AN EVALUATION OF THE ECONOMIC IMPACTS ASSOCIATED WITH THE MACKENZIE VALLEY GAS PIPELINE AND MACKENZIE DELTA GAS DEVELOPMENT

AN UPDATE

Prepared For

RESOURCES, WILDLIFE AND ECONOMIC DEVELOPMENT
GOVERNMENT OF THE NORTHWEST TERRITORIES

AND

TRANSCANADA PIPELINES LIMITED

Prepared By

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INTRODUCTION

In the early part of 2002, the Government of the Northwest Territories (GNWT) and TransCanada PipeLines Ltd. (TCPL) requested an assessment of the economic impacts associated with the development and production of gas reserves in the Mackenzie Delta and the construction and operation of a pipeline running from the Mackenzie Delta down the Mackenzie Valley to an interconnect with the TCPL system in northern Alberta. In response to that request, **Wright Mansell Research Ltd.** (WMR) **completed the study** ***An Evaluation of the Economic Impacts Associated with the Mackenzie Valley Pipeline and Mackenzie Valley Gas Development***, dated May 1, 2002 (**hereafter referred to as the** ***2002 Mackenzie Valley Study***).

Since that time there has been considerable additional effort put into evaluation and planning in relation to the project. In some cases this has meant significant changes to the configuration of the project. The new plans call for a liquids (NGLs) pipeline from Inuvik to Norman Wells, and a substantial gas plant at Inuvik, that was not envisioned in the 2002 Mackenzie Valley Study. This has significantly increased investment costs in facilities and pipelines, and consequently has decreased the financial flows to governments and the producers. In addition, uncertainty about the volumes of gas that may be developed from the northern Mackenzie Valley now calls for the consideration of three scenarios for projected throughput volumes, rather than the single case of a full pipeline that was previously considered. Exploration has not so far realized the gas volumes that were assumed to be available in the earlier study. In this study, exploration costs are included in the cases that must rely upon gas which is yet to be discovered. These exploration costs tend to depress the financial flows to governments and to producers in those cases. Further, there is now much more, and more exact, information regarding the design and costs of all the various components of the project and a new version of the Statistics Canada model incorporating updated coefficients is now available.

This study considers three scenarios for volumes. The first scenario, Case 1, assumes that only the gas from the Anchor fields will be available. Volumes are consequently about 826 MMcf/d but go into decline after 14 years. The second scenario, Case 2, assumes that other presently known gas and discoveries from exploration are sufficient to operate the pipeline at 1.2 bcf/d for about 15 years, before the volumes go into decline. The third scenario, Case 3, assumes that other known gas plus new discoveries from exploration are sufficient to operate the gas pipeline at 1.2 bcf/d for about 25 years. In light of the number and significance of these changes, the Government of the Northwest Territories and TransCanada PipeLines Ltd. (TCPL) requested an update of the economic impacts. This study provides that update for the impacts using the same general format and methodology as outlined in the 2002 Mackenzie Valley Study.

BACKGROUND

The federal government opened up northern Canada to oil and gas exploration in the 1960s and exploration in the Mackenzie Delta area began in that decade. The majority of the exploration drilling in the region to date took place in the 1970s and 1980s in response to rapidly rising energy prices. Nearly 200 exploration wells have been drilled in the area with close to 30% of these wells being successful. The largest gas discoveries have been at Taglu, Parsons Lake and Niglintgak with estimated recoverable gas reserves of 3.0 Tcf, 1.8 Tcf and 0.9 Tcf respectively. Total discovered marketable reserves in the Mackenzie Delta / Beaufort Sea region are estimated to be 9 Tcf, with undiscovered resources believed to be in the range of 52 Tcf, making for an ultimate resource potential of 61 Tcf.

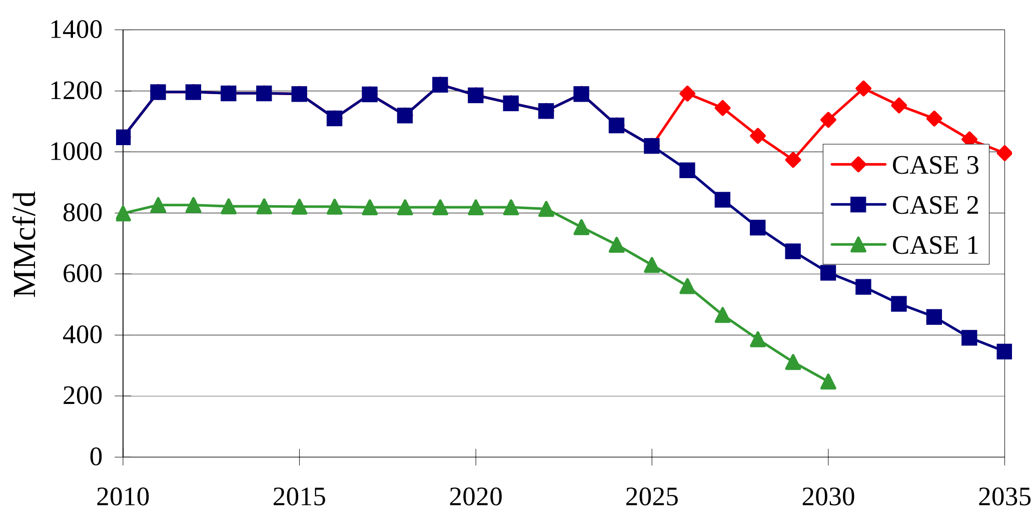
To date, gas development in the region has been constrained by relatively low gas prices and the lack of pipeline access to major gas markets. With expectations of stronger gas prices in the future, a joint venture between the Mackenzie Delta Producer Group (which includes Imperial Oil Resources, Shell Canada, Conoco Phillips Canada and ExxonMobil Canada) and the Aboriginal Pipeline Group (which represents the Aboriginal peoples of the NWT) has recently been formed and is committing $250 million to take a proposed gas development and pipeline construction project to the permit stage before the National Energy Board.

GAS PRICE AND VOLUME CASES

- As in the 2002 Mackenzie Valley Study, **two gas price scenarios** ($3US and $4US) are analyzed in this report. These prices are for Chicago and, as a point of reference, the average price in that market for the 1995-2003 period was just over $3. In both scenarios, gas prices in Chicago are assumed constant in real terms (that is, in 2003$) over the duration of the analysis period. These scenarios are referred to as **the $3 US gas price scenario and the $4 US gas price scenario.** Although the gas price scenarios are defined in terms of 2003US$, **all impact results are reported in 2004 Cdn$.** While the 2002 study used an exchange rate of $1US=$0.67Cdn, this study assumes a rate of $0.75Cdn.

- **Three gas and natural gas liquid** (NGL) **volumes cases** are considered in the analysis. Production would commence in 2010 under all cases and gas production profiles are illustrated in Figure 1.

FIGURE 1: GAS PRODUCTION PROFILES UNDER THE THREE VOLUME CASES: 2010-2035



- **Case 1 involves production only from Niglintgak, Parsons Lake and Taglu (hereafter referred to as the anchor fields).** Production over the early years of the project would be about 826 MMcf/d and would continue until 2028 in the $3US gas price scenario and until 2030 in the $4US gas price scenario.

- In Case 2, it is assumed that gas from other fields already identified in the Mackenzie Delta, as well as from several new discoveries, would be available for production by 2010 so as to achieve gas production of roughly 1.2 Bcf/d over the early years of the project. Through continued exploration and development activity, gas production would be maintained near 1.2 Bcf/d until 2022, after which it would decline. Impacts are evaluated through to 2035.

- In Case 3, gas production is assumed at or near 1.2 Bcf/d for the duration of the analysis period (to 2035). In order to achieve these production levels, continued exploration and development activity would be required. Case 3 corresponds most closely to the analysis shown in the 2002 Mackenzie Valley Study.

Given the three volume cases and two gas price scenarios described above, there are effectively six cases in this report. These are denoted in the analysis that follows by first referring to the volume case and then referring to the gas price scenario.

- CASE 1-3 = Case 1 volumes and $3US gas price; CASE 1-4 = Case 1 volumes and $4US gas price
- CASE 2-3 = Case 2 volumes and $3US gas price; CASE 2-4 = Case 2 volumes and $4US gas price
- CASE 3-3 = Case 3 volumes and $3US gas price: CASE 3-4 = Case 3 volumes and $4US gas price.

ECONOMIC IMPACTS AND VIABILITY

- Various dimensions of the economic impacts associated with these cases are summarized in the following sections. **It is important to note at the outset that in a number of these cases the overall project would not likely be economic and, hence, the impacts associated with those cases are unlikely to materialize.**

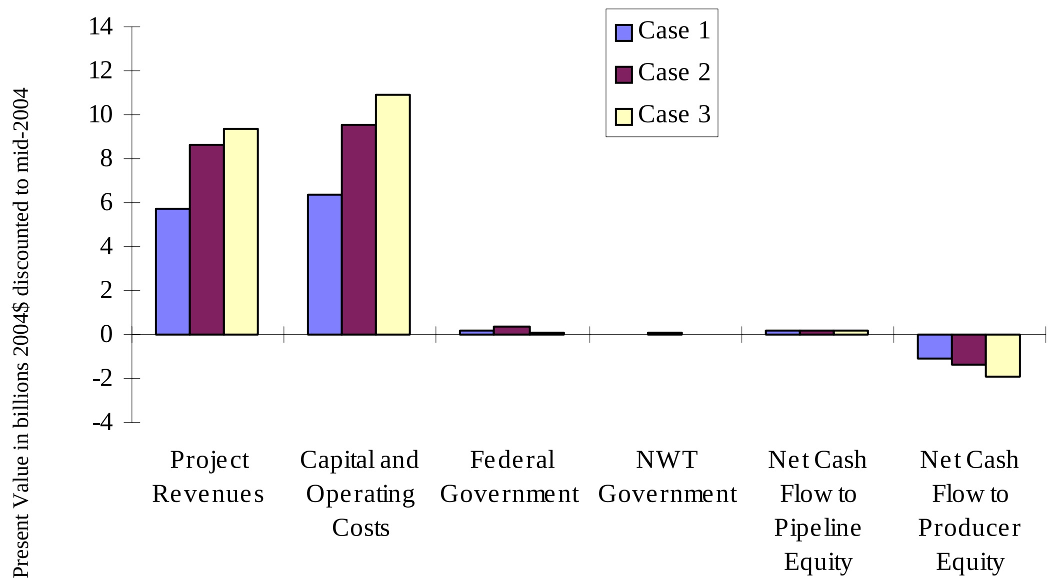
- To be viable, the project must generate sufficient revenues to cover all capital and operating costs (including payments to governments) associated with the exploration, development, production, processing and transportation of the gas and gas liquids. This viability also requires a rate of return sufficient to attract the large amounts of equity and debt capital needed to proceed with a project that has a number of risks such as construction cost and schedule risk, supply risk, market risk, regulatory risk and operating risk. While the potential rates of return needed to support a decision to construct are not known, an illustrative rate of return of 8% (real) was used in this analysis. The NEB approved rates of return for regulated pipelines, which have less risk than what producers face, are in the range of 10% to12% nominal (or around 8% to10% in real terms).

- Although a detailed evaluation of viability was not undertaken, **the results on rates of return summarized below suggest the risk-adjusted rates of return would be insufficient to attract the required capital unless average long term gas prices were substantially higher than $3US and/or costs were significantly lower than those used in the analysis.**

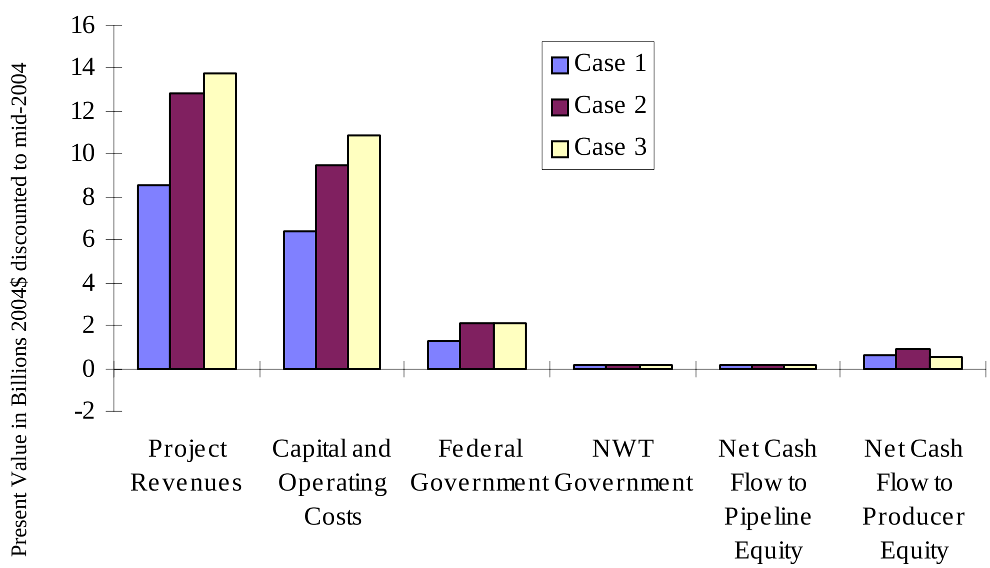
- One method of estimating the returns on investment is to calculate the present value of the returns using an appropriate discount rate that reflects the opportunity cost of funds used by the investor. Present values of the various revenue and cost categories depicted in Figure 2 are calculated using an 8% real after-tax discount rate and the results are summarized in Figure 2. Given the risk profile of the project, a significantly higher discount rate may be justified.

FIGURE 2: PRESENT VALUE OF CUMULATIVE PROJECT REVENUES AND COSTS GIVEN AN 8% AFTER TAX REAL DISCOUNT RATE: 2010-2035

$3US GAS PRICE SCENARIO



$4US GAS PRICE SCENARIO



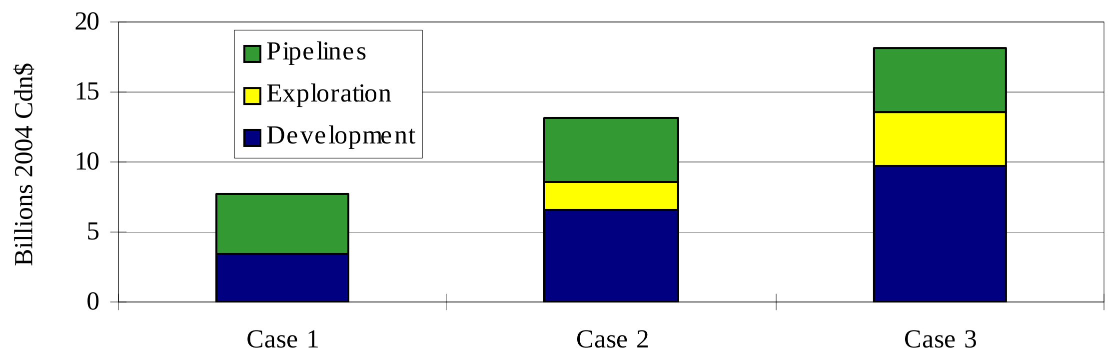
- In the $3US gas price scenario, the present value of the capital and operating costs exceeds the present value of the revenues under all volume cases. Producers would find themselves with negative returns given the illustrative 8% after tax real rate of return that would be required. The present values of the net cash flow to producer equity are positive in the $4US gas price scenario.

- Expressed differently, the internal rate of return on producer sector investment is less than 2% in the $3US gas price scenario and this would clearly not be sufficient to attract financing for the project. Even in the $4US gas price scenario, the internal rate of return only ranges between 9% and 12%.

FINANCIAL FLOWS AND DIRECT IMPACTS OF THE PROJECT

- Direct investment associated with the project is summarized in Figure 3 and is expected to be range from $7.7 billion to $18.2 billion. Pipeline sector investment includes expenditures on a gas pipeline from the Mackenzie Delta to the NWT/Alberta border (the Mackenzie Valley gas pipeline), a natural gas liquids (NGL) pipeline from the Mackenzie Delta to Norman Wells and incremental facilities on the TCPL Alberta system and at Norman Wells to handle project volumes. Under all volume cases, gas producers would construct a gathering system and an Inuvik area gas plant as well as develop the anchor fields. Additional exploration and development expenditures would be made in Cases 2 and 3.

FIGURE 3: EXPLORATION AND DEVELOPMENT EXPENDITURE BY GAS PRODUCERS AND PIPELINE SECTOR INVESTMENT: 2002-2035



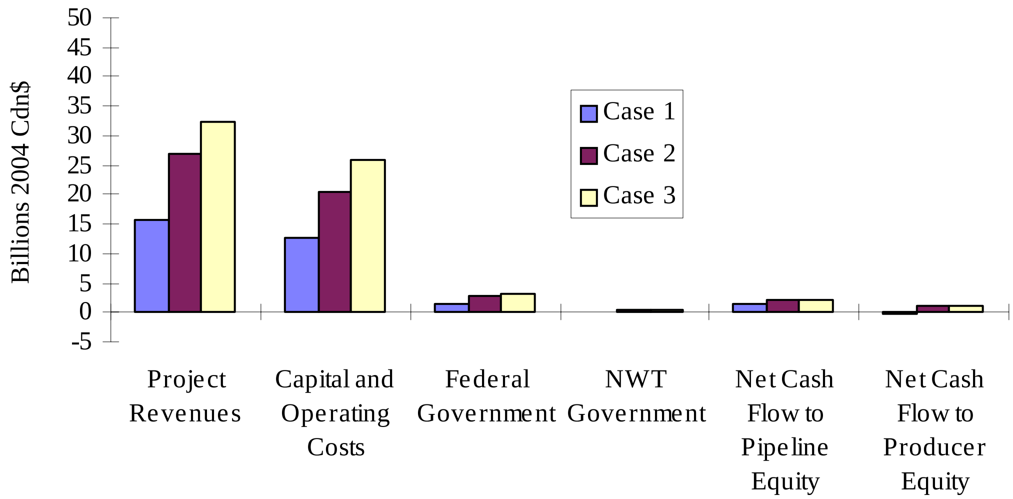
- In Case 1, the majority of the investment (including all pipeline investment) would occur prior to 2010 and would peak between 2007 and 2009. The magnitude of the investment in these years is very large compared to current overall activity levels in the NWT and would almost certainly involve an influx of short-term workers into the region. Projects of this type and magnitude must be properly managed so as to avoid the introduction or amplification of economic instability.

- In Cases 2 and 3, ongoing exploration and development expenditures would have to be made to ensure that there would be sufficient productive capacity to fill the pipeline over time. These are spread over a longer time and, with the resulting smaller annual magnitudes and greater sustainability, impacts could be much more easily absorbed by the NWT economy.

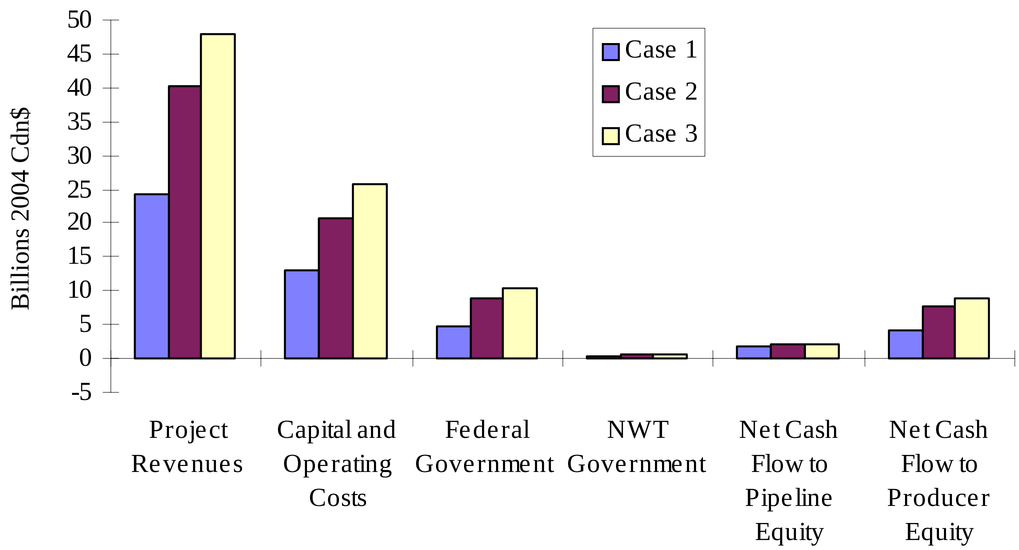
- The total direct revenues generated by the project would include netback revenues to producers (ie. revenues from the sale of the produced gas and NGLs minus the transportation costs of moving the products to market) as well as the revenues from transporting these products to market. Overall direct revenues would range from $15.8 billion to $47.8 billion depending on the case and the distribution of these revenues is illustrated in Figure 4. The relative magnitude of these revenues in the NWT context is noteworthy. The average annual direct revenues range from $0.8 billion to $1.8 billion per year and are equivalent to between 25% and 55% of the value of total current annual output in the NWT.

FIGURE 4: DISTRIBUTION OF CUMULATIVE PROJECT REVENUES AND COSTS: 2010-2035

$3US GAS PRICE SCENARIO



$4US GAS PRICE SCENARIO



- **Between 75% and 80% of the overall revenues would go towards capital and operating costs** (the costs of labour, capital and other inputs to develop, produce, process and transport the gas) **in the $3US gas price scenario.** The remainder of the revenues would be split fairly evenly between cash flow to pipeline equity and to the federal government, while **cash flow to producer equity and to the NWT government would be very small or even negative.**

- **In the $4US gas price case**, resource costs (capital and operating costs) and cash flow to pipeline equity would change only slightly in absolute terms compared to the $3US gas price scenario (but would fall in percentage terms), while **cash flow to producer equity ($4.3 billion to $8.8 billion) and to the federal government ($5.1 billion to $11.0 billion) would be higher given the larger netback revenues.**

- **The federal government would receive between 85% and 95% of the total government revenues depending on the case.** The federal government would directly collect royalties on gas production and income taxes from both gas production and pipeline companies. In addition, due to current fiscal arrangements between the federal and NWT governments it is assumed that 80% of any revenue raised by the NWT government would result in a grant reduction to the territorial government and therefore an effective benefit to the federal government. While not an issue for this report, it can be noted that discussions about the devolution of some federal powers and enhanced northern revenue sharing are ongoing.

Although the size of the cash flow to producer equity may seem quite substantial in the $4 US gas price scenario, both the pipeline and producer sectors (and any private sector investor for that matter) must make a competitive return in order to attract the necessary financial capital. In order to be competitive for this capital, the risk adjusted after tax real rate of return would likely have to be in excess of the 9% to 12% in the $4US scenarios. This would require long term gas prices significantly higher than $4US and / or costs below those used in the analysis.

- The last of the direct economic impacts associated with the project involves the construction and operating employment that would be created. **Between 10,000 and 20,000 person years** of direct employment would be generated by the project, depending on the case. Construction employment would range from 8,000 to 16,000 person years and operating employment from 2,000 to 5,000 person years.

- Construction employment would overwhelmingly take place in the NWT but the sheer magnitude of the personnel requirements would result in many of these jobs being taken by people that would otherwise live outside the region. This is an important consideration in the economic impact analysis.

- Operating employment is expected to be split between the NWT and Alberta. However, unlike some of the construction phase employment impacts, it is expected that the operating phase jobs in the NWT would be taken by NWT residents and these represent another long term sustainable benefit for the people of the region that would be attributable to the project.

ECONOMIC IMPACTS OF THE PROJECT

- The direct and indirect impacts of the project on variables such as Gross Domestic Product (GDP or value added), labour income, government revenues and employment in the economies of the NWT, other Canadian regions, and Canada as a whole are evaluated. Separate evaluations of the impacts associated with four distinct portions of the project (pipeline construction, gas field exploration and development, pipeline operation and gas/NGL production) are presented. Furthermore, construction phase impacts are adjusted to take account of import of labour and other inputs to NWT to meet project requirements. The overall impacts are summarized in Figures 5 to 8.

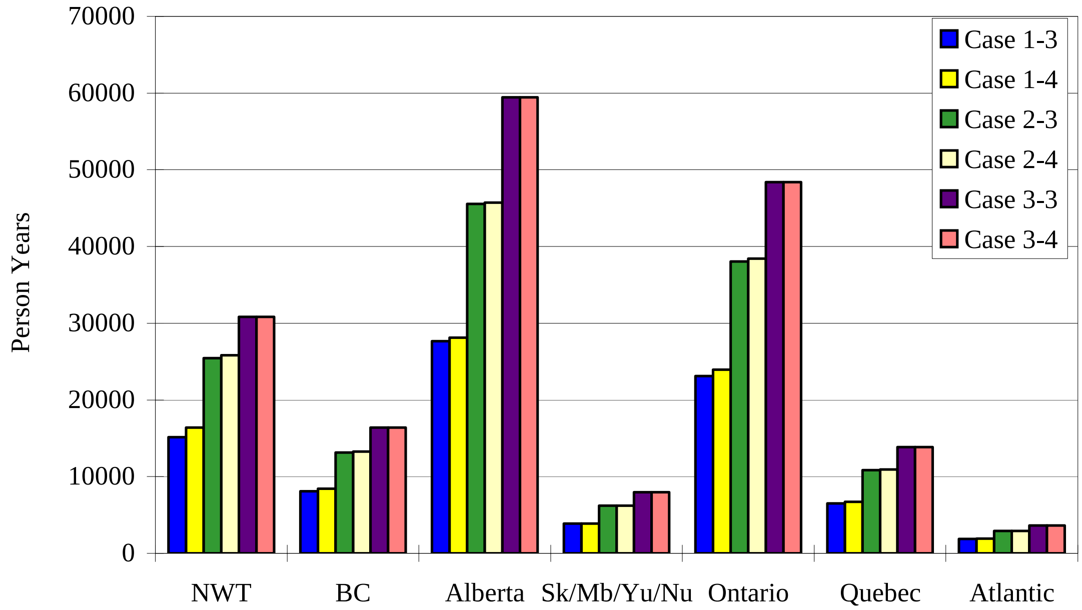
- Employment attributable to the project would range from 86,000 person years to 181,000 person years. The distribution of the employment across regions is shown in Figure 5. Labour income impacts would be between $5 billion and $10 billion and distributed in largely the same manner as the employment impacts.

- In the NWT, employment generated by the project would range from 15,000 to 31,000 person years or between 600 and 1000 jobs on an average annual basis. These employment impacts could effectively reduce the NWT unemployment rate to about half of current levels.

- Employment impacts in particular would be widely distributed across Canada with the largest impacts in Alberta (28,000 to 59,000 person years). Aside from the direct operating employment that would be generated in the province, much of the project management and engineering during the construction phase of the project would be sourced in Alberta. In addition, most of the direct construction phase jobs in the NWT that would be taken by workers from outside the region would likely go to Alberta workers given the nature of the work and the proximity of Alberta to the NWT. Overall, between 30% and 40% of the total employment impacts could be expected in Alberta.

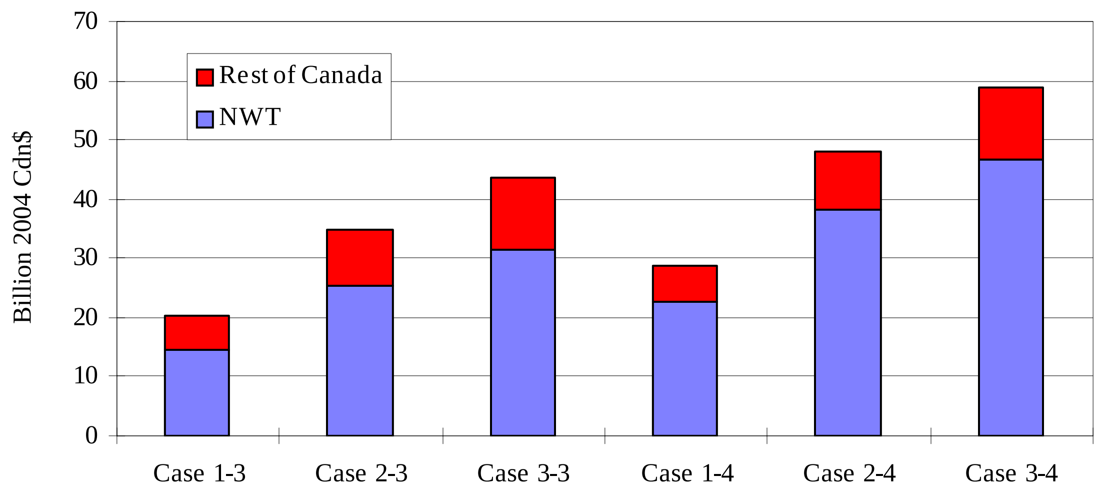
- Ontario would also experience significant employment impacts (23,000 to 48,000 person years). In fact, these would exceed those for the NWT and represent roughly one quarter of the overall employment impacts. These would arise given the ability of the province to directly and indirectly supply manufactured inputs for the project, but also because of the extensive economic linkages the province has throughout Canada. Other regions of Canada would also see significant impacts, especially in relation to their relative economic size.

FIGURE 5: OVERALL EMPLOYMENT IMPACTS OF THE PROJECT: 2004-2035



- Relative to the employment and labour income impacts (which would be expected to be widely distributed across Canada), GDP and government revenue impacts would be more concentrated in the NWT. Figure 6 illustrates the GDP impacts in the NWT and the rest of Canada for the various cases. Overall GDP impacts would range from \$20 billion to \$59 billion and between 70% and 80% of these would occur in the NWT. On an average annual basis, GDP in the NWT would rise by between \$0.6 billion and \$1.5 billion as a result of the project. This would represent an increase of between 20% and 45% over current levels of GDP in the region.

FIGURE 6: CUMULATIVE GDP IMPACTS OF THE PROJECT: 2004-2035



- Overall government revenue impacts are shown in Figure 7 and it is clear that these are very dependent on the gas price scenario. At a $3US gas price, government revenues would range from $4 billion to $7 billion while at a $4US gas price they would be roughly double to between $7 billion and $15 billion. The higher netbacks with $4US gas would substantially increase royalties and taxes collected by governments.

- Figure 7 illustrates that between 55% and 80% of the total government revenues generated by the project would originate in the NWT. However, given the current fiscal arrangements between the NWT and federal governments, the vast majority of any additional government revenue accruing initially to the NWT government is effectively transferred back to the federal government via grant reduction.

- Figure 8 shows territorial and federal government revenue with and without grant reduction. After grant reduction and assuming current arrangements, the impacts on NWT government revenue would be modest, with increases ranging from $0.2 billion to $0.6 billion depending on the gas price scenario. On an average annual basis, these impacts would amount to **between $9 million and $24 million per year and would represent less than a 3% increase above current annual territorial government revenues.** In part because of grant reduction, **the federal government would be the recipient of between 80% and 90% of the overall government revenue generated by the project.**

FIGURE 7: POINT OF ORIGIN CUMULATIVE GOVERNMENT REVENUE IMPACTS OF THE PROJECT: 2004-2035 (EXCLUDING GRANT REDUCTION IMPACTS)

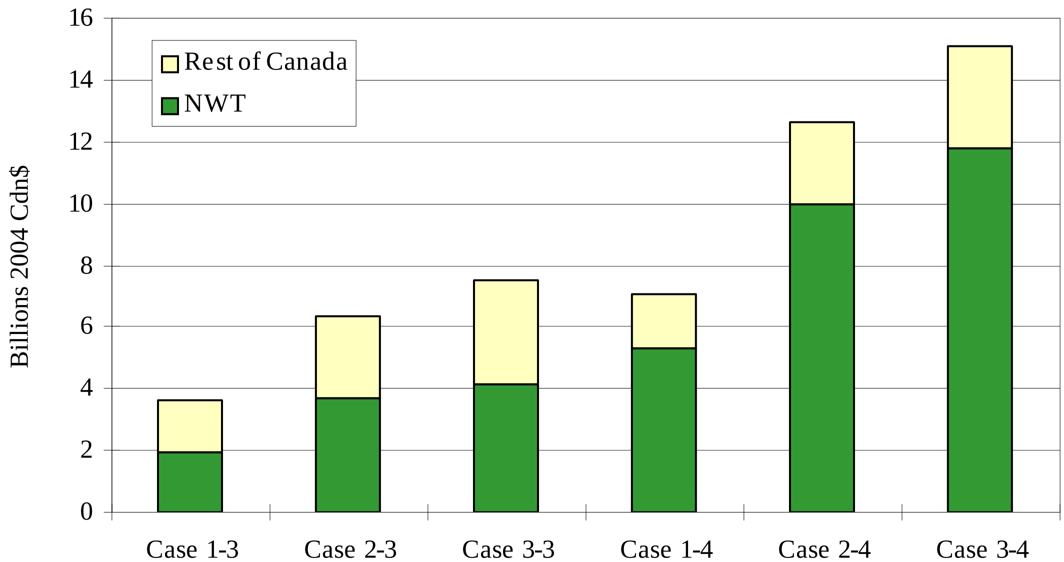
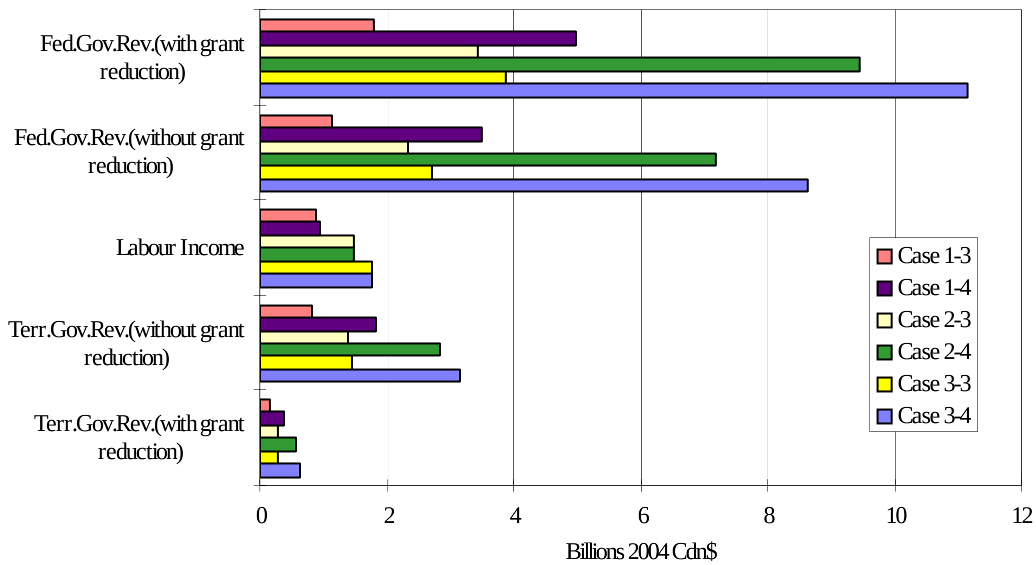


FIGURE 8: CUMULATIVE GOVERNMENT REVENUE AND LABOUR INCOME IMPACTS IN THE NWT: 2004-2035



- The economic impacts associated with the project would be widely distributed across Canada's regions and, as illustrated in Figure 9, across industries and sectors in the economy. The only direct employment impacts shown are those related to pipeline transport, oil and gas extraction, and construction. Together, they would constitute less than 20% of the overall employment impacts.

FIGURE 9: SECTORAL DISTRIBUTION OF TOTAL EMPLOYMENT IMPACTS FOR CASE 1-4: 2004-2028

- Employment in manufacturing is expected to represent roughly 10% of the total employment impact in each of the cases and would be widely distributed across southern Canada. The manufacturing industry in the NWT is currently very small, typically serves only local markets, and does not produce the types of items specifically required for this project. However, if the scale of the oil and gas industry in the NWT were to become sufficiently large in the future, it may become viable to locally produce various manufactured inputs for the industry.

- Some of the largest indirect impacts would occur in oil and gas service industry as well as in industries that provide professional, scientific and technical services. Roughly 20% of the overall employment impacts could be expected in the latter industries, with Alberta based businesses experiencing about half of this impact (much of the project related engineering and management would be sourced in Alberta). For other industries, sizable impacts would be expected in many regions across Canada. The wide distribution of the employment impacts across a variety of sectors in the NWT makes it all the more likely that NWT residents would widely benefit from the project on a sustainable basis.

OTHER IMPACTS AND IMPLICATIONS OF THE PROJECT

- There is another category of economic impacts called induced impacts that relate to the spending of portions of labour income, corporate profits and government revenues generated by an activity. With respect to the spending of labour income created by the project, the induced GDP and employment impacts are estimated to be as follows: an additional $0.2-$0.4 billion and 3,000-6,000 person years in the NWT; and, an additional $3.4-$7.0 billion and 58,000-132,000 person years in Canada. The induced employment impacts related to the spending of labour income would increase the overall employment impacts noted in the previous section by about 20% for the NWT and 70% for Canada.

- Another important source of induced effects relates to the reinvestment of corporate profits. In recent years, the percentage of oil and gas industry net revenue (that is, revenues minus royalties and operating costs) that has been spent on exploration and development in Canada has averaged close to 85%. Applying this percentage to the net revenues generated in the project and taking into consideration additional induced impacts related to the labour income that would be created in the exploration and development process, the total impacts associated with reinvestment of Mackenzie Delta net revenues could add a further $3 billion to $22 billion in terms of GDP, while additional employment impacts could range between 26,000 and 272,000 person years.

- Further induced impacts could be anticipated as the resources that are discovered in the exploration and development process would eventually give rise to additional oil and gas production. Similarly, induced effects related to spending of government revenues could be expected to be quite pronounced given the $4 billion to $15 billion in government revenues that would be directly and indirectly generated by this project.

- The Inuvik area gas plant could be expected to recover roughly 90% of the pentanes plus and about 50% of the butanes contained in the raw gas. The remainder of these products as well as any propane and ethane, would remain entrained in the gas stream that would flow through the Mackenzie Valley gas pipeline and eventually into the TCPL Alberta system.

At some point these remaining liquids might be extracted in Alberta but realistically the remaining extractable NGLs would likely be small.

- To date, the amount of money raised in sales of mineral rights in the NWT has been minimal in comparison to that raised in other regions in Canada that have oil and gas resources. This has been due to the absence of a pipeline to transport the gas (and oil) to market. Rights in the NWT have been issued by the federal government for work commitments and the winning bidders have not had to pay cash bonuses (as is normally the case in southern Canada). The introduction of the Mackenzie Valley pipeline could be expected to change this situation, potentially in a rather dramatic fashion. The federal government and perhaps aboriginal bands could benefit substantially from cash bonuses should this occur.

- Portions of the southern and central NWT may also experience increased exploration activity should the Mackenzie Valley pipeline be completed. Areas that may contain gas reserves may currently be ignored from an exploration perspective simply because there is no way to deliver production to markets. This would change if the Mackenzie Valley pipeline could at some point be accessed by such supplies.

- Households in some NWT communities along the Mackenzie Valley pipeline route or in the Mackenzie Delta could potentially realize lower costs if it was economic to put in place the necessary distribution systems and connections for accessing Mackenzie Delta gas for home heating use. In cases where the distribution and connection economics were favorable, there is the possibility of significant savings by switching from diesel oil to natural gas.

- It is well known that gas pipeline infrastructure south of sixty is running below capacity and is likely to become more so in the future. The introduction of 800 to 1,200 MMcf/d of gas will improve the utilization of existing pipeline infrastructure. In addition it should be noted that the new supply of NGLs available at Norman Wells will improve the utilization of the existing Norman Wells oil pipeline.

- To the extent that the supply augmentation provided by Mackenzie Delta gas supplies could alleviate gas price increases and thereby help to promote a trend away from the use of higher greenhouse gas emitting fuels such as coal and oil in electricity generation and heating, additional benefits to society may be created. For example, assuming that the entire volume of Mackenzie Delta gas would be used to fire new electricity generation that in the absence of this gas would be fired by coal, society would benefit by somewhere between $80 million to $230 million annually due to avoided greenhouse gas emissions.

- In summary, it can be anticipated that, if the project is economically viable and proceeds, it would have significant positive impacts on the overall Canadian economy and would generate major economic benefits for the NWT and other regions. These benefits would be widely distributed among the project stakeholders, as well as among industrial sectors and regions.

1.0 INTRODUCTION

In the early part of 2002, the Government of the Northwest Territories (GNWT) and TransCanada PipeLines Ltd. (TCPL) requested an assessment of the economic impacts associated with the development and production of gas reserves in the Mackenzie Delta and the construction and operation of a pipeline running from the Mackenzie Delta down the Mackenzie Valley to an interconnect with the TCPL system in northern Alberta. In response to that request, Wright Mansell Research Ltd. (WMR) completed the study ***An Evaluation of the Economic Impacts Associated with the Mackenzie Valley Pipeline and Mackenzie Valley Gas Development***, dated May 1, 2002 (hereafter referred to as the ***2002 Mackenzie Valley Study***).

Since that time there has been considerable additional effort put into evaluation and planning in relation to the project. In some cases this has meant significant changes to the configuration of the project. For example, the new plans now call for a liquids pipeline that was not envisioned in 2002 Mackenzie Valley Study and this study now considers three scenarios concerning the volumes of Mackenzie Valley gas. Further, the release by Statistics Canada of a new version of the Input Output Model, allows greater accuracy in the measurement of impacts in the various regions and sectors.

The new plans call for a liquids (NGLs) pipeline from Inuvik to Norman Wells, and a substantial gas plant at Inuvik, that was not envisioned in the 2002 Mackenzie Valley Study. This has significantly increased investment costs in facilities and pipelines, and consequently has decreased the financial flows to governments and the producers. In addition, uncertainty about the volumes of gas that may be developed from the northern Mackenzie Valley now calls for the consideration of three scenarios for projected throughput volumes, rather than the single case of a full pipeline that was previously considered. Exploration has not so far realized the gas volumes that were assumed to be available in the earlier study. In this study, exploration costs are included in the cases that must rely upon gas which is yet to be discovered. These exploration costs tend to depress the financial flows to governments and to producers in those cases. Further, there is now much more, and more exact, information regarding the design and costs of all the various components of the project and a new version of the Statistics Canada Impact Output Model incorporating updated coefficients is now available.

This study considers three scenarios of volumes. The first scenario, Case 1, assumes that only the gas from the Anchor fields will be available. Volumes are consequently about 826 MMcf/d but go into decline after 14 years. The second scenario, Case 2, assumes that other presently known gas and discoveries from exploration are sufficient to operate the pipeline at 1.2 bcf/d for about 15 years, before the volumes go into decline. The third scenario, Case 3, assumes that other known gas plus new discoveries from exploration are sufficient to operate the gas pipeline at 1.2 bcf/d for about 25 years.

Comparison of Assumption in 2002 Mackenzie Valley Study and Present Study	
2002 Mackenzie Valley Study	Present Study
gas pipeline carrying mixture of gas and NGLs from Inuvik to Norman wells. gas plant at Norman Wells	gas pipeline carrying gas from Inuvik to Alberta. liquids pipeline carrying NGLs from Inuvik to Norman Wells. gas plant at Inuvik
gas pipeline is full at 1.2 bcf/d for the entire period.	three cases of volumes: approx. 826 MMcf/d for 14 years + decline, 1.2 bcf/d for 15 years + decline, and approx. 1.2 bcf/d for 25 years.
pipeline operations begin in 2009 and end in 2033	pipeline operations begin in 2010 and end in 2028/2030 in Case 1, and end in 2035 in Cases 2 and 3
no exploration costs considered	exploration costs included in Cases 2 and 3
foreign exchange rate 67 Cdn cents to US$	foreign exchange rate 75 Cdn cents to US$
gas prices US$3/Mcf and US$4/Mcf in Chicago	gas prices US$3/Mcf and US$4/Mcf in Chicago
calculations in 2002 Cdn constant dollars	calculations in 2004 Cdn dollars
total investment costs Cdn$ 7.6 billion	total investment costs range from Cdn$ 7.7 billion to Cdn$18.2, depending on case
employed 1996 version of Statistics Canada Input Output Model	employed new (2000) version of Statistics Canada Input Output Model.

In light of the number and significance of these changes, the Government of the Northwest Territories and TransCanada PipeLines Ltd. (TCPL), requested an update of the economic impacts. This study provides that update for the impacts using the same general format and methodology as outlined in the previous study (ie the 2002 Mackenzie Valley Study).

1.1 Background

The federal government opened up northern Canada to oil and gas exploration in the 1960s and exploration in the Mackenzie Delta area began in that decade. The majority of the exploration drilling in the region to date took place in the 1970s and 1980s in response to rapidly rising energy prices. Nearly 200 exploration wells have been drilled in the area with close to 30% of these wells being successful. The largest discoveries have been at Taglu and Parsons Lake with estimated recoverable gas resources of 2.8 Tcf and 1.9 Tcf respectively. Total discovered marketable reserves in the Mackenzie Delta / Beaufort Sea region are estimated to be 9 Tcf, with undiscovered resources believed to be in the range of 52 Tcf, making for an ultimate resource potential of 61 Tcf.[1]

The first production from the region commenced in 1999 with gas from the Ikhil field being produced to serve consumer needs in nearby Inuvik. This to date represents the only gas production from the region as further development has been constrained by relatively low gas prices and the lack of access to major gas markets.

With higher recent gas prices, there has been renewed interest in the development of fields in the Mackenzie Delta. In 1999, the Northern Oil and Gas Directorate of the federal government's Department of Indian Affairs and Northern Development announced that rights to explore several different areas throughout the Mackenzie Delta region had been granted to two parties with work-bid commitments totalling over $180 million. Another call for bids in 2000 resulted in rights being granted for ten exploration parcels with work-bid commitments of just under half a billion dollars.

[1] See National Energy Board, Canada's Conventional Natural Gas Resources–A Status Report (April 2004).

The increased interest in the region reflects the belief that future gas prices could finally justify the construction of a pipeline to connect Mackenzie Delta supplies to the overall North American gas market. The Mackenzie Gas Project (MGP) is committing $250 million to take the proposed gas development and pipeline construction project to the permit stage before the National Energy Board.

The cost data used in this study has been provided by the Mackenzie Gas Project. It is the most up-to-date and comprehensive now available, and it covers pipeline investment costs, gas plant and gathering system costs, gas field development costs and exploration costs, as well as operating costs for the facilities.

1.2 Study Objectives

The industrial, regional and national economic impacts associated with the construction and operation of the Mackenzie Valley pipeline and Mackenzie Delta field development (hereafter referred to as the project) could be expected to be very substantial. Consequently, they are likely to form an important consideration in evaluating the public interest aspects of the project and in ensuring that its location, design and timing are such that the economic benefits are maximized and that any dislocations or other such costs are minimized. Recognizing this, and recognizing the significant changes in the amount and detail of information concerning the project, the Government of the Northwest Territories and TransCanada PipeLines Ltd. asked Wright Mansell Research Ltd. to update the assessment of the economic impacts. This study is the response to that request.

The specific objectives in this study are to update and analyze the following:

(i) the financial or cash flows generated, their distribution among the various stakeholders, and the direct or first-round impacts on variables such as investment, employment, and government revenues.

(ii) the direct and indirect impacts on variables such as Gross Domestic Product (value added), labour income, government revenues and employment in the economies of the Northwest Territories (NWT), other Canadian regions, and Canada as a whole.

(iii) induced impacts in these economies and impacts on existing pipeline transportation infrastructure in Canada.

(iv) impacts on natural gas liquid supply in Canada and value added opportunities that could result.

(v) effects on values of mineral rights in the NWT and exploration interest in parts of the region outside the Mackenzie Delta.

(vi) benefits to natural gas consumers in the NWT and in Canada overall arising from access to Mackenzie Delta gas supplies.

(vii) benefits to society due to the potential replacement of less environmentally friendly energy sources such as coal with natural gas.

1.3 OUTLINE

Section 2 includes a summary of the assumptions and cases used in the analysis and an outline of the key dimensions of the project. The financial flows associated with the project and their direct impacts on selected variables are also presented.

In Section 3, the regional economic impacts within Canada and overall Canadian economic impacts are described. Considerable attention is focused on the implications of the project for economic growth and development in the NWT.

Section 4 deals with other impacts that could be expected from the project. These include additional induced economic impacts, and issues related to natural gas liquids, mineral rights values in the NWT, exploration interest in the NWT outside the Mackenzie Delta, gains from higher capacity utilization rates on existing southern pipeline infrastructure, consumer benefits due to augmented gas supply, and environmental benefits.

2.0 FINANCIAL FLOWS

The objective in this section is to translate the basic parameters of the project into a series of financial / cash flows and direct economic impacts. These outline the magnitude and allocation of monetary flows to the participants and to the main components (purchase of inputs, returns, taxes etc.) within the various sectors. In addition to providing a measure of the direct (or first-round) impacts of the project, these financial flows serve as inputs to the analyses set out in subsequent sections.

2.1 ASSUMPTIONS

In order to estimate the financial flows and the various economic impacts, it is necessary to make assumptions concerning certain dimensions of the projects and the general economic environment. The assumptions employed are set out in this section.

Gas and Natural Gas Liquid (NGL) Volumes

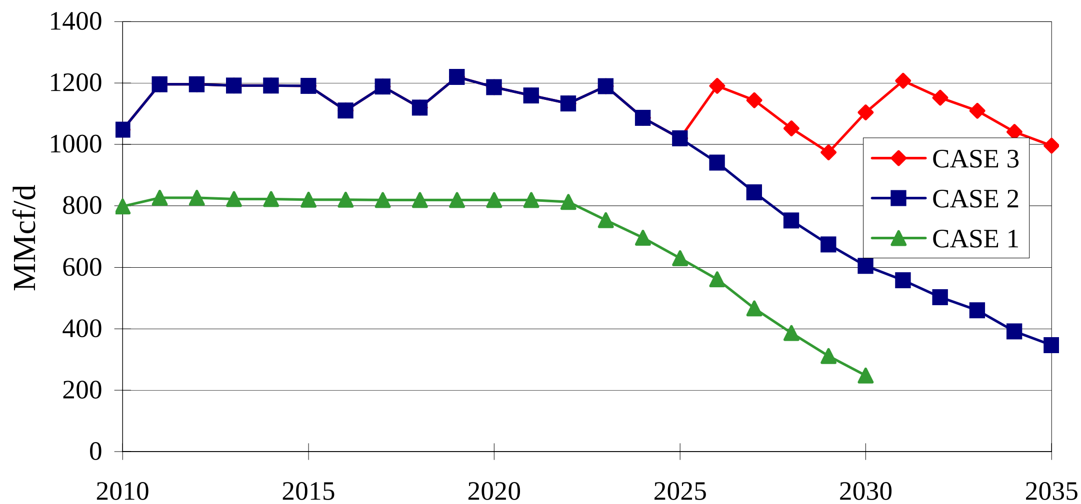
There are three gas and NGL volume cases analyzed in this report. These are summarized below.

Case 1 - Anchor Fields Only

Three 'anchor' fields underpin the Mackenzie Delta gas development project - Niglintgak, Parsons Lake and Taglu. In Case 1, it is assumed that only gas and NGLs from these fields would be produced over the life of the project. The project sponsors have provided detailed production profiles for the anchor fields and the overall gas production profile is illustrated in Figure 2.1 and in Appendix Table A.1. Production is anticipated to commence in 2010 with peak gas production of roughly 826 Mmcf/d (or 302 Bcf/yr). Annual gas production is expected to be relatively constant until 2022, after which the average decline rate is anticipated to be about 14% per year.

Significant NGL production is also expected from the anchor fields. NGL production profiles are illustrated in Figure 2.2 and are also shown in Appendix Table A.2. In Case 1, NGL production is expected to start at a rate of over 10,000 barrels/day in 2010 with more significant production declines occurring earlier than for gas production. Between 2015 and 2030, the average decline rate of NGLs is anticipated to be about 12% per year.

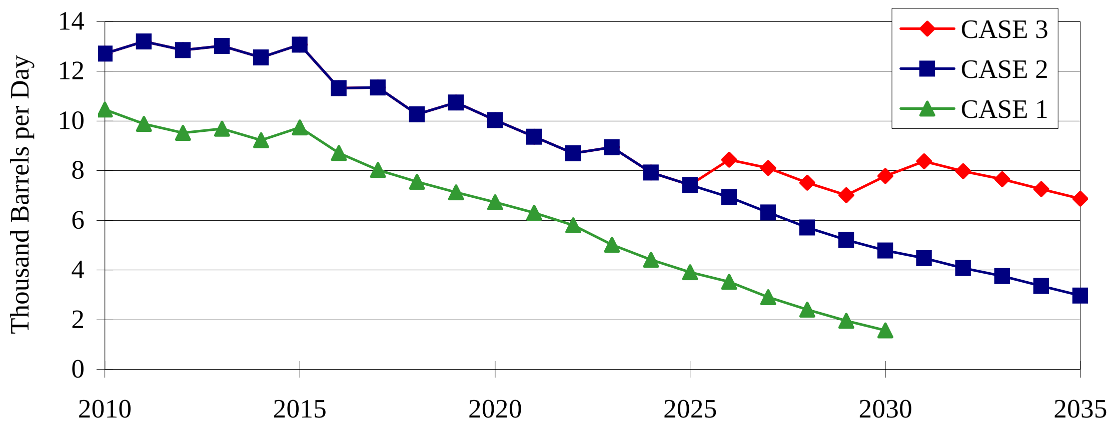
FIGURE 2.1: GAS PRODUCTION PROFILES UNDER THE THREE VOLUME CASES



Case 2 - Anchor Fields + Other Known Gas and Some New Discoveries

For Case 2, it is assumed that gas from other fields already identified in the Mackenzie Delta as well as from several new discoveries would be available for production by 2010. Volumes from these sources plus the anchor fields would total approximately 1.2 Bcf/d (or 438 Bcf/yr) during the initial years of production. The complete production profile is illustrated in Figure 2.1 (and is also shown in Appendix Table A.1). It can be observed that significant production decline is expected to begin by 2023. The decline rate is anticipated to average about 12% per year between 2023 and 2035 (the end of the analysis period).

FIGURE 2.2: NGL PRODUCTION PROFILES UNDER THE THREE VOLUME CASES



NGL production in Case 2 is shown in Figure 2.2 and in Appendix Table A.2. NGL production over the first six years (2010-2015) is expected to be in the range of 13,000 barrels/day. Then, as in Case 1, significant production declines would begin earlier than for gas production, with an average annual decline rate of about 7% through to 2035.

Case 3 - 'Full Pipeline' Case

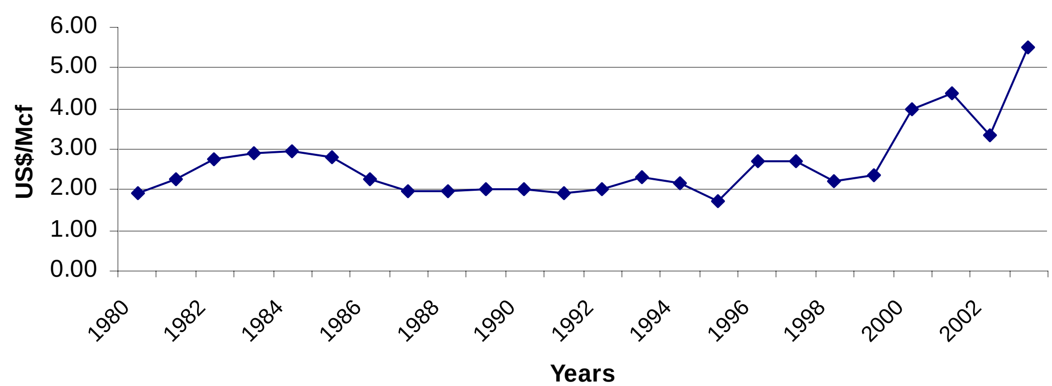
The third scenario for gas volumes has additional new discoveries made in later years of the project such that gas production could be maintained near pipeline capacity (1.2 Bcf/d) until 2035. Case 3 gas volumes and NGL volumes are illustrated in Figures 2.1 and 2.2 respectively and also appear in Appendix Tables 2.1 and 2.2. Case 2 and Case 3 volumes are identical until 2025, after which Case 3 volumes are higher. While gas production in Case 3 is expected to range between 1 Bcf/d and 1.2 Bcf/d for the duration of the project, it is anticipated that NGL production levels at the end of the analysis period would be roughly 60% of those observed over the first few years of production.

It can be noted that in the 2002 Mackenzie Valley Study it was assumed that gas flows would equal 1.2 Bcf/d for a 25 year operating period. As such, Case 3 in this report would most closely correspond to the 2002 analysis. Nevertheless, as is described below, there remain some significant differences in the overall project details incorporated in the current analysis as compared with the 2002 study.

Gas and NGL Prices

Economic impacts are evaluated for two gas price scenarios. As in the 2002 Mackenzie Valley Study, the gas price in Chicago in real (or constant year 2003 dollar) terms is assumed to be $3US/Mcf and $4US/Mcf under the respective scenarios. In each of these scenarios it is assumed that the real price remains constant over time in the analysis. Hereafter, these scenarios are referred to as the $3US gas price scenario and the $4US gas price scenario.

FIGURE 2.3: NATURAL GAS PRICES – ANNUAL AVERAGE (NOMINAL DOLLARS) AT CHICAGO, 1980 to 2003



Source:based on US EIA statistics and Sproule Price Reports.

As shown in Figure 2.3, since 1980 gas prices have ranged from $1.64US to $5.39US per Mcf, and have averaged $3.11US over the 1995 to 2003 period. As noted later, the assumed exchange rate in this analysis is $1US = $0.75 Cdn, compared to $1US = $0.67 Cdn in the 2002 WMR Study.

Other things equal, this higher exchange rate has the effect of reducing the gas price expressed in Cdn dollars.

It is anticipated that the NGLs produced from the Mackenzie Delta fields will consist primarily of condensate/pentanes plus. Prices of these products tend to be very similar to oil prices and for analytical purposes it is assumed that the prices will be identical. Oil prices are also assumed constant in real terms over time and equal $19.50 US/barrel (2003$) in Chicago for the $3US gas price scenario and $26.00 US/barrel in the $4US gas price scenario.

Exchange Rates and Inflation Rates

The US$/Cdn$ exchange rate is assumed to be $0.75US/Cdn$ throughout the period of analysis. Inflation in both countries is assumed to be 2% annually. Although the gas price scenarios are defined in terms of 2003$, <u>all of the economic impact results indicated in the report are shown in 2004$.</u>

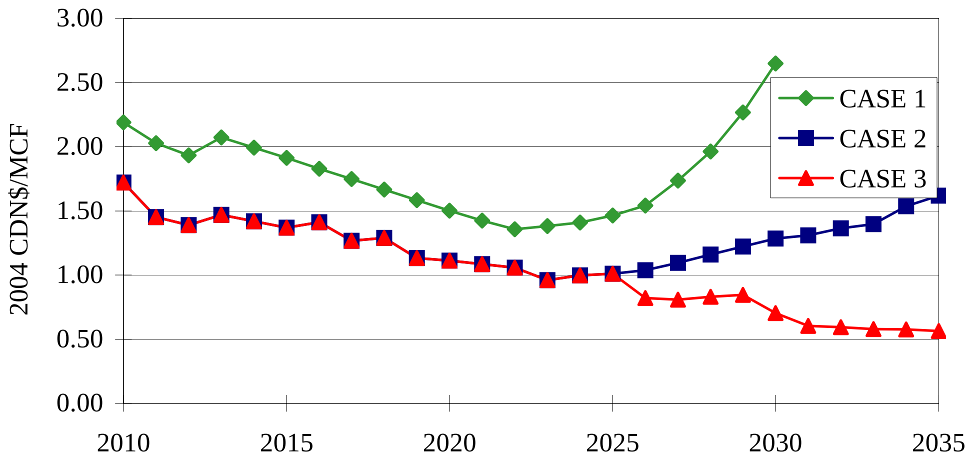
Producer Netbacks

The cost of pipeline transportation to ship gas from the Alberta Border (or AECO) to Chicago is assumed to be $0.98 Cdn/Mcf (2004$) in both gas price scenarios and this is assumed to remain constant over time in real terms. This translates into AECO prices of $3.10 Cdn/Mcf in the $3US Gas Price case and $4.46 Cdn/Mcf in the $4US Gas Price case.

Further, the assumed toll on the TCPL Alberta system from AECO to the anticipated interconnect with the Mackenzie Valley pipeline at the Alberta/NWT border is $0.33 Cdn/Mcf (also remaining constant in real terms over the duration of the project). Consequently, the gas prices at the Alberta/NWT border would be $2.77 Cdn/Mcf in the $3US gas price scenario and $4.13 Cdn/Mcf in the $4US gas price scenario.

In order to arrive at a netback price for Mackenzie Delta gas producers, the toll on the proposed Mackenzie Valley gas pipeline must be subtracted from the price at the Alberta/NWT border.

FIGURE 2.4: PROJECTED TOLLS ON THE MACKENZIE VALLEY GAS PIPELINE IN THE $4 US GAS PRICE SCENARIO: 2010-2035*



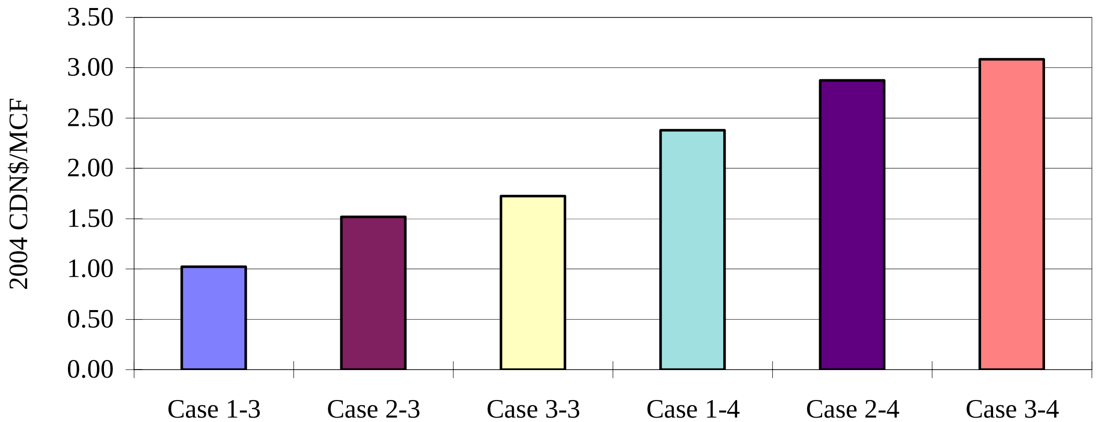
* tolls in Case 1 and Case 2 in the $3 gas price scenario are slightly different than shown here

The expected tolls on the Mackenzie Valley gas pipeline in the $4US gas price scenario are shown in Figure 2.4 for the three volume cases described previously. It can be observed that the tolls in Case 1 are expected to be roughly $0.50/Mcf higher than in either Case 2 or 3 over much of the analysis period. This is the result of the significantly lower volumes in Case 1 with only anchor field production combined with the fact that the incremental capital costs associated with transporting 1.2 Bcf/d of gas versus 0.8 Bcf/d are anticipated to be relatively small (see pipeline capital cost description below). Although the annual cost of service would be higher in Cases 2 and 3 because of the additional compression necessary, the overall costs are spread over greater volumes resulting in a lower per unit toll.

As production declines in Case 1 beyond 2025, the deviation between the Case 1 tolls and the Case 2 and 3 tolls becomes larger over time. Similarly, Case 2 and 3 tolls would no longer be identical beyond 2025 since production from additional discoveries assumed in Case 3 but not in Case 2 allow the allocation of identical cost of service over greater volumes in Case 3. Given the toll patterns illustrated in Figure 2.4, producer netbacks are expected to vary substantially on a year-to-year basis as well as between scenarios. Figure 2.5 shows the average producer netback on gas sales under each of the situations. Given the three volume cases and two gas price scenarios described above, there are effectively six cases in this report. These are denoted in the analysis that follows by first referring to the volume case and then referring to the gas price scenario. For example, Case 1-3 refers to a situation with Case 1 volumes and the $3US gas price scenario. Figure 2.4 illustrates that the average producer netback on gas sales varies from $1.02/Mcf in Case 1-3 to $3.08/Mcf in Case 3-4. The average netbacks in the $4 gas price scenario are roughly $1.36/Mcf higher than in the $3 gas price scenario across all cases.

Producer netbacks on NGLs are calculated in a similar manner to the gas netbacks. Tolls from Chicago to Edmonton ($1.48 US/barrel constant in real terms (2004$), Edmonton to Zama ($1.11 Cdn/barrel constant in real terms), Zama to Norman Wells and Norman Wells to the Mackenzie Delta (both of which were modelled by the project sponsors using a cost of service methodology) are deducted from the Chicago NGL price to arrive at the producer netback. Given the overall volume of NGLs relative to the gas volumes (as shown in Table 2.1) and the respective netback prices for the two commodities, the revenues associated with gas production amount to over 90% of the producer revenues in all cases.

FIGURE 2.5: AVERAGE PRODUCER NETBACKS AT INUVIK ON GAS SALES: 2010-2035



Note: Case 1-3 is volume case 1 and $3 US gas at Chicago; Case 1-4 is volume case 1 and $4 US gas at Chicago; Other Cases are similarly defined with the first number indicating the volume case and the second number indicating the price case.

Table 2.1 shows that over twice as much gas would be produced in Case 3 compared to Case 1 under either gas price scenario. Furthermore, the more attractive netbacks available at the $4US gas price versus the $3US gas price would result in greater gas production in Cases 1 and 2 because fields could continue to operate for an additional year or two before becoming uneconomical and being shut in.

TABLE 2.1: OVERALL GAS AND NGL PRODUCTION IN THE VARIOUS CASES: 2010-2035

Case	1-3	2-3	3-3	1-4	2-4	3-4
Gas Production (Tcf)	5.16	8.86	10.73	5.36	8.95	10.73
NGL Production (million barrels)	47.8	80.2	91.4	49.1	80.7	91.4

Note: Case 1-3 is volume case 1 and $3 US gas at Chicago; Case 1-4 is volume case 1 and $4 US gas at Chicago; Other Cases are similarly defined with the first number indicating the volume case and the second number indicating the price case.

Royalty Rates

Federal royalty rates on frontier gas are determined in the following manner. The royalty as a percentage of gross revenue is one percent when production begins, rising by one percentage point every 18 months to a maximum of five percent of gross revenue until payout.[2] After payout, the royalty is the greater of 30% of net revenue or 5% of gross revenue.[3]

Tax Rates

It is assumed that the federal income tax rate applicable to the pipeline operations will be 22.12%, after adjustments. The gas producers are assumed to be subject to the recent changes in the federal income tax regime, whereby royalties will be deductible in calculating taxable income, and the tax rate will be reduced to a federal rate of 22.12%. It is also assumed that the pipeline would be subject to the large corporations tax (0.23% of capital). The corporate income tax rates in the NWT and Alberta are assumed to remain at 14% and 12.5% respectively.

In establishing the annual revenue requirement that would be associated with the Mackenzie Valley pipeline, $15 million (2003$) per year was included to cover items such as GNWT property taxes and other equivalent fees or land use costs. It is estimated that about one half of this figure would represent GNWT property taxes. In order to estimate property taxes paid by Mackenzie Delta gas producers, the typical proportion of operating costs that consisted of property taxes for oil and gas producers in the NWT over the last decade (4%) is assumed to apply to the Mackenzie Delta producers.

[2] Payout occurs where cumulative gross revenues equal cumulative cost base. Cumulative cost base is the total of allowable capital and operating costs. See http://inac.gc.ca/oil/roy (Department of Indian and Northern Affairs - Government of Canada website) for a detailed description of the royalty regime.

[3] Net revenue is gross revenue minus allowable capital and operating costs.

Grant Reduction in the Territories

Government revenue raised in the NWT (and in the Yukon and Nunavut) by the territorial government would affect the Formula Financing Grant from the federal government. It is assumed that for every $1 of territorial government revenue created by the pipeline and gas development projects, the net effect on territorial government revenue would be $0.20 with the $0.80 going to the federal government in the form of a grant reduction to the territorial government.

It can be noted that discussions on the devolution of some federal powers and enhanced northern revenue sharing are ongoing. However, no attempt is made in this analysis to incorporate any possible changes to the formulas or arrangements regarding federal grants and transfers or incorporate new elements that may arise as Mackenzie Delta resource development plans proceed.

2.2 Direct Investment

The overall project involves substantial investment by both the pipeline and gas producer sectors. A description of the various components of the project and costs is provided in this section.

Mackenzie Valley Gas Pipeline

According to information provided by the project sponsors, the capital cost of a gas pipeline running from the Mackenzie Delta to the NWT/Alberta border would be $3.5 billion (2004$) in Case 1 when maximum gas production would be roughly 826 Mmcf/d. Additional compression would be required in Cases 2 and 3 to bring the pipeline capacity up to 1.2 Bcf/d and this would cost $380 million. As a result, under Cases 2 and 3 the Mackenzie Valley gas pipeline cost would be approximately $3.9 billion.

NGL Pipeline from Inuvik to Norman Wells

Another component of the overall project is an NGL pipeline that would run from the Mackenzie Delta to Norman Wells. This pipeline would have a capacity of approximately 20,000 barrels/day and would cost approximately $540 million. The costs of the NGL pipeline are assumed to be the same under each of the volume cases.

Downstream Pipeline and Facility Requirements

The NGL pipeline from the Mackenzie Delta would connect to the existing Norman Wells pipeline that transports oil to Zama, Alberta. The project sponsors have estimated that approximately $40 million (2004$) would have to be spent on various facilities upgrades at Norman Wells in order to accommodate Mackenzie Delta NGLs.

In addition, TCPL has indicated that given the current supply, demand and capacity situation on the TCPL Alberta system, roughly $150 million in capital expenditures would be required to accommodate the Mackenzie Delta gas volumes. These investment figures are incorporated in the estimation of impacts.

It is well known that gas pipeline infrastructure south of sixty is running below capacity and is likely to become more so in the future. The introduction of 800 to 1,200 MMcf/d of gas from the north will improve the utilization of existing southern pipeline infrastructure, to the benefit of the transmission companies and the southern gas producing industry. In addition it should be noted that the additional NGLs available at Norman Wells will significantly improve the utilization of the existing Norman Wells oil pipeline.

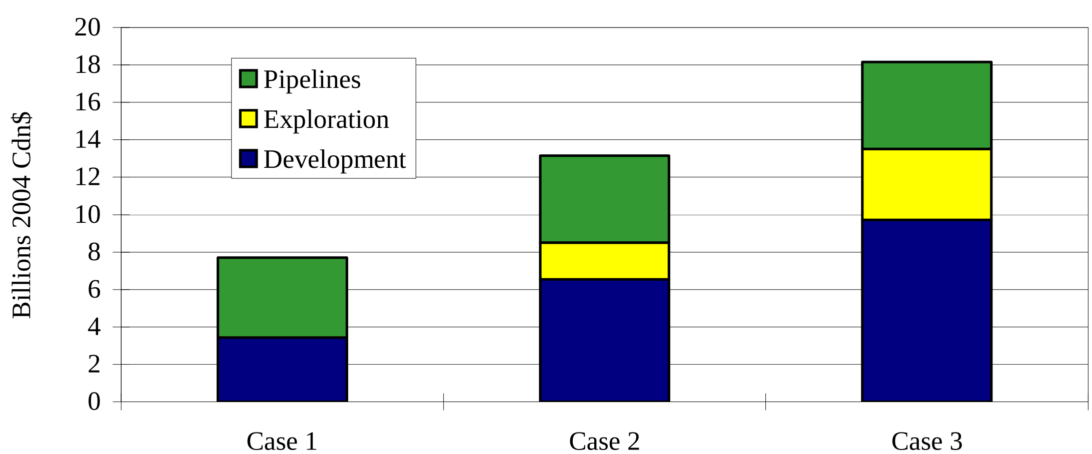
Given the various expenditures by the pipeline sector, it is estimated that its total investment would equal $4.3 billion in Case 1 and $4.6 billion in Cases 2 and 3. These amounts are illustrated in Figure 2.6 along with gas producer investments as described below.

Gas Field Exploration and Development Costs

In Case 1 where only the anchor fields (Niglintgak, Parsons Lake and Taglu) would be developed, the total capital cost is estimated to be $3.4 billion (2004$). This figure includes the cost of development drilling and the construction of a gathering system, various field facilities and a gas plant at Inuvik. Exploration costs associated with the anchor fields have already been spent (i.e. are sunk) and consequently the economic impacts related to these expenditures are not included in this analysis.

In Case 2, other known gas fields in the Mackenize Delta would have to be developed and there would also be expenditures on exploration and development of new discoveries necessary to bring initial gas volumes up to roughly 1.2 Bcf/d. It is estimated that an additional $3.1 billion would have to be spent on development activity in non-anchor fields and that exploration expenditures would amount to $2.0 billion. As a result, the total capital expenditure by the gas producer sector in Case 2 would amount to $8.5 billion.

FIGURE 2.6: EXPLORATION AND DEVELOPMENT EXPENDITURES BY GAS PRODUCERS AND PIPELINE SECTOR INVESTMENT: 2002-2035



In Case 3, additional exploration and development expenditure would be required in the later years of the project to maintain gas production capacity near 1.2 Bcf/d. In comparison to Case 2, another

$1.8 billion in exploration spending and $3.2 billion in development spending would be required bringing the total investment by the gas producer sector to $13.5 billion in Case 3.

Total Investment

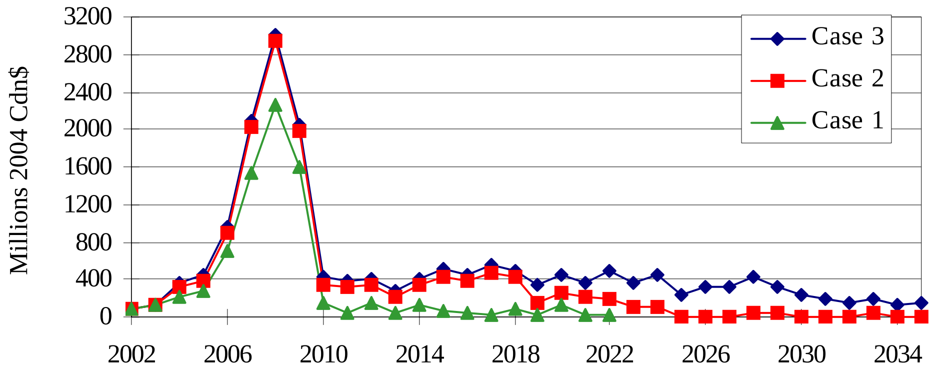
Figure 2.6 shows the total investment by both the gas producer and pipeline sectors over the entire analysis period. In Cases 1, 2 and 3 respectively, total direct investment is estimated to be $7.7 billion, $13.1 billion and $18.2 billion ($2004). The investment in Case 3 is equivalent to roughly 8% of the total investment in Canada in 2003.[4] Almost all of the investment in each of the cases would occur in the NWT. The Case 1 investment alone amounts to more than twice the total Gross Domestic Product (GDP) in the NWT in the year 2003.

Total direct investment by year is illustrated in Figure 2.7 and is described in more detail in Appendix Table A.3. The peak investment years are expected to be 2007-2009, with investment amounts in those years ranging from $1.5-$2.3 billion in Case 1 and from $1.9-$3.1 billion in Cases 2 and 3. The investment in 2008 alone (the peak construction year of the project) under Cases 2 and 3 is almost equal to NWT's 2003 GDP.

The economic impacts arising from expenditures of these magnitudes can be expected to be large and diverse and should provide excellent opportunities for NWT residents. At the same time, however, projects of this type and magnitude must be properly managed so as to avoid the introduction or amplification of economic instability. For example, the labour requirements of the project between 2007 and 2009 almost certainly could not be met exclusively by NWT residents, so an influx of short to medium term workers could be expected. This could create infrastructure and social pressures unless otherwise mitigated. These issues are discussed in more detail in Section 3.7.

[4] See Canadian Statistics section of Statistics Canada website - www.statcan.ca.

FIGURE 2.7: DIRECT PROJECT INVESTMENT BY YEAR: 2002-2035



Although the direct investment in the project would be concentrated in the 2007-2009 period, a significant percentage of the overall investment in Cases 2 and 3 would occur on an ongoing basis later in the analysis period. In Case 3 in particular, exploration and development expenditures would be required essentially throughout the entire operating period of the project in order to ensure there was enough gas production to keep the pipeline operating near or at capacity. In total, it is expected that about $8.9 billion in exploration and development spending would be required during the operating period of the project, or roughly $340 million per year on average. The smaller magnitudes and sustainability of such investment represent impacts that could be much more easily absorbed by the NWT economy without any dislocations. This would provide the opportunity for the development of a truly propulsive industry that can set the stage for more broadly based economic prosperity in the NWT.

For example, the Alberta economy was very similar to the Saskatchewan economy until the late 1940s and the discovery of oil at Leduc. In fact, up to that point the population of Saskatchewan (between 800,000 and 950,000 in the 1930s and 1940s) exceeded that of Alberta. The development of the oil and gas industry has been the principal reason that Alberta currently has a population of over 3 million, while Saskatchewan's population remains barely above 1930s levels. Such an industry gives people an opportunity and a reason to either stay in a region or migrate to a region (with the intention of staying), since the industry requires but also develops highly educated, highly skilled and highly paid workers.[5] Such opportunities for NWT residents should develop with this project.

2.3 Direct Revenues

Direct revenues associated with the project are summarized in Figure 2.8, with additional detail provided in Appendix Figures A.1-A.6. Under the $3US gas price scenario, it could be expected that the operation of the various pipelines and the production of gas and NGLs would generate between $15.8 billion and $32.4 billion (2004 Cdn$) in direct revenues depending on the volume case. On an annual average basis, direct revenues over the operating period of the project would amount to between $800 million/year and $1.2 billion/year, or between 25% and 40% of NWT's 2003 GDP.

Although these revenues are very large, between 75% and 80% of the revenues would go towards resource costs (the costs of labour, capital and other inputs to develop, produce and transport the gas). The remainder of the revenues would be split fairly evenly between private sector returns and government revenues. However, the distribution of each of these could be expected to be skewed towards particular stakeholders. For example, federal government revenues would amount to between $1.5 billion and $3.1 billion and comprise between 9% and 11% of total revenues in the $3US gas price scenario depending on the volume case. On the other hand, after grant reduction the NWT government would receive between $0.1 billion and $0.3 billion or less than 1% of total revenue under any of the volume cases. With respect to the private sector, there would be a net cash flow of between $1.6 billion and $2.2 billion (or between 7% and 10% of total revenues) to pipeline equity. The net cash flow to producer equity is negative in Case 1 under the $3US gas price scenario and amounts to slightly over $1 billion in Case 3 or less than 3% of total revenue.

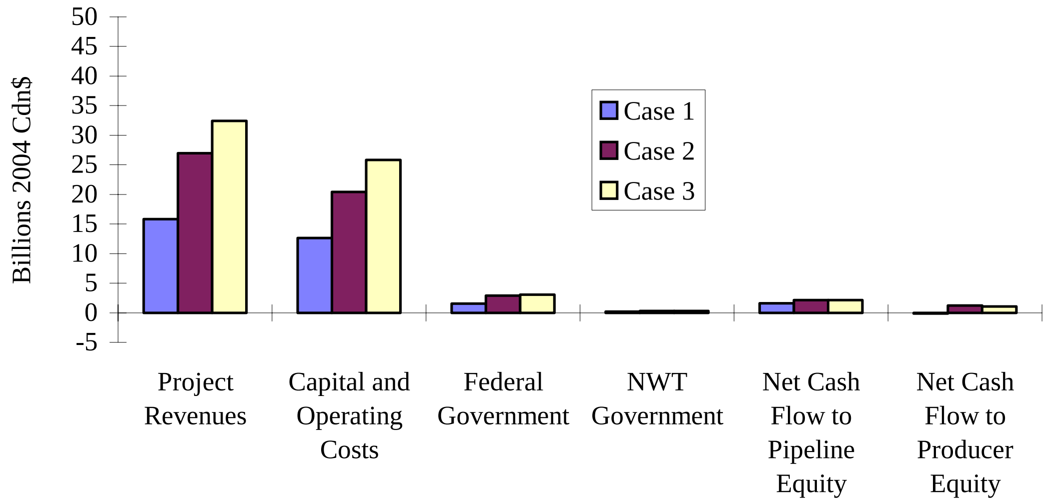
In contrast, government revenues, and net cash flow to producer equity and overall direct revenues are significantly higher in the $4US gas price scenario. Revenues could be expected to range from

[5] Educational attainment levels in Alberta are currently the highest of any region in Canada. Further, average annual earnings in the oil and gas industry in Canada were just under $72,000 in 2001. This was more than double the average annual earnings across all industries in Canada of about $35,000 (see Statistics Canada Catalogue 72-002).

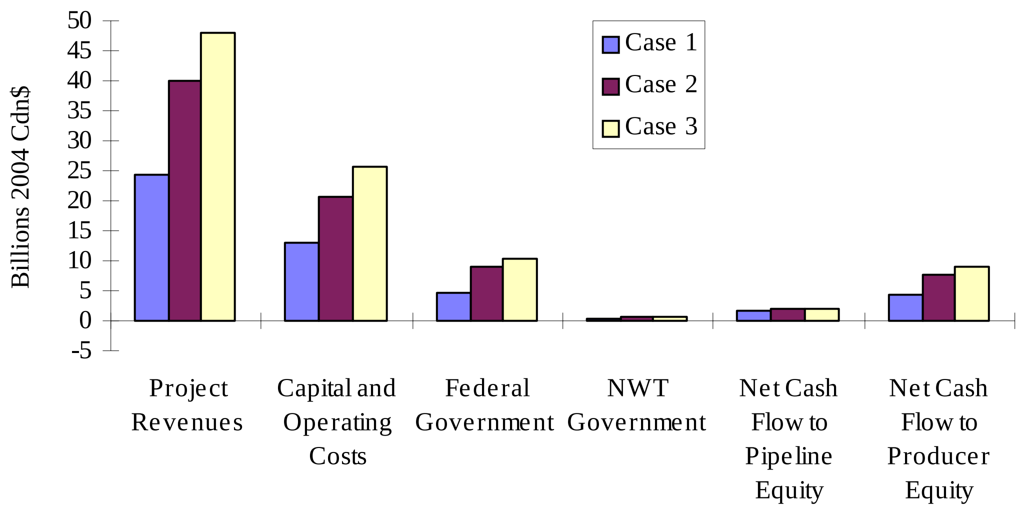
$24.2 billion to $47.8 billion over the different volume cases. On an average annual basis, this would amount to between $1.2 billion and $1.8 billion.

FIGURE 2.8: DISTRIBUTION OF CUMULATIVE PROJECT REVENUES AND COSTS: 2010-2035

$3US GAS PRICE SCENARIO



$4US GAS PRICE SCENARIO



Capital and operating costs and cash flow to pipeline equity change only slightly in absolute terms from the $3US gas price scenario, but decrease relatively to between 50-55% and 5-7% respectively of total revenues. With $4US gas the higher netbacks would be shared by the governments and the producers. Federal government revenues are larger than cash flow to producer equity in all volume cases and comprise 19% to 22% of total revenues. NWT government revenues after grant reduction would amount to between $0.3 and $0.6 billion or less than 2% of revenues in any of the cases. Cash flow to producer equity range from $4.3 billion to $8.8 billion in the various cases and amount to between 18% and 19% of total revenues in the $4US gas price scenario.

Although the size of the cash flow to producer equity may seem quite substantial in this scenario, the analysis of the distribution of revenues to this point ignores an important factor. Both the pipeline and producer sectors (and any private sector investor for that matter) must make a competitive return on any investment that is made in order to attract the necessary financial capital. This is not taken into account by simply looking at the distribution of revenues. One method of estimating the returns on investment with this factor included is to calculate the present value of the net cash flows using an appropriate discount rate that reflects the opportunity cost of money used by the investor. Present values of the various revenue categories depicted in Figure 2.8 are calculated using an illustrative 8% real after-tax discount rate and the results are summarized in Figure 2.9.

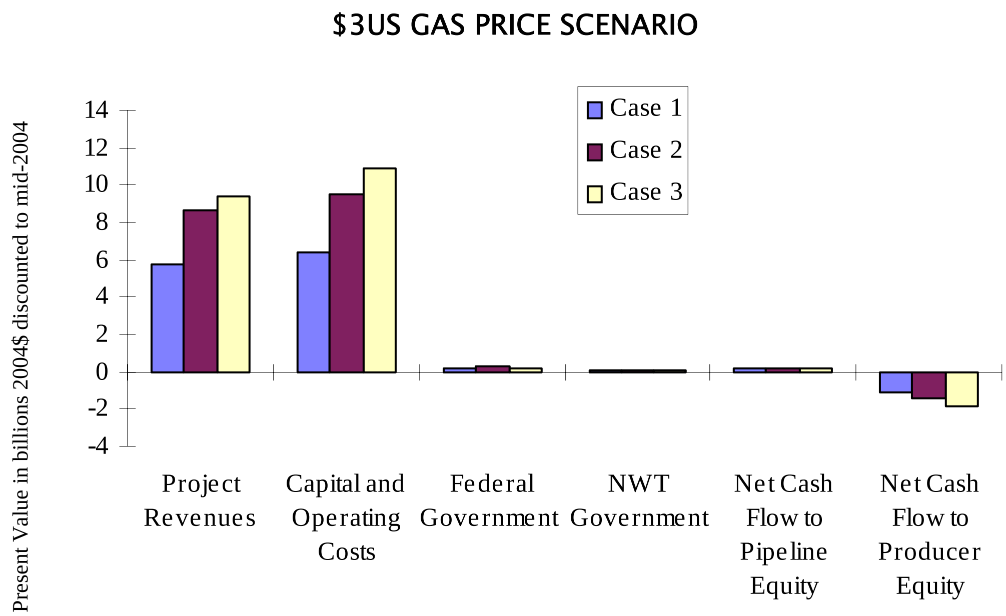
To be viable, the project must generate sufficient revenues to cover all capital and operating costs (including payments to governments) associated with the exploration, development, production, processing and transportation of the gas and gas liquids. This viability also requires a rate of return sufficient to attract the large amounts of equity and debt capital, needed to proceed with a project that has a number of risks such as construction cost and schedule risk, supply risk, market risk, regulatory risk and operating risk. While the potential rates of return needed to support a decision to construct are not known, an illustrative rate of return of 8% (real) was used in this analysis. The NEB approved rates of return for regulated pipelines, which have less risk than what producers face, are in the range of 10% to12% nominal (or about 8% to 10% in real terms). Given the risk profile of this project a real discount rate significantly higher than 8% may be justified.

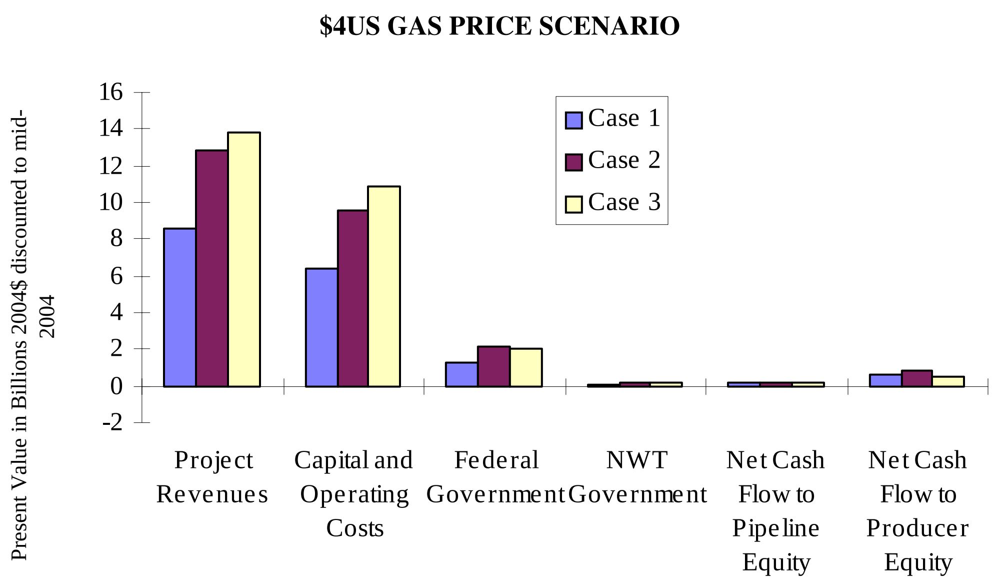
Although a detailed evaluation of viability was not undertaken, the results on rates of return suggest the risk-adjusted rates of return would be insufficient to attract the required capital unless average long term gas prices were substantially higher than $3US and/or costs were significantly lower than those used in the analysis.

In the $3US gas price scenario the present value of the capital and operating costs exceeds the present value of the revenues under all volume cases. Producers would find themselves with negative returns given the assumed 8% after tax real rate of return. The present values of the cash flow to producer equity are positive in the $4US gas price scenario.

Expressed differently, the internal rate of return on producer sector investment is less than 2% in the $3US gas price scenario and this would clearly not be sufficient to attract financing for the project. Even in the $4US gas price scenario, the internal rate of return only ranges between 9% and 12%. Depending on the capital structure of the project and the relative risk of the investment, higher sustained gas prices and/or lower costs may be required to make the project economic.

FIGURE 2.9: PRESENT VALUE OF CUMULATIVE PROJECT REVENUES AND COSTS GIVEN AN 8% AFTER TAX REAL DISCOUNT RATE : 2010-2035



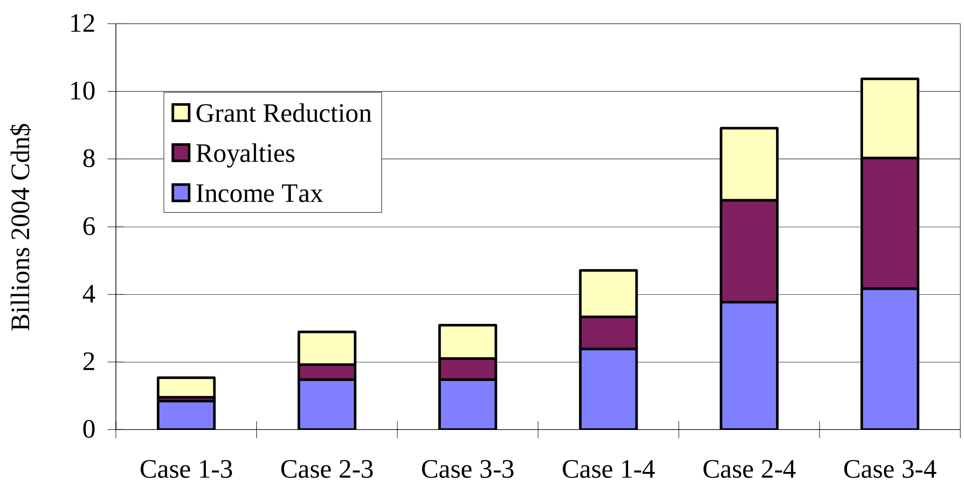


2.4 DIRECT GOVERNMENT REVENUES

Appendix Tables A.4 and A.5 provide a detailed breakdown of government revenues by type for the various levels of government. Given the fact that federal government revenue would comprise more than 85% of the total direct government revenues in either gas price scenario, it is useful to examine the breakdown of that revenue. This is illustrated in Figure 2.10.

Income taxes would make up the largest portion of direct federal government revenue in each of the cases, ranging from 40% to 55% of the total. Royalties would comprise less than 20% of direct federal government revenue in the $3US gas price scenario but would be substantially larger with a $4US gas price. In that situation, royalties would range from just under $1 billion in Case 1 to just below $4 billion in Case 3 and would represent between 20% and 40% of overall direct federal government revenue. In addition to the income taxes and royalties, the federal government would also benefit from grant reduction to the NWT and these amounts range from 20-30% of the total in the $4US gas price scenario to 30-40% of the total in $3US gas price scenario.

FIGURE 2.10: DISTRIBUTION OF DIRECT FEDERAL GOVERNMENT REVENUES: 2010-2035



With respect to other levels of government, as indicated in Tables A.4 and A.5, the Alberta government would collect property and income taxes amounting to between $55 million and $75 million depending on the case.[6] The NWT government revenues after grant reduction were noted earlier and they would translate into $8-9 million per year in the $3US gas price scenario and between $16 million and $23 million per year in the $4US gas price scenario. Given that the annual NWT government revenues in recent years have been less than $1 billion, this is not an insignificant amount.[7]

2.5 Direct Employment

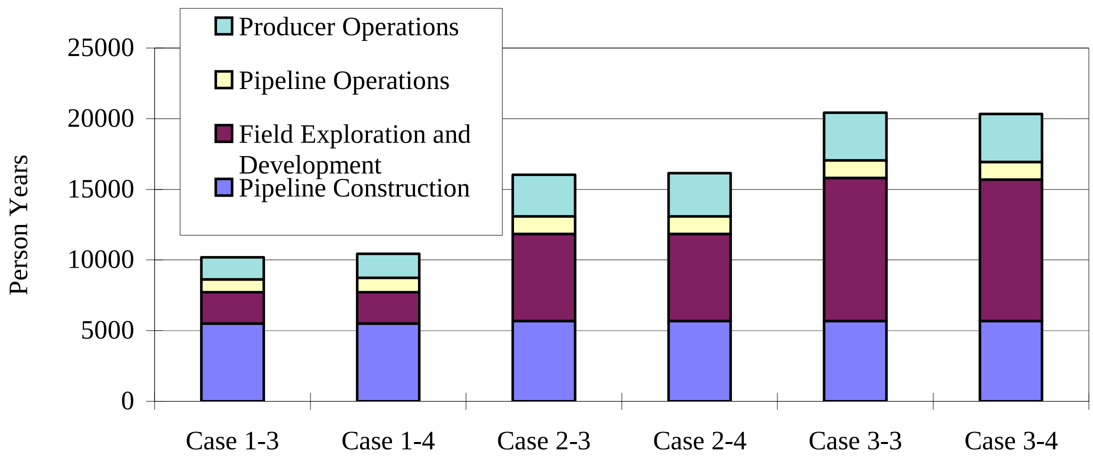
The final dimension of the direct impacts associated with the project involves the direct employment that would be generated. Appendix Table A.6 contains breakdowns by sector (pipeline vs producer), by project phase (construction vs operation) and by region (NWT vs Alberta). In addition, Figure 2.11 summarizes the overall direct employment that could be expected under the various cases.

It is anticipated that cumulative direct employment would range from just over 10,000 person years in Case 1 to about 16,000 person years in Case 2 and slightly more than 20,000 person years in Case 3. In each of the scenarios, direct employment would be dominated by construction phase employment. Pipeline construction (which would include the Mackenzie Valley gas pipeline, the NGL pipeline from the Mackenzie Delta to Norman Wells, and additional facilities on the TCPL Alberta system and at Norman Wells) would create between 5,500 and 5,700 person years of employment, with the larger amounts occurring in Cases 2 and 3 where more compression would be required on the Mackenzie Valley gas pipeline.

[6] Because Alberta provincial government revenue is so small in terms of overall direct revenues, it would not have been noticeable in Figure 2.4 as a separate category and was included in resource costs to ensure the total impact was accurate.

[7] See Territorial Government Finance section of the NWT Bureau of Statistics website - www.stats.gov.nt.ca.

FIGURE 2.11: TOTAL DIRECT EMPLOYMENT BY PROJECT PHASE AND SECTOR: 2010-2035



Direct employment related to field development in Case 1 (where only the anchor fields would be developed) is estimated to be about 2,200 person years. In Cases 2 and 3, additional fields would have to be developed and exploration would also have to take place resulting in direct employment between 6,200 person years in Case 2 to just over 10,000 person years in Case 3. In total, construction phase employment is expected to range between 7,700 person years and 15,700 person years and would constitute roughly three-quarters of all direct employment created under any of the scenarios.

The total direct employment arising from the operation of pipeline and producer facilities is also shown in Figure 2.11. Between 900 and 1250 person years of employment could be expected to be created through the operation of various pipeline facilities over the course of the project. The variation in values relates solely to the different operating time frames under the various scenarios (from 19 years in Case 1-3 to 26 years under Cases 2 and 3).

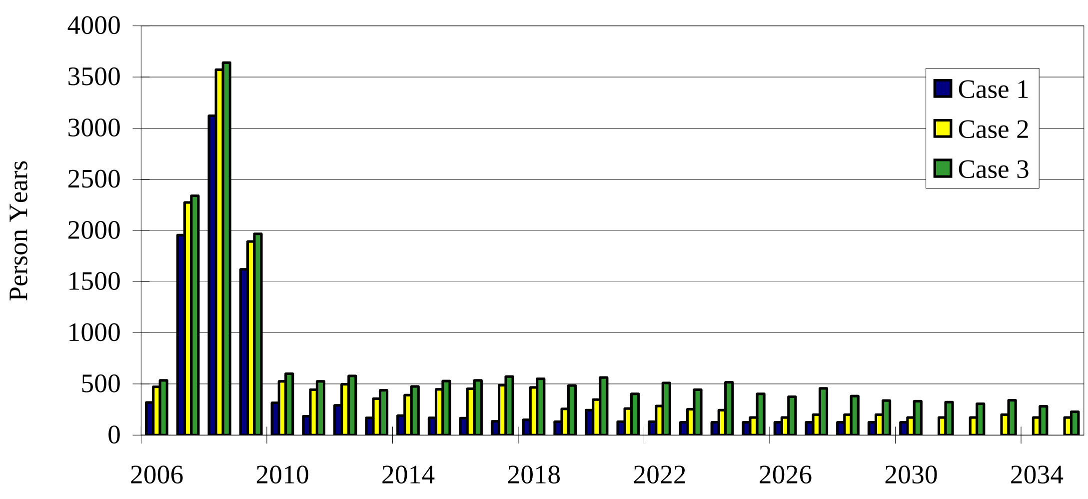
Operation of producer facilities could be expected to range more widely between scenarios given the more extensive development that would be necessary in Case 3 vs Case 2 and in Case 2 vs

Case 1. Total employment related to operation of producer facilities would range from 1500 person years to 3400 person years depending on the scenario. This would translate into average annual employment levels of between 81 jobs in Case 1 to about 130 jobs in Case 3. Roughly 75% of the jobs would be located in the NWT and about 25% in Alberta.

In total, direct employment related to operations of project facilities is expected to range from 2500 person years to 4600 person years, or between about 130 and 180 jobs annually. These would be long-term jobs and about 70% would require residence in the NWT. Although training would likely be required, it is likely that they could easily be accommodated by the labour supply in the region.

In contrast, with respect to construction phase employment, it is expected that a significant number of temporary workers from other parts of Canada would have to be brought into the NWT to aid in pipeline construction and field exploration and development. Figure 2.12 illustrates the direct project employment by year in the various cases.

FIGURE 2.12: ANNUAL DIRECT PROJECT EMPLOYMENT: 2006-2035



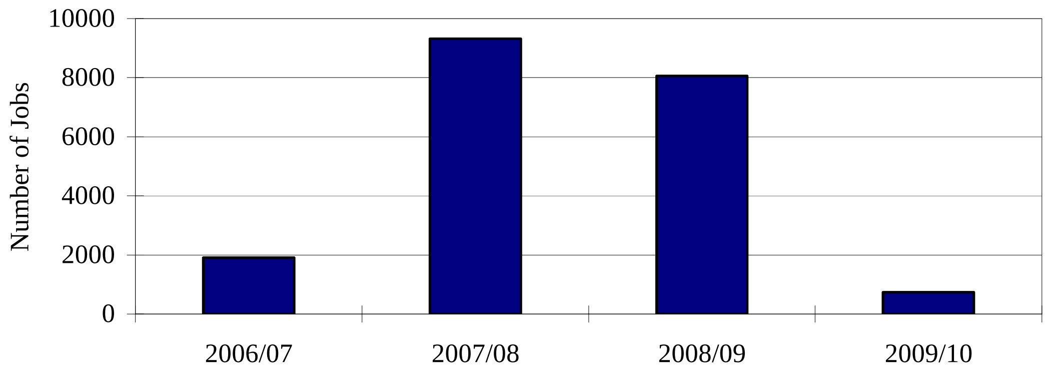
Construction employment would be concentrated in the period 2007-2009 when the bulk of the pipeline construction and the development of the anchor fields (and other known gas in Cases 2 and 3) would take place. Depending on the case, between 3100 and 3600 person years of employment would be created in 2008 alone, along with anywhere from 1600 to 2400 person years in each of 2007 and 2009.

Given that almost all of this impact would occur in the NWT and that in the last year the region had less than 2,000 officially unemployed people in total (many of whom would not have adequate skills to take the particular types of jobs that the project would create), a significant number of temporary workers from other parts of Canada would have to be brought into the NWT.[8] Further, the extent of the requirement for labour 'imports' into the NWT during the peak construction phase is actually understated in Figure 2.12 where annual direct employment impacts are summarized. Both pipeline construction and field development would have to be carried out primarily in the winter and over a relatively short season typically less than three months in total.[9] As a result, since each person working during the season would only actually work less than a third of a person year, significantly more people would be required than is suggested in Figure 2.12 over the peak construction period. This is illustrated in Figure 2.13 where the personnel requirements over the main construction seasons are shown for Case 1. Thousands of workers would be required in the winter seasons of both 2007/2008 and 2008/2009 and this increases the extent to which workers from outside the NWT would have to brought in during the peak construction phase. This issue is addressed in detail in Section 3.7.

[8] Data from NWT Bureau of Statistics, Statistics Quarterly (December 2001). While the general pool of unemployed people in the NWT may be able to find work as labourers or camp workers quite readily during project construction, the project would also require welders, machine and heavy equipment operators, supervisors, inspectors, etc. who would all need to have sufficient training and skill to perform these jobs. It is highly unlikely that the total requirement for these types of positions could be filled by NWT residents.

[9] Depending on the job category, the expected number of days on the job for a worker ranges from 42 to 84. It should also be noted that the average hours per day in these types of job could be expected to be much higher than a typical job. In the analysis, it is assumed that people would work 12 hours per day in construction (versus 8 hours per day typically) and this is used to convert person years to personnel requirements.

FIGURE 2.13: PERSONNEL REQUIREMENTS BY SEASON FOR PROJECT CONSTRUCTION IN CASE 1: 2006-2010



Beyond the peak construction period, there is a much greater possibility that ongoing construction employment could be filled by NWT residents, especially in the later years of the project since many would have already been trained and gained experience. Figure 2.14 illustrates the overall direct employment (construction and operating) generated by the project beyond 2010 (or beyond the peak construction period) by case. Even in Case 1 where there would be limited field development after 2010, close to 500 person years of ongoing construction employment would be created over time in addition to the operating employment described earlier. However, in Cases 2 and 3 the amount ongoing construction employment would be much more substantial as additional exploration and development activity would occur. For example, in Case 2 average annual ongoing construction employment between 2010 and 2018 would be close to 250 person years.

Exploration and development activity would be even more extensive under Case 3 where quite significant ongoing construction employment would be generated through most of the analysis period. Figure 2.15 illustrates the breakdown of ongoing direct employment under Case 3 and shows that significant job opportunities would be created for NWT residents beyond 2010 in that case in particular. Although the ongoing construction jobs would be seasonal in nature, there are not nearly as many as during the peak construction period and it could be expected that a much greater proportion of these jobs would be taken by NWT residents than in the peak construction period, especially once training occurs and experience is gained.

FIGURE 2.14: ONGOING DIRECT PROJECT EMPLOYMENT BEYOND THE PEAK CONSTRUCTION PERIOD: 2010-2035

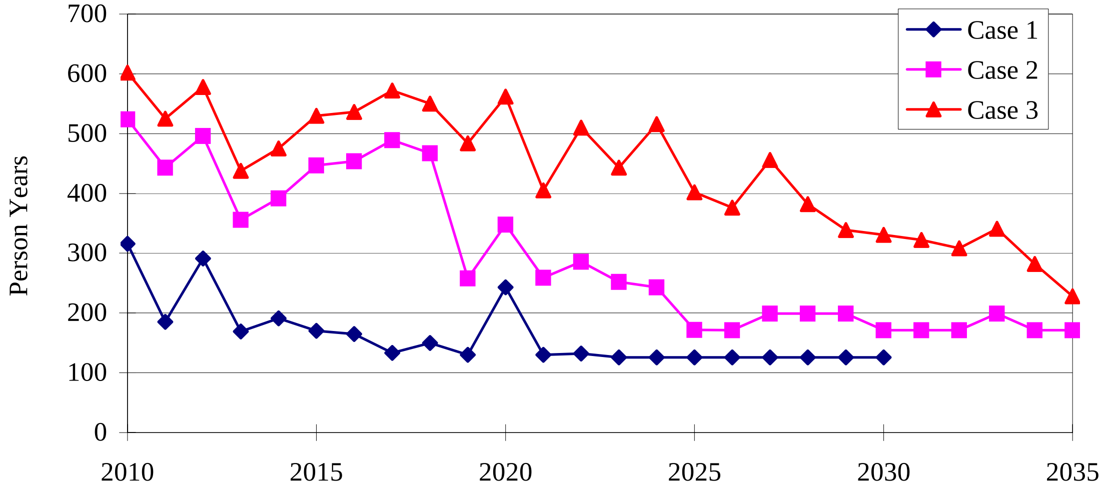
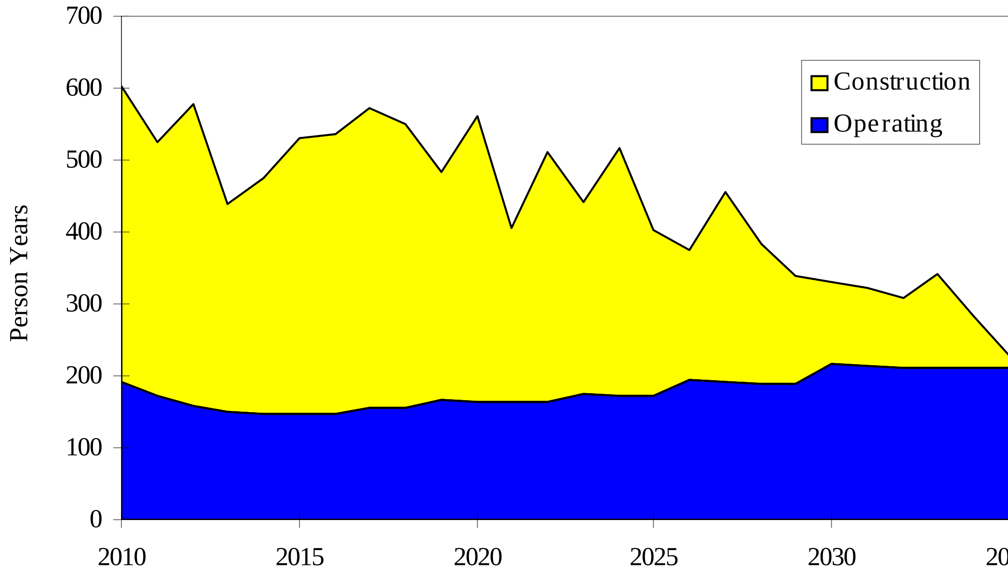


FIGURE 2.15: ONGOING CONSTRUCTION AND OPERATING EMPLOYMENT* IN CASE 3 : 2010-2035



*includes employment associated with exploration and development

3.0 DIRECT AND INDIRECT ECONOMIC IMPACTS

In addition to the direct impacts outlined in the previous section, the Mackenzie Valley pipeline and Mackenzie Delta field development can be expected to generate a wide variety of indirect impacts in the NWT and throughout Canada. This section deals with the indirect and total impacts in Canada overall and in individual regions.

3.1 METHODOLOGY

The effects of the project can be expected to be widely distributed geographically and extend well beyond the NWT and northern Alberta where the project is physically located. In addition, industries other than just the pipeline and gas production industries are likely to experience changes because of the project. In order to determine the ultimate effects, it is necessary to take into account the many complex sectoral and regional interactions that exist in the economy.

Many of the direct inputs involved in the projects would be purchased from other regions and from outside Canada. Purchases from foreign suppliers represent ‘leakages’ from a Canadian perspective and will produce no additional impacts in the domestic economy. However, if demand for direct inputs is satisfied by Canadian suppliers, this creates various indirect impacts in Canada. For example, demand for pipe in the NWT could lead to increased steel pipe production in Saskatchewan. This, in turn, would lead to additional purchases of inputs from Saskatchewan, other regions in Canada and foreign sources.

The standard method of measuring the net impacts after all complex actions and reactions are complete involves the use of an interregional input-output model. An input-output model simulates the effect on the economy when overall output of an industry changes in a specific region or when final demand for a particular commodity changes in a specific region (these changes are referred to as shocks). The latest Statistics Canada Interprovincial Input-Output Model (2000 Version) is utilized in this study to estimate economic impacts. The 2002 Mackenzie Valley Study employed the earlier (1996) version. The model offers a high level of disaggregation (719 commodities, 300 industries and 13 regions) and, hence, offers the flexibility to allow the incorporation of project specific information to the greatest extent possible.

This type of analysis relies on several fundamental assumptions. First, production technologies are assumed fixed. In other words, each industry is assumed to use the same proportions of inputs to produce its output regardless of the quantity of outputs produced. Consequently, any impacts calculated will reflect the average effect in a region, in contrast to the marginal effect of a particular project which quite possibly could differ. For example, the introduction of what may be a new industry to a region or the large scale expansion of an existing industry may significantly affect the inter-industry relationships within and outside the region. This is an important issue in this analysis because some of the industries that are being 'shocked' in the analysis are not yet highly developed.

Second, increases in demand from different sectors are assumed to have no effect on the prices of goods. For this assumption to apply it is critical that infrastructure and supporting industries would be able to respond to increases in demand without incurring any significant increases in average costs should expansion be necessary.

Third, the input-output model is by nature a static model with all of the relationships estimated for a specific, past time period. To the extent there have been significant changes in the relationships in the economy since the estimation period, the model results may not provide the most accurate representation of what would actually happen in the current or future environment.

It should also be noted that input-output models can also be used to estimate so called induced effects. The direct and indirect effects created by a project will produce additional labour income, government revenues and corporate profits which can then be spent / reinvested and this will set off another round of impacts. These induced effects are not explicitly considered in the detailed quantitative analysis of this section but could be expected to be quite pronounced, especially in terms of the additional oil and gas exploration, development and ultimately production that may arise through the reinvestment of profits accruing to gas producers. Further, the government revenue impacts would be very significant and this could allow governments to either spend more in the economy or to pay down debt and perhaps set the stage for lower tax rates in the future - something that would also produce additional induced impacts. Finally, the spending of labour income in general would set off even more impacts. The potential induced impacts associated with the project are discussed in Section 4.1 and in certain cases, rough approximations of the magnitudes of such impacts are provided.

In this evaluation of the direct and indirect impacts associated with the Mackenzie Valley pipeline and Mackenzie Delta field development, there are three industries (as defined by Statistics Canada) that would experience changes depending on the project phase (construction vs operation) and the sector (pipeline vs. gas production) that is being considered. These industries are oil and gas facility construction, natural gas pipeline transportation, and oil and gas production. Table 3.1 illustrates the input structure of these industries for Canada.[10] The numbers shown are per $100 of industry output and illustrate input usage by industry. For example, for every $100 spent on oil and gas facility construction, Table 3.1 indicates that $19.68 would go towards purchases of services incidental to mining.

The key difference between oil and gas facility construction and either natural gas pipeline transportation or oil and gas production is the overall percentage of purchased inputs (other than direct labour) that make up the total value of output. In oil and gas facility construction, purchased inputs comprise about 71% of the value of output, compared to roughly 30% in oil and gas production and only 23% in natural gas pipeline transportation. All of the indirect impacts that are calculated by an input-output model are related to these purchased inputs.

Consequently, a large proportion of construction phase impacts would be indirect whereas operation phase impacts would be dominated by direct impacts associated with the high proportion

[10] It should be noted that for a number of reasons, adjustments may be necessary to either the shock given to an input-output model or the results produced by the model. First, it may be that the level of aggregation in the model, even in its most detailed form, is not sufficient to accurately portray what would happen in a particular scenario. This is especially important for pipeline construction because this type of construction is lumped into the oil and gas facility construction category (i.e. along with the drilling of oil wells, the construction of oil and gas production facilities, etc.) in the Statistics Canada model. Material inputs differ significantly in pipeline construction versus general oil and gas facility construction and this must be taken into account when shocking the input-output model. Second, if an industry is not well developed in a particular region, results from the input-output may not provide a reasonable portrayal of the impacts of a project. This is often apparent by observing the extent to which the actual direct impacts expected from a project differ from the calculated direct impacts in the input-output model. To account for these differences, adjustments may be required either to the shock given to the model or the final results produced by the model.

of direct GDP that is typical of the industries involved on the operations side. In addition, during the construction phase there is the potential for far more leakages from the domestic economy in the form of imports than in the operations phase because of the high proportion of purchased inputs.

TABLE 3.1: DISTRIBUTION OF INDUSTRY INPUTS AND EXPENDITURES PER $100 OF INDUSTRY OUTPUT*: CANADA - 2000

Input/Expenditure Item	**Oil & Gas Facility Construction**	**Natural Gas Pipeline Transportation**	**Oil & Gas Production**
PURCHASED INPUTS			
Services Incidental to Mining	19.68		4.86
Crude Mineral Oils			1.04
Natural Gas		1.57	
Steel Pipes and Tubes	11.14		
Metal Tanks	1.10		
Fittings	1.07		
Valves	4.54		
Construction and Mining Machinery	1.30		1.43
Measuring and Controlling Instruments	2.64		
Repair Construction, Machinery & Equipment Repair		1.79	
Finance, Insurance and Real Estate	1.92	4.77	3.91
Wholesale Margins	2.62		
Electric Power			1.05
Architectural, Engineering & Scien. Services	10.68		
Other Business Services**	1.61	3.69	5.08
Operating Supplies***	5.61	5.20	8.25
Travelling/Entertainment		1.23	
Other Purchased Inputs	7.04	4.61	4.00
Total Purchased Inputs	**70.95**	**22.86**	**29.62**
DIRECT GDP			
Labour Income	24.33	11.93	4.61
Operating Surplus****	2.36	59.47	64.17
Indirect Taxes	2.36	5.74	1.60
Total Direct GDP	**29.05**	**77.14**	**70.38**

* Inputs where value is less than 1% of output placed into Other Purchased Inputs unless otherwise noted
** Architectural, Engineering & Scien. Services for Pipeline and Oil and Gas Production included here
*** Includes Rentals of Machinery and Equipment, Spare Parts, Maintenance and Office Supplies
**** Includes interest, depreciation, depletion allowances, royalties, income taxes and after tax profit

Source: Statistics Canada Input-Output Division

Although the Statistics Canada model contains coefficients which reflect the average import content of the purchases made by a given industry, the project sponsors have provided detailed sourcing information for major expenditure items during the construction phase and this was used wherever possible in order the evaluate economic impacts. The results are outlined in the next four subsections.

3.2 Pipeline Construction Impacts

Table 3.2 summarizes the impacts associated with the construction of the Mackenzie Valley gas pipeline in the NWT, the NGL pipeline from the Mackenzie Delta to Norman Wells, and additional facilities on the TCPL Alberta system and at Norman Wells. Capital expenditures would amount to $4.3 billion (2004 Cdn$) in Case 1 and $4.6 billion in Cases 2 and 3 (reflecting the additional compression necessary in those cases). These expenditures could be expected to generate an increase in Canadian Gross Domestic Product (GDP) ranging from $2.8 billion to $3.0 billion. In each case the overall GDP intensity ratio (GDP / capital cost) is 0.66 and this reflects the fact that a significant portion of the materials required for the pipeline would have to be imported. Total direct and indirect imports would range from $1.3 billion to $1.4 billion, or just over 30% of the total investment involved in this phase of the project.

The overall labour income impacts of between $2.0 billion and $2.2 billion represent more than 70% of the overall GDP impacts, with slight variations in this percentage across regions. Similarly, the ratio of the total government revenues (between $0.7 billion and $0.8 billion overall) to GDP is about one quarter for Canada as a whole with minor variations in this ratio between individual regions.

Roughly 35% of the overall GDP impact would be felt in the NWT, a percentage which may seem surprisingly low given that over 95% of the capital costs are attributable to the region in any of the cases. However, for small economies like that of the NWT, many of the indirect impacts (especially those related to manufactured materials) are transferred to other regions. Ontario, for example, could be expected to supply much of the pipe and other materials used in the project. Furthermore, many of the costs relating to project engineering, development and management that are allocated to the NWT would likely be sourced in Alberta. These factors contribute to a wide distribution of pipeline construction impacts across regions of Canada.

TABLE 3.2: IMPACTS OF MACKENZIE VALLEY PIPELINE CONSTRUCTION : 2002-2010*

(millions of 2004 Cdn$, employment in person years)

CASE 1	NWT	BC	Alta	SMYN**	Ont	Que	Atlantic	Total
Capital Costs	4111		150					4261
Gross Domestic Product	986	116	736	111	683	151	14	2797
Labour Income	826	79	522	50	434	100	8	2018
Federal Government Revenue	156	21	132	15	132	22	2	480
Terr./Prov. Government Revenue	65	11	45	17	94	19	1	253
Grant Reduction	-52			-1				-53
Adjusted Terr./Prov. Gov't Revenue	13	11	45	16	94	19	1	200
Adjusted Federal Gov't Revenue	208	21	132	16	132	22	2	533
Total Government Revenue	221	32	177	32	226	41	3	733
Employment	9037	1987	8480	1214	8465	2345	209	31737

CASES 2 AND 3	NWT	BC	Alta	SMYN**	Ont	Que	Atlantic	Total
Capital Costs	4495		150					4645
Gross Domestic Product	1062	127	828	118	735	164	16	3049
Labour Income	877	86	584	54	467	108	9	2185
Federal Government Revenue	167	23	148	17	142	24	2	521
Terr./Prov. Government Revenue	70	13	51	18	100	20	2	273
Grant Reduction	-56			-1				-56
Adjusted Terr./Prov. Gov't Revenue	14	13	51	17	100	20	2	216
Adjusted Federal Gov't Revenue	222	23	148	17	142	24	2	578
Total Government Revenue	236	35	199	34	242	44	4	794
Employment	9501	2173	9509	1325	9122	2538	227	34395

* Expected leakages of economic impacts from the NWT to other regions due to labour market constraints are not incorporated in this table

** Saskatchewan / Manitoba / Yukon / Nunavut

Despite the factors noted above, the NWT would still experience the greatest impacts of any region and the magnitudes of these impacts relative to the size of the economy are impressive. The GDP impact is equivalent to over 30 % of the region's 2003 GDP level while the employment impact is equivalent to more than 40% of the NWT's total employment in 2003.

However, it must be noted that the values shown in Table 3.2 do not reflect the potential leakages associated with regional labour force constraints during the peak construction phases of the project and the 'imports' of labour (as discussed in Section 2.5). This issue is addressed in detail in Section 3.7 where the NWT impacts as well as the impacts in other regions shown in Table 3.2 are adjusted to reflect the degree to which labour from other regions would ultimately contribute to the project requirements in the NWT.

3.3 Field Exploration and Development Impacts

The impacts associated with the development of the Mackenzie Delta gas fields (including a gathering system and a gas plant at Inuvik) as well as exploration expenditures in Cases 2 and 3 are shown in Table 3.3. Capital expenditures in Cases 1, 2 and 3 of $3.4 billion, $8.5 billion and $13.5 billion respectively could be expected to produce GDP impacts of $2.4 billion, $5.7 billion and $9.1 billion under the three cases. The GDP impact relative to the capital expenditures would be slightly higher than for pipeline construction since proportionally not as many materials are involved resulting in fewer direct and indirect imports.

TABLE 3.3: IMPACTS OF MACKENZIE DELTA GAS FIELD EXPLORATION AND DEVELOPMENT: 2002-2035*

(millions of 2004 Cdn$, employment in person years)

CASE 1 ***	NWT	BC	Alta	SMYN**	Ont	Que	Atlantic	Total
Capital Costs	3438							3438
Gross Domestic Product	847	104	678	69	531	125	12	2366
Labour Income	369	71	452	37	344	83	7	1363
Federal Government Revenue	93	19	116	10	102	18	2	360
Terr./Prov. Government Revenue	46	11	40	9	65	15	1	188
Grant Reduction	-36			-1				-37
Adjusted Terr./Prov. Gov't Revenue	9	11	40	9	65	15	1	151
Adjusted Federal Gov't Revenue	130	19	116	11	102	18	2	397
Total Government Revenue	139	30	157	19	167	34	3	548
Employment	5415	1765	7645	946	6762	1969	176	24679

CASE 2	NWT	BC	Alta	SMYN**	Ont	Que	Atlantic	Total
Capital Costs	8508							8508
Gross Domestic Product	2086	256	1634	157	1277	302	29	5742
Labour Income	947	173	1084	88	831	203	16	3343
Federal Government Revenue	333	47	279	23	244	44	4	974
Terr./Prov. Government Revenue	114	26	97	20	155	37	3	452
Grant Reduction	-91			-2				-92
Adjusted Terr./Prov. Gov't Revenue	23	26	97	19	155	37	3	360
Adjusted Federal Gov't Revenue	424	47	279	24	244	44	4	1067
Total Government Revenue	447	73	376	43	399	82	7	1426
Employment	14033	4324	18432	2240	16355	4803	431	60617

CASE 3	NWT	BC	Alta	SMYN**	Ont	Que	Atlantic	Total
Capital Costs	13510							13510
Gross Domestic Product	3310	405	2576	244	2014	478	46	9074
Labour Income	1515	274	1708	138	1312	321	26	5293
Federal Government Revenue	570	74	440	36	385	70	6	1580
Terr./Prov. Government Revenue	180	42	152	31	242	59	5	712
Grant Reduction	-144			-2				147
Adjusted Terr./Prov. Gov't Revenue	36	42	152	29	242	59	5	565
Adjusted Federal Gov't Revenue	715	74	440	38	385	70	6	1727
Total Government Revenue	751	115	593	67	627	129	11	2293
Employment	22503	6848	29076	3517	25820	7599	682	96046

* Expected leakages of economic impacts from the NWT to other regions due to labour market constraints are not incorporated in this table

** Saskatchewan / Manitoba / Yukon / Nunavut

*** Since exploration expenditures for the anchor fields have already been made, only development related impacts are considered in this analysis

Even so, the proportion of the GDP impact that would be felt in the NWT is expected to be very similar to that observed for pipeline construction and is about 35% in all of the cases. Labour income, government revenue and employment impacts in the NWT would represent anywhere from 20-35% of the corresponding national impacts (depending on the case) and it can be observed that impacts in Alberta and Ontario would in some situations be larger than those in the NWT. Furthermore, given that the effect of labour supply constraints in the NWT is not taken into account in Table 3.3, the overall impacts in the NWT would be lower than indicated in the table.

However, unlike in pipeline construction, these impacts would be spread over nearly 30 years so there is a much higher tendency for sustainable benefits from field exploration and development going to northern residents. As the industry becomes established in the Mackenzie Delta region, it would likely become one of the key industries in the local economy.

The impacts shown in Table 3.3 for the rest of Canada follow a pattern observed in pipeline construction. Indirect impacts tend to be concentrated in larger provinces and those closer to the NWT. In addition, it can be observed that labour income impacts tend to constitute roughly two-thirds of the total GDP impacts in any region. This is in stark contrast to the impacts arising from the operation phase of the pipelines and operations associated with natural gas and NGL production.

3.4 Pipeline Operation Impacts

Table 3.4 summarizes the economic impacts associated with the operation of the Mackenzie Valley gas pipeline, the NGL pipeline from the Mackenzie Delta to Norman Wells, as well as the incremental cost of service on the TCPL Alberta system and at Norman Wells to accommodate Mackenzie Delta volumes over the period 2010-2035. Since many impacts would overwhelmingly be concentrated in the NWT, results are shown just for the NWT and for the rest of Canada (denoted as ‘other’ in the table). More detail regarding the distribution of impacts in the rest of Canada can be found in Appendix Tables A.7 and A.8.

The total cost of service would range from roughly $10.8 billion to $13.5 billion depending on the case. As was noted earlier in the study, the operating period is 19 years (2010-2028) in Case 1-3, 21 years (2010-2030) in Case 1-4 and 26 years (2010-2035) in Cases 2 and 3. These differences are the primary reason that the pipeline operation impacts vary from case to case. Overall GDP impacts would be between $10.5 billion and $13.1 billion and correspond in each case to a GDP intensity ratio (GDP / direct output) of 0.97. These ratios are very high and reflect the fact that in pipeline operations, most of the cost of service is direct GDP (direct value added).

With only limited inputs being purchased by the pipeline companies during the operating phase, there would be little need for imports of materials. Overall imports related to pipeline operations would amount to less than $0.4 billion over the entire operating period in any of the cases. Further, given that the bulk of the GDP impact would be direct, it would also be concentrated in the regions where the pipeline services would be provided. Consequently, the NWT would receive 95% of the GDP impacts associated with pipeline operations in each of the cases.

Government revenue impacts for this portion of the project also follow the same pattern, with more than 85% of the government revenues shown in Table 3.4 being government revenues that would be directly created by the operation of the pipelines (the property and income taxes payable by the pipeline companies). Total government revenues would range from $1.8 billion to $2.3 billion depending on the case. It is noteworthy that the grant reduction that arises for the NWT under current fiscal arrangements is much more significant than was shown in either of the construction phase impact tables.

TABLE 3.4: IMPACTS OF PIPELINE OPERATIONS: 2010-2035
(millions of 2004 Cdn$, employment in person years)

	$3US GAS PRICE			$4US GAS PRICE		
CASE 1	**NWT**	**Other**	**Total**	**NWT**	**Other**	**Total**
Direct Output	10330	499	10829	10776	551	11327
Gross Domestic Product	9594	953	10546	9955	1057	11012
Labour Income	271	369	640	302	410	712
Federal Government Revenue	885	145	1031	914	162	1075
Terr./Prov. Government Revenue	701	109	809	733	121	854
Grant Reduction	-560		-561	-586		-587
Adjusted Terr./Prov. Gov't Revenue	140	108	249	147	120	267
Adjusted Federal Gov't Revenue	1446	146	1592	1500	162	1662
Total Government Revenue	1586	254	1840	1647	282	1929
Employment	6252	8222	14474	6965	9153	16117
CASE 2	**NWT**	**Other**	**Total**	**NWT**	**Other**	**Total**
Direct Output	12671	683	13354	12808	683	13490
Gross Domestic Product	11625	1327	12952	11761	1327	13089
Labour Income	383	520	902	383	520	903
Federal Government Revenue	1059	204	1263	1070	204	1273
Terr./Prov. Government Revenue	859	152	1011	864	152	1015
Grant Reduction	-687	-1	-688	-691	-1	-692
Adjusted Terr./Prov. Gov't Revenue	172	151	323	173	151	324
Adjusted Federal Gov't Revenue	1747	204	1951	1761	204	1965
Total Government Revenue	1918	355	2274	1933	355	2289
Employment	8857	11637	20494	8859	11639	20497
CASE 3	**NWT**	**Other**	**Total**	**NWT**	**Other**	**Total**
Direct Output	12817	683	13499	12817	683	13499
Gross Domestic Product	11764	1332	13095	11764	1332	13095
Labour Income	384	523	907	384	523	907
Federal Government Revenue	1070	204	1275	1070	204	1275
Terr./Prov. Government Revenue	864	152	1016	964	152	1016
Grant Reduction	-691	-1	-692	-691	-1	-692
Adjusted Terr./Prov. Gov't Revenue	173	151	324	173	151	324
Adjusted Federal Gov't Revenue	1762	205	1967	1762	205	1967
Total Government Revenue	1934	356	2291	1934	356	2291
Employment	8906	11704	20609	8906	11704	20609

While GDP and government revenue impacts would be concentrated in the NWT, Table 3.4 shows that employment and labour income impacts would be more dispersed across the country. As noted in Section 2.5 and in Table A.6, the direct employment associated with pipeline operations is only expected to be between 900 and 1300 person years in the various cases and would constitute less than 10% of the overall employment impact regardless of the case. As a result, the bulk of the employment impacts shown in Table 3.4 would be indirect and these tend to be more widely dispersed geographically. Still, between 40% and 45% of the employment and labour income impacts would be observed in the NWT.

Given the more substantial employment impacts in other parts of the country, it is useful to examine the distribution of these impacts more carefully. Table 3.5 shows employment impacts related both to the pipeline operation and the gas and NGL production (described more completely in the following section). Most of the indirect employment impacts would occur in Ontario (roughly 22% of the total employment impacts) with significant impacts also expected in Alberta, B.C. and Quebec.

TABLE 3.5: DISTRIBUTION OF EMPLOYMENT IMPACTS : 2010-2035*

(employment in person years)

PIPELINE OPERATION	NWT	BC	Alta	SMYN**	Ont	Que	Atlantic	Total
Case 1-3	6252	1734	1958	309	3159	858	205	14474
Case 1-4	6965	1932	2173	344	3519	956	229	16117
Case 2-3	8857	2462	2744	438	4484	1217	292	20494
Case 2-4	8859	2462	2745	438	4484	1218	292	20497
Cases 3-3 and 3-4	8906	2476	2758	441	4511	1225	293	20609
GAS AND NGL PRODUCTION	**NWT**	**BC**	**Alta**	**SMYN****	**Ont**	**Que**	**Atlantic**	**Total**
Case 1-3	4935	1441	2534	275	4730	1324	129	15368
Case 1-4	5458	1589	2782	303	5219	1461	143	16955
Case 2-3	8759	2468	4345	471	8104	2268	222	26636
Case 2-4	9138	2570	4511	490	8441	2362	231	27743
Cases 3-3 and 3-4	9739	2721	4853	519	8936	2501	244	29512

Overall employment impacts associated with pipeline operations could be expected to range from 15,000 to 21,000 person years depending on the case. Relative to the construction phase impacts, these impacts appear quite modest. For example, Mackenzie Delta field exploration and development in Case 3 is estimated to create 96,000 person years of employment given a capital expenditure of about $13.5 billion (an amount equivalent to Case 3 pipeline operation revenue).

However, in contrast to the construction phase impacts, it is reasonable to assume that essentially all of the labour income and employment impacts shown for the operating phase in the NWT would in fact be felt by residents of the region. Once this factor is taken into account, the labour income and employment impacts associated with the operating phase are clearly significant in the overall picture and represent sustainable long term impacts that are arguably more beneficial to an economy than the more concentrated impacts during the peak construction phase.

3.5 Gas and NGL Production Impacts

Impacts relating to the production of Mackenzie Delta gas and NGLs are shown in Table 3.5 for the various cases. As with the pipeline operation impacts described in the previous section, results are shown for the NWT and for the rest of Canada. Appendix Tables A.9 and A.10 show the regional impacts in more detail.

Depending on the case considered, overall employment impacts associated with gas and NGL production would range from 15,000 person years to 30,000 person years. In contrast to the GDP and government revenue impacts, employment and labour income impacts vary mainly by volume case as opposed to gas price scenario and involve primarily indirect impacts. As was noted in Section 2.5, direct employment related to field operations is expected to range from 1500 to 3400 person years and would constitute only about 10% of the overall employment impacts in this portion of the project.

As was observed for pipeline operations, employment and labour income impacts associated with gas and NGL production would tend to be widely dispersed across the country. In fact, there is less of a concentration of these impacts in the NWT compared to those shown for pipeline operations, with only about one third expected to occur in the NWT. Table 3.5 in the previous section also contains employment impacts by province related to hydrocarbon production from the Mackenzie Delta and it can be observed that more than 30% of the impacts could be expected in Ontario, over 15% in Alberta and close to 10% in both B.C. and Quebec.

While total employment and labour income impacts related to gas and NGL production in the rest of Canada would exceed those in the NWT, GDP and government revenue impacts would generally be much larger in the NWT. Although gas production does involve higher operating costs and, consequently, more indirect imports than pipeline operation, leakages from the local economy are quite small (even in the case of the NWT) and the ratio of GDP to value of production in the NWT would range from 0.84 to 0.96 depending on the case.

Table 3.6 illustrates the effect of higher gas prices and improved pipeline capacity utilization, both of which increase netback revenue and boost GDP and government revenue impacts. GDP impacts could be expected to range from $4.6 billion to $18.3 billion in the $3US gas price scenario and from $12.5 billion to $33.7 billion in the $4US gas price scenario. Government revenue impacts in the $3US gas price scenario would be equivalent to between 10% and 15% of the GDP impacts while the higher netbacks in the $4US gas price case would raise government

TABLE 3.6: IMPACTS OF GAS AND NGL PRODUCTION: 2010-2035

(millions of 2004 Cdn$, employment in person years)

	$3US GAS PRICE			$4US GAS PRICE		
CASE 1	**NWT**	**Other**	**Total**	**NWT**	**Other**	**Total**
Direct Output	4984		4984	12861		12861
Gross Domestic Product	3880	748	4628	11645	824	12468
Labour Income	315	518	833	349	570	919
Federal Government Revenue	146	137	283	2495	151	2646
Terr./Prov. Government Revenue	68	78	146	1039	86	1126
Grant Reduction	-54		-55	-832		-832
Adjusted Terr./Prov. Gov't Revenue	14	78	91	208	86	294
Adjusted Federal Gov't Revenue	200	137	337	3326	151	3478
Total Government Revenue	214	215	429	3534	237	3771
Employment	4935	10433	15368	5458	11497	16955
CASE 2	**NWT**	**Other**	**Total**	**NWT**	**Other**	**Total**
Direct Output	13624		13624	26613		26613
Gross Domestic Product	11734	1280	13014	24646	1332	25978
Labour Income	565	886	1451	589	922	1511
Federal Government Revenue	984	235	1219	5838	244	6082
Terr./Prov. Government Revenue	432	134	565	1879	139	2018
Grant Reduction	-345	-1	-346	-1503	-1	-1504
Adjusted Terr./Prov. Gov't Revenue	86	133	220	376	139	514
Adjusted Federal Gov't Revenue	1330	235	1565	7341	245	7585
Total Government Revenue	1416	368	1784	7717	383	8100
Employment	8759	17877	26636	9138	18605	27743
CASE 3	**NWT**	**Other**	**Total**	**NWT**	**Other**	**Total**
Direct Output	18936		18936	34342		34342
Gross Domestic Product	16848	1416	18264	32254	1416	33670
Labour Income	629	982	1611	629	982	1611
Federal Government Revenue	1174	260	1434	7102	260	7362
Terr./Prov. Government Revenue	438	148	586	2142	148	2290
Grant Reduction	-350	-1	-351	-1713	-1	-1714
Adjusted Terr./Prov. Gov't Revenue	88	147	235	428	147	576
Adjusted Federal Gov't Revenue	1525	260	1785	8816	260	9076
Total Government Revenue	1612	408	2020	9244	408	9652
Employment	9739	19774	29512	9739	19774	29512

revenues to about 30% of GDP impacts. Clearly these impacts are extremely sensitive to both gas price and pipeline load factors.

Finally, like the pipeline operation impacts, all impacts associated with gas and NGL production in the Mackenzie Delta that are indicated as NWT impacts in Table 3.6 would remain in the region and would provide a sustainable long term benefit to the residents of the NWT.

3.6 Unadjusted Overall Impacts

The results described in the previous sections for the various elements of the project can be combined in order to illustrate overall impacts. Appendix Tables A.11 and A.12 contain detailed results by region. As noted in Sections 3.2 and 3.3, a portion of the impacts that are attributed to the NWT during the construction phase of the project would likely be felt by residents of other regions as labour from outside the NWT is brought in to meet project requirements. An estimation of these effects follows in Section 3.7 and detailed regional results are presented given the necessary adjustments for the expected leakages of economic impacts from the NWT to other regions that arise from labour market constraints in the NWT.

Prior to that analysis, a brief summary of the overall project impacts in the various cases is shown below in Table 3.7. GDP impacts could be expected to range from $20.3 billion to $58.9 billion and represent between 85% to 90% of the value of direct output associated with the project. Labour income generated by the project would be between $4.9 billion and $10.0 billion and would constitute anywhere from 15% to 25% of the overall GDP impact. Total government revenues would range from $3.5 billion to $15.0 billion while the total employment created by the project would be between 86,000 and 181,000 person years. It is clear that the economic impacts associated with the project would be substantial regardless of which case may actually unfold.

TABLE 3.7: OVERALL PROJECT IMPACTS: 2004-2035
(millions of 2004 Cdn$, employment in person years)

	$3US GAS PRICE			$4US GAS PRICE		
	Case 1	Case 2	Case 3	Case 1	Case 2	Case 3
Direct Output	23512	40130	50590	31887	53256	65996
Gross Domestic Product	20337	34757	43482	28643	47857	58888
Labour Income	4853	7881	9997	5011	7941	9997
Total Government Revenue	3549	6278	7397	6981	12609	15029
Employment	86258	142141	180562	89489	143252	180562

3.7 Adjustments to Impacts Related to Labour Market Constraints

The results shown throughout Section 3 to this point reflect impacts that would occur in Canada's various geographic regions without taking into account imported labour. These estimates of labour income and employment impacts would only accrue to citizens of a particular region should there be sufficient people in the region with sufficient skills to fill all of the jobs that would be created there. For the NWT it is necessary to re-examine these impacts given the small and widely dispersed population.

As of the first quarter of 2004, the population of the NWT was approximately 42,200.[11] The labour force has averaged 22,300 in recent months and the NWT participation rate (labour force as a percentage of working age population) has been 74%, significantly higher than the national average of 68%. Over the past year and a half, the number of unemployed people in the NWT has averaged 1400 with an unemployment rate of 6.3% (below the national average of 7.6%).[12]

The additional employment opportunities associated with the pipeline and gas development projects considered in this analysis would be useful in ameliorating some of the unemployment in

[11] Data from current indicators section of NWT Bureau of Statistics website.

the region, especially during the operating phase when more of the employment is of a long-term, stable nature. However, the magnitude and labour requirements of the projects in the construction phase are so large that the unemployed labour pool in the NWT could not be expected to fill all of the jobs necessary. Some of this would be due to skill issues, but the sheer numbers of workers required is a factor as well. For example, Figure 2.13 illustrated that during the main construction seasons during the winters of 2007/08 and 2008/09 close to 10,000 workers may be required.

Clearly there would be significant opportunities for local participation in the construction of the pipeline facilities and in gas field exploration and development. The extent depends on the size, location and mobility of the unemployed labour pool in the NWT, along with skill requirements for the various positions. In this regard, environmental and socioeconomic consultants to the MGP have performed some detailed analysis for the project sponsors and the results have been used in this report to make estimates of the extent to which employment generated by the project in the NWT would be taken by NWT residents.[13]

During the peak construction period from 2006-2010, about 16% of the direct employment and 26% of the indirect employment could be expected to be taken by NWT residents in Case 1, given worker skill levels and labour market constraints in the region. In Cases 2 and 3, additional exploration and development expenditures beyond that expected in Case 1 would also occur during the peak construction period and all employment related to such activity is assumed to be filled by workers from outside the NWT. There would also be some exploration and development activity prior to the peak construction period in Cases 2 and 3 where significantly fewer workers would be required. Labour market constraints would not be as much of a factor in those periods but skill issues would still exist. Consequently, it is assumed that 30% of the direct and indirect employment in those periods would be taken by NWT residents. Given these assumptions, the amount of employment that could be expected to accrue to NWT residents is summarized in Table 3.8 for the various cases.

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[12] Data from NWT Bureau of Statistics, Monthly Labour Force Survey (April 2004). Unemployment and unemployment rate data from the same source and from www.statcan.ca.
[13] An environmental and socioeconomic report will be filed with regulatory boards in the near future.

TABLE 3.8: CONSTRUCTION PHASE EMPLOYMENT IN THE NWT GIVEN LABOUR MARKET CONSTRAINTS : 2004-2035

(all values in person years)

2004-2010	**Case 1**	**Case 2**	**Case 3**
Total Direct and Indirect Employment in the NWT	13193	16390	17262
Employment for NWT Residents	2754	3102	3225
Employment Leakages to Other Regions	10439	13288	14037
2011-2035	**Case 1**	**Case 2**	**Case 3**
Total Direct and Indirect Employment in the NWT	1259	7146	14742
Employment for NWT Residents	1198	4711	8973
Employment Leakages to Other Regions	61	2435	5769
OVERALL	**Case 1**	**Case 2**	**Case 3**
Total Direct and Indirect Employment in the NWT	14452	23534	32004
Employment for NWT Residents	3952	7813	12198
Employment Leakages to Other Regions	10500	15721	19806

Over the period 2004-2010, between 2,800 and 3,200 person years of construction phase direct and indirect employment in the NWT could be expected to be taken by NWT residents out of total employment ranging from 13,200 to 17,200 person years. In each of the cases, this amounts to only about 20% of the overall employment impact in the region and reflects the huge labour requirements of the project relative to the skill levels and size of the labour force in the NWT. Between 10,400 and 14,000 person years of employment in the region could be expected to be taken by workers from outside the NWT in this period.

However, beyond 2010 the construction phase employment is significantly lower on an annual basis and labour market constraints are not expected to be such a significant factor. In order to estimate the amount of construction related employment that would accrue to NWT residents after 2010, figures relating to the maximum potential NWT resident participation during the peak construction period (figures which reflect skill constraints) were extrapolated out to the end of the analysis period using population projections from the NWT Bureau of Statistics.[14] Given these

[14] See Population Projections by Community for the NWT (2004-2019) on the NWT Bureau of Statistics website. The average annual population growth rate of 1.15% was used to extrapolate the potential NWT resident participation in project related employment on an annual basis.

annual maximum participation estimates, direct and indirect employment related to pipeline and gas field operations were subtracted in order to arrive at the potential number of workers with appropriate skills that could take the construction related jobs created on an ongoing basis.[15] If the number of jobs in any given year exceeded the available number of workers, it was assumed that the jobs would have to be taken by non-NWT residents.

As shown in Table 3.8, leakages of employment to other regions could be expected to be much lower for the period beyond 2010. In Case 1, it is estimated that almost all of the ongoing employment could be taken by NWT residents. In Cases 2 and 3, the extent of the exploration and development activity would at times require a significant number of workers be brought in from other regions. Nevertheless, roughly 60% to 65% of the direct and indirect construction related employment would still accrue to NWT residents.

For the overall period, these estimates suggest that between 4,000 and 12,200 person years of construction related employment in the NWT would go NWT residents. Given that the total construction related employment in the region would range from 14,500 to 32,000 person years, NWT residents could be expected to capture between 25% and 40% of these employment impacts. This would leave between 10,500 and 19,800 person years of employment to be allocated among workers in other regions.

Given the nature of the project, regional shares of overall oil and gas exploration and development expenditures over the last decade are used to allocate impacts which would leak out of the NWT to other regions. Although the discussion has focused on the employment impacts, the leakages would also involve labour income, GDP and government revenue impacts. Tables 3.9 and 3.10 contain the estimates of overall impacts associated with the project once NWT labour market constraints are taken into account.

[15] As noted in Sections 3.4 and 3.5, it is assumed that all direct and indirect operating related employment would be taken by NWT residents.

GDP and government revenue impacts in the NWT would be far greater than in any single province. In the $3US gas price scenario, more than 70% of the overall GDP impact would be felt in the NWT and this percentage would rise to about 80% in the $4US gas price scenario. On an average annual basis, GDP in the NWT would rise by between $0.6 billion and $1.5 billion (depending on the case) as a result of the project. This would represent an increase of between 20% and 45% over current levels in the region.

Anywhere from 55% to 80% of the total government revenue impacts associated with the project would occur in the NWT. Between 80% and 90% of the overall government revenue impacts (which would range from $3.6 billion to $15.1 billion) would be received by the federal government. It can be noted that the government revenue impacts would be substantially larger in the $4 US gas price scenario given the significantly higher netbacks that would be generated.

Given the leakages of construction phase employment and labour income from the NWT as well as the fact that the impacts on these items would primarily be indirect given the project characteristics, only about 20% of employment and labour income impacts would be felt by NWT residents. Nevertheless, the additional employment generated by the project would range from 15,000 to 31,000 person years or between 600 and 1000 jobs on an average annual basis[16]. These employment impacts could effectively reduce the NWT unemployment rate to half the current level. However, it might be expected that the improved economic environment in the region would draw discouraged workers back into the labour force and this combined with natural increase in the population and perhaps a greater incentive for in-migration to the NWT would likely prevent the unemployment rate from falling to unsustainably low levels that are associated with high levels on inflation.

The largest employment and labour income impacts associated with the project could be expected in Alberta, with gains ranging from 28,000 to 59,000 person years. Aside from the direct operating employment that would be generated in the province, much of the project management and engineering during the construction phase of the project would be sourced in Alberta. In addition, most of the direct construction phase jobs in the NWT that would be taken by workers from outside

[16] These and subsequent average annual impacts are estimated for the period starting in 2004.

the region would likely go to Alberta workers given the nature of the work and the proximity of Alberta to the NWT. Overall, between 30% and 40% of the total employment and labour income impacts could be expected in Alberta.

Ontario would also experience significant employment and labour income impacts, in fact exceeding those for the NWT. Employment impacts would range from 23,000 to 48,000 person years and would constitute roughly one quarter of the overall employment impacts. Other regions of Canada would also see significant impacts, especially given the relative size of the various regional economies in the country.

TABLE 3.9: OVERALL IMPACTS AFTER ADJUSTMENTS FOR NWT LABOUR MARKET CONSTRAINTS - $3US GAS PRICE SCENARIO: 2004-2035

(millions of 2004 Cdn$, employment in person years)

CASE 1	**NWT**	**BC**	**Alta**	**SMYN***	**Ont**	**Que**	**Atlantic**	**Total**
Investment / Revenue	22864		649					23512
Gross Domestic Product	14420	488	2779	314	1789	404	144	20337
Labour Income	894	369	1815	207	1169	274	126	4853
Federal Government Revenue	1130	93	490	52	346	59	23	2193
Terr./Prov. Government Revenue	826	46	199	38	230	50	17	1406
Grant Reduction	-661			-2				-663
Adjusted Terr./Prov. Gov't Revenue	165	46	199	36	230	50	17	743
Adjusted Federal Gov't Revenue	1790	93	490	54	346	59	23	2856
Total Government Revenue	1955	139	689	90	576	110	39	3599
Employment	15140	8081	27653	3898	23116	6495	1875	86258
CASE 2	**NWT**	**BC**	**Alta**	**SMYN***	**Ont**	**Que**	**Atlantic**	**Total**
Investment / Revenue	39298		833					40130
Gross Domestic Product	25204	790	4465	476	2934	670	219	34757
Labour Income	1468	593	2931	321	1925	456	189	7881
Federal Government Revenue	2322	150	785	79	566	98	35	4035
Terr./Prov. Government Revenue	1396	76	311	56	368	83	25	2315
Grant Reduction	-1117			-3				-1120
Adjusted Terr./Prov. Gov't Revenue	279	76	311	53	368	83	25	1195
Adjusted Federal Gov't Revenue	3439	150	785	83	566	98	35	5156
Total Government Revenue	3718	226	1095	136	934	182	60	6351
Employment	25428	13155	45564	6203	38064	10827	2900	142141
CASE 3	**NWT**	**BC**	**Alta**	**SMYN***	**Ont**	**Que**	**Atlantic**	**Total**
Investment / Revenue	49758		833					50590
Gross Domestic Product	31341	991	5677	603	3736	859	275	43482
Labour Income	1762	741	3813	410	2450	584	236	9997
Federal Government Revenue	2702	188	1003	101	720	126	43	4884
Terr./Prov. Government Revenue	1453	96	382	71	464	107	32	2605
Grant Reduction	-1163			-4				-1167
Adjusted Terr./Prov. Gov't Revenue	291	96	382	66	464	107	32	1438
Adjusted Federal Gov't Revenue	3865	188	1003	105	720	126	43	6051
Total Government Revenue	4156	284	1386	171	1184	233	75	7488
Employment	30843	16397	59465	7981	48388	13863	3624	180562

* Saskatchewan / Manitoba / Yukon / Nunavut

TABLE 3.10: OVERALL IMPACTS AFTER ADJUSTMENTS FOR NWT LABOUR MARKET CONSTRAINTS - $4US GAS PRICE SCENARIO: 2004-2035

(millions of 2004 Cdn$, employment in person years)

CASE 1	**NWT**	**BC**	**Alta**	**SMYN***	**Ont**	**Que**	**Atlantic**	**Total**
Investment / Revenue	31186		701					31887
Gross Domestic Product	22546	507	2859	318	1851	418	146	28643
Labour Income	958	383	1839	209	1211	283	127	5011
Federal Government Revenue	3507	96	502	53	358	61	23	4600
Terr./Prov. Government Revenue	1830	48	207	39	237	52	17	2430
Grant Reduction	-1464			-2				-1466
Adjusted Terr./Prov. Gov't Revenue	366	48	207	37	237	52	17	964
Adjusted Federal Gov't Revenue	4971	96	502	55	358	61	23	6066
Total Government Revenue	5337	144	709	91	595	113	40	7030
Employment	16375	8428	28116	3961	23965	6730	1912	89489
CASE 2	**NWT**	**BC**	**Alta**	**SMYN***	**Ont**	**Que**	**Atlantic**	**Total**
Investment / Revenue	52423		833					53256
Gross Domestic Product	38252	796	4478	477	2960	675	219	47857
Labour Income	1492	597	2940	321	1942	460	189	7941
Federal Government Revenue	7186	151	787	79	571	99	35	8908
Terr./Prov. Government Revenue	2848	76	311	57	371	84	25	3773
Grant Reduction	-2278			-3				-2282
Adjusted Terr./Prov. Gov't Revenue	570	76	311	53	371	84	25	1491
Adjusted Federal Gov't Revenue	9464	151	787	83	571	99	35	11190
Total Government Revenue	10003	227	1098	136	943	183	60	12681
Employment	25808	13258	45731	6223	38042	10921	2909	143252
CASE 3	**NWT**	**BC**	**Alta**	**SMYN***	**Ont**	**Que**	**Atlantic**	**Total**
Investment / Revenue	65164		833					65966
Gross Domestic Product	46746	991	5677	603	3736	859	275	58888
Labour Income	1762	741	3813	410	2450	584	236	9997
Federal Government Revenue	8630	188	1003	101	720	126	43	10812
Terr./Prov. Government Revenue	3157	96	382	71	464	107	32	4309
Grant Reduction	-2526			-4				-2530
Adjusted Terr./Prov. Gov't Revenue	631	96	382	66	464	107	32	1778
Adjusted Federal Gov't Revenue	11156	188	1003	105	720	126	43	13342
Total Government Revenue	11787	284	1386	171	1184	233	75	15120
Employment	30843	16397	59465	7981	48388	13863	3624	180562

*Saskatchewan / Manitoba / Yukon / Nunavut

Not only would the employment and labour income impacts be dispersed quite widely across regions Canada, they would also be distributed among a variety of industries. Appendix Tables A.13 and A.14 contain the employment distributions by sector and region for the various cases while Figure 3.1 illustrates the employment distribution for Case 1-4. Although overall employment impacts are significantly higher in Cases 2 and 3, the relative distribution of employment between industries and regions is very similar in all of the cases.

Figure 3.1 illustrates the distribution of employment generated by the project across various sectors and industries. Employment impacts in industries where direct employment would occur as a result of the project are indicated by the top three bars in Figure 3.1. It can be observed that employment impacts in the pipeline transport and oil and gas extraction industries would effectively only be in the NWT and Alberta. These impacts consist almost entirely of direct operating employment and are relatively small given the size of impacts in other industries (less than 3% of the total in any of the cases). Construction employment would comprise between 10% and 15% of the overall employment generated by the project depending on the case. Employment effects in construction would occur primarily in the NWT (even with the significant leakages described in this

FIGURE 3.1: SECTORAL DISTRIBUTION OF TOTAL EMPLOYMENT IMPACTS IN CASE 1-4: 2004-2035

section) and Alberta but it is anticipated that workers from other parts of the country with drilling and/or pipeline construction experience would be drawn to the project as well.

Although classified as indirect activity throughout the report, the manufacturing of pipes, compressors, valves and other products represents a key component of the overall economic impact. Employment in manufacturing is expected to represent roughly 10% of the total employment impact in each of the cases. Many items related to oil and gas facilities would be manufactured in Alberta but there would also be significant activity in Ontario and the rest of Canada. The NWT would not be expected to produce the manufactured inputs specifically required for this type of project (i.e. large and small diameter pipe, valves, fittings, metering equipment, vessels, wellheads, etc.) given the current structure of the economy. However, if the scale of Mackenzie Delta field development were to become sufficiently large in the future, it may become viable to produce some manufactured inputs locally.

Some of the largest indirect impacts would occur in oil and gas service industry as well as in industries that provide professional, scientific and technical services. Roughly 20% of the overall employment impacts could be expected in the latter industries with Alberta based businesses experiencing about half of this impact (much of the project related engineering and management would be sourced in Alberta). For industries such as finance, rentals and leasing as well as miscellaneous other industries, sizable impacts would be expected in many regions across Canada.

In general, the broad distribution of employment impacts over a variety of sectors in the NWT would make it all the more likely that NWT residents would widely benefit from the project on a sustained basis.

4.0 OTHER IMPACTS AND IMPLICATIONS

There are a variety of impacts relating to the construction and operation of the Mackenzie Valley pipeline and Mackenzie Delta gas fields beyond those explicitly modelled in Sections 2 and 3 which could be quite significant. These impacts as well as other potential implications of the project are discussed in this section.

4.1 INDUCED ECONOMIC IMPACTS

As noted in Section 3.1, there is another category of economic impacts called induced impacts that relate to the spending of portions of labour income, corporate profits and government revenues generated by an activity. The induced impacts related to the spending of labour income are often incorporated in input-output analysis. For example, the NWT government has an input-output model that can produce 'closed' model results which include this type of induced impact.

The ultimate impact resulting from the spending of labour income associated with an activity depends on the perspective taken. For example, in a small region within a country, a large proportion of consumer spending would be on items that were not produced in that region and this would tend to limit the induced impacts generated in that region. However, if the perspective is broadened to the country, it is more likely that consumer spending would be on items that were produced in the country and larger induced impacts could be expected on a country-wide basis vs. the regional basis.

For the NWT, it appears that the induced GDP associated with any activity is approximately equal to between 20% and 30% of the direct plus indirect labour income generated by the project.[17] In comparison, for Alberta this ratio rises to about 45% and for Canada as a whole, our experience suggests that the ratio is closer to 70%.[18] Further, using the same sources, the ratios of induced

[17] These percentages were derived using various results presented in Canadian Energy Research Institute, *A Comparison of Natural Gas Pipeline Options for the North*, October 2000.

[18] In Alberta Treasury's Alberta Economic Multipliers, intensity ratios are presented for the open (direct + indirect impacts only) and closed (direct + indirect + labour spending related induced impacts) versions of the Alberta input-output model. The difference in GDP intensity ratios for any given industry under the open and closed models is consistently about 45% of the direct and indirect labour income. The

employment per million dollars of induced GDP in the NWT, Alberta and Canada are approximately 13, 19 and 17 respectively.

Given the results presented in Tables 3.9 and 3.10 that reflect the direct and indirect impacts associated with the project in the various cases and the percentages and ratios noted above, induced GDP and employment impacts related to the spending of labour income would be as follows: an additional $0.2-$0.4 billion and 2,900-5,700 person years in the NWT; an additional $0.8-$1.7 billion and 15,500-32,600 person years in Alberta; and, an additional $3.4-$7.0 billion and 57,700-132,000 person years in Canada. The induced employment impacts related to the spending of labour income would increase the overall employment impacts shown in Table 3.10 by about 20% for the NWT, 55% for Alberta and 70% for Canada.

Another important source of induced effects relates to the reinvestment of corporate profits. The oil and gas industry in particular reinvests a very high proportion of overall earnings in the form of exploration and development expenditures. In the last decade, the percentage of net revenue (that is, revenues minus royalties and operating costs) that has been spent on exploration and development in Canada has averaged close to 85%.[19] Given the values shown in Figures A.1-A.6 for the Mackenzie Delta gas producers in the various cases, it could be expected that between $3 and $23 billion would be reinvested over the life of the project on exploration and development somewhere in Canada.

The overall economic impacts associated with this activity would be roughly proportional (given the respective capital costs) to those shown in Table 3.3 for Mackenzie Delta field development. For Canada as a whole, between $2 billion and $16 billion in GDP impacts would be generated and employment impacts ranging from 13,000 to 164,000 person years could be expected. The additional induced GDP impacts related to spending of the labour income associated with this additional exploration and development would amount to between $1 billion and $6 billion, with additional induced employment ranging from 13,000 to 108,000 person years. In total then, the

percentage for the national economy was derived from several studies that WMR has performed over the last few years.

[19] Data from the Canadian Association of Petroleum Producers *Statistical Handbook*. The average is for the 1991-2000 period.

direct, indirect and induced impacts associated with reinvestment of Mackenzie Delta net revenues would range from $3 billion to $22 billion in terms of GDP, while the employment impacts would be between 26,000 and 272,000 person years.

Further impacts could be anticipated as the reserves that are discovered in the exploration and development process would eventually give rise to additional oil and gas production. The estimation of these effects requires more detailed modelling and is beyond the scope of this study. Similarly, induced effects related to spending of government revenues could be expected to be quite pronounced given the $4 billion to $15 billion in government revenues that would be directly and indirectly generated by this project.

4.2 Value Added Opportunities Using Mackenzie Delta NGLs

The Inuvik area gas plant could be expected to recover roughly 90% of the pentanes plus and about 50% of the butanes contained in Mackenzie Delta raw gas. The remainder of these products as well as any propane and ethane would remain entrained in the gas stream that would flow through the Mackenzie Valley gas pipeline and eventually into the TCPL Alberta system. At some point these liquids could be extracted at either Cochrane or Empress and this could provide opportunities to add value to the NGLs.

In particular, the use of ethane as petrochemical feedstock for the production of ethylene and subsequently polyethylene represents one of the most effective ways of adding value to Canada's natural resources. Furthermore, it has been one of the best examples of successful diversification in Canada. Alberta's ethane based petrochemical industry is now a world scale producer of ethylene and polyethylene and represents one of the key manufacturing industries in the province. Despite the fact that a significant portion of the Alberta's ethane supply is now exported on the Alliance pipeline without any upgrading into value added products in Canada, Alberta's ethane based petrochemical industry remains competitive and would surely welcome the opportunity to access additional NGL supplies.

4.3 Mineral Rights Values and Exploration Opportunities in the NWT

Oil and gas producers in Canada have paid less than $100 million for mineral rights in the NWT over the last 20 years.[20] Over the same period, these producers have spent nearly $17 billion on the acquisition of mineral rights in Alberta. Rights in the NWT have been issued by the federal government for work commitments and winning bidders have not had to pay cash bonuses as is normally the case in southern Canada. One of the reasons is that in many cases there has been no foreseeable method of delivering the oil or gas that might be found in many parts of the region to markets. The introduction of the Mackenzie Valley pipeline could be expected to change this situation, potentially in a rather dramatic fashion. The federal government and perhaps native bands could benefit substantially should this occur.

Access to an actual pipeline would certainly improve the expected profitability of any investment in the NWT. This impact would likely be most pronounced with respect to properties in the Mackenzie Delta but there is the possibility of opening up other potential supply sources. Known and yet to-be-discovered gas in the Colville Hills area and probable gas reserves in other portions of the central and southern NWT could be explored or developed as soon as a viable pipeline is available to connect them. At present there is no way to exploit gas reserves in the NWT except for small quantities going to Inuvik through the Ikhil Project, gas use in Norman Wells, and gas developments in the Liard area of the southern NWT. If the Mackenzie Valley pipeline could at some point be accessed by presently unconnected existing and potential supplies it would significantly increase further exploration and development, and the value of the relevant petroleum sub-surface rights. This type of activity could be very beneficial to the overall NWT economy as well as to smaller communities in the NWT because the scale of activity would not have to be particularly large to have a significant economic impact. It is the type of activity that, should new discoveries be made, can also give rise to a longer-term sustainable local industry.

[20] Data from Canadian Association of Petroleum Producers Statistical Handbook.

4.4 Benefits to NWT Residents of Access to Natural Gas

Households in NWT communities along the Mackenzie Valley pipeline route could potentially realize a significant benefit if they could access Mackenzie Delta gas for home heating use. Currently heating oil (diesel oil) is the fuel of choice for heating the homes of many NWT residents and in 2001, the average annual bill for heating oil in Yellowknife was $1726.[21] Heating oil prices so far in 2004 have been about 10% higher than in 2001. Consequently, an average annual heating bill of $1900 in Yellowknife is assumed to determine the potential savings by households that would switch to natural gas heating should the project proceed.

The average annual cost noted above must be adjusted to take into account where conversions to natural gas would likely take place in the NWT. It seems unlikely that consumers in Yellowknife would be able to access Mackenzie Delta gas for heating, given the distance between the city and the proposed Mackenzie Valley pipeline and the fact that any proposed lateral that would connect Yellowknife would have to pass through lengthy sections of surface bedrock. The most likely areas to see local natural gas service would be larger communities in the Mackenzie Delta and directly along the pipeline route.

Both Inuvik and Norman Wells currently have residential natural gas service. As noted in Section 1, Inuvik is served by gas from Ikhil that is approximately 50 km from Inuvik. The gas price for Inuvik consumers is roughly 85% of that for diesel oil on a heating equivalent basis. However, the fact that there is only a 15% saving using gas versus diesel oil may largely be due to unusually high infrastructure costs in that particular situation - namely, the requirement of a 50km dedicated pipeline from the gas field to Inuvik. In cases where the gas supply was closer to the population centre and essentially only distribution infrastructure would be required to provide service, it is possible that savings could be much greater.

For example, Fort Simpson and Fort Good Hope both lie directly on the proposed pipeline route. Further, it is possible that within the Mackenzie Delta region itself new fields would be discovered

[21] Data from a Statistics Canada 2001 Family Expenditure Survey for Yellowknife.

that are very close to population centres like Tuktoyaktuk or Aklavik.[22] In these cases the markup over the netback price in the gas field might not be as large as what is currently observed at Inuvik.

In order to establish a range of values, potential consumer savings in Fort Simpson and Tuktoyaktuk are evaluated. These centres are used because amongst the communities that might be candidates for natural gas service to consumers, they respectively have the lowest and highest cost of living. Compared to Yellowknife, the cost of living in Fort Simpson is about 15% higher while in Tuktoyaktuk it is roughly 40% higher.[23] In addition, Tuktoyaktuk is significantly further north than Yellowknife and measurably colder on average. As a result, it could be expected that average fuel use in Tuktoyaktuk would be higher than in Yellowknife. Given these considerations, it is estimated that current annual diesel oil costs would range from about $2200 to $2900 per year.

The expected cost of gas to residential consumers in the NWT is estimated by taking the netback gas price in the Mackenzie Delta and adding on a markup which would be mainly distribution margin but could include items like municipal fees as well.[24] Assuming that the distribution and connection costs were within some reasonable range, and depending on the case, this would translate into an average gas price for residential consumers of between $8.50/GJ and $10.50/GJ. Given the annual heating requirements for the typical household, savings of up to $1100-$1500 per year might be realized by switching to natural gas. However, it must be emphasized that this does not factor in the costs of conversion and, further, that no detailed analysis has been undertaken to

[22] Population in the various communities designated as potential candidates for natural gas service were as follows for 2003: Aklavik - 656; Fort Good Hope - 540; Tuktoyaktuk - 990; and Fort Simpson - 1237 (population data from NWT Bureau of Statistics,). While it may seem that it would be unlikely that any party would find it worthwhile to set up a gas distribution network in such small communities, Norman Wells with a population of 797 in 2003 currently has such infrastructure. The only other community of similar size in the Mackenzie Delta region is Fort McPherson with population of 808 in 2003. However, this community is smaller than Inuvik (population 3435 in 2003) and over 100 km from the proposed pipeline route (or further away from a gas source than Inuvik is from Ikhil).

[23] Data from NWT Bureau of Statistics, *Statistics Quarterly* (December 2001).

[24] The estimated markup is based on information contained in National Energy Board *Canadian Energy Supply and Demand 1993-2010* (December 1994) regarding fieldgate prices of gas and the price of gas to residential consumers in B.C. and the Territories. It is assumed that in real terms the markups evident there had remained constant over time. Converting to 2004$, the resulting markup is just over $4/GJ. While the information may appear dated, the current markup by ATCO in Calgary is virtually identical. For service in Fort Simpson and Tuktoyaktuk, this markup is inflated by the cost of living differential between those communities and Edmonton (the basis of all of the aforementioned cost of living comparisons). In addition, for Fort Simpson the cost of moving Mackenzie Delta gas along the Mackenzie Valley pipeline to Fort Simpson is also included in the estimated price to consumers.

determine feasibility, costs and economic viability of particular distribution and connection systems. These maximum potential savings indicated here should be interpreted at this point as simply suggesting that a detailed analysis of the viability of distribution and connection for some selected communities close to the pipeline may be warranted.

4.5 Impacts on Existing Pipeline Infrastructure

The gas pipeline infrastructure south of sixty is running below capacity and this underutilization will become more pronounced in the absence of northern gas supply and transmission development. In general, reductions in utilization rates translate into higher per unit tolls. The introduction of 800 to 1200 MMcf/d of gas will improve the utilization of pipeline infrastructure. In addition, the new supply of NGLs available at Norman Wells will improve the utilization of the existing Norman Wells oil pipeline.

4.6 Gains to Canadian Gas Consumers

There could be benefits to Canadian gas consumers in general as a result of the introduction of Mackenzie Delta volumes into the North American market. Between now and the anticipated start-up date of Mackenzie Delta flows, it is widely anticipated that there will be a significant increase in North American natural gas demand. The Energy Information Agency (EIA) of the U.S. Government's Department of Energy (DOE) projects that annual American demand will rise by approximately 5.3 Tcf between 2002 and 2015, or equivalently, show an average growth rate of about 1.6% per year.[25] Other forecasters indicate increases ranging from 3.8 Tcf to 8.3 Tcf on an annual basis over the period.[26] For Canada, the NEB forecasts end use demand for natural gas will rise by between 0.56 PJ to 0.59 PJ over the 2002-2015 period, or at an annual average rate of between 1.6% and 1.7%.[27]

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[25] See U.S. Department of Energy, Energy Information Agency, *Annual Energy Outlook 2004* (January 2004) - http://www.eia.doe/gov/oiaf/aeo.

[26] See Table 31 of U.S. Department of Energy, Energy Information Agency, *Annual Energy Outlook 2004* (January 2004) - http://www.eia.doe/gov/oiaf/aeo.

Although rising demand is expected to be coupled to some extent with rising supply, the tightening of the natural gas market that begun in 2000 is expected to persist over the longer term and keep natural gas prices at the historically high levels that have been observed over the last four years. For example, the natural gas price at Henry Hub between 2000 and 2003 averaged $4.19 US/MMBtu compared to $2.39 US/MMBtu over the 1996-1999 period and $2.02 US/MMBtu over the 1990s.[28] While some moderation in near term prices is generally expected, forecasters suggest that US natural gas prices could range from anywhere between $3US/Mcf (2003$) and $4.25US/Mcf by 2015.

In most of these forecasts, it is assumed that some amount of Mackenzie Delta gas will be flowing to North American gas markets by 2015. Without Mackenzie Delta gas, it is likely that continental natural gas prices would be higher than indicated in the forecasts. No detailed analysis has been performed with respect to the value of this gain to Canadian consumers associated with lower prices resulting from the addition of Mackenzie Delta gas.

4.7 Reductions in Greenhouse Gas Emissions

Under the Kyoto Protocol, Canada and other industrialized countries agreed in principle to cut greenhouse gas (GHG) emissions (emissions of carbon dioxide (CO2), methane and nitrous oxide) below 1990 levels by 2008-2012.[29] Currently, GHG emissions in Canada are substantially higher than 1990 levels and some significant progress on the emission reduction front would have to made if target levels are to be reached by the end of the decade.[30]

To this end, the replacement of coal with natural gas in electricity generation could provide major reductions in GHG emissions. For example, in Canada in 1995, roughly 88 MT of CO2 equivalent were emitted by the electricity generators that burned coal compared to only 10 MT of CO2 equivalent from those burning natural gas.[31] To a large extent this reflects the higher amount of electricity generated via coal versus natural gas (a ratio of about four to one in 1995) but it is also

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[27] See National Energy Board, *Canada's Energy Future: Scenarios for Supply and Demand to 2025* (July 2003) - http://www.neb-one.gc.ca/SupplyDemand/2003. The range represents results over the NEB's Supply Push and Techno Vert scenarios.

[28] Historical gas prices from Sproule Associates Limited website (www.sproule.com/prices/gas).

[29] The Kyoto Protocol was signed in December 1997. Canada agreed to reduce GHG emissions to 6% below 1990 levels by 2008-2012. The agreement has not been ratified,

[30] The increase in GHG emissions over the period 1990-1997 was approximately 13%.

due to the fact natural gas combustion does not produce as many GHG emissions per unit of energy as coal.[32] Depending on the type of coal, CO2 emissions per energy equivalent are anywhere between 64% and 90% higher than for natural gas. This is somewhat offset by the fact that the ratio of total natural gas production to marketable gas production typically is somewhere between 1.15 to 1.2 in Canada.[33] However, even with this factor incorporated, GHG emissions per unit of energy equivalent are significantly higher for coal than for natural gas.

Over the past few years, there has been a trend in North America towards proportionally greater gas fired electricity generation versus coal fired generation. In Alberta for example, a substantial portion of the electricity generation capacity added over the last few years is gas fired. This trend could be halted if the relative price of natural gas (that is, relative to coal prices) rises substantially over time.

Consequently, to the extent that the supply augmentation provided by Mackenzie Delta gas supplies can alleviate gas price increases and thereby help to promote a trend away from the use of higher GHG emitting fuels in electricity generation (and in heating as well), additional benefits to society may be created. Although there is significant uncertainty regarding the value of preventing GHG emissions under the Kyoto agreement, the federal government has recently indicated that it would cap the price of emissions of CO2 equivalent at $15 per tonne.[34] Assuming that the entire volume of Mackenzie Delta gas would be used to fire new electricity generation that in the absence of this gas would be fired by coal, society would benefit by somewhere between $80 million to $230 million annually due to avoided GHG emissions.

[31] See Natural Resources Canada,, *Canada's Energy Outlook 1996-2000* (April 1997).
[32] The CO2 emissions per TJ of natural gas equal 49.68 T. Depending on the type of coal, CO2 emissions range from 81.6 to 94.3 T/TJ. The CO2 emissions for gasoline and oils range from 68 T/TJ to 74 T/TJ. Data from A.P. Jaques, *Canada's Greenhouse Gas Emission: Estimates for 1990*, Environment Canada (December 1992).
[33] See Canadian Association of Petroleum Producers (CAPP) *Statistical Handbook*.
[34] Estimates have been made of the value of preventing GHG emissions in the context of an emission permit trading system. For example, see Charles River Associates*, Report of the Upstream Oil and Gas Working Group of the Industry Issues - Table to the National Climate Change Secretariat*. It is estimated that the value per tonne of CO2 equivalent in 2010 could range from $25.74 Cdn - $130.59 Cdn, depending on whether credit would be given to international reductions in GHG emissions.

APPENDIX

In this appendix, diagrams that trace the financial flows in the various cases are presented in Figures A.1 to A.6. The present values of the financial flows by case are also shown in Figures A.7 to A.12. While each figure has a common format, it is instructive to explain the flows with reference to a particular case - for example, Case 1-3 as shown in Figure A.1.

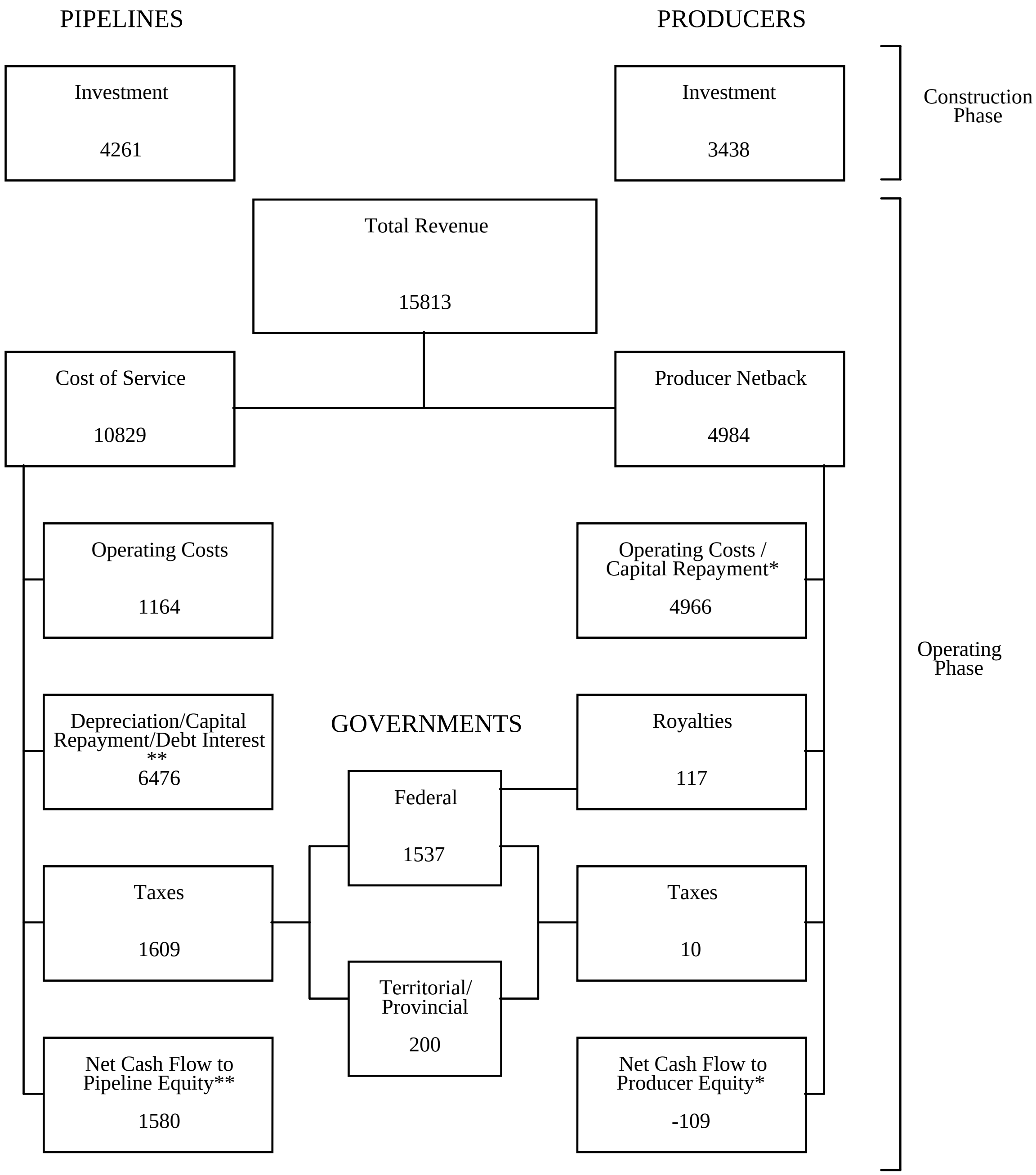
Initially, it should be observed that the pipeline sector is represented on the left hand side of the figure while the producer sector is depicted on the right hand side. The integration of these contributors is portrayed in the central boxes which measure the generation of income from the sale of gas and by-products and the allocation of taxation and royalty revenue to governments.

More specifically, if one starts at the top of Figure A.1, there is a construction phase in which investment in pipeline and production facilities creates an opportunity for producers to sell gas. The pipeline sector receives a cost of service ($10.8 billion 2004Cdn$) which is distributed to operating costs, depreciation and debt servicing, income and property taxes and a return on equity. In the producer sector, after paying for the cost of service, the netback revenue ($5.0 billion) is allocated to operating and other production costs, royalties, income and property taxes, and a return. From these activities, the government sector receives property taxes, income taxes and royalties totalling $1.737 billion. These are allocated according to jurisdiction.

FIGURE A.1

CASH FLOWS : CASE 1-3 (ANCHOR FIELDS ONLY, $3US GAS), 2002-2028

(millions of 2004 Canadian dollars)



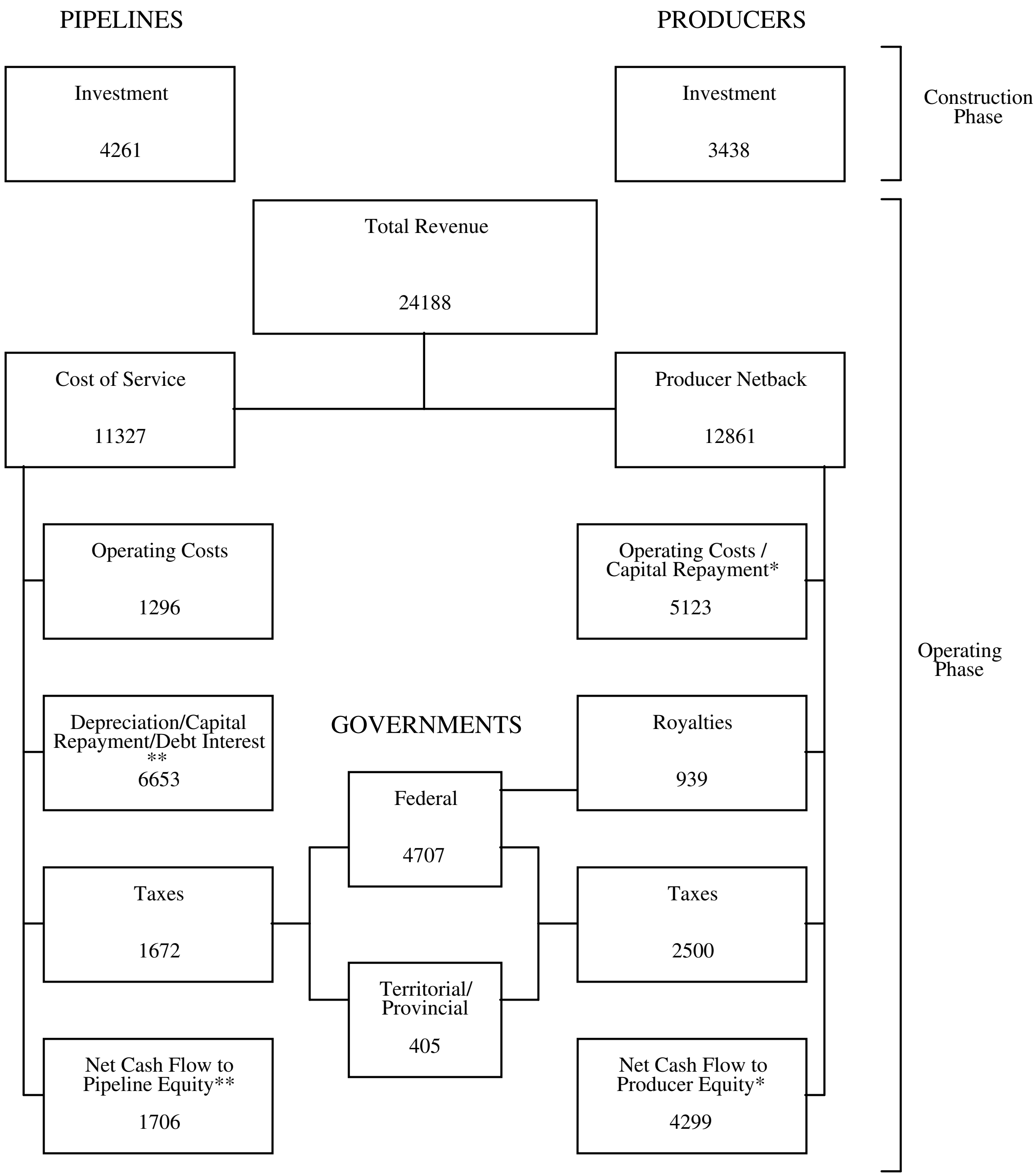
* assumes 100% equity financing

** assumes 70% debt / 30% equity financing

FIGURE A.2

CASH FLOWS : CASE 1-4 (ANCHOR FIELDS ONLY, $4US GAS), 2002-2030

(millions of 2004 Canadian dollars)



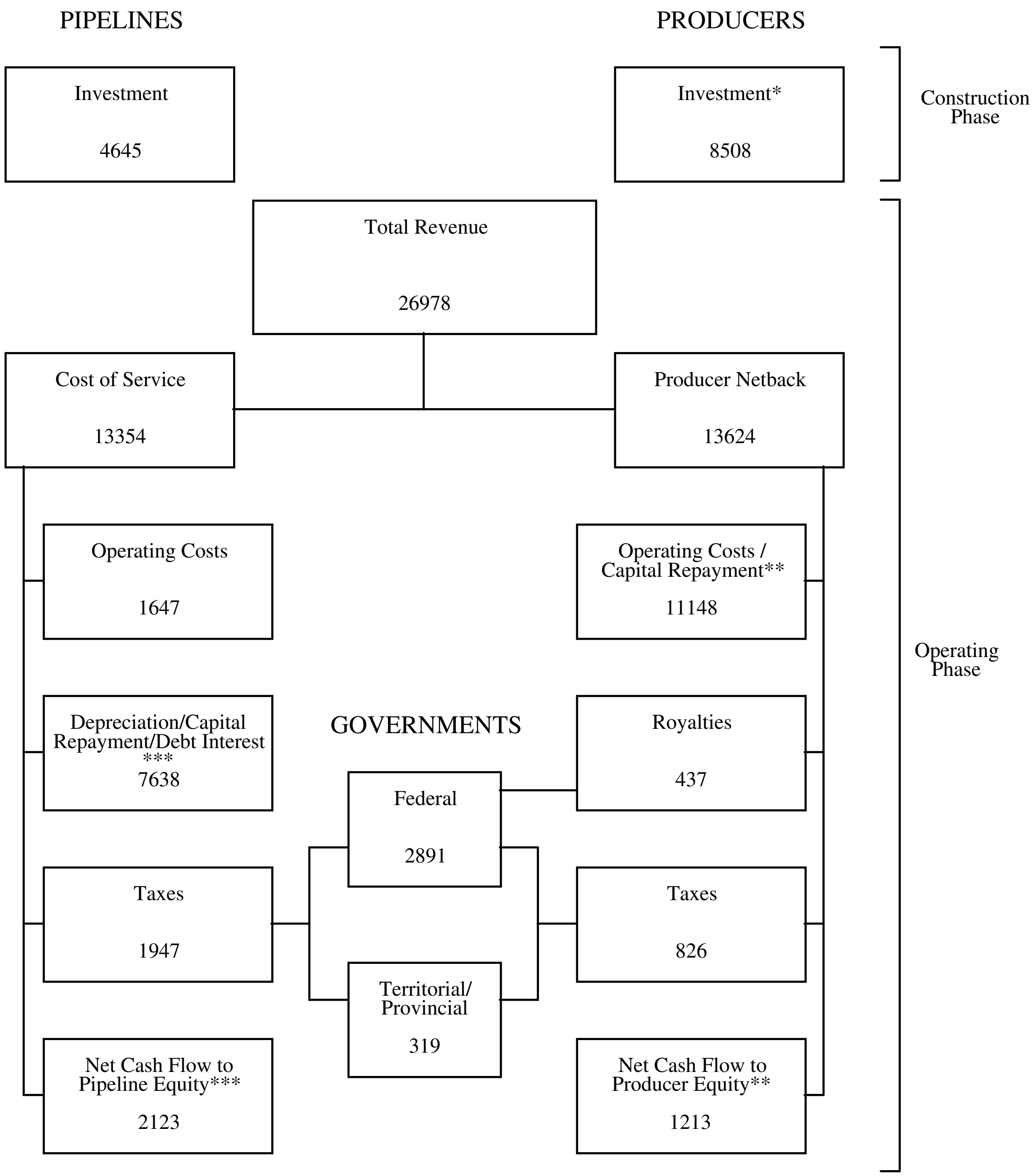
* assumes 100% equity financing

** assumes 70% debt / 30% equity financing

FIGURE A.3

CASH FLOWS : CASE 2-3 (1.2 BCF/D TO 2023, $3US GAS), 2002-2035

(millions of 2004 Canadian dollars)



* includes exploration expenditure (1973)

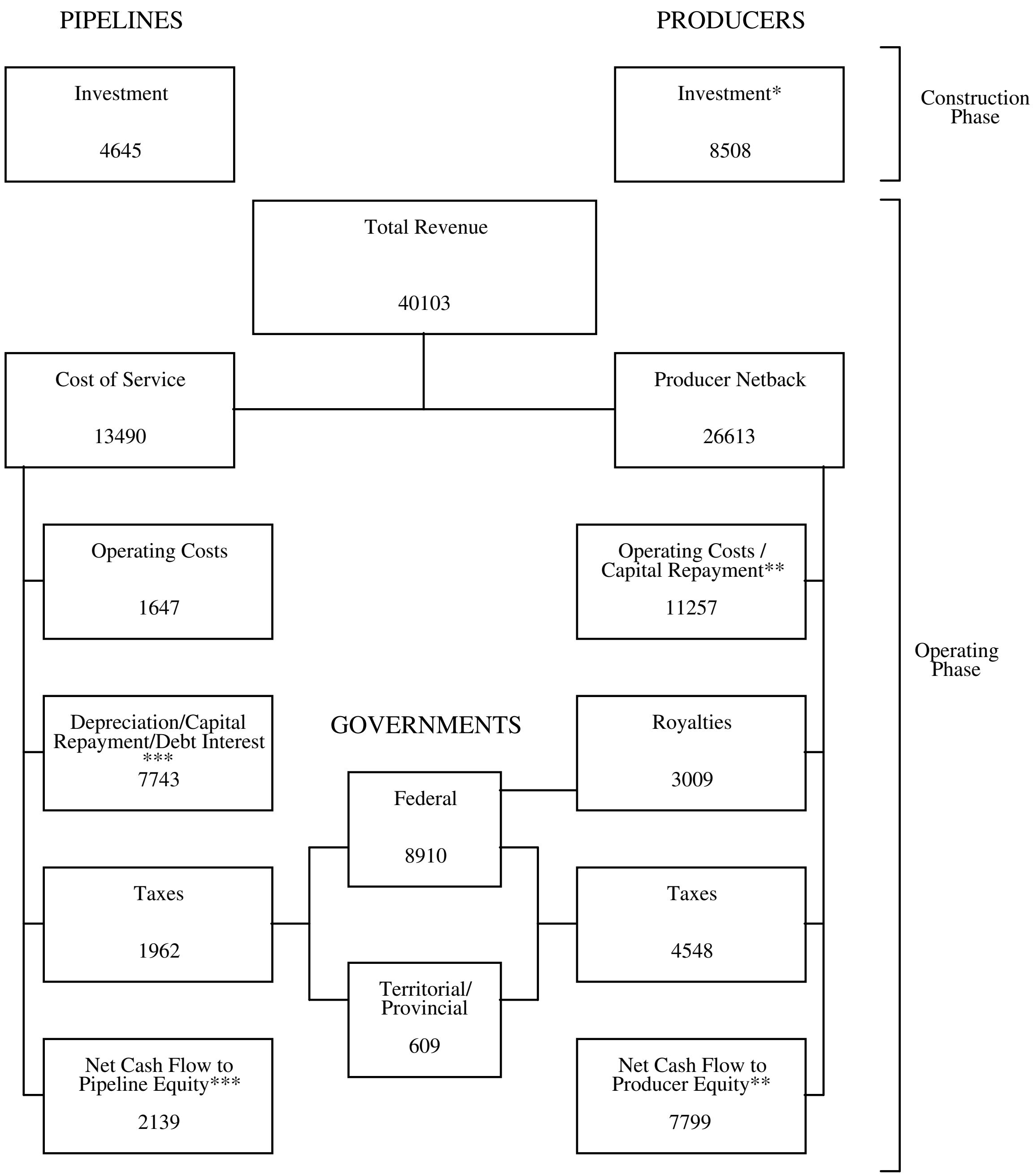
** assumes 100% equity financing

*** assumes 70% debt / 30% equity financing

FIGURE A.4

CASH FLOWS : CASE 2-4 (1.2 BCF/D TO 2023, $4US GAS), 2002-2035

(millions of 2004 Canadian dollars)



* includes exploration expenditure (1973)

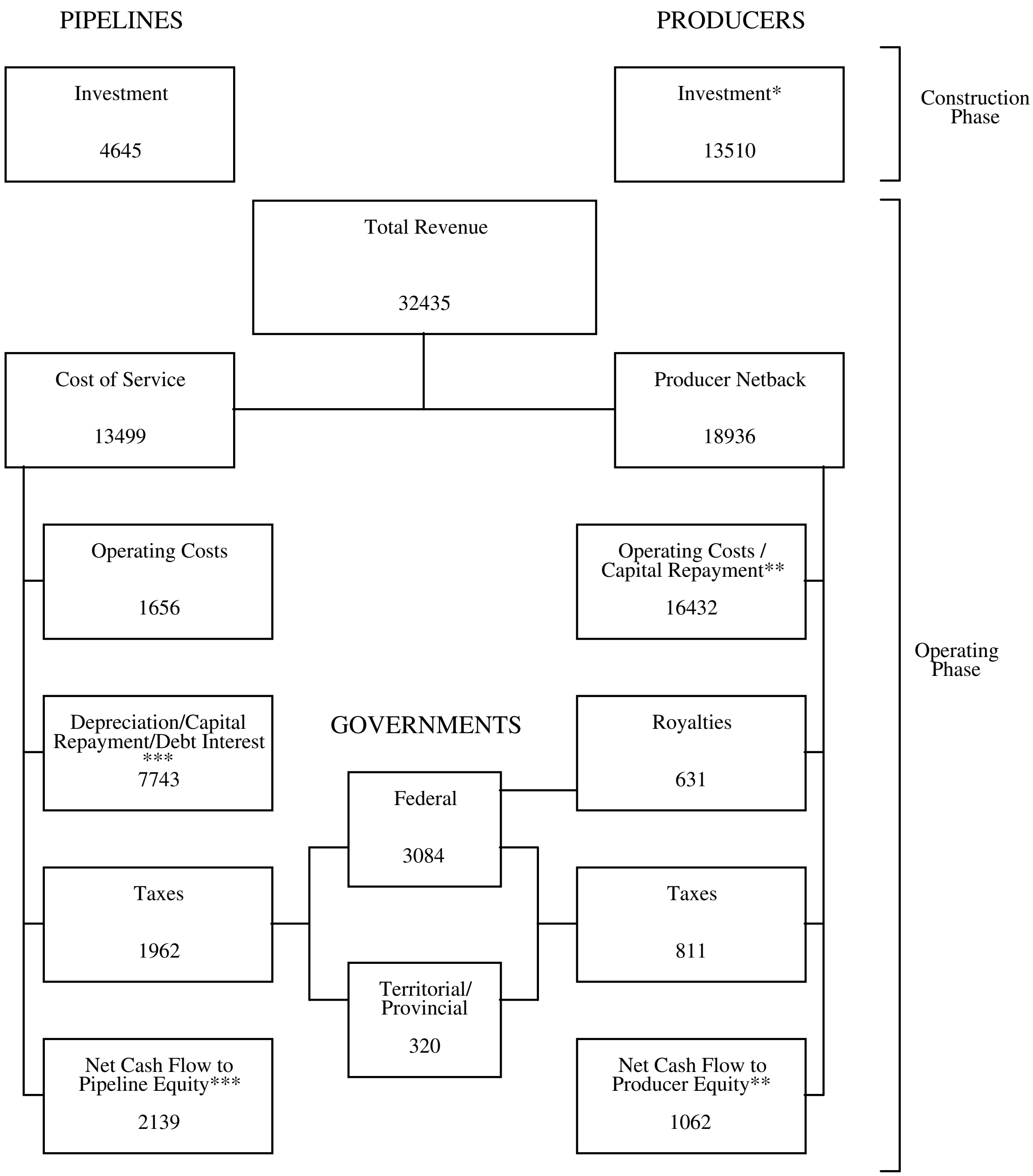
** assumes 100% equity financing

*** assumes 70% debt / 30% equity financing

FIGURE A.5

CASH FLOWS : CASE 3-3 (1.2 BCF/D TO 2035, $3US GAS), 2002-2035

(millions of 2004 Canadian dollars)



* includes exploration expenditure (3788)

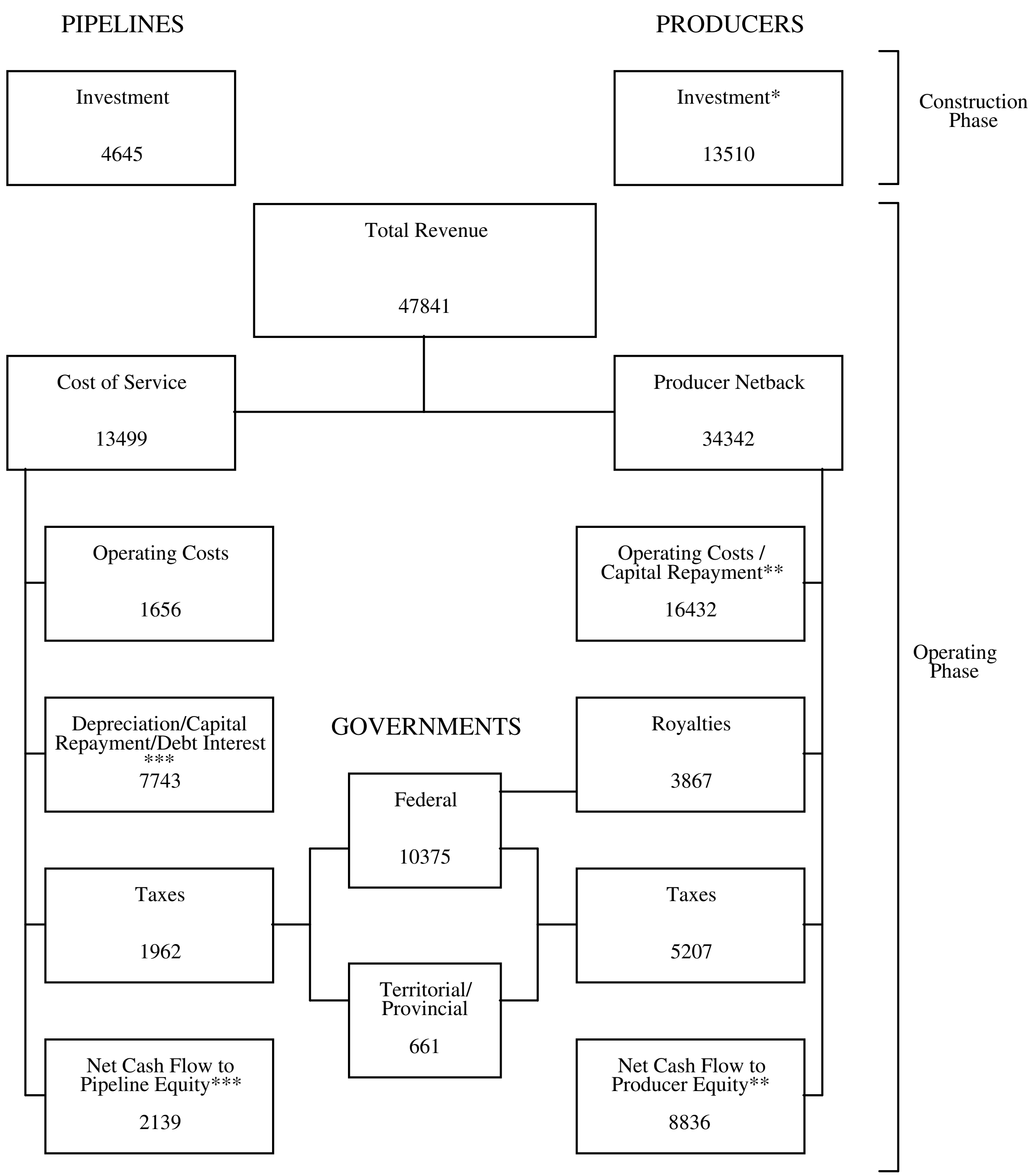
** assumes 100% equity financing

*** assumes 70% debt / 30% equity financing

FIGURE A.6

CASH FLOWS : CASE 3-4 (1.2 BCF/D TO 2035, $4US GAS), 2002-2035

(millions of 2004 Canadian dollars)



* includes exploration expenditure (3788)

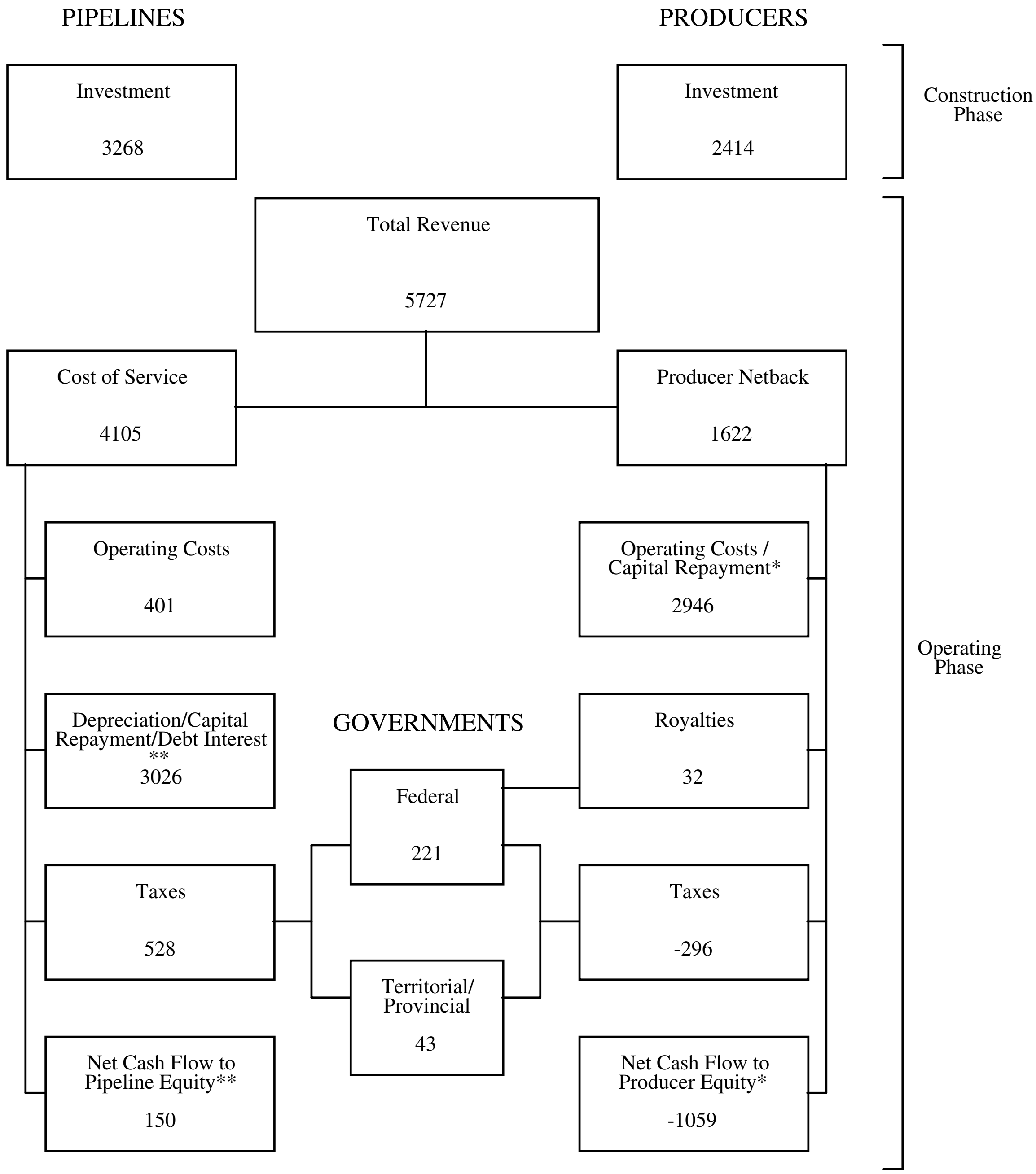
** assumes 100% equity financing

*** assumes 70% debt / 30% equity financing

FIGURE A.7

PRESENT VALUES OF CASH FLOWS : CASE 1-3
(ANCHOR FIELDS ONLY, $3US GAS), 2002-2028

(millions of 2004 Canadian dollars discounted at 8% to mid-2004)



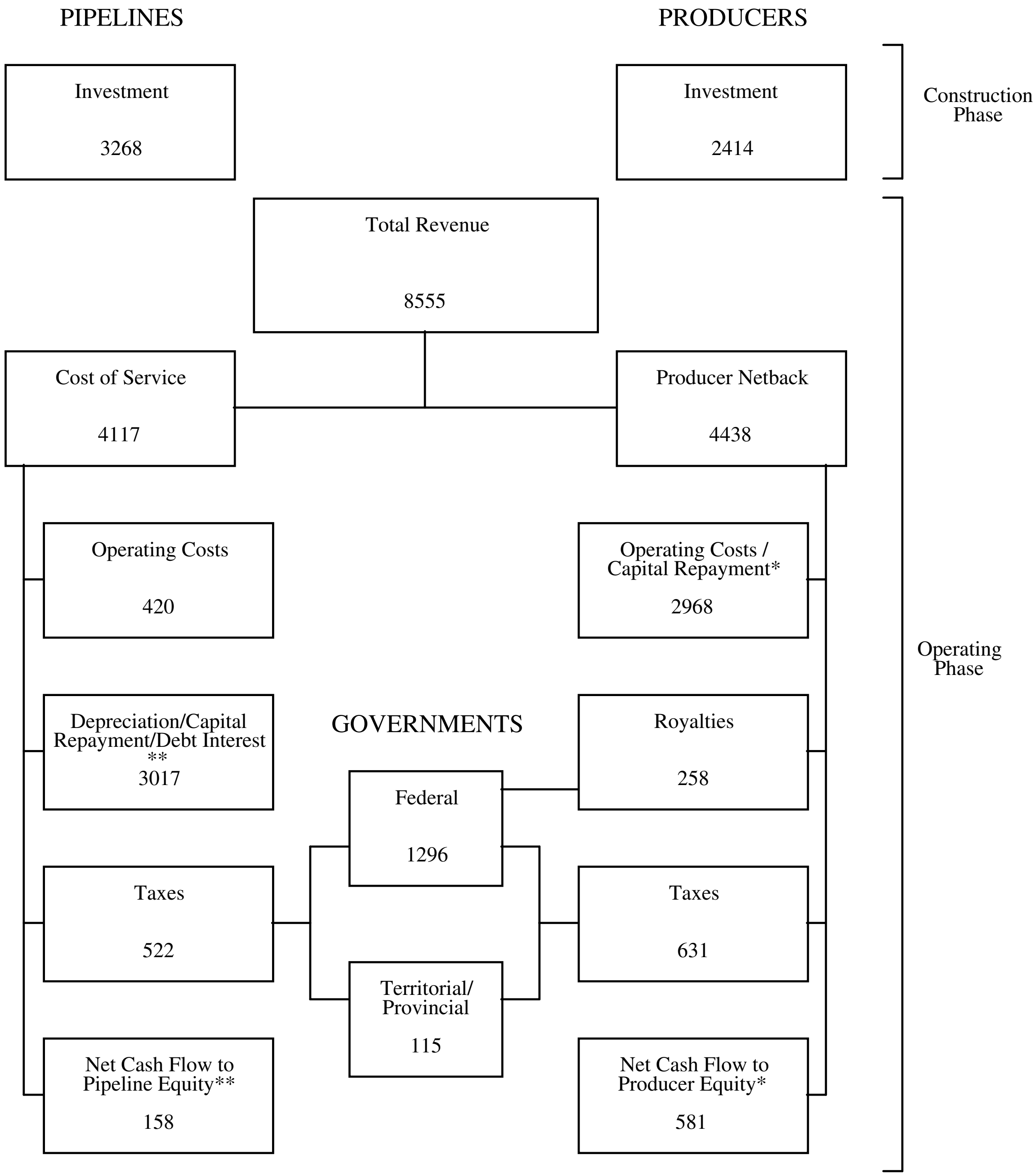
* assumes 100% equity financing

** assumes 70% debt / 30% equity financing

FIGURE A.8

PRESENT VALUES OF CASH FLOWS : CASE 1-4
(ANCHOR FIELDS ONLY, $4US GAS), 2002-2030

(millions of 2004 Canadian dollars discounted at 8% to mid-2004)



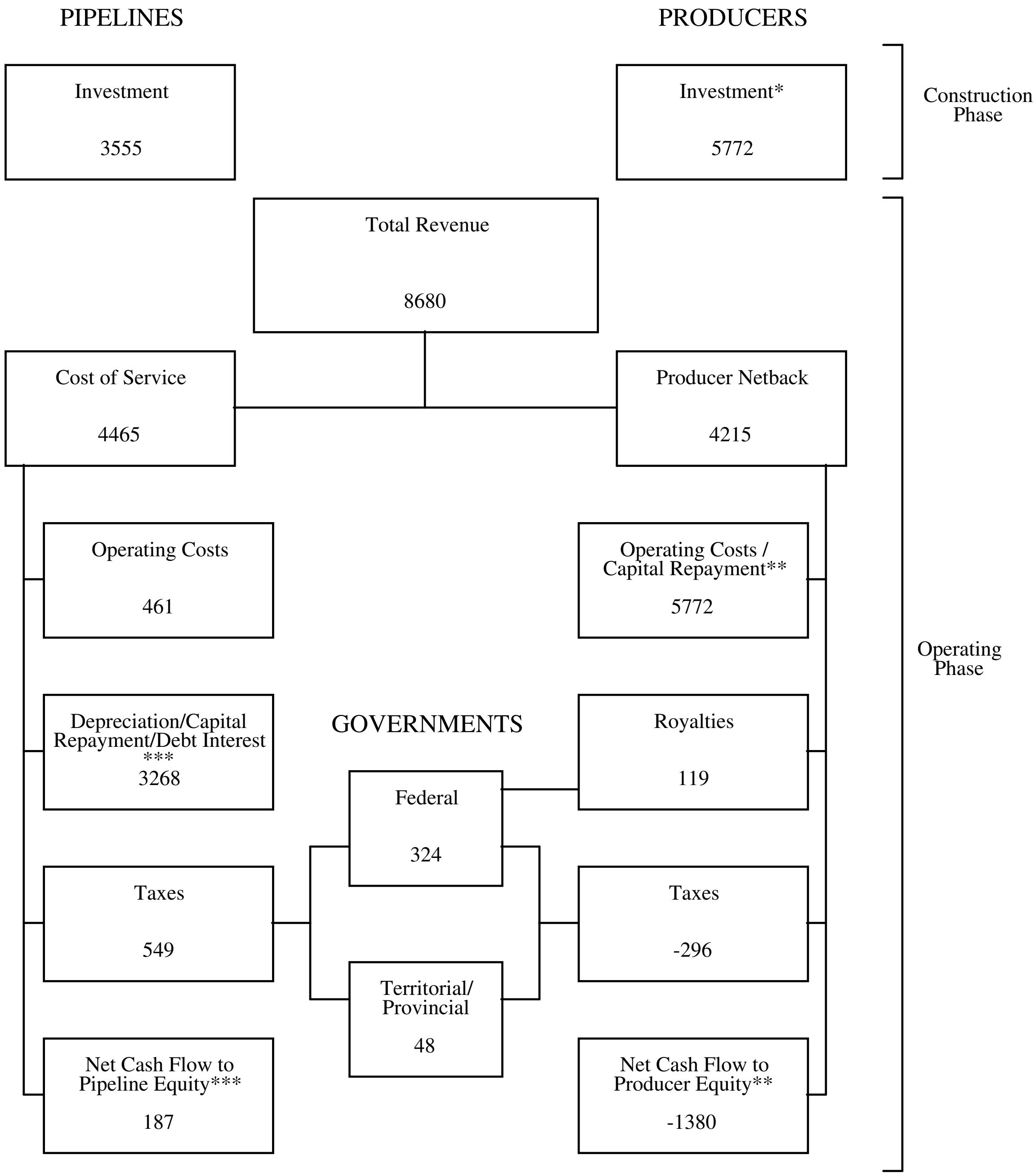
* assumes 100% equity financing

** assumes 70% debt / 30% equity financing

FIGURE A.9

PRESENT VALUES OF CASH FLOWS : CASE 2-3
(1.2 BCF/D TO 2023, $3US GAS), 2002-2035

(millions of 2004 Canadian dollars discounted at 8% to mid-2004)



* includes exploration expenditure (1173)

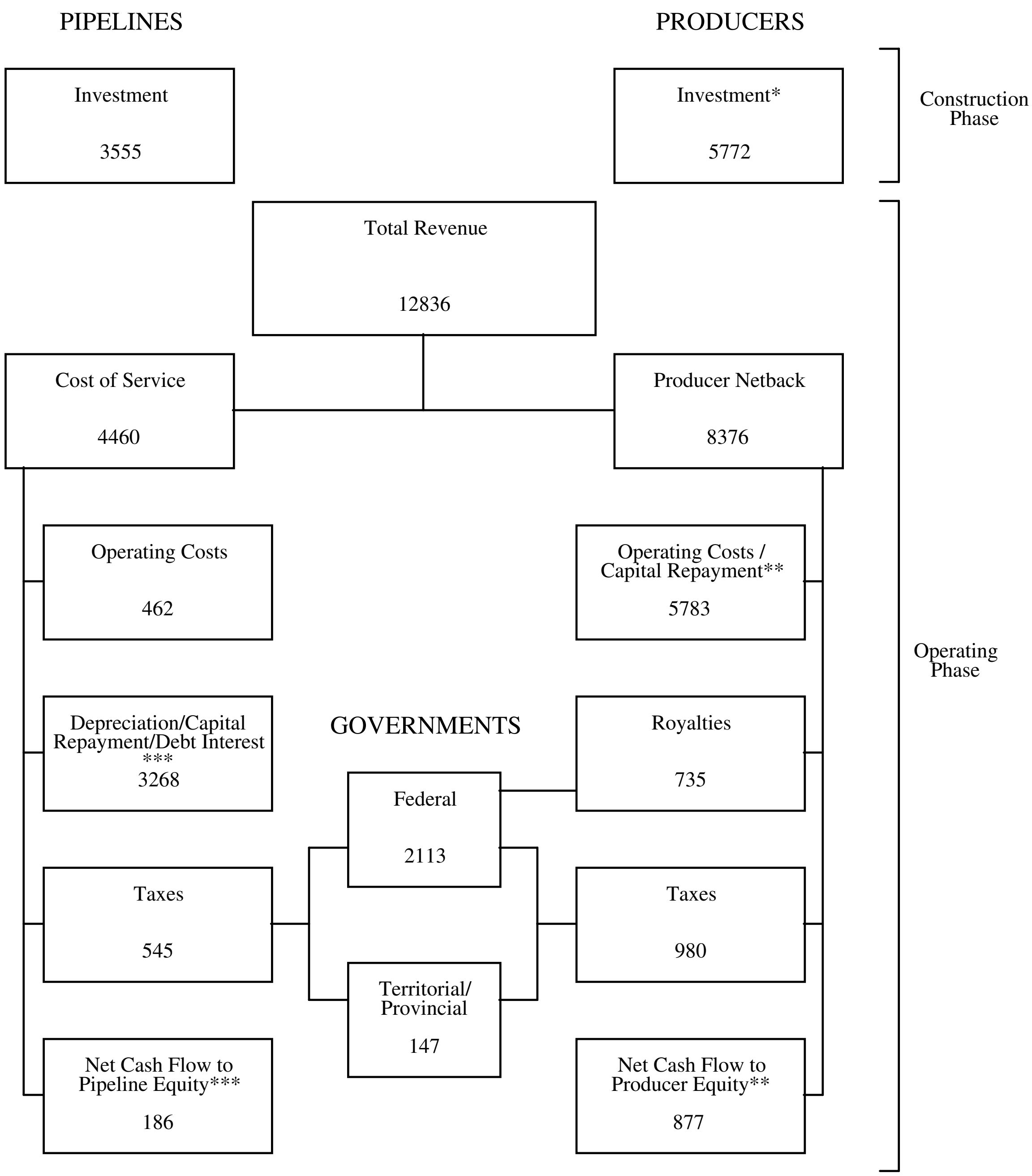
** assumes 100% equity financing

*** assumes 70% debt / 30% equity financing

FIGURE A.10

PRESENT VALUES OF CASH FLOWS : CASE 2-4
(1.2 BCF/D TO 2023, $4US GAS), 2002-2035

(millions of 2004 Canadian dollars discounted at 8% to mid-2004)



* includes exploration expenditure (1173)

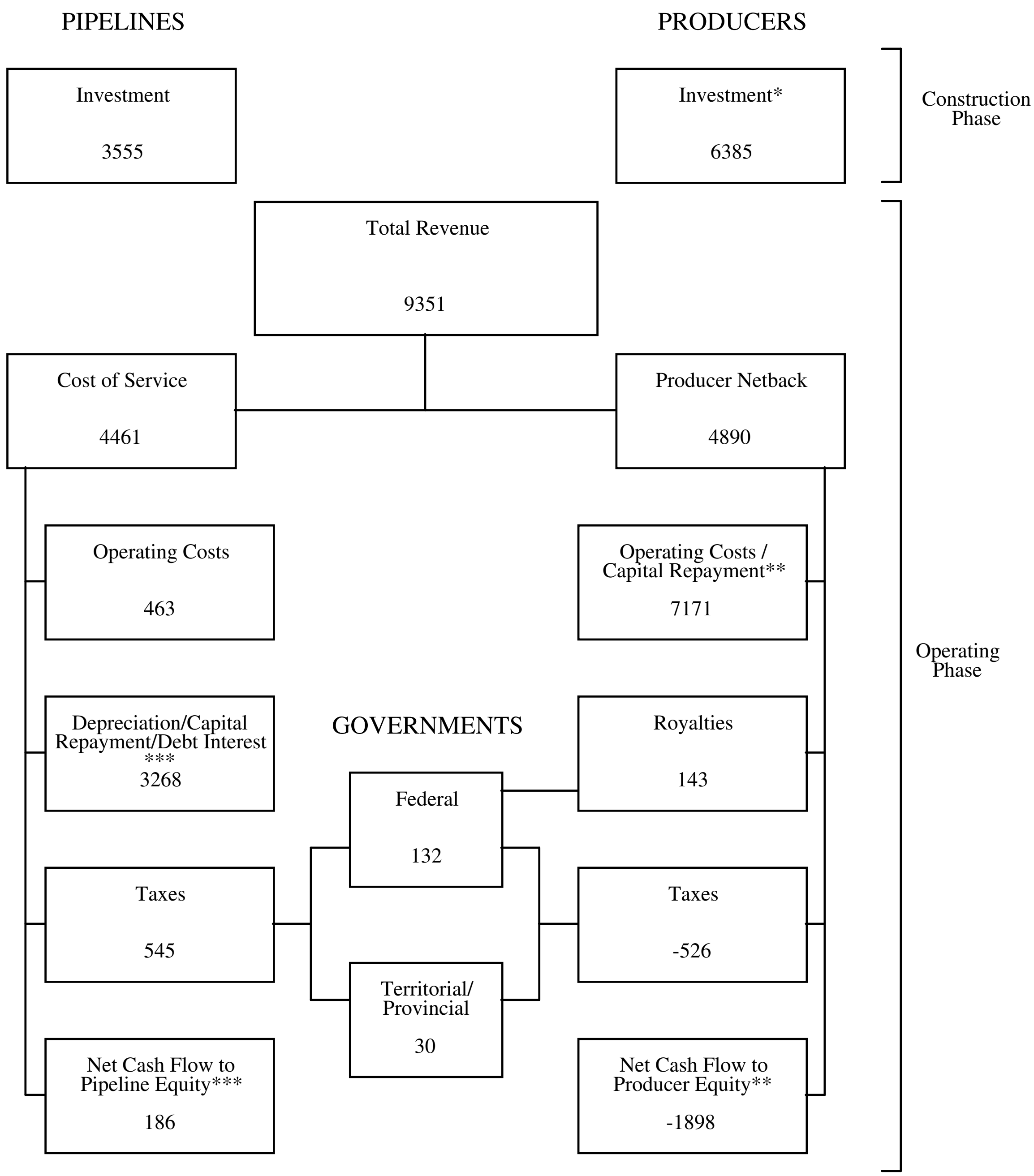
** assumes 100% equity financing

*** assumes 70% debt / 30% equity financing

FIGURE A.11

PRESENT VALUES OF CASH FLOWS : CASE 3-3
(1.2 BCF/D TO 2035, $3US GAS), 2002-2035

(millions of 2004 Canadian dollars discounted at 8% to mid-2004)



* includes exploration expenditure (2008)

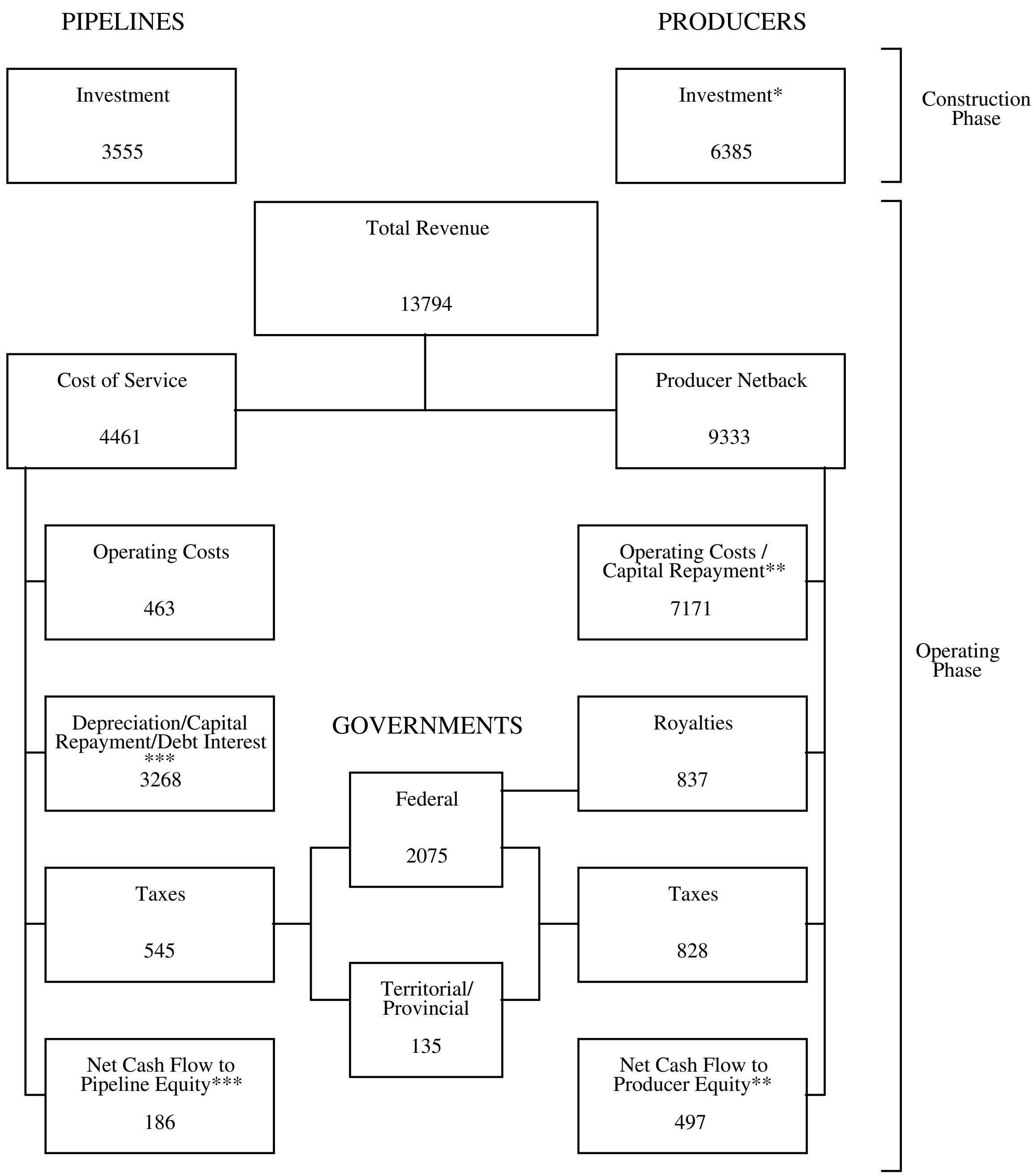
** assumes 100% equity financing

*** assumes 70% debt / 30% equity financing

FIGURE A.12

PRESENT VALUES OF CASH FLOWS : CASE 3-4
(1.2 BCF/D TO 2035, $4US GAS), 2002-2035

(millions of 2004 Canadian dollars discounted at 8% to mid-2004)



* includes exploration expenditure (2008)

** assumes 100% equity financing

*** assumes 70% debt / 30% equity financing

TABLE A.1: ANNUAL GAS PRODUCTION BY CASE: 2010-2035

(Bcf)

	Case 1-3	**Case 1-4**	**Case 2-3**	**Case 2-4**	**Case 3-3**	**Case 3-4**
2010	291	291	383	383	383	383
2011	302	302	437	437	437	437
2012	302	302	437	437	437	437
2013	300	300	435	435	435	435
2014	300	300	435	435	435	435
2015	299	299	435	435	435	435
2016	299	299	405	405	405	405
2017	299	299	434	434	434	434
2018	299	299	409	409	409	409
2019	299	299	445	445	445	445
2020	299	299	433	433	433	433
2021	299	299	423	423	423	423
2022	297	297	414	414	414	414
2023	275	275	434	434	434	434
2024	254	254	397	397	397	397
2025	230	230	372	372	372	372
2026	205	205	343	343	435	435
2027	170	170	308	308	418	418
2028	141	141	275	275	384	384
2029		114	246	246	356	356
2030		90	221	221	403	403
2031			204	204	441	441
2032			165	183	421	421
2033			147	168	405	405
2034			131	143	380	380
2035			93	126	364	364
Total	**5160**	**5364**	**8860**	**8945**	**10734**	**10734**

TABLE A.2: ANNUAL NATURAL GAS LIQUIDS PRODUCTION BY CASE: 2010-2035

(thousand barrels)

	Case 1-3	Case 1-4	Case 2-3	Case 2-4	Case 3-3	Case 3-4
2010	3817	3817	4638	4638	4638	4638
2011	3605	3605	4820	4820	4820	4820
2012	3477	3477	4692	4692	4692	4692
2013	3539	3539	4754	4754	4754	4754
2014	3367	3367	4583	4583	4583	4583
2015	3557	3557	4772	4772	4772	4772
2016	3181	3181	4134	4134	4134	4134
2017	2929	2929	4144	4144	4144	4144
2018	2757	2757	3746	3746	3746	3746
2019	2604	2604	3921	3921	3921	3921
2020	2458	2458	3664	3664	3664	3664
2021	2301	2301	3420	3420	3420	3420
2022	2118	2118	3173	3173	3173	3173
2023	1830	1830	3263	3263	3263	3263
2024	1609	1609	2893	2893	2893	2893
2025	1427	1427	2712	2712	2712	2712
2026	1285	1285	2533	2533	3081	3081
2027	1062	1062	2304	2304	2961	2961
2028	880	880	2085	2085	2742	2742
2029		712	1904	1904	2561	2561
2030		573	1746	1746	2841	2841
2031			1634	1634	3058	3058
2032			1390	1488	2912	2912
2033			1296	1373	2797	2797
2034			1151	1224	2648	2648
2035			834	1083	2506	2506
Total	**47802**	**49087**	**80209**	**80705**	**91436**	**91436**

TABLE A.3: DISTRIBUTION OF INVESTMENT BY SECTOR AND YEAR: 2002-2035

(millions of 2004 Cdn$)

	Case 1 Pipelines	Case 1 Producers	Case 1 Total	Case 2/3 Pipelines	Case 2 Producers	Case 2 Total	Case 3 Producers	Case 3 Total
2002	36	48	85	36	48	85	48	85
2003	87	39	126	87	39	126	39	126
2004	123	83	205	123	189	312	246	369
2005	157	123	280	157	230	387	287	443
2006	369	334	703	408	483	891	542	949
2007	935	603	1538	1033	986	2020	1047	2080
2008	1353	907	2260	1493	1455	2948	1519	3012
2009	1118	482	1600	1216	767	1983	836	2052
2010	83	67	150	92	257	348	329	421
2011		35	35		315	315	392	392
2012		147	147		336	336	412	412
2013		39	39		209	209	286	286
2014		136	136		338	338	414	414
2015		63	63		428	428	504	504
2016		43	43		378	378	454	454
2017		29	29		468	468	545	545
2018		86	86		424	424	500	500
2019		14	14		143	143	352	352
2020		126	126		246	246	444	444
2021		14	14		208	208	366	366
2022		19	19		192	192	492	492
2023					102	102	355	355
2024					102	102	450	450
2025							224	224
2026							316	316
2027					41	41	326	326
2028					41	41	428	428
2029					41	41	316	316
2030							235	235
2031							194	194
2032							153	153
2033					41	41	184	184
2034							122	122
2035							153	153
Total	**4261**	**3438**	**7699**	**4645**	**8508**	**13153**	**13510**	**18155**

TABLE A.4: DISTRIBUTION OF DIRECT GOVERNMENT REVENUES – $3US GAS PRICE: 2010-2035*

(millions of 2004 Cdn $)

CASE 1	**Property Tax**	**Income Tax**	**Royalties**	**Total**
Federal		843	117	960
Alberta	30	25		55
NWT	264	457		721
- Grant Reduction	211	366		577
Adjusted NWT	53	91		144
Adjusted Federal	211	1209	117	1537
Total	**294**	**1325**	**117**	**1736**

CASE 2	**Property Tax**	**Income Tax**	**Royalties**	**Total**
Federal		1482	437	1919
Alberta	41	34		75
NWT	384	832		1216
- Grant Reduction	307	666		973
Adjusted NWT	77	166		243
Adjusted Federal	307	2148	437	2892
Total	**425**	**2348**	**437**	**3210**

CASE 3	**Property Tax**	**Income Tax**	**Royalties**	**Total**
Federal		1476	631	2107
Alberta	41	34		75
NWT	396	825		1221
- Grant Reduction	317	660		977
Adjusted NWT	79	165		244
Adjusted Federal	317	2136	631	3084
Total	**437**	**2335**	**631**	**3403**

* Personal income taxes on direct labour income not included

TABLE A.5: DISTRIBUTION OF DIRECT GOVERNMENT REVENUES – $4US GAS PRICE : 2010-2035*

(millions of 2004 Cdn $)

CASE 1	Property Tax	Income Tax	Royalties	Total
Federal		2391	939	3330
Alberta	33	28		61
NWT	291	1429		1720
- Grant Reduction	233	1143		1376
Adjusted NWT	58	286		344
Adjusted Federal	233	3534	939	4706
Total	**324**	**3848**	**939**	**5111**

CASE 2	Property Tax	Income Tax	Royalties	Total
Federal		3769	3009	6778
Alberta	41	34		75
NWT	389	2276		2665
- Grant Reduction	311	1821		2132
Adjusted NWT	78	455		533
Adjusted Federal	311	5590	3009	8910
Total	**430**	**6079**	**3009**	**9518**

CASE 3	Property Tax	Income Tax	Royalties	Total
Federal		4168	3867	8035
Alberta	41	34		75
NWT	396	2529		2925
- Grant Reduction	317	2023		2340
Adjusted NWT	79	506		585
Adjusted Federal	317	6191	3867	10375
Total	**437**	**6731**	**3867**	**11035**

* Personal income taxes on direct labour income not included

TABLE A.6: DIRECT EMPLOYMENT BY CATEGORY AND REGION

(person years)

	$3US GAS PRICE			$4US GAS PRICE		
CASE 1	**NWT**	**Alberta**	**Total**	**NWT**	**Alberta**	**Total**
Pipeline Construction	5318	187	5505	5318	187	5505
Pipeline Operation	588	324	912	654	353	1007
Pipeline Total	5906	511	6417	5972	540	6512
Field Development	2222		2222	2222		2222
Producer Operation	1132	408	1540	1262	436	1698
Producer Total	3354	408	3762	3484	436	3920
Total Construction	7540	187	7727	7540	187	7727
Total Operation	1720	732	2452	1916	789	2705
Total	**9260**	**919**	**10179**	**9456**	**976**	**10432**

CASE 2	**NWT**	**Alberta**	**Total**	**NWT**	**Alberta**	**Total**
Pipeline Construction	5496	187	5683	5496	187	5683
Pipeline Operation	817	425	1242	817	425	1242
Pipeline Total	6313	612	6925	6313	612	6925
Field Expl. & Development	6162		6162	6162		6162
Producer Operation	2244	702	2946	2352	717	3069
Producer Total	8406	702	9108	8514	717	9231
Total Construction	11658	187	11845	11658	187	11845
Total Operation	3061	1127	4188	3169	1142	4311
Total	**14719**	**1314**	**16033**	**14827**	**1329**	**16156**

CASE 3	**NWT**	**Alberta**	**Total**	**NWT**	**Alberta**	**Total**
Pipeline Construction	5496	187	5683	5496	187	5683
Pipeline Operation	817	425	1242	817	425	1242
Pipeline Total	6313	612	6925	6313	612	6925
Field Expl. & Development	10017		10017	10017		10017
Producer Operation	2555	836	3391	2555	836	3391
Producer Total	12572	836	13408	12572	836	13408
Total Construction	15513	187	15700	15513	187	15700
Total Operation	3372	1261	4633	3372	1261	4633
Total	**18885**	**1448**	**20333**	**18885**	**1448**	**20333**

Note: NWT cost impacts not adjusted for labour market constraints

TABLE A.7: PIPELINE OPERATIONS IMPACTS - $3US GAS PRICE: 2010-2035

(millions of 2004 Cdn$, employment in person years)

CASE 1	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	10330		499					10829
Gross Domestic Product	9594	95	562	18	213	53	12	10546
Labour Income	271	67	101	11	146	35	8	640
Federal Government Revenue	885	17	74	3	41	8	2	1031
Terr./Prov. Government Revenue	701	9	65	2	24	7	1	809
Grant Reduction	560	0	0	0	0	0	0	561
Adjusted Terr./Prov. Gov. Rev.	140	9	65	2	24	7	1	249
Adjusted Federal Gov. Rev.	1446	17	74	3	41	8	2	1592
Total Government Revenue	1586	27	140	5	66	14	3	1840
Employment	6252	1734	1958	309	3159	858	205	14474

CASE 2	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	12671		683					13354
Gross Domestic Product	11625	135	773	26	302	75	17	12952
Labour Income	383	95	140	16	207	50	12	902
Federal Government Revenue	1059	25	103	4	59	11	2	1263
Terr./Prov. Government Revenue	859	13	90	3	35	9	2	1011
Grant Reduction	687	0	0	1	0	0	0	688
Adjusted Terr./Prov. Gov. Rev.	172	13	90	3	35	9	2	323
Adjusted Federal Gov. Rev.	1747	25	103	4	59	11	2	1951
Total Government Revenue	1918	38	192	7	93	20	4	2274
Employment	8857	2462	2744	438	4484	1217	292	20494

CASE 3	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	12817		683					13499
Gross Domestic Product	11764	136	774	26	304	75	17	13095
Labour Income	384	96	141	16	208	50	12	907
Federal Government Revenue	1070	25	103	4	59	11	2	1275
Terr./Prov. Government Revenue	864	13	90	3	35	9	2	1016
Grant Reduction	691	0	0	1	0	0	0	692
Adjusted Terr./Prov. Gov. Rev.	173	13	90	3	35	9	2	324
Adjusted Federal Gov. Rev.	1762	25	103	4	59	11	2	1967
Total Government Revenue	1934	38	193	7	94	20	4	2291
Employment	8906	2476	2758	441	4511	1225	293	20609

* Saskatchewan / Manitoba / Yukon / Nunavut

TABLE A.8: PIPELINE OPERATIONS IMPACTS - $4US GAS PRICE: 2010-2035

(millions of 2004 Cdn$, employment in person years)

CASE 1	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	10776		551					11327
Gross Domestic Product	9955	106	621	20	237	59	13	11012
Labour Income	302	75	112	13	162	39	9	712
Federal Government Revenue	914	19	82	3	46	9	2	1075
Terr./Prov. Government Revenue	733	10	72	2	27	7	1	854
Grant Reduction	586	0	0	0	0	0	0	587
Adjusted Terr./Prov. Gov. Rev.	147	10	72	2	27	7	1	267
Adjusted Federal Gov. Rev.	1500	19	82	3	46	9	2	1662
Total Government Revenue	1647	30	155	5	73	16	3	1929
Employment	6965	1932	2173	344	3519	956	229	16117

CASE 2	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	12808		683					13490
Gross Domestic Product	11761	135	773	26	302	75	17	13089
Labour Income	383	95	140	16	207	50	12	903
Federal Government Revenue	1070	25	103	4	59	11	2	1273
Terr./Prov. Government Revenue	864	13	90	3	35	9	2	1015
Grant Reduction	691	0	0	1	0	0	0	692
Adjusted Terr./Prov. Gov. Rev.	173	13	90	3	35	9	2	324
Adjusted Federal Gov. Rev.	1761	25	103	4	59	11	2	1965
Total Government Revenue	1933	38	192	7	94	20	4	2289
Employment	8859	2462	2745	438	4484	1218	292	20497

CASE 3	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	12817		683					13499
Gross Domestic Product	11764	136	774	26	304	75	17	13095
Labour Income	384	96	141	16	208	50	12	907
Federal Government Revenue	1070	25	103	4	59	11	2	1275
Terr./Prov. Government Revenue	864	13	90	3	35	9	2	1016
Grant Reduction	691	0	0	1	0	0	0	692
Adjusted Terr./Prov. Gov. Rev.	173	13	90	3	35	9	2	324
Adjusted Federal Gov. Rev.	1762	25	103	4	59	11	2	1967
Total Government Revenue	1934	38	193	7	94	20	4	2291
Employment	8906	2476	2758	441	4511	1225	293	20609

* Saskatchewan / Manitoba / Yukon / Nunavut

TABLE A.9: PRODUCER OPERATIONS IMPACTS - $3US GAS PRICE: 2010-2035

(millions of 2004 Cdn$, employment in person years)

CASE 1	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	4984							4984
Gross Domestic Product	3880	75	209	18	362	75	8	4628
Labour Income	315	55	146	11	245	55	5	833
Federal Government Revenue	146	14	37	3	71	11	1	283
Terr./Prov. Government Revenue	68	7	12	2	46	10	1	146
Grant Reduction	54	0	0	0	0	0	0	55
Adjusted Terr./Prov. Gov. Rev.	14	7	12	2	46	10	1	91
Adjusted Federal Gov. Rev.	200	14	37	3	71	11	1	337
Total Government Revenue	214	21	49	5	117	21	2	429
Employment	4935	1441	2534	275	4730	1324	129	15368

CASE 2	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	13624							13624
Gross Domestic Product	11734	129	357	31	620	129	14	13014
Labour Income	565	95	250	19	420	95	9	1451
Federal Government Revenue	984	24	63	4	122	20	2	1219
Terr./Prov. Government Revenue	432	12	21	3	79	17	1	565
Grant Reduction	345	0	0	1	0	0	0	346
Adjusted Terr./Prov. Gov. Rev.	86	12	21	3	79	17	1	220
Adjusted Federal Gov. Rev.	1330	24	63	5	122	20	2	1565
Total Government Revenue	1416	37	84	8	200	36	3	1784
Employment	8759	2468	4345	471	8104	2268	222	26636

CASE 3	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	18936							18936
Gross Domestic Product	16848	142	399	34	684	142	15	18264
Labour Income	629	105	280	21	463	104	10	1611
Federal Government Revenue	1174	27	70	5	134	22	2	1434
Terr./Prov. Government Revenue	438	14	23	4	87	18	2	586
Grant Reduction	350	0	0	1	0	0	0	351
Adjusted Terr./Prov. Gov. Rev.	88	14	23	3	87	18	2	235
Adjusted Federal Gov. Rev.	1525	27	70	5	134	22	2	1785
Total Government Revenue	1612	41	94	9	221	40	4	2020
Employment	9739	2721	4853	519	8936	2501	244	29512

* Saskatchewan / Manitoba / Yukon / Nunavut

TABLE A.10: PRODUCER OPERATIONS IMPACTS - $4US GAS PRICE: 2010-2035

(millions of 2004 Cdn$, employment in person years)

CASE 1	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	12861							12861
Gross Domestic Product	11645	83	229	20	399	83	9	12468
Labour Income	349	61	160	12	270	61	6	919
Federal Government Revenue	2495	16	40	3	78	13	1	2646
Terr./Prov. Government Revenue	1039	8	14	2	51	11	1	1126
Grant Reduction	832	0	0	0	0	0	0	832
Adjusted Terr./Prov. Gov. Rev.	208	8	14	2	51	11	1	294
Adjusted Federal Gov. Rev.	3326	16	40	3	78	13	1	3478
Total Government Revenue	3534	24	54	5	129	23	2	3771
Employment	5458	1589	2782	303	5219	1461	143	16955

CASE 2	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	26613							26613
Gross Domestic Product	24646	134	370	32	646	134	14	25978
Labour Income	589	99	258	20	437	99	9	1511
Federal Government Revenue	5838	25	65	5	127	20	2	6082
Terr./Prov. Government Revenue	1879	13	22	4	82	17	2	2018
Grant Reduction	1503	0	0	1	0	0	0	1504
Adjusted Terr./Prov. Gov. Rev.	376	13	22	3	82	17	2	514
Adjusted Federal Gov. Rev.	7341	25	65	5	127	20	2	7585
Total Government Revenue	7717	38	87	8	209	38	4	8100
Employment	9138	2570	4511	490	8441	2362	231	27743

CASE 3	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	34342							34342
Gross Domestic Product	32254	142	399	34	684	142	15	33670
Labour Income	629	105	280	21	463	104	10	1611
Federal Government Revenue	7102	27	70	5	134	22	2	7362
Terr./Prov. Government Revenue	2142	14	23	4	87	18	2	2290
Grant Reduction	1713	0	0	1	0	0	0	1714
Adjusted Terr./Prov. Gov. Rev.	428	14	23	3	87	18	2	576
Adjusted Federal Gov. Rev.	8816	27	70	5	134	22	2	9076
Total Government Revenue	9244	41	94	9	221	40	4	9652
Employment	9739	2721	4853	519	8936	2501	244	29512

* Saskatchewan / Manitoba / Yukon / Nunavut

TABLE A.11: UNADJUSTED OVERALL IMPACTS - $3US GAS PRICE: 2002-2035

(millions of 2004 Cdn$, employment in person years)

CASE 1	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	22864		649					23512
Gross Domestic Product	15307	390	2185	216	1789	404	46	20337
Labour Income	1781	272	1221	110	1169	274	28	4853
Federal Government Revenue	1280	71	359	31	346	59	6	2153
Terr./Prov. Government Revenue	879	38	163	30	230	50	5	1396
Grant Reduction	703	0	0	2	0	0	0	705
Adjusted Terr./Prov. Gov. Rev.	176	38	163	28	230	50	5	691
Adjusted Federal Gov. Rev.	1983	71	359	33	346	59	6	2859
Total Government Revenue	2159	110	523	61	576	110	11	3549
Employment	25640	6926	20618	2743	23116	6495	720	86258

CASE 2	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	39298		833					40130
Gross Domestic Product	26507	647	3591	332	2934	670	75	34757
Labour Income	2771	449	2057	177	1925	456	45	7881
Federal Government Revenue	2544	119	593	48	566	98	10	3977
Terr./Prov. Government Revenue	1474	64	258	45	368	83	8	2301
Grant Reduction	1179	0	0	3	0	0	0	1183
Adjusted Terr./Prov. Gov. Rev.	295	64	258	42	368	83	8	1118
Adjusted Federal Gov. Rev.	3723	119	593	51	566	98	10	5160
Total Government Revenue	4018	183	851	93	934	182	18	6278
Employment	41150	11426	35030	4474	38064	10827	1170	142141

CASE 3	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	49758		833					50590
Gross Domestic Product	32983	810	4577	422	3736	859	94	43482
Labour Income	3405	561	2712	229	2450	584	56	9997
Federal Government Revenue	2982	148	761	61	720	126	13	4811
Terr./Prov. Government Revenue	1552	81	316	56	464	107	10	2587
Grant Reduction	1242	0	0	4	0	0	0	1246
Adjusted Terr./Prov. Gov. Rev.	310	81	316	52	464	107	10	1341
Adjusted Federal Gov. Rev.	4223	148	761	65	720	126	13	6057
Total Government Revenue	4534	230	1078	117	1184	233	23	7397
Employment	50648	14219	46196	5802	48388	13863	1446	180562

* Saskatchewan / Manitoba / Yukon / Nunavut

TABLE A.12: UNADJUSTED OVERALL IMPACTS - $4US GAS PRICE: 2002-2035

(millions of 2004 Cdn$, employment in person years)

CASE 1	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	31186		701					31887
Gross Domestic Product	23432	409	2265	220	1851	418	48	28643
Labour Income	1845	285	1245	112	1211	283	29	5011
Federal Government Revenue	3658	75	371	31	358	61	7	4561
Terr./Prov. Government Revenue	1883	40	171	31	237	52	5	2420
Grant Reduction	1506	0	0	2	0	0	0	1508
Adjusted Terr./Prov. Gov. Rev.	377	40	171	29	237	52	5	911
Adjusted Federal Gov. Rev.	5164	75	371	33	358	61	7	6069
Total Government Revenue	5541	115	542	62	595	113	12	6981
Employment	26875	7273	21081	2806	23965	6730	757	89489

CASE 2	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	52423		833					53256
Gross Domestic Product	39556	652	3605	334	2960	675	76	47857
Labour Income	2796	453	2066	178	1942	460	46	7941
Federal Government Revenue	7407	120	595	48	571	99	10	8850
Terr./Prov. Government Revenue	2926	65	259	45	371	84	8	3758
Grant Reduction	2341	0	0	3	0	0	0	2344
Adjusted Terr./Prov. Gov. Rev.	585	65	259	42	371	84	8	1414
Adjusted Federal Gov. Rev.	9748	120	595	51	571	99	10	11195
Total Government Revenue	10333	184	854	93	943	183	18	12609
Employment	41530	11529	35197	4494	38402	10921	1180	143252

CASE 3	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	65164		833					65996
Gross Domestic Product	48389	810	4577	422	3736	859	94	58888
Labour Income	3405	561	2712	229	2450	584	56	9997
Federal Government Revenue	8909	148	761	61	720	126	13	10738
Terr./Prov. Government Revenue	3256	81	316	56	464	107	10	4290
Grant Reduction	2605	0	0	4	0	0	0	2609
Adjusted Terr./Prov. Gov. Rev.	651	81	316	52	464	107	10	1681
Adjusted Federal Gov. Rev.	11514	148	761	65	720	126	13	13348
Total Government Revenue	12165	230	1078	117	1184	233	23	15029
Employment	50648	14219	46196	5802	48388	13863	1446	180562

* Saskatchewan / Manitoba / Yukon / Nunavut

TABLE A.13: SECTORAL DISTRIBUTION OF EMPLOYMENT IMPACTS – $3US GAS PRICE: 2004-2035

(in person years)

CASE 1	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Oil and Gas Extraction	1136	4	509	3	0	0	1	1653
Oil and Gas Services	2009	216	3533	251	4059	1963	173	12204
Construction	4407	708	4268	679	156	40	656	10916
Manufacturing	99	757	1628	922	3047	1240	230	7923
Trade	884	986	2336	559	3009	967	123	8864
Pipeline Transportation	589	1	342	1	1	0	0	935
Transportation and Storage	864	534	1311	283	1154	455	105	4707
Finance / Rentals / Leasing	2396	626	1562	252	3764	423	107	9130
Prof / Scien / Tech Services	1131	2453	8678	350	3960	425	267	17263
Other	1623	1795	3486	597	3966	983	214	12664
Total	**15140**	**8081**	**27653**	**3898**	**23116**	**6495**	**1875**	**86259**

CASE 2	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Oil and Gas Extraction	2251	7	869	5	1	0	1	3134
Oil and Gas Services	3999	310	5691	371	6967	3369	236	20942
Construction	6151	1137	6735	1086	252	65	1051	16476
Manufacturing	190	1310	3364	1536	4785	2075	375	13636
Trade	1612	1616	3897	885	4944	1608	186	14747
Pipeline Transportation	819	2	455	2	2	0	0	1280
Transportation and Storage	1441	854	2106	435	1823	710	161	7530
Finance / Rentals / Leasing	4046	1015	2507	389	6189	697	160	15002
Prof / Scien / Tech Services	2175	3999	14279	551	6572	693	401	28671
Other	2743	2906	5662	945	6529	1610	329	20723
Total	**25428**	**13155**	**45564**	**6203**	**38064**	**10826**	**2900**	**142141**

CASE 3	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Oil and Gas Extraction	2566	8	1052	6	1	0	1	3634
Oil and Gas Services	5546	357	7086	436	8991	4347	262	27025
Construction	6649	1534	9075	1471	321	83	1427	20560
Manufacturing	266	1732	4794	2042	6140	2734	478	18186
Trade	2130	2025	5019	1123	6351	2083	222	18952
Pipeline Transportation	820	3	464	2	2	0	0	1291
Transportation and Storage	1745	1033	2630	540	2198	846	194	9186
Finance / Rentals / Leasing	4722	1261	3166	477	7647	881	188	18341
Prof / Scien / Tech Services	3045	4954	19039	697	8491	857	456	37539
Other	3355	3491	7141	1186	8247	2032	397	25849
Total	**30843**	**16397**	**59465**	**7981**	**48389**	**13863**	**3624**	**180563**

* Saskatchewan / Manitoba / Yukon / Nunavut

TABLE A.14: SECTORAL DISTRIBUTION OF EMPLOYMENT IMPACTS – $4US GAS PRICE: 2004-2035

(in person years)

CASE 1	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Oil and Gas Extraction	1266	4	540	3	0	0	1	1814
Oil and Gas Services	2136	218	3621	254	4204	2032	173	12638
Construction	4722	711	4272	680	161	42	656	11243
Manufacturing	105	778	1658	933	3104	1267	238	8084
Trade	951	1027	2395	572	3102	997	126	9169
Pipeline Transportation	655	2	372	1	1	0	0	1031
Transportation and Storage	943	563	1356	290	1219	483	108	4962
Finance / Rentals / Leasing	2626	653	1598	259	3957	440	110	9643
Prof / Scien / Tech Services	1203	2570	8712	355	4089	446	280	17655
Other	1768	1903	3593	614	4128	1023	221	13251
Total	**16375**	**8428**	**28116**	**3961**	**23965**	**6730**	**1912**	**89489**

CASE 2	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Oil and Gas Extraction	2359	7	885	5	1	0	1	3258
Oil and Gas Services	4087	311	5750	372	7066	3417	236	21239
Construction	6156	1137	6736	1086	254	66	1051	16484
Manufacturing	191	1316	3372	1539	4806	2083	377	13685
Trade	1631	1628	3915	889	4979	1618	186	14847
Pipeline Transportation	819	2	455	2	2	0	0	1281
Transportation and Storage	1456	861	2116	437	1837	713	162	7581
Finance / Rentals / Leasing	4140	1022	2517	391	6263	703	160	15196
Prof / Scien / Tech Services	2196	4034	14289	553	6608	700	405	28785
Other	2773	2940	5695	949	6586	1622	331	20897
Total	**25808**	**13258**	**45731**	**6223**	**38402**	**10921**	**2909**	**143252**

CASE 3	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Oil and Gas Extraction	2566	8	1052	6	1	0	1	3634
Oil and Gas Services	5546	357	7086	436	8991	4347	262	27025
Construction	6649	1534	9075	1471	321	83	1427	20560
Manufacturing	266	1732	4794	2042	6140	2734	478	18186
Trade	2130	2025	5019	1123	6351	2083	222	18952
Pipeline Transportation	820	3	464	2	2	0	0	1291
Transportation and Storage	1745	1033	2630	540	2198	846	194	9186
Finance / Rentals / Leasing	4722	1261	3166	477	7647	881	188	18341
Prof / Scien / Tech Services	3045	4954	19039	697	8491	857	456	37539
Other	3355	3491	7141	1186	8247	2032	397	25849
Total	**30843**	**16397**	**59465**	**7981**	**48389**	**13863**	**3624**	**180563**

* Saskatchewan / Manitoba / Yukon / Nunavut