4	$0.0	-$692.8	-$242.8	$1.5	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$1,352.6	$21.3	$0.0	$21.3	$0.0	$742.0	$236.4	$6.8	$0.0
14	$0.0	$232.6	$237.8	$54.7	54.7	$1,352.6	$49.1	$0.0	$49.1	$0.0	$778.4	$225.5	$14.2	$0.0
15	$0.0	$177.6	$237.8	$54.7	54.7	$1,352.6	$64.9	$19.5	$84.4	$35.9	$762.2	$200.7	$22.2	$9.5
16	$0.0	$177.6	$237.8	$54.7	54.7	$1,352.6	$87.2	$69.8	$157.0	$128.7	$596.8	$142.9	$37.6	$30.8
17	$0.0	$177.6	$230.5	$50.6	50.6	$1,251.2	$90.0	$65.8	$155.8	$121.2	$515.3	$112.2	$33.9	$26.4
18	$0.0	$118.4	$223.8	$46.8	46.8	$1,157.4	$83.3	$63.9	$147.2	$117.8	$503.3	$99.6	$29.1	$23.3
19	$18.9	$118.4	$217.6	$43.3	43.3	$1,070.6	$77.0	$58.4	$135.4	$107.6	$429.2	$77.2	$24.4	$19.4
20	$0.0	$0.0	$211.9	$40.1	40.1	$990.3	$71.3	$60.9	$132.1	$112.2	$494.0	$80.8	$21.6	$18.3
21	$0.0	$0.0	$206.6	$37.1	37.1	$916.0	$65.9	$59.2	$125.2	$109.2	$438.0	$65.1	$18.6	$16.2
22	$0.0	$0.0	$201.7	$34.3	34.3	$847.3	$61.0	$56.5	$117.5	$104.1	$389.7	$52.7	$15.9	$14.1
23	$0.0	$0.0	$197.2	$31.7	31.7	$783.7	$56.4	$53.1	$109.5	$97.8	$347.6	$42.7	$13.4	$12.0
24	$0.0	$0.0	$193.0	$29.3	29.3	$725.0	$52.2	$49.3	$101.5	$90.8	$310.4	$34.7	$11.3	$10.1
25	$0.0	$100.0	$189.1	$27.1	27.1	$670.6	$48.3	$43.9	$92.1	$80.8	$181.4	$18.4	$9.4	$8.2
Total	**$622.0**	**$4,939.3**	**$2,917.9**	**$578.1**	**578.1**	**$14,281.3**	**$832.2**	**$600.2**	**$1,432.4**	**$1,106.3**	**$2,685.5**	**-$351.6**	**$259.9**	**$188.3**
											Nom IRR	**9.0%**		
											Real IRR	**6.9%**		

*Totals do not always equal column sums due to rounding.

Table 3B.3: Selected Statistics for Economic and Rent Analysis of Short Pipeline Oil Scenario - $30 US/bb l

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$242.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$242.1	-$112.9	$0.0	$0.0
10	$0.0	$962.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$968.2	-$410.6	$0.0	$0.0
11	$0.0	$1,234.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,253.2	-$483.2	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$550.6	$5.3	$0.0	$5.3	$0.0	-$602.0	-$211.0	$1.9	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$1,623.2	$25.7	$0.0	$25.7	$0.0	$1,008.1	$321.2	$8.2	$0.0
14	$0.0	$232.6	$237.8	$54.7	54.7	$1,623.2	$59.3	$28.8	$88.1	$53.1	$956.7	$277.1	$25.5	$15.4
15	$0.0	$177.6	$237.8	$54.7	54.7	$1,623.2	$78.4	$93.7	$172.1	$172.6	$808.3	$212.8	$45.3	$45.5
16	$0.0	$177.6	$237.8	$54.7	54.7	$1,623.2	$105.3	$100.1	$205.4	$184.5	$763.0	$182.7	$49.2	$44.2
17	$0.0	$177.6	$230.5	$50.6	50.6	$1,501.4	$108.8	$93.5	$202.4	$172.4	$667.8	$145.3	$44.0	$37.5
18	$0.0	$118.4	$223.8	$46.8	46.8	$1,388.8	$100.6	$89.6	$190.2	$165.2	$644.3	$127.5	$37.6	$32.7
19	$18.9	$118.4	$217.6	$43.3	43.3	$1,284.7	$93.1	$82.2	$175.3	$151.5	$559.6	$100.7	$31.5	$27.2
20	$0.0	$0.0	$211.9	$40.1	40.1	$1,188.3	$129.4	$77.6	$207.1	$143.1	$586.1	$95.8	$33.9	$23.4
21	$0.0	$0.0	$206.6	$37.1	37.1	$1,099.2	$175.1	$68.1	$243.2	$125.6	$486.7	$72.3	$36.2	$18.7
22	$0.0	$0.0	$201.7	$34.3	34.3	$1,016.8	$159.7	$65.0	$224.6	$119.8	$436.3	$59.0	$30.4	$16.2
23	$0.0	$0.0	$197.2	$31.7	31.7	$940.5	$145.4	$61.2	$206.6	$112.8	$392.2	$48.2	$25.4	$13.9
24	$0.0	$0.0	$193.0	$29.3	29.3	$870.0	$132.1	$57.1	$189.2	$105.2	$353.2	$39.4	$21.1	$11.8
25	$0.0	$100.0	$189.1	$27.1	27.1	$804.7	$93.7	$54.5	$148.2	$100.4	$239.8	$24.3	$15.0	$10.2
Total	**$622.0**	**$4,939.3**	**$2,917.9**	**$578.1**	**578.1**	**$17,137.6**	**$1,412.1**	**$871.4**	**$2,283.5**	**$1,606.3**	**$4,190.6**	**-$2.0**	**$405.2**	**$296.5**
											Nom IRR	**12.2%**		
											Real IRR	**10.0%**		

*Totals do not always equal column sums due to rounding.

Table 3B.4: Selected Statistics for Economic and Rent Analysis of Short Pipeline Oil Scenario - $35 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$242.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$242.1	-$112.9	$0.0	$0.0
10	$0.0	$962.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$968.2	-$410.6	$0.0	$0.0
11	$0.0	$1,234.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,253.2	-$483.2	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$642.4	$6.2	$0.0	$6.2	$0.0	-$511.1	-$179.1	$2.2	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$1,893.7	$30.1	$0.0	$30.1	$0.0	$1,274.2	$406.0	$9.6	$0.0
14	$0.0	$232.6	$237.8	$54.7	54.7	$1,893.7	$69.5	$101.8	$171.4	$187.7	$1,009.4	$292.4	$49.6	$54.4
15	$0.0	$177.6	$237.8	$54.7	54.7	$1,893.7	$91.9	$124.5	$216.4	$229.5	$977.6	$257.4	$57.0	$60.4
16	$0.0	$177.6	$237.8	$54.7	54.7	$1,893.7	$123.5	$130.4	$253.9	$240.4	$929.3	$222.5	$60.8	$57.5
17	$0.0	$177.6	$230.5	$50.6	50.6	$1,751.7	$127.6	$121.3	$248.9	$223.6	$820.3	$178.5	$54.2	$48.7
18	$0.0	$118.4	$223.8	$46.8	46.8	$1,620.3	$233.1	$101.5	$334.6	$187.1	$709.6	$140.4	$66.2	$37.0
19	$18.9	$118.4	$217.6	$43.3	43.3	$1,498.8	$225.0	$92.0	$317.0	$169.6	$613.8	$110.4	$57.0	$30.5
20	$0.0	$0.0	$211.9	$40.1	40.1	$1,386.4	$231.5	$89.2	$320.6	$164.4	$649.4	$106.2	$52.4	$26.9
21	$0.0	$0.0	$206.6	$37.1	37.1	$1,282.4	$211.8	$85.7	$297.5	$158.0	$583.2	$86.7	$44.2	$23.5
22	$0.0	$0.0	$201.7	$34.3	34.3	$1,186.2	$193.6	$81.3	$274.8	$149.8	$525.6	$71.0	$37.1	$20.2
23	$0.0	$0.0	$197.2	$31.7	31.7	$1,097.2	$176.7	$76.3	$253.0	$140.6	$474.8	$58.3	$31.1	$17.3
24	$0.0	$0.0	$193.0	$29.3	29.3	$1,014.9	$161.1	$71.0	$232.1	$130.9	$429.6	$48.0	$25.9	$14.6
25	$0.0	$100.0	$189.1	$27.1	27.1	$938.8	$120.5	$67.4	$187.9	$124.2	$310.5	$31.5	$19.1	$12.6
Total	**$622.0**	**$4,939.3**	**$2,917.9**	**$578.1**	**578.1**	**$19,993.9**	**$2,002.2**	**$1,142.3**	**$3,144.5**	**$2,105.7**	**$5,686.5**	**$332.7**	**$566.4**	**$403.6**
											Nom IRR	**14.8%**		
											Real IRR	**12.5%**		

*****Totals do not always equal column sums due to rounding.

Table 3B.5: Selected Statistics for Economic and Rent Analysis of Short Pipeline Oil Scenario - $40 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$242.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$242.1	-$112.9	$0.0	$0.0
10	$0.0	$962.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$968.2	-$410.6	$0.0	$0.0
11	$0.0	$1,234.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,253.2	-$483.2	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$734.1	$7.2	$0.0	$7.2	$0.0	-$420.3	-$147.3	$2.5	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$2,164.2	$34.6	$29.1	$63.7	$53.7	$1,457.4	$464.4	$20.3	$17.1
14	$0.0	$232.6	$237.8	$54.7	54.7	$2,164.2	$79.8	$146.3	$226.1	$269.7	$1,143.3	$331.2	$65.5	$78.1
15	$0.0	$177.6	$237.8	$54.7	54.7	$2,164.2	$105.5	$155.3	$260.8	$286.3	$1,146.9	$302.0	$68.7	$75.4
16	$0.0	$177.6	$237.8	$54.7	54.7	$2,164.2	$169.9	$157.3	$327.2	$290.0	$1,076.9	$257.8	$78.3	$69.4
17	$0.0	$177.6	$230.5	$50.6	50.6	$2,001.9	$314.8	$128.9	$443.7	$237.6	$861.8	$187.6	$96.6	$51.7
18	$0.0	$118.4	$223.8	$46.8	46.8	$1,851.8	$298.1	$121.4	$419.6	$223.9	$819.2	$162.1	$83.0	$44.3
19	$18.9	$118.4	$217.6	$43.3	43.3	$1,712.9	$267.8	$112.6	$380.4	$207.5	$726.6	$130.7	$68.4	$37.3
20	$0.0	$0.0	$211.9	$40.1	40.1	$1,584.4	$271.1	$108.2	$379.2	$199.4	$753.8	$123.2	$62.0	$32.6
21	$0.0	$0.0	$206.6	$37.1	37.1	$1,465.6	$248.4	$103.3	$351.7	$190.4	$679.8	$101.0	$52.3	$28.3
22	$0.0	$0.0	$201.7	$34.3	34.3	$1,355.7	$227.4	$97.5	$325.0	$179.8	$614.9	$83.1	$43.9	$24.3
23	$0.0	$0.0	$197.2	$31.7	31.7	$1,254.0	$208.1	$91.3	$299.4	$168.3	$557.5	$68.5	$36.8	$20.7
24	$0.0	$0.0	$193.0	$29.3	29.3	$1,159.9	$190.1	$84.9	$275.1	$156.5	$506.0	$56.5	$30.7	$17.5
25	$0.0	$100.0	$189.1	$27.1	27.1	$1,072.9	$147.4	$80.2	$227.6	$147.9	$381.2	$38.7	$23.1	$15.0
Total	**$622.0**	**$4,939.3**	**$2,917.9**	**$578.1**	**578.1**	**$22,850.1**	**$2,570.0**	**$1,416.4**	**$3,986.5**	**$2,611.0**	**$7,195.5**	**$662.1**	**$732.1**	**$511.7**
											Nom IRR	**17.0%**		
											Real IRR	**14.7%**		

*Totals do not always equal column sums due to rounding.

Table 3B.6: Selected Statistics for Economic and Rent Analysis of Short Pipeline Oil Scenario - $45 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$242.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$242.1	-$112.9	$0.0	$0.0
10	$0.0	$962.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$968.2	-$410.6	$0.0	$0.0
11	$0.0	$1,234.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,253.2	-$483.2	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$825.9	$8.1	$0.0	$8.1	$0.0	-$329.4	-$115.5	$2.8	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$2,434.8	$39.0	$71.8	$110.8	$132.3	$1,602.3	$510.6	$35.3	$42.1
14	$0.0	$232.6	$237.8	$54.7	54.7	$2,434.8	$90.0	$177.5	$267.5	$327.3	$1,314.8	$380.9	$77.5	$94.8
15	$0.0	$177.6	$237.8	$54.7	54.7	$2,434.8	$119.0	$186.2	$305.2	$343.2	$1,316.2	$346.6	$80.4	$90.4
16	$0.0	$177.6	$237.8	$54.7	54.7	$2,434.8	$359.0	$167.1	$526.1	$308.0	$1,130.6	$270.6	$125.9	$73.7
17	$0.0	$177.6	$230.5	$50.6	50.6	$2,252.1	$364.8	$152.9	$517.7	$281.9	$993.7	$216.3	$112.7	$61.3
18	$0.0	$118.4	$223.8	$46.8	46.8	$2,083.2	$344.4	$143.7	$488.1	$264.8	$941.2	$186.2	$96.6	$52.4
19	$18.9	$118.4	$217.6	$43.3	43.3	$1,927.0	$310.6	$133.1	$443.8	$245.4	$839.5	$151.0	$79.8	$44.1
20	$0.0	$0.0	$211.9	$40.1	40.1	$1,782.5	$310.7	$127.2	$437.9	$234.5	$858.2	$140.3	$71.6	$38.3
21	$0.0	$0.0	$206.6	$37.1	37.1	$1,648.8	$285.0	$120.9	$405.9	$222.8	$776.4	$115.4	$60.3	$33.1
22	$0.0	$0.0	$201.7	$34.3	34.3	$1,525.1	$261.3	$113.8	$375.1	$209.7	$704.3	$95.2	$50.7	$28.3
23	$0.0	$0.0	$197.2	$31.7	31.7	$1,410.7	$254.2	$104.6	$358.8	$192.8	$630.3	$77.4	$44.1	$23.7
24	$0.0	$0.0	$193.0	$29.3	29.3	$1,304.9	$328.7	$85.7	$414.4	$158.0	$510.3	$57.0	$46.3	$17.6
25	$0.0	$100.0	$189.1	$27.1	27.1	$1,207.1	$261.3	$82.7	$343.9	$152.4	$394.5	$40.1	$34.9	$15.5
Total	**$622.0**	**$4,939.3**	**$2,917.9**	**$578.1**	**578.1**	**$25,706.4**	**$3,336.2**	**$1,667.0**	**$5,003.2**	**$3,072.9**	**$8,573.1**	**$974.6**	**$918.9**	**$615.5**
											Nom IRR	**18.9%**		
											Real IRR	**16.6%**		

*****Totals do not always equal column sums due to rounding.

Table 3B.7: Selected Statistics for Economic and Rent Analysis of Short Pipeline Oil Scenario - $50 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$242.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$242.1	-$112.9	$0.0	$0.0
10	$0.0	$962.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$968.2	-$410.6	$0.0	$0.0
11	$0.0	$1,234.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,253.2	-$483.2	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$917.7	$9.0	$0.0	$9.0	$0.0	-$238.6	-$83.6	$3.2	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$2,705.3	$43.4	$114.4	$157.8	$210.8	$1,747.3	$556.7	$50.3	$67.2
14	$0.0	$232.6	$237.8	$54.7	54.7	$2,705.3	$100.6	$208.7	$309.4	$384.7	$1,486.0	$430.4	$89.6	$111.4
15	$0.0	$177.6	$237.8	$54.7	54.7	$2,705.3	$244.2	$203.6	$447.8	$375.3	$1,412.0	$371.8	$117.9	$98.8
16	$0.0	$177.6	$237.8	$54.7	54.7	$2,705.3	$454.0	$188.1	$642.1	$346.8	$1,246.2	$298.3	$153.7	$83.0
17	$0.0	$177.6	$230.5	$50.6	50.6	$2,502.4	$414.9	$176.9	$591.8	$326.1	$1,125.6	$245.0	$128.8	$71.0
18	$0.0	$118.4	$223.8	$46.8	46.8	$2,314.7	$390.7	$165.9	$556.6	$305.8	$1,063.2	$210.3	$110.1	$60.5
19	$18.9	$118.4	$217.6	$43.3	43.3	$2,141.1	$400.4	$148.1	$548.4	$272.9	$921.5	$165.7	$98.6	$49.1
20	$0.0	$0.0	$211.9	$40.1	40.1	$1,980.5	$525.4	$125.2	$650.6	$230.8	$847.1	$138.5	$106.4	$37.7
21	$0.0	$0.0	$206.6	$37.1	37.1	$1,832.0	$482.5	$119.2	$601.7	$219.7	$766.9	$114.0	$89.4	$32.7
22	$0.0	$0.0	$201.7	$34.3	34.3	$1,694.6	$442.8	$112.3	$555.2	$207.1	$696.3	$94.1	$75.0	$28.0
23	$0.0	$0.0	$197.2	$31.7	31.7	$1,567.5	$406.1	$105.1	$511.3	$193.8	$633.5	$77.8	$62.8	$23.8
24	$0.0	$0.0	$193.0	$29.3	29.3	$1,449.9	$372.2	$97.9	$470.1	$180.4	$577.1	$64.5	$52.5	$20.1
25	$0.0	$100.0	$189.1	$27.1	27.1	$1,341.2	$301.5	$93.9	$395.4	$173.1	$456.4	$46.3	$40.1	$17.6
Total	**$622.0**	**$4,939.3**	**$2,917.9**	**$578.1**	**578.1**	**$28,562.7**	**$4,587.8**	**$1,859.4**	**$6,447.2**	**$3,427.5**	**$9,630.8**	**$1,232.5**	**$1,178.5**	**$701.0**
											Nom IRR	**20.4%**		
											Real IRR	**18.1%**		

*Totals do not always equal column sums due to rounding.

Table 3B.8: Selected Statistics for Economic and Rent Analysis of Short Pipeline Oil Scenario - $55 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$242.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$242.1	-$112.9	$0.0	$0.0
10	$0.0	$962.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$968.2	-$410.6	$0.0	$0.0
11	$0.0	$1,234.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,253.2	-$483.2	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$1,009.4	$9.9	$0.0	$9.9	$0.0	-$147.7	-$51.8	$3.5	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$2,975.8	$47.9	$157.0	$204.9	$289.4	$1,892.2	$602.9	$65.3	$92.2
14	$0.0	$232.6	$237.8	$54.7	54.7	$2,975.8	$125.5	$238.2	$363.7	$439.1	$1,647.9	$477.3	$105.3	$127.2
15	$0.0	$177.6	$237.8	$54.7	54.7	$2,975.8	$407.0	$216.6	$623.5	$399.2	$1,482.9	$390.5	$164.2	$105.1
16	$0.0	$177.6	$237.8	$54.7	54.7	$2,975.8	$508.1	$214.1	$722.2	$394.7	$1,388.8	$332.5	$172.9	$94.5
17	$0.0	$177.6	$230.5	$50.6	50.6	$2,752.6	$464.9	$201.0	$665.9	$370.4	$1,257.5	$273.7	$144.9	$80.6
18	$0.0	$118.4	$223.8	$46.8	46.8	$2,546.2	$630.7	$164.9	$795.6	$303.9	$1,057.6	$209.2	$157.4	$60.1
19	$18.9	$118.4	$217.6	$43.3	43.3	$2,355.2	$594.4	$150.5	$744.9	$277.4	$934.6	$168.1	$134.0	$49.9
20	$0.0	$0.0	$211.9	$40.1	40.1	$2,178.6	$584.8	$141.8	$726.7	$261.4	$938.5	$153.4	$118.8	$42.7
21	$0.0	$0.0	$206.6	$37.1	37.1	$2,015.2	$537.5	$134.6	$672.0	$248.0	$851.4	$126.6	$99.9	$36.9
22	$0.0	$0.0	$201.7	$34.3	34.3	$1,864.0	$493.7	$126.6	$620.3	$233.3	$774.5	$104.7	$83.8	$31.5
23	$0.0	$0.0	$197.2	$31.7	31.7	$1,724.2	$453.2	$118.3	$571.5	$218.1	$705.8	$86.7	$70.2	$26.8
24	$0.0	$0.0	$193.0	$29.3	29.3	$1,594.9	$415.7	$110.1	$525.7	$202.9	$644.0	$71.9	$58.7	$22.7
25	$0.0	$100.0	$189.1	$27.1	27.1	$1,475.3	$341.8	$105.2	$447.0	$193.9	$518.2	$52.6	$45.4	$19.7
Total	**$622.0**	**$4,939.3**	**$2,917.9**	**$578.1**	**578.1**	**$31,418.9**	**$5,615.0**	**$2,078.7**	**$7,693.7**	**$3,831.7**	**$10,836.4**	**$1,500.9**	**$1,424.3**	**$789.9**
											Nom IRR	**21.8%**		
											Real IRR	**19.4%**		

*****Totals do not always equal column sums due to rounding.

Table 3B.9: Selected Statistics for Economic and Rent Analysis of Short Pipeline Oil Scenario - $60 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$242.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$242.1	-$112.9	$0.0	$0.0
10	$0.0	$962.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$968.2	-$410.6	$0.0	$0.0
11	$0.0	$1,234.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,253.2	-$483.2	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$1,101.2	$10.8	$0.0	$10.8	$0.0	-$56.9	-$19.9	$3.8	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$3,246.3	$52.3	$199.6	$251.9	$368.0	$2,037.1	$649.1	$80.3	$117.2
14	$0.0	$232.6	$237.8	$54.7	54.7	$3,246.3	$149.9	$267.7	$417.6	$493.5	$1,810.0	$524.3	$121.0	$143.0
15	$0.0	$177.6	$237.8	$54.7	54.7	$3,246.3	$561.6	$230.5	$792.0	$424.8	$1,559.3	$410.6	$208.6	$111.9
16	$0.0	$177.6	$237.8	$54.7	54.7	$3,246.3	$562.2	$240.1	$802.2	$442.5	$1,531.4	$366.6	$192.1	$105.9
17	$0.0	$177.6	$230.5	$50.6	50.6	$3,002.9	$730.8	$199.1	$929.8	$367.0	$1,247.2	$271.4	$202.4	$79.9
18	$0.0	$118.4	$223.8	$46.8	46.8	$2,777.6	$725.0	$181.3	$906.3	$334.3	$1,148.0	$227.1	$179.3	$66.1
19	$18.9	$118.4	$217.6	$43.3	43.3	$2,569.3	$658.7	$168.5	$827.1	$310.5	$1,033.4	$185.9	$148.8	$55.8
20	$0.0	$0.0	$211.9	$40.1	40.1	$2,376.6	$644.3	$158.5	$802.7	$292.1	$1,029.8	$168.4	$131.3	$47.8
21	$0.0	$0.0	$206.6	$37.1	37.1	$2,198.4	$592.4	$149.9	$742.4	$276.4	$935.9	$139.1	$110.4	$41.1
22	$0.0	$0.0	$201.7	$34.3	34.3	$2,033.5	$544.5	$140.8	$685.3	$259.6	$852.6	$115.2	$92.6	$35.1
23	$0.0	$0.0	$197.2	$31.7	31.7	$1,881.0	$500.2	$131.5	$631.7	$242.4	$778.1	$95.6	$77.6	$29.8
24	$0.0	$0.0	$193.0	$29.3	29.3	$1,739.9	$459.2	$122.2	$581.4	$225.3	$710.9	$79.4	$64.9	$25.2
25	$0.0	$100.0	$189.1	$27.1	27.1	$1,609.4	$382.0	$116.5	$498.5	$214.7	$580.1	$58.9	$50.6	$21.8
Total	**$622.0**	**$4,939.3**	**$2,917.9**	**$578.1**	**578.1**	**$34,275.2**	**$6,573.7**	**$2,306.2**	**$8,879.9**	**$4,251.0**	**$12,087.2**	**$1,774.2**	**$1,663.4**	**$880.5**
											Nom IRR	**23.1%**		
											Real IRR	**20.7%**		

*****Totals do not always equal column sums due to rounding.

Table 3B.10: Selected Statistics for Economic and Rent Analysis of Short Pipeline Oil Scenario - $65 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$242.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$242.1	-$112.9	$0.0	$0.0
10	$0.0	$962.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$968.2	-$410.6	$0.0	$0.0
11	$0.0	$1,234.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,253.2	-$483.2	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$1,193.0	$11.7	$0.0	$11.7	$0.0	$34.0	$11.9	$4.1	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$3,516.9	$57.9	$242.1	$300.0	$446.3	$2,181.3	$695.0	$95.6	$142.2
14	$0.0	$232.6	$237.8	$54.7	54.7	$3,516.9	$280.9	$284.5	$565.4	$524.4	$1,901.9	$550.9	$163.8	$151.9
15	$0.0	$177.6	$237.8	$54.7	54.7	$3,516.9	$616.3	$256.4	$872.6	$472.6	$1,701.5	$448.1	$229.8	$124.4
16	$0.0	$177.6	$237.8	$54.7	54.7	$3,516.9	$758.4	$249.0	$1,007.4	$459.0	$1,580.3	$378.3	$241.2	$109.9
17	$0.0	$177.6	$230.5	$50.6	50.6	$3,253.1	$847.5	$215.1	$1,062.6	$396.5	$1,335.2	$290.6	$231.3	$86.3
18	$0.0	$118.4	$223.8	$46.8	46.8	$3,009.1	$794.4	$200.8	$995.2	$370.1	$1,254.7	$248.2	$196.9	$73.2
19	$18.9	$118.4	$217.6	$43.3	43.3	$2,783.4	$722.9	$186.4	$909.3	$343.7	$1,132.1	$203.6	$163.6	$61.8
20	$0.0	$0.0	$211.9	$40.1	40.1	$2,574.7	$703.7	$175.1	$878.8	$322.8	$1,121.1	$183.3	$143.7	$52.8
21	$0.0	$0.0	$206.6	$37.1	37.1	$2,381.6	$647.4	$165.3	$812.7	$304.8	$1,020.4	$151.7	$120.8	$45.3
22	$0.0	$0.0	$201.7	$34.3	34.3	$2,203.0	$595.4	$155.0	$750.4	$285.8	$930.8	$125.8	$101.4	$38.6
23	$0.0	$0.0	$197.2	$31.7	31.7	$2,037.7	$547.2	$144.6	$691.9	$266.6	$850.4	$104.5	$85.0	$32.8
24	$0.0	$0.0	$193.0	$29.3	29.3	$1,884.9	$502.7	$134.4	$637.1	$247.8	$777.7	$86.9	$71.1	$27.7
25	$0.0	$100.0	$189.1	$27.1	27.1	$1,743.5	$422.2	$127.7	$550.0	$235.4	$641.9	$65.2	$55.8	$23.9
Total	**$622.0**	**$4,939.3**	**$2,917.9**	**$578.1**	**578.1**	**$37,131.5**	**$7,508.6**	**$2,536.5**	**$10,045.1**	**$4,675.6**	**$13,353.6**	**$2,046.5**	**$1,904.0**	**$970.8**
											Nom IRR	**24.3%**		
											Real IRR	**21.8%**		

*****Totals do not always equal column sums due to rounding.

Table 3B.11: Selected Statistics for Economic and Rent Analysis of Short Pipeline Oil Scenario - $70 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$242.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$242.1	-$112.9	$0.0	$0.0
10	$0.0	$962.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$968.2	-$410.6	$0.0	$0.0
11	$0.0	$1,234.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,253.2	-$483.2	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$1,284.7	$12.7	$0.0	$12.7	$0.0	$124.8	$43.7	$4.4	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$3,787.4	$76.3	$283.0	$359.4	$521.7	$2,316.9	$738.2	$114.5	$166.2
14	$0.0	$232.6	$237.8	$54.7	54.7	$3,787.4	$397.9	$302.9	$700.8	$558.3	$2,003.1	$580.2	$203.0	$161.7
15	$0.0	$177.6	$237.8	$54.7	54.7	$3,787.4	$670.4	$282.3	$952.7	$520.4	$1,844.1	$485.6	$250.9	$137.0
16	$0.0	$177.6	$237.8	$54.7	54.7	$3,787.4	$970.9	$255.9	$1,226.9	$471.8	$1,618.5	$387.5	$293.7	$112.9
17	$0.0	$177.6	$230.5	$50.6	50.6	$3,503.3	$922.6	$236.1	$1,158.7	$435.2	$1,450.6	$315.7	$252.2	$94.7
18	$0.0	$118.4	$223.8	$46.8	46.8	$3,240.6	$863.8	$220.2	$1,084.1	$405.9	$1,361.5	$269.4	$214.5	$80.3
19	$18.9	$118.4	$217.6	$43.3	43.3	$2,997.5	$787.1	$204.4	$991.6	$376.8	$1,230.9	$221.4	$178.3	$67.8
20	$0.0	$0.0	$211.9	$40.1	40.1	$2,772.7	$763.1	$191.7	$954.8	$353.4	$1,212.5	$198.3	$156.1	$57.8
21	$0.0	$0.0	$206.6	$37.1	37.1	$2,564.8	$702.4	$180.7	$883.1	$333.1	$1,104.9	$164.2	$131.3	$49.5
22	$0.0	$0.0	$201.7	$34.3	34.3	$2,372.4	$646.2	$169.3	$815.5	$312.0	$1,008.9	$136.3	$110.2	$42.2
23	$0.0	$0.0	$197.2	$31.7	31.7	$2,194.5	$594.2	$157.8	$752.1	$290.9	$922.6	$113.3	$92.4	$35.7
24	$0.0	$0.0	$193.0	$29.3	29.3	$2,029.9	$546.2	$146.6	$692.8	$270.2	$844.6	$94.3	$77.4	$30.2
25	$0.0	$100.0	$189.1	$27.1	27.1	$1,877.7	$462.5	$139.0	$601.5	$256.2	$703.8	$71.5	$61.1	$26.0
Total	**$622.0**	**$4,939.3**	**$2,917.9**	**$578.1**	**578.1**	**$39,987.7**	**$8,416.4**	**$2,770.1**	**$11,186.5**	**$5,106.3**	**$14,637.8**	**$2,322.2**	**$2,139.9**	**$1,062.2**
											Nom IRR	**25.4%**		
											Real IRR	**22.9%**		

*Totals do not always equal column sums due to rounding.

Table 3B.12: Selected Statistics for Economic and Rent Analysis of Short Pipeline Oil Scenario - $75 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$242.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$242.1	-$112.9	$0.0	$0.0
10	$0.0	$962.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$968.2	-$410.6	$0.0	$0.0
11	$0.0	$1,234.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,253.2	-$483.2	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$1,376.5	$13.6	$0.0	$13.6	$0.0	$215.7	$75.6	$4.8	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$4,057.9	$94.5	$324.0	$418.5	$597.2	$2,452.8	$781.5	$133.4	$190.3
14	$0.0	$232.6	$237.8	$54.7	54.7	$4,057.9	$511.9	$321.7	$833.6	$593.0	$2,106.2	$610.1	$241.5	$171.8
15	$0.0	$177.6	$237.8	$54.7	54.7	$4,057.9	$820.5	$296.8	$1,117.3	$547.1	$1,923.4	$506.5	$294.2	$144.1
16	$0.0	$177.6	$237.8	$54.7	54.7	$4,057.9	$1,086.7	$274.5	$1,361.2	$506.0	$1,720.5	$411.9	$325.9	$121.1
17	$0.0	$177.6	$230.5	$50.6	50.6	$3,753.6	$997.7	$257.1	$1,254.8	$474.0	$1,566.0	$340.8	$273.1	$103.2
18	$0.0	$118.4	$223.8	$46.8	46.8	$3,472.1	$933.3	$239.7	$1,172.9	$441.8	$1,468.2	$290.5	$232.1	$87.4
19	$18.9	$118.4	$217.6	$43.3	43.3	$3,211.7	$851.4	$222.4	$1,073.8	$410.0	$1,329.6	$239.1	$193.1	$73.7
20	$0.0	$0.0	$211.9	$40.1	40.1	$2,970.8	$822.5	$208.4	$1,030.9	$384.1	$1,303.8	$213.2	$168.6	$62.8
21	$0.0	$0.0	$206.6	$37.1	37.1	$2,748.0	$757.3	$196.1	$953.4	$361.5	$1,189.4	$176.8	$141.7	$53.7
22	$0.0	$0.0	$201.7	$34.3	34.3	$2,541.9	$697.0	$183.5	$880.5	$338.3	$1,087.1	$146.9	$119.0	$45.7
23	$0.0	$0.0	$197.2	$31.7	31.7	$2,351.2	$641.3	$171.0	$812.2	$315.2	$994.9	$122.2	$99.8	$38.7
24	$0.0	$0.0	$193.0	$29.3	29.3	$2,174.9	$589.7	$158.8	$748.4	$292.7	$911.5	$101.8	$83.6	$32.7
25	$0.0	$100.0	$189.1	$27.1	27.1	$2,011.8	$502.7	$150.3	$653.0	$277.0	$765.6	$77.7	$66.3	$28.1
Total	**$622.0**	**$4,939.3**	**$2,917.9**	**$578.1**	**578.1**	**$42,844.0**	**$9,320.1**	**$3,004.2**	**$12,324.3**	**$5,537.8**	**$15,924.8**	**$2,597.2**	**$2,376.9**	**$1,153.3**
											Nom IRR	**26.4%**		
											Real IRR	**23.9%**		

*****Totals do not always equal column sums due to rounding.

Table 3B.13: Selected Statistics for Economic and Rent Analysis of Short Pipeline Oil Scenario - $80 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$242.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$242.1	-$112.9	$0.0	$0.0
10	$0.0	$962.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$968.2	-$410.6	$0.0	$0.0
11	$0.0	$1,234.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,253.2	-$483.2	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$1,468.3	$14.5	$0.0	$14.5	$0.0	$306.5	$107.4	$5.1	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$4,328.5	$112.5	$365.0	$477.5	$672.8	$2,588.8	$824.9	$152.1	$214.4
14	$0.0	$232.6	$237.8	$54.7	54.7	$4,328.5	$623.6	$340.7	$964.3	$628.1	$2,210.8	$640.4	$279.3	$181.9
15	$0.0	$177.6	$237.8	$54.7	54.7	$4,328.5	$997.8	$308.0	$1,305.8	$567.7	$1,984.8	$522.7	$343.9	$149.5
16	$0.0	$177.6	$237.8	$54.7	54.7	$4,328.5	$1,167.9	$297.2	$1,465.1	$547.9	$1,845.2	$441.7	$350.7	$131.2
17	$0.0	$177.6	$230.5	$50.6	50.6	$4,003.8	$1,072.8	$278.2	$1,350.9	$512.7	$1,681.4	$365.9	$294.0	$111.6
18	$0.0	$118.4	$223.8	$46.8	46.8	$3,703.5	$1,002.7	$259.1	$1,261.8	$477.6	$1,575.0	$311.6	$249.6	$94.5
19	$18.9	$118.4	$217.6	$43.3	43.3	$3,425.8	$915.6	$240.4	$1,156.0	$443.1	$1,428.3	$256.9	$207.9	$79.7
20	$0.0	$0.0	$211.9	$40.1	40.1	$3,168.8	$881.9	$225.0	$1,106.9	$414.8	$1,395.2	$228.1	$181.0	$67.8
21	$0.0	$0.0	$206.6	$37.1	37.1	$2,931.2	$812.3	$211.5	$1,023.8	$389.9	$1,273.8	$189.3	$152.2	$58.0
22	$0.0	$0.0	$201.7	$34.3	34.3	$2,711.3	$747.9	$197.7	$945.6	$364.5	$1,165.2	$157.5	$127.8	$49.3
23	$0.0	$0.0	$197.2	$31.7	31.7	$2,508.0	$688.3	$184.2	$872.4	$339.5	$1,067.2	$131.1	$107.2	$41.7
24	$0.0	$0.0	$193.0	$29.3	29.3	$2,319.9	$633.2	$171.0	$804.1	$315.1	$978.3	$109.3	$89.8	$35.2
25	$0.0	$100.0	$189.1	$27.1	27.1	$2,145.9	$542.9	$161.5	$704.5	$297.7	$827.5	$84.0	$71.5	$30.2
Total	**$622.0**	**$4,939.3**	**$2,917.9**	**$578.1**	**578.1**	**$45,700.3**	**$10,213.8**	**$3,239.5**	**$13,453.3**	**$5,971.5**	**$17,218.3**	**$2,873.4**	**$2,612.2**	**$1,244.9**
											Nom IRR	**27.4%**		
											Real IRR	**24.9%**		

***Totals do not always equal column sums due to rounding.

Table 3B.14: Selected Statistics for Economic and Rent Analysis of Short Pipeline Oil Scenario - $85 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$242.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$242.1	-$112.9	$0.0	$0.0
10	$0.0	$962.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$968.2	-$410.6	$0.0	$0.0
11	$0.0	$1,234.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,253.2	-$483.2	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$1,560.0	$15.4	$0.0	$15.4	$0.0	$397.4	$139.3	$5.4	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$4,599.0	$130.2	$406.0	$536.2	$748.4	$2,724.9	$868.2	$170.9	$238.5
14	$0.0	$232.6	$237.8	$54.7	54.7	$4,599.0	$733.5	$360.0	$1,093.5	$663.6	$2,316.6	$671.0	$316.8	$192.2
15	$0.0	$177.6	$237.8	$54.7	54.7	$4,599.0	$1,164.0	$320.5	$1,484.5	$590.8	$2,053.5	$540.8	$390.9	$155.6
16	$0.0	$177.6	$237.8	$54.7	54.7	$4,599.0	$1,249.0	$320.0	$1,569.0	$589.8	$1,970.0	$471.6	$375.6	$141.2
17	$0.0	$177.6	$230.5	$50.6	50.6	$4,254.1	$1,147.8	$299.2	$1,447.0	$551.5	$1,796.8	$391.0	$314.9	$120.0
18	$0.0	$118.4	$223.8	$46.8	46.8	$3,935.0	$1,072.2	$278.6	$1,350.7	$513.5	$1,681.7	$332.7	$267.2	$101.6
19	$18.9	$118.4	$217.6	$43.3	43.3	$3,639.9	$979.8	$258.4	$1,238.2	$476.3	$1,527.1	$274.7	$222.7	$85.7
20	$0.0	$0.0	$211.9	$40.1	40.1	$3,366.9	$941.3	$241.6	$1,183.0	$445.4	$1,486.5	$243.1	$193.4	$72.8
21	$0.0	$0.0	$206.6	$37.1	37.1	$3,114.4	$867.2	$226.9	$1,094.1	$418.2	$1,358.3	$201.9	$162.6	$62.2
22	$0.0	$0.0	$201.7	$34.3	34.3	$2,880.8	$798.7	$212.0	$1,010.7	$390.8	$1,243.4	$168.0	$136.6	$52.8
23	$0.0	$0.0	$197.2	$31.7	31.7	$2,664.7	$735.3	$197.3	$932.6	$363.7	$1,139.5	$140.0	$114.6	$44.7
24	$0.0	$0.0	$193.0	$29.3	29.3	$2,464.9	$676.7	$183.1	$859.8	$337.6	$1,045.2	$116.7	$96.0	$37.7
25	$0.0	$100.0	$189.1	$27.1	27.1	$2,280.0	$583.2	$172.8	$756.0	$318.5	$889.3	$90.3	$76.7	$32.3
Total	**$622.0**	**$4,939.3**	**$2,917.9**	**$578.1**	**578.1**	**$48,556.5**	**$11,094.5**	**$3,476.4**	**$14,570.9**	**$6,408.1**	**$18,520.4**	**$3,151.9**	**$2,844.4**	**$1,337.3**
											Nom IRR	**28.3%**		
											Real IRR	**25.8%**		

***Totals do not always equal column sums due to rounding.**

Table 3B.15: Selected Statistics for Economic and Rent Analysis of Short Pipeline Oil Scenario - $90 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$242.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$242.1	-$112.9	$0.0	$0.0
10	$0.0	$962.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$968.2	-$410.6	$0.0	$0.0
11	$0.0	$1,234.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,253.2	-$483.2	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$1,651.8	$16.3	$0.0	$16.3	$0.0	$488.2	$171.1	$5.7	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$4,869.5	$147.8	$447.1	$594.9	$824.1	$2,861.2	$911.7	$189.6	$262.6
14	$0.0	$232.6	$237.8	$54.7	54.7	$4,869.5	$842.1	$379.4	$1,221.6	$699.4	$2,423.3	$701.9	$353.8	$202.6
15	$0.0	$177.6	$237.8	$54.7	54.7	$4,869.5	$1,322.5	$333.9	$1,656.4	$615.6	$2,127.4	$560.2	$436.2	$162.1
16	$0.0	$177.6	$237.8	$54.7	54.7	$4,869.5	$1,330.2	$342.7	$1,672.9	$631.7	$2,094.8	$501.5	$400.5	$151.2
17	$0.0	$177.6	$230.5	$50.6	50.6	$4,504.3	$1,222.9	$320.2	$1,543.1	$590.2	$1,912.2	$416.1	$335.8	$128.5
18	$0.0	$118.4	$223.8	$46.8	46.8	$4,166.5	$1,141.6	$298.0	$1,439.6	$549.3	$1,788.5	$353.8	$284.8	$108.7
19	$18.9	$118.4	$217.6	$43.3	43.3	$3,854.0	$1,044.1	$276.4	$1,320.4	$509.4	$1,625.8	$292.4	$237.5	$91.6
20	$0.0	$0.0	$211.9	$40.1	40.1	$3,564.9	$1,000.8	$258.3	$1,259.0	$476.1	$1,577.8	$258.0	$205.9	$77.8
21	$0.0	$0.0	$206.6	$37.1	37.1	$3,297.6	$922.2	$242.3	$1,164.5	$446.6	$1,442.8	$214.5	$173.1	$66.4
22	$0.0	$0.0	$201.7	$34.3	34.3	$3,050.3	$849.5	$226.2	$1,075.8	$417.0	$1,321.5	$178.6	$145.4	$56.3
23	$0.0	$0.0	$197.2	$31.7	31.7	$2,821.5	$782.3	$210.5	$992.8	$388.0	$1,211.8	$148.9	$122.0	$47.7
24	$0.0	$0.0	$193.0	$29.3	29.3	$2,609.9	$720.2	$195.3	$915.5	$360.0	$1,112.1	$124.2	$102.2	$40.2
25	$0.0	$100.0	$189.1	$27.1	27.1	$2,414.1	$623.4	$184.1	$807.5	$339.3	$951.2	$96.6	$82.0	$34.4
Total	**$622.0**	**$4,939.3**	**$2,917.9**	**$578.1**	**578.1**	**$51,412.8**	**$11,965.9**	**$3,714.3**	**$15,680.3**	**$6,846.7**	**$19,828.6**	**$3,432.0**	**$3,074.4**	**$1,430.1**
											Nom IRR	**29.2%**		
											Real IRR	**26.7%**		

*****Totals do not always equal column sums due to rounding.

Table 3B.16: Selected Statistics for Economic and Rent Analysis of Short Pipeline Oil Scenario - $95 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$242.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$242.1	-$112.9	$0.0	$0.0
10	$0.0	$962.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$968.2	-$410.6	$0.0	$0.0
11	$0.0	$1,234.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,253.2	-$483.2	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$1,743.6	$17.2	$10.6	$27.8	$19.5	$549.0	$192.4	$9.7	$6.8
13	$0.0	$296.8	$237.8	$54.7	54.7	$5,140.0	$190.7	$474.7	$665.4	$875.1	$3,010.2	$959.1	$212.0	$278.8
14	$0.0	$232.6	$237.8	$54.7	54.7	$5,140.0	$1,008.4	$392.0	$1,400.3	$722.5	$2,492.0	$721.9	$405.6	$209.3
15	$0.0	$177.6	$237.8	$54.7	54.7	$5,140.0	$1,411.4	$355.7	$1,767.1	$655.7	$2,247.0	$591.7	$465.3	$172.7
16	$0.0	$177.6	$237.8	$54.7	54.7	$5,140.0	$1,411.4	$365.4	$1,776.8	$673.6	$2,219.5	$531.3	$425.3	$161.3
17	$0.0	$177.6	$230.5	$50.6	50.6	$4,754.5	$1,298.0	$341.2	$1,639.2	$629.0	$2,027.6	$441.3	$356.7	$136.9
18	$0.0	$118.4	$223.8	$46.8	46.8	$4,397.9	$1,211.0	$317.4	$1,528.5	$585.1	$1,895.2	$375.0	$302.4	$115.8
19	$18.9	$118.4	$217.6	$43.3	43.3	$4,068.1	$1,108.3	$294.4	$1,402.6	$542.6	$1,724.6	$310.2	$252.3	$97.6
20	$0.0	$0.0	$211.9	$40.1	40.1	$3,763.0	$1,060.2	$274.9	$1,335.1	$506.8	$1,669.2	$272.9	$218.3	$82.9
21	$0.0	$0.0	$206.6	$37.1	37.1	$3,480.8	$977.2	$257.7	$1,234.8	$475.0	$1,527.3	$227.0	$183.5	$70.6
22	$0.0	$0.0	$201.7	$34.3	34.3	$3,219.7	$900.4	$240.5	$1,140.8	$443.2	$1,399.6	$189.1	$154.2	$59.9
23	$0.0	$0.0	$197.2	$31.7	31.7	$2,978.2	$829.4	$223.7	$1,053.0	$412.3	$1,284.1	$157.7	$129.4	$50.6
24	$0.0	$0.0	$193.0	$29.3	29.3	$2,754.9	$763.7	$207.5	$971.2	$382.5	$1,178.9	$131.7	$108.5	$42.7
25	$0.0	$100.0	$189.1	$27.1	27.1	$2,548.2	$663.6	$195.3	$859.0	$360.0	$1,013.0	$102.8	$87.2	$36.6
Total	**$622.0**	**$4,939.3**	**$2,917.9**	**$578.1**	**578.1**	**$54,269.1**	**$12,850.7**	**$3,950.9**	**$16,801.6**	**$7,282.8**	**$21,127.5**	**$3,706.8**	**$3,310.5**	**$1,522.4**
											Nom IRR	**30.0%**		
											Real IRR	**27.4%**		

***Totals do not always equal column sums due to rounding.**

Table 3B.17: Selected Statistics for Economic and Rent Analysis of Short Pipeline Oil Scenario - $100 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$242.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$242.1	-$112.9	$0.0	$0.0
10	$0.0	$962.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$968.2	-$410.6	$0.0	$0.0
11	$0.0	$1,234.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,253.2	-$483.2	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$1,835.3	$18.2	$21.5	$39.6	$39.5	$608.9	$213.4	$13.9	$13.9
13	$0.0	$296.8	$237.8	$54.7	54.7	$5,410.6	$274.2	$497.2	$771.4	$916.4	$3,133.4	$998.4	$245.8	$292.0
14	$0.0	$232.6	$237.8	$54.7	54.7	$5,410.6	$1,143.1	$408.3	$1,551.4	$752.5	$2,581.5	$747.8	$449.4	$218.0
15	$0.0	$177.6	$237.8	$54.7	54.7	$5,410.6	$1,492.5	$378.5	$1,871.0	$697.6	$2,371.8	$624.6	$492.7	$183.7
16	$0.0	$177.6	$237.8	$54.7	54.7	$5,410.6	$1,492.5	$388.1	$1,880.7	$715.5	$2,344.3	$561.2	$450.2	$171.3
17	$0.0	$177.6	$230.5	$50.6	50.6	$5,004.8	$1,373.1	$362.2	$1,735.3	$667.7	$2,143.0	$466.4	$377.6	$145.3
18	$0.0	$118.4	$223.8	$46.8	46.8	$4,629.4	$1,280.5	$336.9	$1,617.4	$621.0	$2,002.0	$396.1	$320.0	$122.9
19	$18.9	$118.4	$217.6	$43.3	43.3	$4,282.2	$1,172.5	$312.3	$1,484.9	$575.7	$1,823.3	$327.9	$267.1	$103.6
20	$0.0	$0.0	$211.9	$40.1	40.1	$3,961.0	$1,119.6	$291.6	$1,411.1	$537.4	$1,760.5	$287.9	$230.7	$87.9
21	$0.0	$0.0	$206.6	$37.1	37.1	$3,664.0	$1,032.1	$273.1	$1,305.2	$503.3	$1,611.8	$239.6	$194.0	$74.8
22	$0.0	$0.0	$201.7	$34.3	34.3	$3,389.2	$951.2	$254.7	$1,205.9	$469.5	$1,477.8	$199.7	$163.0	$63.4
23	$0.0	$0.0	$197.2	$31.7	31.7	$3,135.0	$876.4	$236.8	$1,113.2	$436.5	$1,356.4	$166.6	$136.8	$53.6
24	$0.0	$0.0	$193.0	$29.3	29.3	$2,899.9	$807.2	$219.7	$1,026.8	$404.9	$1,245.8	$139.1	$114.7	$45.2
25	$0.0	$100.0	$189.1	$27.1	27.1	$2,682.4	$703.9	$206.6	$910.5	$380.8	$1,074.9	$109.1	$92.4	$38.7
Total	**$622.0**	**$4,939.3**	**$2,917.9**	**$578.1**	**578.1**	**$57,125.4**	**$13,737.0**	**$4,187.3**	**$17,924.3**	**$7,718.6**	**$22,425.3**	**$3,980.3**	**$3,548.2**	**$1,614.2**
											Nom IRR	**30.7%**		
											Real IRR	**28.2%**		

*****Totals do not always equal column sums due to rounding.

Appendix 3C: Results of Economic and Rent Analysis – Long Pipeline Oil Scenario ($2006)

Table 3C.1: Selected Statistics for Economic and Rent Analysis of Long Pipeline Oil Scenario - $20 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$347.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$347.1	-$161.9	$0.0	$0.0
10	$0.0	$1,067.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,073.2	-$455.1	$0.0	$0.0
11	$0.0	$1,339.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,358.2	-$523.6	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$367.1	$3.5	$0.0	$3.5	$0.0	-$783.7	-$274.7	$1.2	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$1,082.1	$16.8	$0.0	$16.8	$0.0	$475.9	$151.6	$5.4	$0.0
14	$0.0	$232.6	$237.8	$54.7	54.7	$1,082.1	$38.9	$0.0	$38.9	$0.0	$518.1	$150.1	$11.3	$0.0
15	$0.0	$177.6	$237.8	$54.7	54.7	$1,082.1	$51.4	$0.0	$51.4	$0.0	$560.6	$147.6	$13.5	$0.0
16	$0.0	$177.6	$237.8	$54.7	54.7	$1,082.1	$69.0	$0.0	$69.0	$0.0	$543.0	$130.0	$16.5	$0.0
17	$0.0	$177.6	$230.5	$50.6	50.6	$1,001.0	$71.3	$0.0	$71.3	$0.0	$470.9	$102.5	$15.5	$0.0
18	$0.0	$118.4	$223.8	$46.8	46.8	$925.9	$65.9	$6.8	$72.8	$12.6	$451.4	$89.3	$14.4	$2.5
19	$18.9	$118.4	$217.6	$43.3	43.3	$856.4	$61.0	$33.7	$94.7	$62.1	$301.3	$54.2	$17.0	$11.2
20	$0.0	$0.0	$211.9	$40.1	40.1	$792.2	$56.4	$38.2	$94.6	$70.4	$375.2	$61.4	$15.5	$11.5
21	$0.0	$0.0	$206.6	$37.1	37.1	$732.8	$52.2	$38.4	$90.6	$70.8	$327.7	$48.7	$13.5	$10.5
22	$0.0	$0.0	$201.7	$34.3	34.3	$677.8	$48.3	$37.3	$85.6	$68.8	$287.5	$38.8	$11.6	$9.3
23	$0.0	$0.0	$197.2	$31.7	31.7	$627.0	$44.6	$35.4	$80.0	$65.2	$252.8	$31.1	$9.8	$8.0
24	$0.0	$0.0	$193.0	$29.3	29.3	$580.0	$41.3	$33.0	$74.3	$60.8	$222.6	$24.9	$8.3	$6.8
25	$0.0	$100.0	$189.1	$27.1	27.1	$536.5	$38.2	$28.8	$67.0	$53.1	$100.1	$10.2	$6.8	$5.4
Total	**$622.0**	**$5,254.3**	**$2,917.9**	**$578.1**	**578.1**	**$11,425.1**	**$658.7**	**$251.6**	**$910.4**	**$463.9**	**$678.7**	**-$865.8**	**$160.3**	**$65.2**
											Nom IRR	**3.9%**		
											Real IRR	**1.9%**		

*****Totals do not always equal column sums due to rounding.

Table 3C.2: Selected Statistics for Economic and Rent Analysis of Long Pipeline Oil Scenario - $25 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$347.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$347.1	-$161.9	$0.0	$0.0
10	$0.0	$1,067.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,073.2	-$455.1	$0.0	$0.0
11	$0.0	$1,339.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,358.2	-$523.6	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$458.8	$4.4	$0.0	$4.4	$0.0	-$692.8	-$242.8	$1.5	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$1,352.6	$21.3	$0.0	$21.3	$0.0	$742.0	$236.4	$6.8	$0.0
14	$0.0	$232.6	$237.8	$54.7	54.7	$1,352.6	$49.1	$0.0	$49.1	$0.0	$778.4	$225.5	$14.2	$0.0
15	$0.0	$177.6	$237.8	$54.7	54.7	$1,352.6	$64.9	$0.0	$64.9	$0.0	$817.6	$215.3	$17.1	$0.0
16	$0.0	$177.6	$237.8	$54.7	54.7	$1,352.6	$87.2	$62.4	$149.5	$115.0	$617.9	$147.9	$35.8	$27.5
17	$0.0	$177.6	$230.5	$50.6	50.6	$1,251.2	$90.0	$64.0	$154.1	$118.1	$520.2	$113.2	$33.5	$25.7
18	$0.0	$118.4	$223.8	$46.8	46.8	$1,157.4	$83.3	$62.6	$145.9	$115.5	$506.9	$100.3	$28.9	$22.8
19	$18.9	$118.4	$217.6	$43.3	43.3	$1,070.6	$77.0	$57.5	$134.5	$105.9	$431.8	$77.7	$24.2	$19.1
20	$0.0	$0.0	$211.9	$40.1	40.1	$990.3	$71.3	$60.2	$131.4	$110.9	$495.9	$81.1	$21.5	$18.1
21	$0.0	$0.0	$206.6	$37.1	37.1	$916.0	$65.9	$58.7	$124.7	$108.3	$439.4	$65.3	$18.5	$16.1
22	$0.0	$0.0	$201.7	$34.3	34.3	$847.3	$61.0	$56.1	$117.1	$103.5	$390.8	$52.8	$15.8	$14.0
23	$0.0	$0.0	$197.2	$31.7	31.7	$783.7	$56.4	$52.8	$109.2	$97.3	$348.3	$42.8	$13.4	$12.0
24	$0.0	$0.0	$193.0	$29.3	29.3	$725.0	$52.2	$49.1	$101.3	$90.5	$310.9	$34.7	$11.3	$10.1
25	$0.0	$100.0	$189.1	$27.1	27.1	$670.6	$48.3	$43.7	$92.0	$80.6	$181.8	$18.5	$9.3	$8.2
Total	**$622.0**	**$5,254.3**	**$2,917.9**	**$578.1**	**578.1**	**$14,281.3**	**$832.2**	**$567.2**	**$1,399.3**	**$1,045.5**	**$2,464.4**	**-$462.8**	**$251.9**	**$173.6**
											Nom IRR	**8.2%**		
											Real IRR	**6.1%**		

*****Totals do not always equal column sums due to rounding.

Table 3C.3: Selected Statistics for Economic and Rent Analysis of Long Pipeline Oil Scenario - $30 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$347.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$347.1	-$161.9	$0.0	$0.0
10	$0.0	$1,067.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,073.2	-$455.1	$0.0	$0.0
11	$0.0	$1,339.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,358.2	-$523.6	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$550.6	$5.3	$0.0	$5.3	$0.0	-$602.0	-$211.0	$1.9	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$1,623.2	$25.7	$0.0	$25.7	$0.0	$1,008.1	$321.2	$8.2	$0.0
14	$0.0	$232.6	$237.8	$54.7	54.7	$1,623.2	$59.3	$6.9	$66.2	$12.6	$1,019.2	$295.2	$19.2	$3.7
15	$0.0	$177.6	$237.8	$54.7	54.7	$1,623.2	$78.4	$90.5	$168.9	$166.8	$817.3	$215.2	$44.5	$43.9
16	$0.0	$177.6	$237.8	$54.7	54.7	$1,623.2	$105.3	$97.8	$203.1	$180.2	$769.7	$184.2	$48.6	$43.1
17	$0.0	$177.6	$230.5	$50.6	50.6	$1,501.4	$108.8	$91.8	$200.6	$169.3	$672.7	$146.4	$43.7	$36.8
18	$0.0	$118.4	$223.8	$46.8	46.8	$1,388.8	$100.6	$88.3	$189.0	$162.8	$647.9	$128.2	$37.4	$32.2
19	$18.9	$118.4	$217.6	$43.3	43.3	$1,284.7	$93.1	$81.2	$174.3	$149.7	$562.3	$101.1	$31.4	$26.9
20	$0.0	$0.0	$211.9	$40.1	40.1	$1,188.3	$86.1	$82.2	$168.3	$151.4	$616.6	$100.8	$27.5	$24.8
21	$0.0	$0.0	$206.6	$37.1	37.1	$1,099.2	$101.8	$76.4	$178.2	$140.9	$536.4	$79.7	$26.5	$20.9
22	$0.0	$0.0	$201.7	$34.3	34.3	$1,016.8	$159.7	$64.6	$224.3	$119.1	$437.4	$59.1	$30.3	$16.1
23	$0.0	$0.0	$197.2	$31.7	31.7	$940.5	$145.4	$60.9	$206.3	$112.3	$393.0	$48.3	$25.3	$13.8
24	$0.0	$0.0	$193.0	$29.3	29.3	$870.0	$132.1	$56.9	$189.0	$104.9	$353.8	$39.5	$21.1	$11.7
25	$0.0	$100.0	$189.1	$27.1	27.1	$804.7	$93.7	$54.3	$148.1	$100.2	$240.3	$24.4	$15.0	$10.2
Total	**$622.0**	**$5,254.3**	**$2,917.9**	**$578.1**	**578.1**	**$17,137.6**	**$1,295.4**	**$851.9**	**$2,147.3**	**$1,570.3**	**$4,047.9**	**-$99.0**	**$380.5**	**$284.2**
											Nom IRR	**11.4%**		
											Real IRR	**9.2%**		

***Totals do not always equal column sums due to rounding.**

Table 3C.4: Selected Statistics for Economic and Rent Analysis of Long Pipeline Oil Scenario - $35 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$347.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$347.1	-$161.9	$0.0	$0.0
10	$0.0	$1,067.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,073.2	-$455.1	$0.0	$0.0
11	$0.0	$1,339.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,358.2	-$523.6	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$642.4	$6.2	$0.0	$6.2	$0.0	-$511.1	-$179.1	$2.2	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$1,893.7	$30.1	$0.0	$30.1	$0.0	$1,274.2	$406.0	$9.6	$0.0
14	$0.0	$232.6	$237.8	$54.7	54.7	$1,893.7	$69.5	$79.9	$149.4	$147.2	$1,071.9	$310.5	$43.3	$42.7
15	$0.0	$177.6	$237.8	$54.7	54.7	$1,893.7	$91.9	$121.3	$213.3	$223.6	$986.6	$259.8	$56.2	$58.9
16	$0.0	$177.6	$237.8	$54.7	54.7	$1,893.7	$123.5	$128.1	$251.6	$236.1	$935.9	$224.0	$60.2	$56.5
17	$0.0	$177.6	$230.5	$50.6	50.6	$1,751.7	$127.6	$119.6	$247.2	$220.5	$825.2	$179.6	$53.8	$48.0
18	$0.0	$118.4	$223.8	$46.8	46.8	$1,620.3	$148.1	$110.4	$258.5	$203.5	$769.1	$152.2	$51.1	$40.3
19	$18.9	$118.4	$217.6	$43.3	43.3	$1,498.8	$225.0	$91.1	$316.1	$167.9	$616.4	$110.9	$56.9	$30.2
20	$0.0	$0.0	$211.9	$40.1	40.1	$1,386.4	$231.5	$88.5	$319.9	$163.1	$651.3	$106.5	$52.3	$26.7
21	$0.0	$0.0	$206.6	$37.1	37.1	$1,282.4	$211.8	$85.2	$297.0	$157.1	$584.7	$86.9	$44.1	$23.3
22	$0.0	$0.0	$201.7	$34.3	34.3	$1,186.2	$193.6	$80.9	$274.4	$149.1	$526.7	$71.2	$37.1	$20.1
23	$0.0	$0.0	$197.2	$31.7	31.7	$1,097.2	$176.7	$76.0	$252.7	$140.1	$475.6	$58.4	$31.0	$17.2
24	$0.0	$0.0	$193.0	$29.3	29.3	$1,014.9	$161.1	$70.8	$231.9	$130.5	$430.2	$48.0	$25.9	$14.6
25	$0.0	$100.0	$189.1	$27.1	27.1	$938.8	$120.5	$67.2	$187.8	$123.9	$310.9	$31.6	$19.1	$12.6
Total	**$622.0**	**$5,254.3**	**$2,917.9**	**$578.1**	**578.1**	**$19,993.9**	**$1,917.2**	**$1,119.0**	**$3,036.2**	**$2,062.6**	**$5,522.9**	**$235.0**	**$542.8**	**$391.0**
											Nom IRR	**14.0%**		
											Real IRR	**11.7%**		

*****Totals do not always equal column sums due to rounding.

Table 3C.5: Selected Statistics for Economic and Rent Analysis of Long Pipeline Oil Scenario - $40 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$347.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$347.1	-$161.9	$0.0	$0.0
10	$0.0	$1,067.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,073.2	-$455.1	$0.0	$0.0
11	$0.0	$1,339.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,358.2	-$523.6	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$734.1	$7.2	$0.0	$7.2	$0.0	-$420.3	-$147.3	$2.5	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$2,164.2	$34.6	$11.1	$45.7	$20.5	$1,508.6	$480.7	$14.6	$6.5
14	$0.0	$232.6	$237.8	$54.7	54.7	$2,164.2	$79.8	$142.0	$221.8	$261.7	$1,155.6	$334.7	$64.2	$75.8
15	$0.0	$177.6	$237.8	$54.7	54.7	$2,164.2	$105.5	$152.2	$257.6	$280.5	$1,155.9	$304.4	$67.8	$73.9
16	$0.0	$177.6	$237.8	$54.7	54.7	$2,164.2	$141.7	$158.3	$300.0	$291.9	$1,102.2	$263.8	$71.8	$69.9
17	$0.0	$177.6	$230.5	$50.6	50.6	$2,001.9	$259.4	$133.8	$393.2	$246.7	$903.2	$196.6	$85.6	$53.7
18	$0.0	$118.4	$223.8	$46.8	46.8	$1,851.8	$298.1	$120.2	$418.3	$221.5	$822.8	$162.8	$82.8	$43.8
19	$18.9	$118.4	$217.6	$43.3	43.3	$1,712.9	$267.8	$111.7	$379.5	$205.8	$729.3	$131.2	$68.3	$37.0
20	$0.0	$0.0	$211.9	$40.1	40.1	$1,584.4	$271.1	$107.5	$378.6	$198.2	$755.7	$123.6	$61.9	$32.4
21	$0.0	$0.0	$206.6	$37.1	37.1	$1,465.6	$248.4	$102.8	$351.2	$189.5	$681.2	$101.3	$52.2	$28.2
22	$0.0	$0.0	$201.7	$34.3	34.3	$1,355.7	$227.4	$97.2	$324.6	$179.1	$616.0	$83.2	$43.9	$24.2
23	$0.0	$0.0	$197.2	$31.7	31.7	$1,254.0	$208.1	$91.0	$299.1	$167.8	$558.2	$68.6	$36.7	$20.6
24	$0.0	$0.0	$193.0	$29.3	29.3	$1,159.9	$190.1	$84.7	$274.9	$156.2	$506.6	$56.6	$30.7	$17.4
25	$0.0	$100.0	$189.1	$27.1	27.1	$1,072.9	$147.4	$80.1	$227.5	$147.6	$381.6	$38.7	$23.1	$15.0
Total	**$622.0**	**$5,254.3**	**$2,917.9**	**$578.1**	**578.1**	**$22,850.1**	**$2,486.5**	**$1,392.6**	**$3,879.0**	**$2,567.0**	**$7,032.0**	**$567.4**	**$706.1**	**$498.4**
											Nom IRR	**16.2%**		
											Real IRR	**13.9%**		

*Totals do not always equal column sums due to rounding.

Table 3C.6: Selected Statistics for Economic and Rent Analysis of Long Pipeline Oil Scenario - $45 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$347.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$347.1	-$161.9	$0.0	$0.0
10	$0.0	$1,067.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,073.2	-$455.1	$0.0	$0.0
11	$0.0	$1,339.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,358.2	-$523.6	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$825.9	$8.1	$0.0	$8.1	$0.0	-$329.4	-$115.5	$2.8	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$2,434.8	$39.0	$53.8	$92.8	$99.1	$1,653.5	$526.9	$29.6	$31.6
14	$0.0	$232.6	$237.8	$54.7	54.7	$2,434.8	$90.0	$173.2	$263.2	$319.3	$1,327.1	$384.4	$76.2	$92.5
15	$0.0	$177.6	$237.8	$54.7	54.7	$2,434.8	$119.0	$183.0	$302.0	$337.3	$1,325.2	$349.0	$79.5	$88.8
16	$0.0	$177.6	$237.8	$54.7	54.7	$2,434.8	$285.4	$173.6	$459.0	$319.9	$1,185.7	$283.8	$109.9	$76.6
17	$0.0	$177.6	$230.5	$50.6	50.6	$2,252.1	$364.8	$151.2	$516.0	$278.7	$998.6	$217.3	$112.3	$60.7
18	$0.0	$118.4	$223.8	$46.8	46.8	$2,083.2	$344.4	$142.4	$486.8	$262.5	$944.8	$186.9	$96.3	$51.9
19	$18.9	$118.4	$217.6	$43.3	43.3	$1,927.0	$310.6	$132.2	$442.9	$243.7	$842.1	$151.5	$79.7	$43.8
20	$0.0	$0.0	$211.9	$40.1	40.1	$1,782.5	$310.7	$126.5	$437.2	$233.2	$860.1	$140.6	$71.5	$38.1
21	$0.0	$0.0	$206.6	$37.1	37.1	$1,648.8	$285.0	$120.4	$405.4	$221.9	$777.8	$115.6	$60.3	$33.0
22	$0.0	$0.0	$201.7	$34.3	34.3	$1,525.1	$261.3	$113.4	$374.8	$209.1	$705.3	$95.3	$50.6	$28.3
23	$0.0	$0.0	$197.2	$31.7	31.7	$1,410.7	$239.4	$106.1	$345.5	$195.5	$640.8	$78.7	$42.4	$24.0
24	$0.0	$0.0	$193.0	$29.3	29.3	$1,304.9	$219.1	$98.6	$317.8	$181.8	$583.0	$65.1	$35.5	$20.3
25	$0.0	$100.0	$189.1	$27.1	27.1	$1,207.1	$174.2	$93.0	$267.2	$171.4	$452.3	$45.9	$27.1	$17.4
Total	**$622.0**	**$5,254.3**	**$2,917.9**	**$578.1**	**578.1**	**$25,706.4**	**$3,051.2**	**$1,667.3**	**$4,718.5**	**$3,073.5**	**$8,542.3**	**$894.2**	**$873.7**	**$607.0**
											Nom IRR	**18.1%**		
											Real IRR	**15.8%**		

*****Totals do not always equal column sums due to rounding.

Table 3C.7: Selected Statistics for Economic and Rent Analysis of Long Pipeline Oil Scenario - $50 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$347.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$347.1	-$161.9	$0.0	$0.0
10	$0.0	$1,067.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,073.2	-$455.1	$0.0	$0.0
11	$0.0	$1,339.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,358.2	-$523.6	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$917.7	$9.0	$0.0	$9.0	$0.0	-$238.6	-$83.6	$3.2	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$2,705.3	$43.4	$96.4	$139.8	$177.7	$1,798.4	$573.0	$44.6	$56.6
14	$0.0	$232.6	$237.8	$54.7	54.7	$2,705.3	$100.2	$204.4	$304.7	$376.9	$1,498.6	$434.1	$88.3	$109.2
15	$0.0	$177.6	$237.8	$54.7	54.7	$2,705.3	$157.6	$210.8	$368.4	$388.6	$1,478.0	$389.2	$97.0	$102.3
16	$0.0	$177.6	$237.8	$54.7	54.7	$2,705.3	$454.0	$185.8	$639.8	$342.5	$1,252.9	$299.9	$153.2	$82.0
17	$0.0	$177.6	$230.5	$50.6	50.6	$2,502.4	$414.9	$175.2	$590.1	$323.0	$1,130.5	$246.0	$128.4	$70.3
18	$0.0	$118.4	$223.8	$46.8	46.8	$2,314.7	$390.7	$164.6	$555.3	$303.5	$1,066.8	$211.1	$109.9	$60.0
19	$18.9	$118.4	$217.6	$43.3	43.3	$2,141.1	$353.5	$152.8	$506.2	$281.6	$955.0	$171.8	$91.0	$50.6
20	$0.0	$0.0	$211.9	$40.1	40.1	$1,980.5	$350.3	$145.5	$495.8	$268.2	$964.5	$157.7	$81.1	$43.9
21	$0.0	$0.0	$206.6	$37.1	37.1	$1,832.0	$469.8	$120.2	$590.0	$221.6	$776.8	$115.5	$87.7	$32.9
22	$0.0	$0.0	$201.7	$34.3	34.3	$1,694.6	$442.8	$112.0	$554.8	$206.4	$697.4	$94.2	$75.0	$27.9
23	$0.0	$0.0	$197.2	$31.7	31.7	$1,567.5	$406.1	$104.9	$511.0	$193.3	$634.3	$77.9	$62.8	$23.7
24	$0.0	$0.0	$193.0	$29.3	29.3	$1,449.9	$372.2	$97.7	$469.9	$180.1	$577.7	$64.5	$52.5	$20.1
25	$0.0	$100.0	$189.1	$27.1	27.1	$1,341.2	$301.5	$93.8	$395.3	$172.9	$456.8	$46.4	$40.1	$17.6
Total	**$622.0**	**$5,254.3**	**$2,917.9**	**$578.1**	**578.1**	**$28,562.7**	**$4,266.0**	**$1,864.1**	**$6,130.1**	**$3,436.2**	**$9,624.2**	**$1,166.3**	**$1,114.6**	**$697.2**
											Nom IRR	**19.7%**		
											Real IRR	**17.4%**		

*****Totals do not always equal column sums due to rounding.

Table 3C.8: Selected Statistics for Economic and Rent Analysis of Long Pipeline Oil Scenario - $55 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$347.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$347.1	-$161.9	$0.0	$0.0
10	$0.0	$1,067.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,073.2	-$455.1	$0.0	$0.0
11	$0.0	$1,339.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,358.2	-$523.6	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$1,009.4	$9.9	$0.0	$9.9	$0.0	-$147.7	-$51.8	$3.5	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$2,975.8	$47.9	$139.0	$186.9	$256.2	$1,943.3	$619.2	$59.5	$81.6
14	$0.0	$232.6	$237.8	$54.7	54.7	$2,975.8	$116.4	$235.0	$351.4	$433.1	$1,666.1	$482.6	$101.8	$125.5
15	$0.0	$177.6	$237.8	$54.7	54.7	$2,975.8	$329.4	$222.7	$552.1	$410.5	$1,543.1	$406.3	$145.4	$108.1
16	$0.0	$177.6	$237.8	$54.7	54.7	$2,975.8	$508.1	$211.8	$719.8	$390.4	$1,395.5	$334.1	$172.3	$93.4
17	$0.0	$177.6	$230.5	$50.6	50.6	$2,752.6	$464.9	$199.2	$664.2	$367.3	$1,262.4	$274.7	$144.5	$79.9
18	$0.0	$118.4	$223.8	$46.8	46.8	$2,546.2	$469.2	$183.0	$652.2	$337.3	$1,167.6	$231.0	$129.0	$66.7
19	$18.9	$118.4	$217.6	$43.3	43.3	$2,355.2	$594.4	$149.5	$744.0	$275.7	$937.3	$168.6	$133.8	$49.6
20	$0.0	$0.0	$211.9	$40.1	40.1	$2,178.6	$584.8	$141.1	$726.0	$260.2	$940.4	$153.8	$118.7	$42.5
21	$0.0	$0.0	$206.6	$37.1	37.1	$2,015.2	$537.5	$134.1	$671.5	$247.1	$852.9	$126.8	$99.8	$36.7
22	$0.0	$0.0	$201.7	$34.3	34.3	$1,864.0	$493.7	$126.2	$619.9	$232.6	$775.5	$104.8	$83.8	$31.4
23	$0.0	$0.0	$197.2	$31.7	31.7	$1,724.2	$453.2	$118.0	$571.2	$217.6	$706.6	$86.8	$70.2	$26.7
24	$0.0	$0.0	$193.0	$29.3	29.3	$1,594.9	$415.7	$109.9	$525.5	$202.5	$644.6	$72.0	$58.7	$22.6
25	$0.0	$100.0	$189.1	$27.1	27.1	$1,475.3	$341.8	$105.1	$446.8	$193.6	$518.6	$52.7	$45.4	$19.7
Total	**$622.0**	**$5,254.3**	**$2,917.9**	**$578.1**	**578.1**	**$31,418.9**	**$5,366.9**	**$2,074.5**	**$7,441.4**	**$3,824.1**	**$10,781.3**	**$1,430.1**	**$1,366.4**	**$784.6**
											Nom IRR	**21.1%**		
											Real IRR	**18.7%**		

*****Totals do not always equal column sums due to rounding.

Table 3C.9: Selected Statistics for Economic and Rent Analysis of Long Pipeline Oil Scenario - $60 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$347.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$347.1	-$161.9	$0.0	$0.0
10	$0.0	$1,067.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,073.2	-$455.1	$0.0	$0.0
11	$0.0	$1,339.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,358.2	-$523.6	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$1,101.2	$10.8	$0.0	$10.8	$0.0	-$56.9	-$19.9	$3.8	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$3,246.3	$52.3	$181.6	$233.9	$334.8	$2,088.3	$665.4	$74.5	$106.7
14	$0.0	$232.6	$237.8	$54.7	54.7	$3,246.3	$141.0	$264.5	$405.4	$487.5	$1,828.2	$529.6	$117.4	$141.2
15	$0.0	$177.6	$237.8	$54.7	54.7	$3,246.3	$489.2	$236.0	$725.1	$435.0	$1,616.0	$425.6	$191.0	$114.5
16	$0.0	$177.6	$237.8	$54.7	54.7	$3,246.3	$562.2	$237.7	$799.9	$438.2	$1,538.0	$368.2	$191.5	$104.9
17	$0.0	$177.6	$230.5	$50.6	50.6	$3,002.9	$599.2	$213.1	$812.4	$392.9	$1,338.8	$291.4	$176.8	$85.5
18	$0.0	$118.4	$223.8	$46.8	46.8	$2,777.6	$725.0	$180.1	$905.0	$331.9	$1,151.6	$227.8	$179.1	$65.7
19	$18.9	$118.4	$217.6	$43.3	43.3	$2,569.3	$658.7	$167.5	$826.2	$308.8	$1,036.0	$186.3	$148.6	$55.5
20	$0.0	$0.0	$211.9	$40.1	40.1	$2,376.6	$644.3	$157.8	$802.0	$290.8	$1,031.8	$168.7	$131.1	$47.6
21	$0.0	$0.0	$206.6	$37.1	37.1	$2,198.4	$592.4	$149.4	$741.9	$275.5	$937.3	$139.3	$110.3	$40.9
22	$0.0	$0.0	$201.7	$34.3	34.3	$2,033.5	$544.5	$140.4	$685.0	$258.9	$853.7	$115.4	$92.6	$35.0
23	$0.0	$0.0	$197.2	$31.7	31.7	$1,881.0	$500.2	$131.2	$631.4	$241.9	$778.8	$95.7	$77.6	$29.7
24	$0.0	$0.0	$193.0	$29.3	29.3	$1,739.9	$459.2	$122.0	$581.2	$225.0	$711.4	$79.5	$64.9	$25.1
25	$0.0	$100.0	$189.1	$27.1	27.1	$1,609.4	$382.0	$116.3	$498.3	$214.4	$580.5	$58.9	$50.6	$21.8
Total	**$622.0**	**$5,254.3**	**$2,917.9**	**$578.1**	**578.1**	**$34,275.2**	**$6,360.9**	**$2,297.8**	**$8,658.7**	**$4,235.6**	**$12,008.8**	**$1,700.3**	**$1,609.7**	**$874.2**
											Nom IRR	**22.4%**		
											Real IRR	**20.0%**		

*****Totals do not always equal column sums due to rounding.

Table 3C.10: Selected Statistics for Economic and Rent Analysis of Long Pipeline Oil Scenario - $65 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$347.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$347.1	-$161.9	$0.0	$0.0
10	$0.0	$1,067.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,073.2	-$455.1	$0.0	$0.0
11	$0.0	$1,339.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,358.2	-$523.6	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$1,193.0	$11.7	$0.0	$11.7	$0.0	$34.0	$11.9	$4.1	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$3,516.9	$56.7	$224.2	$281.0	$413.3	$2,233.2	$711.6	$89.5	$131.7
14	$0.0	$232.6	$237.8	$54.7	54.7	$3,516.9	$195.2	$290.4	$485.6	$535.4	$1,970.7	$570.8	$140.7	$155.1
15	$0.0	$177.6	$237.8	$54.7	54.7	$3,516.9	$616.3	$253.2	$869.5	$466.7	$1,710.5	$450.4	$229.0	$122.9
16	$0.0	$177.6	$237.8	$54.7	54.7	$3,516.9	$637.9	$261.1	$899.0	$481.3	$1,666.4	$398.9	$215.2	$115.2
17	$0.0	$177.6	$230.5	$50.6	50.6	$3,253.1	$847.5	$213.4	$1,060.9	$393.3	$1,340.0	$291.6	$230.9	$85.6
18	$0.0	$118.4	$223.8	$46.8	46.8	$3,009.1	$794.4	$199.5	$993.9	$367.8	$1,258.3	$249.0	$196.6	$72.8
19	$18.9	$118.4	$217.6	$43.3	43.3	$2,783.4	$722.9	$185.5	$908.4	$342.0	$1,134.8	$204.1	$163.4	$61.5
20	$0.0	$0.0	$211.9	$40.1	40.1	$2,574.7	$703.7	$174.4	$878.1	$321.5	$1,123.1	$183.6	$143.6	$52.6
21	$0.0	$0.0	$206.6	$37.1	37.1	$2,381.6	$647.4	$164.8	$812.2	$303.8	$1,021.8	$151.9	$120.7	$45.2
22	$0.0	$0.0	$201.7	$34.3	34.3	$2,203.0	$595.4	$154.7	$750.0	$285.1	$931.8	$125.9	$101.4	$38.5
23	$0.0	$0.0	$197.2	$31.7	31.7	$2,037.7	$547.2	$144.4	$691.6	$266.1	$851.1	$104.6	$85.0	$32.7
24	$0.0	$0.0	$193.0	$29.3	29.3	$1,884.9	$502.7	$134.2	$636.9	$247.4	$778.3	$86.9	$71.1	$27.6
25	$0.0	$100.0	$189.1	$27.1	27.1	$1,743.5	$422.2	$127.6	$549.8	$235.2	$642.3	$65.2	$55.8	$23.9
Total	**$622.0**	**$5,254.3**	**$2,917.9**	**$578.1**	**578.1**	**$37,131.5**	**$7,301.2**	**$2,527.5**	**$9,828.7**	**$4,659.0**	**$13,271.6**	**$1,975.0**	**$1,847.0**	**$965.2**
											Nom IRR	**23.6%**		
											Real IRR	**21.1%**		

*Totals do not always equal column sums due to rounding.

Table 3C.11: Selected Statistics for Economic and Rent Analysis of Long Pipeline Oil Scenario - $70 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$347.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$347.1	-$161.9	$0.0	$0.0
10	$0.0	$1,067.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,073.2	-$455.1	$0.0	$0.0
11	$0.0	$1,339.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,358.2	-$523.6	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$1,284.7	$12.7	$0.0	$12.7	$0.0	$124.8	$43.7	$4.4	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$3,787.4	$64.5	$266.5	$330.9	$491.2	$2,375.9	$757.0	$105.4	$156.5
14	$0.0	$232.6	$237.8	$54.7	54.7	$3,787.4	$323.9	$307.5	$631.4	$566.7	$2,064.1	$597.9	$182.9	$164.2
15	$0.0	$177.6	$237.8	$54.7	54.7	$3,787.4	$670.4	$279.2	$949.5	$514.6	$1,853.1	$488.0	$250.0	$135.5
16	$0.0	$177.6	$237.8	$54.7	54.7	$3,787.4	$872.5	$265.4	$1,138.0	$489.3	$1,690.0	$404.6	$272.4	$117.1
17	$0.0	$177.6	$230.5	$50.6	50.6	$3,503.3	$922.6	$234.4	$1,157.0	$432.1	$1,455.4	$316.7	$251.8	$94.0
18	$0.0	$118.4	$223.8	$46.8	46.8	$3,240.6	$863.8	$219.0	$1,082.8	$403.6	$1,365.1	$270.1	$214.2	$79.9
19	$18.9	$118.4	$217.6	$43.3	43.3	$2,997.5	$787.1	$203.5	$990.6	$375.1	$1,233.5	$221.9	$178.2	$67.5
20	$0.0	$0.0	$211.9	$40.1	40.1	$2,772.7	$763.1	$191.1	$954.1	$352.2	$1,214.4	$198.6	$156.0	$57.6
21	$0.0	$0.0	$206.6	$37.1	37.1	$2,564.8	$702.4	$180.2	$882.6	$332.2	$1,106.3	$164.4	$131.2	$49.4
22	$0.0	$0.0	$201.7	$34.3	34.3	$2,372.4	$646.2	$168.9	$815.1	$311.4	$1,010.0	$136.5	$110.1	$42.1
23	$0.0	$0.0	$197.2	$31.7	31.7	$2,194.5	$594.2	$157.5	$751.8	$290.4	$923.4	$113.4	$92.4	$35.7
24	$0.0	$0.0	$193.0	$29.3	29.3	$2,029.9	$546.2	$146.4	$692.6	$269.9	$845.2	$94.4	$77.3	$30.1
25	$0.0	$100.0	$189.1	$27.1	27.1	$1,877.7	$462.5	$138.8	$601.3	$255.9	$704.2	$71.5	$61.0	$26.0
Total	**$622.0**	**$5,254.3**	**$2,917.9**	**$578.1**	**578.1**	**$39,987.7**	**$8,232.1**	**$2,758.3**	**$10,990.4**	**$5,084.5**	**$14,540.7**	**$2,247.3**	**$2,087.5**	**$1,055.5**
											Nom IRR	**24.7%**		
											Real IRR	**22.2%**		

*****Totals do not always equal column sums due to rounding.

Table 3C.12: Selected Statistics for Economic and Rent Analysis of Long Pipeline Oil Scenario - $75 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$347.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$347.1	-$161.9	$0.0	$0.0
10	$0.0	$1,067.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,073.2	-$455.1	$0.0	$0.0
11	$0.0	$1,339.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,358.2	-$523.6	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$1,376.5	$13.6	$0.0	$13.6	$0.0	$215.7	$75.6	$4.8	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$4,057.9	$82.8	$307.4	$390.2	$566.7	$2,511.7	$800.3	$124.3	$180.6
14	$0.0	$232.6	$237.8	$54.7	54.7	$4,057.9	$440.7	$325.9	$766.6	$600.8	$2,165.4	$627.2	$222.1	$174.0
15	$0.0	$177.6	$237.8	$54.7	54.7	$4,057.9	$724.5	$305.1	$1,029.6	$562.5	$1,995.7	$525.5	$271.1	$148.1
16	$0.0	$177.6	$237.8	$54.7	54.7	$4,057.9	$1,078.7	$273.1	$1,351.9	$503.5	$1,732.4	$414.7	$323.6	$120.5
17	$0.0	$177.6	$230.5	$50.6	50.6	$3,753.6	$997.7	$255.4	$1,253.1	$470.8	$1,570.8	$341.9	$272.7	$102.5
18	$0.0	$118.4	$223.8	$46.8	46.8	$3,472.1	$933.3	$238.4	$1,171.7	$439.5	$1,471.8	$291.2	$231.8	$86.9
19	$18.9	$118.4	$217.6	$43.3	43.3	$3,211.7	$851.4	$221.5	$1,072.8	$408.3	$1,332.2	$239.6	$193.0	$73.4
20	$0.0	$0.0	$211.9	$40.1	40.1	$2,970.8	$822.5	$207.7	$1,030.2	$382.8	$1,305.8	$213.5	$168.4	$62.6
21	$0.0	$0.0	$206.6	$37.1	37.1	$2,748.0	$757.3	$195.6	$952.9	$360.6	$1,190.8	$177.0	$141.6	$53.6
22	$0.0	$0.0	$201.7	$34.3	34.3	$2,541.9	$697.0	$183.1	$880.2	$337.6	$1,088.1	$147.0	$118.9	$45.6
23	$0.0	$0.0	$197.2	$31.7	31.7	$2,351.2	$641.3	$170.7	$812.0	$314.7	$995.7	$122.3	$99.7	$38.7
24	$0.0	$0.0	$193.0	$29.3	29.3	$2,174.9	$589.7	$158.6	$748.2	$292.3	$912.0	$101.9	$83.6	$32.6
25	$0.0	$100.0	$189.1	$27.1	27.1	$2,011.8	$502.7	$150.1	$652.8	$276.7	$766.0	$77.8	$66.3	$28.1
Total	**$622.0**	**$5,254.3**	**$2,917.9**	**$578.1**	**578.1**	**$42,844.0**	**$9,133.1**	**$2,992.7**	**$12,125.8**	**$5,516.6**	**$15,829.4**	**$2,524.1**	**$2,322.0**	**$1,147.3**
											Nom IRR	**25.7%**		
											Real IRR	**23.2%**		

*****Totals do not always equal column sums due to rounding.

Table 3C.13: Selected Statistics for Economic and Rent Analysis of Long Pipeline Oil Scenario - $80 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$347.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$347.1	-$161.9	$0.0	$0.0
10	$0.0	$1,067.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,073.2	-$455.1	$0.0	$0.0
11	$0.0	$1,339.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,358.2	-$523.6	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$1,468.3	$14.5	$0.0	$14.5	$0.0	$306.5	$107.4	$5.1	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$4,328.5	$100.8	$348.4	$449.2	$642.2	$2,647.6	$843.6	$143.1	$204.6
14	$0.0	$232.6	$237.8	$54.7	54.7	$4,328.5	$554.6	$344.7	$899.3	$635.4	$2,268.6	$657.1	$260.5	$184.1
15	$0.0	$177.6	$237.8	$54.7	54.7	$4,328.5	$904.1	$316.0	$1,220.1	$582.6	$2,055.6	$541.3	$321.3	$153.4
16	$0.0	$177.6	$237.8	$54.7	54.7	$4,328.5	$1,167.9	$294.9	$1,462.8	$543.6	$1,851.9	$443.3	$350.2	$130.1
17	$0.0	$177.6	$230.5	$50.6	50.6	$4,003.8	$1,072.8	$276.4	$1,349.2	$509.6	$1,686.2	$367.0	$293.6	$110.9
18	$0.0	$118.4	$223.8	$46.8	46.8	$3,703.5	$1,002.7	$257.8	$1,260.6	$475.3	$1,578.6	$312.3	$249.4	$94.0
19	$18.9	$118.4	$217.6	$43.3	43.3	$3,425.8	$915.6	$239.5	$1,155.1	$441.4	$1,431.0	$257.4	$207.7	$79.4
20	$0.0	$0.0	$211.9	$40.1	40.1	$3,168.8	$881.9	$224.3	$1,106.2	$413.5	$1,397.1	$228.4	$180.9	$67.6
21	$0.0	$0.0	$206.6	$37.1	37.1	$2,931.2	$812.3	$211.0	$1,023.3	$388.9	$1,275.3	$189.6	$152.1	$57.8
22	$0.0	$0.0	$201.7	$34.3	34.3	$2,711.3	$747.9	$197.4	$945.2	$363.8	$1,166.3	$157.6	$127.7	$49.2
23	$0.0	$0.0	$197.2	$31.7	31.7	$2,508.0	$688.3	$183.9	$872.2	$338.9	$1,068.0	$131.2	$107.1	$41.6
24	$0.0	$0.0	$193.0	$29.3	29.3	$2,319.9	$633.2	$170.8	$803.9	$314.8	$978.9	$109.3	$89.8	$35.2
25	$0.0	$100.0	$189.1	$27.1	27.1	$2,145.9	$542.9	$161.4	$704.3	$297.5	$827.9	$84.1	$71.5	$30.2
Total	**$622.0**	**$5,254.3**	**$2,917.9**	**$578.1**	**578.1**	**$45,700.3**	**$10,039.5**	**$3,226.5**	**$13,266.0**	**$5,947.5**	**$17,114.6**	**$2,798.2**	**$2,560.1**	**$1,238.1**
											Nom IRR	**26.7%**		
											Real IRR	**24.2%**		

***Totals do not always equal column sums due to rounding.

Table 3C.14: Selected Statistics for Economic and Rent Analysis of Long Pipeline Oil Scenario - $85 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$347.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$347.1	-$161.9	$0.0	$0.0
10	$0.0	$1,067.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,073.2	-$455.1	$0.0	$0.0
11	$0.0	$1,339.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,358.2	-$523.6	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$1,560.0	$15.4	$0.0	$15.4	$0.0	$397.4	$139.3	$5.4	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$4,599.0	$118.7	$389.4	$508.1	$717.8	$2,783.7	$887.0	$161.9	$228.7
14	$0.0	$232.6	$237.8	$54.7	54.7	$4,599.0	$666.4	$363.7	$1,030.2	$670.5	$2,373.1	$687.4	$298.4	$194.2
15	$0.0	$177.6	$237.8	$54.7	54.7	$4,599.0	$1,079.4	$327.5	$1,406.9	$603.6	$2,118.3	$557.8	$370.5	$159.0
16	$0.0	$177.6	$237.8	$54.7	54.7	$4,599.0	$1,249.0	$317.6	$1,566.7	$585.5	$1,976.6	$473.2	$375.0	$140.2
17	$0.0	$177.6	$230.5	$50.6	50.6	$4,254.1	$1,147.8	$297.5	$1,445.3	$548.3	$1,801.6	$392.1	$314.5	$119.3
18	$0.0	$118.4	$223.8	$46.8	46.8	$3,935.0	$1,072.2	$277.3	$1,349.4	$511.1	$1,685.3	$333.4	$267.0	$101.1
19	$18.9	$118.4	$217.6	$43.3	43.3	$3,639.9	$979.8	$257.5	$1,237.3	$474.6	$1,529.7	$275.1	$222.5	$85.4
20	$0.0	$0.0	$211.9	$40.1	40.1	$3,366.9	$941.3	$241.0	$1,182.3	$444.2	$1,488.4	$243.4	$193.3	$72.6
21	$0.0	$0.0	$206.6	$37.1	37.1	$3,114.4	$867.2	$226.4	$1,093.6	$417.3	$1,359.8	$202.1	$162.6	$62.0
22	$0.0	$0.0	$201.7	$34.3	34.3	$2,880.8	$798.7	$211.6	$1,010.3	$390.1	$1,244.4	$168.2	$136.5	$52.7
23	$0.0	$0.0	$197.2	$31.7	31.7	$2,664.7	$735.3	$197.0	$932.4	$363.2	$1,140.3	$140.1	$114.5	$44.6
24	$0.0	$0.0	$193.0	$29.3	29.3	$2,464.9	$676.7	$182.9	$859.6	$337.2	$1,045.8	$116.8	$96.0	$37.7
25	$0.0	$100.0	$189.1	$27.1	27.1	$2,280.0	$583.2	$172.6	$755.8	$318.2	$889.7	$90.3	$76.7	$32.3
Total	**$622.0**	**$5,254.3**	**$2,917.9**	**$578.1**	**578.1**	**$48,556.5**	**$10,931.3**	**$3,462.0**	**$14,393.3**	**$6,381.7**	**$18,409.4**	**$3,074.7**	**$2,795.0**	**$1,329.8**
											Nom IRR	**27.6%**		
											Real IRR	**25.1%**		

*****Totals do not always equal column sums due to rounding.

Table 3C.15: Selected Statistics for Economic and Rent Analysis of Long Pipeline Oil Scenario - $90 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$347.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$347.1	-$161.9	$0.0	$0.0
10	$0.0	$1,067.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,073.2	-$455.1	$0.0	$0.0
11	$0.0	$1,339.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,358.2	-$523.6	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$1,651.8	$16.3	$0.0	$16.3	$0.0	$488.2	$171.1	$5.7	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$4,869.5	$136.4	$430.4	$566.8	$793.4	$2,919.9	$930.4	$180.6	$252.8
14	$0.0	$232.6	$237.8	$54.7	54.7	$4,869.5	$776.6	$383.0	$1,159.6	$706.0	$2,478.8	$718.0	$335.9	$204.5
15	$0.0	$177.6	$237.8	$54.7	54.7	$4,869.5	$1,244.8	$340.1	$1,584.9	$626.9	$2,187.6	$576.1	$417.4	$165.1
16	$0.0	$177.6	$237.8	$54.7	54.7	$4,869.5	$1,330.2	$340.4	$1,670.6	$627.4	$2,101.4	$503.1	$399.9	$150.2
17	$0.0	$177.6	$230.5	$50.6	50.6	$4,504.3	$1,222.9	$318.5	$1,541.4	$587.1	$1,917.0	$417.2	$335.5	$127.8
18	$0.0	$118.4	$223.8	$46.8	46.8	$4,166.5	$1,141.6	$296.7	$1,438.3	$547.0	$1,792.1	$354.5	$284.6	$108.2
19	$18.9	$118.4	$217.6	$43.3	43.3	$3,854.0	$1,044.1	$275.4	$1,319.5	$507.7	$1,628.5	$292.9	$237.3	$91.3
20	$0.0	$0.0	$211.9	$40.1	40.1	$3,564.9	$1,000.8	$257.6	$1,258.4	$474.8	$1,579.8	$258.3	$205.8	$77.6
21	$0.0	$0.0	$206.6	$37.1	37.1	$3,297.6	$922.2	$241.8	$1,164.0	$445.7	$1,444.2	$214.7	$173.0	$66.2
22	$0.0	$0.0	$201.7	$34.3	34.3	$3,050.3	$849.5	$225.8	$1,075.4	$416.3	$1,322.6	$178.7	$145.3	$56.3
23	$0.0	$0.0	$197.2	$31.7	31.7	$2,821.5	$782.3	$210.2	$992.5	$387.5	$1,212.6	$149.0	$121.9	$47.6
24	$0.0	$0.0	$193.0	$29.3	29.3	$2,609.9	$720.2	$195.1	$915.3	$359.7	$1,112.6	$124.3	$102.2	$40.2
25	$0.0	$100.0	$189.1	$27.1	27.1	$2,414.1	$623.4	$183.9	$807.3	$339.0	$951.6	$96.6	$82.0	$34.4
Total	**$622.0**	**$5,254.3**	**$2,917.9**	**$578.1**	**578.1**	**$51,412.8**	**$11,811.3**	**$3,699.0**	**$15,510.3**	**$6,818.4**	**$19,711.9**	**$3,353.3**	**$3,027.0**	**$1,422.2**
											Nom IRR	**28.5%**		
											Real IRR	**26.0%**		

*****Totals do not always equal column sums due to rounding.

Table 3C.16: Selected Statistics for Economic and Rent Analysis of Long Pipeline Oil Scenario - $95 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$347.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$347.1	-$161.9	$0.0	$0.0
10	$0.0	$1,067.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,073.2	-$455.1	$0.0	$0.0
11	$0.0	$1,339.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,358.2	-$523.6	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$1,743.6	$17.2	$0.0	$17.2	$0.0	$579.1	$203.0	$6.0	$0.0
13	$0.0	$296.8	$237.8	$54.7	54.7	$5,140.0	$153.9	$471.5	$625.4	$869.1	$3,056.1	$973.8	$199.3	$276.9
14	$0.0	$232.6	$237.8	$54.7	54.7	$5,140.0	$885.4	$402.4	$1,287.8	$741.7	$2,585.3	$748.9	$373.0	$214.9
15	$0.0	$177.6	$237.8	$54.7	54.7	$5,140.0	$1,403.1	$353.6	$1,756.6	$651.7	$2,261.5	$595.5	$462.6	$171.6
16	$0.0	$177.6	$237.8	$54.7	54.7	$5,140.0	$1,411.4	$363.1	$1,774.4	$669.3	$2,226.1	$532.9	$424.8	$160.2
17	$0.0	$177.6	$230.5	$50.6	50.6	$4,754.5	$1,298.0	$339.5	$1,637.5	$625.8	$2,032.4	$442.3	$356.4	$136.2
18	$0.0	$118.4	$223.8	$46.8	46.8	$4,397.9	$1,211.0	$316.2	$1,527.2	$582.8	$1,898.8	$375.7	$302.2	$115.3
19	$18.9	$118.4	$217.6	$43.3	43.3	$4,068.1	$1,108.3	$293.4	$1,401.7	$540.9	$1,727.2	$310.7	$252.1	$97.3
20	$0.0	$0.0	$211.9	$40.1	40.1	$3,763.0	$1,060.2	$274.2	$1,334.4	$505.5	$1,671.1	$273.2	$218.2	$82.7
21	$0.0	$0.0	$206.6	$37.1	37.1	$3,480.8	$977.2	$257.2	$1,234.3	$474.0	$1,528.7	$227.2	$183.5	$70.5
22	$0.0	$0.0	$201.7	$34.3	34.3	$3,219.7	$900.4	$240.1	$1,140.5	$442.6	$1,400.7	$189.3	$154.1	$59.8
23	$0.0	$0.0	$197.2	$31.7	31.7	$2,978.2	$829.4	$223.4	$1,052.7	$411.8	$1,284.8	$157.8	$129.3	$50.6
24	$0.0	$0.0	$193.0	$29.3	29.3	$2,754.9	$763.7	$207.3	$971.0	$382.1	$1,179.5	$131.7	$108.4	$42.7
25	$0.0	$100.0	$189.1	$27.1	27.1	$2,548.2	$663.6	$195.2	$858.8	$359.8	$1,013.4	$102.9	$87.2	$36.5
Total	**$622.0**	**$5,254.3**	**$2,917.9**	**$578.1**	**578.1**	**$54,269.1**	**$12,682.7**	**$3,936.9**	**$16,619.7**	**$7,257.1**	**$21,020.2**	**$3,633.5**	**$3,257.1**	**$1,515.1**
											Nom IRR	**29.3%**		
											Real IRR	**26.8%**		

*****Totals do not always equal column sums due to rounding.

Table 3C.17: Selected Statistics for Economic and Rent Analysis of Long Pipeline Oil Scenario - $100 US/bbl

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Annual Prod (mm bbl)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$6.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$6.2	-$3.8	$0.0	$0.0
7	$0.0	$12.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$12.4	-$7.0	$0.0	$0.0
8	$0.0	$24.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$24.7	-$12.7	$0.0	$0.0
9	$0.0	$347.1	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$347.1	-$161.9	$0.0	$0.0
10	$0.0	$1,067.3	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,073.2	-$455.1	$0.0	$0.0
11	$0.0	$1,339.3	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,358.2	-$523.6	$0.0	$0.0
12	$0.0	$1,058.1	$70.5	$18.6	18.6	$1,835.3	$18.2	$9.1	$27.3	$16.8	$644.1	$225.7	$9.6	$5.9
13	$0.0	$296.8	$237.8	$54.7	54.7	$5,410.6	$183.3	$502.2	$685.5	$925.7	$3,210.0	$1,022.8	$218.4	$295.0
14	$0.0	$232.6	$237.8	$54.7	54.7	$5,410.6	$1,062.7	$413.6	$1,476.3	$762.4	$2,646.7	$766.7	$427.6	$220.8
15	$0.0	$177.6	$237.8	$54.7	54.7	$5,410.6	$1,492.5	$375.3	$1,867.8	$691.8	$2,380.8	$626.9	$491.9	$182.2
16	$0.0	$177.6	$237.8	$54.7	54.7	$5,410.6	$1,492.5	$385.8	$1,878.3	$711.2	$2,350.9	$562.8	$449.7	$170.2
17	$0.0	$177.6	$230.5	$50.6	50.6	$5,004.8	$1,373.1	$360.5	$1,733.6	$664.6	$2,147.8	$467.4	$377.3	$144.6
18	$0.0	$118.4	$223.8	$46.8	46.8	$4,629.4	$1,280.5	$335.6	$1,616.1	$618.7	$2,005.5	$396.8	$319.7	$122.4
19	$18.9	$118.4	$217.6	$43.3	43.3	$4,282.2	$1,172.5	$311.4	$1,483.9	$574.0	$1,825.9	$328.4	$266.9	$103.2
20	$0.0	$0.0	$211.9	$40.1	40.1	$3,961.0	$1,119.6	$290.9	$1,410.5	$536.2	$1,762.4	$288.2	$230.6	$87.7
21	$0.0	$0.0	$206.6	$37.1	37.1	$3,664.0	$1,032.1	$272.6	$1,304.7	$502.4	$1,613.2	$239.8	$193.9	$74.7
22	$0.0	$0.0	$201.7	$34.3	34.3	$3,389.2	$951.2	$254.3	$1,205.5	$468.8	$1,478.8	$199.8	$162.9	$63.3
23	$0.0	$0.0	$197.2	$31.7	31.7	$3,135.0	$876.4	$236.5	$1,112.9	$436.0	$1,357.1	$166.7	$136.7	$53.6
24	$0.0	$0.0	$193.0	$29.3	29.3	$2,899.9	$807.2	$219.5	$1,026.6	$404.6	$1,246.4	$139.2	$114.7	$45.2
25	$0.0	$100.0	$189.1	$27.1	27.1	$2,682.4	$703.9	$206.4	$910.3	$380.5	$1,075.3	$109.2	$92.4	$38.6
Total	**$622.0**	**$5,254.3**	**$2,917.9**	**$578.1**	**578.1**	**$57,125.4**	**$13,565.7**	**$4,173.7**	**$17,739.4**	**$7,693.5**	**$22,320.3**	**$3,909.0**	**$3,492.3**	**$1,607.4**
											Nom IRR	**30.1%**		
											Real IRR	**27.5%**		

*Totals do not always equal column sums due to rounding.

Appendix 3D: Results of Economic and Rent Analysis – Short Pipeline Wet Gas Scenario ($2006)

Table 3D.1: Selected Statistics for Economic and Rent Analysis of Short Pipeline Wet Gas Scenario - $2 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$145.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$145.7	-$68.0	$0.0	$0.0
10	$0.0	$588.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$594.7	-$252.2	$0.0	$0.0
11	$0.0	$956.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$974.8	-$375.8	$0.0	$0.0
12	$0.0	$854.0	$80.7	$80.5	220.4	$294.3	$4.3	$0.0	$4.3	$0.0	-$725.1	-$254.1	$1.5	$0.0
13	$0.0	$99.4	$90.9	$160.9	440.8	$565.7	$8.1	$0.0	$8.1	$0.0	$206.4	$65.8	$2.6	$0.0
14	$0.0	$96.1	$90.9	$160.9	440.8	$565.7	$8.1	$0.0	$8.1	$0.0	$209.7	$60.8	$2.3	$0.0
15	$0.0	$0.0	$90.9	$160.9	440.8	$565.7	$8.1	$0.0	$8.1	$0.0	$305.8	$80.5	$2.1	$0.0
16	$0.0	$59.2	$90.9	$160.9	440.8	$565.7	$8.1	$0.0	$8.1	$0.0	$246.6	$59.0	$1.9	$0.0
17	$0.0	$59.2	$90.9	$160.9	440.8	$565.7	$8.1	$0.0	$8.1	$0.0	$246.6	$53.7	$1.8	$0.0
18	$0.0	$0.0	$90.9	$160.9	440.8	$565.7	$8.1	$0.0	$8.1	$0.0	$305.8	$60.5	$1.6	$0.0
19	$0.0	$59.2	$90.9	$160.9	440.8	$565.7	$8.1	$0.0	$8.1	$0.0	$246.6	$44.4	$1.5	$0.0
20	$0.0	$59.2	$90.9	$160.9	440.8	$565.7	$8.1	$0.0	$8.1	$0.0	$246.6	$40.3	$1.3	$0.0
21	$0.0	$0.0	$90.9	$160.9	440.8	$565.7	$8.1	$0.0	$8.1	$0.0	$305.8	$45.5	$1.2	$0.0
22	$0.0	$59.2	$90.9	$160.9	440.8	$565.7	$8.1	$15.6	$23.7	$28.7	$202.3	$27.3	$3.2	$3.9
23	$0.0	$59.2	$90.9	$160.9	440.8	$565.7	$8.1	$28.9	$37.0	$53.2	$164.5	$20.2	$4.5	$6.5
24	$0.0	$0.0	$90.9	$160.9	440.8	$565.7	$8.1	$31.2	$39.3	$57.5	$217.1	$24.2	$4.4	$6.4
25	$0.0	$59.2	$86.4	$125.3	343.4	$445.8	$6.4	$21.3	$27.7	$39.3	$107.7	$10.9	$2.8	$4.0
26	$0.0	$59.2	$82.9	$97.6	267.5	$352.3	$5.1	$13.7	$18.8	$25.3	$68.5	$6.3	$1.7	$2.3
27	$0.0	$0.0	$80.2	$76.1	208.4	$279.5	$4.1	$9.9	$14.0	$18.3	$91.0	$7.6	$1.2	$1.5
28	$0.0	$59.2	$78.1	$59.3	162.3	$222.8	$3.3	$4.7	$8.0	$8.7	$9.6	$0.7	$0.6	$0.7
29	$0.0	$0.0	$76.4	$46.2	126.5	$178.7	$2.6	$2.8	$5.5	$5.2	$45.4	$3.1	$0.4	$0.4

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
30	$18.9	$59.2	$75.1	$36.0	98.5	$144.2	$2.2	$0.0	$2.2	$0.0	-$47.1	-$3.0	$0.1	$0.0
31	$0.0	$0.0	$74.1	$28.0	76.7	$117.4	$1.8	$0.0	$1.8	$0.0	$13.5	$0.8	$0.1	$0.0
32	$0.0	$0.0	$73.3	$21.8	59.8	$96.6	$1.5	$0.0	$1.5	$0.0	-$0.1	$0.0	$0.1	$0.0
33	$0.0	$0.0	$72.7	$17.0	46.6	$80.3	$1.3	-$1.1	$0.1	-$2.1	-$7.5	-$0.4	$0.0	-$0.1
34	$0.0	$0.0	$72.3	$13.2	36.3	$67.6	$1.1	-$2.2	-$1.1	-$4.0	-$12.9	-$0.6	$0.0	-$0.2
35	$0.0	$0.0	$71.9	$10.3	28.3	$57.7	$0.9	-$2.9	-$2.0	-$5.4	-$17.1	-$0.7	-$0.1	-$0.2
36	$0.0	$100.0	$71.6	$8.0	22.0	$50.1	$2.1	-$3.5	-$1.4	-$6.5	-$121.6	-$4.3	-$0.1	-$0.2
Total	**$622.0**	**$3,463.0**	**$2,111.2**	**$2,550.2**		**$9,175.9**	**$133.8**	**$118.4**	**$252.2**	**$218.2**	**-$40.9**	**-$831.5**	**$36.8**	**$25.0**
											Nom. IRR	**1.8%**		
											Real IRR	**-0.2%**		

***Totals do not always equal column sums due to rounding.**

Table 3D.2: Selected Statistics for Economic and Rent Analysis of Short Pipeline Wet Gas Scenario - $3 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$145.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$145.7	-$68.0	$0.0	$0.0
10	$0.0	$588.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$594.7	-$252.2	$0.0	$0.0
11	$0.0	$956.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$974.8	-$375.8	$0.0	$0.0
12	$0.0	$854.0	$80.7	$80.5	220.4	$392.2	$6.2	$0.0	$6.2	$0.0	-$629.2	-$220.5	$2.2	$0.0
13	$0.0	$99.4	$90.9	$160.9	440.8	$761.5	$12.0	$0.0	$12.0	$0.0	$398.2	$126.9	$3.8	$0.0
14	$0.0	$96.1	$90.9	$160.9	440.8	$761.5	$12.0	$0.0	$12.0	$0.0	$401.6	$116.3	$3.5	$0.0
15	$0.0	$0.0	$90.9	$160.9	440.8	$761.5	$12.0	$0.0	$12.0	$0.0	$497.6	$131.0	$3.2	$0.0
16	$0.0	$59.2	$90.9	$160.9	440.8	$761.5	$12.0	$0.0	$12.0	$0.0	$438.4	$105.0	$2.9	$0.0
17	$0.0	$59.2	$90.9	$160.9	440.8	$761.5	$12.0	$3.5	$15.5	$6.5	$428.4	$93.2	$3.4	$1.4
18	$0.0	$0.0	$90.9	$160.9	440.8	$761.5	$12.0	$44.2	$56.2	$81.5	$372.0	$73.6	$11.1	$16.1
19	$0.0	$59.2	$90.9	$160.9	440.8	$761.5	$12.0	$46.4	$58.4	$85.5	$306.6	$55.1	$10.5	$15.4
20	$0.0	$59.2	$90.9	$160.9	440.8	$761.5	$12.0	$48.0	$60.0	$88.5	$301.9	$49.4	$9.8	$14.5
21	$0.0	$0.0	$90.9	$160.9	440.8	$761.5	$12.0	$51.4	$63.4	$94.7	$351.5	$52.2	$9.4	$14.1
22	$0.0	$59.2	$90.9	$160.9	440.8	$761.5	$30.0	$49.5	$79.5	$91.2	$279.7	$37.8	$10.7	$12.3
23	$0.0	$59.2	$90.9	$160.9	440.8	$761.5	$30.0	$49.7	$79.8	$91.7	$279.0	$34.3	$9.8	$11.3
24	$0.0	$0.0	$90.9	$160.9	440.8	$761.5	$30.0	$52.1	$82.1	$96.0	$331.6	$37.0	$9.2	$10.7
25	$0.0	$59.2	$86.4	$125.3	343.4	$598.2	$23.6	$37.6	$61.2	$69.2	$196.8	$20.0	$6.2	$7.0
26	$0.0	$59.2	$82.9	$97.6	267.5	$471.1	$18.7	$26.3	$45.0	$48.5	$137.8	$12.7	$4.2	$4.5
27	$0.0	$0.0	$80.2	$76.1	208.4	$372.1	$14.8	$19.7	$34.5	$36.4	$144.8	$12.2	$2.9	$3.1
28	$0.0	$59.2	$78.1	$59.3	162.3	$294.9	$11.8	$12.3	$24.1	$22.7	$51.5	$3.9	$1.8	$1.7
29	$0.0	$0.0	$76.4	$46.2	126.5	$234.8	$9.4	$8.8	$18.2	$16.2	$77.9	$5.4	$1.3	$1.1
30	$18.9	$59.2	$75.1	$36.0	98.5	$188.0	$7.6	$1.4	$9.1	$2.7	-$12.9	-$0.8	$0.6	$0.2
31	$0.0	$0.0	$74.1	$28.0	76.7	$151.5	$8.4	$1.7	$10.1	$3.2	$36.0	$2.1	$0.6	$0.2
32	$0.0	$0.0	$73.3	$21.8	59.8	$123.1	$5.1	$0.6	$5.6	$1.0	$21.3	$1.1	$0.3	$0.1

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.0	46.6	$101.0	$4.2	$0.0	$4.2	$0.0	$7.1	$0.3	$0.2	$0.0
34	$0.0	$0.0	$72.3	$13.2	36.3	$83.7	$3.5	-$0.2	$3.3	-$0.4	-$4.7	-$0.2	$0.1	$0.0
35	$0.0	$0.0	$71.9	$10.3	28.3	$70.3	$3.0	-$1.4	$1.6	-$2.6	-$10.9	-$0.4	$0.1	-$0.1
36	$0.0	$100.0	$71.6	$8.0	22.0	$59.8	$2.6	-$2.4	$0.2	-$4.4	-$115.6	-$4.1	$0.0	-$0.2
Total	**$622.0**	**$3,463.0**	**$2,111.2**	**$2,550.2**		**$12,278.1**	**$317.1**	**$449.3**	**$766.4**	**$828.1**	**$1,937.3**	**-$436.7**	**$107.7**	**$113.3**
											Nom. IRR	**7.7%**		
											Real IRR	**5.6%**		

*****Totals do not always equal column sums due to rounding.

Table 3D.3: Selected Statistics for Economic and Rent Analysis of Short Pipeline Wet Gas Scenario - $4 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$145.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$145.7	-$68.0	$0.0	$0.0
10	$0.0	$588.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$594.7	-$252.2	$0.0	$0.0
11	$0.0	$956.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$974.8	-$375.8	$0.0	$0.0
12	$0.0	$854.0	$80.7	$80.5	220.4	$490.1	$8.2	$0.0	$8.2	$0.0	-$533.3	-$186.9	$2.9	$0.0
13	$0.0	$99.4	$90.9	$160.9	440.8	$957.2	$15.9	$0.0	$15.9	$0.0	$590.0	$188.0	$5.1	$0.0
14	$0.0	$96.1	$90.9	$160.9	440.8	$957.2	$15.9	$0.0	$15.9	$0.0	$593.4	$171.9	$4.6	$0.0
15	$0.0	$0.0	$90.9	$160.9	440.8	$957.2	$15.9	$8.9	$24.8	$16.4	$664.1	$174.9	$6.5	$4.3
16	$0.0	$59.2	$90.9	$160.9	440.8	$957.2	$15.9	$56.0	$71.9	$103.1	$471.2	$112.8	$17.2	$24.7
17	$0.0	$59.2	$90.9	$160.9	440.8	$957.2	$15.9	$61.2	$77.1	$112.8	$456.2	$99.3	$16.8	$24.6
18	$0.0	$0.0	$90.9	$160.9	440.8	$957.2	$15.9	$67.2	$83.1	$123.9	$498.4	$98.6	$16.4	$24.5
19	$0.0	$59.2	$90.9	$160.9	440.8	$957.2	$39.8	$66.5	$106.3	$122.6	$417.2	$75.0	$19.1	$22.1
20	$0.0	$59.2	$90.9	$160.9	440.8	$957.2	$39.8	$68.2	$108.0	$125.7	$412.5	$67.4	$17.7	$20.5
21	$0.0	$0.0	$90.9	$160.9	440.8	$957.2	$139.3	$59.6	$198.9	$109.9	$396.6	$59.0	$29.6	$16.3
22	$0.0	$59.2	$90.9	$160.9	440.8	$957.2	$127.3	$61.3	$188.6	$113.0	$344.6	$46.6	$25.5	$15.3
23	$0.0	$59.2	$90.9	$160.9	440.8	$957.2	$127.3	$61.5	$188.8	$113.5	$343.9	$42.2	$23.2	$13.9
24	$0.0	$0.0	$90.9	$160.9	440.8	$957.2	$139.3	$62.4	$201.7	$115.1	$388.6	$43.4	$22.5	$12.9
25	$0.0	$59.2	$86.4	$125.3	343.4	$750.7	$94.1	$47.4	$141.5	$87.4	$250.9	$25.5	$14.4	$8.9
26	$0.0	$59.2	$82.9	$97.6	267.5	$589.9	$68.2	$34.6	$102.9	$63.8	$183.4	$16.9	$9.5	$5.9
27	$0.0	$0.0	$80.2	$76.1	208.4	$464.6	$105.1	$20.0	$125.1	$36.9	$146.3	$12.3	$10.5	$3.1
28	$0.0	$59.2	$78.1	$59.3	162.3	$367.0	$56.7	$15.6	$72.3	$28.7	$69.4	$5.3	$5.5	$2.2
29	$0.0	$0.0	$76.4	$46.2	126.5	$291.0	$56.3	$9.9	$66.2	$18.2	$84.0	$5.8	$4.6	$1.3
30	$18.9	$59.2	$75.1	$36.0	98.5	$231.7	$12.0	$6.2	$18.2	$11.4	$13.0	$0.8	$1.1	$0.7
31	$0.0	$0.0	$74.1	$28.0	76.7	$185.6	$26.6	$3.7	$30.3	$6.7	$46.5	$2.7	$1.7	$0.4
32	$0.0	$0.0	$73.3	$21.8	59.8	$149.6	$16.5	$2.4	$18.9	$4.4	$31.3	$1.6	$1.0	$0.2

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.0	46.6	$121.6	$8.6	$1.3	$9.9	$2.4	$19.6	$0.9	$0.5	$0.1
34	$0.0	$0.0	$72.3	$13.2	36.3	$99.8	$4.3	$0.2	$4.5	$0.3	$9.5	$0.4	$0.2	$0.0
35	$0.0	$0.0	$71.9	$10.3	28.3	$82.8	$3.6	$0.0	$3.6	$0.0	-$3.0	-$0.1	$0.1	$0.0
36	$0.0	$100.0	$71.6	$8.0	22.0	$69.6	$3.1	-$1.2	$1.9	-$2.2	-$109.7	-$3.9	$0.1	-$0.1
Total	**$622.0**	**$3,463.0**	**$2,111.2**	**$2,550.2**		**$15,380.4**	**$1,171.7**	**$712.8**	**$1,884.6**	**$1,314.0**	**$3,435.5**	**-$119.8**	**$256.3**	**$201.8**
											Nom. IRR	**11.1%**		
											Real IRR	**8.9%**		

***Totals do not always equal column sums due to rounding.**

Table 3D.4: Selected Statistics for Economic and Rent Analysis of Short Pipeline Wet Gas Scenario - $5 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$145.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$145.7	-$68.0	$0.0	$0.0
10	$0.0	$588.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$594.7	-$252.2	$0.0	$0.0
11	$0.0	$956.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$974.8	-$375.8	$0.0	$0.0
12	$0.0	$854.0	$80.7	$80.5	220.4	$587.9	$10.1	$0.0	$10.1	$0.0	-$437.4	-$153.3	$3.6	$0.0
13	$0.0	$99.4	$90.9	$160.9	440.8	$1,152.9	$19.8	$0.0	$19.8	$0.0	$781.9	$249.1	$6.3	$0.0
14	$0.0	$96.1	$90.9	$160.9	440.8	$1,152.9	$19.8	$15.9	$35.8	$29.3	$740.0	$214.3	$10.4	$8.5
15	$0.0	$0.0	$90.9	$160.9	440.8	$1,152.9	$19.8	$71.8	$91.7	$132.4	$677.0	$178.3	$24.1	$34.9
16	$0.0	$59.2	$90.9	$160.9	440.8	$1,152.9	$19.8	$79.0	$98.8	$145.6	$597.5	$143.0	$23.7	$34.8
17	$0.0	$59.2	$90.9	$160.9	440.8	$1,152.9	$49.6	$80.7	$130.3	$148.7	$563.0	$122.5	$28.3	$32.4
18	$0.0	$0.0	$90.9	$160.9	440.8	$1,152.9	$49.6	$86.7	$136.3	$159.7	$605.1	$119.7	$27.0	$31.6
19	$0.0	$59.2	$90.9	$160.9	440.8	$1,152.9	$166.4	$74.8	$241.3	$137.9	$462.7	$83.2	$43.4	$24.8
20	$0.0	$59.2	$90.9	$160.9	440.8	$1,152.9	$166.4	$76.5	$242.9	$141.0	$458.0	$74.9	$39.7	$23.0
21	$0.0	$0.0	$90.9	$160.9	440.8	$1,152.9	$178.4	$78.4	$256.8	$144.5	$499.8	$74.3	$38.2	$21.5
22	$0.0	$59.2	$90.9	$160.9	440.8	$1,152.9	$291.3	$65.1	$356.4	$120.0	$365.5	$49.4	$48.2	$16.2
23	$0.0	$59.2	$90.9	$160.9	440.8	$1,152.9	$291.3	$65.4	$356.6	$120.5	$364.8	$44.8	$43.8	$14.8
24	$0.0	$0.0	$90.9	$160.9	440.8	$1,152.9	$312.2	$65.2	$377.4	$120.2	$403.6	$45.1	$42.1	$13.4
25	$0.0	$59.2	$86.4	$125.3	343.4	$903.2	$218.1	$50.8	$268.9	$93.7	$269.7	$27.4	$27.3	$9.5
26	$0.0	$59.2	$82.9	$97.6	267.5	$708.7	$161.0	$37.8	$198.8	$69.6	$200.6	$18.5	$18.3	$6.4
27	$0.0	$0.0	$80.2	$76.1	208.4	$557.1	$137.5	$27.2	$164.7	$50.2	$185.9	$15.6	$13.8	$4.2
28	$0.0	$59.2	$78.1	$59.3	162.3	$439.1	$81.9	$21.2	$103.1	$39.1	$100.3	$7.6	$7.9	$3.0
29	$0.0	$0.0	$76.4	$46.2	126.5	$347.1	$75.9	$14.3	$90.2	$26.3	$108.1	$7.5	$6.3	$1.8
30	$18.9	$59.2	$75.1	$36.0	98.5	$275.5	$27.3	$9.6	$36.9	$17.7	$31.7	$2.0	$2.3	$1.1
31	$0.0	$0.0	$74.1	$28.0	76.7	$219.7	$38.6	$6.3	$44.9	$11.6	$61.1	$3.5	$2.6	$0.7
32	$0.0	$0.0	$73.3	$21.8	59.8	$176.2	$25.8	$4.4	$30.3	$8.2	$42.6	$2.2	$1.6	$0.4

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.0	46.6	$142.3	$15.9	$2.9	$18.8	$5.3	$28.5	$1.3	$0.9	$0.3
34	$0.0	$0.0	$72.3	$13.2	36.3	$115.9	$8.1	$1.6	$9.7	$3.0	$17.6	$0.8	$0.4	$0.1
35	$0.0	$0.0	$71.9	$10.3	28.3	$95.4	$4.3	$0.4	$4.6	$0.7	$7.9	$0.3	$0.2	$0.0
36	$0.0	$100.0	$71.6	$8.0	22.0	$79.4	$3.6	$0.0	$3.5	-$0.1	-$103.7	-$3.7	$0.1	$0.0
Total	**$622.0**	**$3,463.0**	**$2,111.2**	**$2,550.2**		**$18,482.7**	**$2,392.7**	**$935.9**	**$3,328.6**	**$1,725.2**	**$4,682.6**	**$148.3**	**$460.4**	**$283.5**
											Nom. IRR	**13.5%**		
											Real IRR	**11.3%**		

*****Totals do not always equal column sums due to rounding.

Table 3D.5: Selected Statistics for Economic and Rent Analysis of Short Pipeline Wet Gas Scenario - $6 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$145.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$145.7	-$68.0	$0.0	$0.0
10	$0.0	$588.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$594.7	-$252.2	$0.0	$0.0
11	$0.0	$956.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$974.8	-$375.8	$0.0	$0.0
12	$0.0	$854.0	$80.7	$80.5	220.4	$685.8	$12.1	$0.0	$12.1	$0.0	-$341.5	-$119.7	$4.2	$0.0
13	$0.0	$99.4	$90.9	$160.9	440.8	$1,348.7	$23.8	$0.0	$23.8	$0.0	$973.7	$310.3	$7.6	$0.0
14	$0.0	$96.1	$90.9	$160.9	440.8	$1,348.7	$23.8	$72.6	$96.3	$133.8	$770.7	$223.2	$27.9	$38.7
15	$0.0	$0.0	$90.9	$160.9	440.8	$1,348.7	$23.8	$94.9	$118.6	$174.9	$803.4	$211.6	$31.2	$46.0
16	$0.0	$59.2	$90.9	$160.9	440.8	$1,348.7	$59.4	$97.7	$157.1	$180.1	$700.4	$167.7	$37.6	$43.1
17	$0.0	$59.2	$90.9	$160.9	440.8	$1,348.7	$205.6	$85.4	$291.0	$157.5	$589.2	$128.2	$63.3	$34.3
18	$0.0	$0.0	$90.9	$160.9	440.8	$1,348.7	$217.6	$90.0	$307.5	$165.9	$623.4	$123.3	$60.8	$32.8
19	$0.0	$59.2	$90.9	$160.9	440.8	$1,348.7	$205.6	$93.6	$299.2	$172.6	$565.9	$101.8	$53.8	$31.0
20	$0.0	$59.2	$90.9	$160.9	440.8	$1,348.7	$359.8	$76.8	$436.6	$141.5	$459.6	$75.2	$71.4	$23.1
21	$0.0	$0.0	$90.9	$160.9	440.8	$1,348.7	$380.7	$77.6	$458.3	$143.1	$495.4	$73.6	$68.1	$21.3
22	$0.0	$59.2	$90.9	$160.9	440.8	$1,348.7	$359.8	$80.4	$440.2	$148.2	$449.3	$60.7	$59.5	$20.0
23	$0.0	$59.2	$90.9	$160.9	440.8	$1,348.7	$359.8	$80.6	$440.4	$148.6	$448.6	$55.1	$54.1	$18.3
24	$0.0	$0.0	$90.9	$160.9	440.8	$1,348.7	$380.7	$80.4	$461.2	$148.3	$487.4	$54.4	$51.5	$16.6
25	$0.0	$59.2	$86.4	$125.3	343.4	$1,055.7	$271.4	$62.7	$334.1	$115.6	$335.0	$34.0	$33.9	$11.7
26	$0.0	$59.2	$82.9	$97.6	267.5	$827.4	$202.6	$47.0	$249.6	$86.7	$251.4	$23.2	$23.0	$8.0
27	$0.0	$0.0	$80.2	$76.1	208.4	$649.7	$169.9	$34.4	$204.3	$63.5	$225.6	$18.9	$17.1	$5.3
28	$0.0	$59.2	$78.1	$59.3	162.3	$511.2	$107.2	$26.8	$134.0	$49.5	$131.1	$10.0	$10.2	$3.8
29	$0.0	$0.0	$76.4	$46.2	126.5	$403.3	$95.6	$18.6	$114.2	$34.4	$132.1	$9.2	$7.9	$2.4
30	$18.9	$59.2	$75.1	$36.0	98.5	$319.2	$42.6	$13.0	$55.6	$24.0	$50.5	$3.2	$3.5	$1.5
31	$0.0	$0.0	$74.1	$28.0	76.7	$253.7	$50.5	$9.0	$59.4	$16.5	$75.7	$4.3	$3.4	$0.9
32	$0.0	$0.0	$73.3	$21.8	59.8	$202.7	$35.1	$6.5	$41.6	$12.0	$54.0	$2.8	$2.2	$0.6

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.0	46.6	$163.0	$23.1	$4.5	$27.6	$8.3	$37.4	$1.8	$1.3	$0.4
34	$0.0	$0.0	$72.3	$13.2	36.3	$132.1	$13.7	$2.9	$16.6	$5.3	$24.5	$1.1	$0.7	$0.2
35	$0.0	$0.0	$71.9	$10.3	28.3	$107.9	$6.5	$1.6	$8.1	$2.9	$14.7	$0.6	$0.3	$0.1
36	$0.0	$100.0	$71.6	$8.0	22.0	$89.2	$4.1	$0.0	$4.1	$0.0	-$94.5	-$3.4	$0.1	$0.0
Total	**$622.0**	**$3,463.0**	**$2,111.2**	**$2,550.2**		**$21,584.9**	**$3,634.5**	**$1,157.2**	**$4,791.7**	**$2,133.0**	**$5,913.9**	**$390.9**	**$695.0**	**$360.3**
											Nom. IRR	**15.5%**		
											Real IRR	**13.2%**		

*****Totals do not always equal column sums due to rounding.

Table 3D.6: Selected Statistics for Economic and Rent Analysis of Short Pipeline Wet Gas Scenario - $7 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$145.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$145.7	-$68.0	$0.0	$0.0
10	$0.0	$588.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$594.7	-$252.2	$0.0	$0.0
11	$0.0	$956.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$974.8	-$375.8	$0.0	$0.0
12	$0.0	$854.0	$80.7	$80.5	220.4	$783.7	$14.1	$0.0	$14.1	$0.0	-$245.5	-$86.1	$4.9	$0.0
13	$0.0	$99.4	$90.9	$160.9	440.8	$1,544.4	$27.7	$23.8	$51.5	$47.9	$1,093.8	$348.5	$16.4	$15.3
14	$0.0	$96.1	$90.9	$160.9	440.8	$1,544.4	$27.7	$105.9	$133.5	$195.2	$867.9	$251.4	$38.7	$56.5
15	$0.0	$0.0	$90.9	$160.9	440.8	$1,544.4	$69.2	$112.9	$182.1	$208.1	$902.4	$237.6	$47.9	$54.8
16	$0.0	$59.2	$90.9	$160.9	440.8	$1,544.4	$244.7	$99.0	$343.7	$182.4	$707.3	$169.3	$82.3	$43.7
17	$0.0	$59.2	$90.9	$160.9	440.8	$1,544.4	$244.7	$104.2	$349.0	$192.1	$692.3	$150.7	$75.9	$41.8
18	$0.0	$0.0	$90.9	$160.9	440.8	$1,544.4	$449.2	$85.7	$534.9	$157.9	$599.8	$118.7	$105.8	$31.2
19	$0.0	$59.2	$90.9	$160.9	440.8	$1,544.4	$428.3	$90.4	$518.7	$166.6	$548.1	$98.6	$93.3	$30.0
20	$0.0	$59.2	$90.9	$160.9	440.8	$1,544.4	$428.3	$92.0	$520.3	$169.6	$543.4	$88.9	$85.1	$27.7
21	$0.0	$0.0	$90.9	$160.9	440.8	$1,544.4	$449.2	$92.9	$542.1	$171.2	$579.3	$86.1	$80.6	$25.5
22	$0.0	$59.2	$90.9	$160.9	440.8	$1,544.4	$428.3	$95.7	$524.0	$176.3	$533.1	$72.0	$70.8	$23.8
23	$0.0	$59.2	$90.9	$160.9	440.8	$1,544.4	$428.3	$95.9	$524.2	$176.8	$532.4	$65.4	$64.4	$21.7
24	$0.0	$0.0	$90.9	$160.9	440.8	$1,544.4	$449.2	$95.7	$544.9	$176.4	$571.2	$63.8	$60.9	$19.7
25	$0.0	$59.2	$86.4	$125.3	343.4	$1,208.2	$324.8	$74.6	$399.4	$137.5	$400.3	$40.6	$40.5	$14.0
26	$0.0	$59.2	$82.9	$97.6	267.5	$946.2	$244.2	$56.3	$300.4	$103.7	$302.3	$27.9	$27.7	$9.6
27	$0.0	$0.0	$80.2	$76.1	208.4	$742.2	$202.3	$41.7	$243.9	$76.8	$265.2	$22.3	$20.5	$6.4
28	$0.0	$59.2	$78.1	$59.3	162.3	$583.2	$132.4	$32.5	$164.8	$59.8	$162.0	$12.4	$12.6	$4.6
29	$0.0	$0.0	$76.4	$46.2	126.5	$459.4	$115.2	$23.0	$138.3	$42.4	$156.2	$10.8	$9.6	$2.9
30	$18.9	$59.2	$75.1	$36.0	98.5	$363.0	$57.9	$16.4	$74.3	$30.2	$69.2	$4.4	$4.7	$1.9
31	$0.0	$0.0	$74.1	$28.0	76.7	$287.8	$62.4	$11.6	$74.0	$21.4	$90.2	$5.2	$4.2	$1.2
32	$0.0	$0.0	$73.3	$21.8	59.8	$229.3	$44.4	$8.6	$53.0	$15.8	$65.4	$3.4	$2.8	$0.8

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.0	46.6	$183.7	$30.3	$6.1	$36.5	$11.3	$46.2	$2.2	$1.7	$0.5
34	$0.0	$0.0	$72.3	$13.2	36.3	$148.2	$19.4	$4.1	$23.5	$7.6	$31.4	$1.4	$1.0	$0.3
35	$0.0	$0.0	$71.9	$10.3	28.3	$120.5	$10.9	$2.6	$13.4	$4.7	$20.1	$0.8	$0.5	$0.2
36	$0.0	$100.0	$71.6	$8.0	22.0	$98.9	$4.5	$0.0	$4.5	$0.0	-$85.2	-$3.0	$0.2	$0.0
Total	**$622.0**	**$3,463.0**	**$2,111.2**	**$2,550.2**		**$24,687.2**	**$4,937.7**	**$1,371.5**	**$6,309.2**	**$2,532.1**	**$7,099.6**	**$612.9**	**$953.0**	**$434.2**
											Nom. IRR	**17.1%**		
											Real IRR	**14.8%**		

***Totals do not always equal column sums due to rounding.

Table 3D.7: Selected Statistics for Economic and Rent Analysis of Short Pipeline Wet Gas Scenario - $8 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$145.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$145.7	-$68.0	$0.0	$0.0
10	$0.0	$588.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$594.7	-$252.2	$0.0	$0.0
11	$0.0	$956.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$974.8	-$375.8	$0.0	$0.0
12	$0.0	$854.0	$80.7	$80.5	220.4	$881.6	$16.0	$0.0	$16.0	$0.0	-$149.6	-$52.4	$5.6	$0.0
13	$0.0	$99.4	$90.9	$160.9	440.8	$1,740.2	$31.6	$58.1	$89.7	$116.8	$1,182.4	$376.7	$28.6	$37.2
14	$0.0	$96.1	$90.9	$160.9	440.8	$1,740.2	$31.6	$128.9	$160.5	$237.6	$994.2	$288.0	$46.5	$68.8
15	$0.0	$0.0	$90.9	$160.9	440.8	$1,740.2	$79.0	$135.2	$214.2	$249.3	$1,024.9	$269.9	$56.4	$65.6
16	$0.0	$59.2	$90.9	$160.9	440.8	$1,740.2	$283.9	$117.7	$401.6	$217.1	$810.4	$194.0	$96.1	$52.0
17	$0.0	$59.2	$90.9	$160.9	440.8	$1,740.2	$496.8	$97.5	$594.3	$179.6	$655.2	$142.6	$129.3	$39.1
18	$0.0	$0.0	$90.9	$160.9	440.8	$1,740.2	$517.7	$100.9	$618.7	$186.1	$683.6	$135.2	$122.4	$36.8
19	$0.0	$59.2	$90.9	$160.9	440.8	$1,740.2	$496.8	$105.6	$602.5	$194.7	$631.9	$113.7	$108.4	$35.0
20	$0.0	$59.2	$90.9	$160.9	440.8	$1,740.2	$496.8	$107.3	$604.1	$197.8	$627.3	$102.6	$98.8	$32.3
21	$0.0	$0.0	$90.9	$160.9	440.8	$1,740.2	$517.7	$108.2	$625.9	$199.4	$663.1	$98.6	$93.0	$29.6
22	$0.0	$59.2	$90.9	$160.9	440.8	$1,740.2	$496.8	$110.9	$607.7	$204.5	$616.9	$83.4	$82.1	$27.6
23	$0.0	$59.2	$90.9	$160.9	440.8	$1,740.2	$496.8	$111.2	$608.0	$204.9	$616.3	$75.7	$74.7	$25.2
24	$0.0	$0.0	$90.9	$160.9	440.8	$1,740.2	$517.7	$111.0	$628.7	$204.6	$655.0	$73.2	$70.2	$22.8
25	$0.0	$59.2	$86.4	$125.3	343.4	$1,360.6	$378.2	$86.5	$464.7	$159.5	$465.6	$47.3	$47.2	$16.2
26	$0.0	$59.2	$82.9	$97.6	267.5	$1,065.0	$285.7	$65.5	$351.3	$120.8	$353.2	$32.6	$32.4	$11.2
27	$0.0	$0.0	$80.2	$76.1	208.4	$834.7	$234.7	$48.9	$283.5	$90.1	$304.8	$25.6	$23.8	$7.6
28	$0.0	$59.2	$78.1	$59.3	162.3	$655.3	$157.6	$38.1	$195.7	$70.2	$192.9	$14.7	$14.9	$5.4
29	$0.0	$0.0	$76.4	$46.2	126.5	$515.6	$134.9	$27.4	$162.3	$50.5	$180.2	$12.5	$11.3	$3.5
30	$18.9	$59.2	$75.1	$36.0	98.5	$406.7	$73.2	$19.8	$93.1	$36.5	$87.9	$5.5	$5.9	$2.3
31	$0.0	$0.0	$74.1	$28.0	76.7	$321.9	$74.3	$14.3	$88.6	$26.3	$104.8	$6.0	$5.1	$1.5
32	$0.0	$0.0	$73.3	$21.8	59.8	$255.8	$53.7	$10.7	$64.3	$19.6	$76.7	$4.0	$3.4	$1.0

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.0	46.6	$204.4	$37.6	$7.7	$45.3	$14.3	$55.1	$2.6	$2.1	$0.7
34	$0.0	$0.0	$72.3	$13.2	36.3	$164.3	$25.0	$5.4	$30.4	$10.0	$38.3	$1.7	$1.3	$0.4
35	$0.0	$0.0	$71.9	$10.3	28.3	$133.0	$15.3	$3.5	$18.8	$6.5	$25.5	$1.0	$0.7	$0.3
36	$0.0	$100.0	$71.6	$8.0	22.0	$108.7	$5.0	$0.9	$5.9	$1.6	-$78.5	-$2.8	$0.2	$0.1
Total	**$622.0**	**$3,463.0**	**$2,111.2**	**$2,550.2**		**$27,789.4**	**$5,954.5**	**$1,621.3**	**$7,575.8**	**$2,998.3**	**$8,469.0**	**$871.5**	**$1,160.4**	**$522.2**
											Nom. IRR	**18.7%**		
											Real IRR	**16.4%**		

***Totals do not always equal column sums due to rounding.

Table 3D.8: Selected Statistics for Economic and Rent Analysis of Short Pipeline Wet Gas Scenario - $9 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$145.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$145.7	-$68.0	$0.0	$0.0
10	$0.0	$588.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$594.7	-$252.2	$0.0	$0.0
11	$0.0	$956.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$974.8	-$375.8	$0.0	$0.0
12	$0.0	$854.0	$80.7	$80.5	220.4	$979.4	$18.0	$0.0	$18.0	$0.0	-$53.7	-$18.8	$6.3	$0.0
13	$0.0	$99.4	$90.9	$160.9	440.8	$1,935.9	$35.5	$92.4	$127.9	$185.8	$1,271.0	$405.0	$40.8	$59.2
14	$0.0	$96.1	$90.9	$160.9	440.8	$1,935.9	$35.5	$151.9	$187.4	$280.0	$1,120.6	$324.6	$54.3	$81.1
15	$0.0	$0.0	$90.9	$160.9	440.8	$1,935.9	$335.0	$128.0	$463.0	$235.9	$985.2	$259.4	$121.9	$62.1
16	$0.0	$59.2	$90.9	$160.9	440.8	$1,935.9	$323.0	$136.5	$459.6	$251.7	$913.6	$218.7	$110.0	$60.3
17	$0.0	$59.2	$90.9	$160.9	440.8	$1,935.9	$565.3	$112.7	$678.0	$207.8	$739.1	$160.8	$147.6	$45.2
18	$0.0	$0.0	$90.9	$160.9	440.8	$1,935.9	$586.2	$116.2	$702.5	$214.2	$767.4	$151.8	$139.0	$42.4
19	$0.0	$59.2	$90.9	$160.9	440.8	$1,935.9	$565.3	$120.9	$686.2	$222.9	$715.8	$128.7	$123.4	$40.1
20	$0.0	$59.2	$90.9	$160.9	440.8	$1,935.9	$565.3	$122.6	$687.9	$225.9	$711.1	$116.3	$112.5	$36.9
21	$0.0	$0.0	$90.9	$160.9	440.8	$1,935.9	$586.2	$123.4	$709.7	$227.5	$746.9	$111.0	$105.5	$33.8
22	$0.0	$59.2	$90.9	$160.9	440.8	$1,935.9	$565.3	$126.2	$691.5	$232.6	$700.8	$94.7	$93.4	$31.4
23	$0.0	$59.2	$90.9	$160.9	440.8	$1,935.9	$565.3	$126.4	$691.7	$233.0	$700.1	$86.0	$85.0	$28.6
24	$0.0	$0.0	$90.9	$160.9	440.8	$1,935.9	$586.2	$126.3	$712.5	$232.7	$738.9	$82.5	$79.6	$26.0
25	$0.0	$59.2	$86.4	$125.3	343.4	$1,513.1	$431.5	$98.4	$529.9	$181.4	$530.9	$53.9	$53.8	$18.4
26	$0.0	$59.2	$82.9	$97.6	267.5	$1,183.8	$327.3	$74.8	$402.1	$137.9	$404.0	$37.3	$37.1	$12.7
27	$0.0	$0.0	$80.2	$76.1	208.4	$927.2	$267.0	$56.1	$323.1	$103.4	$344.4	$28.9	$27.1	$8.7
28	$0.0	$59.2	$78.1	$59.3	162.3	$727.4	$182.9	$43.7	$226.5	$80.5	$223.7	$17.1	$17.3	$6.1
29	$0.0	$0.0	$76.4	$46.2	126.5	$571.7	$154.5	$31.8	$186.3	$58.6	$204.3	$14.2	$12.9	$4.1
30	$18.9	$59.2	$75.1	$36.0	98.5	$450.4	$88.5	$23.2	$111.8	$42.8	$106.7	$6.7	$7.0	$2.7
31	$0.0	$0.0	$74.1	$28.0	76.7	$356.0	$86.3	$16.9	$103.2	$31.2	$119.4	$6.8	$5.9	$1.8
32	$0.0	$0.0	$73.3	$21.8	59.8	$282.4	$63.0	$12.7	$75.7	$23.5	$88.1	$4.6	$3.9	$1.2

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.0	46.6	$225.0	$44.8	$9.4	$54.2	$17.2	$63.9	$3.0	$2.6	$0.8
34	$0.0	$0.0	$72.3	$13.2	36.3	$180.4	$30.7	$6.7	$37.3	$12.3	$45.2	$1.9	$1.6	$0.5
35	$0.0	$0.0	$71.9	$10.3	28.3	$145.6	$19.7	$4.5	$24.2	$8.3	$30.8	$1.2	$0.9	$0.3
36	$0.0	$100.0	$71.6	$8.0	22.0	$118.5	$5.5	$2.0	$7.5	$3.7	-$72.4	-$2.6	$0.3	$0.1
Total	**$622.0**	**$3,463.0**	**$2,111.2**	**$2,550.2**		**$30,891.7**	**$7,034.1**	**$1,863.8**	**$8,897.9**	**$3,451.0**	**$9,796.5**	**$1,113.7**	**$1,389.7**	**$604.7**
											Nom. IRR	**20.1%**		
											Real IRR	**17.8%**		

*****Totals do not always equal column sums due to rounding.

Table 3D.9: Selected Statistics for Economic and Rent Analysis of Short Pipeline Wet Gas Scenario - $10 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$145.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$145.7	-$68.0	$0.0	$0.0
10	$0.0	$588.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$594.7	-$252.2	$0.0	$0.0
11	$0.0	$956.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$974.8	-$375.8	$0.0	$0.0
12	$0.0	$854.0	$80.7	$80.5	220.4	$1,077.3	$19.9	$0.0	$19.9	$0.0	$42.2	$14.8	$7.0	$0.0
13	$0.0	$99.4	$90.9	$160.9	440.8	$2,131.6	$39.4	$126.7	$166.1	$254.7	$1,359.6	$433.2	$52.9	$81.2
14	$0.0	$96.1	$90.9	$160.9	440.8	$2,131.6	$98.5	$167.8	$266.4	$309.4	$1,208.0	$349.9	$77.2	$89.6
15	$0.0	$0.0	$90.9	$160.9	440.8	$2,131.6	$374.1	$146.8	$520.9	$270.6	$1,088.3	$286.6	$137.2	$71.2
16	$0.0	$59.2	$90.9	$160.9	440.8	$2,131.6	$633.8	$122.7	$756.6	$226.2	$837.8	$200.6	$181.1	$54.2
17	$0.0	$59.2	$90.9	$160.9	440.8	$2,131.6	$633.8	$128.0	$761.8	$235.9	$822.9	$179.1	$165.8	$51.3
18	$0.0	$0.0	$90.9	$160.9	440.8	$2,131.6	$654.8	$131.5	$786.2	$242.4	$851.2	$168.4	$155.6	$48.0
19	$0.0	$59.2	$90.9	$160.9	440.8	$2,131.6	$633.8	$136.2	$770.0	$251.0	$799.6	$143.8	$138.5	$45.2
20	$0.0	$59.2	$90.9	$160.9	440.8	$2,131.6	$633.8	$137.8	$771.7	$254.1	$794.9	$130.0	$126.2	$41.5
21	$0.0	$0.0	$90.9	$160.9	440.8	$2,131.6	$654.8	$138.7	$793.4	$255.6	$830.7	$123.5	$117.9	$38.0
22	$0.0	$59.2	$90.9	$160.9	440.8	$2,131.6	$633.8	$141.5	$775.3	$260.8	$784.6	$106.0	$104.8	$35.2
23	$0.0	$59.2	$90.9	$160.9	440.8	$2,131.6	$633.8	$141.7	$775.5	$261.2	$783.9	$96.3	$95.3	$32.1
24	$0.0	$0.0	$90.9	$160.9	440.8	$2,131.6	$654.8	$141.5	$796.3	$260.9	$822.7	$91.9	$88.9	$29.1
25	$0.0	$59.2	$86.4	$125.3	343.4	$1,665.6	$484.9	$110.3	$595.2	$203.3	$596.2	$60.5	$60.4	$20.6
26	$0.0	$59.2	$82.9	$97.6	267.5	$1,302.6	$368.9	$84.1	$453.0	$155.0	$454.9	$42.0	$41.8	$14.3
27	$0.0	$0.0	$80.2	$76.1	208.4	$1,019.8	$299.4	$63.3	$362.7	$116.7	$384.1	$32.2	$30.4	$9.8
28	$0.0	$59.2	$78.1	$59.3	162.3	$799.5	$208.1	$49.3	$257.4	$90.9	$254.6	$19.4	$19.6	$6.9
29	$0.0	$0.0	$76.4	$46.2	126.5	$627.9	$174.2	$36.2	$210.3	$66.7	$228.3	$15.8	$14.6	$4.6
30	$18.9	$59.2	$75.1	$36.0	98.5	$494.2	$103.9	$26.6	$130.5	$49.1	$125.4	$7.9	$8.2	$3.1
31	$0.0	$0.0	$74.1	$28.0	76.7	$390.0	$98.2	$19.6	$117.8	$36.1	$134.0	$7.7	$6.7	$2.1
32	$0.0	$0.0	$73.3	$21.8	59.8	$308.9	$72.3	$14.8	$87.1	$27.3	$99.5	$5.2	$4.5	$1.4

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.0	46.6	$245.7	$52.1	$11.0	$63.0	$20.2	$72.8	$3.4	$3.0	$1.0
34	$0.0	$0.0	$72.3	$13.2	36.3	$196.5	$36.3	$7.9	$44.2	$14.6	$52.1	$2.2	$1.9	$0.6
35	$0.0	$0.0	$71.9	$10.3	28.3	$158.1	$24.1	$5.5	$29.6	$10.1	$36.2	$1.4	$1.2	$0.4
36	$0.0	$100.0	$71.6	$8.0	22.0	$128.3	$6.0	$3.1	$9.1	$5.7	-$66.3	-$2.4	$0.3	$0.2
Total	**$622.0**	**$3,463.0**	**$2,111.2**	**$2,550.2**		**$33,994.0**	**$8,227.5**	**$2,092.6**	**$10,320.1**	**$3,878.6**	**$11,049.0**	**$1,339.3**	**$1,641.1**	**$681.7**
											Nom. IRR	**21.3%**		
											Real IRR	**18.9%**		

*****Totals do not always equal column sums due to rounding.

Appendix 3E: Results of Economic and Rent Analysis – Long Pipeline Wet Gas Scenario ($2006)

Table 3E.1: Selected Statistics for Economic and Rent Analysis of Long Pipeline Wet Gas Scenario - $2 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$265.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$265.7	-$123.9	$0.0	$0.0
10	$0.0	$708.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$714.7	-$303.1	$0.0	$0.0
11	$0.0	$1,076.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,094.8	-$422.1	$0.0	$0.0
12	$0.0	$854.0	$80.7	$80.5	220.4	$294.3	$4.3	$0.0	$4.3	$0.0	-$725.1	-$254.1	$1.5	$0.0
13	$0.0	$99.4	$90.9	$160.9	440.8	$565.7	$8.1	$0.0	$8.1	$0.0	$206.4	$65.8	$2.6	$0.0
14	$0.0	$96.1	$90.9	$160.9	440.8	$565.7	$8.1	$0.0	$8.1	$0.0	$209.7	$60.8	$2.3	$0.0
15	$0.0	$0.0	$90.9	$160.9	440.8	$565.7	$8.1	$0.0	$8.1	$0.0	$305.8	$80.5	$2.1	$0.0
16	$0.0	$59.2	$90.9	$160.9	440.8	$565.7	$8.1	$0.0	$8.1	$0.0	$246.6	$59.0	$1.9	$0.0
17	$0.0	$59.2	$90.9	$160.9	440.8	$565.7	$8.1	$0.0	$8.1	$0.0	$246.6	$53.7	$1.8	$0.0
18	$0.0	$0.0	$90.9	$160.9	440.8	$565.7	$8.1	$0.0	$8.1	$0.0	$305.8	$60.5	$1.6	$0.0
19	$0.0	$59.2	$90.9	$160.9	440.8	$565.7	$8.1	$0.0	$8.1	$0.0	$246.6	$44.4	$1.5	$0.0
20	$0.0	$59.2	$90.9	$160.9	440.8	$565.7	$8.1	$0.0	$8.1	$0.0	$246.6	$40.3	$1.3	$0.0
21	$0.0	$0.0	$90.9	$160.9	440.8	$565.7	$8.1	$0.0	$8.1	$0.0	$305.8	$45.5	$1.2	$0.0
22	$0.0	$59.2	$90.9	$160.9	440.8	$565.7	$8.1	$0.0	$8.1	$0.0	$246.6	$33.3	$1.1	$0.0
23	$0.0	$59.2	$90.9	$160.9	440.8	$565.7	$8.1	$11.7	$19.8	$21.5	$213.4	$26.2	$2.4	$2.6
24	$0.0	$0.0	$90.9	$160.9	440.8	$565.7	$8.1	$31.0	$39.1	$57.1	$217.7	$24.3	$4.4	$6.4
25	$0.0	$59.2	$86.4	$125.3	343.4	$445.8	$6.4	$21.2	$27.6	$39.0	$108.2	$11.0	$2.8	$4.0
26	$0.0	$59.2	$82.9	$97.6	267.5	$352.3	$5.1	$13.6	$18.7	$25.0	$68.9	$6.4	$1.7	$2.3
27	$0.0	$0.0	$80.2	$76.1	208.4	$279.5	$4.1	$9.8	$13.9	$18.1	$91.2	$7.7	$1.2	$1.5
28	$0.0	$59.2	$78.1	$59.3	162.3	$222.8	$3.3	$4.6	$7.9	$8.5	$9.8	$0.7	$0.6	$0.7
29	$0.0	$0.0	$76.4	$46.2	126.5	$178.7	$2.6	$2.8	$5.4	$5.1	$45.5	$3.2	$0.4	$0.4
30	$18.9	$59.2	$75.1	$36.0	98.5	$144.2	$2.2	$0.0	$2.2	$0.0	-$47.1	-$3.0	$0.1	$0.0

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
31	$0.0	$0.0	$74.1	$28.0	76.7	$117.4	$1.8	$0.0	$1.8	$0.0	$13.5	$0.8	$0.1	$0.0
32	$0.0	$0.0	$73.3	$21.8	59.8	$96.6	$1.5	$0.0	$1.5	$0.0	-$0.1	$0.0	$0.1	$0.0
33	$0.0	$0.0	$72.7	$17.0	46.6	$80.3	$1.3	-$1.1	$0.1	-$2.1	-$7.5	-$0.4	$0.0	-$0.1
34	$0.0	$0.0	$72.3	$13.2	36.3	$67.6	$1.1	-$2.2	-$1.1	-$4.0	-$12.9	-$0.6	$0.0	-$0.2
35	$0.0	$0.0	$71.9	$10.3	28.3	$57.7	$0.9	-$2.9	-$2.0	-$5.4	-$17.1	-$0.7	-$0.1	-$0.2
36	$0.0	$100.0	$71.6	$8.0	22.0	$50.1	$2.1	-$3.5	-$1.4	-$6.5	-$121.6	-$4.3	-$0.1	-$0.2
Total	**$622.0**	**$3,823.0**	**$2,111.2**	**$2,550.2**		**$9,175.9**	**$133.8**	**$84.9**	**$218.7**	**$156.5**	**-$305.6**	**-$972.5**	**$32.5**	**$17.1**
											Nom. IRR	**0.9%**		
											Real IRR	**-1.1%**		

*****Totals do not always equal column sums due to rounding.

Table 3E.2: Selected Statistics for Economic and Rent Analysis of Long Pipeline Wet Gas Scenario - $3 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$265.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$265.7	-$123.9	$0.0	$0.0
10	$0.0	$708.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$714.7	-$303.1	$0.0	$0.0
11	$0.0	$1,076.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,094.8	-$422.1	$0.0	$0.0
12	$0.0	$854.0	$80.7	$80.5	220.4	$392.2	$6.2	$0.0	$6.2	$0.0	-$629.2	-$220.5	$2.2	$0.0
13	$0.0	$99.4	$90.9	$160.9	440.8	$761.5	$12.0	$0.0	$12.0	$0.0	$398.2	$126.9	$3.8	$0.0
14	$0.0	$96.1	$90.9	$160.9	440.8	$761.5	$12.0	$0.0	$12.0	$0.0	$401.6	$116.3	$3.5	$0.0
15	$0.0	$0.0	$90.9	$160.9	440.8	$761.5	$12.0	$0.0	$12.0	$0.0	$497.6	$131.0	$3.2	$0.0
16	$0.0	$59.2	$90.9	$160.9	440.8	$761.5	$12.0	$0.0	$12.0	$0.0	$438.4	$105.0	$2.9	$0.0
17	$0.0	$59.2	$90.9	$160.9	440.8	$761.5	$12.0	$0.0	$12.0	$0.0	$438.4	$95.4	$2.6	$0.0
18	$0.0	$0.0	$90.9	$160.9	440.8	$761.5	$12.0	$15.1	$27.1	$27.8	$454.7	$90.0	$5.4	$5.5
19	$0.0	$59.2	$90.9	$160.9	440.8	$761.5	$12.0	$45.3	$57.3	$83.5	$309.6	$55.7	$10.3	$15.0
20	$0.0	$59.2	$90.9	$160.9	440.8	$761.5	$12.0	$47.2	$59.3	$87.1	$304.1	$49.7	$9.7	$14.2
21	$0.0	$0.0	$90.9	$160.9	440.8	$761.5	$12.0	$50.8	$62.8	$93.7	$353.1	$52.5	$9.3	$13.9
22	$0.0	$59.2	$90.9	$160.9	440.8	$761.5	$12.0	$51.2	$63.2	$94.4	$292.7	$39.6	$8.5	$12.8
23	$0.0	$59.2	$90.9	$160.9	440.8	$761.5	$12.0	$51.6	$63.6	$95.1	$291.8	$35.8	$7.8	$11.7
24	$0.0	$0.0	$90.9	$160.9	440.8	$761.5	$30.0	$51.8	$81.9	$95.6	$332.2	$37.1	$9.1	$10.7
25	$0.0	$59.2	$86.4	$125.3	343.4	$598.2	$23.6	$37.4	$61.0	$68.9	$197.3	$20.0	$6.2	$7.0
26	$0.0	$59.2	$82.9	$97.6	267.5	$471.1	$18.7	$26.2	$44.9	$48.3	$138.2	$12.8	$4.1	$4.5
27	$0.0	$0.0	$80.2	$76.1	208.4	$372.1	$14.8	$19.7	$34.5	$36.2	$145.1	$12.2	$2.9	$3.0
28	$0.0	$59.2	$78.1	$59.3	162.3	$294.9	$11.8	$12.3	$24.0	$22.6	$51.7	$3.9	$1.8	$1.7
29	$0.0	$0.0	$76.4	$46.2	126.5	$234.8	$9.4	$8.7	$18.1	$16.1	$78.0	$5.4	$1.3	$1.1
30	$18.9	$59.2	$75.1	$36.0	98.5	$188.0	$7.6	$1.4	$9.0	$2.6	-$12.8	-$0.8	$0.6	$0.2
31	$0.0	$0.0	$74.1	$28.0	76.7	$151.5	$6.2	$2.0	$8.2	$3.7	$37.6	$2.2	$0.5	$0.2
32	$0.0	$0.0	$73.3	$21.8	59.8	$123.1	$5.1	$0.5	$5.6	$1.0	$21.4	$1.1	$0.3	$0.1

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.0	46.6	$101.0	$4.2	$0.0	$4.2	$0.0	$7.1	$0.3	$0.2	$0.0
34	$0.0	$0.0	$72.3	$13.2	36.3	$83.7	$3.5	-$0.2	$3.3	-$0.4	-$4.7	-$0.2	$0.1	$0.0
35	$0.0	$0.0	$71.9	$10.3	28.3	$70.3	$3.0	-$1.4	$1.6	-$2.6	-$10.9	-$0.4	$0.1	-$0.1
36	$0.0	$100.0	$71.6	$8.0	22.0	$59.8	$2.6	-$2.4	$0.2	-$4.4	-$115.6	-$4.1	$0.0	-$0.2
Total	**$622.0**	**$3,823.0**	**$2,111.2**	**$2,550.2**		**$12,278.1**	**$278.9**	**$417.3**	**$696.1**	**$769.2**	**$1,706.5**	**-$566.5**	**$96.4**	**$101.3**
											Nom. IRR	**6.7%**		
											Real IRR	**4.6%**		

***Totals do not always equal column sums due to rounding.**

Table 3E.3: Selected Statistics for Economic and Rent Analysis of Long Pipeline Wet Gas Scenario - $4 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$265.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$265.7	-$123.9	$0.0	$0.0
10	$0.0	$708.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$714.7	-$303.1	$0.0	$0.0
11	$0.0	$1,076.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,094.8	-$422.1	$0.0	$0.0
12	$0.0	$854.0	$80.7	$80.5	220.4	$490.1	$8.2	$0.0	$8.2	$0.0	-$533.3	-$186.9	$2.9	$0.0
13	$0.0	$99.4	$90.9	$160.9	440.8	$957.2	$15.9	$0.0	$15.9	$0.0	$590.0	$188.0	$5.1	$0.0
14	$0.0	$96.1	$90.9	$160.9	440.8	$957.2	$15.9	$0.0	$15.9	$0.0	$593.4	$171.9	$4.6	$0.0
15	$0.0	$0.0	$90.9	$160.9	440.8	$957.2	$15.9	$0.0	$15.9	$0.0	$689.5	$181.6	$4.2	$0.0
16	$0.0	$59.2	$90.9	$160.9	440.8	$957.2	$15.9	$34.3	$50.2	$63.3	$532.7	$127.5	$12.0	$15.1
17	$0.0	$59.2	$90.9	$160.9	440.8	$957.2	$15.9	$59.2	$75.2	$109.2	$461.8	$100.5	$16.4	$23.8
18	$0.0	$0.0	$90.9	$160.9	440.8	$957.2	$15.9	$65.8	$81.7	$121.2	$502.5	$99.4	$16.2	$24.0
19	$0.0	$59.2	$90.9	$160.9	440.8	$957.2	$15.9	$68.3	$84.3	$126.0	$435.9	$78.4	$15.2	$22.7
20	$0.0	$59.2	$90.9	$160.9	440.8	$957.2	$39.8	$67.4	$107.2	$124.2	$414.7	$67.8	$17.5	$20.3
21	$0.0	$0.0	$90.9	$160.9	440.8	$957.2	$39.8	$71.0	$110.8	$130.8	$463.8	$68.9	$16.5	$19.4
22	$0.0	$59.2	$90.9	$160.9	440.8	$957.2	$39.8	$71.4	$111.2	$131.6	$403.4	$54.5	$15.0	$17.8
23	$0.0	$59.2	$90.9	$160.9	440.8	$957.2	$127.3	$61.2	$188.5	$112.9	$344.8	$42.4	$23.2	$13.9
24	$0.0	$0.0	$90.9	$160.9	440.8	$957.2	$139.3	$62.2	$201.5	$114.7	$389.2	$43.5	$22.5	$12.8
25	$0.0	$59.2	$86.4	$125.3	343.4	$750.7	$94.1	$47.2	$141.3	$87.1	$251.4	$25.5	$14.3	$8.8
26	$0.0	$59.2	$82.9	$97.6	267.5	$589.9	$68.2	$34.5	$102.8	$63.6	$183.8	$17.0	$9.5	$5.9
27	$0.0	$0.0	$80.2	$76.1	208.4	$464.6	$60.1	$25.3	$85.4	$46.7	$176.2	$14.8	$7.2	$3.9
28	$0.0	$59.2	$78.1	$59.3	162.3	$367.0	$32.4	$18.4	$50.8	$34.0	$85.6	$6.5	$3.9	$2.6
29	$0.0	$0.0	$76.4	$46.2	126.5	$291.0	$32.2	$12.7	$44.9	$23.5	$100.1	$6.9	$3.1	$1.6
30	$18.9	$59.2	$75.1	$36.0	98.5	$231.7	$9.8	$6.4	$16.2	$11.8	$14.6	$0.9	$1.0	$0.7
31	$0.0	$0.0	$74.1	$28.0	76.7	$185.6	$15.2	$5.0	$20.2	$9.2	$54.1	$3.1	$1.2	$0.5
32	$0.0	$0.0	$73.3	$21.8	59.8	$149.6	$9.4	$3.2	$12.6	$5.9	$36.0	$1.9	$0.7	$0.3

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.0	46.6	$121.6	$5.2	$1.7	$6.9	$3.1	$21.9	$1.0	$0.3	$0.1
34	$0.0	$0.0	$72.3	$13.2	36.3	$99.8	$4.3	$0.1	$4.5	$0.3	$9.6	$0.4	$0.2	$0.0
35	$0.0	$0.0	$71.9	$10.3	28.3	$82.8	$3.6	$0.0	$3.6	$0.0	-$3.0	-$0.1	$0.1	$0.0
36	$0.0	$100.0	$71.6	$8.0	22.0	$69.6	$3.1	-$1.2	$1.9	-$2.2	-$109.7	-$3.9	$0.1	-$0.1
Total	**$622.0**	**$3,823.0**	**$2,111.2**	**$2,550.2**		**$15,380.4**	**$843.4**	**$714.3**	**$1,557.7**	**$1,316.8**	**$3,399.6**	**-$221.8**	**$212.7**	**$194.3**
											Nom. IRR	**10.2%**		
											Real IRR	**8.1%**		

***Totals do not always equal column sums due to rounding.

Table 3E.4: Selected Statistics for Economic and Rent Analysis of Long Pipeline Wet Gas Scenario - $5 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$265.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$265.7	-$123.9	$0.0	$0.0
10	$0.0	$708.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$714.7	-$303.1	$0.0	$0.0
11	$0.0	$1,076.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,094.8	-$422.1	$0.0	$0.0
12	$0.0	$854.0	$80.7	$80.5	220.4	$587.9	$10.1	$0.0	$10.1	$0.0	-$437.4	-$153.3	$3.6	$0.0
13	$0.0	$99.4	$90.9	$160.9	440.8	$1,152.9	$19.8	$0.0	$19.8	$0.0	$781.9	$249.1	$6.3	$0.0
14	$0.0	$96.1	$90.9	$160.9	440.8	$1,152.9	$19.8	$0.0	$19.8	$0.0	$785.2	$227.5	$5.7	$0.0
15	$0.0	$0.0	$90.9	$160.9	440.8	$1,152.9	$19.8	$59.2	$79.1	$109.2	$712.9	$187.7	$20.8	$28.7
16	$0.0	$59.2	$90.9	$160.9	440.8	$1,152.9	$19.8	$76.3	$96.1	$140.6	$605.1	$144.9	$23.0	$33.7
17	$0.0	$59.2	$90.9	$160.9	440.8	$1,152.9	$19.8	$82.3	$102.1	$151.6	$588.2	$128.0	$22.2	$33.0
18	$0.0	$0.0	$90.9	$160.9	440.8	$1,152.9	$49.6	$85.2	$134.8	$157.1	$609.2	$120.5	$26.7	$31.1
19	$0.0	$59.2	$90.9	$160.9	440.8	$1,152.9	$49.6	$87.8	$137.4	$161.8	$542.7	$97.6	$24.7	$29.1
20	$0.0	$59.2	$90.9	$160.9	440.8	$1,152.9	$166.4	$75.7	$242.1	$139.5	$460.3	$75.3	$39.6	$22.8
21	$0.0	$0.0	$90.9	$160.9	440.8	$1,152.9	$178.4	$77.8	$256.2	$143.5	$501.4	$74.5	$38.1	$21.3
22	$0.0	$59.2	$90.9	$160.9	440.8	$1,152.9	$166.4	$79.7	$246.1	$146.9	$448.9	$60.7	$33.3	$19.8
23	$0.0	$59.2	$90.9	$160.9	440.8	$1,152.9	$166.4	$80.0	$246.5	$147.5	$447.9	$55.0	$30.3	$18.1
24	$0.0	$0.0	$90.9	$160.9	440.8	$1,152.9	$312.2	$65.0	$377.2	$119.7	$404.2	$45.1	$42.1	$13.4
25	$0.0	$59.2	$86.4	$125.3	343.4	$903.2	$218.1	$50.7	$268.7	$93.4	$270.2	$27.4	$27.3	$9.5
26	$0.0	$59.2	$82.9	$97.6	267.5	$708.7	$161.0	$37.6	$198.6	$69.4	$200.9	$18.5	$18.3	$6.4
27	$0.0	$0.0	$80.2	$76.1	208.4	$557.1	$137.5	$27.1	$164.6	$50.0	$186.2	$15.6	$13.8	$4.2
28	$0.0	$59.2	$78.1	$59.3	162.3	$439.1	$81.9	$21.1	$103.1	$39.0	$100.5	$7.7	$7.9	$3.0
29	$0.0	$0.0	$76.4	$46.2	126.5	$347.1	$75.9	$14.2	$90.1	$26.2	$108.2	$7.5	$6.3	$1.8
30	$18.9	$59.2	$75.1	$36.0	98.5	$275.5	$27.3	$9.5	$36.9	$17.6	$31.8	$2.0	$2.3	$1.1
31	$0.0	$0.0	$74.1	$28.0	76.7	$219.7	$38.6	$6.3	$44.8	$11.6	$61.1	$3.5	$2.6	$0.7
32	$0.0	$0.0	$73.3	$21.8	59.8	$176.2	$25.8	$4.4	$30.2	$8.2	$42.7	$2.2	$1.6	$0.4

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.0	46.6	$142.3	$15.9	$2.9	$18.8	$5.3	$28.5	$1.4	$0.9	$0.3
34	$0.0	$0.0	$72.3	$13.2	36.3	$115.9	$8.1	$1.6	$9.7	$3.0	$17.7	$0.8	$0.4	$0.1
35	$0.0	$0.0	$71.9	$10.3	28.3	$95.4	$4.3	$0.3	$4.6	$0.6	$7.9	$0.3	$0.2	$0.0
36	$0.0	$100.0	$71.6	$8.0	22.0	$79.4	$3.6	$0.0	$3.5	-$0.1	-$103.7	-$3.7	$0.1	$0.0
Total	**$622.0**	**$3,823.0**	**$2,111.2**	**$2,550.2**		**$18,482.7**	**$1,996.4**	**$944.8**	**$2,941.2**	**$1,741.6**	**$4,693.5**	**$62.5**	**$398.0**	**$278.5**
											Nom. IRR	**12.7%**		
											Real IRR	**10.5%**		

*****Totals do not always equal column sums due to rounding.

Table 3E.5: Selected Statistics for Economic and Rent Analysis of Long Pipeline Wet Gas Scenario - $6 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$265.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$265.7	-$123.9	$0.0	$0.0
10	$0.0	$708.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$714.7	-$303.1	$0.0	$0.0
11	$0.0	$1,076.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,094.8	-$422.1	$0.0	$0.0
12	$0.0	$854.0	$80.7	$80.5	220.4	$685.8	$12.1	$0.0	$12.1	$0.0	-$341.5	-$119.7	$4.2	$0.0
13	$0.0	$99.4	$90.9	$160.9	440.8	$1,348.7	$23.8	$0.0	$23.8	$0.0	$973.7	$310.3	$7.6	$0.0
14	$0.0	$96.1	$90.9	$160.9	440.8	$1,348.7	$23.8	$47.5	$71.2	$87.5	$842.1	$243.9	$20.6	$25.3
15	$0.0	$0.0	$90.9	$160.9	440.8	$1,348.7	$23.8	$91.2	$115.0	$168.2	$813.7	$214.3	$30.3	$44.3
16	$0.0	$59.2	$90.9	$160.9	440.8	$1,348.7	$23.8	$99.3	$123.1	$183.1	$731.5	$175.1	$29.5	$43.8
17	$0.0	$59.2	$90.9	$160.9	440.8	$1,348.7	$59.4	$101.0	$160.4	$186.2	$691.1	$150.4	$34.9	$40.5
18	$0.0	$0.0	$90.9	$160.9	440.8	$1,348.7	$217.6	$88.5	$306.1	$163.2	$627.5	$124.2	$60.6	$32.3
19	$0.0	$59.2	$90.9	$160.9	440.8	$1,348.7	$205.6	$92.6	$298.1	$170.6	$568.9	$102.3	$53.6	$30.7
20	$0.0	$59.2	$90.9	$160.9	440.8	$1,348.7	$205.6	$94.5	$300.1	$174.2	$563.4	$92.1	$49.1	$28.5
21	$0.0	$0.0	$90.9	$160.9	440.8	$1,348.7	$380.7	$77.0	$457.8	$142.0	$497.1	$73.9	$68.0	$21.1
22	$0.0	$59.2	$90.9	$160.9	440.8	$1,348.7	$359.8	$80.0	$439.8	$147.4	$450.5	$60.9	$59.4	$19.9
23	$0.0	$59.2	$90.9	$160.9	440.8	$1,348.7	$359.8	$80.3	$440.1	$148.0	$449.5	$55.2	$54.1	$18.2
24	$0.0	$0.0	$90.9	$160.9	440.8	$1,348.7	$380.7	$80.2	$460.9	$147.9	$488.0	$54.5	$51.5	$16.5
25	$0.0	$59.2	$86.4	$125.3	343.4	$1,055.7	$271.4	$62.5	$334.0	$115.3	$335.5	$34.1	$33.9	$11.7
26	$0.0	$59.2	$82.9	$97.6	267.5	$827.4	$202.6	$46.9	$249.5	$86.4	$251.8	$23.2	$23.0	$8.0
27	$0.0	$0.0	$80.2	$76.1	208.4	$649.7	$169.9	$34.4	$204.2	$63.3	$225.8	$18.9	$17.1	$5.3
28	$0.0	$59.2	$78.1	$59.3	162.3	$511.2	$107.2	$26.8	$133.9	$49.3	$131.3	$10.0	$10.2	$3.8
29	$0.0	$0.0	$76.4	$46.2	126.5	$403.3	$95.6	$18.6	$114.2	$34.3	$132.3	$9.2	$7.9	$2.4
30	$18.9	$59.2	$75.1	$36.0	98.5	$319.2	$42.6	$13.0	$55.6	$23.9	$50.6	$3.2	$3.5	$1.5
31	$0.0	$0.0	$74.1	$28.0	76.7	$253.7	$50.5	$8.9	$59.4	$16.5	$75.7	$4.3	$3.4	$0.9
32	$0.0	$0.0	$73.3	$21.8	59.8	$202.7	$35.1	$6.5	$41.6	$12.0	$54.0	$2.8	$2.2	$0.6

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.0	46.6	$163.0	$23.1	$4.5	$27.6	$8.3	$37.4	$1.8	$1.3	$0.4
34	$0.0	$0.0	$72.3	$13.2	36.3	$132.1	$13.7	$2.9	$16.6	$5.3	$24.6	$1.1	$0.7	$0.2
35	$0.0	$0.0	$71.9	$10.3	28.3	$107.9	$6.5	$1.6	$8.1	$2.9	$14.7	$0.6	$0.3	$0.1
36	$0.0	$100.0	$71.6	$8.0	22.0	$89.2	$4.1	$0.0	$4.1	$0.0	-$94.5	-$3.4	$0.1	$0.0
Total	**$622.0**	**$3,823.0**	**$2,111.2**	**$2,550.2**		**$21,584.9**	**$3,298.5**	**$1,158.7**	**$4,457.2**	**$2,135.8**	**$5,885.6**	**$309.8**	**$627.1**	**$356.1**
											Nom. IRR	**14.7%**		
											Real IRR	**12.4%**		

*****Totals do not always equal column sums due to rounding.

Table 3E.6: Selected Statistics for Economic and Rent Analysis of Long Pipeline Wet Gas Scenario - $7 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$265.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$265.7	-$123.9	$0.0	$0.0
10	$0.0	$708.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$714.7	-$303.1	$0.0	$0.0
11	$0.0	$1,076.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,094.8	-$422.1	$0.0	$0.0
12	$0.0	$854.0	$80.7	$80.5	220.4	$783.7	$14.1	$0.0	$14.1	$0.0	-$245.5	-$86.1	$4.9	$0.0
13	$0.0	$99.4	$90.9	$160.9	440.8	$1,544.4	$27.7	$3.3	$30.9	$6.5	$1,155.7	$368.3	$9.9	$2.1
14	$0.0	$96.1	$90.9	$160.9	440.8	$1,544.4	$27.7	$100.9	$128.6	$186.0	$881.9	$255.5	$37.3	$53.9
15	$0.0	$0.0	$90.9	$160.9	440.8	$1,544.4	$27.7	$114.3	$141.9	$210.6	$940.1	$247.5	$37.4	$55.5
16	$0.0	$59.2	$90.9	$160.9	440.8	$1,544.4	$69.2	$117.4	$186.5	$216.3	$830.5	$198.8	$44.7	$51.8
17	$0.0	$59.2	$90.9	$160.9	440.8	$1,544.4	$244.7	$102.2	$347.0	$188.5	$697.9	$151.9	$75.5	$41.0
18	$0.0	$0.0	$90.9	$160.9	440.8	$1,544.4	$256.7	$107.3	$364.0	$197.9	$730.7	$144.6	$72.0	$39.1
19	$0.0	$59.2	$90.9	$160.9	440.8	$1,544.4	$428.3	$89.3	$517.6	$164.6	$551.1	$99.1	$93.1	$29.6
20	$0.0	$59.2	$90.9	$160.9	440.8	$1,544.4	$428.3	$91.2	$519.5	$168.2	$545.6	$89.2	$85.0	$27.5
21	$0.0	$0.0	$90.9	$160.9	440.8	$1,544.4	$449.2	$92.3	$541.5	$170.2	$580.9	$86.3	$80.5	$25.3
22	$0.0	$59.2	$90.9	$160.9	440.8	$1,544.4	$428.3	$95.2	$523.5	$175.5	$534.3	$72.2	$70.7	$23.7
23	$0.0	$59.2	$90.9	$160.9	440.8	$1,544.4	$428.3	$95.6	$523.9	$176.2	$533.3	$65.5	$64.4	$21.6
24	$0.0	$0.0	$90.9	$160.9	440.8	$1,544.4	$449.2	$95.5	$544.7	$176.0	$571.9	$63.9	$60.8	$19.7
25	$0.0	$59.2	$86.4	$125.3	343.4	$1,208.2	$324.8	$74.4	$399.2	$137.2	$400.8	$40.7	$40.5	$13.9
26	$0.0	$59.2	$82.9	$97.6	267.5	$946.2	$244.2	$56.2	$300.3	$103.5	$302.6	$27.9	$27.7	$9.6
27	$0.0	$0.0	$80.2	$76.1	208.4	$742.2	$202.3	$41.6	$243.8	$76.6	$265.4	$22.3	$20.5	$6.4
28	$0.0	$59.2	$78.1	$59.3	162.3	$583.2	$132.4	$32.4	$164.8	$59.7	$162.2	$12.4	$12.6	$4.6
29	$0.0	$0.0	$76.4	$46.2	126.5	$459.4	$115.2	$23.0	$138.2	$42.4	$156.3	$10.8	$9.6	$2.9
30	$18.9	$59.2	$75.1	$36.0	98.5	$363.0	$57.9	$16.4	$74.3	$30.2	$69.3	$4.4	$4.7	$1.9
31	$0.0	$0.0	$74.1	$28.0	76.7	$287.8	$62.4	$11.6	$74.0	$21.4	$90.3	$5.2	$4.2	$1.2
32	$0.0	$0.0	$73.3	$21.8	59.8	$229.3	$44.4	$8.6	$53.0	$15.8	$65.4	$3.4	$2.8	$0.8

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.0	46.6	$183.7	$30.3	$6.1	$36.5	$11.3	$46.2	$2.2	$1.7	$0.5
34	$0.0	$0.0	$72.3	$13.2	36.3	$148.2	$19.4	$4.1	$23.5	$7.6	$31.5	$1.4	$1.0	$0.3
35	$0.0	$0.0	$71.9	$10.3	28.3	$120.5	$10.9	$2.6	$13.4	$4.7	$20.1	$0.8	$0.5	$0.2
36	$0.0	$100.0	$71.6	$8.0	22.0	$98.9	$4.5	$0.0	$4.5	$0.0	-$85.2	-$3.0	$0.2	$0.0
Total	**$622.0**	**$3,823.0**	**$2,111.2**	**$2,550.2**		**$24,687.2**	**$4,528.1**	**$1,381.5**	**$5,909.5**	**$2,547.0**	**$7,124.3**	**$551.8**	**$862.1**	**$433.2**
											Nom. IRR	**16.4%**		
											Real IRR	**14.1%**		

*****Totals do not always equal column sums due to rounding.

Table 3E.7: Selected Statistics for Economic and Rent Analysis of Long Pipeline Wet Gas Scenario - $8 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$265.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$265.7	-$123.9	$0.0	$0.0
10	$0.0	$708.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$714.7	-$303.1	$0.0	$0.0
11	$0.0	$1,076.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,094.8	-$422.1	$0.0	$0.0
12	$0.0	$854.0	$80.7	$80.5	220.4	$881.6	$16.0	$0.0	$16.0	$0.0	-$149.6	-$52.4	$5.6	$0.0
13	$0.0	$99.4	$90.9	$160.9	440.8	$1,740.2	$31.6	$37.6	$69.1	$75.5	$1,244.3	$396.5	$22.0	$24.1
14	$0.0	$96.1	$90.9	$160.9	440.8	$1,740.2	$31.6	$123.9	$155.5	$228.5	$1,008.3	$292.1	$45.1	$66.2
15	$0.0	$0.0	$90.9	$160.9	440.8	$1,740.2	$79.0	$131.6	$210.6	$242.6	$1,035.2	$272.6	$55.4	$63.9
16	$0.0	$59.2	$90.9	$160.9	440.8	$1,740.2	$283.9	$115.1	$399.0	$212.1	$818.0	$195.8	$95.5	$50.8
17	$0.0	$59.2	$90.9	$160.9	440.8	$1,740.2	$283.9	$121.0	$404.9	$223.1	$801.1	$174.3	$88.1	$48.6
18	$0.0	$0.0	$90.9	$160.9	440.8	$1,740.2	$517.7	$99.5	$617.2	$183.4	$687.7	$136.1	$122.1	$36.3
19	$0.0	$59.2	$90.9	$160.9	440.8	$1,740.2	$496.8	$104.6	$601.4	$192.8	$635.0	$114.2	$108.2	$34.7
20	$0.0	$59.2	$90.9	$160.9	440.8	$1,740.2	$496.8	$106.5	$603.3	$196.3	$629.5	$102.9	$98.6	$32.1
21	$0.0	$0.0	$90.9	$160.9	440.8	$1,740.2	$517.7	$107.6	$625.3	$198.3	$664.7	$98.8	$92.9	$29.5
22	$0.0	$59.2	$90.9	$160.9	440.8	$1,740.2	$496.8	$110.5	$607.3	$203.7	$618.1	$83.5	$82.1	$27.5
23	$0.0	$59.2	$90.9	$160.9	440.8	$1,740.2	$496.8	$110.9	$607.7	$204.3	$617.1	$75.8	$74.6	$25.1
24	$0.0	$0.0	$90.9	$160.9	440.8	$1,740.2	$517.7	$110.8	$628.5	$204.2	$655.7	$73.2	$70.2	$22.8
25	$0.0	$59.2	$86.4	$125.3	343.4	$1,360.6	$378.2	$86.3	$464.5	$159.1	$466.0	$47.3	$47.2	$16.2
26	$0.0	$59.2	$82.9	$97.6	267.5	$1,065.0	$285.7	$65.4	$351.2	$120.6	$353.5	$32.6	$32.4	$11.1
27	$0.0	$0.0	$80.2	$76.1	208.4	$834.7	$234.7	$48.8	$283.4	$89.9	$305.1	$25.6	$23.8	$7.5
28	$0.0	$59.2	$78.1	$59.3	162.3	$655.3	$157.6	$38.0	$195.6	$70.1	$193.1	$14.7	$14.9	$5.3
29	$0.0	$0.0	$76.4	$46.2	126.5	$515.6	$134.9	$27.4	$162.2	$50.4	$180.3	$12.5	$11.2	$3.5
30	$18.9	$59.2	$75.1	$36.0	98.5	$406.7	$73.2	$19.8	$93.0	$36.5	$88.0	$5.6	$5.9	$2.3
31	$0.0	$0.0	$74.1	$28.0	76.7	$321.9	$74.3	$14.3	$88.6	$26.3	$104.9	$6.0	$5.1	$1.5
32	$0.0	$0.0	$73.3	$21.8	59.8	$255.8	$53.7	$10.6	$64.3	$19.6	$76.8	$4.0	$3.4	$1.0

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.0	46.6	$204.4	$37.6	$7.7	$45.3	$14.2	$55.1	$2.6	$2.1	$0.7
34	$0.0	$0.0	$72.3	$13.2	36.3	$164.3	$25.0	$5.4	$30.4	$9.9	$38.4	$1.7	$1.3	$0.4
35	$0.0	$0.0	$71.9	$10.3	28.3	$133.0	$15.3	$3.5	$18.8	$6.5	$25.5	$1.0	$0.7	$0.3
36	$0.0	$100.0	$71.6	$8.0	22.0	$108.7	$5.0	$0.9	$5.9	$1.6	-$78.5	-$2.8	$0.2	$0.1
Total	**$622.0**	**$3,823.0**	**$2,111.2**	**$2,550.2**		**$27,789.4**	**$5,741.6**	**$1,607.6**	**$7,349.2**	**$2,969.7**	**$8,364.2**	**$780.9**	**$1,108.8**	**$511.3**
											Nom. IRR	**17.8%**		
											Real IRR	**15.5%**		

***Totals do not always equal column sums due to rounding.

Table 3E.8: Selected Statistics for Economic and Rent Analysis of Long Pipeline Wet Gas Scenario - $9 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$265.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$265.7	-$123.9	$0.0	$0.0
10	$0.0	$708.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$714.7	-$303.1	$0.0	$0.0
11	$0.0	$1,076.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,094.8	-$422.1	$0.0	$0.0
12	$0.0	$854.0	$80.7	$80.5	220.4	$979.4	$18.0	$0.0	$18.0	$0.0	-$53.7	-$18.8	$6.3	$0.0
13	$0.0	$99.4	$90.9	$160.9	440.8	$1,935.9	$35.5	$71.9	$107.4	$144.4	$1,332.9	$424.7	$34.2	$46.0
14	$0.0	$96.1	$90.9	$160.9	440.8	$1,935.9	$35.5	$147.0	$182.5	$270.9	$1,134.6	$328.7	$52.9	$78.5
15	$0.0	$0.0	$90.9	$160.9	440.8	$1,935.9	$88.7	$153.9	$242.7	$283.7	$1,157.7	$304.9	$63.9	$74.7
16	$0.0	$59.2	$90.9	$160.9	440.8	$1,935.9	$323.0	$133.9	$456.9	$246.8	$921.2	$220.5	$109.4	$59.1
17	$0.0	$59.2	$90.9	$160.9	440.8	$1,935.9	$565.3	$110.8	$676.1	$204.2	$744.6	$162.1	$147.1	$44.4
18	$0.0	$0.0	$90.9	$160.9	440.8	$1,935.9	$586.2	$114.8	$701.0	$211.6	$771.5	$152.6	$138.7	$41.9
19	$0.0	$59.2	$90.9	$160.9	440.8	$1,935.9	$565.3	$119.9	$685.2	$220.9	$718.8	$129.3	$123.2	$39.7
20	$0.0	$59.2	$90.9	$160.9	440.8	$1,935.9	$565.3	$121.8	$687.1	$224.5	$713.3	$116.6	$112.3	$36.7
21	$0.0	$0.0	$90.9	$160.9	440.8	$1,935.9	$586.2	$122.8	$709.1	$226.4	$748.5	$111.3	$105.4	$33.7
22	$0.0	$59.2	$90.9	$160.9	440.8	$1,935.9	$565.3	$125.8	$691.1	$231.8	$702.0	$94.9	$93.4	$31.3
23	$0.0	$59.2	$90.9	$160.9	440.8	$1,935.9	$565.3	$126.1	$691.4	$232.5	$701.0	$86.1	$84.9	$28.6
24	$0.0	$0.0	$90.9	$160.9	440.8	$1,935.9	$586.2	$126.0	$712.3	$232.3	$739.5	$82.6	$79.5	$25.9
25	$0.0	$59.2	$86.4	$125.3	343.4	$1,513.1	$431.5	$98.2	$529.8	$181.1	$531.3	$53.9	$53.8	$18.4
26	$0.0	$59.2	$82.9	$97.6	267.5	$1,183.8	$327.3	$74.7	$402.0	$137.7	$404.4	$37.3	$37.1	$12.7
27	$0.0	$0.0	$80.2	$76.1	208.4	$927.2	$267.0	$56.0	$323.0	$103.2	$344.7	$28.9	$27.1	$8.7
28	$0.0	$59.2	$78.1	$59.3	162.3	$727.4	$182.9	$43.6	$226.5	$80.4	$223.9	$17.1	$17.3	$6.1
29	$0.0	$0.0	$76.4	$46.2	126.5	$571.7	$154.5	$31.7	$186.3	$58.5	$204.4	$14.2	$12.9	$4.1
30	$18.9	$59.2	$75.1	$36.0	98.5	$450.4	$88.5	$23.2	$111.7	$42.8	$106.8	$6.7	$7.0	$2.7
31	$0.0	$0.0	$74.1	$28.0	76.7	$356.0	$86.3	$16.9	$103.2	$31.2	$119.5	$6.8	$5.9	$1.8
32	$0.0	$0.0	$73.3	$21.8	59.8	$282.4	$63.0	$12.7	$75.7	$23.4	$88.1	$4.6	$3.9	$1.2

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.0	46.6	$225.0	$44.8	$9.3	$54.2	$17.2	$64.0	$3.0	$2.6	$0.8
34	$0.0	$0.0	$72.3	$13.2	36.3	$180.4	$30.7	$6.6	$37.3	$12.3	$45.3	$1.9	$1.6	$0.5
35	$0.0	$0.0	$71.9	$10.3	28.3	$145.6	$19.7	$4.5	$24.2	$8.3	$30.9	$1.2	$0.9	$0.3
36	$0.0	$100.0	$71.6	$8.0	22.0	$118.5	$5.5	$2.0	$7.5	$3.7	-$72.4	-$2.6	$0.3	$0.1
Total	**$622.0**	**$3,823.0**	**$2,111.2**	**$2,550.2**		**$30,891.7**	**$6,787.8**	**$1,854.1**	**$8,641.9**	**$3,429.8**	**$9,713.6**	**$1,035.2**	**$1,321.8**	**$597.9**
											Nom. IRR	**19.3%**		
											Real IRR	**17.0%**		

*****Totals do not always equal column sums due to rounding.

Table 3E.9: Selected Statistics for Economic and Rent Analysis of Long Pipeline Wet Gas Scenario - $10 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$265.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$265.7	-$123.9	$0.0	$0.0
10	$0.0	$708.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$714.7	-$303.1	$0.0	$0.0
11	$0.0	$1,076.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,094.8	-$422.1	$0.0	$0.0
12	$0.0	$854.0	$80.7	$80.5	220.4	$1,077.3	$19.9	$0.0	$19.9	$0.0	$42.2	$14.8	$7.0	$0.0
13	$0.0	$99.4	$90.9	$160.9	440.8	$2,131.6	$39.4	$106.2	$145.6	$213.4	$1,421.5	$452.9	$46.4	$68.0
14	$0.0	$96.1	$90.9	$160.9	440.8	$2,131.6	$39.4	$170.0	$209.4	$313.3	$1,261.0	$365.3	$60.7	$90.8
15	$0.0	$0.0	$90.9	$160.9	440.8	$2,131.6	$374.1	$143.1	$517.3	$263.9	$1,098.7	$289.3	$136.2	$69.5
16	$0.0	$59.2	$90.9	$160.9	440.8	$2,131.6	$362.2	$152.7	$514.8	$281.4	$1,024.4	$245.2	$123.3	$67.4
17	$0.0	$59.2	$90.9	$160.9	440.8	$2,131.6	$633.8	$126.0	$759.9	$232.3	$828.5	$180.3	$165.4	$50.6
18	$0.0	$0.0	$90.9	$160.9	440.8	$2,131.6	$654.8	$130.0	$784.8	$239.7	$855.3	$169.2	$155.3	$47.4
19	$0.0	$59.2	$90.9	$160.9	440.8	$2,131.6	$633.8	$135.1	$768.9	$249.1	$802.6	$144.4	$138.3	$44.8
20	$0.0	$59.2	$90.9	$160.9	440.8	$2,131.6	$633.8	$137.1	$770.9	$252.6	$797.1	$130.3	$126.0	$41.3
21	$0.0	$0.0	$90.9	$160.9	440.8	$2,131.6	$654.8	$138.1	$792.9	$254.6	$832.4	$123.7	$117.9	$37.8
22	$0.0	$59.2	$90.9	$160.9	440.8	$2,131.6	$633.8	$141.0	$774.9	$260.0	$785.8	$106.2	$104.7	$35.1
23	$0.0	$59.2	$90.9	$160.9	440.8	$2,131.6	$633.8	$141.4	$775.2	$260.6	$784.8	$96.4	$95.2	$32.0
24	$0.0	$0.0	$90.9	$160.9	440.8	$2,131.6	$654.8	$141.3	$796.0	$260.4	$823.3	$91.9	$88.9	$29.1
25	$0.0	$59.2	$86.4	$125.3	343.4	$1,665.6	$484.9	$110.1	$595.0	$203.0	$596.6	$60.6	$60.4	$20.6
26	$0.0	$59.2	$82.9	$97.6	267.5	$1,302.6	$368.9	$84.0	$452.8	$154.8	$455.2	$42.0	$41.8	$14.3
27	$0.0	$0.0	$80.2	$76.1	208.4	$1,019.8	$299.4	$63.2	$362.7	$116.6	$384.3	$32.2	$30.4	$9.8
28	$0.0	$59.2	$78.1	$59.3	162.3	$799.5	$208.1	$49.3	$257.3	$90.8	$254.8	$19.4	$19.6	$6.9
29	$0.0	$0.0	$76.4	$46.2	126.5	$627.9	$174.2	$36.1	$210.3	$66.6	$228.4	$15.8	$14.6	$4.6
30	$18.9	$59.2	$75.1	$36.0	98.5	$494.2	$103.9	$26.6	$130.5	$49.0	$125.5	$7.9	$8.2	$3.1
31	$0.0	$0.0	$74.1	$28.0	76.7	$390.0	$98.2	$19.6	$117.8	$36.1	$134.1	$7.7	$6.7	$2.1
32	$0.0	$0.0	$73.3	$21.8	59.8	$308.9	$72.3	$14.8	$87.0	$27.2	$99.5	$5.2	$4.5	$1.4

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.0	46.6	$245.7	$52.1	$11.0	$63.0	$20.2	$72.8	$3.4	$3.0	$1.0
34	$0.0	$0.0	$72.3	$13.2	36.3	$196.5	$36.3	$7.9	$44.2	$14.6	$52.2	$2.2	$1.9	$0.6
35	$0.0	$0.0	$71.9	$10.3	28.3	$158.1	$24.1	$5.5	$29.6	$10.1	$36.2	$1.4	$1.2	$0.4
36	$0.0	$100.0	$71.6	$8.0	22.0	$128.3	$6.0	$3.1	$9.1	$5.7	-$66.2	-$2.4	$0.3	$0.2
Total	**$622.0**	**$3,823.0**	**$2,111.2**	**$2,550.2**		**$33,994.0**	**$7,896.7**	**$2,093.1**	**$9,989.8**	**$3,876.0**	**$11,021.8**	**$1,272.3**	**$1,557.9**	**$678.7**
											Nom. IRR	**20.5%**		
											Real IRR	**18.2%**		

*****Totals do not always equal column sums due to rounding.

Appendix 3F: Results of Economic and Rent Analysis – Short Pipeline Dry Gas Scenario ($2006)

Table 3F.1: Selected Statistics for Economic and Rent Analysis of Short Pipeline Dry Scenario - $2 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$145.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$145.7	-$68.0	$0.0	$0.0
10	$0.0	$588.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$594.7	-$252.2	$0.0	$0.0
11	$0.0	$931.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$949.8	-$366.2	$0.0	$0.0
12	$0.0	$779.0	$80.7	$83.7	229.4	$203.7	$2.4	$0.0	$2.4	$0.0	-$742.1	-$260.1	$0.8	$0.0
13	$0.0	$99.4	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$44.8	$14.3	$1.5	$0.0
14	$0.0	$95.3	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$48.9	$14.2	$1.4	$0.0
15	$0.0	$0.0	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$144.2	$38.0	$1.3	$0.0
16	$0.0	$59.2	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$85.0	$20.4	$1.1	$0.0
17	$0.0	$59.2	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$85.0	$18.5	$1.0	$0.0
18	$0.0	$0.0	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$144.2	$28.5	$0.9	$0.0
19	$0.0	$59.2	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$85.0	$15.3	$0.9	$0.0
20	$0.0	$59.2	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$85.0	$13.9	$0.8	$0.0
21	$0.0	$0.0	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$144.2	$21.4	$0.7	$0.0
22	$0.0	$59.2	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$85.0	$11.5	$0.6	$0.0
23	$0.0	$59.2	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$85.0	$10.4	$0.6	$0.0
24	$0.0	$0.0	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$144.2	$16.1	$0.5	$0.0
25	$0.0	$59.2	$86.4	$130.4	357.4	$317.3	$3.7	$0.0	$3.7	$0.0	$37.6	$3.8	$0.4	$0.0
26	$0.0	$59.2	$82.9	$101.6	278.4	$247.2	$2.9	$0.0	$2.9	$0.0	$0.6	$0.1	$0.3	$0.0
27	$0.0	$0.0	$80.2	$79.2	216.9	$192.6	$2.3	$0.0	$2.3	$0.0	$31.0	$2.6	$0.2	$0.0
28	$0.0	$59.2	$78.1	$61.7	168.9	$150.0	$1.8	$0.0	$1.8	$0.0	-$50.7	-$3.9	$0.1	$0.0
29	$0.0	$0.0	$76.4	$48.0	131.6	$116.9	$1.4	-$0.9	$0.5	-$1.7	-$6.4	-$0.4	$0.0	-$0.1
30	$18.9	$59.2	$75.1	$37.4	102.5	$91.0	$1.1	-$2.6	-$1.5	-$4.8	-$93.3	-$5.9	-$0.1	-$0.3

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
31	$0.0	$0.0	$74.1	$29.1	79.9	$70.9	$0.8	-$3.9	-$3.0	-$7.2	-$22.1	-$1.3	-$0.2	-$0.4
32	$0.0	$0.0	$73.3	$22.7	62.2	$55.2	$0.7	-$4.9	-$4.2	-$9.0	-$27.5	-$1.4	-$0.2	-$0.5
33	$0.0	$0.0	$72.7	$17.7	48.5	$43.0	$0.5	-$5.7	-$5.2	-$10.5	-$31.7	-$1.5	-$0.2	-$0.5
34	$0.0	$0.0	$72.3	$13.8	37.8	$33.5	$0.4	-$6.3	-$5.9	-$11.6	-$35.0	-$1.5	-$0.3	-$0.5
35	$0.0	$0.0	$71.9	$10.7	29.4	$26.1	$0.3	-$6.8	-$6.5	-$12.5	-$37.5	-$1.5	-$0.3	-$0.5
36	$0.0	$100.0	$71.6	$8.4	22.9	$20.3	$0.6	-$7.2	-$6.6	-$13.2	-$139.9	-$5.0	-$0.2	-$0.5
Total	**$622.0**	**$3,362.3**	**$2,111.2**	**$2,653.7**		**$6,456.3**	**$76.4**	**-$38.2**	**$38.2**	**-$70.4**	**-$2,260.7**	**-$1,224.1**	**$11.8**	**-$3.3**
											Nom. IRR			
											Real IRR			

*****Totals do not always equal column sums due to rounding.

Table 3F.2: Selected Statistics for Economic and Rent Analysis of Short Pipeline Dry Gas Scenario - $3 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$145.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$145.7	-$68.0	$0.0	$0.0
10	$0.0	$588.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$594.7	-$252.2	$0.0	$0.0
11	$0.0	$931.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$949.8	-$366.2	$0.0	$0.0
12	$0.0	$779.0	$80.7	$83.7	229.4	$305.5	$4.4	$0.0	$4.4	$0.0	-$642.3	-$225.1	$1.6	$0.0
13	$0.0	$99.4	$90.9	$167.4	458.7	$611.1	$8.9	$0.0	$8.9	$0.0	$244.4	$77.9	$2.8	$0.0
14	$0.0	$95.3	$90.9	$167.4	458.7	$611.1	$8.9	$0.0	$8.9	$0.0	$248.5	$72.0	$2.6	$0.0
15	$0.0	$0.0	$90.9	$167.4	458.7	$611.1	$8.9	$0.0	$8.9	$0.0	$343.8	$90.5	$2.3	$0.0
16	$0.0	$59.2	$90.9	$167.4	458.7	$611.1	$8.9	$0.0	$8.9	$0.0	$284.6	$68.1	$2.1	$0.0
17	$0.0	$59.2	$90.9	$167.4	458.7	$611.1	$8.9	$0.0	$8.9	$0.0	$284.6	$61.9	$1.9	$0.0
18	$0.0	$0.0	$90.9	$167.4	458.7	$611.1	$8.9	$0.0	$8.9	$0.0	$343.8	$68.0	$1.8	$0.0
19	$0.0	$59.2	$90.9	$167.4	458.7	$611.1	$8.9	$0.0	$8.9	$0.0	$284.6	$51.2	$1.6	$0.0
20	$0.0	$59.2	$90.9	$167.4	458.7	$611.1	$8.9	$1.7	$10.6	$3.2	$279.7	$45.7	$1.7	$0.5
21	$0.0	$0.0	$90.9	$167.4	458.7	$611.1	$8.9	$33.2	$42.0	$61.1	$249.5	$37.1	$6.2	$9.1
22	$0.0	$59.2	$90.9	$167.4	458.7	$611.1	$8.9	$33.4	$42.2	$61.5	$189.8	$25.6	$5.7	$8.3
23	$0.0	$59.2	$90.9	$167.4	458.7	$611.1	$8.9	$33.6	$42.4	$61.9	$189.2	$23.2	$5.2	$7.6
24	$0.0	$0.0	$90.9	$167.4	458.7	$611.1	$8.9	$35.9	$44.7	$66.1	$241.9	$27.0	$5.0	$7.4
25	$0.0	$59.2	$86.4	$130.4	357.4	$476.0	$6.9	$24.4	$31.3	$44.9	$123.8	$12.6	$3.2	$4.6
26	$0.0	$59.2	$82.9	$101.6	278.4	$370.8	$5.4	$15.5	$20.8	$28.5	$77.8	$7.2	$1.9	$2.6
27	$0.0	$0.0	$80.2	$79.2	216.9	$288.9	$4.2	$10.7	$14.9	$19.7	$94.9	$8.0	$1.2	$1.7
28	$0.0	$59.2	$78.1	$61.7	168.9	$225.0	$3.3	$4.7	$8.0	$8.7	$9.4	$0.7	$0.6	$0.7
29	$0.0	$0.0	$76.4	$48.0	131.6	$175.3	$2.5	$2.2	$4.8	$4.1	$41.9	$2.9	$0.3	$0.3
30	$18.9	$59.2	$75.1	$37.4	102.5	$136.6	$2.0	$0.0	$2.0	$0.0	-$56.1	-$3.5	$0.1	$0.0
31	$0.0	$0.0	$74.1	$29.1	79.9	$106.4	$1.5	$0.0	$1.5	$0.0	$1.6	$0.1	$0.1	$0.0
32	$0.0	$0.0	$73.3	$22.7	62.2	$82.9	$1.2	-$1.6	-$0.4	-$2.9	-$9.9	-$0.5	$0.0	-$0.2

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.7	48.5	$64.6	$0.9	-$3.1	-$2.2	-$5.7	-$18.0	-$0.9	-$0.1	-$0.3
34	$0.0	$0.0	$72.3	$13.8	37.8	$50.3	$0.7	-$4.3	-$3.6	-$7.9	-$24.3	-$1.0	-$0.2	-$0.3
35	$0.0	$0.0	$71.9	$10.7	29.4	$39.2	$0.6	-$5.2	-$4.6	-$9.6	-$29.2	-$1.1	-$0.2	-$0.4
36	$0.0	$100.0	$71.6	$8.4	22.9	$30.5	$1.1	-$5.9	-$4.8	-$10.9	-$133.7	-$4.8	-$0.2	-$0.4
Total	**$622.0**	**$3,362.3**	**$2,111.2**	**$2,653.7**		**$9,684.5**	**$141.3**	**$175.0**	**$316.3**	**$322.6**	**$296.4**	**-$727.7**	**$47.5**	**$41.2**
											Nom. IRR	**3.2%**		
											Real IRR	**1.1%**		

***Totals do not always equal column sums due to rounding.**

Table 3F.3: Selected Statistics for Economic and Rent Analysis of Short Pipeline Dry Gas Scenario - $4 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$145.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$145.7	-$68.0	$0.0	$0.0
10	$0.0	$588.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$594.7	-$252.2	$0.0	$0.0
11	$0.0	$931.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$949.8	-$366.2	$0.0	$0.0
12	$0.0	$779.0	$80.7	$83.7	229.4	$407.4	$6.5	$0.0	$6.5	$0.0	-$542.5	-$190.2	$2.3	$0.0
13	$0.0	$99.4	$90.9	$167.4	458.7	$814.7	$12.9	$0.0	$12.9	$0.0	$444.0	$141.5	$4.1	$0.0
14	$0.0	$95.3	$90.9	$167.4	458.7	$814.7	$12.9	$0.0	$12.9	$0.0	$448.1	$129.8	$3.7	$0.0
15	$0.0	$0.0	$90.9	$167.4	458.7	$814.7	$12.9	$0.0	$12.9	$0.0	$543.5	$143.1	$3.4	$0.0
16	$0.0	$59.2	$90.9	$167.4	458.7	$814.7	$12.9	$0.0	$12.9	$0.0	$484.2	$115.9	$3.1	$0.0
17	$0.0	$59.2	$90.9	$167.4	458.7	$814.7	$12.9	$39.8	$52.8	$73.4	$371.0	$80.7	$11.5	$16.0
18	$0.0	$0.0	$90.9	$167.4	458.7	$814.7	$12.9	$50.2	$63.2	$92.6	$400.6	$79.3	$12.5	$18.3
19	$0.0	$59.2	$90.9	$167.4	458.7	$814.7	$12.9	$52.3	$65.2	$96.4	$335.6	$60.4	$11.7	$17.3
20	$0.0	$59.2	$90.9	$167.4	458.7	$814.7	$12.9	$53.8	$66.8	$99.2	$331.2	$54.2	$10.9	$16.2
21	$0.0	$0.0	$90.9	$167.4	458.7	$814.7	$32.4	$54.8	$87.2	$101.0	$368.3	$54.7	$13.0	$15.0
22	$0.0	$59.2	$90.9	$167.4	458.7	$814.7	$32.4	$55.0	$87.4	$101.4	$308.5	$41.7	$11.8	$13.7
23	$0.0	$59.2	$90.9	$167.4	458.7	$814.7	$32.4	$55.2	$87.5	$101.7	$307.9	$37.8	$10.8	$12.5
24	$0.0	$0.0	$90.9	$167.4	458.7	$814.7	$32.4	$57.5	$89.8	$106.0	$360.6	$40.3	$10.0	$11.8
25	$0.0	$59.2	$86.4	$130.4	357.4	$634.7	$69.9	$35.8	$105.7	$66.1	$186.9	$19.0	$10.7	$6.7
26	$0.0	$59.2	$82.9	$101.6	278.4	$494.4	$48.4	$25.1	$73.5	$46.3	$130.9	$12.1	$6.8	$4.3
27	$0.0	$0.0	$80.2	$79.2	216.9	$385.1	$43.6	$17.5	$61.1	$32.3	$132.4	$11.1	$5.1	$2.7
28	$0.0	$59.2	$78.1	$61.7	168.9	$300.0	$18.5	$11.9	$30.4	$21.9	$48.8	$3.7	$2.3	$1.7
29	$0.0	$0.0	$76.4	$48.0	131.6	$233.7	$20.3	$7.1	$27.5	$13.1	$68.7	$4.8	$1.9	$0.9
30	$18.9	$59.2	$75.1	$37.4	102.5	$182.1	$7.2	$0.6	$7.9	$1.1	-$17.6	-$1.1	$0.5	$0.1
31	$0.0	$0.0	$74.1	$29.1	79.9	$141.8	$6.2	$0.7	$7.0	$1.3	$30.3	$1.7	$0.4	$0.1
32	$0.0	$0.0	$73.3	$22.7	62.2	$110.5	$4.4	$0.0	$4.4	$0.0	$10.1	$0.5	$0.2	$0.0

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.7	48.5	$86.1	$3.4	-$0.5	$2.9	-$1.0	-$6.3	-$0.3	$0.1	$0.0
34	$0.0	$0.0	$72.3	$13.8	37.8	$67.0	$2.7	-$2.3	$0.4	-$4.2	-$15.2	-$0.7	$0.0	-$0.2
35	$0.0	$0.0	$71.9	$10.7	29.4	$52.2	$2.1	-$3.6	-$1.6	-$6.7	-$22.1	-$0.9	-$0.1	-$0.3
36	$0.0	$100.0	$71.6	$8.4	22.9	$40.7	$1.6	-$4.7	-$3.1	-$8.7	-$127.5	-$4.5	-$0.1	-$0.3
Total	**$622.0**	**$3,362.3**	**$2,111.2**	**$2,653.7**		**$12,912.6**	**$467.8**	**$506.3**	**$974.1**	**$933.3**	**$2,256.1**	**-$336.0**	**$136.8**	**$136.5**
											Nom. IRR	**8.7%**		
											Real IRR	**6.6%**		

*****Totals do not always equal column sums due to rounding.

Table 3F.4: Selected Statistics for Economic and Rent Analysis of Short Pipeline Dry Gas Scenario - $5 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$145.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$145.7	-$68.0	$0.0	$0.0
10	$0.0	$588.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$594.7	-$252.2	$0.0	$0.0
11	$0.0	$931.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$949.8	-$366.2	$0.0	$0.0
12	$0.0	$779.0	$80.7	$83.7	229.4	$509.2	$8.5	$0.0	$8.5	$0.0	-$442.7	-$155.2	$3.0	$0.0
13	$0.0	$99.4	$90.9	$167.4	458.7	$1,018.4	$17.0	$0.0	$17.0	$0.0	$643.7	$205.1	$5.4	$0.0
14	$0.0	$95.3	$90.9	$167.4	458.7	$1,018.4	$17.0	$0.0	$17.0	$0.0	$647.7	$187.6	$4.9	$0.0
15	$0.0	$0.0	$90.9	$167.4	458.7	$1,018.4	$17.0	$36.7	$53.7	$67.7	$638.7	$168.2	$14.1	$17.8
16	$0.0	$59.2	$90.9	$167.4	458.7	$1,018.4	$17.0	$63.4	$80.4	$116.9	$503.5	$120.5	$19.3	$28.0
17	$0.0	$59.2	$90.9	$167.4	458.7	$1,018.4	$17.0	$68.4	$85.4	$126.1	$489.4	$106.5	$18.6	$27.4
18	$0.0	$0.0	$90.9	$167.4	458.7	$1,018.4	$42.5	$71.1	$113.7	$131.1	$515.3	$101.9	$22.5	$25.9
19	$0.0	$59.2	$90.9	$167.4	458.7	$1,018.4	$42.5	$73.2	$115.7	$134.9	$450.3	$81.0	$20.8	$24.3
20	$0.0	$59.2	$90.9	$167.4	458.7	$1,018.4	$138.2	$63.2	$201.5	$116.6	$382.8	$62.6	$32.9	$19.1
21	$0.0	$0.0	$90.9	$167.4	458.7	$1,018.4	$150.2	$65.1	$215.3	$120.0	$424.8	$63.1	$32.0	$17.8
22	$0.0	$59.2	$90.9	$167.4	458.7	$1,018.4	$138.2	$66.7	$205.0	$123.0	$372.9	$50.4	$27.7	$16.6
23	$0.0	$59.2	$90.9	$167.4	458.7	$1,018.4	$138.2	$66.9	$205.2	$123.4	$372.4	$45.7	$25.2	$15.2
24	$0.0	$0.0	$90.9	$167.4	458.7	$1,018.4	$262.8	$54.3	$317.1	$100.0	$342.9	$38.3	$35.4	$11.2
25	$0.0	$59.2	$86.4	$130.4	357.4	$793.3	$177.8	$41.9	$219.7	$77.3	$220.3	$22.4	$22.3	$7.8
26	$0.0	$59.2	$82.9	$101.6	278.4	$618.0	$127.9	$30.4	$158.3	$56.1	$159.9	$14.8	$14.6	$5.2
27	$0.0	$0.0	$80.2	$79.2	216.9	$481.4	$109.9	$21.1	$131.0	$38.9	$152.1	$12.8	$11.0	$3.3
28	$0.0	$59.2	$78.1	$61.7	168.9	$375.0	$58.7	$16.1	$74.7	$29.6	$71.8	$5.5	$5.7	$2.3
29	$0.0	$0.0	$76.4	$48.0	131.6	$292.2	$56.0	$9.9	$65.9	$18.2	$83.7	$5.8	$4.6	$1.3
30	$18.9	$59.2	$75.1	$37.4	102.5	$227.6	$10.0	$5.7	$15.8	$10.6	$10.6	$0.7	$1.0	$0.7
31	$0.0	$0.0	$74.1	$29.1	79.9	$177.3	$23.3	$2.9	$26.2	$5.4	$42.4	$2.4	$1.5	$0.3
32	$0.0	$0.0	$73.3	$22.7	62.2	$138.1	$12.2	$1.4	$13.6	$2.6	$25.9	$1.4	$0.7	$0.1

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.7	48.5	$107.6	$4.5	$0.0	$4.5	$0.0	$12.6	$0.6	$0.2	$0.0
34	$0.0	$0.0	$72.3	$13.8	37.8	$83.8	$3.5	-$0.3	$3.2	-$0.5	-$5.0	-$0.2	$0.1	$0.0
35	$0.0	$0.0	$71.9	$10.7	29.4	$65.3	$2.7	-$2.1	$0.6	-$3.8	-$14.2	-$0.6	$0.0	-$0.2
36	$0.0	$100.0	$71.6	$8.4	22.9	$50.9	$2.1	-$3.5	-$1.4	-$6.4	-$121.3	-$4.3	$0.0	-$0.2
Total	**$622.0**	**$3,362.3**	**$2,111.2**	**$2,653.7**		**$16,140.8**	**$1,595.2**	**$752.7**	**$2,347.9**	**$1,387.5**	**$3,656.3**	**-$33.6**	**$323.6**	**$223.8**
											Nom. IRR	**11.9%**		
											Real IRR	**9.7%**		

*****Totals do not always equal column sums due to rounding.

Table 3F.5: Selected Statistics for Economic and Rent Analysis of Short Pipeline Dry Gas Scenario - $6 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$145.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$145.7	-$68.0	$0.0	$0.0
10	$0.0	$588.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$594.7	-$252.2	$0.0	$0.0
11	$0.0	$931.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$949.8	-$366.2	$0.0	$0.0
12	$0.0	$779.0	$80.7	$83.7	229.4	$611.1	$10.5	$0.0	$10.5	$0.0	-$342.9	-$120.2	$3.7	$0.0
13	$0.0	$99.4	$90.9	$167.4	458.7	$1,222.1	$21.1	$0.0	$21.1	$0.0	$843.3	$268.7	$6.7	$0.0
14	$0.0	$95.3	$90.9	$167.4	458.7	$1,222.1	$21.1	$38.6	$59.7	$71.1	$737.6	$213.7	$17.3	$20.6
15	$0.0	$0.0	$90.9	$167.4	458.7	$1,222.1	$21.1	$80.6	$101.7	$148.6	$713.4	$187.9	$26.8	$39.1
16	$0.0	$59.2	$90.9	$167.4	458.7	$1,222.1	$21.1	$87.4	$108.5	$161.0	$635.0	$152.0	$26.0	$38.6
17	$0.0	$59.2	$90.9	$167.4	458.7	$1,222.1	$52.7	$88.6	$141.3	$163.2	$600.0	$130.6	$30.7	$35.5
18	$0.0	$0.0	$90.9	$167.4	458.7	$1,222.1	$190.9	$77.8	$268.7	$143.4	$551.7	$109.2	$53.2	$28.4
19	$0.0	$59.2	$90.9	$167.4	458.7	$1,222.1	$179.0	$81.2	$260.2	$149.8	$494.6	$89.0	$46.8	$26.9
20	$0.0	$59.2	$90.9	$167.4	458.7	$1,222.1	$179.0	$82.8	$261.8	$152.6	$490.2	$80.1	$42.8	$25.0
21	$0.0	$0.0	$90.9	$167.4	458.7	$1,222.1	$334.1	$67.5	$401.6	$124.3	$437.8	$65.1	$59.7	$18.5
22	$0.0	$59.2	$90.9	$167.4	458.7	$1,222.1	$313.2	$70.2	$383.4	$129.3	$391.8	$52.9	$51.8	$17.5
23	$0.0	$59.2	$90.9	$167.4	458.7	$1,222.1	$313.2	$70.4	$383.6	$129.7	$391.3	$48.1	$47.1	$15.9
24	$0.0	$0.0	$90.9	$167.4	458.7	$1,222.1	$334.1	$70.2	$404.3	$129.3	$430.2	$48.0	$45.2	$14.4
25	$0.0	$59.2	$86.4	$130.4	357.4	$952.0	$233.4	$54.3	$287.7	$100.1	$288.2	$29.3	$29.2	$10.2
26	$0.0	$59.2	$82.9	$101.6	278.4	$741.6	$171.2	$40.1	$211.2	$73.8	$212.8	$19.6	$19.5	$6.8
27	$0.0	$0.0	$80.2	$79.2	216.9	$577.7	$143.6	$28.6	$172.3	$52.8	$193.3	$16.2	$14.5	$4.4
28	$0.0	$59.2	$78.1	$61.7	168.9	$450.0	$84.9	$21.9	$106.8	$40.4	$103.9	$7.9	$8.1	$3.1
29	$0.0	$0.0	$76.4	$48.0	131.6	$350.6	$76.5	$14.4	$90.9	$26.6	$108.7	$7.5	$6.3	$1.8
30	$18.9	$59.2	$75.1	$37.4	102.5	$273.1	$26.0	$9.3	$35.3	$17.1	$30.1	$1.9	$2.2	$1.1
31	$0.0	$0.0	$74.1	$29.1	79.9	$212.8	$35.7	$5.7	$41.4	$10.5	$57.6	$3.3	$2.4	$0.6
32	$0.0	$0.0	$73.3	$22.7	62.2	$165.7	$21.8	$3.6	$25.4	$6.6	$37.7	$2.0	$1.3	$0.3

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.7	48.5	$129.1	$11.0	$1.8	$12.8	$3.4	$22.5	$1.1	$0.6	$0.2
34	$0.0	$0.0	$72.3	$13.8	37.8	$100.6	$4.3	$0.2	$4.5	$0.3	$9.6	$0.4	$0.2	$0.0
35	$0.0	$0.0	$71.9	$10.7	29.4	$78.3	$3.4	-$0.5	$2.9	-$0.9	-$6.2	-$0.2	$0.1	$0.0
36	$0.0	$100.0	$71.6	$8.4	22.9	$61.0	$2.6	-$2.3	$0.4	-$4.2	-$115.1	-$4.1	$0.0	-$0.1
Total	**$622.0**	**$3,362.3**	**$2,111.2**	**$2,653.7**		**$19,368.9**	**$2,805.7**	**$992.2**	**$3,797.8**	**$1,828.9**	**$4,993.1**	**$239.3**	**$542.2**	**$308.7**
											Nom. IRR	**14.3%**		
											Real IRR	**12.1%**		

***Totals do not always equal column sums due to rounding.

Table3F.6: Selected Statistics for Economic and Rent Analysis of Short Pipeline Dry Gas Scenario - $7 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$145.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$145.7	-$68.0	$0.0	$0.0
10	$0.0	$588.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$594.7	-$252.2	$0.0	$0.0
11	$0.0	$931.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$949.8	-$366.2	$0.0	$0.0
12	$0.0	$779.0	$80.7	$83.7	229.4	$712.9	$12.6	$0.0	$12.6	$0.0	-$243.1	-$85.2	$4.4	$0.0
13	$0.0	$99.4	$90.9	$167.4	458.7	$1,425.8	$25.2	$4.6	$29.8	$9.2	$1,029.1	$327.9	$9.5	$2.9
14	$0.0	$95.3	$90.9	$167.4	458.7	$1,425.8	$25.2	$93.0	$118.2	$171.5	$782.4	$226.6	$34.2	$49.7
15	$0.0	$0.0	$90.9	$167.4	458.7	$1,425.8	$25.2	$104.6	$129.7	$192.8	$845.0	$222.5	$34.2	$50.8
16	$0.0	$59.2	$90.9	$167.4	458.7	$1,425.8	$62.9	$106.8	$169.7	$196.9	$741.7	$177.6	$40.6	$47.1
17	$0.0	$59.2	$90.9	$167.4	458.7	$1,425.8	$219.7	$93.0	$312.7	$171.3	$624.2	$135.8	$68.0	$37.3
18	$0.0	$0.0	$90.9	$167.4	458.7	$1,425.8	$231.7	$97.3	$329.0	$179.4	$659.0	$130.4	$65.1	$35.5
19	$0.0	$59.2	$90.9	$167.4	458.7	$1,425.8	$384.5	$81.0	$465.5	$149.4	$493.4	$88.7	$83.7	$26.9
20	$0.0	$59.2	$90.9	$167.4	458.7	$1,425.8	$384.5	$82.6	$467.1	$152.2	$489.0	$80.0	$76.4	$24.9
21	$0.0	$0.0	$90.9	$167.4	458.7	$1,425.8	$405.4	$83.3	$488.8	$153.6	$525.0	$78.0	$72.7	$22.8
22	$0.0	$59.2	$90.9	$167.4	458.7	$1,425.8	$384.5	$86.1	$470.6	$158.6	$479.1	$64.7	$63.6	$21.4
23	$0.0	$59.2	$90.9	$167.4	458.7	$1,425.8	$384.5	$86.3	$470.7	$159.0	$478.5	$58.8	$57.8	$19.5
24	$0.0	$0.0	$90.9	$167.4	458.7	$1,425.8	$405.4	$86.0	$491.5	$158.6	$517.4	$57.8	$54.9	$17.7
25	$0.0	$59.2	$86.4	$130.4	357.4	$1,110.7	$288.9	$66.7	$355.6	$122.9	$356.2	$36.2	$36.1	$12.5
26	$0.0	$59.2	$82.9	$101.6	278.4	$865.2	$214.4	$49.7	$264.1	$91.6	$265.8	$24.5	$24.4	$8.5
27	$0.0	$0.0	$80.2	$79.2	216.9	$674.0	$177.3	$36.1	$213.5	$66.6	$234.6	$19.7	$17.9	$5.6
28	$0.0	$59.2	$78.1	$61.7	168.9	$525.1	$111.2	$27.8	$138.9	$51.2	$136.0	$10.4	$10.6	$3.9
29	$0.0	$0.0	$76.4	$48.0	131.6	$409.0	$96.9	$19.0	$115.9	$35.0	$133.7	$9.3	$8.0	$2.4
30	$18.9	$59.2	$75.1	$37.4	102.5	$318.6	$41.9	$12.8	$54.7	$23.7	$49.6	$3.1	$3.5	$1.5
31	$0.0	$0.0	$74.1	$29.1	79.9	$248.2	$48.1	$8.5	$56.6	$15.6	$72.8	$4.2	$3.2	$0.9
32	$0.0	$0.0	$73.3	$22.7	62.2	$193.4	$31.5	$5.7	$37.2	$10.5	$49.6	$2.6	$1.9	$0.5

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.7	48.5	$150.6	$18.5	$3.5	$22.0	$6.5	$31.7	$1.5	$1.0	$0.3
34	$0.0	$0.0	$72.3	$13.8	37.8	$117.3	$8.4	$1.7	$10.1	$3.1	$18.0	$0.8	$0.4	$0.1
35	$0.0	$0.0	$71.9	$10.7	29.4	$91.4	$4.0	$0.0	$4.0	$0.0	$4.7	$0.2	$0.2	$0.0
36	$0.0	$100.0	$71.6	$8.4	22.9	$71.2	$3.1	-$1.1	$2.1	-$1.9	-$108.9	-$3.9	$0.1	-$0.1
Total	**$622.0**	**$3,362.3**	**$2,111.2**	**$2,653.7**		**$22,597.1**	**$3,995.6**	**$1,235.0**	**$5,230.6**	**$2,277.3**	**$6,340.1**	**$501.5**	**$772.5**	**$392.7**
											Nom. IRR	**16.4%**		
											Real IRR	**14.1%**		

***Totals do not always equal column sums due to rounding.

Table 3F.7: Selected Statistics for Economic and Rent Analysis of Short Pipeline Dry Gas Scenario - $8 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$145.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$145.7	-$68.0	$0.0	$0.0
10	$0.0	$588.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$594.7	-$252.2	$0.0	$0.0
11	$0.0	$931.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$949.8	-$366.2	$0.0	$0.0
12	$0.0	$779.0	$80.7	$83.7	229.4	$814.7	$14.6	$0.0	$14.6	$0.0	-$143.3	-$50.2	$5.1	$0.0
13	$0.0	$99.4	$90.9	$167.4	458.7	$1,629.5	$29.2	$40.3	$69.5	$81.0	$1,121.2	$357.3	$22.2	$25.8
14	$0.0	$95.3	$90.9	$167.4	458.7	$1,629.5	$29.2	$117.0	$146.2	$215.7	$913.9	$264.7	$42.4	$62.5
15	$0.0	$0.0	$90.9	$167.4	458.7	$1,629.5	$73.1	$123.3	$196.4	$227.2	$947.6	$249.5	$51.7	$59.8
16	$0.0	$59.2	$90.9	$167.4	458.7	$1,629.5	$260.4	$107.5	$368.0	$198.2	$745.7	$178.5	$88.1	$47.5
17	$0.0	$59.2	$90.9	$167.4	458.7	$1,629.5	$260.4	$112.5	$373.0	$207.4	$731.6	$159.2	$81.2	$45.1
18	$0.0	$0.0	$90.9	$167.4	458.7	$1,629.5	$476.7	$92.4	$569.1	$170.3	$631.8	$125.0	$112.6	$33.7
19	$0.0	$59.2	$90.9	$167.4	458.7	$1,629.5	$455.8	$96.9	$552.7	$178.6	$580.6	$104.4	$99.4	$32.1
20	$0.0	$59.2	$90.9	$167.4	458.7	$1,629.5	$455.8	$98.5	$554.2	$181.5	$576.2	$94.2	$90.6	$29.7
21	$0.0	$0.0	$90.9	$167.4	458.7	$1,629.5	$476.7	$99.2	$575.9	$182.9	$612.3	$91.0	$85.6	$27.2
22	$0.0	$59.2	$90.9	$167.4	458.7	$1,629.5	$455.8	$101.9	$557.7	$187.9	$566.3	$76.5	$75.4	$25.4
23	$0.0	$59.2	$90.9	$167.4	458.7	$1,629.5	$455.8	$102.1	$557.9	$188.3	$565.7	$69.5	$68.5	$23.1
24	$0.0	$0.0	$90.9	$167.4	458.7	$1,629.5	$476.7	$101.9	$578.6	$187.9	$604.6	$67.5	$64.6	$21.0
25	$0.0	$59.2	$86.4	$130.4	357.4	$1,269.4	$344.4	$79.1	$423.5	$145.7	$424.1	$43.1	$43.0	$14.8
26	$0.0	$59.2	$82.9	$101.6	278.4	$988.8	$257.7	$59.3	$317.0	$109.4	$318.7	$29.4	$29.3	$10.1
27	$0.0	$0.0	$80.2	$79.2	216.9	$770.3	$211.0	$43.7	$254.7	$80.5	$275.8	$23.1	$21.4	$6.8
28	$0.0	$59.2	$78.1	$61.7	168.9	$600.1	$137.4	$33.6	$171.0	$61.9	$168.1	$12.8	$13.0	$4.7
29	$0.0	$0.0	$76.4	$48.0	131.6	$467.4	$117.4	$23.5	$140.9	$43.4	$158.7	$11.0	$9.8	$3.0
30	$18.9	$59.2	$75.1	$37.4	102.5	$364.1	$57.8	$16.4	$74.2	$30.2	$69.1	$4.4	$4.7	$1.9
31	$0.0	$0.0	$74.1	$29.1	79.9	$283.7	$60.6	$11.2	$71.8	$20.7	$88.0	$5.0	$4.1	$1.2
32	$0.0	$0.0	$73.3	$22.7	62.2	$221.0	$41.2	$7.9	$49.1	$14.5	$61.4	$3.2	$2.6	$0.8

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.7	48.5	$172.1	$26.1	$5.2	$31.2	$9.5	$41.0	$1.9	$1.5	$0.5
34	$0.0	$0.0	$72.3	$13.8	37.8	$134.1	$14.3	$3.0	$17.3	$5.6	$25.2	$1.1	$0.7	$0.2
35	$0.0	$0.0	$71.9	$10.7	29.4	$104.5	$5.1	$1.3	$6.4	$2.4	$13.0	$0.5	$0.3	$0.1
36	$0.0	$100.0	$71.6	$8.4	22.9	$81.4	$3.7	$0.0	$3.7	$0.0	-$102.2	-$3.6	$0.1	$0.0
Total	**$622.0**	**$3,362.3**	**$2,111.2**	**$2,653.7**		**$25,825.3**	**$5,197.0**	**$1,477.7**	**$6,674.7**	**$2,730.6**	**$7,670.8**	**$748.5**	**$1,017.8**	**$476.9**
											Nom. IRR	**18.1%**		
											Real IRR	**15.7%**		

*****Totals do not always equal column sums due to rounding.

Table 3F.8: Selected Statistics for Economic and Rent Analysis of Short Pipeline Dry Gas Scenario - $9 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$145.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$145.7	-$68.0	$0.0	$0.0
10	$0.0	$588.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$594.7	-$252.2	$0.0	$0.0
11	$0.0	$931.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$949.8	-$366.2	$0.0	$0.0
12	$0.0	$779.0	$80.7	$83.7	229.4	$916.6	$16.7	$0.0	$16.7	$0.0	-$43.5	-$15.2	$5.8	$0.0
13	$0.0	$99.4	$90.9	$167.4	458.7	$1,833.2	$33.3	$76.0	$109.3	$152.7	$1,213.4	$386.6	$34.8	$48.7
14	$0.0	$95.3	$90.9	$167.4	458.7	$1,833.2	$33.3	$141.0	$174.3	$259.8	$1,045.4	$302.8	$50.5	$75.3
15	$0.0	$0.0	$90.9	$167.4	458.7	$1,833.2	$313.1	$118.9	$432.0	$219.2	$923.6	$243.2	$113.8	$57.7
16	$0.0	$59.2	$90.9	$167.4	458.7	$1,833.2	$301.2	$127.1	$428.3	$234.3	$853.1	$204.2	$102.5	$56.1
17	$0.0	$59.2	$90.9	$167.4	458.7	$1,833.2	$527.1	$105.0	$632.0	$193.5	$690.1	$150.2	$137.5	$42.1
18	$0.0	$0.0	$90.9	$167.4	458.7	$1,833.2	$548.0	$108.3	$656.3	$199.5	$719.0	$142.3	$129.8	$39.5
19	$0.0	$59.2	$90.9	$167.4	458.7	$1,833.2	$527.1	$112.8	$639.9	$207.9	$667.8	$120.1	$115.1	$37.4
20	$0.0	$59.2	$90.9	$167.4	458.7	$1,833.2	$527.1	$114.3	$641.4	$210.8	$663.4	$108.5	$104.9	$34.5
21	$0.0	$0.0	$90.9	$167.4	458.7	$1,833.2	$548.0	$115.1	$663.1	$212.2	$699.5	$104.0	$98.6	$31.5
22	$0.0	$59.2	$90.9	$167.4	458.7	$1,833.2	$527.1	$117.8	$644.9	$217.2	$653.5	$88.3	$87.1	$29.4
23	$0.0	$59.2	$90.9	$167.4	458.7	$1,833.2	$527.1	$118.0	$645.1	$217.6	$652.9	$80.2	$79.2	$26.7
24	$0.0	$0.0	$90.9	$167.4	458.7	$1,833.2	$548.0	$117.8	$665.8	$217.2	$691.8	$77.3	$74.4	$24.3
25	$0.0	$59.2	$86.4	$130.4	357.4	$1,428.0	$400.0	$91.4	$491.4	$168.5	$492.1	$50.0	$49.9	$17.1
26	$0.0	$59.2	$82.9	$101.6	278.4	$1,112.4	$300.9	$69.0	$369.9	$127.2	$371.6	$34.3	$34.1	$11.7
27	$0.0	$0.0	$80.2	$79.2	216.9	$866.6	$244.7	$51.2	$295.9	$94.3	$317.0	$26.6	$24.8	$7.9
28	$0.0	$59.2	$78.1	$61.7	168.9	$675.1	$163.7	$39.5	$203.1	$72.7	$200.2	$15.3	$15.5	$5.5
29	$0.0	$0.0	$76.4	$48.0	131.6	$525.9	$137.8	$28.1	$165.9	$51.8	$183.8	$12.7	$11.5	$3.6
30	$18.9	$59.2	$75.1	$37.4	102.5	$409.7	$73.8	$20.0	$93.7	$36.8	$88.5	$5.6	$5.9	$2.3
31	$0.0	$0.0	$74.1	$29.1	79.9	$319.1	$73.0	$14.0	$87.0	$25.8	$103.1	$5.9	$5.0	$1.5
32	$0.0	$0.0	$73.3	$22.7	62.2	$248.6	$50.8	$10.0	$60.9	$18.5	$73.2	$3.8	$3.2	$1.0

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.7	48.5	$193.7	$33.6	$6.9	$40.5	$12.6	$50.2	$2.4	$1.9	$0.6
34	$0.0	$0.0	$72.3	$13.8	37.8	$150.9	$20.1	$4.3	$24.5	$8.0	$32.4	$1.4	$1.1	$0.3
35	$0.0	$0.0	$71.9	$10.7	29.4	$117.5	$9.7	$2.3	$12.0	$4.3	$18.6	$0.7	$0.5	$0.2
36	$0.0	$100.0	$71.6	$8.4	22.9	$91.5	$4.2	$0.0	$4.2	$0.0	-$92.6	-$3.3	$0.1	$0.0
Total	**$622.0**	**$3,362.3**	**$2,111.2**	**$2,653.7**		**$29,053.4**	**$6,489.3**	**$1,708.6**	**$8,197.9**	**$3,162.2**	**$8,944.1**	**$977.2**	**$1,287.6**	**$554.8**
											Nom. IRR	**19.4%**		
											Real IRR	**17.1%**		

*****Totals do not always equal column sums due to rounding.

Table 3F.9: Selected Statistics for Economic and Rent Analysis of Short Pipeline Dry Gas Scenario - $10 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$145.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$145.7	-$68.0	$0.0	$0.0
10	$0.0	$588.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$594.7	-$252.2	$0.0	$0.0
11	$0.0	$931.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$949.8	-$366.2	$0.0	$0.0
12	$0.0	$779.0	$80.7	$83.7	229.4	$1,018.4	$18.7	$0.0	$18.7	$0.0	$56.3	$19.7	$6.6	$0.0
13	$0.0	$99.4	$90.9	$167.4	458.7	$2,036.8	$37.4	$111.7	$149.1	$224.5	$1,305.6	$416.0	$47.5	$71.5
14	$0.0	$95.3	$90.9	$167.4	458.7	$2,036.8	$93.5	$158.2	$251.6	$291.6	$1,140.0	$330.2	$72.9	$84.5
15	$0.0	$0.0	$90.9	$167.4	458.7	$2,036.8	$353.9	$138.5	$492.3	$255.2	$1,031.0	$271.5	$129.6	$67.2
16	$0.0	$59.2	$90.9	$167.4	458.7	$2,036.8	$598.4	$115.9	$714.2	$213.6	$791.5	$189.5	$171.0	$51.1
17	$0.0	$59.2	$90.9	$167.4	458.7	$2,036.8	$598.4	$120.8	$719.2	$222.8	$777.3	$169.2	$156.5	$48.5
18	$0.0	$0.0	$90.9	$167.4	458.7	$2,036.8	$619.3	$124.1	$743.4	$228.8	$806.2	$159.5	$147.1	$45.3
19	$0.0	$59.2	$90.9	$167.4	458.7	$2,036.8	$598.4	$128.7	$727.1	$237.2	$755.0	$135.8	$130.8	$42.7
20	$0.0	$59.2	$90.9	$167.4	458.7	$2,036.8	$598.4	$130.2	$728.6	$240.1	$750.6	$122.7	$119.1	$39.3
21	$0.0	$0.0	$90.9	$167.4	458.7	$2,036.8	$619.3	$131.0	$750.3	$241.5	$786.7	$116.9	$111.5	$35.9
22	$0.0	$59.2	$90.9	$167.4	458.7	$2,036.8	$598.4	$133.7	$732.1	$246.5	$740.7	$100.1	$98.9	$33.3
23	$0.0	$59.2	$90.9	$167.4	458.7	$2,036.8	$598.4	$133.9	$732.3	$246.8	$740.2	$90.9	$90.0	$30.3
24	$0.0	$0.0	$90.9	$167.4	458.7	$2,036.8	$619.3	$133.7	$753.0	$246.5	$779.0	$87.0	$84.1	$27.5
25	$0.0	$59.2	$86.4	$130.4	357.4	$1,586.7	$455.5	$103.8	$559.3	$191.3	$560.0	$56.9	$56.8	$19.4
26	$0.0	$59.2	$82.9	$101.6	278.4	$1,236.0	$344.2	$78.6	$422.8	$144.9	$424.6	$39.2	$39.0	$13.4
27	$0.0	$0.0	$80.2	$79.2	216.9	$962.9	$278.4	$58.7	$337.1	$108.2	$358.3	$30.1	$28.3	$9.1
28	$0.0	$59.2	$78.1	$61.7	168.9	$750.1	$189.9	$45.3	$235.3	$83.5	$232.3	$17.7	$17.9	$6.4
29	$0.0	$0.0	$76.4	$48.0	131.6	$584.3	$158.3	$32.6	$190.9	$60.2	$208.8	$14.5	$13.2	$4.2
30	$18.9	$59.2	$75.1	$37.4	102.5	$455.2	$89.7	$23.5	$113.2	$43.3	$108.0	$6.8	$7.1	$2.7
31	$0.0	$0.0	$74.1	$29.1	79.9	$354.6	$85.4	$16.8	$102.1	$30.9	$118.3	$6.8	$5.9	$1.8
32	$0.0	$0.0	$73.3	$22.7	62.2	$276.2	$60.5	$12.2	$72.7	$22.5	$85.1	$4.4	$3.8	$1.2

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.7	48.5	$215.2	$41.1	$8.5	$49.7	$15.7	$59.4	$2.8	$2.4	$0.7
34	$0.0	$0.0	$72.3	$13.8	37.8	$167.6	$26.0	$5.6	$31.6	$10.4	$39.5	$1.7	$1.4	$0.4
35	$0.0	$0.0	$71.9	$10.7	29.4	$130.6	$14.3	$3.3	$17.6	$6.1	$24.2	$0.9	$0.7	$0.2
36	$0.0	$100.0	$71.6	$8.4	22.9	$101.7	$4.7	$0.1	$4.7	$0.1	-$83.1	-$3.0	$0.2	$0.0
Total	**$622.0**	**$3,362.3**	**$2,111.2**	**$2,653.7**		**$32,281.6**	**$7,699.5**	**$1,949.4**	**$9,648.9**	**$3,612.1**	**$10,271.4**	**$1,217.3**	**$1,542.2**	**$636.6**
											Nom. IRR	**20.8%**		
											Real IRR	**18.4%**		

***Totals do not always equal column sums due to rounding.

Appendix 3G: Results of Economic and Rent Analysis – Long Pipeline Dry Gas Scenario ($2006)

Table 3G.1: Selected Statistics for Economic and Rent Analysis of Long Pipeline Dry Gas Scenario - $2 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$265.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$265.7	-$123.9	$0.0	$0.0
10	$0.0	$708.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$714.7	-$303.1	$0.0	$0.0
11	$0.0	$1,051.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,069.8	-$412.5	$0.0	$0.0
12	$0.0	$779.0	$80.7	$83.7	229.4	$203.7	$2.4	$0.0	$2.4	$0.0	-$742.1	-$260.1	$0.8	$0.0
13	$0.0	$99.4	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$44.8	$14.3	$1.5	$0.0
14	$0.0	$96.1	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$48.2	$14.0	$1.4	$0.0
15	$0.0	$0.0	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$144.2	$38.0	$1.3	$0.0
16	$0.0	$59.2	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$85.0	$20.4	$1.1	$0.0
17	$0.0	$59.2	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$85.0	$18.5	$1.0	$0.0
18	$0.0	$0.0	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$144.2	$28.5	$0.9	$0.0
19	$0.0	$59.2	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$85.0	$15.3	$0.9	$0.0
20	$0.0	$59.2	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$85.0	$13.9	$0.8	$0.0
21	$0.0	$0.0	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$144.2	$21.4	$0.7	$0.0
22	$0.0	$59.2	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$85.0	$11.5	$0.6	$0.0
23	$0.0	$59.2	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$85.0	$10.4	$0.6	$0.0
24	$0.0	$0.0	$90.9	$167.4	458.7	$407.4	$4.8	$0.0	$4.8	$0.0	$144.2	$16.1	$0.5	$0.0
25	$0.0	$59.2	$86.4	$130.4	357.4	$317.3	$3.7	$0.0	$3.7	$0.0	$37.6	$3.8	$0.4	$0.0
26	$0.0	$59.2	$82.9	$101.6	278.4	$247.2	$2.9	$0.0	$2.9	$0.0	$0.6	$0.1	$0.3	$0.0
27	$0.0	$0.0	$80.2	$79.2	216.9	$192.6	$2.3	$0.0	$2.3	$0.0	$31.0	$2.6	$0.2	$0.0
28	$0.0	$59.2	$78.1	$61.7	168.9	$150.0	$1.8	$0.0	$1.8	$0.0	-$50.7	-$3.9	$0.1	$0.0
29	$0.0	$0.0	$76.4	$48.0	131.6	$116.9	$1.4	-$0.9	$0.5	-$1.7	-$6.4	-$0.4	$0.0	-$0.1
30	$18.9	$59.2	$75.1	$37.4	102.5	$91.0	$1.1	-$2.6	-$1.5	-$4.8	-$93.3	-$5.9	-$0.1	-$0.3

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
31	$0.0	$0.0	$74.1	$29.1	79.9	$70.9	$0.8	-$3.9	-$3.0	-$7.2	-$22.1	-$1.3	-$0.2	-$0.4
32	$0.0	$0.0	$73.3	$22.7	62.2	$55.2	$0.7	-$4.9	-$4.2	-$9.0	-$27.5	-$1.4	-$0.2	-$0.5
33	$0.0	$0.0	$72.7	$17.7	48.5	$43.0	$0.5	-$5.7	-$5.2	-$10.5	-$31.7	-$1.5	-$0.2	-$0.5
34	$0.0	$0.0	$72.3	$13.8	37.8	$33.5	$0.4	-$6.3	-$5.9	-$11.6	-$35.0	-$1.5	-$0.3	-$0.5
35	$0.0	$0.0	$71.9	$10.7	29.4	$26.1	$0.3	-$6.8	-$6.5	-$12.5	-$37.5	-$1.5	-$0.3	-$0.5
36	$0.0	$100.0	$71.6	$8.4	22.9	$20.3	$0.6	-$7.2	-$6.6	-$13.2	-$139.9	-$5.0	-$0.2	-$0.5
Total	**$622.0**	**$3,723.0**	**$2,111.2**	**$2,653.7**		**$6,456.3**	**$76.4**	**-$38.2**	**$38.2**	**-$70.4**	**-$2,621.4**	**-$1,377.4**	**$11.8**	**-$3.3**
											Nom. IRR			
											Real IRR			

*****Totals do not always equal column sums due to rounding.

Table 3G.2: Selected Statistics for Economic and Rent Analysis of Long Pipeline Dry Gas Scenario - $3 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$265.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$265.7	-$123.9	$0.0	$0.0
10	$0.0	$708.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$714.7	-$303.1	$0.0	$0.0
11	$0.0	$1,051.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,069.8	-$412.5	$0.0	$0.0
12	$0.0	$779.0	$80.7	$83.7	229.4	$305.5	$4.4	$0.0	$4.4	$0.0	-$642.3	-$225.1	$1.6	$0.0
13	$0.0	$99.4	$90.9	$167.4	458.7	$611.1	$8.9	$0.0	$8.9	$0.0	$244.4	$77.9	$2.8	$0.0
14	$0.0	$96.1	$90.9	$167.4	458.7	$611.1	$8.9	$0.0	$8.9	$0.0	$247.8	$71.8	$2.6	$0.0
15	$0.0	$0.0	$90.9	$167.4	458.7	$611.1	$8.9	$0.0	$8.9	$0.0	$343.8	$90.5	$2.3	$0.0
16	$0.0	$59.2	$90.9	$167.4	458.7	$611.1	$8.9	$0.0	$8.9	$0.0	$284.6	$68.1	$2.1	$0.0
17	$0.0	$59.2	$90.9	$167.4	458.7	$611.1	$8.9	$0.0	$8.9	$0.0	$284.6	$61.9	$1.9	$0.0
18	$0.0	$0.0	$90.9	$167.4	458.7	$611.1	$8.9	$0.0	$8.9	$0.0	$343.8	$68.0	$1.8	$0.0
19	$0.0	$59.2	$90.9	$167.4	458.7	$611.1	$8.9	$0.0	$8.9	$0.0	$284.6	$51.2	$1.6	$0.0
20	$0.0	$59.2	$90.9	$167.4	458.7	$611.1	$8.9	$0.0	$8.9	$0.0	$284.6	$46.5	$1.5	$0.0
21	$0.0	$0.0	$90.9	$167.4	458.7	$611.1	$8.9	$1.8	$10.6	$3.2	$338.8	$50.4	$1.6	$0.5
22	$0.0	$59.2	$90.9	$167.4	458.7	$611.1	$8.9	$32.9	$41.8	$60.7	$191.0	$25.8	$5.7	$8.2
23	$0.0	$59.2	$90.9	$167.4	458.7	$611.1	$8.9	$33.2	$42.1	$61.3	$190.1	$23.4	$5.2	$7.5
24	$0.0	$0.0	$90.9	$167.4	458.7	$611.1	$8.9	$35.6	$44.5	$65.7	$242.5	$27.1	$5.0	$7.3
25	$0.0	$59.2	$86.4	$130.4	357.4	$476.0	$6.9	$24.2	$31.1	$44.6	$124.3	$12.6	$3.2	$4.5
26	$0.0	$59.2	$82.9	$101.6	278.4	$370.8	$5.4	$15.3	$20.7	$28.3	$78.1	$7.2	$1.9	$2.6
27	$0.0	$0.0	$80.2	$79.2	216.9	$288.9	$4.2	$10.6	$14.8	$19.6	$95.1	$8.0	$1.2	$1.6
28	$0.0	$59.2	$78.1	$61.7	168.9	$225.0	$3.3	$4.6	$7.9	$8.5	$9.6	$0.7	$0.6	$0.7
29	$0.0	$0.0	$76.4	$48.0	131.6	$175.3	$2.5	$2.2	$4.7	$4.0	$42.1	$2.9	$0.3	$0.3
30	$18.9	$59.2	$75.1	$37.4	102.5	$136.6	$2.0	$0.0	$2.0	$0.0	-$56.1	-$3.5	$0.1	$0.0
31	$0.0	$0.0	$74.1	$29.1	79.9	$106.4	$1.5	$0.0	$1.5	$0.0	$1.6	$0.1	$0.1	$0.0
32	$0.0	$0.0	$73.3	$22.7	62.2	$82.9	$1.2	-$1.6	-$0.4	-$2.9	-$9.9	-$0.5	$0.0	-$0.2

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.7	48.5	$64.6	$0.9	-$3.1	-$2.2	-$5.7	-$18.0	-$0.9	-$0.1	-$0.3
34	$0.0	$0.0	$72.3	$13.8	37.8	$50.3	$0.7	-$4.3	-$3.6	-$7.9	-$24.3	-$1.0	-$0.2	-$0.3
35	$0.0	$0.0	$71.9	$10.7	29.4	$39.2	$0.6	-$5.2	-$4.6	-$9.6	-$29.2	-$1.1	-$0.2	-$0.4
36	$0.0	$100.0	$71.6	$8.4	22.9	$30.5	$1.1	-$5.9	-$4.8	-$10.9	-$133.7	-$4.8	-$0.2	-$0.4
Total	**$622.0**	**$3,723.0**	**$2,111.2**	**$2,653.7**		**$9,684.5**	**$141.3**	**$140.4**	**$281.7**	**$258.8**	**$34.1**	**-$866.5**	**$42.3**	**$31.7**
											Nom. IRR	**2.1%**		
											Real IRR	**0.1%**		

***Totals do not always equal column sums due to rounding.

Table 3G.3: Selected Statistics for Economic and Rent Analysis of Long Pipeline Dry Gas Scenario - $4 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$265.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$265.7	-$123.9	$0.0	$0.0
10	$0.0	$708.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$714.7	-$303.1	$0.0	$0.0
11	$0.0	$1,051.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,069.8	-$412.5	$0.0	$0.0
12	$0.0	$779.0	$80.7	$83.7	229.4	$407.4	$6.5	$0.0	$6.5	$0.0	-$542.5	-$190.2	$2.3	$0.0
13	$0.0	$99.4	$90.9	$167.4	458.7	$814.7	$12.9	$0.0	$12.9	$0.0	$444.0	$141.5	$4.1	$0.0
14	$0.0	$96.1	$90.9	$167.4	458.7	$814.7	$12.9	$0.0	$12.9	$0.0	$447.4	$129.6	$3.7	$0.0
15	$0.0	$0.0	$90.9	$167.4	458.7	$814.7	$12.9	$0.0	$12.9	$0.0	$543.5	$143.1	$3.4	$0.0
16	$0.0	$59.2	$90.9	$167.4	458.7	$814.7	$12.9	$0.0	$12.9	$0.0	$484.2	$115.9	$3.1	$0.0
17	$0.0	$59.2	$90.9	$167.4	458.7	$814.7	$12.9	$8.1	$21.0	$14.9	$461.3	$100.4	$4.6	$3.2
18	$0.0	$0.0	$90.9	$167.4	458.7	$814.7	$12.9	$48.8	$61.7	$89.9	$404.7	$80.1	$12.2	$17.8
19	$0.0	$59.2	$90.9	$167.4	458.7	$814.7	$12.9	$51.2	$64.2	$94.4	$338.6	$60.9	$11.5	$17.0
20	$0.0	$59.2	$90.9	$167.4	458.7	$814.7	$12.9	$53.0	$66.0	$97.8	$333.4	$54.5	$10.8	$16.0
21	$0.0	$0.0	$90.9	$167.4	458.7	$814.7	$12.9	$56.5	$69.5	$104.2	$382.7	$56.9	$10.3	$15.5
22	$0.0	$59.2	$90.9	$167.4	458.7	$814.7	$32.4	$54.6	$86.9	$100.6	$309.7	$41.8	$11.7	$13.6
23	$0.0	$59.2	$90.9	$167.4	458.7	$814.7	$32.4	$54.9	$87.2	$101.1	$308.8	$37.9	$10.7	$12.4
24	$0.0	$0.0	$90.9	$167.4	458.7	$814.7	$32.4	$57.3	$89.6	$105.5	$361.2	$40.3	$10.0	$11.8
25	$0.0	$59.2	$86.4	$130.4	357.4	$634.7	$25.2	$41.0	$66.2	$75.6	$216.8	$22.0	$6.7	$7.7
26	$0.0	$59.2	$82.9	$101.6	278.4	$494.4	$19.6	$28.5	$48.1	$52.4	$150.2	$13.9	$4.4	$4.8
27	$0.0	$0.0	$80.2	$79.2	216.9	$385.1	$15.3	$20.8	$36.1	$38.4	$151.3	$12.7	$3.0	$3.2
28	$0.0	$59.2	$78.1	$61.7	168.9	$300.0	$11.9	$12.6	$24.5	$23.2	$53.3	$4.1	$1.9	$1.8
29	$0.0	$0.0	$76.4	$48.0	131.6	$233.7	$20.3	$7.1	$27.4	$13.0	$68.8	$4.8	$1.9	$0.9
30	$18.9	$59.2	$75.1	$37.4	102.5	$182.1	$7.2	$0.6	$7.8	$1.1	-$17.5	-$1.1	$0.5	$0.1
31	$0.0	$0.0	$74.1	$29.1	79.9	$141.8	$6.2	$0.7	$6.9	$1.3	$30.4	$1.7	$0.4	$0.1
32	$0.0	$0.0	$73.3	$22.7	62.2	$110.5	$4.4	$0.0	$4.4	$0.0	$10.1	$0.5	$0.2	$0.0

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.7	48.5	$86.1	$3.4	-$0.5	$2.9	-$1.0	-$6.3	-$0.3	$0.1	$0.0
34	$0.0	$0.0	$72.3	$13.8	37.8	$67.0	$2.7	-$2.3	$0.4	-$4.2	-$15.2	-$0.7	$0.0	-$0.2
35	$0.0	$0.0	$71.9	$10.7	29.4	$52.2	$2.1	-$3.6	-$1.6	-$6.7	-$22.1	-$0.9	-$0.1	-$0.3
36	$0.0	$100.0	$71.6	$8.4	22.9	$40.7	$1.6	-$4.7	-$3.1	-$8.7	-$127.5	-$4.5	-$0.1	-$0.3
Total	**$622.0**	**$3,723.0**	**$2,111.2**	**$2,653.7**		**$12,912.6**	**$340.1**	**$484.4**	**$824.6**	**$893.0**	**$2,085.2**	**-$458.7**	**$117.6**	**$125.1**
											Nom. IRR	**7.8%**		
											Real IRR	**5.7%**		

***Totals do not always equal column sums due to rounding.**

Table 3G.4: Selected Statistics for Economic and Rent Analysis of Long Pipeline Dry Gas Scenario - $5 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$265.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$265.7	-$123.9	$0.0	$0.0
10	$0.0	$708.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$714.7	-$303.1	$0.0	$0.0
11	$0.0	$1,051.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,069.8	-$412.5	$0.0	$0.0
12	$0.0	$779.0	$80.7	$83.7	229.4	$509.2	$8.5	$0.0	$8.5	$0.0	-$442.7	-$155.2	$3.0	$0.0
13	$0.0	$99.4	$90.9	$167.4	458.7	$1,018.4	$17.0	$0.0	$17.0	$0.0	$643.7	$205.1	$5.4	$0.0
14	$0.0	$96.1	$90.9	$167.4	458.7	$1,018.4	$17.0	$0.0	$17.0	$0.0	$647.0	$187.4	$4.9	$0.0
15	$0.0	$0.0	$90.9	$167.4	458.7	$1,018.4	$17.0	$8.4	$25.5	$15.6	$719.1	$189.4	$6.7	$4.1
16	$0.0	$59.2	$90.9	$167.4	458.7	$1,018.4	$17.0	$60.7	$77.8	$111.9	$511.2	$122.4	$18.6	$26.8
17	$0.0	$59.2	$90.9	$167.4	458.7	$1,018.4	$17.0	$66.4	$83.4	$122.4	$495.0	$107.7	$18.2	$26.6
18	$0.0	$0.0	$90.9	$167.4	458.7	$1,018.4	$17.0	$72.7	$89.8	$134.1	$536.2	$106.1	$17.8	$26.5
19	$0.0	$59.2	$90.9	$167.4	458.7	$1,018.4	$42.5	$72.1	$114.7	$132.9	$453.3	$81.5	$20.6	$23.9
20	$0.0	$59.2	$90.9	$167.4	458.7	$1,018.4	$42.5	$73.9	$116.5	$136.3	$448.1	$73.3	$19.0	$22.3
21	$0.0	$0.0	$90.9	$167.4	458.7	$1,018.4	$42.5	$77.4	$120.0	$142.7	$497.4	$73.9	$17.8	$21.2
22	$0.0	$59.2	$90.9	$167.4	458.7	$1,018.4	$138.2	$66.3	$204.5	$122.2	$374.1	$50.6	$27.6	$16.5
23	$0.0	$59.2	$90.9	$167.4	458.7	$1,018.4	$138.2	$66.6	$204.8	$122.8	$373.3	$45.9	$25.2	$15.1
24	$0.0	$0.0	$90.9	$167.4	458.7	$1,018.4	$150.2	$67.6	$217.8	$124.5	$417.8	$46.7	$24.3	$13.9
25	$0.0	$59.2	$86.4	$130.4	357.4	$793.3	$101.6	$50.9	$152.5	$93.8	$271.0	$27.5	$15.5	$9.5
26	$0.0	$59.2	$82.9	$101.6	278.4	$618.0	$73.1	$36.9	$110.0	$68.0	$196.4	$18.1	$10.1	$6.3
27	$0.0	$0.0	$80.2	$79.2	216.9	$481.4	$109.9	$21.0	$131.0	$38.8	$152.4	$12.8	$11.0	$3.3
28	$0.0	$59.2	$78.1	$61.7	168.9	$375.0	$58.7	$16.0	$74.7	$29.5	$71.9	$5.5	$5.7	$2.2
29	$0.0	$0.0	$76.4	$48.0	131.6	$292.2	$56.0	$9.8	$65.8	$18.1	$83.8	$5.8	$4.6	$1.3
30	$18.9	$59.2	$75.1	$37.4	102.5	$227.6	$10.0	$5.7	$15.7	$10.5	$10.7	$0.7	$1.0	$0.7
31	$0.0	$0.0	$74.1	$29.1	79.9	$177.3	$23.3	$2.9	$26.2	$5.3	$42.5	$2.4	$1.5	$0.3
32	$0.0	$0.0	$73.3	$22.7	62.2	$138.1	$12.2	$1.4	$13.6	$2.6	$26.0	$1.4	$0.7	$0.1

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.7	48.5	$107.6	$4.5	$0.0	$4.5	$0.0	$12.7	$0.6	$0.2	$0.0
34	$0.0	$0.0	$72.3	$13.8	37.8	$83.8	$3.5	-$0.3	$3.2	-$0.5	-$5.0	-$0.2	$0.1	$0.0
35	$0.0	$0.0	$71.9	$10.7	29.4	$65.3	$2.7	-$2.1	$0.6	-$3.8	-$14.2	-$0.6	$0.0	-$0.2
36	$0.0	$100.0	$71.6	$8.4	22.9	$50.9	$2.1	-$3.5	-$1.4	-$6.4	-$121.3	-$4.3	$0.0	-$0.2
Total	**$622.0**	**$3,723.0**	**$2,111.2**	**$2,653.7**		**$16,140.8**	**$1,122.7**	**$771.0**	**$1,893.7**	**$1,421.3**	**$3,716.0**	**-$119.4**	**$259.6**	**$220.2**
											Nom. IRR	**11.1%**		
											Real IRR	**9.0%**		

***Totals do not always equal column sums due to rounding.

Table 3G.5: Selected Statistics for Economic and Rent Analysis of Long Pipeline Dry Gas Scenario - $6 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$265.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$265.7	-$123.9	$0.0	$0.0
10	$0.0	$708.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$714.7	-$303.1	$0.0	$0.0
11	$0.0	$1,051.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,069.8	-$412.5	$0.0	$0.0
12	$0.0	$779.0	$80.7	$83.7	229.4	$611.1	$10.5	$0.0	$10.5	$0.0	-$342.9	-$120.2	$3.7	$0.0
13	$0.0	$99.4	$90.9	$167.4	458.7	$1,222.1	$21.1	$0.0	$21.1	$0.0	$843.3	$268.7	$6.7	$0.0
14	$0.0	$96.1	$90.9	$167.4	458.7	$1,222.1	$21.1	$13.5	$34.6	$24.8	$808.3	$234.1	$10.0	$7.2
15	$0.0	$0.0	$90.9	$167.4	458.7	$1,222.1	$21.1	$77.0	$98.1	$141.9	$723.8	$190.6	$25.8	$37.4
16	$0.0	$59.2	$90.9	$167.4	458.7	$1,222.1	$21.1	$84.7	$105.8	$156.1	$642.7	$153.9	$25.3	$37.4
17	$0.0	$59.2	$90.9	$167.4	458.7	$1,222.1	$52.7	$86.6	$139.3	$159.6	$605.7	$131.8	$30.3	$34.7
18	$0.0	$0.0	$90.9	$167.4	458.7	$1,222.1	$52.7	$92.9	$145.6	$171.3	$646.9	$128.0	$28.8	$33.9
19	$0.0	$59.2	$90.9	$167.4	458.7	$1,222.1	$179.0	$80.2	$259.2	$147.8	$497.6	$89.5	$46.6	$26.6
20	$0.0	$59.2	$90.9	$167.4	458.7	$1,222.1	$179.0	$82.0	$261.0	$151.2	$492.4	$80.5	$42.7	$24.7
21	$0.0	$0.0	$90.9	$167.4	458.7	$1,222.1	$190.9	$84.1	$275.0	$155.0	$533.8	$79.3	$40.9	$23.0
22	$0.0	$59.2	$90.9	$167.4	458.7	$1,222.1	$313.2	$69.7	$383.0	$128.6	$393.0	$53.1	$51.7	$17.4
23	$0.0	$59.2	$90.9	$167.4	458.7	$1,222.1	$313.2	$70.1	$383.3	$129.1	$392.2	$48.2	$47.1	$15.9
24	$0.0	$0.0	$90.9	$167.4	458.7	$1,222.1	$334.1	$69.9	$404.1	$128.9	$430.8	$48.1	$45.1	$14.4
25	$0.0	$59.2	$86.4	$130.4	357.4	$952.0	$233.4	$54.1	$287.5	$99.8	$288.7	$29.3	$29.2	$10.1
26	$0.0	$59.2	$82.9	$101.6	278.4	$741.6	$171.2	$39.9	$211.1	$73.6	$213.2	$19.7	$19.5	$6.8
27	$0.0	$0.0	$80.2	$79.2	216.9	$577.7	$143.6	$28.5	$172.2	$52.6	$193.6	$16.2	$14.4	$4.4
28	$0.0	$59.2	$78.1	$61.7	168.9	$450.0	$84.9	$21.8	$106.8	$40.2	$104.1	$7.9	$8.1	$3.1
29	$0.0	$0.0	$76.4	$48.0	131.6	$350.6	$76.5	$14.4	$90.8	$26.5	$108.8	$7.5	$6.3	$1.8
30	$18.9	$59.2	$75.1	$37.4	102.5	$273.1	$26.0	$9.3	$35.2	$17.1	$30.2	$1.9	$2.2	$1.1
31	$0.0	$0.0	$74.1	$29.1	79.9	$212.8	$35.7	$5.7	$41.4	$10.4	$57.7	$3.3	$2.4	$0.6

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
32	$0.0	$0.0	$73.3	$22.7	62.2	$165.7	$21.8	$3.5	$25.4	$6.5	$37.8	$2.0	$1.3	$0.3
33	$0.0	$0.0	$72.7	$17.7	48.5	$129.1	$11.0	$1.8	$12.8	$3.3	$22.6	$1.1	$0.6	$0.2
34	$0.0	$0.0	$72.3	$13.8	37.8	$100.6	$4.3	$0.2	$4.5	$0.3	$9.7	$0.4	$0.2	$0.0
35	$0.0	$0.0	$71.9	$10.7	29.4	$78.3	$3.4	-$0.5	$2.9	-$0.9	-$6.2	-$0.2	$0.1	$0.0
36	$0.0	$100.0	$71.6	$8.4	22.9	$61.0	$2.6	-$2.3	$0.4	-$4.2	-$115.1	-$4.1	$0.0	-$0.1
Total	**$622.0**	**$3,723.0**	**$2,111.2**	**$2,653.7**		**$19,368.9**	**$2,524.3**	**$987.1**	**$3,511.3**	**$1,819.5**	**$4,928.3**	**$147.0**	**$489.2**	**$300.8**
											Nom. IRR	**13.4%**		
											Real IRR	**11.2%**		

*****Totals do not always equal column sums due to rounding.

Table 3G.6: Selected Statistics for Economic and Rent Analysis of Long Pipeline Dry Gas Scenario - $7 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$265.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$265.7	-$123.9	$0.0	$0.0
10	$0.0	$708.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$714.7	-$303.1	$0.0	$0.0
11	$0.0	$1,051.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,069.8	-$412.5	$0.0	$0.0
12	$0.0	$779.0	$80.7	$83.7	229.4	$712.9	$12.6	$0.0	$12.6	$0.0	-$243.1	-$85.2	$4.4	$0.0
13	$0.0	$99.4	$90.9	$167.4	458.7	$1,425.8	$25.2	$0.0	$25.2	$0.0	$1,042.9	$332.3	$8.0	$0.0
14	$0.0	$96.1	$90.9	$167.4	458.7	$1,425.8	$25.2	$72.4	$97.6	$133.5	$840.3	$243.4	$28.3	$38.7
15	$0.0	$0.0	$90.9	$167.4	458.7	$1,425.8	$25.2	$100.9	$126.1	$186.0	$855.3	$225.2	$33.2	$49.0
16	$0.0	$59.2	$90.9	$167.4	458.7	$1,425.8	$62.9	$104.1	$167.0	$191.9	$749.3	$179.4	$40.0	$45.9
17	$0.0	$59.2	$90.9	$167.4	458.7	$1,425.8	$62.9	$109.8	$172.7	$202.4	$733.1	$159.6	$37.6	$44.0
18	$0.0	$0.0	$90.9	$167.4	458.7	$1,425.8	$231.7	$95.9	$327.5	$176.7	$663.2	$131.2	$64.8	$35.0
19	$0.0	$59.2	$90.9	$167.4	458.7	$1,425.8	$219.7	$99.7	$319.4	$183.8	$604.9	$108.8	$57.5	$33.1
20	$0.0	$59.2	$90.9	$167.4	458.7	$1,425.8	$384.5	$81.8	$466.3	$150.8	$491.2	$80.3	$76.2	$24.6
21	$0.0	$0.0	$90.9	$167.4	458.7	$1,425.8	$405.4	$82.8	$488.2	$152.6	$526.7	$78.3	$72.6	$22.7
22	$0.0	$59.2	$90.9	$167.4	458.7	$1,425.8	$384.5	$85.6	$470.1	$157.9	$480.3	$64.9	$63.5	$21.3
23	$0.0	$59.2	$90.9	$167.4	458.7	$1,425.8	$384.5	$85.9	$470.4	$158.4	$479.4	$58.9	$57.8	$19.5
24	$0.0	$0.0	$90.9	$167.4	458.7	$1,425.8	$405.4	$85.8	$491.2	$158.2	$518.0	$57.9	$54.9	$17.7
25	$0.0	$59.2	$86.4	$130.4	357.4	$1,110.7	$288.9	$66.5	$355.4	$122.6	$356.6	$36.2	$36.1	$12.4
26	$0.0	$59.2	$82.9	$101.6	278.4	$865.2	$214.4	$49.6	$264.0	$91.4	$266.1	$24.6	$24.4	$8.4
27	$0.0	$0.0	$80.2	$79.2	216.9	$674.0	$177.3	$36.1	$213.4	$66.5	$234.8	$19.7	$17.9	$5.6
28	$0.0	$59.2	$78.1	$61.7	168.9	$525.1	$111.2	$27.7	$138.9	$51.0	$136.2	$10.4	$10.6	$3.9
29	$0.0	$0.0	$76.4	$48.0	131.6	$409.0	$96.9	$18.9	$115.8	$34.9	$133.9	$9.3	$8.0	$2.4
30	$18.9	$59.2	$75.1	$37.4	102.5	$318.6	$41.9	$12.8	$54.7	$23.6	$49.7	$3.1	$3.4	$1.5
31	$0.0	$0.0	$74.1	$29.1	79.9	$248.2	$48.1	$8.4	$56.6	$15.5	$72.8	$4.2	$3.2	$0.9
32	$0.0	$0.0	$73.3	$22.7	62.2	$193.4	$31.5	$5.7	$37.2	$10.5	$49.6	$2.6	$1.9	$0.5

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.7	48.5	$150.6	$18.5	$3.5	$22.0	$6.4	$31.8	$1.5	$1.0	$0.3
34	$0.0	$0.0	$72.3	$13.8	37.8	$117.3	$8.4	$1.7	$10.1	$3.1	$18.0	$0.8	$0.4	$0.1
35	$0.0	$0.0	$71.9	$10.7	29.4	$91.4	$4.0	$0.0	$4.0	$0.0	$4.7	$0.2	$0.2	$0.0
36	$0.0	$100.0	$71.6	$8.4	22.9	$71.2	$3.1	-$1.1	$2.1	-$1.9	-$108.9	-$3.9	$0.1	-$0.1
Total	**$622.0**	**$3,723.0**	**$2,111.2**	**$2,653.7**		**$22,597.1**	**$3,674.1**	**$1,234.6**	**$4,908.7**	**$2,275.8**	**$6,302.7**	**$419.8**	**$706.0**	**$387.5**
											Nom. IRR	**15.5%**		
											Real IRR	**13.2%**		

*****Totals do not always equal column sums due to rounding.

Table 3G.7: Selected Statistics for Economic and Rent Analysis of Long Pipeline Dry Gas Scenario - $8 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$265.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$265.7	-$123.9	$0.0	$0.0
10	$0.0	$708.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$714.7	-$303.1	$0.0	$0.0
11	$0.0	$1,051.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,069.8	-$412.5	$0.0	$0.0
12	$0.0	$779.0	$80.7	$83.7	229.4	$814.7	$14.6	$0.0	$14.6	$0.0	-$143.3	-$50.2	$5.1	$0.0
13	$0.0	$99.4	$90.9	$167.4	458.7	$1,629.5	$29.2	$19.7	$49.0	$39.6	$1,183.1	$377.0	$15.6	$12.6
14	$0.0	$96.1	$90.9	$167.4	458.7	$1,629.5	$29.2	$112.0	$141.3	$206.5	$927.2	$268.6	$40.9	$59.8
15	$0.0	$0.0	$90.9	$167.4	458.7	$1,629.5	$73.1	$119.6	$192.7	$220.5	$957.9	$252.3	$50.7	$58.1
16	$0.0	$59.2	$90.9	$167.4	458.7	$1,629.5	$73.1	$127.3	$200.4	$234.7	$876.8	$209.9	$48.0	$56.2
17	$0.0	$59.2	$90.9	$167.4	458.7	$1,629.5	$260.4	$110.5	$371.0	$203.8	$737.2	$160.4	$80.7	$44.3
18	$0.0	$0.0	$90.9	$167.4	458.7	$1,629.5	$476.7	$90.9	$567.6	$167.6	$635.9	$125.8	$112.3	$33.2
19	$0.0	$59.2	$90.9	$167.4	458.7	$1,629.5	$455.8	$95.8	$551.6	$176.7	$583.6	$105.0	$99.2	$31.8
20	$0.0	$59.2	$90.9	$167.4	458.7	$1,629.5	$455.8	$97.7	$553.5	$180.0	$578.4	$94.6	$90.5	$29.4
21	$0.0	$0.0	$90.9	$167.4	458.7	$1,629.5	$476.7	$98.7	$575.4	$181.9	$613.9	$91.3	$85.5	$27.0
22	$0.0	$59.2	$90.9	$167.4	458.7	$1,629.5	$455.8	$101.5	$557.3	$187.1	$567.5	$76.7	$75.3	$25.3
23	$0.0	$59.2	$90.9	$167.4	458.7	$1,629.5	$455.8	$101.8	$557.6	$187.7	$566.6	$69.6	$68.5	$23.1
24	$0.0	$0.0	$90.9	$167.4	458.7	$1,629.5	$476.7	$101.7	$578.4	$187.5	$605.2	$67.6	$64.6	$20.9
25	$0.0	$59.2	$86.4	$130.4	357.4	$1,269.4	$344.4	$78.9	$423.3	$145.4	$424.6	$43.1	$43.0	$14.8
26	$0.0	$59.2	$82.9	$101.6	278.4	$988.8	$257.7	$59.2	$316.9	$109.2	$319.1	$29.4	$29.2	$10.1
27	$0.0	$0.0	$80.2	$79.2	216.9	$770.3	$211.0	$43.6	$254.6	$80.3	$276.1	$23.2	$21.4	$6.7
28	$0.0	$59.2	$78.1	$61.7	168.9	$600.1	$137.4	$33.5	$171.0	$61.8	$168.3	$12.8	$13.0	$4.7
29	$0.0	$0.0	$76.4	$48.0	131.6	$467.4	$117.4	$23.5	$140.9	$43.3	$158.9	$11.0	$9.8	$3.0
30	$18.9	$59.2	$75.1	$37.4	102.5	$364.1	$57.8	$16.4	$74.2	$30.2	$69.2	$4.4	$4.7	$1.9
31	$0.0	$0.0	$74.1	$29.1	79.9	$283.7	$60.6	$11.2	$71.7	$20.6	$88.0	$5.0	$4.1	$1.2
32	$0.0	$0.0	$73.3	$22.7	62.2	$221.0	$41.2	$7.9	$49.0	$14.5	$61.5	$3.2	$2.6	$0.8

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.7	48.5	$172.1	$26.1	$5.2	$31.2	$9.5	$41.0	$1.9	$1.5	$0.5
34	$0.0	$0.0	$72.3	$13.8	37.8	$134.1	$14.3	$3.0	$17.3	$5.5	$25.2	$1.1	$0.7	$0.2
35	$0.0	$0.0	$71.9	$10.7	29.4	$104.5	$5.1	$1.3	$6.4	$2.4	$13.1	$0.5	$0.3	$0.1
36	$0.0	$100.0	$71.6	$8.4	22.9	$81.4	$3.7	$0.0	$3.7	$0.0	-$102.2	-$3.6	$0.1	$0.0
Total	**$622.0**	**$3,723.0**	**$2,111.2**	**$2,653.7**		**$25,825.3**	**$5,009.7**	**$1,460.9**	**$6,470.6**	**$2,696.2**	**$7,548.6**	**$656.8**	**$967.4**	**$465.6**
											Nom. IRR	**17.1%**		
											Real IRR	**14.8%**		

*****Totals do not always equal column sums due to rounding.

Table 3G.8: Selected Statistics for Economic and Rent Analysis of Long Pipeline Dry Gas Scenario - $9 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$265.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$265.7	-$123.9	$0.0	$0.0
10	$0.0	$708.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$714.7	-$303.1	$0.0	$0.0
11	$0.0	$1,051.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,069.8	-$412.5	$0.0	$0.0
12	$0.0	$779.0	$80.7	$83.7	229.4	$916.6	$16.7	$0.0	$16.7	$0.0	-$43.5	-$15.2	$5.8	$0.0
13	$0.0	$99.4	$90.9	$167.4	458.7	$1,833.2	$33.3	$55.4	$88.7	$111.4	$1,275.3	$406.4	$28.3	$35.5
14	$0.0	$96.1	$90.9	$167.4	458.7	$1,833.2	$33.3	$136.0	$169.3	$250.7	$1,058.7	$306.7	$49.0	$72.6
15	$0.0	$0.0	$90.9	$167.4	458.7	$1,833.2	$83.3	$142.8	$226.1	$263.3	$1,085.4	$285.8	$59.5	$69.3
16	$0.0	$59.2	$90.9	$167.4	458.7	$1,833.2	$301.2	$124.4	$425.6	$229.3	$860.7	$206.0	$101.9	$54.9
17	$0.0	$59.2	$90.9	$167.4	458.7	$1,833.2	$527.1	$103.0	$630.1	$189.8	$695.7	$151.4	$137.1	$41.3
18	$0.0	$0.0	$90.9	$167.4	458.7	$1,833.2	$548.0	$106.8	$654.8	$196.9	$723.1	$143.1	$129.5	$38.9
19	$0.0	$59.2	$90.9	$167.4	458.7	$1,833.2	$527.1	$111.7	$638.8	$206.0	$670.8	$120.7	$114.9	$37.0
20	$0.0	$59.2	$90.9	$167.4	458.7	$1,833.2	$527.1	$113.6	$640.6	$209.3	$665.7	$108.8	$104.7	$34.2
21	$0.0	$0.0	$90.9	$167.4	458.7	$1,833.2	$548.0	$114.5	$662.5	$211.1	$701.1	$104.2	$98.5	$31.4
22	$0.0	$59.2	$90.9	$167.4	458.7	$1,833.2	$527.1	$117.4	$644.5	$216.4	$654.7	$88.5	$87.1	$29.2
23	$0.0	$59.2	$90.9	$167.4	458.7	$1,833.2	$527.1	$117.7	$644.8	$217.0	$653.8	$80.3	$79.2	$26.7
24	$0.0	$0.0	$90.9	$167.4	458.7	$1,833.2	$548.0	$117.6	$665.6	$216.8	$692.5	$77.3	$74.3	$24.2
25	$0.0	$59.2	$86.4	$130.4	357.4	$1,428.0	$400.0	$91.3	$491.2	$168.2	$492.5	$50.0	$49.9	$17.1
26	$0.0	$59.2	$82.9	$101.6	278.4	$1,112.4	$300.9	$68.9	$369.8	$126.9	$372.0	$34.3	$34.1	$11.7
27	$0.0	$0.0	$80.2	$79.2	216.9	$866.6	$244.7	$51.1	$295.8	$94.1	$317.3	$26.6	$24.8	$7.9
28	$0.0	$59.2	$78.1	$61.7	168.9	$675.1	$163.7	$39.4	$203.1	$72.6	$200.4	$15.3	$15.5	$5.5
29	$0.0	$0.0	$76.4	$48.0	131.6	$525.9	$137.8	$28.0	$165.9	$51.7	$183.9	$12.8	$11.5	$3.6
30	$18.9	$59.2	$75.1	$37.4	102.5	$409.7	$73.8	$19.9	$93.7	$36.7	$88.6	$5.6	$5.9	$2.3
31	$0.0	$0.0	$74.1	$29.1	79.9	$319.1	$73.0	$14.0	$86.9	$25.7	$103.2	$5.9	$5.0	$1.5
32	$0.0	$0.0	$73.3	$22.7	62.2	$248.6	$50.8	$10.0	$60.9	$18.5	$73.3	$3.8	$3.2	$1.0

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.7	48.5	$193.7	$33.6	$6.8	$40.4	$12.6	$50.2	$2.4	$1.9	$0.6
34	$0.0	$0.0	$72.3	$13.8	37.8	$150.9	$20.1	$4.3	$24.5	$7.9	$32.4	$1.4	$1.1	$0.3
35	$0.0	$0.0	$71.9	$10.7	29.4	$117.5	$9.7	$2.3	$12.0	$4.2	$18.7	$0.7	$0.5	$0.2
36	$0.0	$100.0	$71.6	$8.4	22.9	$91.5	$4.2	$0.0	$4.2	$0.0	-$92.6	-$3.3	$0.1	$0.0
Total	**$622.0**	**$3,723.0**	**$2,111.2**	**$2,653.7**		**$29,053.4**	**$6,259.5**	**$1,696.9**	**$7,956.4**	**$3,137.2**	**$8,849.9**	**$895.8**	**$1,223.5**	**$547.0**
											Nom. IRR	**18.6%**		
											Real IRR	**16.2%**		

*****Totals do not always equal column sums due to rounding.

Table 3G.9: Selected Statistics for Economic and Rent Analysis of Long Pipeline Dry Gas Scenario - $10 US/mmbtu

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
1	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$40.0	$0.0	$0.0
2	$40.0	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$40.0	-$36.4	$0.0	$0.0
3	$166.5	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$166.5	-$137.6	$0.0	$0.0
4	$142.6	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$142.6	-$107.2	$0.0	$0.0
5	$213.9	$0.0	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$213.9	-$146.1	$0.0	$0.0
6	$0.0	$5.2	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$5.2	-$3.2	$0.0	$0.0
7	$0.0	$10.4	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$10.4	-$5.9	$0.0	$0.0
8	$0.0	$15.3	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$15.3	-$7.8	$0.0	$0.0
9	$0.0	$265.7	$0.0	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$265.7	-$123.9	$0.0	$0.0
10	$0.0	$708.8	$5.9	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$714.7	-$303.1	$0.0	$0.0
11	$0.0	$1,051.0	$18.8	$0.0	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$1,069.8	-$412.5	$0.0	$0.0
12	$0.0	$779.0	$80.7	$83.7	229.4	$1,018.4	$18.7	$0.0	$18.7	$0.0	$56.3	$19.7	$6.6	$0.0
13	$0.0	$99.4	$90.9	$167.4	458.7	$2,036.8	$37.4	$91.1	$128.5	$183.1	$1,367.5	$435.7	$40.9	$58.3
14	$0.0	$96.1	$90.9	$167.4	458.7	$2,036.8	$37.4	$160.0	$197.3	$294.8	$1,190.3	$344.8	$57.2	$85.4
15	$0.0	$0.0	$90.9	$167.4	458.7	$2,036.8	$353.9	$134.8	$488.7	$248.5	$1,041.3	$274.2	$128.7	$65.4
16	$0.0	$59.2	$90.9	$167.4	458.7	$2,036.8	$341.9	$144.0	$485.9	$265.4	$968.1	$231.7	$116.3	$63.5
17	$0.0	$59.2	$90.9	$167.4	458.7	$2,036.8	$598.4	$118.9	$717.2	$219.1	$782.9	$170.4	$156.1	$47.7
18	$0.0	$0.0	$90.9	$167.4	458.7	$2,036.8	$619.3	$122.7	$742.0	$226.2	$810.4	$160.3	$146.8	$44.7
19	$0.0	$59.2	$90.9	$167.4	458.7	$2,036.8	$598.4	$127.6	$726.0	$235.3	$758.1	$136.3	$130.6	$42.3
20	$0.0	$59.2	$90.9	$167.4	458.7	$2,036.8	$598.4	$129.4	$727.8	$238.6	$752.9	$123.1	$119.0	$39.0
21	$0.0	$0.0	$90.9	$167.4	458.7	$2,036.8	$619.3	$130.4	$749.7	$240.4	$788.3	$117.2	$111.4	$35.7
22	$0.0	$59.2	$90.9	$167.4	458.7	$2,036.8	$598.4	$133.3	$731.7	$245.7	$741.9	$100.3	$98.9	$33.2
23	$0.0	$59.2	$90.9	$167.4	458.7	$2,036.8	$598.4	$133.6	$732.0	$246.3	$741.1	$91.0	$89.9	$30.3
24	$0.0	$0.0	$90.9	$167.4	458.7	$2,036.8	$619.3	$133.5	$752.8	$246.0	$779.7	$87.1	$84.1	$27.5
25	$0.0	$59.2	$86.4	$130.4	357.4	$1,586.7	$455.5	$103.6	$559.1	$191.0	$560.5	$56.9	$56.8	$19.4
26	$0.0	$59.2	$82.9	$101.6	278.4	$1,236.0	$344.2	$78.5	$422.7	$144.7	$424.9	$39.2	$39.0	$13.4
27	$0.0	$0.0	$80.2	$79.2	216.9	$962.9	$278.4	$58.6	$337.0	$108.0	$358.5	$30.1	$28.3	$9.1
28	$0.0	$59.2	$78.1	$61.7	168.9	$750.1	$189.9	$45.2	$235.2	$83.4	$232.5	$17.7	$17.9	$6.4
29	$0.0	$0.0	$76.4	$48.0	131.6	$584.3	$158.3	$32.6	$190.9	$60.1	$208.9	$14.5	$13.2	$4.2
30	$18.9	$59.2	$75.1	$37.4	102.5	$455.2	$89.7	$23.5	$113.2	$43.3	$108.1	$6.8	$7.1	$2.7
31	$0.0	$0.0	$74.1	$29.1	79.9	$354.6	$85.4	$16.7	$102.1	$30.8	$118.4	$6.8	$5.9	$1.8
32	$0.0	$0.0	$73.3	$22.7	62.2	$276.2	$60.5	$12.2	$72.7	$22.4	$85.1	$4.4	$3.8	$1.2

Year	Pre-Dev Expend ($ M Cdn.)	Dev Expend ($ M Cdn.)	Prod Expend ($ M Cdn.)	Trans Expend ($ M Cdn.)	Daily Prod (mmcf)	Revenue ($ M Cdn.)	Total Royalties ($ M Cdn.)	Prov CIT ($ M Cdn.)	Prov Revenue ($ M Cdn.)	Fed CIT ($ M Cdn.)	After -Tax NCF ($ M Cdn.)	PV After-Tax NCF ($ M Cdn.)	PV Prov Revenue ($ M Cdn.)	PV Fed Revenue ($ M Cdn.)
33	$0.0	$0.0	$72.7	$17.7	48.5	$215.2	$41.1	$8.5	$49.7	$15.7	$59.4	$2.8	$2.4	$0.7
34	$0.0	$0.0	$72.3	$13.8	37.8	$167.6	$26.0	$5.6	$31.6	$10.4	$39.6	$1.7	$1.4	$0.4
35	$0.0	$0.0	$71.9	$10.7	29.4	$130.6	$14.3	$3.3	$17.6	$6.1	$24.2	$0.9	$0.7	$0.2
36	$0.0	$100.0	$71.6	$8.4	22.9	$101.7	$4.7	$0.1	$4.7	$0.1	-$83.1	-$3.0	$0.2	$0.0
Total	**$622.0**	**$3,723.0**	**$2,111.2**	**$2,653.7**		**$32,281.6**	**$7,387.0**	**$1,947.7**	**$9,334.6**	**$3,605.4**	**$10,231.7**	**$1,147.2**	**$1,463.0**	**$632.6**
											Nom. IRR	**19.9%**		
											Real IRR	**17.6%**		

*****Totals do not always equal column sums due to rounding.

Appendix 3H: Least Squares Estimates of Parameters of Revenue Equations

Case		Nominal Revenue Equation	Discounted Revenue Equation
SPOS:	Provincial Government	y = 221.87x - 4382.8 (R^2 = 0.997)	y = 44.173x - 937.21 (R^2 = 0.994)
	Federal Government	y = 87.651x - 1018.9 (R^2 = 0.999)	y = 18.898x - 263.32 (R^2 = 0.999)
	Companies	y = 261.74x - 3655.6 (R^2 = 0.999)	y = 57.538x - 1717.9 (R^2 = 0.999)
LPOS:	Provincial Government	y = 220.6x - 4483.3 (R^2 = 0.996)	y = 43.634x - 947.76 (R^2 = 0.993)
	Federal Government	y = 87.939x - 1062.4 (R^2 = 0.998)	y = 18.981x - 276.88 (R^2 = 0.999)
	Companies	y = 262.72x - 3826.8 (R^2 = 0.998)	y = 57.993x - 1827.9 (R^2 = 0.997)
SPWGS:	Provincial Government	y = 1317.2x - 3000.0 (R^2 = 0.994)	y = 209.38x - 511.86 (R^2 = 0.987)
	Federal Government	y = 444.8x - 549.02 (R^2 = 0.998)	y = 81.567x - 130.84 (R^2 = 0.999)
	Companies	y = 1340.4x - 2226.4 (R^2 = 0.996)	y = 263.07x - 1235.4 (R^2 = 0.993)
LPWGS:	Provincial Government	y = 1291.2x - 3107.1 (R^2 = 0.989)	y = 200.57x - 512.51 (R^2 = 0.982)
	Federal Government	y = 449.57x - 592.62 (R^2 = 0.996)	y = 82.117x - 140.7 (R^2 = 0.999)
	Companies	y = 1361.6x - 2435.8 (R^2 = 0.994)	y = 271.28x - 1377.5 (R^2 = 0.991)
SPDGS:	Provincial Government	y = 1272.9x - 3501.2 (R^2 = 0.980)	y = 200.88x - 573.97 (R^2 = 0.968)
	Federal Government	y = 462.18x - 974.88 (R^2 = 0.999)	y = 82.517x - 187.32 (R^2 = 0.998)
	Companies	y = 1493.1x - 4273.5 (R^2 = 0.987)	y = 293.08x - 1607.2 (R^2 = 0.983)
LPDGS:	Provincial Government	y = 1242x - 3538.3 (R^2 = 0.972)	y = 191.52x - 562.43 (R^2 = 0.959)
	Federal Government	y = 463.25x - 997.72 (R^2 = 0.997)	y = 82.317x - 192.9 (R^2 = 0.997)
	Companies	y = 1522.9x - 4573.5 (R^2 = 0.983)	y = 302.55x - 1765.7 (R^2 = 0.981)

*y = net revenue (economic rent); x = oil or gas price; R^2 = coefficient of determination (measure of goodness of fit of linear trend line).

Appendices Section 4

Appendix 4A: Disaggregated Expenditures

Table 4A.1: Exploration Expenditures ($million 2006)

Seismic Surveys (yrs 1-2)	**80.0**
Labour (20%)	16.0
Goods & services (80%)	64.0
Mobilization/Demobilization (yrs 3&19)	**42.8**
Labour (20%)	8.6
Goods & services (80%)	34.2
Exploration&Deline't Well Drilling (7 wells) (yrs 3-5)*	**499.2**
Total Exploration Cost	**622.0**

*Well drilling disaggregated in Table 4A.5.

Table 4A.2: Oil Development Expenditures ($million 2006)

	Oil
Development Well Drilling (36 wells) (yrs 10-19)*	**2131.5**
Short Pipeline Capital Cost (yrs 9-11)**	**315.0**
Labour (15%)	47.3
Materials (38%)	119.7
Installation & commissioning (47%)	148.1
Transshippment Facility Capital Cost (yrs 9-11)	**300.0**
Labour (30%)	90.0
Equipment & machinery (32%)	96.0
Related facilities (19%)	57.0
Indirect field costs/camp (19%)	57.0
Production Facility & Other Capital Cost (yrs 6-25)	**2192.8**
Production Facility Sub-Structure Capital Cost	631.5
Production Facility Topsides Capital Cost	947.3
Equipment (50%)	473.6
Fabrication (22%)	208.4
Installation (5%)	47.4
Hookup & Commissioning (3%)	28.4
Design Engineering (16%)	151.6
Construction Management (4%)	37.9
Project Management	175.4
Salaries and Benefits (43.6%)	76.5
Computing/Communication (5.8%)	10.2
Office Expenses (6.3%)	11.1
Staff Expenses (4.9%)	8.6
Insurance (11.9%)	20.9
Environmental Impact Studies (21.2%)	37.2
Overhead (6.3%)	11.1
Subsea Facilities Capital Cost	438.6
Engineering (33.3%)	146.2
Equipment (66.7%)	292.4
Total	**4939.3**

* Well drilling disaggregated in Table 4A.5.

** Long pipeline cost = short pipeline cost × 2.

Table 4A.3: Gas Development Expenditures ($million 2006)

	Dry Gas	Wet Gas
Development Well Drilling (20 wells) (yrs 10-19)*	**1184.2**	**1184.2**
Short Pipeline Capital Cost (yrs 9-11)**	**360.0**	**360.0**
Labour (15%)	54.0	54.0
Materials (38%)	136.8	136.8
Installation & Commissioning (47%)	**169.2**	**169.2**
Onshore Gas Plant Capital Cost (yrs 11-12)		225.0
Labour (30%)		67.5
Equipment & machinery (32%)		72.0
Related facilities (19%)		42.8
Indirect field costs/camp (19%)		42.8
Onshore NGL Plant Capital Cost (yrs 11-12)		**100.0**
Labour (30%)		30.0
Equipment & machinery (34%)		34.0
Related facilities (18%)		18.0
Indirect field costs/camp (18%)		18.0
Production Facility & Other Capital Cost (yrs 6-36)	**1818.8**	**1593.8**
Gas Separation Unit	**225.0**	
Labour (30%)	67.5	
Equipment & machinery (32%)	72.0	
Related facilities (19%)	42.8	
Indirect field costs/camp (19%)	42.8	
Sub-Structure Capital Cost	459.0	459.0
Production Facility Topsides Capital Cost	688.5	688.5
Equipment (50%)	344.3	344.3
Fabrication (22%)	151.5	151.5
Installation (5%)	34.4	34.4
Hookup & Commissioning (3%)	20.7	20.7
Design Engineering (16%)	110.2	110.2
Construction Management (4%)	27.5	27.5
Project Management	127.5	127.5
Salaries and Benefits (43.6)	55.6	55.6
Computing/Communication (5.8%)	7.4	7.4
Office Expenses (6.3%)	8.0	8.0
Staff Expenses (4.9%)	6.2	6.2
Insurance (11.9%)	15.2	15.2
Environmental Impact Studies (21.2%)	27.0	27.0
Overhead (6.3%)	8.0	8.0
Subsea Facilities Capital Cost	318.8	318.8
Engineering (33.3%)	106.1	106.1
Equipment (66.7%)	212.6	212.6
Total	**3362.0**	**3463.0**

* Well drilling disaggregated in Table 4A.5

** Long pipeline cost = short pipeline cost × 2.

Table 4A.4: Production Expenditures ($million 2006)

	Oil	**Gas**
Management Personnel (5%)	145.9	105.6
Management Office (5%)	145.9	105.6
Maintenance & Inspection (10%)	291.8	211.1
Well Interventions (15%)	437.7	316.7
Production Facility Personnel (5%)	145.9	105.6
Production Facility Chemicals (10%)	291.8	211.1
Production Facility Onshore Support (10%)	291.8	211.1
Other Offshore Operations (5%)	145.9	105.6
Logistics Vessels (25%)	729.5	527.8
Logistics Helicopters (10%)	291.8	211.1
Total	**2917.9**	**2111.3**

Table 4A.5: Drilling Costs per Well (%)

Assumed Cost Per Well	% of Total Cost	Labour	Materials	Services	Equipment Rental	Sub-Contracts	EPIC*
		Distribution of Line Expenditures (%)					
Drilling rig	49.7	10		5	85		
Camp and catering costs	0.3	20		5		75	
Total Rig Costs	**50.0**						
Helicopters	4.5	5		10	85		
Supply vessels	9.8	18			82		
Fuel and lubricants	3.0	2	96	2			
Travel	0.3			100			
Communications equipment/service	0.5	15	10	10	65		
Weather forecasting/ice surveillance	0.5	84		0	16		
ROV and diving services	0.7	56		10	34		
Supply base	0.5	65		35			
Trucking	0.2	75		25			
Warehouse/yard	0.1	75		25			
Containers/cargo handling	0.7	37	23		35		5
Total Logistics/Site Related Costs	**20.8**						
Contract supervision/wellsite geologist	0.2	100					
Company labour	0.5	100					
Total Personnel Costs	**0.7**						
Fishing tools and services	0.1	20		15	65		
Rentals - surface/subsurface	0.7				100		
Oil spill contingency	0.1			20	80		
Centrifuges and personnel (drilling fluids)	0.4	5	10		85		
Tubing rental, inspection and repair	0.1	15		10	75		
MWD directional	3.9	20	3	20	41	12	4
Total Services Costs	**5.3**						
Wellhead	0.2	3		2	95		
Casing	1.9	6	92	2			
Casing - 3rd party mill inspection	0.1	95		5			
Casing accessories	0.3		100				
Casing running services	0.3	36		34	30		
Total Tangibles/Intangibles Costs	**2.8**						
Mud and chemical products & services (water based)	2.2	17	60	10	13		
Drill bits	1.1	5	90	5			
Cementing products & services	0.7	15	58	10	17		
Total Downhole/Well Consumables Costs	**4.0**						
Coring	0.7	8	34	11	21	23	3
Core analysis	0.5	30	10	60			
Sample analysis and distribution	0.1	70	10	20			
Total Testing and Analysis Costs	**1.3**						
Logging while drilling (LWD) - wireline	1.5	20	3	20	41	12	4
Mud Logging	0.7	74		2	24		
Electric logging	1.9	4		12	72	5	7
Total Logging Costs	**4.1**						
Tubing	1.0	6	90	2			
Completion Equipment	2.0	4	96				
Completion Fluid	0.3	17	60	10	13		
Completion Services	6.4	1	92	5	2		
Completion Personnel	0.4	95		5			
Total Testing & Completions Costs	**10.1**						
Total Other Costs	**0.9**			100			
Total Cost	**100.0**						

*EPIC = engineering, procurement, installation, commissioning services.

Appendix 4B: BC Expenditure Leakages

Table 4B.1: BC Expenditure Leakages - Oil

	Before leakages ($M 2006)	After leakages ($M 2006)	Leakage rate
Exploration			
Total	622	206	0.668
Labour (includes operating surplus)	107	62	0.424
Materials & services	514	145	0.719
Accident contingency	0		
Total including contingency	**622**		
Development, short			
Total	4,937	1,756	0.644
Labour	490	336	0.315
Materials & services	4,447	1,420	0.681
Accident contingency	2		
Total including contingency	**4,939**		
Development, long			
Total	5,252	1,863	0.645
Labour	537	355	0.340
Materials & services	4,715	1,508	0.680
Accident contingency	2		
Total including contingency	**5,254**		
Production			
Total	2,918	2,244	0.231
Labour	292	204	0.300
Materials & services	2,626	2,040	0.223

Table 4B.2: BC Expenditure Leakages - Gas

	Before leakages ($M 2006)	After leakages ($M 2006)	Leakage rate
Exploration			
Total	622	206	0.668
Labour (includes operating surplus)	107	62	0.424
Materials & services	514	145	0.719
Accident contingency	0		
Total including contingency	**622**		
Development, wet gas short			
Total	3,462	1,271	0.633
Labour	361	252	0.300
Materials & services	3,101	1,018	0.672
Accident contingency	1		
Total including contingency	**3,463**		
Development, wet gas long			
Total	3,822	1,392	0.636
Labour	415	274	0.339
Materials & services	3,407	1,118	0.672
Accident contingency	1		
Total including contingency	**3,823**		
Development, dry gas short			
Total	3,361	1,215	0.639
Labour	331	225	0.319
Materials & services	3,030	989	0.674
Accident contingency	1		
Total including contingency	**3,362**		
Development, dry gas long			
Total	3,722	1,336	0.641
Labour	385	247	0.358
Materials & services	3,337	1,089	0.674
Accident contingency	1		
Total including contingency	**3,723**		
Production			
Total	2,111	1,624	0.231
Labour	211	148	0.300
Materials & services	1,900	1,476	0.223