THE MACKENZIE GAS PROJECT:

A FINANCIAL AND ECONOMIC ASSESSMENT

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Prepared for:

ALTERNATIVES NORTH

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GLOSSARY OF TERMS

1. **Canadian Development Expenditures (CDE):** development expenditures eligible for a 30% write-off in the year of occurrence.
2. **Canadian Exploration Expense (CEE):**[1] is the amount, if any, by which a corporation's specified development expenses for the year exceed its total development assistance for the year. Development expenses relate to the drilling or completing of a well resulting in the discovery that a natural underground reservoir containing petroleum or natural gas, and where the discovery occurred at any time before six months after the end of the year. These expenses are eligible for 100% write-off in the year of occurrence.
3. **Capital Cost Allowances (CCA):** a tax deduction that Canadian tax laws allow a business to claim for the loss in value of capital assets due to wear and tear or obsolescence.
4. **Direct Impacts**: equivalent to the level of direct value-added (or GDP) generated by an industry.
5. **Net Domestic Product (GDP or Value-Added)**: a measure of the total flow of goods and services produced by the economy and used for final domestic consumption, investment and export (e.g., excluding immediate consumption). GDP can be calculated in three different ways, all of which yield the same results. The first method, used in this Report, estimates the difference between the value of net output of all industries minus the value of net material inputs used for immediate production (excluding indirect taxes). The second method sums the values of Wages and Salaries, Supplementary Labour Income (Benefits), Operating Surplus (Profits plus Depreciation plus Interest on Long Term Debt) and Indirect Taxes for all industries. And the third method sums the values for personal consumption, government expenditures, investment (including changes to inventories) and net exports. In addition to total GDP for the economy, GDP is also estimated for individual industrial sectors.

[1] For a full explanation, see http://lois.justice.gc.ca/en/I-3.3/C.R.C.-c.945/136444.html

6. **Indirect Impacts**: the impacts resulting from the expenses (goods and services) of a firm or industry used in the production process. The purchase of goods or services increases the economic activity of the supplying firms and, in turn, the supplying firms themselves must purchase their own goods and services which generates further economic activity in those supplying firms.

7. **Induced Impacts**: the impacts resulting from the wages and salaries paid by a firm or industry. When the wages and salaries are spent (less taxes and savings), the economic activity of the firms supplying those goods and services increases. As well, the supplying firms themselves will pay additional wages and salaries to their own employees which, when spent, generates more economic activity.

8. **Input-Output Model**: comprised of three tables or matrices: a **Make** matrix, a **Use** matrix, and a **Final Demand** matrix. The Make matrix lists all the different outputs produced by each industry. The Use matrix lists all the different purchases (material inputs) by each industry used in the production process as well as itemizing all taxes (explicit and implicit) paid by the industry (GST is not a company-level tax; rather it is a tax paid by final consumers but channelled through the company). The Final Demand matrix lists all the various purchases by persons (including GST), by government, by industries for investment purposes, plus all net exports (exports minus imports) of each commodity (good or service). Mathematically re-arranging the tables enables one to determine how much additional production will be generated in the economy from an increase in demand for a commodity or series of commodities.

9. **Intermediate Demand (material inputs):** sales to each industrial sector used for further production.

10. **Internal Rate of Return (IRR):** discount rate at which the present value of the future cash flows of an investment equals the cost of the investment. When the IRR is greater than the required return – called hurdle rate in capital budgeting – the investment is acceptable. The internal rate of return is the average rate earned by each and every dollar invested during the period. This rate is influenced by the timing and size of the cash inflows and outflows and the beginning and ending depreciated book or market value of the investment.

11. **Payout Date:** the date at which project revenues exceed project costs (capital investment and operating costs).

12. **Person-Year (PY) Employment**: the total level of employment in a firm or industry when part-time positions are counted as a fraction of full-time positions. For example, four half time positions equal 2 Peron-Years of work.

13. **Producer Prices**: the value of a commodity (good or service) at the factory gate. It excludes all indirect taxes, as well as wholesale, retail, and transportation costs (called "margins") associated with the final selling (purchaser) price.

14. **Purchaser Prices**: the price of a commodity (good or service) actually invoiced to the purchaser. It includes the factory gate cost of the commodity plus any additional costs associated with indirect taxes, wholesale and retail margins, and costs associated with transporting the commodity from the factory gate to the final purchaser.

15. **Royalty**: a percentage interest in the value of production from a lease that is retained and paid to the mineral rights owner, in this case the Federal Government.

16. **Sunk Costs:** Costs incurred in the past and unaffected by any future action and thus irrelevant to decision making. In economics and in business decision-making, sunk costs are costs that have

already been incurred and which cannot be recovered to any significant degree. Sunk costs are sometimes contrasted with incremental costs, which are the costs that will change due to the proposed course of action. In microeconomic theory, only incremental costs are relevant to a decision. If one were to let sunk costs influence the decision, one would not be assessing a proposal exclusively on its own merits. Note that sunk costs are still relevant for determining income taxes as they remain available for write-offs.

17. **Value-Added**: a term identical to GDP in concept, but referring to a particular business or occasionally an industry sub-sector.

EXECUTIVE SUMMARY

The Mackenzie Gas Project (MGP) will deliver dry natural gas from the Mackenzie Valley region (the Inuvik Gas Facility) down to Zama, located just south of the NWT/Alberta border from where the gas will hook into the NOVA Gas Pipeline for delivery into the Alberta system. Associated condensates will be stripped at the Inuvik Gas Facility and moved to Norman Wells from where it will flow through the existing Enbridge Pipeline to Zama and thence into the Alberta system over the existing Rainbow Pipeline.

The Mackenzie Valley Pipeline (MV Pipeline) itself will function as a regulated utility earning a fixed rate of return on invested capital. The Gathering System consists of a number of pipeline laterals connecting the various fields to the Gas Plant, the Inuvik Gas Facility (comprising a Gas Plant/Compression Station and a Liquids Stabilisation Plant to separate out the condensates), and a Liquids Line for delivering condensates to Norman Wells. Although not strictly regulated, according to the proponents[2] the Gathering System components will be operated as though they are regulated utilities, each earning a cost of service sufficient to earn a prescribed rate of return with unit tolls set at the cost of service divided by gas or condensate throughput. In contrast, the various natural gas fields will function as separate standard businesses, with their rates of return dependent on their specific production profile, their unique capital investment and operating costs, on Edmonton-based prices for natural gas and condensates, and on the unit tolls charged by the Gathering System and MV Pipeline.

Alternatives North, the group who commissioned this Report, is interested in understanding the financial implications of constructing the MGP, specifically the financial characteristics of the proposed natural gas fields: what are the returns (total and by field) that can be expected under conventional assumptions; what is the time profile of these returns; and of these returns, how much will accrue to the proponents and how much to various orders of government. In addition, they are interested in the level of government revenues the MV Pipeline and the Gathering System will generate, particularly the expected amount accruing to the Government of the NWT.

In order to answer these questions, Pacific Analytics was requested to build a stand-alone financial Model of the MGP, accounting for the construction and the operating of the MV Pipeline itself, of the assorted Gathering System components that process and deliver gas to the MV Pipeline from the various natural gas fields, and of the fields themselves. Expected annual production is based on various production scenarios provided by GLJ Associates,[3] while prices, capital investment and operating costs as well as assumptions regarding debt ratios, debt costs, and other data. are taken from the proponents' Environmental Impact Statement (EIS) submissions to the National Energy Board (NEB) and to the Joint Review Panel (JRP). Imperial Oil staff also provided direct assistance in identifying assumptions and calculation methods. Assumptions and calculations underlying pipeline costs of service, royalty payments and income taxes payable follow statutory standards and rates. The Model also includes a comprehensive accounting of individual Gathering System components and MV Pipeline costs of service and internal rates of return and, as well, forecasts revenues, costs (capital and operating), internal rates of return and taxes (royalties and corporate income taxes) for each field into the future to the year 2055.

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[2] The proponents of the Mackenzie Gas Project include Imperial Oil, ConocoPhillips, Shell, ExxonMobil and the Aboriginal Pipeline Group (APG). The three Anchor Fields (Niglintgak, Taglu, and Parsons Lake) are owned by Shell, Imperial Oil, and ConocoPhillips respectively.

[3] Gilbert, Laustsen and Jung Associates Ltd. "*Mackenzie Gas Project: Gas Resource and Supply Study*", prepared for Imperial Oil Resources Ventures Limited, May 2004.

In order to be able to test the implications of different assumptions (e.g., different production scenarios, different natural gas/condensate prices, different capital investment costs, etc.), the Model was designed such that all important variables (including all royalty/tax statutory rates including write-off and Canadian Development Expense – CDE - rates) can be changed by the user.

A forensic peer review of the Model was undertaken in order to ensure that all of the Model results are calculated correctly. The complete Model was provided to the reviewer, enabling him to examine directly all formulae.[4] A change to the Model was made as a result of comments from the GNWT in October 2006. This change consisted of correcting a division error when calculating unit tolls from the MV Pipeline Cost of Service estimate. At the same time another minor adjustment was made (calculation of tolls using the after-tax ROE and adding taxes back in to get the total the Cost of Service estimate rather than using before tax ROE). A revised version of the report, reflecting these changes to the Model and resulting figures, was submitted in November 2006.

RESULTS

Exec Table 1 displays a summary of financial results for various cases examined with the Model.

Exec Table 1: Summary of Financial Results ($ Millions)

	Base Case Anchor Only	Base Case GLJ	Sensitivity Case #1 Prices	Sensitivity Case #2 Capital Costs
GS + MV Pipeline				
After-Tax CF	$7,964	$9,251	$9,251	$11,689
After-Tax IRR	**8.3%**	**8.4%**	**8.4%**	**8.4%**
After-Tax IRR*	**9.6%**	**9.7%**	**9.7%**	**9.4%**
Income Taxes	$3,648	$3,784	$3,784	$4,787
- to Canada	*$2,307*	*$2,393*	*$2,393*	*$3,027*
- to NWT	*$1,341*	*$1,391*	*$1,391*	*$1,760*
Fields				
Before Income-Tax CF	$21,739	$96,380	$110,169	$87,730
Before Income-Tax IRR	**30.6%**	**29.7%**	**32.4%**	**23.3%**
Before Income-Tax IRR*	**38.9%**	**34.4%**	**38.2%**	**25.5%**
After-Tax CF	$14,597	$64,609	$73,848	$58,807
After-Tax IRR	**25.7%**	**24.2%**	**26.6%**	**18.8%**
After-Tax IRR*	**32.0%**	**27.5%**	**30.6%**	**20.4%**
Federal Royalties	$7,528	$41,911	$47,796	$38,386
Field Inc. Taxes	$7,142	$31,771	$36,321	$28,923
- to Canada	*$4,545*	*$20,218*	*$23,113*	*$18,406*
- to Alb & NWT	*$2,597*	*$11,553*	*$13,208*	*$10,517*
Avg. Annual Tax	**$328**	**$930**	**$1,059**	**$855**
- to Canada ($2003)	*$256*	*$769*	*$878*	*$702*
- to Alb & NWT ($2003)	*$72*	*$160*	*$181*	*$152*

* Internal Rates of Return (IRRs) calculated excluding "sunk" investment costs. "Sunk" investment costs are defined as "unrecoverable past expenditures … [which] should not normally be taken into account when determining whether to continue a project or abandon it, because they cannot be recovered either way." See footnote 32.

[4] The peer review was undertaken by Mr. Paul Precht, former Executive Director, *Markets and Regulatory Policy* with the Alberta Department of Energy where he was directly responsible for forecasting production and energy revenues to Alberta and for analysis of fiscal and taxation policies impacting the Alberta petroleum industry.

1. **Base Case Anchor Only:** assumes only the three Anchor Fields (Niglintgak, Taglu and Parsons Lake) are brought on stream during the life of the MV Pipeline. After-tax cash flows to field producers are estimated at $14.6 billion over the 27 year life of the Anchor Fields Only, earning an annual Internal Rate of Return of 32.0% (25.7% if sunk investment costs are included – see footnote 32 for an explanation of "sunk costs"). These are relatively high IRRs, particularly since Anchor Field production is moderately low risk.[5]

   Total taxes (royalties, field income taxes and pipeline income taxes[6]) accruing to Governments reach $18.3 billion over the 27 years of operation, of which $14.4 billion would go to the Federal Government and the remaining $3.9 billion to the Governments of Alberta and the NWT. In real dollar terms ($2003), the Federal Government would receive on average $256 million per annum and the Governments of Alberta and the NWT $72 million per year.[7]

2. **Base Case GLJ:** this is the full production Base Case as identified in the Gilbert Laustsen and Jung Associates Ltd. Study (GLJ Study) prepared for Imperial Oil in 2004. After-tax cash flows to field producers in this case are estimated at $64.6 billion over the 45 year life of the Pipeline life, earning an annual after-tax Internal Rate of Return of 24.2% (27.5% if sunk investment costs are excluded).

   Total taxes (royalties, field income taxes and pipeline income taxes) accruing to Governments reach $77.5 billion over the 45 years of operation, of which $64.5 billion would go to the Federal Government and the remaining $12.9 billion to the Governments of Alberta and the NWT. In real dollar terms ($2003), the Federal Government would receive on average $769 million per annum and the Governments of Alberta and the NWT $160 million per year.

3. **Price Increase of 10%:** this scenario assumes the GLJ Base Case with a 10% increase in real dollar gas and condensate prices for each year over the 45 year period. After-tax cash flows to field producers with this price increase are estimated at $73.8 billion over the 45 year life of the Pipeline life, earning an annual Internal Rate of Return of 26.6% (30.6% if sunk investment costs are excluded). This suggests that for every 10% increase in natural gas and condensate real prices, Internal Rates of Return increase by 2% to 3%.

   Total taxes (royalties, field income taxes and pipeline income taxes) accruing to Governments reach $87.9 billion over the 45 years of operation, of which $73.3 billion would go to the Federal Government and the remaining $14.6 billion to the Governments of Alberta and the NWT. In real dollar terms ($2003), the Federal Government would receive on average $878 million per annum and the Governments of Alberta and the NWT $181 million per year.

4. **Capital Cost Increase of 30%:** this scenario assumes the GLJ Base Case except that capital investment costs each year are increased by 30%. After-tax cash flows to field producers with this price increase are estimated at $58.8 billion over the 45 year life of the Pipeline life, earning an annual Internal Rate of Return of 18.8% (20.4% if sunk investment costs are exclude). This suggests that for every 30% increase in capital construction costs, Internal Rates of Return decrease by 5% to 7%.

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[5] Risk-free returns are roughly equal to the long-term bond rate (before income tax rate of 4.5%). Low risk returns (for, say, regulated natural gas pipelines) are in the range of 10%-12%. The Alaska Gas Pipeline has an assumed a pre-income tax IRR of 17.8% based on natural gas prices of $5.50/mcf (see http://www.gov.state.ak.us/gasline/faq.php). When questioned about possible 30% returns, Imperial Oil itself indicated that is "certainly not our expectation." Hearing Order GH-1-2004 – MGP VOLUME 21 - July 31 2006.

[6] The estimate of Pipeline taxes assumes that the Aboriginal Pipeline Group (APG) as proposed part owners of the MV Pipeline pay equivalent income taxes as other owners and that these taxes are filed with and accrue to the federal and NWT governments.

[7] These shares of taxes assumes that the Federal Government does not take back monies from its present contributions to the GNWT and further, that there are no negotiated agreements to transfer a part of royalties to the Government of NWT.

Total taxes (royalties, field income taxes and pipeline income taxes) accruing to Governments reach $72.1 billion over the 45 years of operation, of which $59.8 billion would go to the Federal Government and the remaining $12.3 billion to the Governments of Alberta and the NWT. In real dollar terms ($2003), the Federal Government would receive on average $702 million per annum and the Governments of Alberta and the NWT $152 million per year.

Along with the financial implications of the MGP, the economic (direct, indirect and induced) impacts are calculated for Net Domestic Product (GDP), Labour Income, Taxes and Employment. The direct plus indirect impacts of the GLJ Base Case are highlighted in Exec Table 2.

To 2055 the direct and indirect impacts of building and operating the MV Pipeline are expected to increase GDP in Canada by $115.3 billion, with the NWT receiving the bulk of that increase ($102.0 billion).[8] Of the $11.5 billion in Labour Income earned throughout Canada (208,962 person-years of work), some $3.9 billion (58,659 person-years of work) will be earned within the NWT. However, it is expected that a large number of employees working in the NWT will have permanent residence elsewhere. The expected employment and payroll of NWT residents are estimated at 34,737 person-years and $2.14 billion respectively.

Exec Table 2: Economic Impacts (Direct plus Indirect) of the GLJ Base Case ($2003 Billions)

	FIELDS		PIPELINE		FIELDS + PIPELINE	
	Develop	Oper	Develop	Oper	Total	Ann. Avg.
All Canada Impacts						
GDP	$10.5	$90.6	$2.5	$11.7	**$115.3**	**$2.56**
Labour Income	$6.1	$2.8	$1.8	$0.8	**$11.5**	**$0.26**
Royalties	$0.0	$41.9	$0.0	$0.0	**$41.9**	**$0.93**
Corporate Income Taxes*	$0.0	$20.9	$0.0	$1.7	**$22.6**	**$0.50**
Other Fed Rev.**	$1.8	$0.8	$0.4	$0.2	**$3.2**	**$0.07**
Other Prov/Terr. Rev.**	$0.8	$0.4	$0.2	$0.1	**$1.6**	**$0.04**
Employment (PY)	111,171	50,607	28,724	18,460	**208,962**	**4,644**
NWT Impacts						
GDP	$3.8	$86.8	$0.9	$10.5	**$102.0**	**$2.27**
Labour Income	$1.8	$1.1	$0.7	$0.3	**$3.9**	**$0.09**
Royalties	$0.0	$0.0	$0.0	$0.0	**$0.0**	**$0.00**
Corporate Income Taxes*	$0.0	$11.9	$0.0	$1.0	**$12.9**	**$0.29**
Other Fed Rev.**	$0.7	$0.1	$0.1	$0.0	**$0.9**	**$0.02**
Other NWT Rev.**	$0.2	$0.0	$0.1	$0.0	**$0.3**	**$0.01**
Employment (PY)	26,047	16,700	7,934	7,977	**58,659**	**1,304**
NWT Resident LI*	*$0.58*	*$1.08*	*$0.14*	*$0.34*	***$2.14***	***$0.05***
NWT Resident Emp.*	*8,577*	*16,700*	*1,482*	*7,977*	***34,737***	***772***

* Excludes indirect corporate taxes (i.e., corporate taxes paid by suppliers of goods and services) but assumes producers and pipeline owners file taxes in Canada and the NWT.

** Includes taxes such as property taxes, import duties and excise taxes, but excludes both direct and indirect personal income taxes as well as payroll taxes paid by employees and employers.

*** NWT Resident Labour Income and Employment assumes a proportion of Development labour activity in the NWT is taken up by non-residents; it is assumed that labour demand by Operations can be fulfilled by NWT residents.

[8] GDP (Gross Domestic Product) is defined by Statistics Canada as equal to Labour Incomes (including benefits) plus Operating Surplus, the latter being equal to the sum of Corporate Profits, Corporate Taxes, Royalties, Depreciation and Interest Payments). While it is true that NWT GDP increases by $102.0 billion, the vast proportion of this GDP increase is in the form of Operating Surplus, the vast proportion of which is sent out of the Territory. Thus, the increase in GDP provides virtually no benefit to the people of the NWT.

Peak development impacts occur in 2010, generating $1.5 billion in GDP in Canada, of which $552.8 million takes place in NWT. Peak operations impacts occur in 2014, generating $2.8 billion in GDP within Canada. In this case, almost all of the impacts ($2.6 billion) fall within the NWT. To provide some context, this GDP impact in 2014 would represent an increase of about 64% to the present economy of the NWT.

In addition to Royalties and Corporate Income Taxes, the MGP is expected to contribute $3.2 billion to the Federal Government and another $1.6 billion to various provincial, territorial and local governments. Of the latter, the Government of the NWT (and local authorities) is expected to receive $0.3 billion over the life of the Pipeline.

1.0 INTRODUCTION

In the spring of 2006, Pacific Analytics was commissioned by Alternatives North to prepare a stand-alone financial projection model of the proposed Mackenzie Gas Project (herein MGP) basing the main assumptions on data provided to the National Energy Board (NEB) and the Joint Review Panel (JRP) by the proponents of the MGP, Imperial Oil et. al.[9]

While there were (and still are) a number of questions regarding the environmental and social impacts of the MGP on the land and people of the Northwest Territories (NWT), the main economic/financial questions concerning Alternatives North focused on the expected after-tax rates of return that owners of the producing fields and of the MV Pipeline itself could expect if the MGP were constructed, and the level of taxes that governments, and particularly the Government of NWT, could expect to receive over the life of the pipeline. Linked to this was the question of corporate profitability and government's stake as owner of the resource: whether the present royalty system would provide "too little" or "too much" incentive to build the pipeline and whether government was receiving an adequate share of net revenues.

One of the issues noted by Alternatives North was the importance of the assumptions in projecting the financial results of the MGP. To this end, the development of the Model structure emphasised the ability to change a vast array of different input variables. While this Report examines a number of different scenarios based on differing input assumptions, the reader should be aware that virtually any assumption in the Model can be changed easily and the impacts determined.

It also should be noted that the projections assessed here do not necessarily reflect the views of Pacific Analytics. As intimated earlier, the underlying assumptions of the projections are those of the MGP proponents as stated in their submissions to the NEB and the JRP.

A forensic peer review of the Model was undertaken in order to ensure that all of the Model results are calculated correctly. The complete Model was provided to the reviewer, enabling him to examine directly all formulae.[10] A change to the Model was made as a result of comments from the GNWT in October 2006. This change consisted of correcting a division error when calculating unit tolls from the MV Pipeline Cost of Service estimate. At the same time another minor adjustment was made (calculation of tolls using the after-tax ROE and adding taxes back in to get the total the Cost of Service estimate rather than using before tax ROE). A revised version of the report, reflecting these changes to the Model and resulting figures, was submitted in November 2006.

[9] The proponents of the Mackenzie Valley Natural Gas Pipeline Project include Imperial Oil, ConocoPhillips, Shell, ExxonMobil and the Aboriginal Pipeline Group (APG). The three Anchor Fields (Niglintgak, Taglu, and Parsons Lake) are owned by Shell, Imperial Oil, and ConocoPhillips respectively.

[10] The peer review was undertaken by Mr. Paul Precht, former Executive Director, *Markets and Regulatory Policy* with the Alberta Department of Energy where he was directly responsible for forecasting production and energy revenues to Alberta and for analysis of fiscal and taxation policies impacting the Alberta petroleum industry.

2.0 MODEL STRUCTURE AND METHODOLOGY

The Model comprises five main worksheets, plus worksheets containing the various alternative scenarios.

1. the first worksheet (Variables) contains input assumptions that the user can change;
2. the second worksheet (Forecasts) contains a number of different output forecasts (daily output in mmcf and barrels for natural gas and condensate production respectively) for each field for each of the years 2011 to 2055. The user can select any one of these forecasts for inclusion in the financial model;
3. the third worksheet (Expenditures) contains a number of different expenditure forecasts (construction and operating expenditures for each of the years 2002 to 2055 for each field as well as for the various Gathering System laterals and the MV Pipeline itself);
4. the fourth worksheet (Financials) contains the financial model;
5. the fifth worksheet (Economics) contains the economic model that calculates the direct, indirect and induced impacts (GDP, Labour Income, Employment, and Taxes) resulting from the construction and operation of the Pipeline and all the ancillary fields and gathering systems.
6. the remaining worksheets are identical to the "Financials" worksheet with the exception of different selected assumptions (e.g., the "BaseCase - Anchor Only" worksheet has Anchor Only production and expense assumptions but with all other assumptions the same).

The Model follows a standard methodology for determining net after-tax Cash Flows and the resulting Internal Rates of Return (IRR) for each field. In a nutshell, for each field and year the production of natural gas and of condensates are multiplied by their prices (determined at Edmonton) to generate Net Revenues by field. Field Expenditures (annual capital and operating expenses) are subtracted from Net Revenues each year to give annual Cash Flows Before Tolls.

Cost of Service for each of the Gathering System components (laterals, the Gas Facility - Gas Plant and Liquids Separation Plant - and the Liquids Line) and the Cost of Service for the MV Pipeline itself are calculated as regulated utilities earning prescribed rates of return. The resulting unit tolls (costs of service divided by the gas/condensate throughput) plus estimates of the unit costs to move the natural gas from Zama (the end of the MV Pipeline) to Edmonton and condensate from Norman Wells to Edmonton are removed from the Cash Flows Before Tolls to give an estimate of Cash Flows After Tolls for each field. The estimation of Royalties follows the *Frontier Lands Petroleum Royalty Regulations*[11] and is calculated for each field based on its own particular production profile and payout date. Applicable income taxes are then determined based on announced income tax rates.[12] These two taxes are removed to give After-Tax Cash Flows for each field, from which Internal Rates of Return are calculated. Income tax payments also are calculated for the Gathering System and the MV Pipeline.[13]

The principal drivers of the Model include the following:

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[11] http://laws.justice.gc.ca/en/C-8.5/SOR-92-26/text.html

[12] The income tax assumption is that the proponents are required to file federal and NWT income taxes and are not able to divert income to other, lower tax jurisdictions.

[13] The Appendix provides a more detailed explanation of the Model structure.

1. Production: forecasts of annual natural gas and condensates production over a period of 45 years (2011 – 2055) are taken from the 2004 GLJ Study prepared for and used by Imperial Oil[14] in their financial estimates and as well from NEB forecasts (included in the GLJ Report) of expected production. Forecasts include production by contingent (known) fields and prospective (unknown) fields (production for 30 individual fields are projected although the Model aggregates the data into 10 major fields).

   Assumptions: Model includes four different production scenarios: GLJ Anchor Fields Only; GLJ Base Case; the NEB P50 Case (included in the GLJ Study for reference), the NEB High Capacity Case (also included in the GLJ Study).

2. Prices: following on Imperial Oil's methodology, expected prices for natural gas (Alberta AECO – C Spot) and condensates (Edmonton Pentanes) are taken from the publicly available Sproule forecast.[15] The Model generates annual Net Revenues (realizable in Edmonton) by field (production multiplied by price).

   Assumptions: Base Case prices are taken from Sproule's July 2006 forecast of real prices (converted to $2003) which differs somewhat from the Sproule prices used by Imperial Oil in their Environmental Impact Statement (EIS) provided to the NEB and JRP and which therefore will result in somewhat different financial results. Three alternative price forecasts (+10% from base case each year, -10% from base case each year, and flat $5.00 natural gas) are included for scenario testing purposes.

3. Field Capital Investment and Operating Costs: annual capital investments for each Anchor Field (separately for well drilling and pipeline interconnects to the Gathering System laterals) are provided by Imperial Oil in their EIS. Imperial Oil also provides average annual operating costs for each field. Net Revenues (from 2 above) minus annual capital invested and operating costs yields annual Cash Flows Before Tolls in the Model.

   Assumptions: capital investment for fields other than the three Anchor Fields had to be estimated. Investment was separated into two components: drilling and interconnects. Drilling capital was estimated based on EIS data on the expected number of wells required (production wells and dry wells) times well drilling costs.[16] The time profile of drilling conservatively assumes that wells are drilled over a five-year period prior to production coming on stream. Where there is a ramp-up of production, drilling is spread across the production profile. The Model includes a choice variable for the number of wells required for each field for scenario testing purposes.

   Interconnect costs for each field were based on the expected kilometres of required interconnect for each field[17] times the average per kilometre interconnect cost (assumed equal to the average Anchor Field per kilometre interconnect cost).

   Operating costs for the three Anchor Fields are taken from the EIS.[18] For non-Anchor Fields, operating costs are assumed to be proportional to the field capital costs based on average Anchor Field costs.

4. Gathering System Capital Investment and Operating Costs: for the purposes of the Model,[19] each lateral of the Gathering System (e.g., Niglintgak to Taglu) is treated as a (quasi) regulated utility

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[14] "*Mackenzie Gas Project: Gas Resource and Supply Study*", prepared for Imperial Oil Resources Ventures Limited, prepared by Gilbert Laustsen Jung Associates Ltd. (herein GLJ Study), May 2004.

[15] Sproule website: http://www.sproule.com/prices/gas_escalated.htm

[16] Imperial Oil Response to JRP Request, Information Request Round 2, September 21, 2005.

[17] EIS Additional Information: Cumulative Effects – Hypothetical Scenario (Section 11.2), March 2005.

[18] EIS Volume 2: Project Description Section 9 Expenditures and Workforce.

earning a prescribed annual rate of return (18.8% before tax). "Cost of Service" estimates based on invested capital[20] are determined in the Model with average unit tolls ($/mcf) determined by dividing Cost of Service by total flow of gas through the particular lateral.

Each field has its own Gathering System path (e.g., gas from Niglintgak flows through the Niglintgak-to-Taglu lateral, then through the Taglu-to-Junction lateral while gas from the Taglu field only flows through the Taglu-to-Junction lateral) hence total unit toll costs vary from field to field. Annual operating costs for each lateral are taken from the EIS.[21]

5. <u>MV Pipeline Capital Investment and Operating Costs</u>: the MV Pipeline is a regulated utility under the NEB earning a prescribed annual rate of return (11.09% after tax[22]). The estimation of total "Cost of Service" and unit tolls is determined in the same manner as is done for the Gathering System laterals and matches (with the exception of the first year production) how Imperial Oil calculates tolls in their financial estimates.[23]

6. <u>Other Tolls</u>: the MV Pipeline ends just south of the Alberta-NWT border at Zama where it will connect to a NOVA pipeline for delivery into the Alberta system. Unit toll costs for delivery from Zama to Edmonton are assumed to remain at 2006 levels in real terms. For condensate, unit toll costs over the existing Enbridge liquids pipeline from Norman Wells to Zama is assumed to remain at 2006 levels in real terms as are liquid tolls from Zama into the Alberta system over the Rainbow pipeline.

   Net Revenues minus Gathering System tolls minus MV Pipeline tolls minus Other tolls yields Net Cash Flows After Tolls in the Model. This cash flow effectively describes the total revenues accruing to producers (field owners) after paying all costs (capital investment for drilling and interconnects, annual operating costs, and delivery costs for both natural gas and condensates) but before paying any taxes (royalties and income taxes). From this time series of net cash flows, one determines the Net Internal Rates of Return (IRR) for each field.

7. <u>Royalties</u>: estimation of Royalties follows precisely the accounting methodology laid out by the Canadian Government in their *Frontier Lands Petroleum Royalty Regulations*.[24]

8. <u>Income Taxes</u>: estimation of Income Taxes follows the prescribed method laid out by the Canadian Revenue Agency in terms of what constitutes taxable revenues and allowable write-offs. The income tax rates applied to Taxable Income (Federal rate and NWT rate separately) are based on the latest Federal and NWT budget projections and therefore differs somewhat from what Imperial Oil has used in their EIS financial submissions.

   <u>*Assumptions*</u>: The Federal Income Tax rate is set at 19 percent and the NWT rate is set at 12 percent (the announced rates as of 2011 when production begins). These rates are included as variables so that rates can be changed for scenario testing purposes.

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[19] Imperial Oil itself has stated that the Gathering System will operate as though it were a regulated pipeline earning a rate of return similar to that prescribed by the NEB for other pipelines.

[20] Imperial provides capital investment estimates for each lateral as well as detailing "cost of service" and unit tolls (see Table NEB MEG 3.20-11 to 3.20-19). The accounting methodology for estimating Cost of Service in the Model is the same as the methodology used by Imperial Oil with the exception that Cost of Service in the Model is estimated for 2011, the first year of production (albeit small) whereas Imperial Oil disregards first year (no explanation was found for why first year production was ignored).

[21] Imperial Oil Response to NEB Intervenor Mackenzie Explorer Group Round 3, January 11, 2006.

[22] Toll Principles (AOU7S0) IORVL-134B, June 2006.

[23] see Table NEB MEG 3.20-1 to 3.20-8.

[24] http://laws.justice.gc.ca/en/C-8.5/SOR-92-26/text.html

9. Cash Flow After Taxes and IRRs: Cash Flow Before Taxes minus Royalties and Income Taxes yields annual Cash Flow After Taxes for each field. From this time series of cash flows, one determines the after-tax Internal Rate of Return (IRR) for each field. IRRs are calculated with and without "sunk" investment costs. Sunk investment costs are defined as "unrecoverable past expenditures … [which] should not normally be taken into account when determining whether to continue a project or abandon it, because they cannot be recovered either way" and therefore shouldn't be included in determining the IRR that each field would earn (see footnote 32 on page 10). Note that sunk costs are still recognised when determining income taxes as they remain available for write-offs.

The following sections provide details on the financial impacts of the MGP, focusing on estimated Cash Flows, Internal Rates of Return, and Taxes Paid, the latter broken out by Royalties (where appropriate) and Income Taxes themselves divided between Federal taxes and NWT taxes.

- Section 3.1 examines the returns of the Gathering System and MV Pipeline itself;
- Section 3.2 looks at the Anchor Fields Only;
- Section 3.3 uses the entire Base Case production scenario from the GLJ Study;
- Section 3.4 takes this same GLJ Base Case but assumes that natural gas and condensate prices are 10% higher;
- Section 3.5 concludes by estimating a scenario where capital investment costs are 30% higher than originally estimated;
- Section 4.0 concludes the report by looking at the economic impacts (GDP, employment, labour income and taxes - excluding royalties and income taxes) of the construction and operation of the MGP. The economic impacts are determined for the direct, indirect and induced effects in real $2003.

3.0 FINANCIAL RESULTS

The following sections describe the projected financial returns of the pipeline and gathering system facilities and the proposed natural gas fields, focusing on cash-flows, taxes (royalties and income taxes) and internal rates of return (IRR). The pipelines, operating as (quasi) regulated utilities, are assessed under the EIS assumptions and GLJ Base Case projections.[25] For the natural gas fields, two "base case" scenarios are examined: Anchor Fields Only, and All Fields as described in the GLJ projections. Next, two "sensitivity" cases are assessed: an increase of 10 percent in expected gas and condensate prices; and an increase in capital investment costs of 30 percent for both the Pipeline/Gathering System and field drilling and development costs.

3.1 Pipeline Returns (GLJ Base Case)

The Mackenzie Valley Pipeline running from the Gas Facility to Zama just south of the NWT/Alberta border is to be a regulated utility under the NEB earning a prescribed rate of return on equity (11.09% after-tax). The Gathering System[26] although not strictly regulated, has been proposed by the proponents to function in a

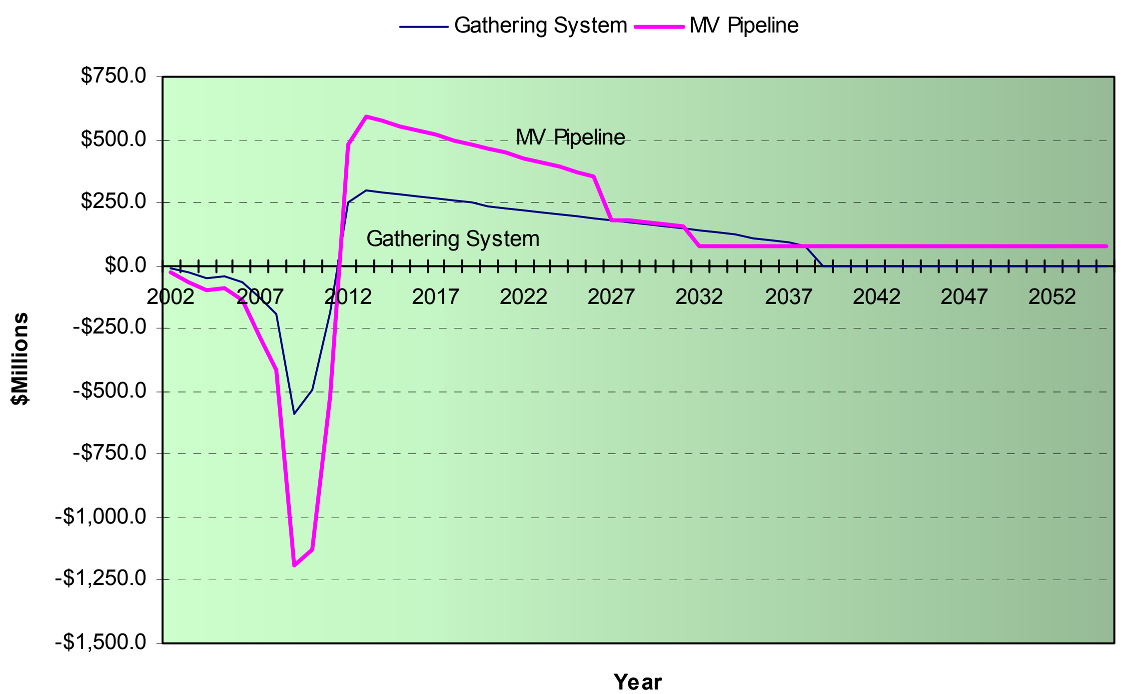
[25] Imperial Oil uses the estimates contained in "*Mackenzie Gas Project: Gas Resource and Supply Study*", prepared for Imperial Oil Resources Ventures Limited, prepared by Gilbert Laustsen and Jung Associates Ltd. (herein GLJ), May 2004.

[26] The Gathering System is made up of a series of laterals collecting natural gas from the various fields plus a Gas Plant, a Gas Liquids Stripping Plant, and a Liquids Line delivering condensates to Norman Wells.

similar manner, earning a prescribed rate of return on equity (11.09% after-tax).[27] After-tax returns are calculated using these rates of return, annual capital costs, operating costs, depreciation rates, equity rates, and other data. from the EIS, and then deducting associated income taxes. Graph 1 displays the time profile of these after-tax returns

Over the course of the 45 years of pipeline operation, the MV Pipeline would expect to earn, after covering all capital costs, $5.79 billion in after-tax revenues (an after-tax IRR of 9.0%[28]) and pay $2.38 billion in income taxes (of which $1.51 billion would go to the Federal Government and $0.88 billion to the Government of the NWT).[29] The total after-tax returns of the Gathering System, after covering all capital costs, would amount to $3.46 billion over the same 45 years (an after-tax IRR of 9.6%), with income taxes reaching $1.40 billion ($886.4 million going to the Federal Government and $515.3 million to the Government of the NWT).

Graph 1: After-Tax Pipeline Returns (GLJ Base Case)



3.2 ANCHOR FIELDS ONLY BASE CASE

Imperial Oil has based its Environmental Impact Statement (EIS) analysis on production from three "anchor" fields: Niglintgak, Taglu and Parsons Lake. The results below are based on Imperial Oil's own data on expected production, capital investment, operating costs, gathering system and pipeline costs of service, and future natural gas and condensate prices. Consequently, the results should be considered as closely

[27] The MV Pipeline and each of the Gathering System components each earn a "cost of service" based on capital costs, rate of return, and income tax liabilities. The annual cost of service is spread across the annual flow of gas, resulting in an average "toll" per mcf.

[28] The NEB provides for a after-tax Return on Equity (ROE) of 11.09%, but equity comprises only 30% of the total capital investment. The remaining 70% is funded by debt.

[29] Our understanding is that the Aboriginal Pipeline Group (APG) will acquire 30 percent of the MV Pipeline facilities. Negotiations are not complete, but assuming that the APG covers 30 percent of the capital costs (with borrowing costs of 6.1%), then the APG can expect to earn 30 percent of after-tax returns (roughly equivalent to $1.7 billion over the life of the MV Pipeline to the year 2055). This assumes that the income tax liabilities of the APG will be equivalent to the other participants in the MV Pipeline.

representing what Imperial Oil itself is expecting (prior to their indication that expected capital costs have changed) in terms of the financial viability of the Anchor Fields supporting the entire MV Pipeline project.

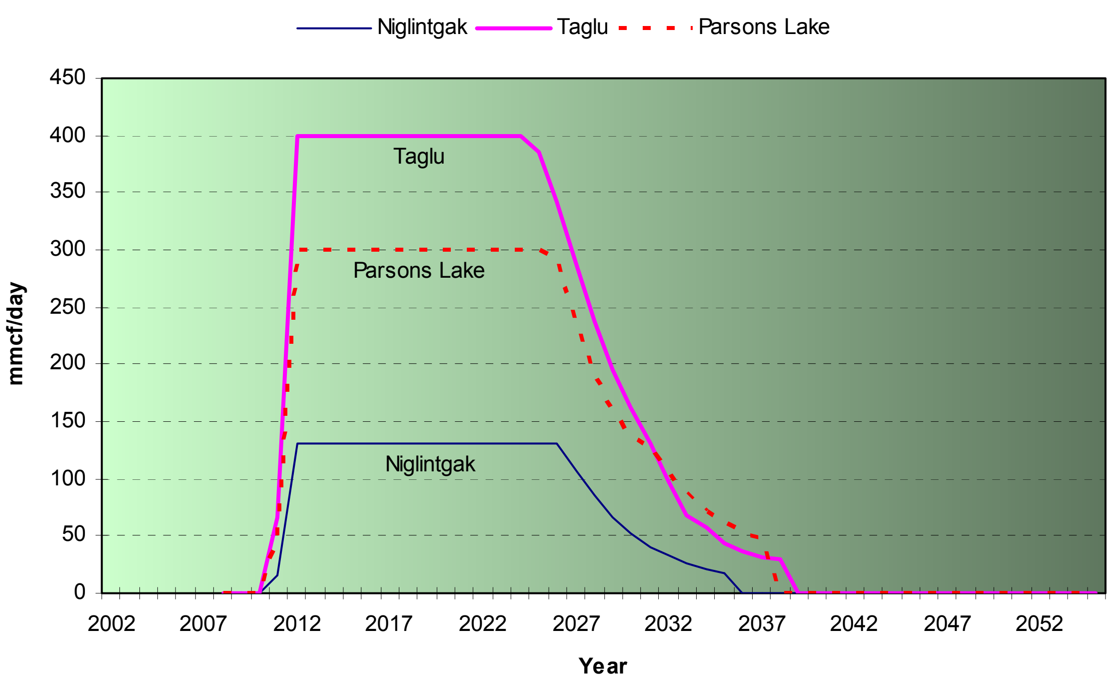
3.2.1 Assumptions

Graph 2 on the following page displays the expected production over time from the three Anchor Fields as determined in the GLJ study. Total production reaches a peak output of 830 mmcf per day almost immediately (2011) and this is maintained until 2024 when total production begins declining with exhaustion by 2038.

A second major assumption is the expected price of natural gas (and condensate) that producers will receive. Imperial Oil uses the oil/natural gas price forecasts generated by Sproule Corporation of Calgary for the first 15 years of the project, and then assumes that real prices remain stable.[30]

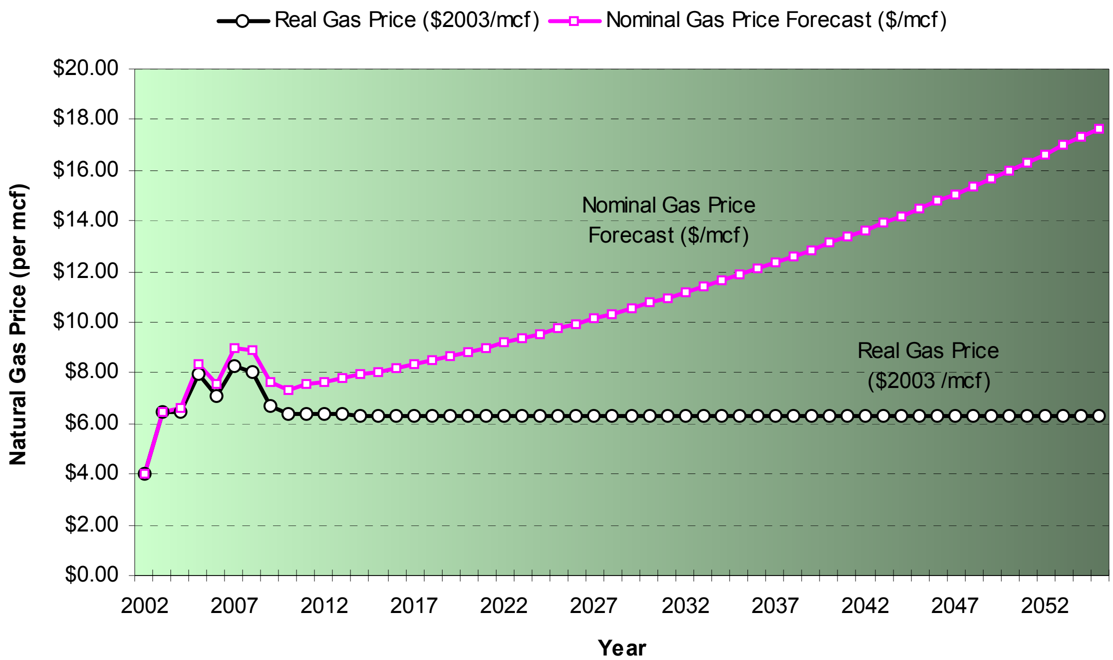
As seen in Graph 3, by start-up year 2011 Sproule (in its July 2006 forecast) is expecting a small decline in real natural gas price from 2006 values and then flat real prices over the next half century. Based on an expected annual inflation rate of 2 percent, nominal gas prices more than double, increasing from a Canadian dollar value of $7.53 per mcf in 2006 to $17.66 per mcf in 2055.

Graph 2: Anchor Field Base Case Production Profile



[30] "Nominal" price refers to the observed market price. "Real" price excludes the effects of general inflation in the economy. If inflation is say, 2% per year, and the "nominal" price of gas increases by 3%, then the "real" price of gas has increased by 1% (correctly: 1.03/1.02 = 1.098 or 0.98%).

Graph 3: Natural Gas Price Forecasts ($Can per mcf)



3.2.2 Anchor Fields Only Base Case Results

Owners of the fields need to earn a "normal" rate of return on their investment[31] after subtracting all associated costs in getting the gas and condensate to southern markets. Besides the actual investment cost in wells (drilling of both dry and producing wells) and related interconnects, there are ongoing annual operating costs, the Gathering System toll costs for delivering the natural gas/condensate to processing facilities, the processing costs themselves, the toll cost of the Mackenzie Pipeline, and the various secondary toll costs for delivering the processed natural gas/condensate to southern markets. Taking revenues earned per year and subtracting all annual costs results in an estimate of annual net cash flows.

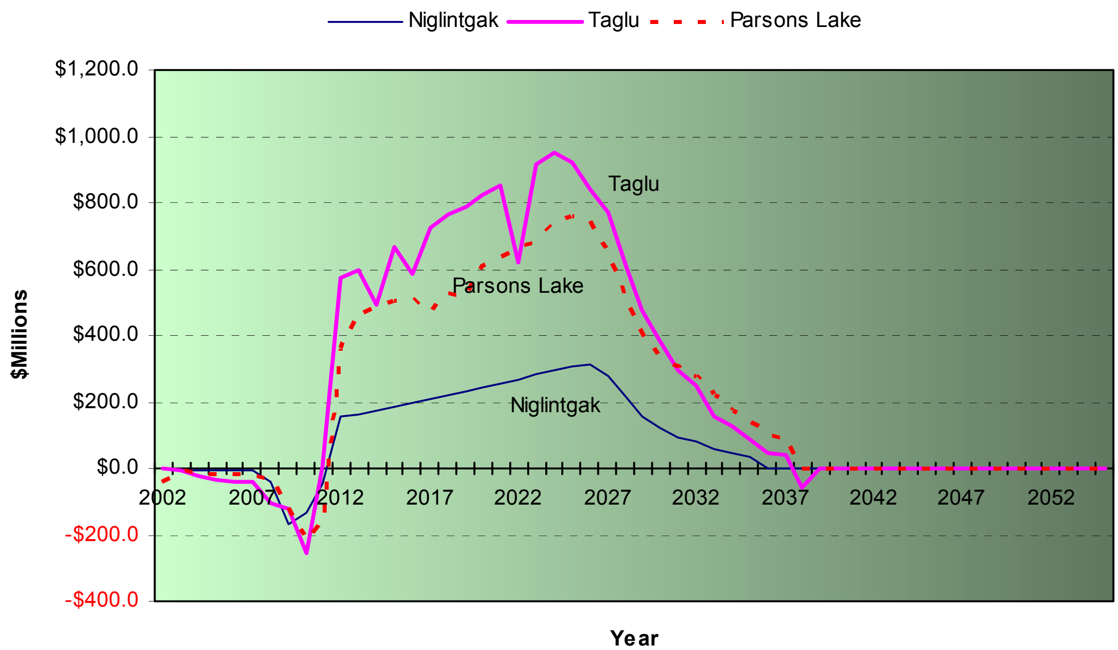
Graph 4 below highlights these annual net cash flows. Note that the years prior to initial production will experience only costs in the form of investment in drilling and connecting wells and hence cash flows are negative.

Net cash flows generally rise over the production profile as nominal natural gas prices increase, falling off after peak production in the mid-2020s. Note that the drop in Taglu cash flow in 2022 is a result of expected new well drilling investment required to maintain Taglu production.

The important return to a business is not the net returns it may generate, but rather the returns they will receive after all taxes are paid. For the Anchor Fields, two taxes are identified: royalties and income taxes.

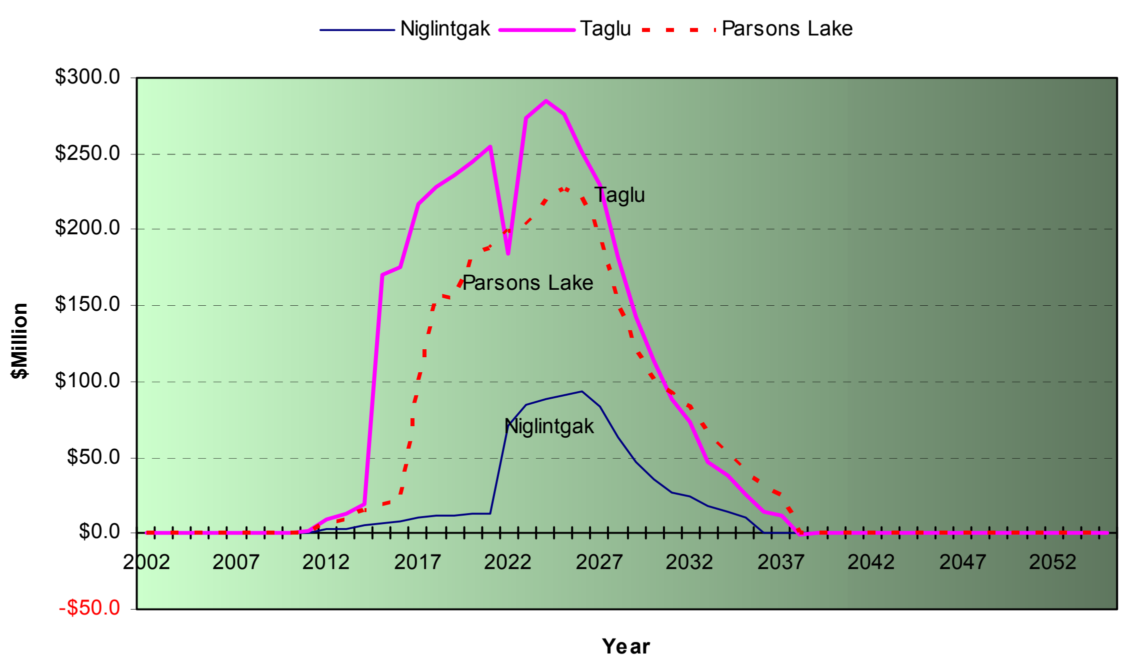
[31] A "normal" rate of return is technically defined as the risk-free rate of return (in Canada usually equated to the Government of Canada long bond rate - equal to about 4.5 percent in August of 2006) plus a "risk premium." Alternatively, a "normal" rate of return is the rate which, in this case Imperial et. al., could earn on other equally risky investments. There is no agreed definition of this "normal" rate of return (it differs from project to project), but given that the Anchor Fields are already proven reserves, one would expect the risk component to be relatively small. For comparison purposes, the relatively low risk MV Pipeline receives a regulated annual after-tax return of 11.09 percent.

Graph 4: Anchor Field Only Base Case Net Cash Flows



The calculation of royalties is a complicated process. Royalties are assessed lower rates of taxation for the first seven years of production (year one = 1% of net revenues rising every 18 months by one percent until year seven onward where the rate is set at 5%) or until net revenues exceed net investment (known as the "payout" date) at which time the royalty rate is set at 30 percent of net revenues (net revenues minus adjusted capital and operating costs) or 5 percent of net revenues, which ever is higher. Graph 5 highlights the annual pattern of royalties for the three Anchor Fields.

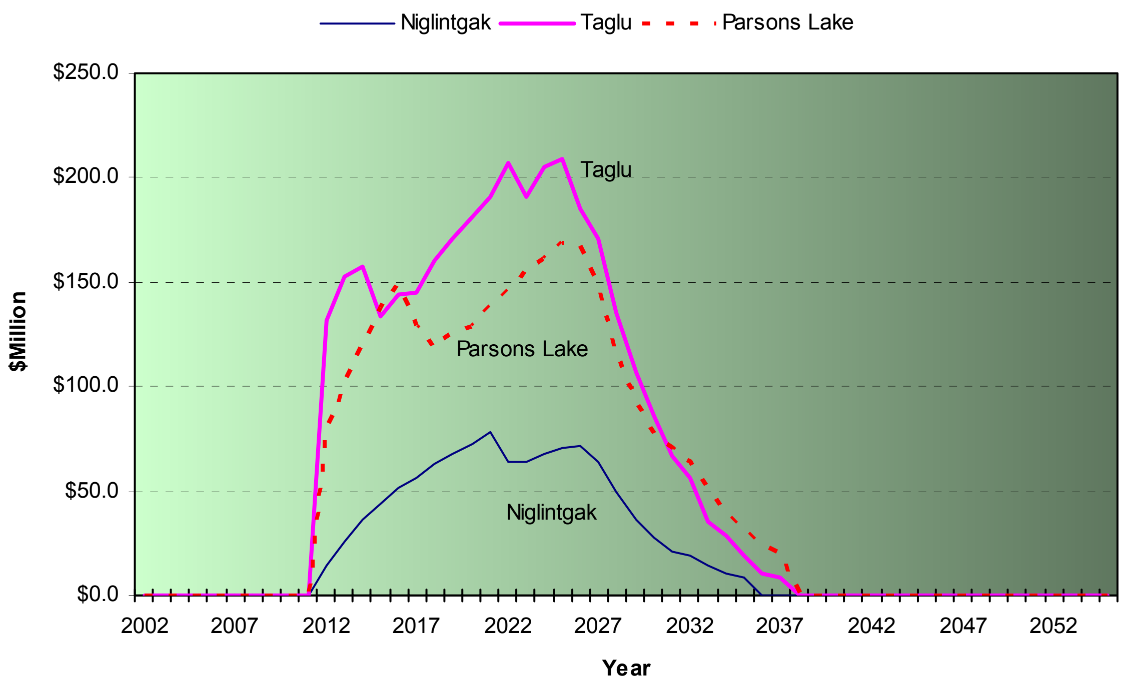
Graph 5: Anchor Field Base Case Royalties



Given the estimated profile of net cash flow and royalties, one can determine the pre-income tax Internal Rate of Return (IRR) for each field. These are computed in the Model as: Niglintgak (28.2%), Taglu (42.0%) and Parsons Lake (41.8%) for an average Anchor Field net IRR of 38.9%[32]

Federal and Territorial income taxes are based on statutory corporate income tax rates multiplied by taxable incomes (net cash flows minus applicable tax exemptions). Graph 6 highlights the annual pattern of income taxes payable by the three Anchor Fields.

Graph 6: Anchor Field Base Case Income Taxes



Deducting these taxes paid gives the after-tax cash flow attributable to each field. These annual cash flows are highlighted in Graph 7. The total after-tax returns accruing to the proponent companies after recovering all capital investment costs will reach just over $14.6 billion during the 27 years the three fields are in operation (Niglintgak: $2.2 billion; Taglu: $6.7 billion; and Parsons Lake: $5.7 billion). The resulting after-tax IRR for each field are: Niglintgak (23.4%), Taglu (34.6%), and Parsons Lake (34.2%), for an annual average Anchor Field after-tax IRR of 32.0%, higher (one would think) than what would be considered "normal" after-tax returns for equivalently "risky" investments.[33]

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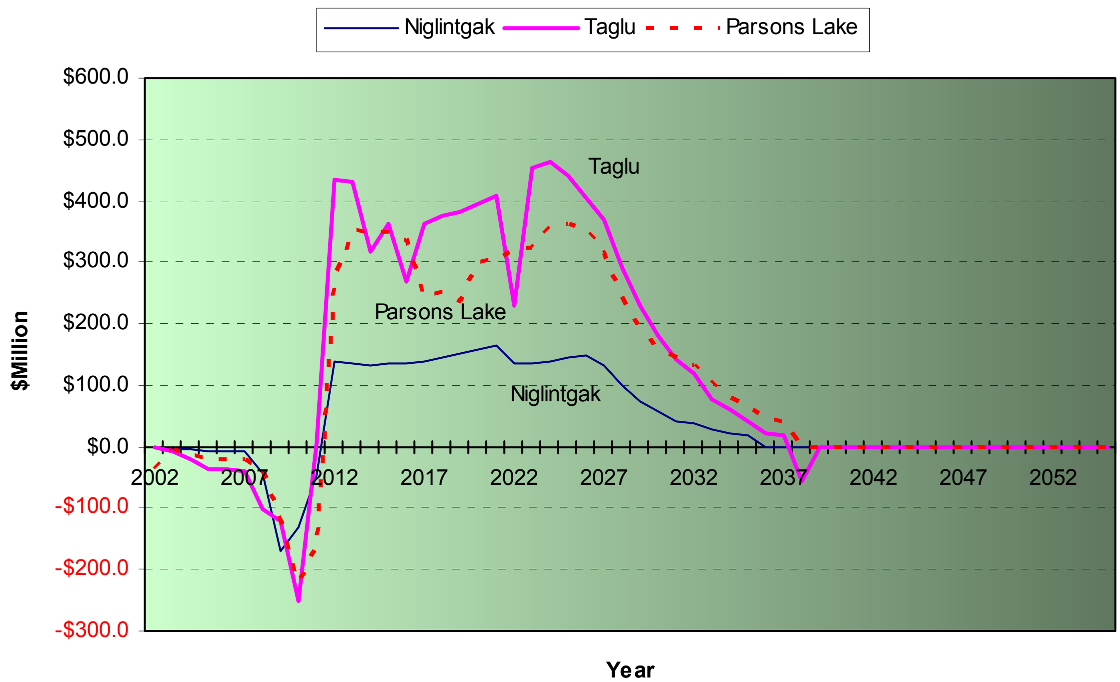
[32] These IRRs exclude investments made prior to 2006. Most economists would argue that pre-2006 investments are "sunk costs" (sunk costs are defined as "unrecoverable past expenditures … [which] should not normally be taken into account when determining whether to continue a project or abandon it, because they cannot be recovered either way" – from Ecoterms http://economics.about.com/od/economicsglossary/g/sunkcosts.htm). Consequently, economists argue that they shouldn't be included in determining the IRR that each field would earn. Note that sunk costs are still recognised when determining income taxes as they remain available for write-offs. If sunk costs are included, the calculated IRRs decrease to: Niglintgak (25.5%), Taglu (34.2%), and Parsons Lake (29.4%) for an average Anchor Field IRR of 30.6%.

[33] If one accepts the argument that sunk costs should be included when assessing the viability of a future investment, then the after-tax IRR for each field decreases to: Niglintgak (21.3%), Taglu (28.6%), and Parsons Lake (24.7%) for an annual average Anchor Field after-tax IRR of 25.7%. The Alaska Gas Pipeline has an assumed 17.8% before income tax IRR based on natural gas prices of $5.50/mcf (see http://www.gov.state.ak.us/gasline/faq.php). In recent NEB Hearings, representatives of Imperial Oil commented

Graph 7: Anchor Field After-Tax Cash Flows



As summarised in Table 1, during the 27 years of operation (2011 to 2038), the three Anchor Fields together will pay a total of $7.5 billion in royalties accruing to the Federal Government, and another $7.1 billion in income taxes. Of the income taxes payable, it is estimated that $4.5 billion go to the Federal Government and the remaining $2.6 billion will accrue to Alberta and NWT Governments.[34] This is over-and-above the additional $1,510.6 million in income taxes collected from the Gathering System ($955.2 million to the Federal Government, $555.3 million to the GNWT) and $2.1 billion collected from the MV Pipeline operations ($1.4 billion to the Federal Government, $0.8 billion to the GNWT). While these figures appear large at first glance, one must remember that the taxes will be collected over a fairly long period of time (27 years) and that the taxes calculated are in nominal terms (that is, they are subject to inflation which reduces the real purchasing value).

In real terms ($2003) royalties paid over the entire 27 years will equal $5.0 billion and total income taxes (including income taxes paid by the Gathering System and the MV Pipeline) over 27 years will equal $7.5 billion, of which $4.7 billion will go to the Government of Canada and $2.7 billion will accrue to the Alberta and NWT Governments. Peak annual real dollar taxation will reach $388.9 million in royalties (2024), $274.1 million in Government of Canada income taxes (2013) and $157.7 million (2013) in income taxes to Alberta and NWT Governments. Real dollar royalties paid will average $130.9 million annually while Government of Canada income taxes will average $124.9 million and Alberta and NWT Governments income taxes will average $71.8 million yearly.

that they did not expect 30% return on investment. "I'm not sure where you get a 30 percent return number. That's certainly not our expectations." Hearing Order GH-1-2004 – MGP VOLUME 21 - July 31 2006.

[34] It is not clear in which jurisdiction Field income taxes will be paid (it is understood that MG Pipeline and Gathering System income taxes will be paid to the GNWT). The legislation appears to say that income taxes will be paid 50% based on the point of sale and 50% based on the location of employment. It has been suggested that, since the sale of gas will occur in Alberta (at Zama), then more than 50% of income taxes will accrue to Alberta since some of the operations employment also is located in Alberta.

Table 1: Summary of Anchor Fields Only Financial Results

	Niglintgak	Taglu	Parsons Lake	Anchor Fields Only
Before Income-Tax CF	$3,343	$9,972	$8,424	$21,739
Before Income-Tax IRR	**25.5%**	**34.2%**	**29.4%**	**30.6%**
Before Income-Tax IRR*	**28.2%**	**42.0%**	**41.8%**	**38.9%**
After-Tax CF	$2,246	$6,683	$5,668	$14,597
After-Tax IRR	**21.3%**	**28.6%**	**24.7%**	**25.7%**
After-Tax IRR*	**23.4%**	**34.6%**	**34.2%**	**32.0%**
Federal Royalties	$839	$3,801	$2,888	$7,528
Field Inc. Taxes	$1,097	$3,289	$2,756	$7,142
- to Canada	*$698*	*$2,093*	*$1,754*	*$4,545*
- to Alb & NWT	*$399*	*$1,196*	*$1,002*	*$2,597*
Pipeline Inc. Taxes				$3,648
- to Canada				*$2,307*
- to Alb & NWT				*$1,341*
Avg. Annual Tax				$328
- to Canada ($2003)				*$256*
- to Alb & NWT				*$72*

* Excludes "sunk" capital costs invested prior to 2006. See footnote 32 for a complete explanation of "sunk" costs.

3.2.3 Alternate Royalty Systems

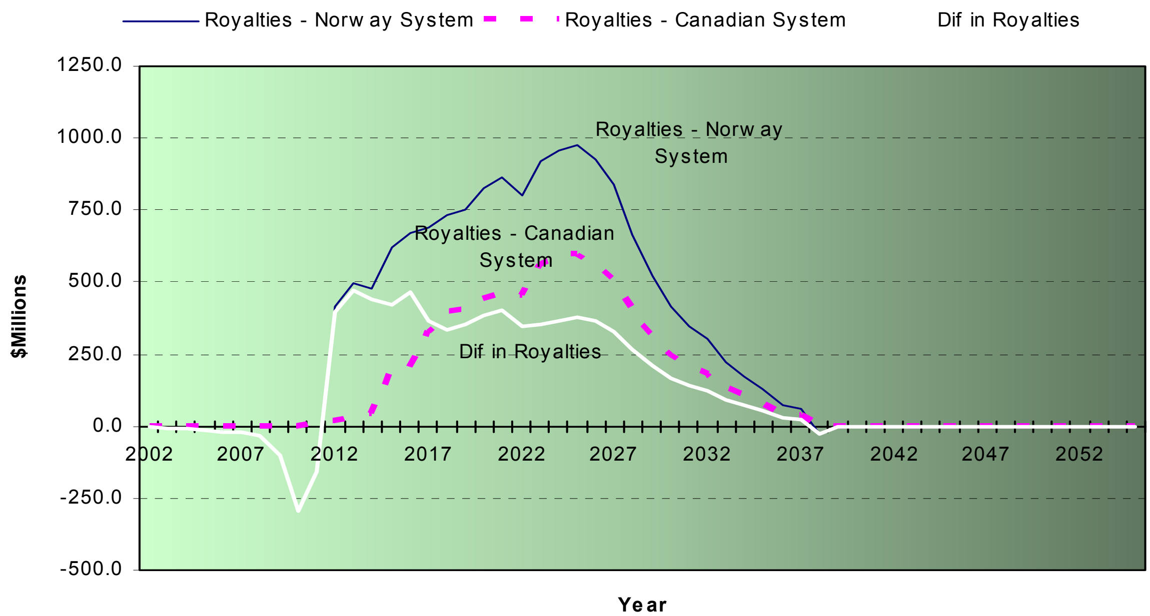
One question Alternatives North asked was how the level and profile of royalties would change if the Federal Government adopted the system used by Norway.[35] Graph 8 provides a visual depiction of the different royalty systems.

Clearly, the Norwegian system collects a higher level of royalties. In total, if the Norway system were adopted and all other aspects of the MV Pipeline Project remained the same, the Federal Government would collect a total of $14.2 billion over the life of the Anchor Fields versus $7.5 billion under the present system. This represents a difference of some $6.7 billion or an increase of 88.6% over *status quo* royalties. Based on the Norwegian system, after-tax cash flows would fall to $7.8 billion from $14.4 billion under the present Canadian system. This would result in an IRR of 27.3% under the Norwegian system versus 32.0% under the present system.

[35] A brief description of the Norwegian Tax System is attached as Appendix B. The Norwegian System is not strictly a "royalty" system, rather it is a "special tax" based on net operating revenues (special tax base) where eligible write-offs include exploration costs, depreciated investment, uplifted investment costs, etc. The "special tax" rate is 50% and the marginal tax is estimated at 78%.

While the Model attempts to duplicate as closely as possible the Norwegian System, the reader should recognize that it is a complicated system and the information available on the potential Mackenzie production does not meet all the requirements for determining precisely the value of the special tax. Consequently, the results for the Norwegian System should be considered only as an approximation. Further information on the Norwegian system as well as other alternative royalty/natural resource taxation systems can be found in "Revenue from Non-Renewable Resources" The Pembina Institute, June 30, 2006.

Graph 8: Comparison of Norwegian and Canadian Royalty System – Anchor Fields Only



3.3 GLJ Base Case – All Fields

In its EIS submissions, Imperial Oil et. al. assumes responsibility for the development of the three aforementioned Anchor Fields, but does not regard the development of any other potential fields as part of its proposal. Consequently, costing data (capital investment costs, operating costs, etc.) are generally not provided and it was necessary to estimate these costs.

While the information provided by Imperial Oil to the NEB hearings provided little specific investment cost data for the additional fields, it does indicate the number and timing of wells it expects would be required to bring this production into operation and the number of kilometres of connecting pipeline that would be needed to link the producing wells to the Gathering System.[36] As well, several studies have estimated the expected drilling costs per well in the different areas.[37] As a proxy for expected investment costs, drilling costs are based on expected well requirements (producing and dry) multiplied by per well drilling costs and the connecting costs are based on the connecting costs per kilometre that the Anchor Fields have (see Section 2.0 for additional detail on how these costs were estimated). In contrast, the GLJ report commissioned by Imperial Oil estimated a production Base Case for all economically viable fields in the Mackenzie Valley. These production data are used to assess the "All Fields" production base case.

3.3.1 Assumptions

Graph 9 displays the expected production over time from the four main plays[38] as determined in the GLJ Study. The Anchor Fields profile is the same as in the previous analysis for Anchor Fields Only base case.

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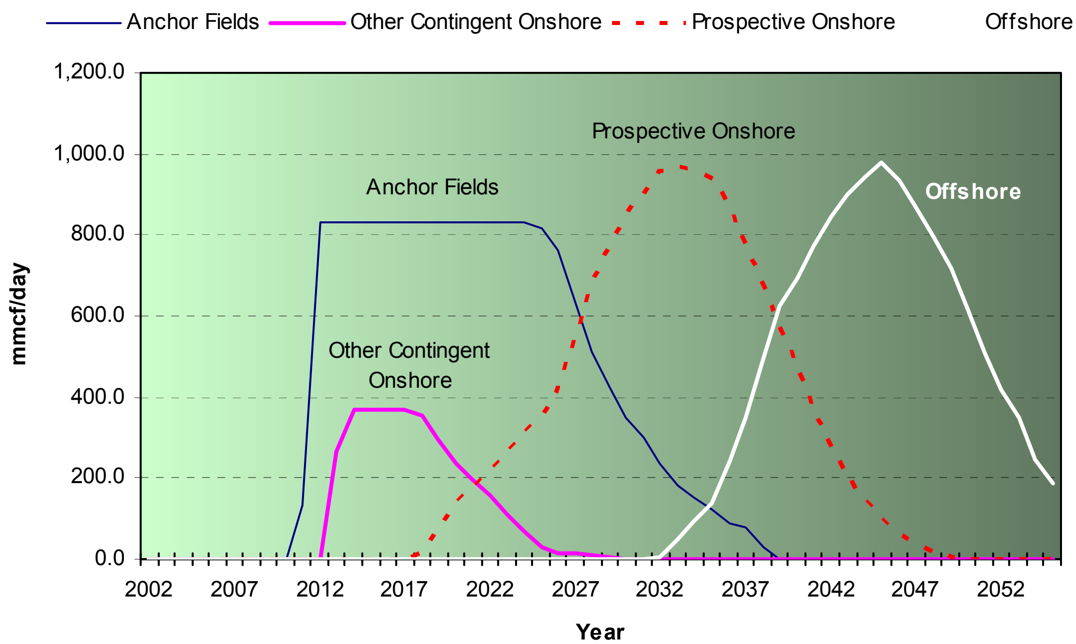
[36] Mackenzie Gas Project EIS Additional Information for the Joint Review Panel, Cumulative Effects – Foreseeable Land Use, Section 11.1 March 2005.

[37] Ibid.

[38] The GLJ Study provides detailed production forecasts for a large number of different fields. For the purposes of this report, these fields have been aggregated into general "plays", although the individual field results are generated in the Model.

Graph 9: GLJ Base Case Production – All Fields



3.3.2 GLJ Base Case Results

Based on these investment assumptions, Graph 10 on the following page displays the rate and profile of net cash flows accruing to each major play. Each play sees an initial negative cash flow as investment is required before production can take place. Once that initial investment period is over, cash flows increase as production increases, tailing off as economically-viable reserves are exhausted.

Royalties are estimated using the same methodology described earlier (see page 13) and Graph 11 highlights the annual pattern of royalties payable by each of the plays.

Given the estimated profile of net cash flow and royalties, one can determine the Internal Rates of Return (IRR) for each play. These are computed in the Model as: Anchor Fields (42.1%[39]), Other Contingent Onshore (20.9%), Prospective Onshore (22.9%), and Offshore (23.0%) for an average Total Play IRR of 34.4%.[40]

Graph 12 highlights the calculated income taxes while Graph 13 highlights the profile of after-tax cash flows for each major play. The resulting after-tax IRR for each play is estimated at: Anchor Fields (34.8%), Contingent Onshore (16.1%), Prospective Onshore (19.4%) and Offshore (19.2%), for an annual average All Fields IRR of 27.5%. If one accepts the argument that sunk costs should be included when assessing the viability of a future investment, then the after-tax IRR for the Anchor Fields decreases to 27.7%, and the annual average All Fields IRR decreases to 24.2%.

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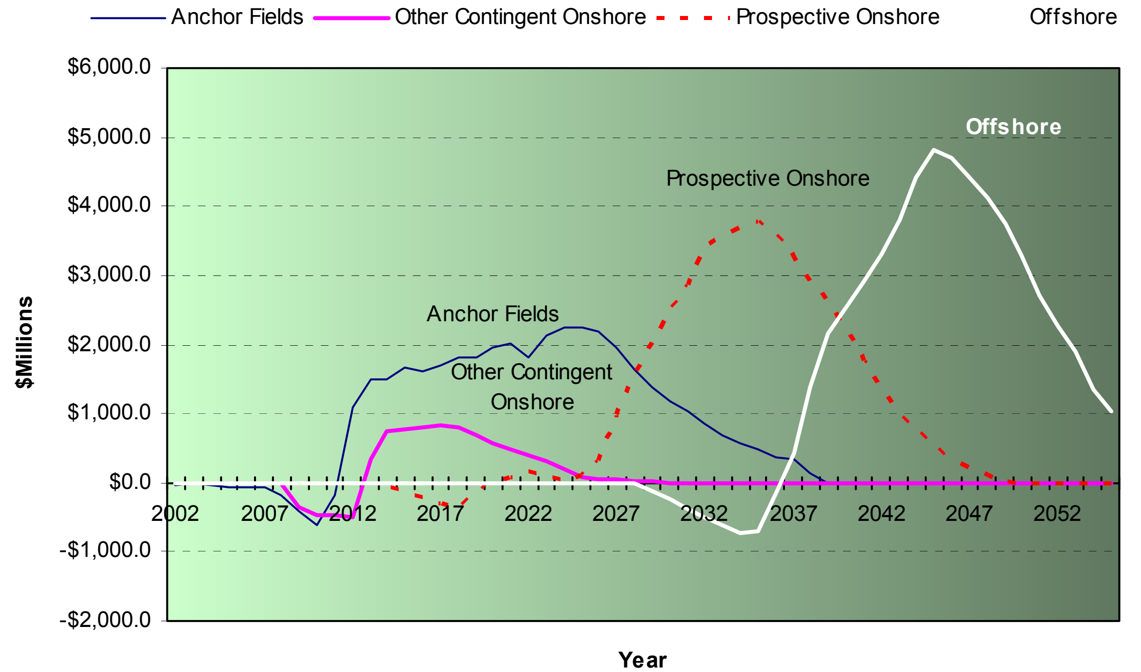
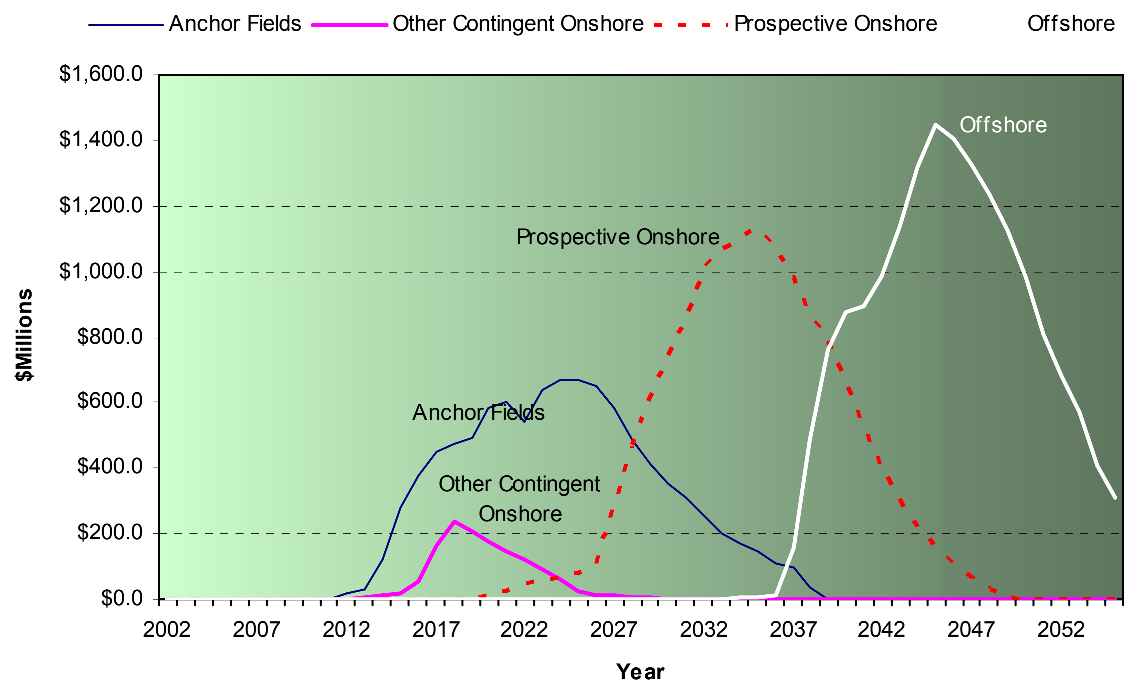
[39] The reader may question why the Anchor Field IRR is slightly higher for the GLJ Base Case than what was reported in the Anchor Field Only section of this report (see page 9). The answer is that with additional natural gas production, the flow through the various Gathering System lines and the MV Pipeline itself is larger, thereby reducing the average per mcf tolls for all production, including production from the Anchor Fields.

[40] If sunk costs are included, the calculated IRR for the Anchor Fields decreases to 32.9%and the All Fields IRR decreases to 29.7%. Note that the IRRs for the other plays do not change since there are no sunk investment costs.

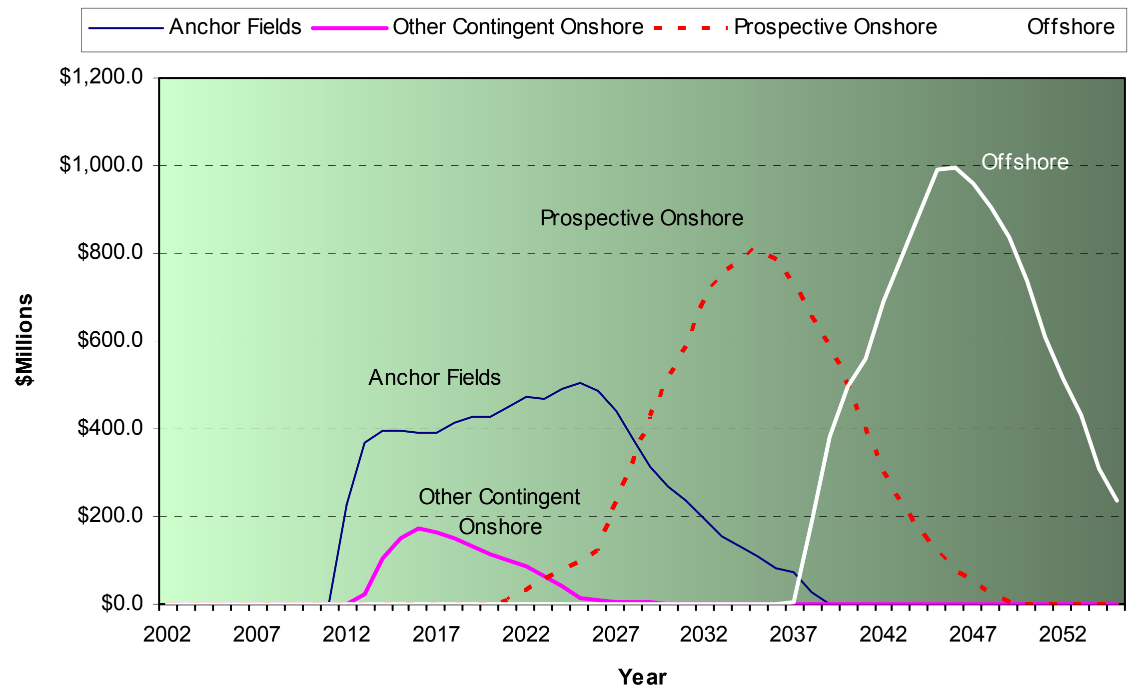
Graph 10: GLJ Base Case Net Cash Flow



Graph 11: GLJ Base Case Royalties



Graph 12: GLJ Base Case Income Taxes



Graph 13: GLJ Base Case After-Tax Cash Flow

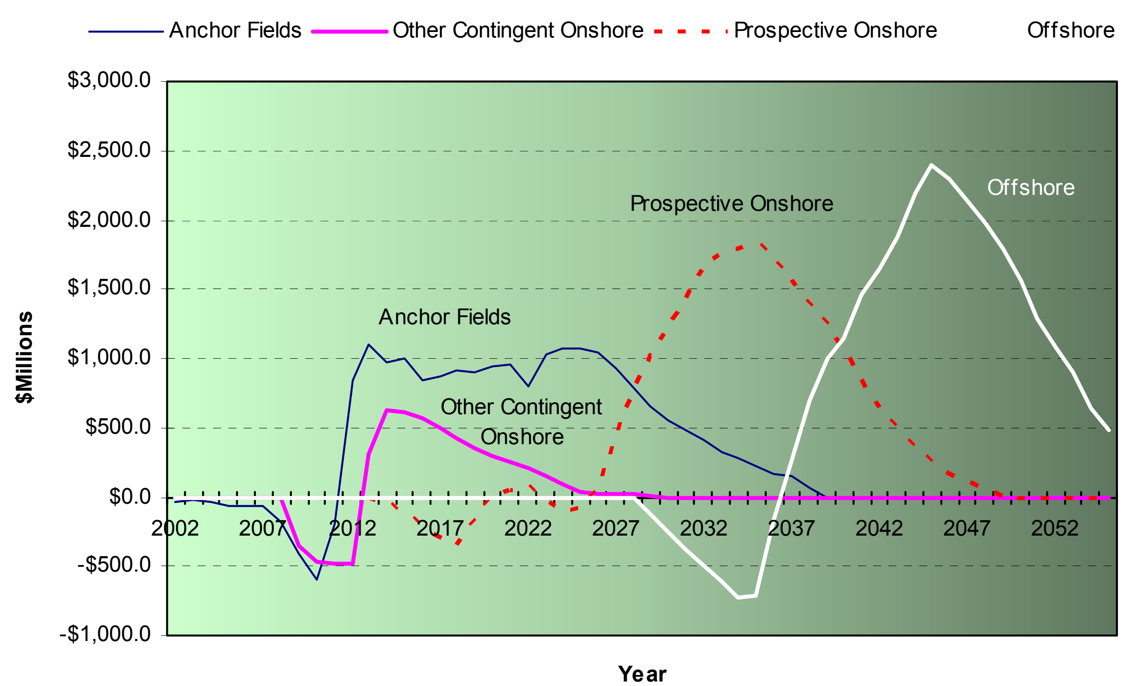


Table 2: Summary of All Fields Financial Results ($ Millions)

	Anchor Fields Only	Contingent Onshore	Prospective Onshore	Offshore	All Fields
Before Income-Tax CF	$26,582	$4,053	$30,845	$34,900	$96,380
Before Income-Tax IRR	**32.9%**	**20.9%**	**22.9%**	**23.0%**	**29.7%**
Before Income-Tax IRR*	**42.1%**	**20.9%**	**22.9%**	**23.0%**	**34.4%**
After-Tax CF	$17,861	$2,711	$20,663	$23,373	$64,609
After-Tax IRR	**27.7%**	**16.1%**	**19.4%**	**19.2%**	**24.2%**
After-Tax IRR*	**34.8%**	**16.1%**	**19.4%**	**19.2%**	**27.5%**
Federal Royalties	$9,764	$1,355	$13,850	$16,942	$41,911
Field Inc. Taxes	$8,721	$1,341	$10,182	$11,527	$31,771
- to Canada	*$5,550*	*$854*	*$6,479*	*$7,335*	$20,218
- to Alb & NWT	*$3,171*	*$488*	*$3,702*	*$4,192*	$11,553
Pipeline Inc. Taxes					$3,784
- to Canada					*$2,393*
- to NWT					*$1,391*
Avg. Annual Tax					$930
- to Canada ($2003)					*$769*
- to Alb & NWT ($2003)					*$160*

* Excludes "sunk" capital costs invested prior to 2006.

During the 45 years of operations (2011 to 2055), All Fields pay a total of $41.9 billion in royalties, and another $35.6 billion in income taxes (including the income taxes payable by the Gathering System and MV Pipeline itself). Of the income taxes payable, it is estimated that $22.6 billion will go to the Federal Government and the remaining $12.9 billion will accrue to the Governments of Alberta and the NWT.

In real terms ($2003) royalties paid over the entire 45 years will equal $22.0 billion and total income taxes (including income taxes paid by the Gathering System and the MV Pipeline) will equal $19.8 billion, of which $12.6 billion will go to the Government of Canada and $7.2 billion will accrue to the Governments of Alberta and the NWT. Peak annual taxation will reach $753.2 million in royalties (2039), $382.9 million in Government of Canada income taxes (2016) and $219.8 million (2016) in the Alberta and the NWT income taxes. Royalties paid will average $488.9 million annually while Government of Canada income taxes will average $280.2 million and income taxes to the Governments of Alberta and the NWT will average $160.5 million yearly in real ($2003) terms.

3.3.3 NEB Production Scenario

The GLJ Study included in its report the National Energy Board's estimate of production NEB_{P50} which describes production with a 50% probability that actual recoveries will equal or exceed the estimate. This production case was also run through the Model to determine the impacts. Effectively, there were no substantive differences between it and the GLJ Base Case (total IRR for the GLJ Base Case is 27.5% while the NEB_{P50} Case has a total IRR of 25.6%.

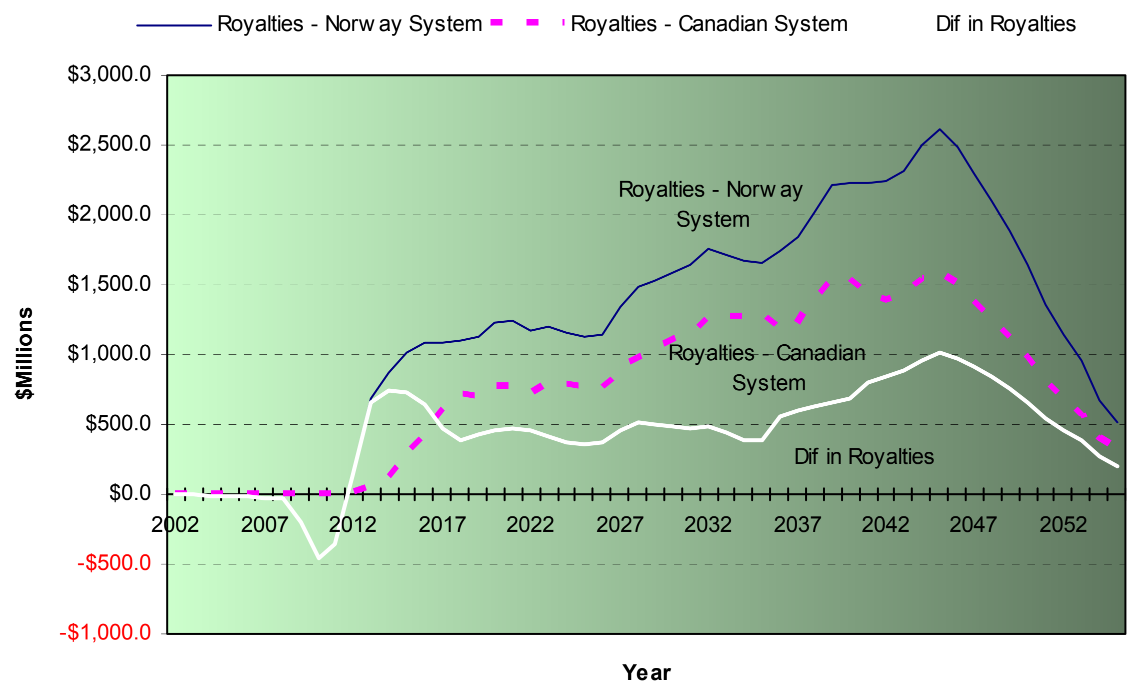
3.3.4 Alternate Royalty Systems

The Norwegian Gas Tax System provides significant incentive for development and during the initial production phase up to the point where an adequate return has been earned.[41] At that point, tax rates increase, but are still designed to ensure continuing adequate rates of return to business without enabling

[41] Further information on the Norwegian Gas Tax System is found in Appendix B as well as in the Pembina Institute publication Revenue from Non-Renewable Resources, June 30, 2006.

windfall profits to be earned. Adopting the Norwegian royalty system for collecting revenues from hydrocarbon development would result in an increase in royalties going to the Federal Government.

Graph 14: Comparison of Norwegian and Canadian Royalty System – GLJ Base Case



Graph 14 below highlights the patterns of royalty collection for both the Norwegian and Canadian systems. Overall, under the Norwegian system $65.6 billion in royalties would be collected while under the present Canadian system only $41.9 billion in royalties are expected to be collected. The Canadian Government[42] then would collect an additional $23.7 billion in royalties over the life of the pipeline if the Norwegian system were adopted. The impact on total IRR would be a drop from 27.5% to 25.2%, suggesting that an increase in royalty rates would not result in an unprofitable business venture.

3.4 Sensitivity Case #1 – 10% Increase in Gas and Condensate Prices

A question that often arises is: what would be the impact on the MGP if natural gas and condensate prices are radically different from what the prices that are now projected? It should be noted that many different price scenarios could be tested using the Model framework; however, we choose one scenario in order to examine the general impacts of a price change. While the impacts are not strictly linear to a change in price, that is, prices being 20% higher than base case prices each year will not result in impacts on cash flows and taxes exactly twice that a 10% increase in prices would create (due to non-linearity of royalty payments). However, the general direction and magnitude will be the same.

3.4.1 *Assumptions*

Sensitivity Case #1 assumes that all other aspects of the Mackenzie Valley Project remain the same (e.g., production profiles, capital costs, toll rates, etc.) as in the GLJ Base Case with the exception that the prices of natural gas and condensate from 2011 onward are 10 percent higher than the GLJ Base Case

[42] As mentioned earlier, the NWT Government does not collect any royalties.

projections. The results ought to show an unequivocal increase in both cash flows to business and taxes to governments.

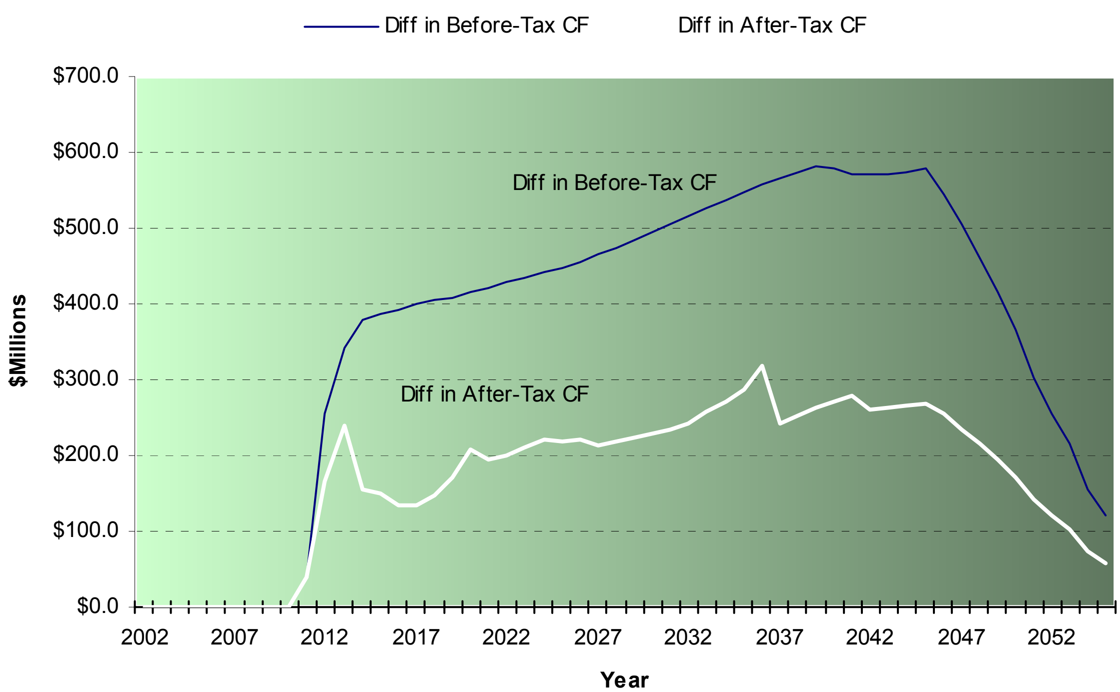
3.4.2 Sensitivity Case #1 Results

The increase in natural gas and condensate prices results in an immediate increase in cash flows. In total, net cash flows are some $157.8 billion, $19.7 billion higher when real prices increase by 10%. Under the same price changes, after-tax cash flows increase to $73.7 billion, some $9.2 billion higher than the GLJ Base Case. Graph 15 displays the impacts on cash flows of this increase in natural gas and condensate prices.

Graph 16 also on the following page shows the differences in taxation due to this 10% price increase. Both royalties and income taxes are larger ($47.8 billion and $36.3 billion respectively), although the profiles are not smooth. This is particularly true for royalties, where taxation is largely driven by a changing "payout" period.

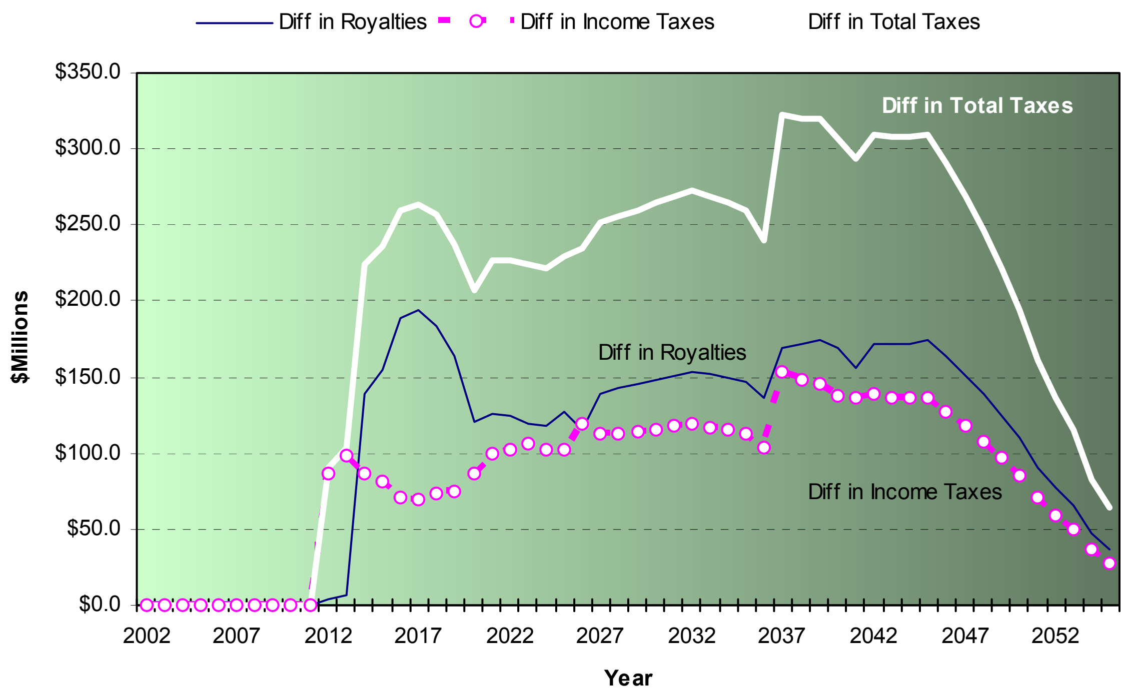
A 10% increase in natural gas and condensate prices results in a 14.3% increase in after-tax return to business and a 14.2% increase in total returns to government.[43] With regards to Internal Rates of Return (IRR), the 10% increase in prices results in an increase in the after-tax IRR for All Fields from 27.5% (24.2% with sunk costs) to 30.6% (26.6% with sunk costs). That is, in approximate terms, every 10% increase in real prices will result in a 2% - 3% increase in the after-tax IRR for All Fields.

Graph 15: Difference in Cash Flows with Gas/Condensate Price Increase of 10%



[43] Note that the percentage increases in after-tax returns (14.2%) and government revenues (14.3%) are higher than the real dollar increase in natural gas and condensate prices (10%). This is because both the after-tax returns and government revenue increases are in nominal terms and include the effects of inflation.

Graph 16: Difference in Taxes with Gas/Condensate Real Price Increase of 10%



3.5 Sensitivity Case #2 – 30% Increase in Capital Costs

Imperial Oil has suggested that, because of the dramatic increase in construction activity in western Canada which has led to a shortage in supply of skilled workers (thereby increasing wage demands) and the very large increases in structural material prices (e.g. steel) due to demand from Asia, the capital costs for the MV Pipeline, Gathering Systems and Anchor Fields are likely under-estimated and could be as much as 30 percent higher. They claim that these increasing costs put the whole project into jeopardy and that there may be a need for a royalty holiday to make the Project economic. Sensitivity Case #2 addresses this question.

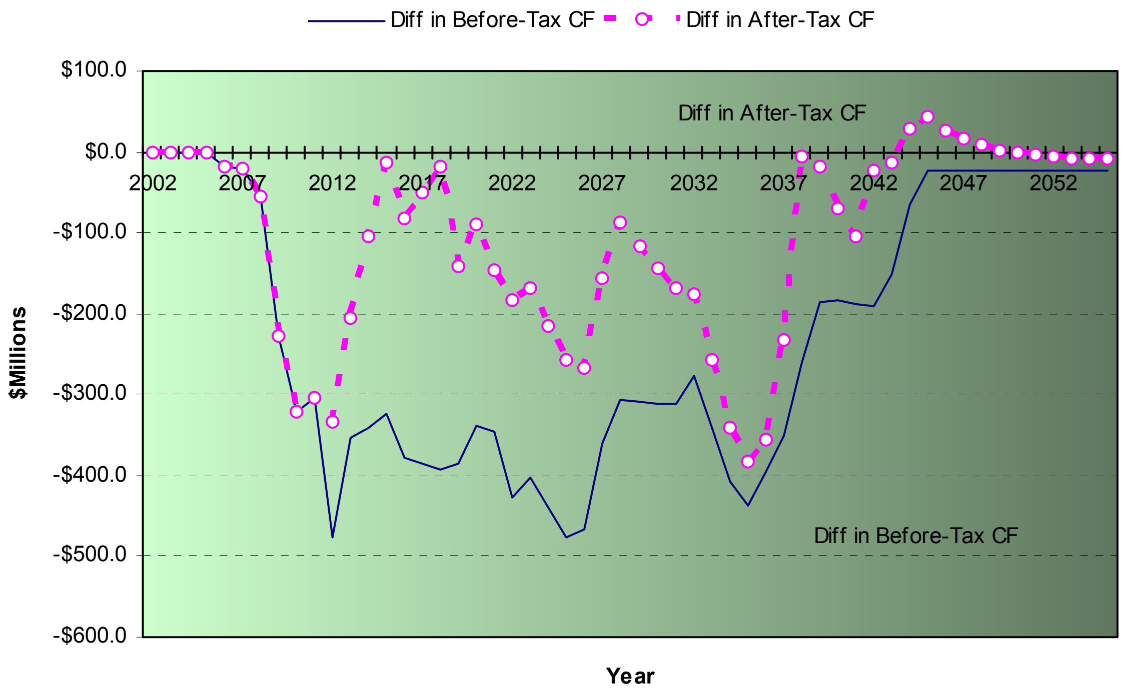
3.5.1 Assumptions

Sensitivity Case #2 assumes that all other aspects of the Mackenzie Valley Project remain the same (e.g., production profiles, gas prices, toll rates etc.) as in the GLJ Base Case with the exception that all investment costs in each year from 2006 onward for all components of the project (Pipeline, Gathering Systems and Fields) are increased by 30 percent. Operating costs are not adjusted.

3.5.2 Sensitivity Case #2 Results

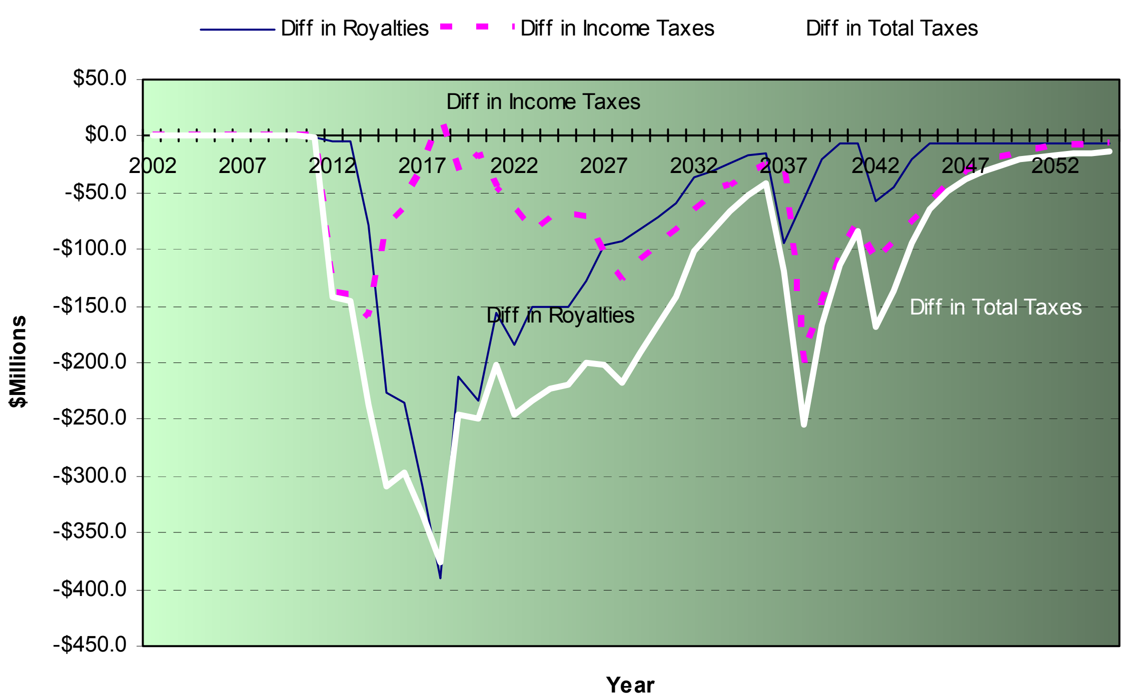
As highlighted in Graph 17, an increase in capital costs will have a number of impacts. First, the investment costs of drilling (both producing and dry wells) and linking up the producing wells to the Gathering System will increase, and this will reduce net cash flow for each field. Second, the increased costs of building the Gathering System and the MV Pipeline itself will result in a higher required cost of service and consequently in higher tolls per mcf. The consequence is that both net and after-tax cash flows are reduced significantly.

Graph 17: Difference in Cash Flows with Capital Cost Increase of 30%



As shown in Graph 18, increased capital costs reduce royalty and income tax payments which is why after-tax cash flows are not affected as much as net cash flows.

Graph 18: Difference in Taxes with Capital Cost Increase of 30%



In approximate terms, a 30% increase in capital costs results in a 9.0% decrease in after-tax return to business and an 8.6% decrease in total returns to government. With regards to Internal Rates of Return (IRR), the 30% increase in capital costs results in a decrease in the IRR for All Fields from 27.5% (24.2% with sunk costs) to 20.4% (18.8% with sunk costs). That is, in approximate terms, a 30% increase in capital costs will result in a 5% - 7% decrease in the IRR for All Fields.

3.6 Results Conclusion

Table 3 below summarises the financial results for the four scenarios estimated with the Model. Notice that the after-tax IRR for the Gathering System plus MV Pipeline remains virtually constant over the four scenarios. This is a direct reflection of the fact that both the Gathering System components and the MV Pipeline function as regulated utilities earning prescribed rates of return.

Table 3: Summary of All Financial Results

	Base Case Anchor Only	Base Case GLJ	Sensitivity Case #1 Prices	Sensitivity Case #2 Capital Costs
GS + MV Pipeline				
After-Tax CF	$7,964	$9,251	$9,251	$11,689
After-Tax IRR	**8.3%**	**8.4%**	**8.4%**	**8.4%**
After-Tax IRR*	**9.6%**	**9.7%**	**9.7%**	**9.4%**
Income Taxes	$3,648	$3,784	$3,784	$4,787
- to Canada	*$2,307*	*$2,393*	*$2,393*	*$3,027*
- to NWT	*$1,341*	*$1,391*	*$1,391*	*$1,760*
Fields				
Before Income-Tax CF	$21,739	$96,380	$110,169	$87,730
Before Income-Tax IRR	**30.6%**	**29.7%**	**32.4%**	**23.3%**
Before Income-Tax IRR*	**38.9%**	**34.4%**	**38.2%**	**25.5%**
After-Tax CF	$14,597	$64,609	$73,848	$58,807
After-Tax IRR	**25.7%**	**24.2%**	**26.6%**	**18.8%**
After-Tax IRR*	**32.0%**	**27.5%**	**30.6%**	**20.4%**
Federal Royalties	$7,528	$41,911	$47,796	$38,386
Field Inc. Taxes	$7,142	$31,771	$36,321	$28,923
- to Canada	*$4,545*	*$20,218*	*$23,113*	*$18,406*
- to Alb & NWT	*$2,597*	*$11,553*	*$13,208*	*$10,517*
Avg. Annual Tax	**$328**	**$930**	**$1,059**	**$855**
- to Canada ($2003)	*$256*	*$769*	*$878*	*$702*
- to Alb & NWT ($2003)	*$72*	*$160*	*$181*	*$152*

* Internal Rates of Return (IRRs) calculated excluding "sunk" investment costs. "Sunk" investment costs are defined as "unrecoverable past expenditures … [which] should not normally be taken into account when determining whether to continue a project or abandon it, because they cannot be recovered either way." See footnote 32.

Base Case Anchor Only: assumes only the three Anchor Fields (Niglintgak, Taglu and Parsons Lake) are brought on stream during the life of the MV Pipeline. After-tax cash flows to field producers are estimated at $14.6 billion over the 27 year life of the Anchor Fields Only, earning an annual Internal Rate of Return of 32.0% (25.7% if sunk investment costs are included – see footnote 32 for an explanation of "sunk costs"). These are relatively high IRRs, particularly since Anchor Field production is moderately low risk.[44]

[44] Risk-free returns are roughly equal to the long-term bond rate (before income tax rate of 4.5%). Low risk returns (for, say, regulated natural gas pipelines) are in the range of 10%-12%. The Alaska Gas Pipeline has an assumed a pre-income tax IRR of 17.8% based on natural gas prices of $5.50/mcf (see http://www.gov.state.ak.us/gasline/faq.php). When questioned about possible

Total taxes (royalties, field income taxes and pipeline income taxes[45]) accruing to Governments reach $18.3 billion over the 27 years of operation, of which $14.4 billion would go to the Federal Government and the remaining $3.9 billion to the Governments of Alberta and the NWT. In real dollar terms ($2003), the Federal Government would receive on average $256 million per annum and the Governments of Alberta and the NWT $72 million per year.[46]

Base Case GLJ: this is the full production Base Case as identified in the Gilbert Laustsen and Jung Associates Ltd. Study (GLJ Study) prepared for Imperial Oil in 2004. After-tax cash flows to field producers in this case are estimated at $64.6 billion over the 45 year life of the Pipeline life, earning an annual after-tax Internal Rate of Return of 27.5% (24.2% if sunk investment costs are included).

Total taxes (royalties, field income taxes and pipeline income taxes) accruing to Governments reach $77.5 billion over the 45 years of operation, of which $64.5 billion would go to the Federal Government and the remaining $12.9 billion to the Governments of Alberta and the NWT. In real dollar terms ($2003), the Federal Government would receive on average $769 million per annum and the Governments of Alberta and the NWT $160 million per year.

Price Increase of 10%: this scenario assumes the GLJ Base Case with a 10% increase in real dollar gas and condensate prices for each year over the 45 year period. After-tax cash flows to field producers with this price increase are estimated at $73.8 billion over the 45 year life of the Pipeline life, earning an annual Internal Rate of Return of 30.6% (26.6% if sunk investment costs are included). This suggests that for every 10% increase in natural gas and condensate real prices, Internal Rates of Return increase by 2% to 3%.

Total taxes (royalties, field income taxes and pipeline income taxes) accruing to Governments reach $87.9 billion over the 45 years of operation, of which $73.3 billion would go to the Federal Government and the remaining $14.6 billion to the Governments of Alberta and the NWT. In real dollar terms ($2003), the Federal Government would receive on average $878 million per annum and the Governments of Alberta and the NWT $181 million per year.

Capital Cost Increase of 30%: this scenario assumes the GLJ Base Case except that capital investment costs each year are increased by 30%. After-tax cash flows to field producers with this price increase are estimated at $58.8 billion over the 45 year life of the Pipeline life, earning an annual Internal Rate of Return of 20.4% (18.8% if sunk investment costs are include). This suggests that for every 30% increase in capital construction costs, Internal Rates of Return decrease by 5% to 7%.

Total taxes (royalties, field income taxes and pipeline income taxes) accruing to Governments reach $72.1 billion over the 45 years of operation, of which $59.8 billion would go to the Federal Government and the remaining $12.3 billion to the Governments of Alberta and the NWT. In real dollar terms ($2003), the Federal Government would receive on average $702 million per annum and the Governments of Alberta and the NWT $152 million per year.

30% returns, Imperial Oil itself indicated that is "certainly not our expectation." Hearing Order GH-1-2004 – MGP VOLUME 21 - July 31 2006.

[45] The estimate of Pipeline taxes assumes that the Aboriginal Pipeline Group (APG) as proposed part owners of the MV Pipeline pay equivalent income taxes as other owners and that these taxes are filed with and accrue to the federal and NWT governments.

[46] These shares of taxes assumes that the Federal Government does not take back monies from its present contributions to the GNWT and further, that there are no negotiated agreements to transfer a part of royalties to the Government of NWT.

4.0 ECONOMIC IMPACTS

The financial results highlighted in Section 3.0 provide important information regarding the fiscal performance of the MV Pipeline, the Gathering System, and the Field Producers including estimates of the contributions to Government revenues over the life of the Pipeline. The financial results, however, do not provide any information on the economic contribution of the MGP to the economy as a whole, in terms of impacts on GDP, Labour Income, Other Taxes (besides Royalties and Corporate Income Taxes) and Employment.

This economic contribution partially stems from activity directly generated by the MGP (i.e., the activity of constructing the Pipeline and Gathering System and the exploration, drilling and developing of the various gas fields, as well as the annual operations of all of these components). In addition to this "direct" contribution or impact on the economy, there are other impacts associated with the purchase of goods and services used to build and operate the various components of the MGP. When, for example, steel pipe is required by the construction company that is building the pipeline, the steel pipe manufacturer itself (if located in Canada) will generate additional economic activity in the economy when it produces the pipe. As well, companies transporting the pipe will increase their business. At the same time, the pipe manufacturer will require its own inputs for producing the pipe (e.g., iron ore or raw steel, electricity, chemicals, etc.). This purchase of say, additional chemicals or materials will increase the economic activity of chemical purchasers who, in turn, have their own requirements for inputs. This chain of new demand stemming from the purchases of goods and services relating to the original direct activity of building and operating the MV Pipeline is called the "indirect" impacts. Beyond that, all of the increased employment stemming from the MV Pipeline and the chain of suppliers of goods and services results in higher wages and salaries, part of which (after deducting personal income taxes and any savings) will be spent on consumer goods and services. This consumer spending will translate into more activity throughout the economy and is known as the "induced" impacts.

Net Domestic Product is a measure of the economic activity occurring in an economy. The direct impact on an economy's GDP from a construction project is defined as the value of the investment minus any imports used in the construction. For the Canadian economy as a whole, the level of imports will be relatively low, resulting in a fairly close relationship between investment and GDP. For the NWT, however, almost all material will be imported from outside the NWT, and therefore one would expect a much lower direct GDP contribution to its regional economy. On the production side, direct GDP is defined as revenues minus all material inputs, whether imported or not, minus some minor taxes.[47] Since the material inputs required to bring the gas to markets are rather small, the production GDP should be relatively close to revenues and further, most of the GDP should be assigned to the NWT.

The indirect impacts of both the construction and production phases, being the result of purchased goods and services most of which are imported, will mostly be assigned to regions other than NWT. Similarly, induced impacts being highly linked to imported consumer goods and services, will mostly be impacting areas outside the NWT. The estimation of the direct, indirect and induced impacts of the MGP is the focus of this section of the Report.

[47] See Appendix C for a discussion of how GDP is calculated as well as for a more comprehensive explanation of direct, indirect and induced impacts.

4.1 INPUT-OUTPUT MODEL

Ordinarily, the prescribed method for determining the direct, indirect and induced impacts of a project is to use the Inter-Provincial Input-Output Model developed by Statistics Canada. The Inter-Provincial I/O tracks the flow of commodities and primary inputs between and among industries and between regions and thus enables one to determine with reasonable accuracy the direct, indirect and induced impacts of an investment such as the building of the MGP[48] However, budgetary limitations precluded the direct use of the Statistics Canada Model (which requires detailed knowledge of investment and operating commodity requirements as well as details regarding import expectations[49]).

In its place it was decided to use the unit (per dollar) impact information contained in the updated Wright Mansell (WR) report[50] and adapt those unit results to the construction and operating data used in this Report. Using the WR results has the advantage of basing our conclusions on detailed commodity use and import information;[51] it has a disadvantage that the specific structure of MGP used here has changed somewhat from when WR did their report (2004) and therefore it may not represent exactly the expected impacts of the present MGP. Nevertheless, the unit differences (i.e., the impacts per dollar of investment or per dollar of operating costs) are likely to be very small and therefore the impacts calculated here should be considered as a very close approximation to actual values.

4.2 ECONOMIC RESULTS

The use of the WR data requires a slight change in definition from that used in Section 3.0. This is because WR combined the Field activities with the Gathering System activities, excluding the Liquids Line, into one component called FIELDS. Into a second component, called PIPELINE, they combined the activities of the Liquids Line and MV Pipeline itself. For each of the two components, they identify two activities, "Development" (which includes the building of the infrastructure and exploration/development costs) and "Operations" (which includes both the operations of the gas fields and the operations of the Gathering System and Pipelines).

The WR data allow for the determination of four different impacts (direct plus indirect combined; direct and indirect were not calculated separately by WR) for all of Canada and for the NWT by itself. These impacts are: GDP (Net Domestic Product), Labour Income, Taxes, and Employment. Taxes are further subdivided into Federal Taxes and Provincial/Territorial Taxes.

Table 4 on the following page highlights the summation of impacts over the life of the MGP ending in 2055 based on the GLJ Base Case. All values are in constant 2003 dollars.

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48 One says "reasonable" because the I/O Model is a static representation of the economy at a point in time (in this case, the year 2000) which may not exactly match the economy today. Nevertheless, the basic input-output structure of an economy does not change radically over a few years and therefore most economists accept the results of input-output analysis as closely representing expected outcomes.

49 In determining the impacts of a project, the level of imports of each commodity (its "import coefficient") is of extreme importance since imports do not add to the domestic economy. The Statistics Canada Model contains average import coefficients by commodity, but for a large project like the MGP with its technically demanding requirements, these import coefficients could be radically different. Thus a proper input-output analysis requires more accurate import coefficients.

50 "*An Evaluation of the Economic Impacts Associated with the Mackenzie Valley Gas Pipeline and Mackenzie Delta Gas Development*", prepared for GNWT and TransCanada Pipelines, prepared by Wright Mansell Research, August 2004.

51 No attempt was made to examine the accuracy of the commodity structure or import coefficients used in the Wright Mansell report (2004).

Table 4: Direct plus Indirect Impacts of GJL Base Case ($2003 Billions)

	FIELDS		PIPELINE		FIELDS + PIPELINE	
	Develop	Oper	Develop	Oper	Total	Ann. Avg.
All Canada Impacts						
GDP	$10.5	$90.6	$2.5	$11.7	**$115.3**	**$2.56**
Labour Income	$6.1	$2.8	$1.8	$0.8	**$11.5**	**$0.26**
Royalties	$0.0	$41.9	$0.0	$0.0	**$41.9**	**$0.93**
Corporate Income Taxes*	$0.0	$20.9	$0.0	$1.7	**$22.6**	**$0.50**
Other Fed Rev.**	$1.8	$0.8	$0.4	$0.2	**$3.2**	**$0.07**
Other Prov/Terr. Rev.**	$0.8	$0.4	$0.2	$0.1	**$1.6**	**$0.04**
Employment (PY)	111,171	50,607	28,724	18,460	**208,962**	**4,644**
NWT Impacts						
GDP	$3.8	$86.8	$0.9	$10.5	**$102.0**	**$2.27**
Labour Income	$1.8	$1.1	$0.7	$0.3	**$3.9**	**$0.09**
Royalties	$0.0	$0.0	$0.0	$0.0	**$0.0**	**$0.00**
Corporate Income Taxes*	$0.0	$11.9	$0.0	$1.0	**$12.9**	**$0.29**
Other Fed Rev.**	$0.7	$0.1	$0.1	$0.0	**$0.9**	**$0.02**
Other NWT Rev.**	$0.2	$0.0	$0.1	$0.0	**$0.3**	**$0.01**
Employment (PY)	26,047	16,700	7,934	7,977	**58,659**	**1,304**
*NWT Resident LI****	*$0.58*	*$1.08*	*$0.14*	*$0.34*	***$2.14***	***$0.05***
*NWT Resident Emp.****	*8,577*	*16,700*	*1,482*	*7,977*	***34,737***	***772***

*Excludes indirect corporate taxes (i.e., corporate taxes paid by suppliers of goods and services).

** Includes taxes such as property taxes, import duties and excise taxes, but excludes both direct and indirect personal income taxes as well as payroll taxes paid by workers and businesses.

*** NWT Resident Labour Income and Employment assumes non-residents take up a proportion of Development labour demand in the NWT; it is assumed that NWT residents can fulfil all labour demanded by Operations.

Over the entire period of activity, the direct and indirect impacts of building and operating the MV Pipeline is expected to increase GDP in Canada by $115.3 billion, with the NWT receiving the bulk of that increase ($102.0 billion). Of the $11.5 billion in Labour Income earned throughout Canada (208,962 person-years of work), approximately $3.9 billion (58,659 person-years of work) will be earned within the NWT. However, it is expected that a large number of employees working in the NWT will reside elsewhere. Based on data contained in the WR report,[52] the expected employment and payroll of NWT residents are estimated at 34,737 person-years and $2.14 billion respectively.

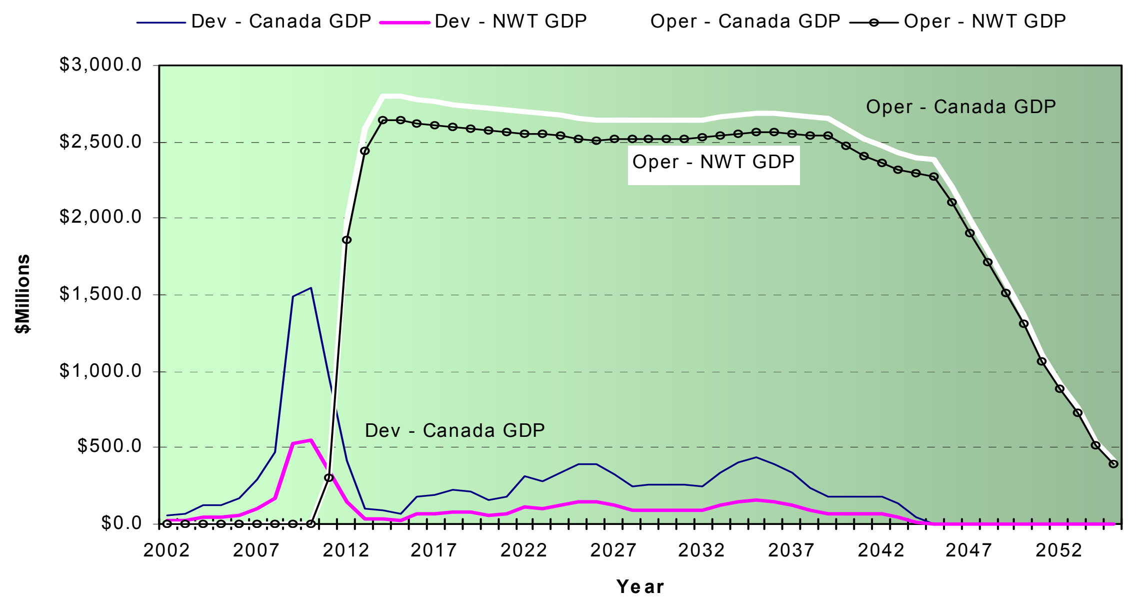
In addition to Royalties and Corporate Income Taxes (estimated in Section 3.0), the MGP is expected to contribute $3.2 billion to the Federal Government and another $1.6 billion to various provincial, territorial and local governments. Of the latter, the Government of the NWT (and local authorities) are expected to receive $0.3 billion over the life of the Pipeline.

Graph 19 on the following page highlights the time profile of estimated GDP impacts for Canada and NWT for Development (Fields and Pipeline combined) and Operations (Fields and Pipeline combined). Peak Development impacts occur in 2010, generating $1.5 billion in GDP in Canada, of which $552.8 million takes place in NWT. Peak Operations impacts occur in 2014, generating $2.8 billion in GDP within Canada. In this case, almost all of the impacts ($2.6 billion) fall within the NWT. To provide some context, this GDP impact in 2014 would represent an increase of about 64% in the present economy of the NWT.[53]

[52] No attempt was made to verify the estimates of resident vs non-resident earnings provided in the WR report.

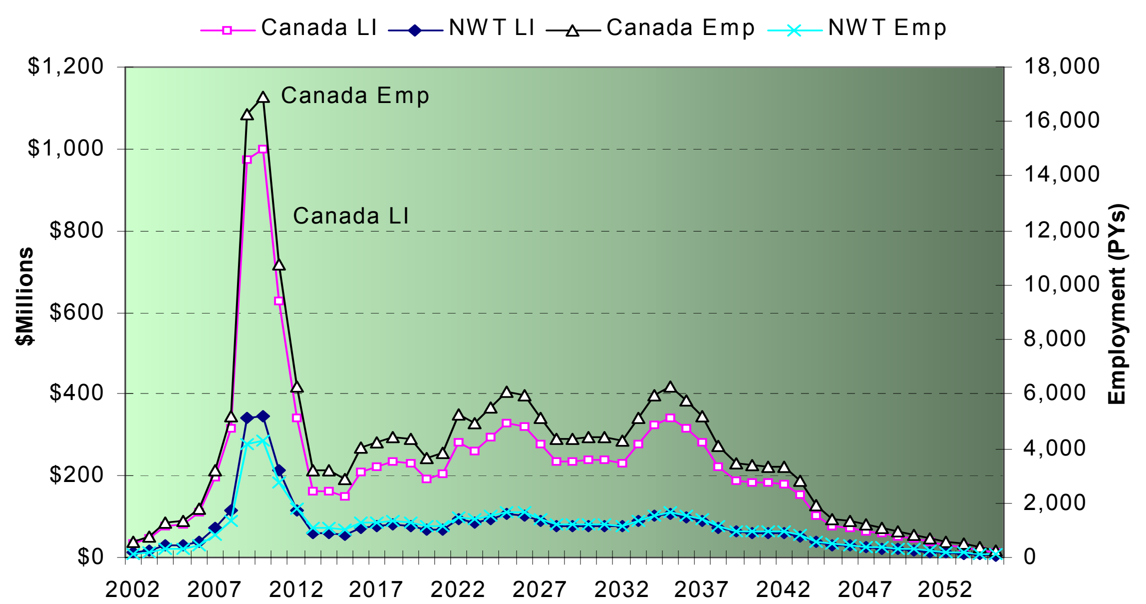
[53] It must be recognized that this increase in GDP is mostly due to Royalties (which go to the Federal Government) and to Operating Surplus, itself made up of depreciation, interest payments and profits to the operating companies, most of which are likely to be repatriated to regions outside the NWT. Thus, the increase in GDP provides virtually no benefit to the people of the NWT.

Graph 19: GDP Impacts (Direct plus Indirect) of GLJ Base Case



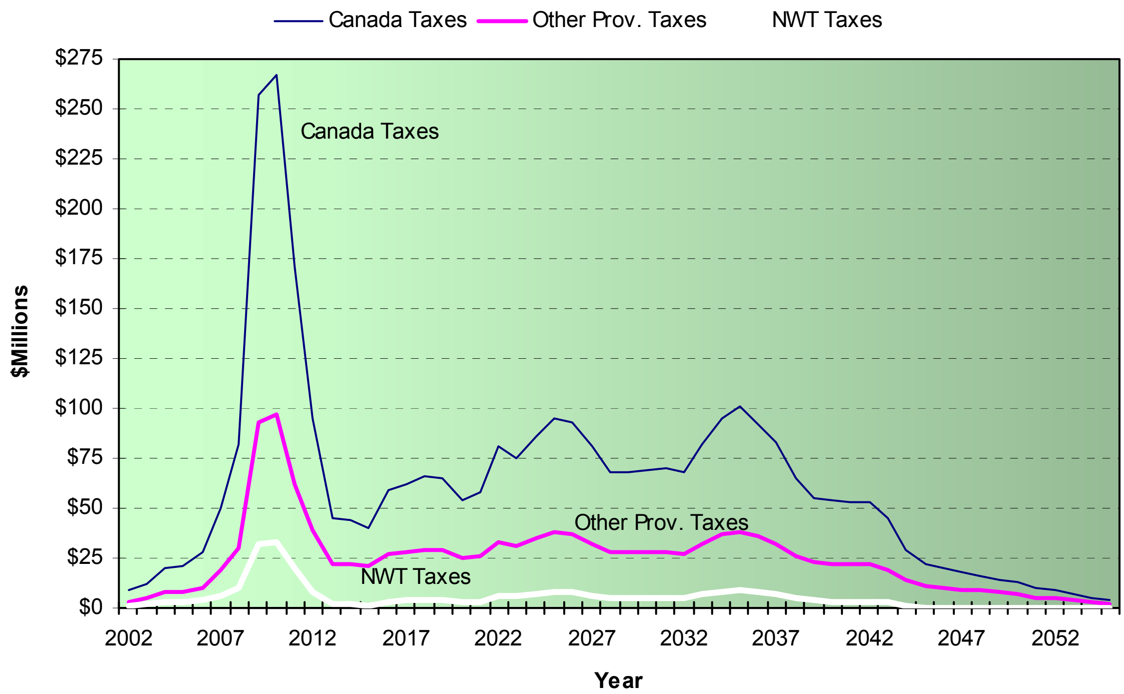
Although the GDP impacts are substantial, particularly for the Operations component, this increase in GDP is not reflected as greatly in Labour Income and Employment. Graph 20 displays the time profile of direct plus indirect Labour Income earnings and in Employment in all of Canada and within the NWT. Not surprisingly, Labour Income and Employment peak during the major construction years 2009 to 2011 with most of the income/employment accruing to individuals outside the NWT.

Graph 20: Labour Income and Employment Impacts (Direct plus Indirect) of GLJ Base Case



Graph 21 displays the equivalent time profile of tax impacts (excluding royalties and corporate income taxes). Again, peak taxation occurs during major construction activity.

Graph 21: Tax Impacts (Direct plus Indirect) of GLJ Base Case



The estimate of economic impacts has been limited to the direct and indirect impacts excluding any induced impacts (economic activity generated through increased wages and salaries used for the purchase of consumer goods and services). According to the WR report, induced GDP in the NWT is equal to between 20% and 30% of direct plus indirect Labour Income and induced Employment is equal to 13 PY per million dollars of induced GDP. Accepting these figures suggests that total induced GDP in the NWT over the entire period would be between $0.4 billion and $0.6 billion and that the total induced Employment (PYs) generated would be between 5,600 and 8,300 over the 50 years of the Project. The PYs, as stated previously, would peak around major construction activities but during MGP operations the induced PYs on average would be about 100 - 150 per year

APPENDIX A: MODEL DESCRIPTION

This Appendix is provided to assist those who wish to use the Model and also sets out assumptions used in creating the Model and input data.

The "Financials" worksheet commences with a select button enabling the user to choose one of a number of Production scenarios (GLJ Anchor Only production; GLJ Base Case production; NEB 50% Probability production; NEB High Capacity production; and Sproule Base Case production). By choosing a scenario (click on cell A9 and a dropdown list button will appear), all the appropriate data (natural gas production and condensate production) are automatically fed in from the "Forecasts" worksheet. The three select buttons (cells A11, A13 and A15) allow the user to override the three Anchor Fields' production with different production scenarios.

The annual number of wells for each play is included as a variable and can be changed by clicking the select button in the appropriate row (e.g., row A31). The annual profile of drilling is assumed to begin five years before first production with the actual number of wells drilled each year based on the change in the rate of production leading to the maximum production level.

Scrolling downward, the reader will notice small **+** and/or **-** icons in the left margin. Clicking these will hide (+) or expand (-) the rows, where the expanded rows reveal production (and other) details that are important for the calculation of correct results but that are not necessary for the user to see at all times. Note that equivalent **+** and/or **–** icons are seen at the top margin, enabling the user to hide or reveal the years 2002 to 2010. Also note that a number of cells have comments attached which provide additional information about the calculations.

Scroll downward to row 104 to the section where Total Net Revenues are calculated. Total Net Revenues depend on Production multiplied by the price received (Alberta AECO – C Spot). The user has a choice of different price forecasts to use (for both natural gas and for condensate) and these can be selected from the select buttons to the left of the price forecasts (cells A105 and A107).

Scrolling down to row 189 will bring the reader to the Expenditure section of the Model. As with Production, the user can choose what Expenditure profile to use (the alternatives are contained in the Worksheet "Expenditures") by clicking the select button in cell A189. There has been a concern that since Imperial Oil prepared the expenditure forecasts costs have increased. Accordingly, the user can choose to increase all of the expenditure values by a set "Inflation" value using the select button in row A191.

Imperial Oil only prepared development costs and operating cost forecasts for the three anchor wells, the related Gathering System and for the Pipeline itself. As a result, it was necessary to prepare estimates of development and operating costs for the remaining fields.

Development costs for the various plays are a function of two factors: the cost of seismic and drilling activity for all the exploration wells (both dry and producing wells); and the cost of linking the producing wells by small interconnects to the already-established Gathering System.

1. The annual number of wells for each play (taken from Revenue section above) is multiplied by the average cost per well (base case taken from the GLJ Report) highlighted in the select box (e.g., A247 for Other Mac Delta Wells).
2. The pipeline linking costs are based on the length of pipeline required to link up to the Gathering System (taken from the March 2005 Additional Information Report submitted by Imperial Oil)

multiplied by an average pipeline cost per km (e.g., select box A248). The pipeline put in place varies year-to-year depending on when the various fields are forecast to come on stream.

In addition to estimating development costs for each play, it also was necessary to estimate annual operating costs. An examination of operating costs for the Anchor Fields found that the ratio of operating costs to development costs were remarkably similar (a difference of less than 4% between the highest and lowest). As a consequence, the operating costs of the remaining plays were set at the same average ratio to construction costs as the Anchor Fields. The Anchor Field costs can be changed by selecting a different annual operating value (e.g., A206).

The development and operating costs for the various Gathering System components as well as the MV Pipeline itself are those provided by the proponent.

Scrolling down to line A363, the reader can see the beginning of the section estimating Transportation Tolls. As modelled, gas producers receive the Edmonton AECO – C Spot Price for each mcf of gas, pay annual operating costs, and pay a toll per mcf for each leg of the Gathering System, MV Pipeline and other pipelines that they use. The section on Transportation Tolls estimates the annual cost of service and the resulting per mcf toll for using each gathering system/pipeline leg.

Determining the transportation tolls is not a straightforward calculation because the transport systems are treated in essence as regulated utilities. Each Gathering System component is permitted to earn a set rate of return (equal to 18.8% before tax) and based on the resulting Cost of Service (equal to the rate of return plus the operating costs plus a capital cost depreciation value) and the flow of gas through the system, the owners of the gas and condensate pay a toll. The Cost of Service is entirely based on the capital and operating cost of the Gathering System. Since the amount of natural gas or condensate flowing through each Gathering System component does not influence directly the Cost of Service, the per-unit cost (e.g., the cost per mcf of natural gas) increases or decreases depending on the flow. If actual output proves to be higher (lower) than forecast, then the return to the producers of the gas will be disproportionately higher (lower) meaning that the risk facing producers is relatively high but the payoffs are also relatively high. In contrast, the risk to the pipeline owners is limited, since they receive a set cost of service.

The method for measuring the Cost of Service for the pipeline is similar to the method employed for the Gathering System components, except the rate of return is equal to 11.09% after tax and cost of debt and AFUDC[54] and income taxes are included in the calculations.[55]

The data for Cost of Service and for the resulting unit cost for each of the Gathering System components and for the MV Pipeline itself are displayed in Rows 365 to 507. Rows 508 to 511 highlight the assumed rate that producers will pay for transporting their natural gas and condensate from the end of the MV Pipeline at the Alberta border to Edmonton and condensate from Norman Wells to Edmonton. Selecting different costing assumptions can change these costs.

Rows 517 to 526 display the Net Cash Flows Before Tolls for each field while Row 551 to 560 highlight Net Cash Flows After Tolls for all the fields. Data in Rows 561 to 615 contain the Gathering System and Pipeline Cash Flow estimates.

The following section calculates Net Cash Flows by subtracting annual capital and operating costs from Net Cash Flows and provides estimates of net Internal Rates of Return for each field.

[54] Allowance for Funds Used During Construction

[55] Strictly speaking, the Gathering System is not a regulated utility, but is operated as a normal profit-seeking business. Nevertheless, the proponents (Imperial Oil et. al.) have indicted that they will be operating the Gathering System as though it were a regulated utility, receiving an after-tax rate of return of 11.77%.

The next section (beginning Row 641) estimates Production Taxes, starting with Royalties for each field. The legislation for determining Royalties is quite complicated. First, various adjusted write-offs are permitted before the calculation of net earnings subject to the royalty payment (essentially 95% of tolls are written off from market revenues). Second, for the first seven years, the royalty rate increases from a value of 1% to a value of 5% after which the royalty rate is the greater of 5% of net earnings or 30% of net revenues which ever is highest. Net revenues are calculated from net earnings and various capital and operating cost write-offs. Both Royalty Rates and Revenue Rates can be altered. Row 815 is the beginning of the Income Tax section where income taxes area calculated for each field as well as for the Gathering System and the MV Pipeline itself. Again, the user can select the income tax rates (federal and NWT rates) as well as different rates for Canadian Development Expenditure (CDE) write-offs.

Row 1002 begins the section on After-Tax Cash Flows for each field and for the Gathering System and MV Pipeline along with estimates of After-Tax Internal Rates of Return.

The next section simply converts the various tax calculations into real dollar terms.

The following section (Row 1060) attempts to replicate the Norwegian royalty system based on the MV Pipeline characteristics, providing an estimate of what royalties would be if the Norwegian system were adopted by Canada. It calculates new royalty levels (Row 1127 – "Special Tax") and new estimated after-tax Cash Flows, including new Internal Rates of Return.

APPENDIX B: NORWEGIAN GAS TAX SYSTEM

This information presented herein is based on a description of the Norwegian natural gas tax system outlined by the Norwegian Petroleum Directorate[56] and is meant to give the reader an introduction to the main features of the tax system on the Norwegian continental shelf (NCS). For complete information, see the Norwegian legal framework. The author has attempted to provide an overview and analysis of the Norwegian system but a more detailed review should be based on the actual legislation and revenues generated in Norway. Nevertheless, the overall comparison is useful in understanding the potential for increased revenues to Canadian governments from the MGP based on what other jurisdictions have implemented.

General Characteristics of the System

Tax rules for upstream activities are based on the ordinary Norwegian corporation tax system, with some special deviations and features, and the addition of a special tax for upstream activities. Both the corporation tax and the special tax are based on the net profits which the petroleum companies derive from the relevant petroleum activities. Even though the Norwegian petroleum tax system is applied with a relatively high marginal tax rate, it has a number of favourable features.

There are no signature bonuses, and all relevant expenses for the activities on the NCS are tax deductible. This concerns not only operating expenditure, but also exploration costs, shut-down and decommissioning costs, and research and development expenditures. Investments are favoured by a high depreciation rate, and deductions may start immediately after the investment has been made. For special tax, the company can also deduct an uplift of 30% of investments. Financial costs may be deducted against both the corporation tax and the special tax.

All income and expenses from upstream activities are consolidated at company level as there is no ring fencing (separation of licenses or production into separate companies for tax purposes) between licences. There is a ring fence at the company level between petroleum extraction and other activities, such as other industrial activities or results from foreign investments.

The Norwegian petroleum tax system is favourable for marginally profitable projects because the uplift allowance will shelter profits from the special tax. In general, the system performs well with regard to net present value per dollar invested, break-even prices and required probability of discovery, as all expenses are tax deductible.

Since the beginning in 1965, the system has been adapted and improved to meet the challenges of an evolving industry. From January 1 2005, new amendments to the petroleum tax act have been implemented. These amendments will increase fiscal certainty for new companies and improve the profitability of investments in higher risk operations (i..e., tail-end production and improved oil recovery).

The Norm Price System

Taxable income from oil production is assessed on the basis of norm prices. The norm price is a tax reference price for Norwegian crudes. The principle for determining the norm price is that it should correspond to the price the petroleum could have been traded for between independent parties in a free market. The Norm Price Board determines the price. The Board comprises four independent members, one member from the Ministry of Petroleum and Energy and one from the Ministry of Finance.

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[56] See the "*Petroleum Tax Act*": http://www.npd.no/English/Emner/Ressursforvaltning/Promotering/whynorway_tax_system.htm

The Norm Price Board forms its decision on a broad-based evaluation of the market value of the Norwegian crude oil taking into account all relevant market information. Important information is reported sales from the companies operating on the NCS as well as monthly average for dated Brent Blend as reported by acknowledged publications. The Norm Price Board meets quarterly to fix monthly norm prices for the previous quarter for each crude. These are presented to the companies in writing. The companies are invited to give their view at quarterly meetings with the Board before the final norm prices are determined. The decision may be appealed to the Ministry of Petroleum and Energy within 30 days of the decision. When the Norm Price Board does not find it reasonable to determine a norm price, the sale price actually obtained is used as the basis for tax assessment. This has been the case for a few crudes, NGL and gas.

Depreciation

A linear depreciation schedule applies to production installations and pipelines. The annual depreciation rate is 16 2/3%, starting from the year the investment was made.

Uplift

The purpose of the uplift is to ensure that normal returns are not subject to special tax. From 2005, the uplift is 7.5% annually over four years (adding up to a total of 30%) of the cost price of depreciable business assets from the year the investment is made. Uplift is deducted when calculating the income eligible for special tax. If uplift exceeds the income subject to special tax, excess uplift may be deducted in subsequent years.

Exploration Costs

Exploration costs may be charged as an expense and be deducted immediately. Alternatively they may be capitalised. Exploration costs are not eligible for uplift.

Reimbursement of Tax Value of Exploration Expenses

Companies which, due to losses, are not in tax position may each year claim reimbursement of the tax value of exploration expenses from the Government. The assessment authorities will refund the amount in the tax assessment for the year in question. If a company has claimed reimbursement of exploration expenses, then these expenses will be excluded from losses carried-forward.

Net Financial Costs

Items regarded as net financial costs are defined in Section 3 d of the *Petroleum Tax Act*. They consist mainly of interest and exchange rate gain/loss. If the company has activities both on the NCS and on land, the net financial costs will be divided on the basis of the tax depreciated value of investments in the two areas.

To deduct all of the net financial costs, a company must have an equity-to-assets ratio of at least 20%. If less than 20% equity-to-assets is held, the financial costs allowable for tax purposes will be reduced towards a level corresponding to a 20% equity-to-assets ratio. See Sections 3d and 3h of the *Petroleum Tax Act* for details.

Losses Carried Forward

Losses may be carried forward without any time limits. Losses incurred from 2002 onwards are carried forward with an addition of interest. The relevant interest rate is calculated as risk-free interest plus a margin after deducting ordinary corporation tax (28%). If a company with accumulated losses is acquired by, or merged with another company, the right to deduct the losses is transferred to the new owner. If a company with accumulated losses ceases activities subject to petroleum taxation, the company may claim reimbursement of the tax value of these losses from the Government. With these rules, the investor can regain the tax value of costs even if it fails to achieve sufficient taxable income.

Other Taxes

Royalty

Royalty is being phased out. For the two remaining fields (Oseberg and Gullfaks) the royalty will be completely removed by the end of 2005.

CO_2 Tax

Burning of oil, diesel and gas - mainly for power production and flaring on the installations - is subject to a CO_2 tax. The fee is currently NOK 0.78 per Sm3 gas or per litre of oil.

Area Fee

After the initial production licence period expires, the licensee must pay a fee calculated per square kilometre. The fee the first year is NOK 7,000 per km². It then rises by NOK 7,000 per km² per year until it reaches NOK 70,000 per km² per year. The fee then stays unchanged for the duration of the licence. In the Barents Sea, the area fee is NOK 7,000 per km² per year.

The royalty, CO_2 tax and area fee can be deducted in the corporation and special tax base.

Other Aspects

Section 10 of the Petroleum Tax Act

A transfer of interest in a production licence from one company to another requires approval by the Ministry of Petroleum and Energy and the Ministry of Finance. The Ministry of Finance approval will set conditions to neutralise tax effects from the transfer. If there is a net tax effect, the Ministry may make adjustments to the tax positions of one or both companies involved in the transfer to ensure tax neutrality. The transaction price will normally be treated as a post-tax amount, significantly reducing the capital required to buy a licence.

The State's Direct Financial Interest (SDFI)

The State also has a direct ownership interest in several oil and gas fields on the continental shelf. This arrangement means that it pays a share of all exploration, investment and operating costs that is equivalent to its ownership share. Like the other licensees, the State receives a corresponding share of the income from oil and gas production on the individual field. The effect of the SDFI for the companies is to reduce the available ownership share in licences, but no cost or risk is transferred from the State to the companies. The SDFI varies from licence to licence. The SDFI is managed by Petoro.

An Overview of the Calculation of the Tax Base:

Operating income
- Operating expenses
- Linear depreciation for investments (6 years)
- Exploration costs
- Royalty, CO_2 tax, area fee
- Net financial costs (limited by the thin capitalisation rule; 20% equity)
- Losses from previous years
= Corporation tax base (tax rate: 28%)
- Uplift (7.5% of investment for 4 years)
- Excess uplift from previous years
=Special tax base (tax rate: 50%)

APPENDIX C: AN INPUT-OUTPUT PRIMER

National Accounting (also termed Economic Accounting) assumes a company undertakes two steps in its production process. First, it purchases material inputs from other industries; and second, it transforms those material inputs into finished goods (or services) ready for resale. Take as an example a construction company. The construction company buys steel pipe from the steel manufacturing sector. Using other material inputs (e.g., electricity, fuel oil, etc.), it transforms the steel pipe into a completed pipeline, which, in turn, is "sold" to the MV Pipeline owners at a selling price (equal to the investment cost) higher than the cost of its inputs. The difference between the selling price (investment cost) and the material input cost is the "mark-up" or "value-added". This value-added is used to pay for the labour, any taxes levied by governments, the depreciation of equipment, any interest costs the construction company may have, and will also generate, the owner hopes, a profit.

National Accounting asserts that the value which the construction sector adds to the economy (hence, the term "value added") is equal **not** to the total revenues of the construction company, but only to this "mark-up" value. That is, the value of an industry to an economy is the difference between the value of its output (effectively, total operating revenues) and the cost of its material inputs. In this way, the construction industry does not claim the value of the steel pipe inputs it uses, which should rightly be accounted for by the steel industry. As a result, there is no double counting when measuring the value of the entire economy.

In terms of the Mackenzie Gas Project, the value-added of the construction industry building the pipeline will be equal to the revenue received (equal to the invested capital) minus all of its material costs for goods or services (material inputs), or:

Value Added = Revenue (or Capital Invested) - Material Inputs

Another way of defining value added is that it is the sum of an industry's payments for labour, for indirect taxes, for depreciation and interest costs, and for profit:

Value Added = Labour + Indirect taxes + Depreciation + Interest Costs + Profit

The resulting value-added of any firm (or industry) is available to be shared among labour (wages, salaries and benefits), indirect taxes and "operating surplus." The operating surplus itself is shared between payments for the use of physical capital (depreciation), payments for the use of monetary capital (interest costs), and payments (profits) to the owner(s) of the enterprise. Value-added is an industry's contribution to, or ***direct impact*** on, the economy. And the sum of value-added of all industries is termed the country's Net Domestic Product (GDP).

An important distinction needs to be made between Financial Accounting and National Accounting. Under financial accounting, an industry which has a high value added (i.e., contributes a lot to the economy), can be unprofitable if, for example, its payments to labour or for interest costs are too high. Alternatively, low value-adding industries can be very profitable to their owners, depending on their usage of labour and their capital structure.

Economists have standardised the measure of the flows of commodities between industries and the inter-relationships of inputs and outputs among industries through the concept of Input-Output (I/O) analysis. The **MAKE** matrix identifies the various types of output the sector produces (the construction industry produces "construction" services). The **USE** matrix highlights all of the various types of inputs used to produce that output (the construction industry uses a variety of inputs including steel pipe, fuel oil, office supplies, etc.).[57] By mathematically manipulating these matrices, it is possible to determine by how much the supply of each commodity will increase when the output of an industry increases by one dollar.

The GDP-to-Output ratio is a measure of the direct contribution to the economy *per dollar of output*. Clearly, an industry that requires a lower dollar value of inputs to produce a given dollar of output is a higher value-adding industry. One must note, however, that a higher GDP-to-Output ratio does *not* imply that the industry is more important to the economy. It merely states that for every dollar of output the impact on the economy is greater. Obviously, when examining an industry's importance to an economy one must also take into account the total output of the industry. There is, however, another important characteristic of an industry that must be examined if one is to determine the importance of a sector to the local economy: its ***linkages*** to other industries.

When inputs such as steel pipe are purchased by the construction sector, the industries supplying those goods and services (in this case, the steel industry) increase their own economic activity. This increased activity itself creates demand for other products. The steel industry, for example, may need more iron ore. Iron ore producers themselves may need more chemicals and fuel oil. The demand for extra chemicals and fuel oil will, in turn, stimulate activity in the chemical and petroleum industries. The increased activity in the chemical industry will create greater demand for its own inputs, perhaps some other primary chemicals. And so it continues down the chain of industries. The sum effects of all this additional economic activity are known as ***indirect impacts***.

Such indirect impacts (also known as "multiplier effects" or "spin-offs") on the economy clearly are important. They should not be ignored (as they usually are with financial accounting) if we are to measure the true benefits of an industry or an investment to an economy. An interesting observation is that, while it is true that high value-adding industries have low indirect impacts, those industries with relatively lower direct impacts have relatively higher indirect impacts. This is because, by definition, low value-adding industries consume more inputs per dollar of output and thus have a greater impact on their supplying industries. It should be noted, however, that the level of indirect impacts is highly influenced by the type of goods and services demanded and by the propensity of the companies (or the economy) to import those particular goods and services. The higher the propensity to import the required goods and services, the lower will be the effects on the local economy. Indeed, an industry that imports all its inputs will have virtually no indirect impact on the economy, save the small level of distributive activity (wholesale, retail and transportation margins) the imports may generate.

Increased industrial activity or investment has a third effect on the economy. When additional wages and salaries are paid out, those dollars (appropriately adjusted for taxes and savings) are available to be re-spent on consumer goods and services. Take, for example, an additional $1 million in wages resulting in say, an increase of $750,000 in disposable income. Depending on the spending patterns, this may result in extra consumer spending of say, $500,000 in the retail sector (the remaining being spent in the entertainment sector, restaurant sector, etc.). This will increase the economic activity of the manufacturers and other suppliers of consumer goods to the retail sector who, in turn, will increase their own employment and their own wage payments. The sum effects of this additional activity due to increased wages are known as ***induced impacts***. Again, it should be clear that, like indirect impacts, induced impacts are highly influenced by the economy's propensity to import as well as by the economy's taxation and savings rates, the level of wages paid to employees and the level of capacity at which the economy is operating.

[57] Output is closely associated with industry revenues but there are important differences. Likewise, inputs are highly related to industry expenses. But, again, the differences are important. For a summary of these differences, see the next sub-section: *Technical Differences*.

The question arises: given that there are many levels of indirect and induced spending which affect many, many different firms and industrial sectors, how can we estimate these impacts on the economy? Fortunately, economists have developed a method to estimate these impacts, by using the same input-output tables to which we already have been introduced.[58] However, since the base information is coming from financial statement data directly provided by operators, it is critical to understand how financial statement data are re-structured to meet National Accounting standards. These differences are discussed below.

Technical Differences

Although the National Accounting (Input-Output) measurement of the value and impacts of an industry begins with the same set of data as the financial results of the industry, a number of adjustments are required in order to conform to strict National Accounting standards. To avoid possible confusion, these technical differences between Financial Accounting and National Accounting should be understood, although not all the differences relate to the Construction industry or to other industries involved in the MGP. The intent here is not to provide a comprehensive or definitive discussion of these differences, however, but rather to provide a cursory overview. For a more in-depth discussion of the differences and of the methodology underlying National Accounting, the interested reader is referred to the National Accounting compendium published by the UN.[59]

The following outlines the major differences:

1. The first and perhaps most important difference is that National Accounting measures <u>all</u> non-tax related revenues and expenses related to production, even those not itemized on the corporate income statement. Hence, gratuities paid to staff are included as output. This increases output but not material inputs, and therefore it increases the estimate of GDP (Output – Inputs) by precisely the amount of gratuities. Using our other definition of GDP (GDP = indirect taxes + wages, salaries and benefits + operating surplus), we see that the increase in GDP is reflected in an increase in wages and salaries equal to the reported gratuities.

   Another (usually) off-budget item is an estimate of the value of imputed room and board provided to employees. On the Output side there is an increase in lodging revenues and, since the provision of room and board is a value to the employee, it is considered equivalent to a wage, and thus contributes to overall GDP equal to the value of the imputed room and board. Statistics Canada has standard values that it uses to assess the value of this room and board.

2. At the same time, National Accounting omits revenues not directly related to the production process. Generally, these incomes are limited to interest and dividend earnings, but include non-operating revenues related to rental incomes, commissions and the like.

3. A third difference is that, under National Accounting, the value of each input in the USE matrix is stated in "producer" prices. That is, all wholesale, retail, and transportation costs included in the "purchaser" price of a commodity are removed, as are all commodity taxes, indirect taxes and import duties. These "distributive and tax margins," as they are called, are explicitly recognized in the USE matrix as separate line items. For the Construction industry, the purchase cost of steel pipe will be equal to the "producer" cost of steel pipe (the cost at the manufacturer's plant gate) plus the cost of transporting the pipe to the NWT (the "transportation" margin) plus any retail/wholesale markups plus any indirect taxes. The

[58] For a detailed discussion of the underlying mathematics of Input-Output analysis, see *<u>Input-Output Analysis: Foundations and Extension</u>*, Ronald E. Miller and Peter D. Blair, Prentice Hall, 1985

[59] *<u>System of National Accounts</u>*, Statistical Papers Series F No 2 Rev. 4, New York, 1993

reader should understand that this does not in any way reduce the total cost of inputs to the industry; it simply re-assigns the costs to different input categories.

4. A fourth difference lies in the treatment of merchandise sales. National Accounting treats the purchase of merchandise as partly a purchase from the manufacturer of the good (equal to the cost price of the good less distributive and tax margins) and partly a purchase from the retailer (equal to the mark-up for the good). Consequently, in an input-output table for a sector selling some retail goods, there is no recognition of the cost of the merchandise on the input (USE) side, and only the mark-up value is recognized on the output (MAKE) side. The cost of the merchandise is captured in the Manufacturing sector as output.

5. Related to this unusual approach to merchandise sales is the treatment of "service margins." When a firm purchases a product (such as liquor, beer or wine) and re-sells it with a mark-up without any fundamental change to it, National Accounting recognizes only the mark-up or "service margin" as output. It then treats the purchase cost of the product (less distributive and tax margins) as an output to the original producer of the good. The main instance that affects most industries (besides retail sales) is alcohol sales. In this case, only the service margins are recognized as output, and the costs are assigned to the alcohol manufacturing sectors (beer, wine and liquor/distillers).