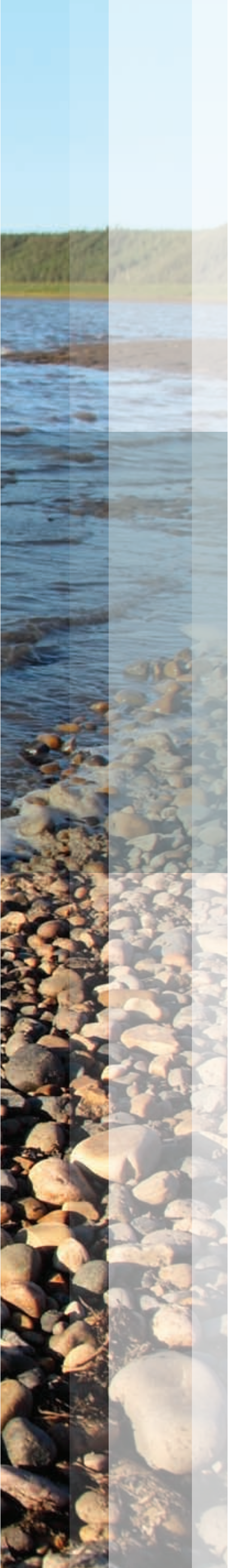

Technical considerations: Implementing the decision

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Chapter 1 Introduction

1.1 The project

The Mackenzie Gas Project is a proposal to produce and transport natural gas and natural gas liquids from the three largest discovered onshore natural gas fields in the Mackenzie Delta area. Natural gas from the Niglintgak, Taglu and Parsons Lake fields would travel via the Mackenzie Valley Pipeline from Inuvik, Northwest Territories, to northwestern Alberta and on to southern markets. Natural gas liquids would be separated from the natural gas at a gas processing facility near Inuvik (Inuvik Area Facility) and transported via a smaller pipeline to Norman Wells, Northwest Territories, where it would connect to the existing Enbridge Pipelines (NW) Inc. Norman Wells Pipeline (see Figure 1-1).

In October 2004 the National Energy Board received the following applications for the construction and operation of the Mackenzie Gas Project:

- the development of three natural gas fields—Niglintgak, Taglu and Parsons Lake development fields—applied for under section 5.1 of the *Canada Oil and Gas Operations Act*;
- the Mackenzie Gathering System, including 189.2 kilometres of upstream gathering pipelines, the Inuvik Area Facility, and a 457.2 kilometre natural gas liquids pipeline from the Inuvik Area Facility to Norman Wells, all applied for under paragraph 5(1)(b) of the *Canada Oil and Gas Operations Act*;
- the 1195.8 kilometre long Mackenzie Valley Pipeline, including three compressor stations, a heater station and associated pipeline facilities to transport natural gas from the Inuvik Area Facility to northwestern Alberta, applied for under section 52 of the *National Energy Board Act*. This pipeline would connect with the existing NOVA Gas Transmission Ltd. system in Alberta; and
- an order, pursuant to Part IV of the *National Energy Board Act*, approving the toll and tariff principles that are to apply to service on the Mackenzie Valley Pipeline.

Did you know?

Pipelines in the North

If the Mackenzie Gas Project proceeds it would be by far the largest pipeline system to be constructed and operated in Canada's North, although it would not be the first. The Canol Pipeline, built during World War II, moved crude oil from Norman Wells to Whitehorse, and in the mid-1980s, Enbridge Pipelines (NW) Inc. built the Norman Wells Pipeline from Norman Wells to Zama, Alberta. Several natural gas pipelines have been built from southern Yukon and the Northwest Territories into British Columbia and Alberta in the last half century and, in the late 1990s, the Ikhil Pipeline was built to supply Inuvik with natural gas.

The Mackenzie Valley Pipeline is designed to transport approximately 34.3 Mm^3/d (1.2 Bcf/d) of natural gas with three compressor stations in operation.

The proponents of the Mackenzie Gas Project are Imperial Oil Resources Ventures Limited, Mackenzie Valley Aboriginal Pipeline Limited Partnership, Imperial Oil Resources Limited, ConocoPhillips Canada (North) Limited, Conoco Phillips Northern Partnership, ExxonMobil Canada Properties and Shell Canada Limited as managing partner of Shell Canada Energy, (collectively, the Proponents).

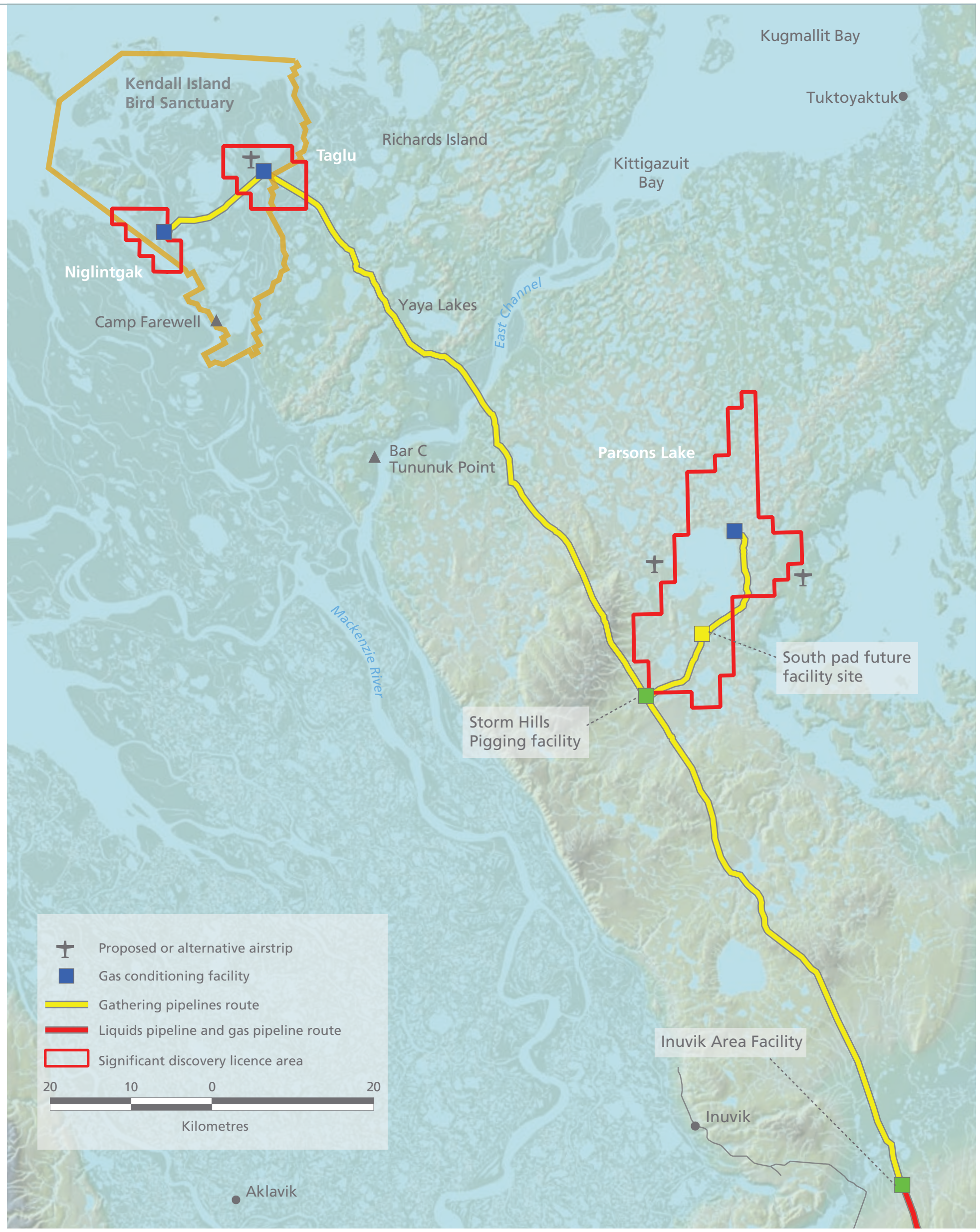
The capital cost of the Mackenzie Gas Project is estimated at $16.2 billion (2006$). It is planned to be in operation by the end of 2018, based on the start of construction in late 2014.

Figure 1-1

Overall project map

Figure 1-2

Development fields and upstream gathering pipeline



1.2 Project description

1.2.1 Niglintgak field

Shell Canada Limited (Shell) applied for approval of a Development Plan under section 5.1 of the *Canada Oil and Gas Operations Act* for the Niglintgak field on 20 October 2004.

The Niglintgak Significant Discovery Licence SDL019 is located about 120 kilometres northwest of Inuvik and 85 kilometres west of Tuktoyaktuk and lies within Kendall Island Bird Sanctuary in the Mackenzie Delta (see Figure 1-2).

The proposed production facilities include:

- six to twelve production wells located on three well pads;
- a system of above-ground flow lines;
- a gas conditioning facility located in the Kumak Channel;
- a disposal well; and
- infrastructure including an emergency shelter and helipads.

Construction is planned over four winter seasons from 2014 to 2018 with operations to commence in 2018 and continue for about 25 years. The initial capital expenditure for drilling and facilities is expected to be \$800 million (2006\$).

1.2.2 Taglu field

Imperial Oil Resources Limited applied for approval of a Development Plan under section 5.1 of the *Canada Oil and Gas Operations Act* for the Taglu field on 7 October 2004.

The Taglu Significant Discovery Licence SDL063 is located about 120 kilometres northwest of Inuvik and 70 kilometres west of Tuktoyaktuk in the Mackenzie Delta (see Figure 1-2).

The proposed production facilities include:

- up to 15 production wells drilled from a single pad;
- one or two disposal wells;
- a gas conditioning facility;
- associated infrastructure including pads and foundations;
- a barge landing site;
- an airstrip and helicopter pad;
- buildings; and
- a water treatment system.

Did you know?

Nominal pipes size (NPS)

Nominal pipe size (NPS) is a set of standard pipe diameters used for pressure piping in North America measured in inches.

Approximate conversions to SI (metric) for the pipes in this project are as follows:

Nominal pipe size	Approximate pipe diameter
NPS 10	250 mm
NPS 16	400 mm
NPS 18	450 mm
NPS 26	650 mm
NPS 30	750 mm
NPS 32	800 mm

Construction is planned to take place from 2014 to 2018 with operations commencing in 2018. The estimated initial capital expenditure for developing the field is $1,750 million (2006$) with an additional $800 million for future compression and infill wells.

1.2.3 Parsons Lake field

ConocoPhillips Canada (North) Limited applied on behalf of itself and ExxonMobil Canada Properties for approval of a Development Plan pursuant to section 5.1 of the *Canada Oil and Gas Operations Act* for the Parsons Lake field on 7 October 2004.

The Parsons Lake Significant Discovery Licences SDL032 and SDL030 are located about 70 kilometres north of Inuvik and 55 kilometres southwest of Tuktoyaktuk, to the east of the Mackenzie Delta on Tuktoyaktuk Peninsula (see Figure 1-2).

The proposed production facilities include:

- a north pad with 9 to 19 production wells;
- disposal wells and a gas conditioning facility;
- a south pad with three to seven production wells;
- flow lines; and
- support infrastructure including an all-weather airstrip.

Construction is planned to take place from 2014 to 2018 with operations commencing in 2018 and expected to continue for 25 or 30 years. The estimated initial cost for developing the field is $1,200 million (2006$) with an additional $350 million for future compression and infill wells.

1.2.4 Mackenzie Gathering System

Imperial Oil Resources Ventures Limited applied on behalf of itself, Shell Canada Limited, ConocoPhillips Canada (North) Limited, and ExxonMobil Canada Properties for authorization under paragraph 5(1)(b) of the *Canada Oil and Gas Operations Act* for the Mackenzie Gathering System on 7 October 2006.

The Mackenzie Gathering System includes:

- approximately 190 kilometres of NPS 16, NPS 18, NPS 26 and NPS 32 gathering pipelines to transport production from the Niglintgak, Taglu and Parsons Lake natural gas fields to the Inuvik Area Facility;
- the Inuvik Area Facility, which would process production from the three development fields;
- an approximately 457 kilometre long NPS 10 natural gas liquids pipeline from the Inuvik Area Facility to Norman Wells; and
- block valves, pigging facilities, and meter stations for the upstream gathering pipelines and the natural gas liquids pipeline.

On 12 October 2007 MGM Energy Corp. executed a Capacity Request Agreement indicating its intent to become either an owner in the Mackenzie gas gathering and processing facilities or to contract for firm capacity in the facilities for an identified volume of 5.66 Mm^3/d (200 MMcf/d). A supply of 2.83 Mm^3/d (100 MMcf/d) from a field known as MGM East would be delivered to a receipt point located at Taglu, and a supply of 2.83 Mm^3/d (100 MMcf/d) from a field known as MGM West would be delivered to a receipt point located at Niglintgak.

MGM Energy Corp. was the only third-party shipper to make a volume commitment to the Mackenzie Gas Project during the course of the proceedings. MGM Energy Corp. did not make a capacity request for space on the Mackenzie Valley Pipeline.

The Mackenzie Gathering System would have the capacity to deliver about 30.9 Mm^3/d (1.1 Bcf/d) of gas to the Mackenzie Valley Pipeline and to transport about 4000 m^3/d (25,200 Bbl/d) of natural gas liquids from the Inuvik Area Facility to Norman Wells. The approximate capital cost of the Mackenzie Gathering System is $3,500 million (2006$). It is scheduled to be in service in 2018.

1.2.5 Mackenzie Valley Pipeline

Imperial Oil Resources Ventures Limited applied on behalf of itself, Mackenzie Valley Aboriginal Pipeline Limited Partnership, Shell Canada Limited, ConocoPhillips Canada (North) Limited, and ExxonMobil Canada Properties for a certificate of public convenience and necessity pursuant to section 52 of the *National Energy Board Act* and an order pursuant to Part IV of the *National Energy Board Act* approving the toll and tariff principles that would apply to the Mackenzie Valley Pipeline (see Figure 1-3). Subsequently, ConocoPhillips Canada (North) Limited’s interests in the Mackenzie Valley Pipeline were transferred to ConocoPhillips Northern Partnership.

The Mackenzie Valley Pipeline includes:

- approximately 1196 kilometres of buried NPS 30 pipeline from the Inuvik Area Facility to a point of interconnection with the NOVA Gas Transmission Ltd. system just south of the Alberta-Northwest Territories boundary;
- three compressor stations, one at Great Bear River to be installed initially and two others at Loon River North and River Between Two Mountains to be installed when additional shipping commitments are received;
- the Trout Lake heater station to be installed when additional shipping commitments are received;
- a meter station located at the Inuvik Area Facility; and
- a pig receiver and block valve just south of the Alberta-Northwest Territories boundary.

As applied for, the Mackenzie Valley Pipeline has a design capacity of 27.3 Mm^3/d (964 MMcf/d) with one compressor station and 34.3 Mm^3/d (1.2 Bcf/d) with three compressors and one heater station in operation. The design capacity is expandable to 49.8 Mm^3/d (1.8 Bcf/d) with a total of 14 compressor stations in operation. The Proponents propose initially to construct a single compressor station and no heater station. The approximate capital cost of the Mackenzie Valley Pipeline is $7,050 million (2006$) with one compressor station at the Great Bear River. The Loon River North and River Between Two Mountains compressor stations and the Trout Lake heater station would add approximately $800 million to the capital cost. The Mackenzie Valley Pipeline is scheduled to be in service in 2018.

1.2.6 Construction schedule

The Proponents indicated that the earliest they would make their final decision on whether or not to proceed with the Mackenzie Gas Project would be at the end of 2013, subject to regulatory approval and receipt of required permits. Should the project proceed as proposed, the detailed design and construction phases of the pipeline and related facilities would commence by 2014 and would be expected to continue into 2018. It would be during this phase that the project activities would have the greatest interaction with the northern communities and the natural environment. The Proponents submitted that this phase of the project would also see the completion of the following activities in the project area:

- field investigation and testing programs to provide data for detailed design;
- procuring and mobilizing materials, equipment, goods and services;
- ongoing consultation with the northern communities;
- developing and constructing infrastructure support, such as borrow sites;
- drilling and completing wells at the development fields; and
- constructing production facilities and flow lines at the development fields.

Figure 1-3

Mackenzie Valley Pipeline and natural gas liquids pipeline

The winter months (mid-October to late April) would be the primary time for pipeline construction activities. The summer months (May to October) would be used for mobilizing equipment, materials and fuel to the sites to support the winter construction. Infrastructure development and facility fabrication and construction are anticipated to proceed year round. A schedule proposed by the Proponents is provided in Figure 1-4.

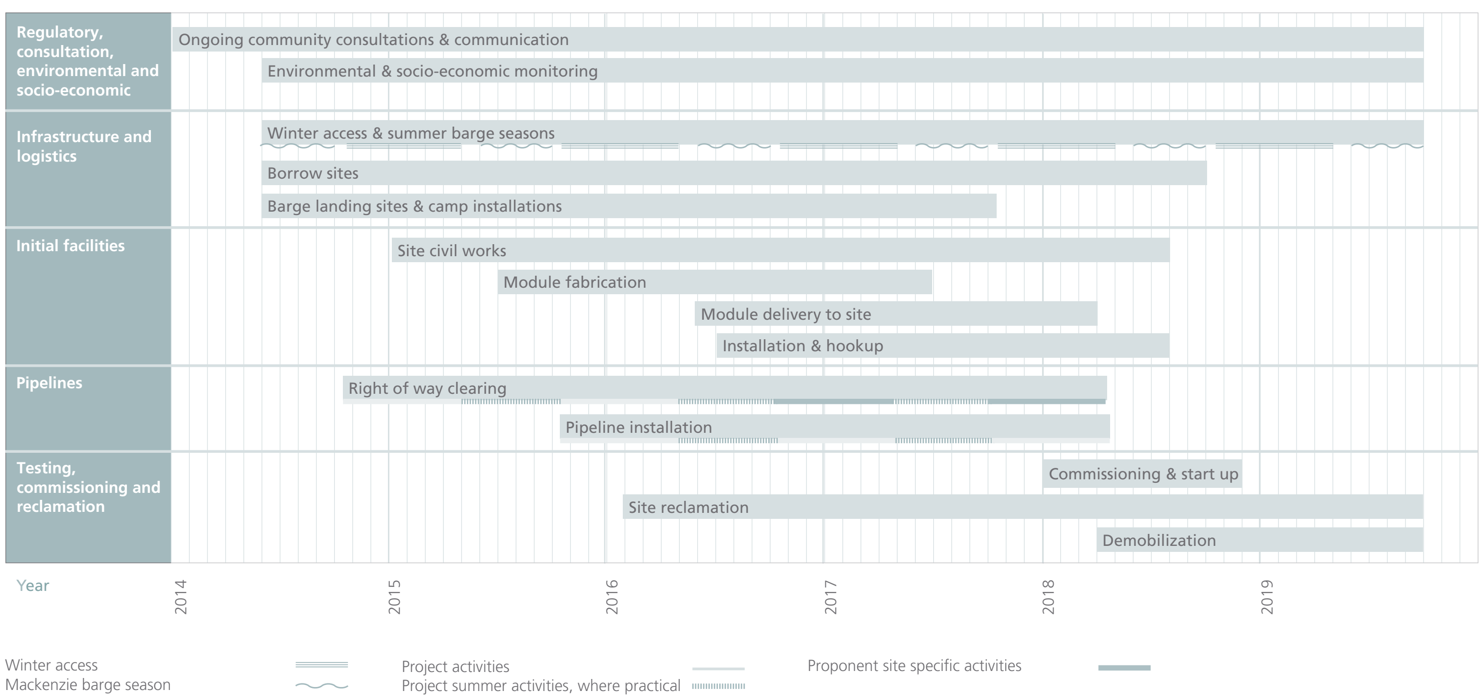
Onsite activities are proposed to commence in early summer 2014 with site preparation and initial development of some construction support infrastructure (barge landing facilities, small construction camps, borrow sites, material staging and fuel storage sites). The winter of 2014 -2015 would see the first sections of the pipeline right of way surveyed, cleared and graded and further development of borrow sites, staging and tank sites, barge landing sites and the main construction camps. The Proponents expect these activities to extend into the summer of 2015. During the summer of 2015, pipeline materials, equipment, camps and fuel would be mobilized to site for the first pipe laying season in the winter of 2015-2016.

The Proponents propose to divide construction of the pipeline into 12 construction spreads (see Figure 1-5). Each spread is expected to require an initial winter season for site preparation, a subsequent winter season for construction of the pipeline and a third winter season for final clean-up. Work would occur sequentially (clearing crews would be followed by pipeline installation and clean-up crews) proceeding in one direction along the spread with minor exceptions at some locations due to weather, construction camp locations or watercourse crossings.

Clearing activities and horizontal directionally drilled water course crossings are expected to be completed on all spreads in the first two winter construction seasons. Commissioning and start-up activities would be scheduled to commence in 2018 after the final

Figure 1-4

Proposed construction schedule for Mackenzie Gathering System and Mackenzie Valley Pipeline



season of pipeline installation. Reclamation and demobilization of camps, equipment and materials are expected to extend into the fall of 2019.

Construction of the station facilities (Inuvik Area Facility, metering facility and Great Bear River Compressor Station) is proposed to commence in the winter of 2014-2015 with survey, clearing and grading of the facility sites. Gravel pads would be installed the following summer. The Proponents submitted that the pile foundations for the facilities would be drilled and installed during the winter and summer of 2016. Construction of the facility modules would occur off site and the Proponents anticipate mobilizing the modules to the facility sites to finalize assembly in the winter of 2017-2018. The Proponents anticipate concluding facility construction in the summer of 2018.

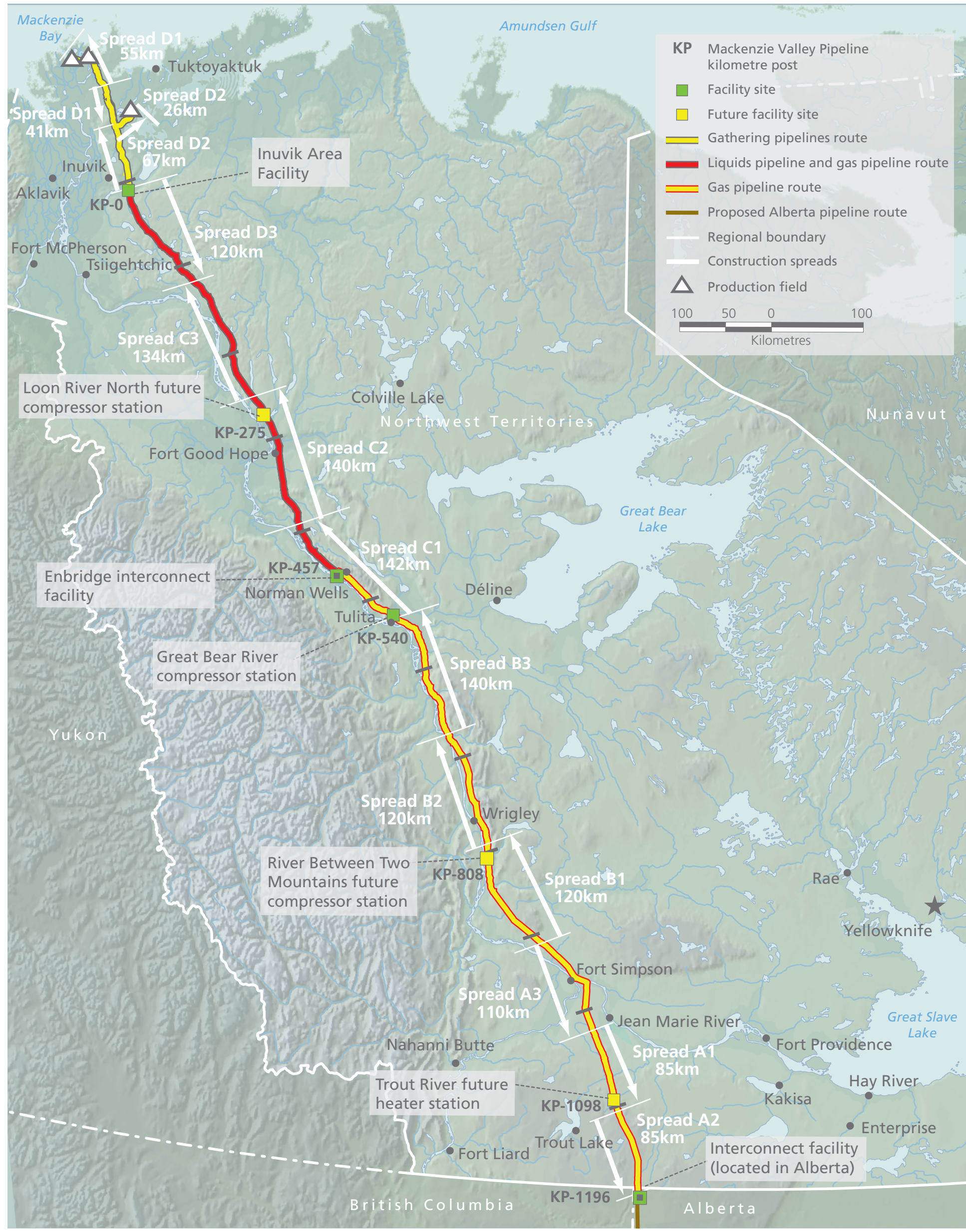


Figure 1-5

Proposed construction spreads

Did you know?

Definitions

Permafrost – soil or rock that remains at or below 0ºC for at least two consecutive years.

Continuous permafrost – permafrost occurs beneath more than 90 percent of land area. Taliks may exist beneath river channels, lakes and in other localized areas.

Extensive discontinuous permafrost – permafrost occurs beneath 65 to 90 percent of land area.

Intermediate discontinuous permafrost – permafrost occurs beneath 35 to 65 percent of land area.

Sporadic discontinuous permafrost – permafrost occurs beneath 10 to 35 percent of land area.

Isolated patches of permafrost – permafrost occurs beneath less than 10 percent of land area.

Talik – a pocket of unfrozen ground in a permafrost area, often beneath a lake or river.

Muskeg – a bog or peatland typically containing Sphagnum moss, willows and stunted black spruce trees. Muskeg can reach depths of 30 metres or more and is a significant impediment to transportation and construction during the summer.

1.3 Project setting

1.3.1 Project environment

The Mackenzie Delta is located above the Arctic Circle and is approximately 14 250 square kilometres in area; more than twice the size of Prince Edward Island. The Mackenzie Delta is the outlet of the Mackenzie River, which flows for approximately 1800 kilometres from Great Slave Lake in the Northwest Territories to the Beaufort Sea. The Mackenzie River is Canada's longest, and one of the world's largest, river systems. Along its route, the Mackenzie River picks up and carries a large amount of silt that settles out in the Mackenzie Delta, forming an extensive network of channels, islands, lakes and ponds. The Canadian North has more lakes than the rest of the world combined and more than 25,000 of them are in the Mackenzie Delta.

The proposed Mackenzie Gas Project stretches over 1000 kilometres from the Mackenzie Delta to northwestern Alberta and generally follows the Mackenzie Valley. The rivers and lakes of the region, including the Mackenzie Delta, support 41 species of fish, including Arctic grayling, northern pike, longnose sucker, slimy sculpin and lake chub. Wildlife populations found in the project area include grizzly bear, polar bear, barren-ground and woodland caribou, moose, marten, lynx, beaver, beluga whale, bowhead whale, ringed seal, and many bird species. On the northeast tip of the Mackenzie Delta, still more than 2000 kilometres from the North Pole, lies Kendall Island Bird Sanctuary. The Sanctuary is home to more than 90 species of birds, including the lesser snow geese, the tundra swan and other migratory birds.

Permafrost lies beneath much of the project area. The Niglintgak and Taglu fields are located in areas of discontinuous permafrost in the Mackenzie Delta (see Figure 1-6). The Parsons Lake field is located on higher ground to the east of the Mackenzie Delta, where the permafrost is continuous. North of the Inuvik Area Facility, the upstream gathering pipelines would be buried for the most part in continuous permafrost. South of the Inuvik Area Facility, the Mackenzie Valley Pipeline and natural gas liquids pipeline would leave the continuous permafrost zone and enter the discontinuous permafrost zone. South of Fort Simpson the Mackenzie Valley Pipeline would enter the sporadic permafrost zone.

The soil in the Mackenzie Delta region is thinly layered and formed from river deposits of silt, sand and gravel. The delta's low-lying geography exposes both the Niglintgak and Taglu fields to regular flooding and occasional storm surges from the Beaufort Sea.

Most of the land along the pipeline route is flat and covered with muskeg, except for a few areas with rolling hills and other features. The Mackenzie Gas Project would cross more than 600 watercourses that vary from small, seasonal streams to large rivers. The vegetation along the route changes from the treeless tundra in the Mackenzie Delta to the boreal forest in Alberta. Large areas of forest in the Mackenzie Valley have burned in recent years. Rare plants and uncommon vegetation types are found throughout the region. Some plants are used for traditional purposes, such as food, medicine, ceremonies or materials.

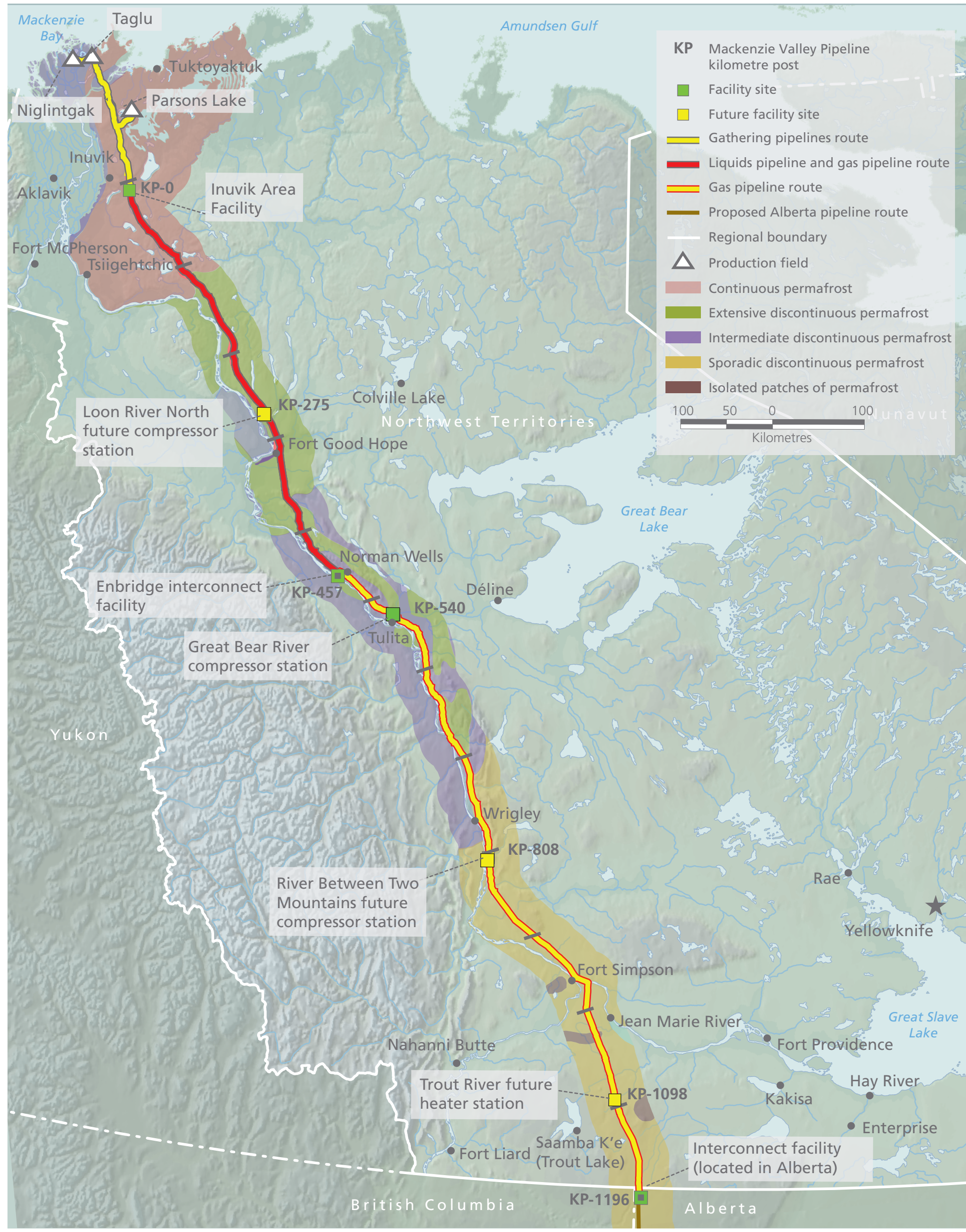


Figure 1-6

Permafrost regions

Figure 1-7

Land claim regions of the Mackenzie Valley

1.3.2 Social, cultural and economic setting

The Proponents identified up to 32 communities in the Northwest Territories and in northwestern Alberta that could be affected by the Mackenzie Gas Project (see Table 1-1). The 26 communities in the Northwest Territories are home to about 35,000 residents and are found in four regions — Inuvialuit Settlement Region, Gwich'in Settlement Area, Sahtu Settlement Area, and the Dehcho Region. The six communities in northwestern Alberta are home to about 7,000 residents and are located in the Dene Tha' First Nation region.

The population in the four regions of the Northwest Territories in the Mackenzie Delta and along the Mackenzie Valley where the Mackenzie Gas Project would be built is about 12,000. More than 75 percent of these people are Aboriginal. Most live in communities smaller than 1,000 people. About half of the total Northwest Territories population and about 40 percent of the northwestern Alberta population is Aboriginal.

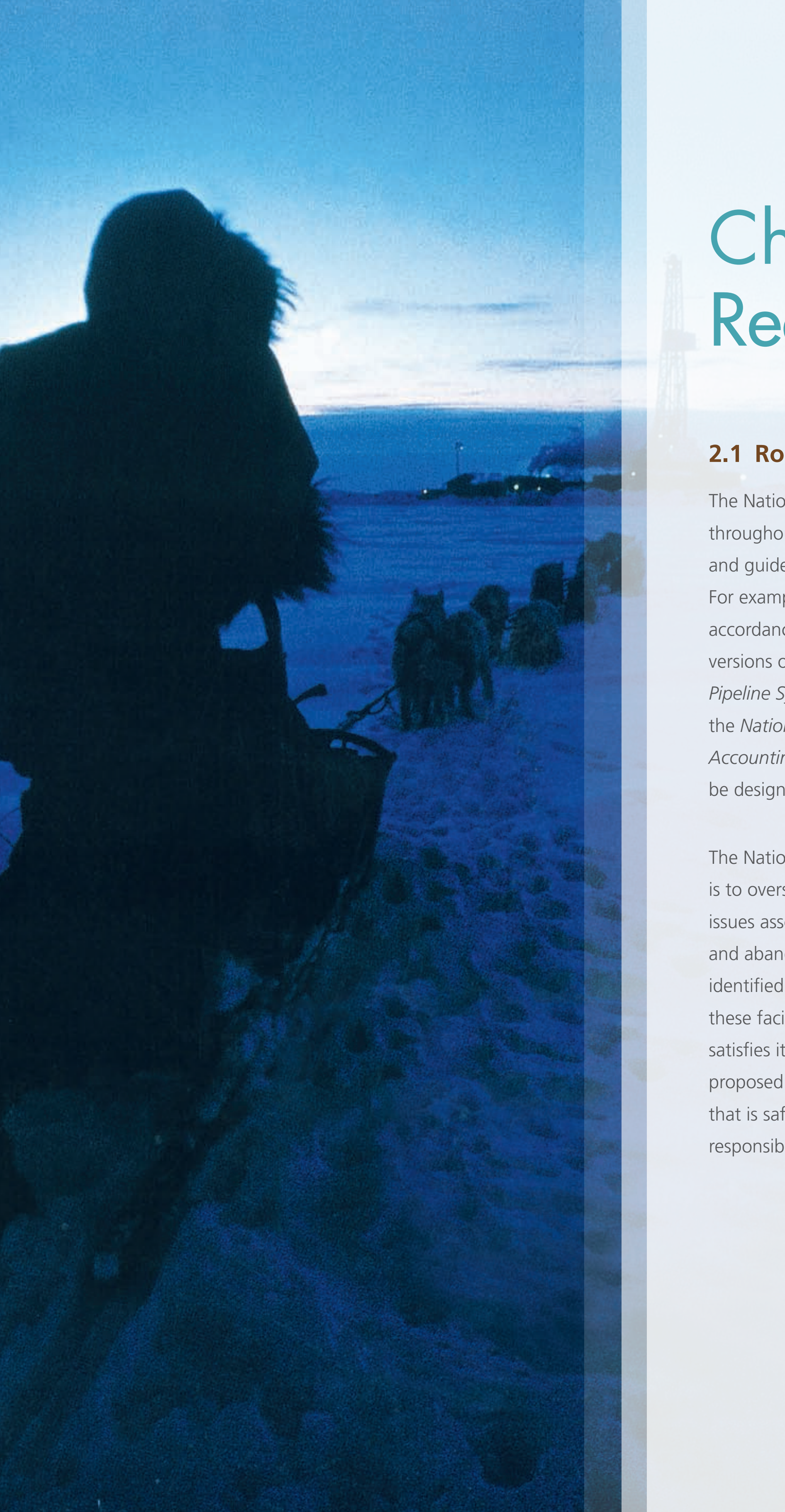
In the project area, some land claims have been settled. The first was the *Inuvialuit Final Agreement* in 1984. In 1992, the Gwich'in signed an agreement that established the Gwich'in Settlement Area. In 1994 the *Sahtu Dene and Metis Land Claim Settlement Act* came into effect. There are ongoing negotiations with the Dehcho (see Figure 1-7).

The cost of living is higher in more northern communities due to their distance from the source of supply for basic goods. Based on a 2000 survey, the cost of living in the Mackenzie Delta was 25 percent to 115 percent higher than in Edmonton, Alberta, depending on the remoteness of the community. Country foods such as caribou and moose are a large part of the diet for many Aboriginal people. Traditional gathering and harvesting supplement earned incomes and help offset the high cost of living. In most communities, government-related employment is the largest and most stable economic influence.

Table 1-1

Potentially affected communities

Area	Region	Community
Northwest Territories	Inuvialuit Settlement Region	Aklavik Tuktoyaktuk Holman Paulatuk Sachs Harbour
	Gwich'in Settlement	Inuvik Fort McPherson Tsiigehtchic
	Sahtu Settlement Area	Norman Wells Fort Good Hope Deline Tulita Colville Lake
	Dehcho Region	Fort Simpson Fort Providence Fort Liard Wrigley Nahanni Butte Trout Lake Jean Marie River Kakisa Hay River Reserve West Point Reserve
	Industrial and commercial centres	Yellowknife Hay River Enterprise
Northwestern Alberta	Dene Tha' First Nation	Chateh Meander River Bushe River
	Industrial and commercial centres	High Level Rainbow Lake Zama City



Chapter 2
Regulatory review process

2.1 Role of the National Energy Board

The National Energy Board regulates safety, security, environmental and economic matters throughout a pipeline project's lifespan. The National Energy Board has developed regulations and guidelines for the safety, security and protection of people, the environment and property. For example, pipelines regulated under the *National Energy Board Act* must be designed in accordance with the National Energy Board's *Onshore Pipeline Regulations, 1999* and the latest versions of relevant design codes, including the *Canadian Standards Association Z662, Oil and Gas Pipeline Systems*. Pipelines must also be operated in accordance with all other regulations under the *National Energy Board Act*, such as the *Toll Information Regulations* and *Gas Pipeline Uniform Accounting Regulations*. Facilities regulated under the *Canada Oil and Gas Operations Act* must be designed and operated in accordance with their own set of regulations.

The National Energy Board's role as regulator is to oversee that safety and environmental issues associated with construction, operation and abandonment of regulated facilities are identified and managed by the owners of these facilities. The National Energy Board satisfies itself that a facility's design and proposed operations would result in a project that is safe, reliable and environmentally responsible before it is approved.

As well as regulating the physical facilities, the National Energy Board oversees the economic aspects of a proposed project. Pipeline development in Canada may occur in a competitive market but often occurs in a monopoly or near-monopoly situation. The National Energy Board's authority for economic regulation of pipelines is intended to ensure that the prices set for transporting the gas, the costs that are incurred by the pipeline proponents and the returns to the pipeline owners are similar to those that would occur if the market were competitive.

Before submitting an application to the National Energy Board, companies must ensure that the proposed project would comply with existing statutory and regulatory requirements.

Once an application is received, the National Energy Board typically reviews the proposed project to:

- assess the application from economic, engineering, safety, environment and lands perspectives;
- ensure that regulated companies have notified and consulted with landowners, Aboriginal peoples, and other affected parties;
- determine how best to provide opportunities for affected people and other stakeholders to provide their input on the proposed project; and
- determine whether, with specific mitigation measures and other conditions, the project would be in the public interest.

2.2 The "public interest"

We must decide whether Canadian society would be better or worse off if the project is approved. The *National Energy Board Act* requires us to consider any public interest that may be affected by granting or refusing the application. To determine if a project is in the public interest, we consider the potential benefits it could bring to Canadians and the burdens it could place on Canadians.

In doing so, we examine engineering, economic, environmental and socio-economic factors. In particular, we assessed:

- the proposed engineering design — whether or not the facilities will be safe;
- the economics of the proposed project — is there sufficient supply and demand, will other parties have access to the facilities; are the tolls and tariffs reasonable;
- the effect the proposed project will have on the environment, as well as the effect the environment will have on the project — the environment includes the physical, social and cultural setting where the facilities would be built; and
- the effect the proposed project would have on individuals, groups, communities and societies.

To ensure that we heard a wide range of views from an informed and engaged public, we carried out activities to encourage meaningful participation in the review process for the Mackenzie Gas Project by all potentially affected people. These activities were designed with the following objectives:

- to share information in a timely manner with the public about the National Energy Board's process;
- to design a process that generally reflects the public's needs and expectations;
- to design a process that takes into account Northerners' experiences and expectations; and
- to ensure that the hearing process provides an opportunity to people from all walks of life to participate fully and in a manner in which they felt comfortable.

If the National Energy Board determines that a project is in the public interest, its role as a regulator would continue through the construction, operation and abandonment phases of the project.

Did you know?

Contributing partners to the Cooperation Plan

Boards and agencies with mandatory public hearing processes:

- Mackenzie Valley Land and Water Board;
- Mackenzie Valley Environmental Impact Review Board;
- Gwich'in Land and Water Board;
- Sahtu Land and Water Board;
- Northwest Territories Water Board;
- Canadian Environmental Assessment Agency;
- National Energy Board; and
- Environmental Impact Review Board for the Inuvialuit Settlement Region.

Other agencies with a direct interest in Environmental Impact Statement and regulatory matters:

- Joint Secretariat for the Inuvialuit Settlement Region;
- Environmental Impact Screening Committee for the Inuvialuit Settlement Region;
- Inuvialuit Game Council;
- Inuvialuit Land Administration;
- Inuvialuit Land Administration Commission; and
- Indian and Northern Affairs Canada.

Observers:

- Nominee of the Dehcho First Nation to the Mackenzie Valley Land and Water Board;
- Government of the Northwest Territories; and
- Government of Yukon.

2.3 Coordination of review process

A renewed interest in developing northern gas resources emerged in 2000. The many agencies that would be affected by a pipeline proposal realized that there would be substantial duplication and overlap of public review processes if each agency worked alone. Beginning in the fall of 2000 the heads of these agencies met to explore means of working cooperatively to minimize duplication and overlap. In June 2002, the agencies signed the *Cooperation Plan for the Environmental Impact Assessment and Regulatory Review of a Northern Gas Pipeline Project through the Northwest Territories* (Cooperation Plan). The Cooperation Plan provided a framework for a joint environmental impact assessment process that met the requirements of the *Inuvialuit Final Agreement*, the *Mackenzie Valley Resource Management Act* and the *Canadian Environmental Assessment Act*. Mr. Rowland J. Harrison, Q.C. of the National Energy Board was appointed as a member of the Joint Review Panel for the Mackenzie Gas Project (Joint Review Panel). To assist the National Energy Board in meeting its environmental requirements, the National Energy Board authorized Mr. Harrison under subsection 15(1) of the *National Energy Board Act* to report and make recommendations on social, cultural, economic and environmental matters pertaining to the Mackenzie Gas Project.

As contemplated in the Cooperation Plan our hearing process was coordinated with the Environmental Impact Review of the Mackenzie Gas Project by the Joint Review Panel. The Joint Review Panel Report and Mr. Harrison's subsection 15(1) report were taken into account in our public interest determination.

The filings made with the National Energy Board and the Mackenzie Valley Land and Water Board initiated the regulatory and environmental review processes (see Table 2-1). The Agreement issued on 22 April 2004 set out details for the environmental impact assessment by a Joint Review Panel, the coordination of hearings between regulatory agencies and the maintenance of a public registry. It also set out the role of the Northern Gas Project Secretariat, which provided logistical, communications, information management, administrative and technical support throughout the review process.

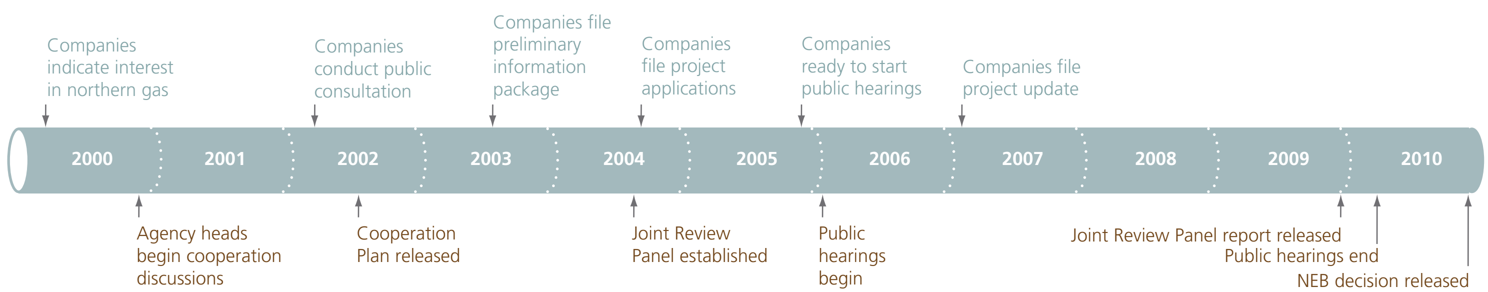
Table 2-1

Initial events in the coordinated review process

Date	Event
18 June 2003	Preliminary information package filed by the Proponents of the Mackenzie Gas Project with the National Energy Board.
21 July 2003	An application for a Type A Land Use Permit and Type B Water Licence for the Camsell Bend Development filed with the Mackenzie Valley Land and Water Board. This triggered the environmental review process.
21 August 2003	Mackenzie Gas Project referred by the Minister of the Environment to a Joint Review Panel under the *Canadian Environmental Assessment Act*.
22 April 2004	Agreement for the Coordination of the Regulatory Review of the Mackenzie Gas Project signed by the parties.
July/August 2004	Agreement for an Environmental Review of the Mackenzie Gas Project signed by the Chair of the Mackenzie Valley Environmental Impact Review Board, Chair of the Inuvialuit Game Council, and Federal Minister of the Environment.

Figure 2-1

Process timeline for review of Mackenzie Gas Project



2.4 National Energy Board hearing process

2.4.1 Overview

The National Energy Board received the applications for the Mackenzie Gas Project in October 2004. Following an initial review we decided to hold a hearing and issued Hearing Order GH-1-2004 on 24 November 2004. Our hearing sessions were coordinated with the Joint Review Panel's hearing sessions (see Figure 2-2).

Hearing Order GH-1-2004 initially contained a list of 12 issues for discussion in the hearing related to the National Energy Board's mandate pursuant to the *National Energy Board Act* and the *Canada Oil and Gas Operations Act*. We focused on engineering, safety and economic matters in our hearing, whereas the Joint Review Panel focused on environmental, cultural, and socio-economic matters. Following the receipt of comments from intervenors, Issue 13 was added to the list of issues (Appendix A – List of issues) by way of Order AO-1-GH-1-2004, dated 23 November 2005, to address concerns about tolls, access, tariff provisions and dispute mechanisms related to the Mackenzie Gathering System. Key events in our hearing process are shown in Table 2-2 and Appendix C – Summary of events.

2.4.2 Events leading up to the oral hearing

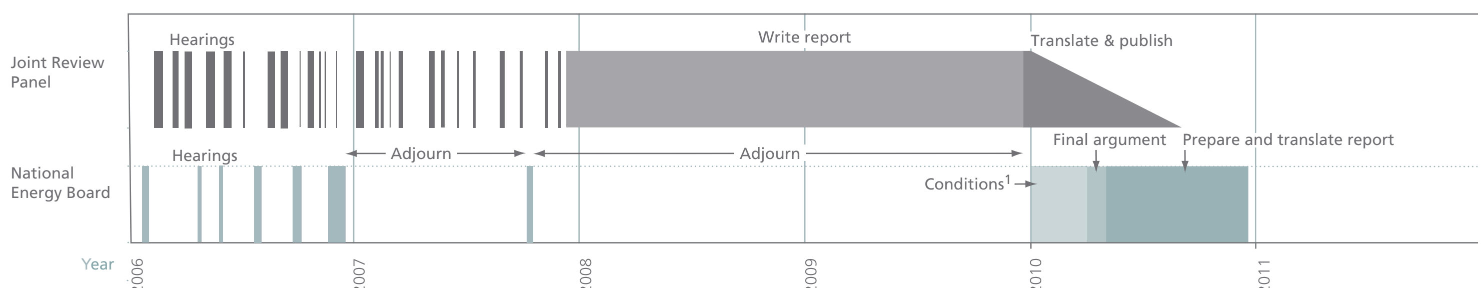
Throughout 2005, we continued our examination of the applications, which included the exchange of several rounds of information requests and the submission of evidence by participants. Also throughout 2005, the National Energy Board, the Joint Review Panel and the Northern Gas Project Secretariat held information sessions in northern communities near the pipeline route to explain their roles and to provide information on the National Energy Board and Joint Review Panel hearing processes. We held a pre-hearing planning conference between 5 and 13 December 2005 in Inuvik, Yellowknife, Fort Good Hope and Fort Simpson. The purpose of the conference was two-fold: to provide information on our hearing process and the National Energy Board's role throughout the lifespan of a pipeline; and to hear participants' views on shaping certain parts of the hearing process to meet their needs.

2.4.3 Oral hearing

By letter of 23 November 2005 the Proponents indicated that they were ready to start the public hearings. We released our hearing schedule on 20 December 2005. The scheduled evidentiary portion of the oral hearing started in Inuvik on 25 January 2006 and ended back in Inuvik on 14 December 2006. The evidentiary hearing involved the questioning of witnesses for the Proponents and intervenors on their filed evidence and the presentation of oral statements by members of the communities. We held hearing sessions on 47 days in 15 communities in the Northwest Territories and Northern Alberta throughout 2006.

Figure 2-2

National Energy Board and Joint Review Panel coordinated hearing schedule



1. Written comment process on NEB response to Joint Review Panel recommendations, including proposed conditions. Addresses NEB role with respect to "consult to modify" aspect of *Mackenzie Valley Resource Management Act*.

On 7 April 2006 Mackenzie Explorer Group filed a motion with us for an order that, when constructed and placed into service, the Mackenzie Gathering System and the Mackenzie Valley Pipeline will be a single pipeline subject to regulation under Part IV of the *National Energy Board Act* and that the Proponents prepare, file and serve the toll principles and the tariff(s) for this single pipeline for approval under Part IV of the *National Energy Board Act*. An oral hearing was held in Yellowknife on 2 June 2006. On 10 July 2006 we denied Mackenzie Explorer Group's motion.

Mackenzie Explorer Group subsequently appealed our decision. The appeal was heard by the Federal Court of Appeal on 23 October 2007 and dismissed on 22 April 2008.

In early 2007, the Proponents filed updates to the applications and on 10 and 11 October 2007 we held an oral hearing session in Yellowknife to examine the updated evidence.

In March 2010 we provided an opportunity for parties to file updated evidence and on 28 March 2010 a hearing session was held in Yellowknife to allow parties the opportunity to examine the updated evidence that was filed by the Proponents, the Government of Canada Crown Consultation Unit and other intervenors. This brought the evidentiary portion of the hearing to a total of 50 days.

Table 2-2

Key events in the National Energy Board hearing process

Date	Event
November 2004 to December 2005	Information sessions and technical review
5 to 13 December 2005	Pre-hearing Planning Conference in Inuvik, Yellowknife, Fort Good Hope, and Fort Simpson
25 January 2006 to 14 December 2006	National Energy Board hearing sessions in 15 Northern communities
2 June 2006	Mackenzie Explorers Group motion heard in Yellowknife
10 July 2006	Ruling on Mackenzie Explorers Group motion
5 February 2007	Proposed conditions initially issued for comment
10 and 11 October 2007	Hearing in Yellowknife to examine updated evidence
14 December 2007	Federal government enacted changes to the *Canada Oil and Gas Operations Act*, granting the National Energy Board the power to regulate tolls, tariffs and access on COGOA pipelines.
22 April 2008	Federal Court of Appeal dismissed Mackenzie Explorer Group's appeal, noting but not basing their decision on the fact that changes to the *Canada Oil and Gas Operations Act* had resolved Mackenzie Explorer Group's concerns.
30 December 2009	Joint Review Panel Report issued
30 December 2009	Mr. Harrison's subsection 15(1) Report issued
Jan. to Mar. 2010	Consult to modify process
28 March 2010	Hearing in Yellowknife to examine updated evidence
12 to 22 April 2010	Final argument in Yellowknife and Inuvik

2.4.4 *National Energy Board Act* subsection 15(1) Member's report

Mr. Rowland J. Harrison, Q.C., the National Energy Board Member appointed to the Joint Review Panel, was authorized under subsection 15(1) of the *National Energy Board Act* to report and make recommendations to the National Energy Board on matters identified in the Environmental Impact Statement Terms of Reference for the Mackenzie Gas Project under Authorization MO-13-2004 dated 15 October 2004 (see *Appendix F – Authorization MO-13-2004*).

Mr. Harrison's subsection 15(1) report was issued on 30 December 2009. In it he adopted the Joint Review Panel Report for the purposes of fulfilling the requirements of his National Energy Board obligation (see *Appendix G – Mr. Rowland J. Harrison's Subsection 15(1) Report*).

2.4.5 Consult to modify process and final argument

The Joint Review Panel Report was issued on 30 December 2009, following which we conducted a "consult to modify" process under section 137 and subsection 141(6) of the *Mackenzie Valley Resource Management Act*. By letter dated 9 March 2010, parties to both the National Energy Board hearing and the Joint Review Panel hearing were invited to comment on Joint Review Panel's

Figure 2-3

Communities where our information sessions and public hearings were held

recommended measures that were directed to the National Energy Board. We received comments from 30 parties, and then made proposed modifications to the recommended measures in the form of proposed conditions, which were cross-referenced to the Joint Review Panel's recommended measures by way of a concordance table. These were presented to the Joint Review Panel for its comment and for the comment of parties in the final argument phase of our hearing (see Section 3.2, Consult to modify process). We received a letter from the Joint Review Panel on 31 March 2010 responding to our proposed conditions.

We resumed our hearing 12 April 2010 in Yellowknife to hear final argument. Our hearing ended on 22 April 2010 in Inuvik after a total of 58 hearing days.

In addition to the evidence obtained through our hearing process, we also considered the Joint Review Panel Report, Mr. Harrison's subsection 15(1) report, the comments received in the consult to modify process, the *Governments of Canada & of the Northwest Territories Final Response to the Joint Review Panel Report for the Proposed Mackenzie Gas Project* and the comments on that response before making our regulatory decisions with respect to the Mackenzie Gas Project. We have adopted the Joint Review Panel's recommendations directed to us, as modified, and they have been included in the conditions to the approvals granted for the Mackenzie Gas Project. The National Energy Board will monitor and enforce the implementation of the conditions in the approvals.

Did you know?

Northern Gas Project Secretariat

The parties responsible for the environmental impact assessment and regulatory review of the Mackenzie Gas Project agreed through the Cooperation Plan to coordinate and harmonize their review and public hearing processes for the Mackenzie Gas Project. The parties determined that their review could most effectively be implemented through the services of a secretariat to support and coordinate the public hearing processes, including all aspects related to public involvement.

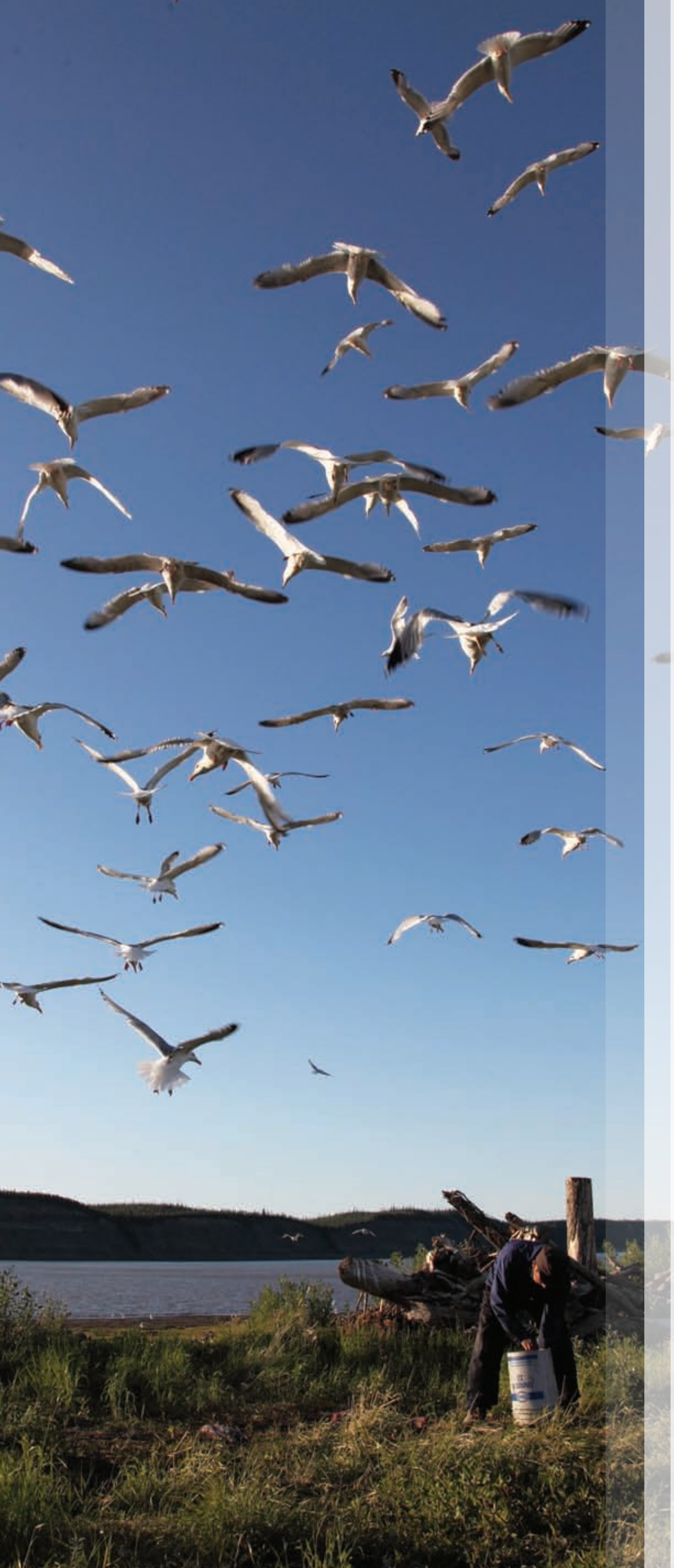
The Northern Gas Project Secretariat was established in 2003 to assist in coordinating the regulatory review and environmental assessment of the Mackenzie Gas Project. An Executive Committee of Chairs, supported by the Northern Gas Project Secretariat, provided the forum through which all involved parties could present their positions and requirements and where cooperative and harmonized approaches would be developed while respecting the need for the review processes to be conducted independently. The committee comprised the Sitting Chairs of the Joint Review Panel, the NEB Panel, the Mackenzie Land and Water Board and the Northwest Territories Water Board.

Leading up to the beginning of public hearings in late January 2006, the Northern Gas Project Secretariat coordinated information sessions with the National Energy Board and Joint Review Panel to explain the review process and to present up-to-date information about how the public could participate. In addition to organizing formal public information sessions, the Northern Gas Project Secretariat conducted several informal visits to the communities along the project route to assist community leaders in their preparations for the public hearing process.

The Northern Gas Project Secretariat published an electronic monthly newsletter in English plain language: The Review – your link to the review of the Mackenzie Gas Project. The goal of the newsletter was to bring the most up-to-date information on the project to community decision-makers and leadership in an easy-to-understand, electronic format. Throughout the hearing process the Northern Gas Project Secretariat maintained offices in Yellowknife, Inuvik, Norman Wells and Fort Simpson.

A list of public information sessions held by the Northern Gas Project Secretariat, the Joint Review Panel and the National Energy Board follows.

2004	Inuvik, NT (Nov. 15) Norman Wells, NT (Nov. 16) Yellowknife, NT (Nov. 17) Fort Simpson, NT (Nov. 23) High Level, AB (Dec. 13) Enterprise, NT (Dec. 14)
2005	Hay River, NT (Jan. 13) Tulita, NT (Feb. 8) Fort Good Hope, NT (Feb. 9) Inuvik, NT (Feb. 28) Norman Wells, NT (Mar. 1) Yellowknife, NT (Mar. 3) Meander River, AB (Mar. 9) Fort Simpson, NT (Mar. 10) Aklavik, NT (Mar. 15) Wrigley, NT (Mar. 16) Tuktoyaktuk, NT (Mar. 23) Saamba K'e (Trout Lake), NT (Oct. 12) Jean Marie River, NT (Oct. 13) Colville Lake, NT (Oct. 19) Tsiigehtchic, NT (Oct. 20) Inuvik, NT (Elders' session) (Oct 20) West Point First Nation, NT (Nov. 2) Ft. Liard, NT (Nov. 14) Nahanni Butte, NT (Nov. 15) Fort Providence, NT (Nov. 21) Kakisa, NT (Nov. 24) Déline, NT (Nov. 25) Fort McPherson, NT (Nov. 29) Tsiigehtchic, NT (Nov. 30)
2006	K'atlodeeche First Nation (Hay River Reserve), NT (Jan. 19)



Chapter 3
Environmental and socio-economic matters

3.1 Joint Review Panel process

In August 2003, the federal Minister of the Environment referred the Mackenzie Gas Project to a Joint Review Panel under the *Canadian Environmental Assessment Act*. In January 2004, the Inuvialuit Environmental Impact Screening Committee, under the *Western Arctic Claim: The Inuvialuit Final Agreement,* made the decision to refer the project to the review panel process. On 20 April 2004, the Mackenzie Valley Environmental Impact Review Board announced that it had decided to refer the project to an environmental impact review. In May 2004, the Minister of Indian Affairs and Northern Development Canada gave his approval for the Mackenzie Valley Environmental Impact Review Board to enter into an agreement to establish a joint review panel. An *Agreement for an Environmental Impact Review of the Mackenzie Gas Project* was released on 9 August 2004. This agreement created the Joint Review Panel, set out its mandate and established the Scope of the Environmental Impact Review, including the factors to be considered in the review.

Under the Joint Review Panel Agreement, the signatory agencies issued the *Environmental Impact Statement Terms of Reference for the Mackenzie Gas Project* in August 2004. The Terms of Reference contained guidelines for the preparation of an Environmental Impact Statement for the Mackenzie Gas Project, including the nature and scope of the issues that the Proponents needed to address. The Environmental Impact Statement served as a basis for the Joint Review Panel's review and evaluation of the potential impacts of the Mackenzie Gas Project on the environment.

As set out in the Joint Review Panel Agreement, the Joint Review Panel was also required to have regard to "the protection of the existing and future social, cultural and economic well-being of residents and communities", in addition to its consideration of environmental matters. The social, cultural and economic concerns that were raised with the Joint Review Panel included:

- resource harvesting;
- land use;
- cultural heritage;
- infrastructure and services; and
- economic, social and cultural impacts.

Our hearing focused on safety, engineering and economic issues, but comments received during the consult to modify process and final argument also included a number of social, cultural and economic issues and concerns.

On 2 September 2004 the federal Minister of Environment appointed Mr. Rowland J. Harrison, Q.C., a member of the National Energy Board, as one of the seven members comprising the Joint Review Panel. On 15 October 2004, the National Energy Board authorized Mr. Harrison to report and make recommendations to us in our consideration of the Mackenzie Gas Project.

On 30 December 2009 the Joint Review Panel issued its report and Mr. Harrison adopted it as his report to us. The report contained 176 recommendations, 85 of which were addressed to us. The remainder required action by various federal and territorial governments and agencies.

3.2 Consult to modify process

Subsection 141(6) and section 137 of the *Mackenzie Valley Resource Management Act* require the National Energy Board as a designated regulatory agency to adopt the recommendations of the Joint Review Panel or, after consulting with the Joint Review Panel, adopt the recommendations with modifications or reject them.

On 6 January 2010, we established a process to consult on the Joint Review Panel recommendations. Parties to both our hearing and the Joint Review Panel hearing were invited to provide comments on recommendations within the National Energy Board's mandate according to the following schedule:

28 January 2010	The Proponents sent comments to us and parties to both hearings
11 February 2010	Parties to both hearings sent comments to us, the Proponents and other parties
18 February 2010	The Proponents sent reply comments to us and parties to both hearings
9 March 2010	We drafted proposed modifications and provided them to the Joint Review Panel for written response
29 March 2010	The Joint Review Panel responded to our proposed modifications

For recommendations that fell outside of the National Energy Board's mandate, we provided a separate administrative process to gather comments for use by other federal and territorial government departments and agencies.

In a letter dated 9 March 2010, attached as Appendix H, we proposed modifications to the Joint Review Panel recommendations that were directed to us and listed our proposed conditions, many of which were designed to address the Joint Review Panel recommendations as modified. We indicated that the proposed modifications preserved the intent of the recommendations and were made to clarify desired end results and timing for implementation. We also stated that some recommendations were not included as conditions because they were duplicative of the requirements of statutes and regulations or of the mandate of other regulatory authorities; required the National Energy Board to delegate its authority to others; related to internal operational matters; or fell outside the scope of the present applications.

The Joint Review Panel responded to the proposed modifications on 29 March 2010. The Joint Review Panel concluded that:

> the NEB Proposed Conditions have not rejected any of the Panel's recommendations that are directed to the NEB and that the modifications proposed by the NEB are primarily for the purpose of ensuring that the implementation of those recommendations conforms to established NEB protocols and procedures, operational requirements and other statutes and regulations.

A copy of the letter is included in Appendix J.

The summary of the Joint Review Panel's recommendations directed to the National Energy Board and references to our associated conditions can be found in the Concordance Table in Appendix I.

3.3 Environmental matters discussed in final argument

In keeping with the purposes of establishing the Joint Review Process, we relied on the Joint Review Panel Report for the environmental and socio-economic assessment of the Mackenzie Gas Project. Matters arising from the Joint Review Panel Report were raised in final argument. These matters were:

- cumulative effects and upstream impacts;
- end use of gas and downstream impacts;
- air quality issues and greenhouse gas emissions;
- impacts of climate change on the project;
- wildlife and species at risk;
- environmental protection plans; and,
- National Energy Board's role in enforcing recommendations directed at others.

3.3.1 Cumulative effects and upstream impacts

To address the potential effects of the project as filed and the potential cumulative effects of future developments, the Joint Review Panel directed recommendations to us, governments, and regulatory agencies and authorities. The Joint Review Panel concluded that, subject to the full implementation of its recommendations, the project is not likely to have significant adverse environmental effects. The Proponents submitted that this conclusion is unsustainable because it was inappropriate for the Joint Review Panel to tie its recommendations related to speculative or hypothetical future developments to the environmental assessment decision for the Mackenzie Gas Project. The Proponents stated that:

> from an environmental assessment perspective, the issue in any event isn't whether the Proponents believe that the addition of future facilities is reasonably foreseeable. The issue is whether there is sufficient detail about future facilities to allow for a meaningful assessment of their effects to be made, which in this case there clearly is not.

The Proponents submitted that future induced development should not be included in the cumulative effects assessment in the first place because it is contrary to the law and contrary to environmental assessment guidance. For this same reason, the National Energy Board should not include conditions about such developments in the Mackenzie Gas Project decision. The Proponents then concluded that the National Energy Board must not include those Joint Review Panel recommendations related to future facilities in the environmental assessment decision for the Mackenzie Gas Project, and that the National Energy Board:

> should make a decision to permit the Mackenzie Gas Project to proceed, subject to the implementation of the mitigative and remedial measures and follow-up programs as proposed in the NEB letters dated March 9 2010, on the basis that the Mackenzie Gas Project is not likely to cause significant adverse environmental effects.

The Sierra Club of Canada countered this by reaffirming what was heard before the Joint Review Panel: that there is a typical sequence of development that follows a pipeline going into a frontier area and that the commonality between the Sproule Associates Limited and Gilbert Laustsen Jung Associates Ltd. supply studies shows likely locations of future development, therefore future development is neither hypothetical nor fanciful. World Wildlife Fund Canada submitted that the Joint Review Panel appropriately exercised its discretion as to what it regards as reasonably foreseeable projects. Both the Sierra Club of Canada and World Wildlife Fund Canada submitted that we should not revisit the Joint Review Panel's conclusion on the importance of induced development for sustainability, but rely on the Joint Review Panel's conclusions and recommendations in light of the delegation of the social and environmental review to it.

Related views were presented on the linkage between future induced developments and sustainability and its relevance to our decision. The Proponents submitted that the basis for the Joint Review Panel's sustainability conclusion on page 585 of the Joint Review Panel Report is flawed because the Joint Review Panel actually assessed future development for which little is known, instead of assessing the Mackenzie Gas Project itself. The Sierra Club of Canada submitted that specialist advisors to the Joint Review Panel emphasized the importance of considering induced development before being able to determine sustainability. The Sierra Club of Canada also proposed that it is incumbent on the National Energy Board to take on the idea of sustainability as part of its own processes.

Parties also stated their concerns to us about how cumulative effects of future development would be managed. The Joint Review Panel Report presented a number of recommendations related to future development directed to us and to government authorities. Alternatives North submitted that Northerners do not want to see the same pattern of hydrocarbon development that happened in Alberta, and that it is unacceptable that each development be assessed separately at different times without adequate up-front consideration of cumulative effects. World Wildlife Fund Canada supported the principle of Conservation First, submitting that this means anticipating cumulative effects and induced development and sequencing up front certain conservation accomplishments while Northerners still have a chance to do so. The Sierra Club of Canada expressed the need for up-front controls on the pace and scale of upstream-induced development. The Sierra Club of Canada supported the Joint Review Panel's position that mitigation must occur up front, in a proactive manner, not as each individual development project is proposed. It suggested that we consider a number of up-front strategies proposed by the Joint Review Panel, such as the federal government's completion of species recovery strategies, interim withdrawals to support a network of protected areas, and land use planning to incorporate thresholds and limits of acceptable change. The Sierra Club of Canada urged us to make sure that the recommendations from the Joint Review Panel to control cumulative impacts from induced development are put in place before the project goes ahead.

The Inuvialuit Regional Corporation submitted that:

> While we do not support the extent to which the Joint Review Panel report recommends additional assessment procedures throughout this expansion process, we nevertheless appreciate, in principle, the need to ensure the future development of our region's hydrocarbon resources does not occur at a scale and pace that will endanger our natural environment and overwhelm the social fabric of our communities.

The Inuvialuit Regional Corporation stated that the Inuvialuit have worked in close partnership with government departments and agencies, with co-management boards, and with other Aboriginal groups to identify both the anticipated impact of these developments and the measures that should be taken to either mitigate or to manage them. The Inuvialuit Regional Corporation would like to see us direct the government to provide the necessary financial resources to allow initiatives such as the Beaufort Sea Strategic Regional Plan of Action, the Beaufort Regional Environmental Assessment process and the impact planning in advance of the Mackenzie Gas Project impact fund to take place. The Mackenzie Valley Aboriginal Pipeline Limited Partnership (Aboriginal Pipeline Group), representing members of the Inuvialuit, Gwich'in and Sahtu, submitted that care must be taken so that the project is not burdened with unreasonable expectations. It objected to the Joint Review Panel's recommendations which would freeze future development, and did not believe that was their mandate in the first place. The Aboriginal Pipeline Group added that:

> We have protected our land for thousands of years. We are proud of this land given to us by the Creator to provide for us. We will continue to use our land wisely.

The Sierra Club of Canada submitted that imposing conditions related to future projects does not fetter the discretion of future panels. The Sierra Club of Canada submitted that, under the *Canadian Environmental Assessment Act* and *Mackenzie Valley Resource Management Act*, mitigation measures relied upon to conclude that a project can go ahead must actually be implemented. Dehcho First Nations submitted their concerns that we did not understand the spirit and intent of many recommendations such as those involving future projects that are not currently before us. Dehcho First Nations suggested adjusting the timing of Joint Review Panel recommendations related to future projects so they apply to this project instead. The Proponents submitted that future development, be it new gas fields or a pipeline expansion, would be subject to the intense scrutiny of the regulatory process, including scrutiny by the National Energy Board.

The Joint Review Panel's response to our proposed modifications to the recommendations stated that, where we noted that a relevant Joint Review Panel recommendation is:

> [o]utside the scope of the Mackenzie Gas Project (MGP) applications as it involves future application(s), [t]he Joint Review Panel does not understand this notation to be a rejection by the NEB of the relevant recommendation. The relevant Joint Review Panel recommendations stand and the Panel expects that they would, accordingly, be considered by the NEB in the specific context of any future applications.

The Sierra Club of Canada held the position that it is relevant that the National Energy Board has jurisdiction over approving future induced developments, but that does not take away from the Joint Review Panel's assertions that this work needs to be done up front. According to the Sierra Club of Canada, rights issuances and exploration in the area will increase, and this is not within the National Energy Board's purview. The Sierra Club of Canada submitted that they would agree with the Joint Review Panel's response interpreted as the Joint Review Panel agrees that once preparatory work is done, then future applications can be dealt with one at a time because the necessary preparatory work is complete.

Views of the Board

The matter of cumulative effects and upstream impacts was heard in full before the Joint Review Panel. We rely on their methodology and conclusions.

In response to the concerns raised regarding the need for up-front planning and the National Energy Board's jurisdiction over future projects, we continue to rely on the Joint Review Panel's assessment to identify mitigation measures appropriate for addressing cumulative effects of future development. We believe that our approach to implementing mitigation measures related to future development at the time of application for that development maintains the spirit and intent of the Joint Review Panel recommendations while adhering to the principles of natural justice and procedural fairness for future projects. The National Energy Board will consider all relevant evidence at the time of future applications, including cumulative impacts on the environment, and will make decisions in the public interest. The Joint Review Panel agrees that this procedural modification does not mean that we are rejecting the Joint Review Panel's recommendations directed at future projects. The Joint Review Panel stated that they expect that [cumulative effects] would be considered by the National Energy Board in the specific context of any future applications. The National Energy Board will continue to play its role in decision-making and project oversight in order to minimize environmental impacts now and in the future.

People at the hearing were concerned about the future. While views differed in the details, common threads included the integration of the land, the economy and the people; the importance of future generations; and community self-reliance. We listened to these views and incorporated them into our public interest determination. We heard from the Inuvialuit Regional Corporation:

> We ask that you consider not only the need to ensure the protection of our environment, but also the provision of economic opportunity to our residents and the social integrity of our communities.

We also heard from the Dehcho Elders and Harvesters:

> We're talking about the future of our children and we need to make sure that things are going to be better for our children in the long future and we don't want anything sitting wrong for our children in the future.

The Aboriginal Pipeline Group stated that they "need to regain socio-economic self-sufficiency for our people today and for our future generations."

The National Energy Board will continue to listen to Northerners through its lifespan regulatory oversight and accompany them in the pursuit of a sustainable energy future. Achieving sustainable outcomes will be a product of many parties including government authorities, communities, industry, and the Canadian public, that all support different pieces of the picture.

3.3.2 End use of gas and downstream impacts

Parties brought forward concerns in final argument related to the downstream impacts of the project and the end use of Mackenzie gas. The Sierra Club of Canada and France Benoît expressed concern that the gas from the Mackenzie Gas Project was intended for use in the oil sands where it would significantly increase greenhouse gas emissions. The Sierra Club of Canada submitted that, short of carbon neutrality, the Mackenzie Gas Project could contribute to a sustainable energy future if the gas is used wisely by displacing more carbon-intensive fuels. The Sierra Club of Canada proposed a National Energy Board certificate condition which would delay 'leave to open' for the pipeline until satisfactory implementation of Joint Review Panel recommendations 8-8 and 8-9. These recommendations were directed at the federal government to implement initiatives to manage greenhouse gas emissions (8-8) and to direct natural gas to 'wise' end-use applications (8-9). Ecology North also recommended the National Energy Board support these Joint Review Panel recommendations.

According to the Proponents, the Mackenzie Gas Project would deliver gas into the Alberta pipeline system where it would be commingled with other gas supplies and sold into markets throughout Canada and the United States. The Proponents submitted that there is no direct connection between the Mackenzie Gas Project facilities and a specific facility where gas will be burned, thus it is not relevant to our decision for us to consider the environmental effects of the combustion of Mackenzie gas at all facilities across North America where the gas could be burned. The Sierra Club of Canada countered that since the location of greenhouse gas emissions is irrelevant to their impacts, it is not logical to ignore end use impacts for the reason that the location of end use is unknown.

Views of the Board

Mackenzie gas would enter the North American market, where it would augment other supplies of natural gas. The end use of this gas would be determined by competitive markets operating within a public policy framework. The Joint Review Panel Report concluded that:

> mandating carbon neutrality and intervening in the market to specify preferred end uses for natural gas cannot be resolved on a project-by-project basis through the environmental assessment process, but must be addressed by governments through comprehensive climate change strategies.

When the National Energy Board is asked to consider the impacts of downstream facilities, it looks for a direct connection between these downstream facilities and the project under consideration. It is not possible to identify any particular downstream facility that would use the gas transported by the Mackenzie Gas Project. The gas would be transported through the TransCanada Alberta System to markets in southern Canada and elsewhere in North America. Where that gas would be delivered depends on future gas sales contracts and it is not possible at this time to determine what portion, if any, would be consumed in Alberta or in which sectors of the North America economy over the life of the pipeline. No specific markets or consumers can be directly linked to the Mackenzie Valley Pipeline and the operation of downstream facilities is not contingent upon receiving Mackenzie gas. Because there is no direct connection between the Mackenzie Valley Pipeline and any particular downstream facility, the environmental effects arising from the operation of downstream facilities do not appear to us to be relevant to the applications before us.

Nevertheless, we believe that augmenting the Canadian supply of natural gas, a relatively clean-burning and efficient fuel source, is of benefit to the Canadian public. Greater gas supply in the market increases the potential that fuels with higher greenhouse gas outputs would be preferentially displaced. Global energy demand is independent of whether Mackenzie gas comes on stream or not. Since natural gas is relatively low in greenhouse gas output per unit of energy produced, overall emissions would tend to be lower than the alternative where other carbon-based energy sources would be used.

3.3.3 Air quality issues and greenhouse gas emissions

Air quality issues

Air quality in the North is considered to be of high quality and Northerners are very concerned that it remains that way. Both Environment Canada and the Proponents agreed that existing air quality in the proposed project area is good and, along with other government regulators, emphasized the need to "keep clean areas clean." This principle requires new industrial development to be "planned, constructed and operated in a manner that minimizes the degradation of air quality in these areas."

Air quality issues for the project included project emissions for the pipeline and development fields, monitoring, and greenhouse gases in the context of monitoring climate change. These are aligned with the issues identified in the Joint Review Panel report. In its view the key air quality issues included:

- the project would be a long-term source of new air emissions in a generally pristine environment, and while impacts are not predicted to exceed relevant standards and guidelines, participants invoked the "keep clean areas clean" principle;
- Environment Canada and the Government of the Northwest Territories recommended the use of best available technology to minimize emissions, while the Proponents countered that they would use best practical technology, which is "technology that considers safety, engineering requirements, cost and environment, to reduce operational emissions"; and
- the project's air emissions would require appropriate monitoring during the construction and operation phases.

The Joint Review Panel noted that the National Energy Board would be the prime regulator of air emissions from the project and that Environment Canada and the Government of the Northwest Territories would play advisory roles. The Joint Review Panel recognized the National Energy Board's expertise and experience in regulating interprovincial aspects of the oil, gas and electric utility industries, including environmental matters. The Joint Review Panel also recognized the extensive environmental and local knowledge that Environment Canada and the Government of the Northwest Territories can provide.

Air emissions can be related to the project-specific effects of construction, operations, and waste incineration. Specific components of air emissions for the project might include: sulphur dioxide; nitrous oxides; ozone; carbon monoxide; carbon dioxide; volatile organic compounds; particulate matter; and compounds that include sulphates and nitrates, together called potential acid input. Carbon dioxide, methane and nitrous oxides are compounds that have the potential to collect in the atmosphere and influence global temperatures (greenhouse gases). Air quality impacts can be local to regional in the case of particulate matter and sulphur dioxide, or global in the case of greenhouse gases.

Specific discussion regarding air quality issues including emissions for the three gas fields is included in Chapter 4, Development fields. Further specific discussion on air emissions pertaining to facility design is found in Chapter 6, Facilities.

The Joint Review Panel report indicated that the Proponents' baseline information was compiled from historical data and results of air quality monitoring that was carried out over one year near the communities of Inuvik and Norman Wells, and periodically at the Parsons Lake and Taglu gas fields. The Proponents' monitoring data and other sources indicated that background concentrations of air contaminants are generally below detection levels or applicable guidelines. The one exception that is not below detection levels is ozone; relatively high background levels were monitored in Inuvik and Norman Wells. The Proponents indicated that elevated ozone levels at high latitudes in the northern hemisphere are thought to result from the intrusion of stratospheric ozone. The Proponents stated that all ground-level concentrations of compounds released by the project during operations at the gas fields, the Inuvik Area Facility, and compressor and heater station sites would increase, but would be below those outlined in applicable federal and territorial guidelines at all locations in the production area and along the pipeline corridor.

Environment Canada recommended that the Proponents design and implement suitable air quality monitoring programs with its help. Environment Canada focused its recommendations on pollution prevention and the use of best available technology and best management practices to minimize the degradation of air quality. Further discussion around application of these principles may be found in Chapter 6, Facilities.

The Dehcho Elders and Harvesters indicated that the project needs to be designed to minimize air quality impacts, with monitoring plans in place to verify the predicted emissions and impacts. Corrective action needs to be taken quickly to avoid impacts upon the land and wildlife from degraded air quality.

Greenhouse gas emissions

Parties were concerned about the impacts of the project on climate change, especially in light of Canada's international efforts under the United Nations Framework Convention on Climate Change and the *Kyoto Protocol*.

Greenhouse gas emissions arising from the project include carbon dioxide, methane and nitrous oxides with each compound having a different climate change potential. During operation, the project would emit greenhouse gases from burning natural gas at combustion related sources such as compressors and methane gas released through normal venting procedures and minor leaks (fugitive emissions). Further specific discussion on air emissions pertaining to facility design is found in Chapter 6, Facilities.

In the Joint Review Panel's view, Environment Canada is responsible for the design and implementation of ongoing climate monitoring in the region, the analysis of the data and the assessment of potential impacts. The Proponents' responsibility should be limited to providing relevant site-specific monitoring information to Environment Canada and ensuring that their operations and maintenance program takes into account any changes beyond that currently predicted.

Alternatives North submitted that the National Energy Board and the Government of Canada have a public interest mandate that requires consideration of greenhouse gas emissions.

Ecology North deemed that high project-specific standards for greenhouse gas emissions, based on a robust and strong definition of best available technology and accompanied by penalties in the cases where they do not meet those project standards or targets, would provide the best possible protection in terms of minimizing upstream greenhouse gas emissions associated with the project.

Sierra Club of Canada submitted that we need to specify an actual target and it is not enough to just leave it up to the Proponents. Sierra Club of Canada indicated that the target should at least match the general recommended target in Joint Review Panel recommendation 8-8.

Views of the Board

We understand the importance of clean air in the North and that air quality must be considered in a cumulative manner. We also recognize the need to minimize greenhouse gas emissions resulting from the project. The Joint Review Panel directed several recommendations to us relating to air quality and air emissions. We have addressed air issues through several conditions for the Mackenzie Gas Project. These conditions are focused on the Proponents taking appropriate measures to minimize air emissions and address air quality. We are committed to working collaboratively with Environment Canada and the Government of the Northwest Territories to protect air quality in the North, recognizing the extensive environmental and local knowledge that these agencies can provide.

Conditions 11, 12 and 13 address technologies for reducing emissions, incorporation of best management practices and best available technologies, and facility design. Condition 12 requires the submission of a report evaluating incinerator emissions from camps and station facilities. Technologies and practices must be reflected in the waste management plans required by Conditions 16 and 59. Condition 67 requires the Proponents to minimize and reduce emissions from flaring. Further specific discussion for these conditions regarding air emissions pertaining to facility design is found in Chapter 6, Facilities.

Air quality monitoring is part of comprehensive environmental monitoring under an environmental management system. Through environmental management, systems are established to address the effects of the project on the environment and of the environment on the project, with the overall goal of minimizing negative impacts. Adaptive management is a systematic process for continually improving management practices by learning from their outcomes.

Environmental monitoring is an important part of environmental management that directly supports adaptive management by observing and evaluating the effects that occur, then changing or adding mitigative measures, as appropriate, to limit or reverse the environmental effects. Environmental monitoring can include:

- compliance monitoring, to verify that all environmental mitigation is implemented as presented in the Environmental Protection Plan (EPP) and environmental alignment sheets and that work is in compliance with environmental regulations; and
- effects monitoring, to assess the effects resulting from project-environment interactions and evaluate the effectiveness of approved mitigation measures. This is further discussed in section 3.3.6, Environmental Protection Plans.

The National Energy Board promotes goal-oriented environmental management and monitoring. This means the National Energy Board tends to require a desired end result and the proponent may choose the means of achieving that result provided the means are acceptable to the National Energy Board. A proponent is expected to implement Environmental Protection and Monitoring and Surveillance Programs which include protection of the environment as one of the main goals.

The *Onshore Pipeline Regulations, 1999* require the proponent to implement an Environmental Protection Program which must include monitoring and adaptive management. (Section 48: “A company shall develop and implement an environmental protection program to anticipate, prevent, mitigate and manage conditions which have a potential to adversely affect the environment.”)

Monitoring is required by the National Energy Board under Section 39 of the *Onshore Pipeline Regulations, 1999*. (“A company shall develop a monitoring and surveillance program for the protection of the pipeline, the public and the environment.”) A monitoring program may:

- identify any issues or potential concerns that may compromise the protection of the environment;
- include methods for developing measures to prevent or mitigate the impact of the identified issues;
- provide for continued monitoring of sites to evaluate success of mitigative measures undertaken;
- provide a system for implementing additional mitigative measures as necessary; and
- provide a feedback system that allows for adaptation of successful mitigation to future pipeline projects.

Monitoring programs may have specific goals and targets and could include methods for evaluating and interpreting collected data such as air quality or emissions data. Monitoring may include any relevant environmental practices (e.g., vegetation establishment, water quality sampling, waste disposal).

Responsibilities of the National Energy Board regarding monitoring include:

- conducting environmental inspections of facilities, verifying compliance with terms and conditions, and assessing the effectiveness of mitigation;

- monitoring ongoing operation and verifying reclamation and maintenance of the project site to acceptable standards; and
- conducting environmental audits, evaluating environmental management systems and environmental programs.

The National Energy Board generally requires the filing of environmental post-construction monitoring reports as a condition of an authorization. The Filing Manual provides guidance for companies on the content of environmental post-construction monitoring reports. The information in monitoring reports should include:

- confirmation of proper implementation of mitigation and reclamation measures used;
- identification of the outstanding environmental issues; and
- discussion of the company's plans for how outstanding issues will be resolved.

We have addressed the monitoring of air emissions through several conditions. Condition 3 requires the Proponents to submit for approval an Environmental Protection Plan prior to pre-construction activities which includes monitoring of activities for this stage of the project. Condition 15 outlines expectations for an Air Quality Monitoring Program and includes the requirement for consultation with other government agencies, location and selection methods of monitoring sites, and complaint response. Condition 16 includes the requirement for monitoring incinerator emissions.

A commitment to continuous improvement, outlined in Joint Review Panel recommendation 8-6, is expected to be a component of the Air Quality Monitoring Program required by Condition 15. We are of the view that the commitment to continuous improvement is not limited to greenhouse gas emissions but should apply to all discharges to the environment, which in this case is the atmosphere. Condition 15 also covers the requirements for methods and locations of monitoring.

Condition 13 requires the Proponents to file a report outlining the use of best available technology for station facility construction. Selection of best available technology is the most significant factor in determining achievable air emissions targets. Condition 59 outlines the requirements for an Environmental Protection Program. The condition requires the Proponents to submit policies, practices and procedures for management of air emissions including maximum proposed greenhouse gas targets and reduction strategies for air emissions including particulate matter, NOx and greenhouse gases. Condition 59 also addresses other matters from the Joint Review Panel recommendations including employee training, monitoring, public communication, waste management and required consultation with Environment Canada and the Government of the Northwest Territories. With these conditions, we find it acceptable for the Proponents to develop greenhouse gas targets for the project consistent with the use of best management practices and in consultation with appropriate government agencies.

3.3.4 Impacts of climate change on the project

Warming of the global and regional climate could raise sea levels and affect weather patterns. The Niglintgak and Taglu fields are located in the low-lying Mackenzie Delta near the Beaufort Sea. We heard concerns that seasonal flooding and storm surges could affect these facilities during the life of the project. The companies provided evidence that the facilities would be high enough to protect them from storm surges and flooding even if sea levels were to rise. Parsons Lake is located on higher ground and further from the sea, so its facilities would be less exposed to possible effects of climate change.

The Sierra Club of Canada was concerned about the lack of peer-reviewed research publications on the effects of climate change, specifically for the Mackenzie Delta over the 30 year lifespan that was used by Shell in the design of the Niglintgak facilities. The Sierra Club of Canada stated that from a design perspective, there is uncertainty regarding the effects of climate change on the permafrost, the rise in sea level and the degree of flooding. The Sierra Club of Canada referred to the Arctic Climate Impact Assessment prepared by the International Arctic Science Committee. The Arctic Climate Impact Assessment states that the Arctic is experiencing the most rapid and severe climate change on earth, including the disappearance of Arctic sea ice which allows higher waves and storm surges.

The Proponents said that climate change would be considered further in detailed engineering design, where required, such as for well pads, pipelines, facilities, and the right of way. Other possible impacts of climate change, such as landform changes and groundwater flows, would be handled through monitoring and mitigation. Overall, the Proponents indicated that their designs were sufficiently conservative to address potential climate change and variability.

Environment Canada indicated that interactions of climate variability and climate change would likely be a more significant environmental stressor on Project components over the anticipated lifespan of the project of about 25 years than currently acknowledged by the Proponents. Therefore, appropriate assessment, monitoring and mitigation approaches must be incorporated into the project's design, maintenance, contingency plans and decommissioning plans. Environment Canada also recommended that, prior to construction:

> climate change modeling employed by the Proponents properly incorporate the upper limit temperature scenarios to ensure that the safety margin built into the project design is adequate to cover the range of future temperature conditions including their variability extremes.

The Joint Review Panel was generally satisfied that the Proponents had taken climate change into account in their design. Nevertheless the Joint Review Panel recommended that the National Energy Board add a condition which would require the Proponents to file final design plans that incorporated further analysis of the impacts of climate change on permafrost and terrain stability over the design life of the project and post-abandonment. The Joint Review Panel was of the view that this analysis should be conducted for a series of representative locations, conditions and terrain types and should incorporate climate variability, in particular, upper limit temperature scenarios to account for the range of future temperature conditions, including variability and extremes, and the impact of this variability on stream flow regimes. The Joint Review Panel added that the results should be incorporated into monitoring, mitigation and adaptive management plans. The Joint Review Panel thought that this analysis should be provided to other appropriate regulators in sufficient time for review and to provide input to the National Energy Board.

Indian and Northern Affairs Canada suggested in final argument that the Proponents should demonstrate how upper limit temperature scenarios have been considered in their design.

Further specific discussion on climate change regarding project design is found in Chapter 4, Development fields and Chapter 6, Facilities.

Views of the Board

We are satisfied with the Proponents' climate change estimates used in the design. Given the uncertainty regarding climate change predictions, a prudent step would be to assess the design using upper limit temperature scenarios as suggested by the Joint Review Panel. As the name implies, upper limit temperature scenarios would be less likely to occur than what has been used by the Proponents for the design of the project. Condition 6 requires the Proponents to submit a report which includes an analysis of the impacts of climate change and variability on permafrost and terrain stability for a series of representative locations and conditions using potential upper limit temperature scenarios which may occur along the pipeline. The analysis is to include potential impact on slope and water course crossing design. We have not specified how the study should be structured. We are of the view that, as part of this study, government departments such as Environment Canada, Indian and Northern Affairs Canada and Natural Resources Canada should be consulted to benefit from their expertise.

Conditions N8, T7 and P8 require the Proponents to provide final detailed design information which incorporates an analysis of the impacts of climate change

and variability on permafrost and terrain stability for each facility using potential upper limit temperature scenarios which may occur during the operational life of the project. The Proponents will also provide information about how upper limit temperature scenarios may impact precipitation, rise in sea level, storm surges, ice floes and flood levels, and watercourse crossing designs. We are of the view that government departments such as Environment Canada, Indian and Northern Affairs Canada and Natural Resources Canada should be consulted to benefit from their expertise for the field design.

3.3.5 Wildlife and species at risk

Throughout final argument, parties reaffirmed the importance of wildlife to the people of the North and to Canada as a whole. The Dehcho stated:

> We have depended on the wildlife and plants to provide for our physical, emotional, and spiritual health, as well as providing our economic base for long before the last ice age.

The Sierra Club of Canada submitted that species at risk are of national interest and that biodiversity loss is a pressing global problem.

Parties presented three outstanding concerns with respect to wildlife and species at risk:

- habitat disruption and sensory disturbance;
- woodland caribou; and
- conditions regarding species at risk.

Habitat disruption and sensory disturbance

Parties to our hearing restated in final argument their concerns about habitat disruption and sensory disturbance to wildlife.

The Dehcho Elders and Harvesters were concerned about the disruption to wildlife that would occur from work on the pipeline. They submitted that disturbance of wildlife and wildlife habitat must be minimized as much as possible for all animals, including those that hibernate and live underground. They stated:

> the destruction of winter feeding, breeding and birthing areas and migration routes of all animals in the clearing of the land for the right of way, facilities and activities must be minimized and, in some cases, avoided by choosing an alternative pipeline route or facility location.

They also confirmed that the pipeline corridor must not be a barrier to wildlife movement.

Sensory disturbance such as noise and vibration were of concern to the Dehcho Elders and Harvesters. They submitted that noise and vibration pollution from the Enbridge pipeline affected animal migration and fish runs and that proper studies need to be undertaken to determine the sensitivities of all fish and wildlife to the sounds and vibrations generated by pipeline operation and how these affect their behaviour patterns, migrations and other activities. The project design should then be changed as required to ensure that its operation has no effect on wildlife behaviour.

Views of the Board

We heard that the Proponents have already committed to some mitigation measures to reduce wildlife disturbance and habitat disruption. These include:

- use of insulation and sound-suppression equipment;
- minimizing the use of flares and lighting;
- preventative maintenance to minimize unplanned activities; and
- altered design of laterals to allow for passage by caribou and harvesters.

It is our view that with the Proponents' commitments and with the additional requirements specified in Conditions 29 through 36 and similar Conditions on the approvals for the three development plans, disturbance to wildlife and their habitats will be minimized. We require the Proponents to submit for approval Wildlife Protection and Management Plans that include pre-construction wildlife surveys, detailed descriptions of mitigation measures and how these will be implemented, and protocols for monitoring and adaptive management. Among the mitigation measures the Proponents must submit are the scheduling of activities to minimize wildlife disturbance, procedures to avoid denning areas, measures to avoid sensory disturbance, and measures to minimize impacts of vehicle and air traffic on wildlife. Annual den surveys and mitigation measures to avoid dens must also be completed and filed with the Government of the Northwest Territories and wildlife management boards.

We require the Proponents to submit Wildlife Protection and Management Plans prior to filing the detailed route. Any adjustments to the detailed route that would minimize impacts to wildlife populations or their habitat will be evaluated and completed at the design stage. The National Energy Board will assess the effectiveness of Wildlife Protection and Management Plans and will monitor their implementation. The National Energy Board will conduct compliance monitoring throughout the lifespan of the project and will require all commitments to be satisfied.

We also require that the Wildlife Protection and Management Plans be developed in consultation with wildlife management boards, the territorial government and Environment Canada. We ask for evidence of this consultation to be provided with the Proponents' submission. Through this, we are satisfied that agencies with expert knowledge on wildlife management in the North will have input into the Plans. We believe that Condition 28 regarding the hiring of local residents as monitors will also assist local residents to identify any areas where mitigation measures are not working. The National Energy Board can direct the Proponents to take appropriate action to adaptively manage the situation. We heard from the Dehcho Elders and Harvesters that, "we need to work together and closely and to make sure that everything is safe". We plan to do so.

Woodland caribou

Canada's *Species at Risk Act* requires the Minister of the Environment to put in place a recovery strategy and action plan for listed wildlife species, which includes boreal woodland caribou. This has not yet been completed. The Sierra Club of Canada submitted that since legal obligations under the *Species at Risk Act* have not been fulfilled, the environmental assessment is not complete because the Joint Review Panel has accordingly been unable to determine the significance of impacts on species at risk such as woodland caribou.

The Proponents submitted that the Joint Review Panel made recommendations to address the uncertainty about the significance of the impacts the project might have on woodland caribou, including recommendation 10-4. Recommendation 10-4 states that a further assessment of the impacts that the project is predicted to have on species listed on Schedule 1 of the *Species at Risk Act* (listed species) should take place once the Proponents have greater certainty about the location of project facilities. It also states that surveys and impact assessments for listed species must be carried out after recovery strategies and action plans have been completed. The Sambaa K'e Dene Band submitted that we had not taken full consideration of Joint Review Panel recommendation 10-4 in our proposed conditions.

The Sierra Club of Canada, Alternatives North, Jean Marie River First Nation and the Sambaa K'e Dene Band submitted that the woodland caribou recovery strategy and action plan must be finalized and approved under the *Species at Risk Act* as a prerequisite to the development of a Wildlife Protection and Management Plan for woodland caribou and in advance of National Energy Board final authorizations. Jean Marie River First Nation also submitted that required mitigation measures include avoidance of critical overwintering habitat for woodland caribou. The proposed Mackenzie Valley Pipeline corridor is home to over-wintering woodland caribou, traditionally harvested by the Sambaa K'e Dene Band members. The Sambaa K'e Dene Band field and literature research carried out over a period of three years, consistent with other woodland caribou research, indicates that these animals are most vulnerable to industrial development during the late winter months — January through March — which is precisely when Mackenzie Gas Project activities will be occurring. The Sierra Club of Canada argued that consideration of the impacts on these key species at risk was meant to be conducted in public hearings, either before the Joint Review Panel or before the National Energy Board, and that this public process was being omitted from the proposed National Energy Board conditions.

Views of the Board

We acknowledge the importance of woodland caribou to the people of the North and of species at risk to Canadian biodiversity. We believe that our Conditions 29 and 30 capture the intent of the Joint Review Panel recommendations related to woodland caribou protection and management, and are within the National Energy Board's abilities to effectively assess, manage, and enforce.

Mitigation measures must be developed by the Proponents in consultation with Environment Canada — the same agency responsible for completing the woodland caribou recovery strategy and action plans under the *Species at Risk Act*. We expect that through this consultation, the Protection and Management Plan for woodland caribou will be informed by the same research that is going into the development of the recovery strategy and action plans.

Conditions 29 and 30 require the Proponents to conduct pre-construction surveys and submit, for National Energy Board approval, updated impact assessments, specific mitigation measures, protocols for monitoring and adaptive management, and provisions for updating the Wildlife Protection and Management Plan for woodland caribou as recovery strategies and action plans are effected and additional knowledge becomes available. Mitigation measures to be described by the Proponents include:

- the timing and dates of project activities to avoid conflict with caribou movement or sensitive feeding and calving time;
- measures to limit predator travel along right of ways;
- access management; and
- measures to avoid or minimize linear disturbance, effects of habitat fragmentation, and barriers to movement.

These mitigation requirements were derived directly from Joint Review Panel recommendations 10-1, 10-4 and 10-16, which had been recommended to the Joint Review Panel by the Government of the Northwest Territories who are involved in the preparation of woodland caribou recovery strategies. We have also stipulated that the Wildlife Protection and Management plans be developed in consultation with Environment Canada, the Government of the Northwest Territories, and wildlife management boards. Based on comments received by parties on the Joint Review Panel recommendations, we also included specific consultation requirements with the Dehcho Boreal Caribou Working Group. Between the combined efforts of the Proponents and these authorities we believe that potential adverse impacts of the project on woodland caribou will be minimized. When the recovery strategies and action plans are finalized, the Proponents are required to update their Wildlife Protection and Management Plans accordingly. However, we expect that such modifications to plans will be minimal since consultation with the parties responsible for developing the recovery strategy and action plan is required throughout.

We recognize that without a recovery strategy for woodland caribou in effect at this time, critical habitat has not yet been established as defined under the *Species at Risk Act* although research is in progress. However, Condition 29 requires Wildlife Protection and Management Plans to be filed for approval by the National Energy Board prior to decisions being made on the detailed route. In the case that the recovery strategy and action plan for woodland caribou remain incomplete at this time, we expect that additional science-based and traditional knowledge will be available to inform the detailed route in avoiding critical habitat to the extent possible. The knowledge of the Dehcho Boreal Caribou Working Group should be a valuable tool for the Proponents in identifying and protecting critical habitat.

We are of the mind that, with the application of the mitigation measures proposed in Conditions 29 and 30, developed in consultation with federal, territorial and Aboriginal government authorities and approved by the National Energy Board prior to filing of the detailed pipeline route, impacts of the project on woodland caribou can be minimized.

Species at risk

Environment Canada submitted that the draft conditions circulated by the National Energy Board may unduly impose survey requirements for those species at risk where the Minister of Environment has determined that its recovery is not feasible at this time, such as the Eskimo curlew. Environment Canada also clarified that the requirements for listed species described in Conditions 29, N22, T21 and P21 should apply to all species at risk added to Schedule 1 of the *Species at Risk Act* at the time the Proponents file their Wildlife Protection and Management Plans with the National Energy Board, not only to those listed species assessed during the Joint Review Panel hearings.

Environment Canada submitted that Condition 34 be amended so that the survey area for yellow rail and western toad be based on the latest information on the species. Environment Canada stated that in some cases, the Committee on the Status of Endangered Species in Canada reports may not include the most up-to-date information, and management authorities for the species may have more current information on species range.

Views of the Board

We agree that pre-construction surveys are not required for species at risk for which recovery is not feasible at this time, and modified our Conditions 29, N22, T21 and P21 accordingly. We expect that any incidental observations of individuals will still be reported as per part (a) of these Conditions. We also agree with Environment Canada's clarification regarding newly listed species at risk. We expect that the Wildlife Protection and Management Plans will address all known species at risk current at the time of Plan submission.

With respect to the survey area for yellow rail and western toad, it is our view that Condition 34 as proposed addresses Environment Canada's concern. Condition 34 requires evidence of consultation with Environment Canada and the Government of the Northwest Territories when preparing the surveys and proposing mitigation and monitoring measures specific to those species. Any discrepancies regarding survey area may be addressed by the Proponents and the appropriate management authorities through this consultation.

3.3.6 Environmental Protection Plans

Concerns regarding protection of the land were raised during final argument. These concerns included impacts to the environment such as air quality, aesthetic impacts, and noise. The Dehcho raised specific concerns regarding project specific environmental monitoring requirements, protection of water resources, and minimizing invasive plant introduction.

The National Energy Board adds a requirement to facility approval documents for a company to develop and file for approval an Environmental Protection Plan. The Environmental Protection Plan is a document that guides environmental oversight for the duration of a project and typically includes elements such as environmental mitigation measures, reclamation and re-vegetation. The Environmental Protection Plans are an important element of our regulatory approach to environmental protection.

The Environmental Protection Plan is an important tool that is used to communicate the environmental procedures and mitigation measures to the Proponent's field personnel and construction or operation contractors. The purpose of the Environmental Protection Plan is to document and communicate all the project-specific environmental protection measures or mitigation committed to by the Proponent in a clear and user-friendly document. It is a way to ensure the Proponent will honour all the environmental commitments that were made during the hearing process. It also helps to outline clear lines of responsibility and accountability for the company.

During review of the Environmental Protection Plan, the National Energy Board verifies that all relevant mitigation and environmental commitments are included. The Proponents use the Environmental Protection Plan to communicate environmental commitments to its contractors and mandatory language is used to facilitate compliance. There is flexibility for the Proponent in developing the overall content of the Environmental Protection Plan. Other plans such as the Waste Management Plan, Wildlife Protection and Management Plan, and Heritage Resources Plan may be incorporated into the Environmental Protection Plan as specific chapters to make it more encompassing for field staff.

The Environmental Protection Plan typically addresses the following:

- specific goals for protecting environmental and socio-economic elements identified as important (air, vegetation, soils, permafrost, native plants, access management, wetlands, water resources, mitigating noise and aesthetic impacts, preventing weeds and invasive species, and reclamation);
- practices and procedures that can be implemented to meet these goals;
- criteria for evaluating the success of practices and procedures, particularly for reclamation and any new mitigation measures;
- incorporation of flexibility by covering options for environmental practices and procedures that may be used;
- criteria by which decisions will be made regarding which practices and procedures to implement and under what circumstances;
- assignment of accountabilities and responsibilities for carrying out environmental practices and procedures, making criteria-based decisions, and how to confirm compliance;
- requirements of permits by other regulators with regulatory responsibilities for the project;
- evidence of consultation with other regulatory agencies that confirms satisfaction of proposed environmental mitigation;
- frequency and scheduling of monitoring activities;
- schedule of expected reporting to the National Energy Board on the progress and success of the mitigation measures implemented;
- inclusion for adaptive management, which allows for appropriate means to evaluate and amend issues that may arise during project operations; and
- effective means of reporting issues that may arise and reporting structures.

The Environmental Protection Plan incorporates the environmental alignment sheets. References to the Environmental Protection Plan are also incorporated into these alignment sheets. The Environmental Protection Plan is a comprehensive document that includes requirements of all regulatory agencies.

The requirement for an Environmental Protection Plan is consistent with National Energy Board goal-oriented regulation. An Environmental Protection Plan must be submitted to the National Energy Board for approval prior to pre-construction activities and pipe-laying operations for the Mackenzie Valley Pipeline and Mackenzie Gathering System. As the project begins the operational phase the Environmental Protection Program (Section 48 of the *Onshore Pipeline Regulations, 1999*) will apply. Prior to any drilling or construction activity relating to a Development Plan Application, authorizations under paragraph 5(1)(b) of the *Canada Oil and Gas Operations Act* would be required. Section 6 of the *Canada Oil and Gas Drilling and Production Regulations* states that an operator shall provide an Environmental Protection Plan for an authorization under paragraph 5(1)(b). Each of the Proponents will submit their own specific Environmental Protection Plan for the applications and may file several plans depending on timing of construction, the type of activity, and site specific considerations.

Alternatives North requested that the Conditions N11, T10, and P10 which deal with Environmental Protection Plans for Kendall Island Bird Sanctuary and Fish Island be filed with the National Energy Board for approval.

Views of the Board

We listened to the issues raised about the land, water resources, invasive species and other biophysical components. Through appropriate environmental management and planning we believe that these matters can be appropriately addressed during all stages of the project. We are committed to protection of the environment and will ensure measures are in place to address potential environmental impacts. A key component of this includes adherence to our conditions and Environmental Protection Plans required by Conditions 3, 38, N11, T10 and P10.

We will ensure that Environmental Protection Plans for the project are enforceable; that commitments made during the hearing are included; that appropriate field practices are incorporated; and that routine field amendments are addressed. The Environmental Protection Plans will facilitate environmental regulatory oversight for the project because they will incorporate all the environmental protection requirements in one document for each portion of the project. The Environmental Protection Plans provide a basis for working collaboratively with other Northern agencies. We will monitor and inspect all aspects of the project and the Environmental Protection Plans will be utilized as a document to verify compliance.

Required Environmental Protection Plans also address Joint Review Panel recommendation 6-4, *Construction and Operation Plan for the Kendall Island Bird Sanctuary and Fish Island*.

Conditions N11, T10, and P10 address Environmental Protection Plan requirements regarding the Development Plan Applications. The National Energy Board will assess future applications for authorizations for work or activity at the anchor fields along with the accompanying Environmental Protection Plan. Environmental mitigation during construction and operation for Fish Island will be addressed through Section 39 and 48 of the *Onshore Pipeline Regulations* and will also be addressed in the specific Environmental Protection Plans.

3.3.7 National Energy Board's role in enforcing recommendations directed to others

During final argument, parties submitted that the National Energy Board has a responsibility as "key gatekeeper" on this file to ensure that all Joint Review Panel recommendations are fulfilled. World Wildlife Fund Canada submitted that the National Energy Board must address the broader roster of Joint Review Panel recommendations, including those directed to government authorities, because they fall within the National Energy Board's fundamental mandate to recommend a project if and only if it is in the public interest. They added that the Joint Review Panel felt compelled to underline that the full suite of recommendations were needed to make the project sustainable. The Sierra Club of Canada submitted that we are leaving critical sustainability issues to others such as governments because almost all those recommendations intended to control the pace and scale of upstream development and those intended to ensure sustainability in relation to the end use of gas are not reflected in the National Energy Board's proposed conditions. Alternatively, the Gwich'in Tribal Council submitted that not all of the Panel's recommendations need to be accepted before the project can proceed; that matters best left to government policy should not be addressed by the recommendations; and that the completion of third-party actions should not be a pre-condition to project advancement.

Some parties had confidence in the ability of Northern agencies to protect the land. The Inuvialuit Regional Corporation stated:

> Much of the responsibility for the health of our environment is held collectively by the organizations and co-management bodies established under our land claim agreement and by the residents of every Inuvialuit community.
>
> Over the past 25 years, the Inuvialuit have gained a high level of confidence in the ability of these organizations and individuals to collectively provide for the

> ongoing health of the environment and wildlife across the Inuvialuit Settlement Region while allowing the orderly conduct of development and other commercial activities.
>
> As we look forward to the future development of the resource within our region, we do so in the comfort that our organizational structures have both the skills and the experience to maintain a responsible and objective balance between the health of our environment and the provisions of economic opportunity to the residents of our communities.

Other parties expressed concern that Joint Review Panel recommendations directed to other authorities would not be met. The Sierra Club of Canada submitted that we must set conditions that provide reasonable assurance that all of the Joint Review Panel's recommendations will be implemented, or say no to the project at this time. The Canadian Parks and Wilderness Society submitted that we should consider conditions that provide a greater level of certainty that recommendations outside the National Energy Board's mandate are fulfilled. The Sierra Club of Canada and Canadian Parks and Wilderness Society gave examples of ways in which we could ensure compliance. The Sierra Club of Canada suggested a two-part approach in which we first weigh the government response to evaluate whether the response commits to substantial implementation of the Joint Review Panel's recommendations, then we add a condition that the certificate does not take effect until the National Energy Board has determined in a public process that governments have met their commitments. Canadian Parks and Wilderness Society suggested other assurances such as timelines, land withdrawals, funding requirements, or checklist tracking. World Wildlife Fund Canada requested we state that this project is only in the public interest if all the Joint Review Panel's recommendations are implemented. World Wildlife Fund Canada cited an example in which another regulator, the Natural Resources Conservation Board, chose to make an approval come into effect upon the completion by government of a statutory order creating a wildland recreation area. World Wildlife Fund Canada suggested that we could, if we chose, take on a similar sequencing consideration and stipulate the order in which things happened, even where those things are not immediately within the National Energy Board's purview. Parties were afforded a further opportunity to comment on these and related matters upon receipt of the government response. In general, parties were concerned about the adequacy of the government response and either proposed strengthened conditions or took the view that, given this response, the project is not in the public interest.

Views of the Board

The National Energy Board has considerable responsibility with respect to the Mackenzie Gas Project. Fourteen federal and territorial agencies, departments and regulatory boards also have a role in managing environmental aspects of the project. After making its regulatory decisions, the National Energy Board collaborates with others to protect wildlife, water, air and vegetation from potential negative impacts resulting from project development.

Our responsibility begins with making the public interest determination. The question central to our public interest determination is whether Northerners and other Canadians would be better or worse off if the Mackenzie Gas Project is approved. This question is answered in *Volume 1, Respecting all voices: Our journey to a decision*.

The public interest determination takes into account benefits and impacts of the project on the land, the people, the economy, and safety and technical concerns. The review and hearing of environmental and socio-economic impacts was conducted by the Joint Review Panel, whose assessment helped inform our determination. In order to make a decision that the project is in the public interest, we had to be assured that environmental impacts could be minimized and that high standards for environmental protection will be maintained throughout the project life. The National Energy Board has within its abilities three important regulatory tools to achieve this. The National Energy Board's authority allows us to condition, enforce and conduct compliance monitoring for a number of requirements related to environmental protection, which include many recommendations of the Joint Review

Panel. The National Energy Board is responsible for lifespan regulation of the project. The National Energy Board also has jurisdiction over the assessment of new applications for future developments. In addition, northern agencies and federal authorities have responsibilities related to monitoring the project and managing the effects. We regard these responsibilities as complementary to the National Energy Board's responsibilities, and the National Energy Board is committed to working in collaboration with others to support an effective and efficient regulatory scheme.

It is our view that conditions contingent upon third-party actions would unduly leave both Northerners and the Proponents in a state of uncertainty about whether and when the project could proceed. We heard that people need certainty and time to make appropriate preparations for development. These preparations include training workers, resolving outstanding land issues, developing job and business opportunities, and conducting detailed permitting by land and water boards, among others. Since we feel that a high standard of environmental protection will be met through the National Energy Board's regulatory authority to enforce those Joint Review Panel recommendations directed to us, to enforce those commitments made by the Proponents during our hearing and the Joint Review Panel hearing over the project's lifespan, and to assess the impacts of future related developments, we believe that a clear public interest determination can be made at this stage without the ultimate reliance on third-party action. We remain committed to collaboration with other authorities to protect wildlife, water, air and vegetation.

3.4 Socio-economic matters discussed in final argument

3.4.1 Socio-Economic Agreement

The Government of the Northwest Territories stated that the Mackenzie Gas Project is crucial to the socio-economic future of the Northwest Territories, and has the potential to:

> transform the Territories from a region dependent on the support and contributions from the rest of Canada to a self-sufficient Territory.

The Government of the Northwest Territories also noted that the Mackenzie Gas Project is expected to impact the well-being of residents and communities in the Northwest Territories, and that a socio-economic agreement for the Mackenzie Gas Project was therefore a critical component of the project.

To address concerns of mutual interest, the Proponents and the Government of the Northwest Territories signed the Socio-Economic Agreement for the Mackenzie Gas Project in 2007. The Agreement outlines commitments that are intended to optimize beneficial opportunities and mitigate negative impacts arising from the Mackenzie Gas Project for Northwest Territories residents. The Socio-Economic Agreement includes measures to address employment and training, social and cultural well-being, business, net effects on government, monitoring, reporting and adaptive management.

The Government of the Northwest Territories requested that we ensure compliance by the Proponents with the terms outlined in the Socio-Economic Agreement by requiring adherence to the Socio-Economic Agreement as a condition of approval.

Views of the Board

The commitments set out in the Socio-Economic Agreement provide important measures for addressing the socio-economic impacts and optimizing the benefits of the Mackenzie Gas Project. Enforcement is best left to the parties to the agreement and we see no value in attaching a condition to the Certificate requiring the implementation of the agreement.

3.4.2 Employment and training

The Dehcho Elders and Harvesters Councils stated that the Proponents and government should provide Dehcho communities with educational and training opportunities, to help mitigate impacts and enhance benefits of the project. The Dehcho Elders and Harvesters Councils stated this should include educational upgrading, safety courses, survival training, as well as information and scholarships for careers as forest rangers, fisheries officers, game wardens, and park rangers. The Dehcho Elders and Harvesters Councils and the Liidlii Kue First Nation also stated that Canada needs to fulfill the original terms of the Mackenzie Gas Project Impacts Fund by limiting it to the Aboriginal communities and regions along the pipeline corridor, and to make the first phase of funding immediately available. The Dehcho Elders and Harvesters Councils and the Liidlii Kue First Nation also suggested that some of the Mackenzie Gas Project Impacts Fund be used for wilderness, language and cultural programs.

The Dehcho Elders and Harvesters Councils also stated ongoing training, information sessions and workshops in Dehcho communities for follow-up and monitoring programs are needed. The Dehcho Elders and Harvesters Councils further stated that Dehcho communities should be provided with financial and logistical support to allow them to hire their own dedicated Mackenzie Gas Project environmental monitors, who would report directly to the Dehcho communities. The Dehcho Elders and Harvesters Councils stated that management, monitoring and follow-up programs for the project must include the direct involvement of the Dehcho, to ensure that the needs and interests of Dehcho communities are represented and protected, and that such programs must fully incorporate Dene knowledge.

To achieve this, the Dehcho Elders and Harvesters Councils recommended the establishment of a Dehcho Mackenzie Gas Project monitoring agency to oversee, observe and protect land, wildlife and habitat during the planning, construction and reclamation of the project. The Sambaa K’e Dene Band also requested that the Proponents or Canada provide funding to the Sambaa K’e Dene Band for an independent environmental monitoring program during and for a period following construction.

Concerns were also raised about training for Mackenzie Gas Project personnel, which the Dehcho Elders and Harvesters Councils stated should include cultural awareness training, seminars and workshops, as well as participation in on-land activities with Dehcho Elders and harvesters.

The Government of Yukon requested that we adopt Joint Review Panel recommendations 15-7 and 15-8, relating to the inclusion of the Yukon in the Proponents’ Human Resources and Employment Database for the Mackenzie Gas Project, and designating Whitehorse as a point-of-hire. Alternatives North requested that the requirement for a communications plan as part of the Proponents’ diversity plan originally included in recommendation 15-9 of the Joint Review Panel be included in our conditions. Northern Pipeline Projects Ltd. recommended that contact between closed camp worker populations and local people should be planned and minimal.

Views of the Board

We recognize the potential benefits, as well as the potentially undesired effects, that employment generated by the Mackenzie Gas Project can bring to communities. A number of our conditions and the Proponents’ commitments address these effects. Condition 28 requires the Proponents to provide information to the National Energy Board related to the hiring of local residents as monitors to carry out compliance and environmental impact monitoring for the Mackenzie Gas Project. In addition, Condition 29 requires the Proponents to prepare and submit to the National Energy Board a number of Wildlife Protection and Management Plans that will address general wildlife and species-specific protection, and will include details on protocols for monitoring and adaptive management, in addition to Conditions 3 and 38 which require Environmental Protection Plans for the Mackenzie Gas Project.

The Socio-Economic Agreement for the Mackenzie Gas Project details the measures and commitments that are intended to minimize the socio-economic impacts of the project and enhance benefits. Section 2 of the Socio-Economic Agreement outlines the employment, training and hiring commitments made by the Proponents, including hiring priorities, points of hire for the Mackenzie Gas

Project, employment requirements and policies, human resources development, and the services and support for employment, education and training that will be provided by the Government of the Northwest Territories. Section 3 of the Socio-Economic Agreement outlines the commitments of the Proponents for promoting cultural preservation and understanding. These include the provision of cultural sensitivity and cross-cultural awareness training for all project workers, and supporting cultural activities such as community-based traditional lifestyle initiatives, traditional harvesting and the promotion of traditional culture and positive relationships with communities.

We believe these measures, commitments and programs will adequately address employment and training needs, and concerns relating to monitoring and cultural protection.

Regarding the recommendation by Northern Pipeline Projects Ltd. related to work camps, we believe the requirements for closed work camps and the preparation by the Proponents of plans to monitor and minimize adverse effects of worker-community interactions as contained in Conditions 24, 25 and 26 will provide for planned and limited interactions between the Mackenzie Gas Project workforce and local communities, and will minimize potential negative interactions.

With respect to the Government of Yukon's request for us to adopt Joint Review Panel recommendations 15-7 and 15-8, we note the Government of Yukon confirmed that these recommendations were consistent with, if not specifically contemplated by, the Proponents' written commitments to the Government of Yukon, and we are therefore confident these issues will be addressed. We are similarly confident that the existing requirements for monitoring and reporting systems contained in Conditions 23, N28, T27 and P27 will sufficiently address communications needs related to the Proponents' diversity plans, and no additional requirements to these conditions are needed.

3.4.3 Impacts to harvesters, land and resources

The Dehcho Elders and Harvesters Councils, the Sambaa K'e Dene Band and the Liidlii Kue First Nation raised a number of concerns regarding potential impacts on harvesters, land and resources in the Dehcho Region. The Sambaa K'e Dene Band stated its opposition to the development of borrow pits within the K'eotsee (Trainor Lake) watershed.

The Sambaa K'e Dene Band also requested that harvester compensation be addressed through a consultation agreement with Canada and the Proponents, through the conclusion of the Dehcho Process, or through the conclusion of an Impact Benefits Agreement.

To address compensation concerns, the Liidlii Kue First Nation requested that we require the Proponents to enter into a benefits agreement with the Liidlii Kue First Nation and the Dehcho First Nations as a condition of approval. The Liidlii Kue First Nation further requested that the agreement include funds to allow the Liidlii Kue First Nation to establish and maintain a monitoring program throughout the life of the project in their territory.

The Dehcho Elders and Harvesters Councils stated that research is required on the traditional Dehcho economy and the impact the project will have on physical, cultural and spiritual health and well-being. The Dehcho Elders and Harvesters Councils also requested that routing and siting of all project facilities avoid burial and sacred sites, and that work along water courses be conducted in a ceremonial manner with the involvement of the Dehcho. To address concerns regarding compensation for resources, the Dehcho Elders and Harvesters Councils requested that Dehcho harvesters be covered by a Harvesters Compensation Agreement before the project is allowed to proceed, and that compensation be provided for the value of all timber stands cleared on the right of way.

Finally, the Dehcho Elders and Harvesters Councils requested that the project be designed and built in a manner that minimizes the aesthetic impacts upon people and wildlife, and that Dehcho communities be involved in the development of a granular management plan for the project. The Dehcho Elders and Harvesters Councils expressed the desire of Dehcho communities to work with the Proponents to identify alternative sources of granular material, and that Dehcho communities, not Canada, be the recipients of any granular royalties.

Views of the Board

We recognize the importance of harvesting to the economy of the Northwest Territories, as well as its socio-economic and cultural importance for Aboriginal communities. In response to the concerns of the Dehcho Elders and Harvesters Councils regarding timber resources, Condition 75 for the Mackenzie Valley Pipeline will require the Proponents to notify and consult with Aboriginal and municipal authorities regarding community use of merchantable timber cleared along the right of way. With respect to harvester compensation, the report of the Joint Review Panel summarized the commitments made by the Proponents to provide compensation to harvesters. The Proponents committed to providing compensation to harvesters in accordance with the terms of the Inuvialuit Final Agreement, and the Comprehensive Land Claim Agreements for the Gwich'in and Sahtu Settlement Areas. They also committed to providing compensation to Dehcho harvesters on terms similar to these final agreements. We are satisfied with the commitments the Proponents have made to address harvester compensation.

For matters relating to granular resources, we will continue to rely on the authority of northern regulatory bodies and federal departments. For concerns over borrow pits and participation in management plans raised by the Sambaa K'e Dene Band and the Dehcho First Nations, the Mackenzie Valley Land and Water Board has regulatory oversight for permitting activities related to granular resource extraction in the Mackenzie Valley. In response to concerns over impacts to burial or sacred sites and aesthetic impacts raised by the Dehcho Elders and Harvesters Councils, Condition 21 requires the Proponents to submit to the National Energy Board their Heritage Resources Management Plan, as reviewed by the Prince of Wales Northern Heritage Centre. The mitigation measures committed to by the Proponents, as detailed in their Environmental Impact Statement, will adequately address aesthetic and visual impacts.

3.4.4 Project reporting

Alternatives North requested that we commit to a full public registry for all Mackenzie Gas Project applications and follow-up to ensure transparency and accountability. They further suggested the public registries of the Mackenzie Valley Environmental Impact Review Board and the Mackenzie Valley Land and Water Board could serve as models.

Views of the Board

We are committed to the open, transparent sharing of information with all those who have an interest in the Mackenzie Gas Project, including the northern institutions and federal departments with whom we will continue to work cooperatively as the project proceeds. Subject to statutory limitations, we will continue to make information about the project publicly available on our repository. For all projects regulated by the National Energy Board that have proceeded to construction, our public repository includes submissions made by proponents relating to their compliance with certificate conditions, as well as responses to these submissions by the National Energy Board.

Chapter 4
Development fields

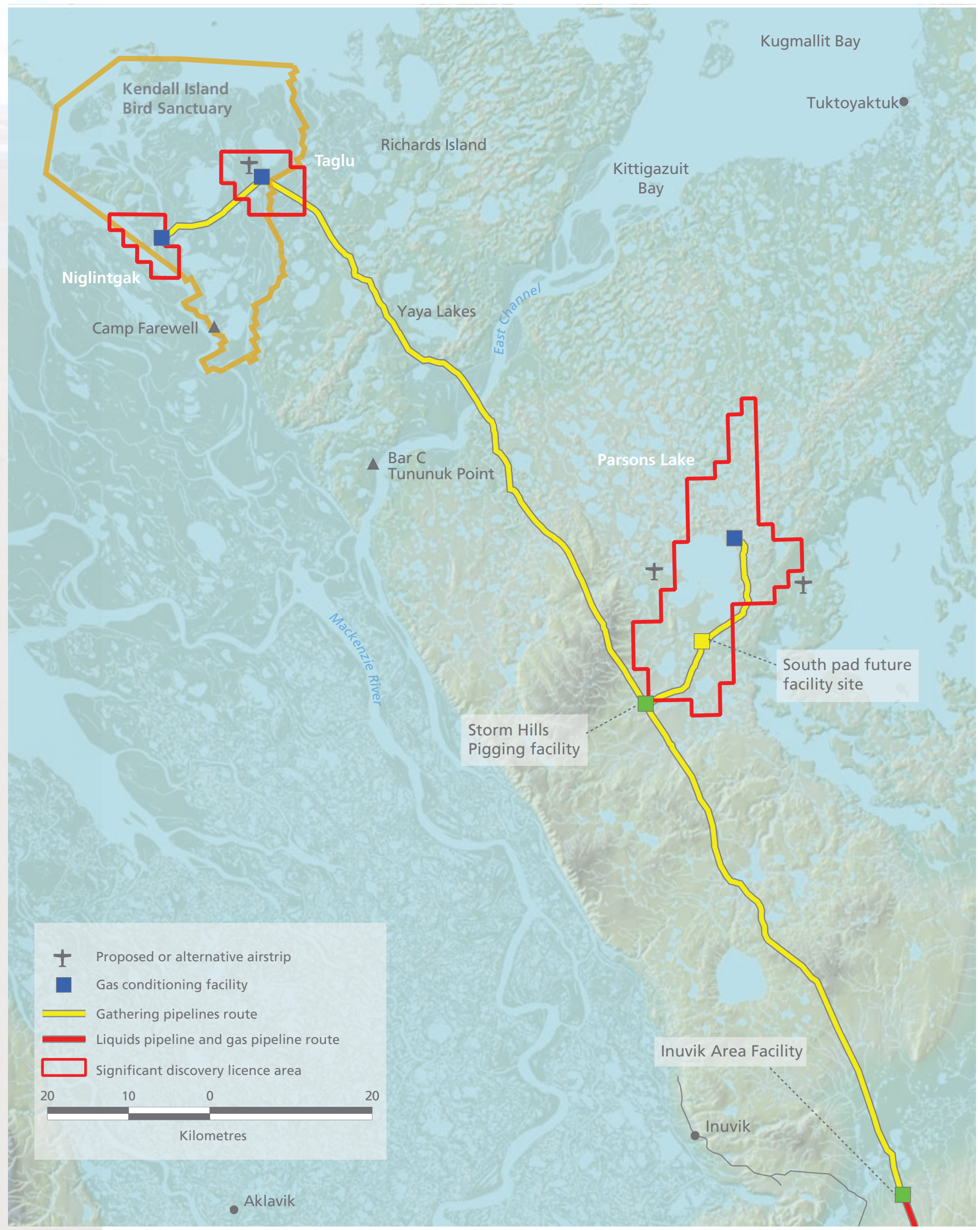


Figure 4-1 **Development fields**

4.1 The reservoirs

The Mackenzie Gas Project is anchored on the production of natural gas from three development fields near the edge of the Mackenzie Delta. These three fields—Niglintgak, Taglu and Parsons Lake—would produce about 172 Gm^3 (6.1 Tcf) of sweet natural gas (see Table 4-1). This is enough gas to heat one million average Canadian homes for almost fifty years.

Each field consists of reservoirs of trapped natural gas. Typically, oil and gas reservoirs are found and the boundaries identified through activities such as two dimensional and three dimensional seismic surveys and drilling and testing of exploratory wells and delineation wells. Results from surveys and tests provide technical information on the sub-surface rock and the trapped gas. Computer models use this information to predict the best locations to put production wells for the most efficient method of extracting the gas. *Appendix D – Development Field Reservoirs: Characteristics and Exploration History* provides additional information on the field reservoirs and exploration history.

Total supply from the anchor fields is projected to be about 24 Mm^3/d (0.850 Bcf/d) of sales gas, with level production for 12 years, following which production would decline until the reservoirs are depleted (see Figure 4-2).

Natural gas liquids production would begin at 1756 m^3/d (11,050 Bbl/d) and would immediately decline (see Figure 4-3).

Table 4-1

Recoverable volumes of natural gas in the development fields

Field	Recoverable volumes of natural gas
Niglintgak	27 Gm^3 (0.95 Tcf)
Taglu	81 Gm^3 (2.8 Tcf)
Parsons Lake	64 Gm^3 (2.3 Tcf)

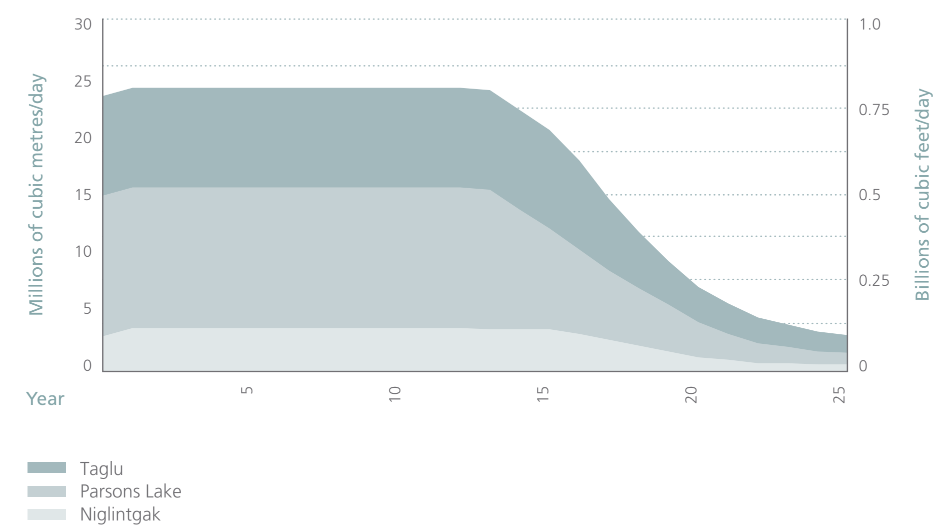


Figure 4-2

Natural gas supply

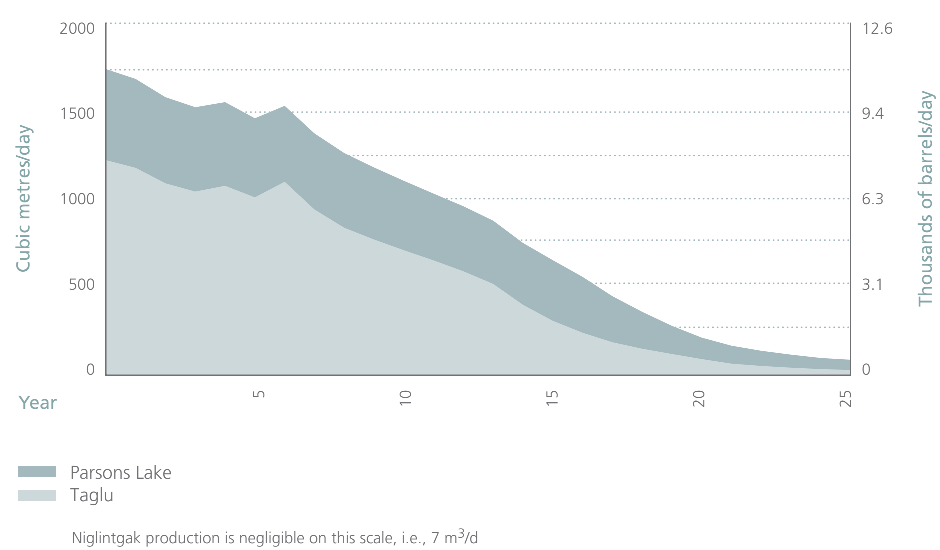


Figure 4-3

Natural gas liquids supply

4.2 Niglintgak

4.2.1 Design of the Niglintgak facilities

Niglintgak is the westernmost of three natural gas fields associated with the project and is the starting point of the proposed Mackenzie Gathering System. Located entirely within Kendall Island Bird Sanctuary, Niglintgak is approximately 120 kilometres northwest of Inuvik and 85 kilometres west of Tuktoyaktuk.

Shell Canada Limited (Shell) is the Proponent for a Development Plan for the Niglintgak field under the *Canada Oil and Gas Operations Act*. Development of the field is estimated to cost $800 million with an estimated annual average operations and maintenance expenditure of $10 million per year for the period 2019 to 2023. Construction is planned over four winter seasons from 2014 to 2018 with production operations to commence in 2018 and continue for about 25 years.

The proposed production facilities include:

- six to twelve production wells located on three well pads;
- a system of above-ground flow lines;
- a gas conditioning facility located in the Kumak Channel;
- a disposal well; and
- infrastructure including an emergency shelter and helipads.

Shell proposes to start construction by barging supplies and equipment to Camp Farewell (refer to Figure 4-1) during late summer 2014 in preparation for winter work. Production is scheduled to start in the summer of 2018. Highlights of the proposed construction and drilling activities are shown in Table 4-2.

Table 4-2

Niglintgak construction highlights schedule

Activity	Season and year
Barge supplies and equipment into Camp Farewell	Late summer 2014
Start constructing well pad pilings, flow line pilings and well pad decking	Winter 2014/15
Option to commence drilling at south well pad	Winter 2014/15
Dredge gas conditioning facility transportation route, if required	Summer 2015
Construct flow lines including horizontal directional drill	Winter 2015/16
Excavate gas conditioning facility set-down site and prepare foundation	Winter 2016/17
Transport gas conditioning facility to set-down location	Summer 2017
Complete drilling and completion program and demobilize	Winter 2017/18
Start up operations and production	Summer 2018

Wells and well pads

All drilling would be conducted from three well pads (north, central and south) which would lie along the shoreline of the Mackenzie River's Middle Channel (see Figure 4-5). Each well pad would be built of steel decking and elevated on steel piles.

From these pads, Shell plans to initially drill six production wells. Once production begins and more is learned about the reservoir, as many as six contingent wells may be needed to optimize natural gas recovery. Shell also indicated that some wells may require commingled production in order to recover gas with a minimal well count. Commingled production is production of oil and gas from more than one pool or zone through a common well-bore without separate measurement of the production from each pool or zone.

Flow lines and water disposal well

After the natural gas is extracted from the reservoir, it would be transported along 10 kilometres of insulated above-ground flow lines to a gas conditioning facility, where the gas would be separated from any liquid hydrocarbons and water. Water that has been removed would be sent to a disposal well on the south well pad. The flow lines would be elevated at least 2.2 metres above ground on vertical supports.

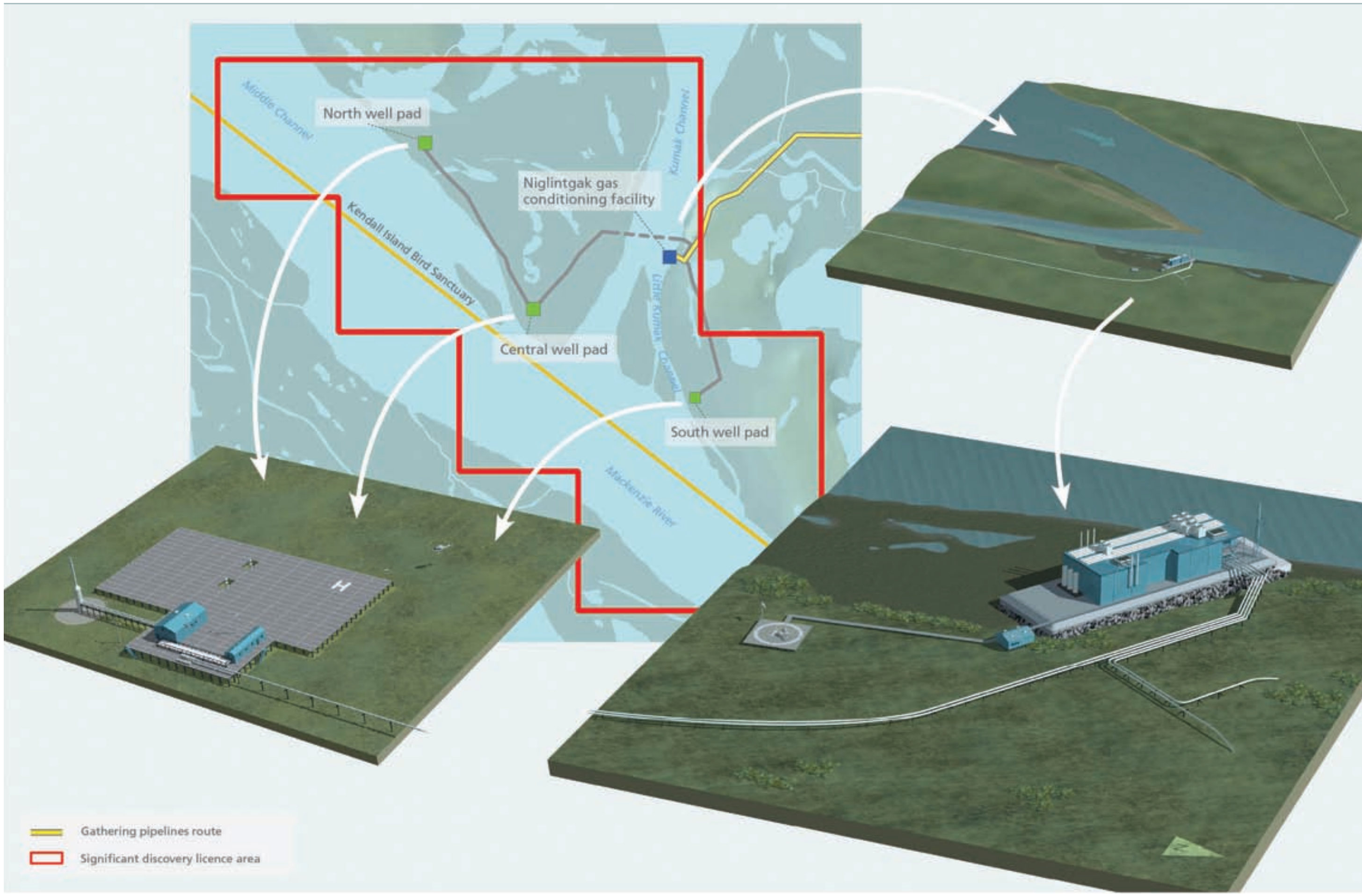


Figure 4-4

Niglintgak production facilities

Gas conditioning facility

Shell's proposed gas conditioning facility would be prefabricated and housed on a lightweight, ice-strengthened steel barge. The gas conditioning facility, designed for a maximum capacity of 4.3 Mm^3/d (150 MMcf/d) consists of several production modules designed to:

- separate the gas from free water and hydrocarbon liquids;
- inject produced water into a disposal well;
- compress and dehydrate the gas;
- inject hydrocarbon liquids into the sales gas line; and
- chill and meter the sales gas before it is pumped into the buried lateral pipeline which connects to the Mackenzie Gathering System.

Shell plans to tow the gas conditioning facility barge through the Beaufort Sea and into Little Kumak Channel in the Mackenzie Delta, where it would be set down on the Kumak Channel flood plain at a location north of the Little Kumak Channel. The current design calls for a barge with a 1.5 metre draft that stretches 50 metres across and 150 metres in length, which is slightly larger than a soccer field. Once the barge reaches its final location, it would be installed onto steel-pile foundations.

Barging

The gas conditioning facility would be transported by barge through the Beaufort Sea and up the Mackenzie River. In summer, beluga whales, bowhead whales and ringed seals all make the southeast Beaufort Sea home. There is the possibility that personnel would encounter groups of marine mammals; however, encounters are anticipated to be short term. Measures such as reducing vessel speeds, using an onboard mammal monitor to watch for aggregations of bowheads, and redirecting vessels to avoid whales could be used to mitigate these concerns. Impacts on water quality during transportation are not expected to be significant as no dredging is anticipated.

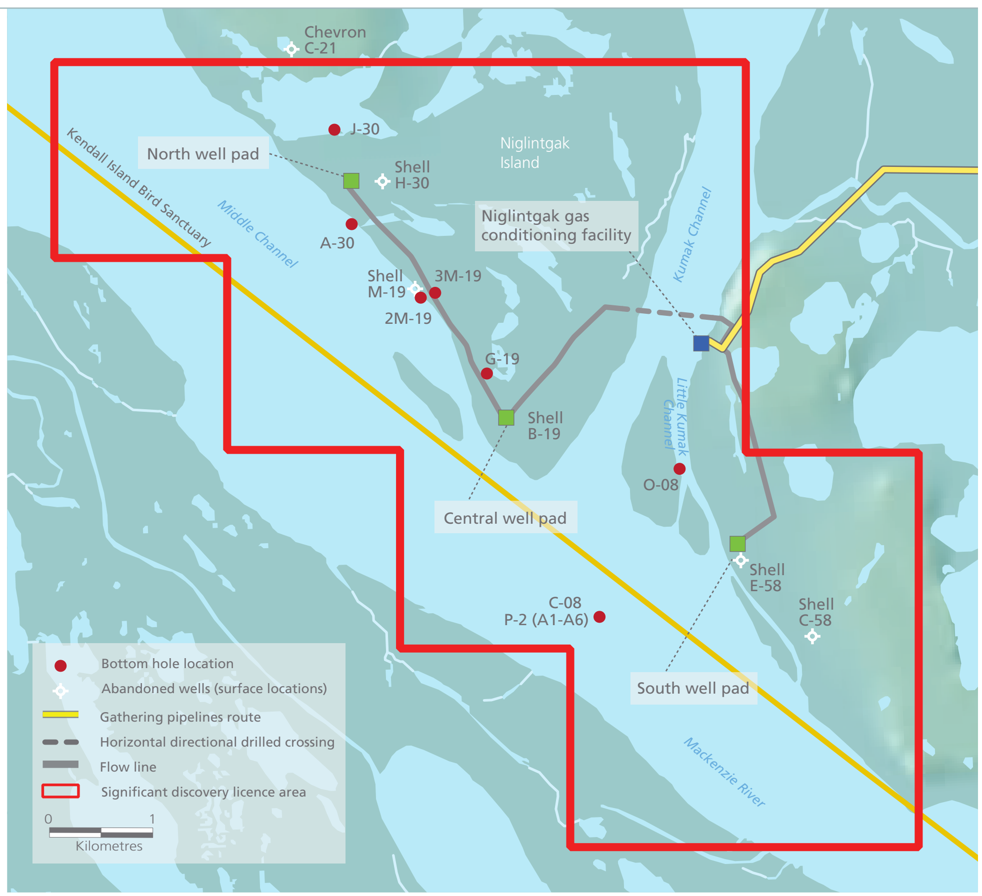
Shell's preferred route to the set-down location runs through the previously dredged Kittigazuit Bay (location shown on Figure 4-1), which is part of an existing shipping lane. This would eliminate the need to dredge the shallow waters at the mouth of the Mackenzie River. Shell plans to perform bathymetry and if required, conduct additional dredging on the transportation route. Proposed production facilities for the Niglintgak field (see Figure 4-4) are described opposite.

Camp Farewell

Camp Farewell, which includes an airstrip, an equipment laydown area, a barge landing site and fuel storage facilities, would be used to support drilling and construction activities at Niglintgak. The camp is Shell's staging and storage facility within Kendall Island Bird Sanctuary and has operated to support northern exploration and drilling activities since the late 1960s. It is located 15 kilometres southeast of the Niglintgak field and provides accommodation for 35 workers and support staff.

Figure 4-5

Niglintgak field map



Views of the Board

We are satisfied with the general approach, conceptual design and plan proposed by Shell for the Niglintgak field. We note that when Shell drills and produces gas from its wells, new geological and reservoir data will be acquired that will determine if additional faulting and compartmentalization exists and whether any contingent wells would be required. Condition N18 requires Shell to submit to the National Energy Board an updated resource management plan within 18 months after production commences or prior to the drilling of contingent wells.

We consider Shell's conceptual plan requiring commingled production in some wells in order to optimize gas recovery with a minimal well count to be acceptable. The National Energy Board will consider commingled production on an individual well basis during drilling and production operations in accordance with section 66 of the *Canada Oil and Gas Drilling and Production Regulations.*

Condition N31 stipulates that the approval of the Development Plan for the Niglintgak field under subsection 5.1(4) of the *Canada Oil and Gas Operations Act* is subject to the Minister of Indian Affairs and Northern Development Canada providing confirmation that Shell has satisfactorily met the Benefits Plan requirements of section 5.2 of the *Canada Oil and Gas Operations Act*.

4.2.2 Development plan issues

During the hearing, we heard the following related to the development of the Niglintgak field:

- matters raised by adjacent rights holders;
- geographic and design issues related to permafrost, subsidence, flood protection and climate change;
- air quality issues and greenhouse gas emissions;
- activity and facility noise levels and environmental footprint in Kendall Island Bird Sanctuary; and
- management of spoils from dredging operations.

Matters raised by adjacent rights holders

On 3 November 2004, the National Energy Board issued a declaration of Commercial Discovery (CDD) for the Niglintgak field, which includes land held and operated by several different parties. Shell is the sole interest holder of Significant Discovery Licence SDL019, which encompasses most of the field (see Figure 4-6). A Significant Discovery Licence interest holder has the right to drill wells and, in the future, obtain production rights for subsurface oil and gas resources.

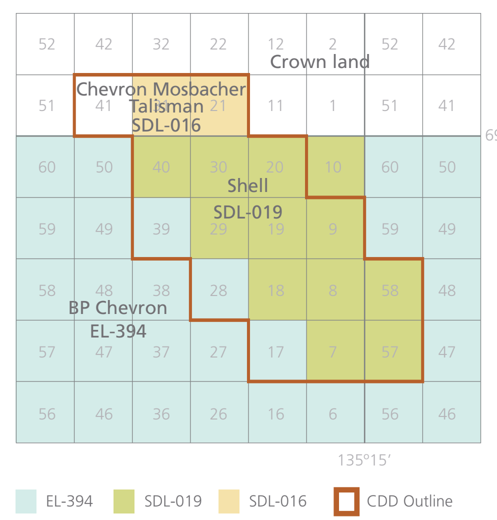
Shell's plans for developing the field are based on the results of reservoir modeling. Shell's models show a reservoir that is smaller and relatively shallow in comparison to the other two fields—the gas reserves lie only about 1000 metres below the surface—and much of the reserves lie underneath the Mackenzie River and its tributaries.

The reservoir is in the poorly consolidated Reindeer Sands geological formation and consists of several separate zones resulting from subsurface faulting. To fully recover the gas in the reservoir, Shell proposes a total of six to twelve wells on the three well pads. These sites were selected because the land has been disturbed by previous drilling activity.

Most of the activity would take place on the north pad where Shell plans to initially drill four gas wells. Initially, one gas well would be drilled on the central pad, and the south pad would contain both a gas well and a water disposal well. To reach the gas reserves, Shell plans to directionally drill under the Mackenzie River. The shallow depth of the reservoir will limit the length of these directionally drilled wells.

Figure 4-6

Commercial discovery declaration area and significant discovery licences for Niglintgak as of 2006



To the north of Significant Discovery Licence SDL019 lies the Significant Discovery Licence SDL016 land held by Mosbacher Operating Ltd. (Mosbacher), Talisman Energy Inc., and Chevron Canada Resources (Chevron) which is also the operator for these lands. To the south, east and west of Shell's land, is Exploration Licence EL394[1] held by Chevron and BP Canada Energy Company with Chevron being the operator.

Chevron and Mosbacher, as interest holders for lands adjacent to the Niglintgak field are concerned that Shell's proposed development would drain their gas resources. Mosbacher and Chevron would prefer to develop the Niglintgak field in collaboration with Shell, either by unitization or by providing third-party access to common facilities.

A unitization agreement would allow parties to jointly develop the field in exchange for a predetermined share of the end product. Shell is opposed to a unitization agreement. Shell also stated that no order for unitization to prevent waste under section 38 of the *Canada Oil and Gas Operations Act* is required as there would be no waste. Shell argued that Chevron and Mosbacher, like Shell, have rights to drill wells and develop their lands, but unlike Shell, Chevron and Mosbacher have chosen not to exercise those rights. In Shell's opinion, the Chevron and Mosbacher lands lie on the outer fringes of the reservoir and there is not enough information about Chevron's and Mosbacher's potential gas reserves to conduct meaningful discussion around unitization. Shell believes the only way Mosbacher and Chevron can prove the extent of gas reserves under their land is by drilling their own wells. This could be assisted by allowing Chevron and Mosbacher access to Shell's well pads so that they may directionally drill wells onto their lands. According to Shell, their proposed well pads could be adjusted to accommodate additional drilling activities, provided all parties could reach a mutually agreeable financial arrangement. If Chevron and Mosbacher choose to drill wells from Shell's well pads, the pads could be extended by 15 metres for each additional well.

According to Shell's estimates, the maximum horizontal reach for wells in the Niglintgak Field is approximately 1.3 to 1.5 kilometres. Chevron and Mosbacher could potentially drill a well from Shell's north and central well pads into their adjacent lands. If an arrangement is reached during the design phase, Shell would consider modifying its facilities, including installing additional river crossings and enlarging flow line structural supports for future expansion and meeting additional fuel gas and power supply requirements for well pads.

Typically when gas fields are developed, wells are positioned according to an established grid of "spacing units", such as that set out in the National Energy Board's *2009 Draft Spacing Requirements*[2]. The *2009 Draft Spacing Requirements* establish a 250 metre off-target area[3] intended to provide adjacent interest holders the opportunity to develop wells on their lands. Shell indicated that the 250 metre off-target area is appropriate, but requested a variance in accordance with the *2009 Draft Spacing Requirements* in order to allow for the optimum location of some wells.

In final argument, both Chevron and Mosbacher indicated that the proposed Niglintgak Development Plan was sub-optimal with respect to minimizing waste and referenced sections 18 and 19 of the *Canada Oil and Gas Operations Act*. In the absence of joint development, both Chevron and Mosbacher submitted to us that Shell should not be granted a variance in accordance with the *2009 Draft Spacing Requirements* for Significant Discovery Licence SDL019 as this would exacerbate drainage of gas from their lands.

Chevron asked us to consider a condition that would require field development to take into consideration the area needs when designing and sizing facilities. Chevron also asked for a condition restricting well density to no more than one well per spacing unit for all Shell lands. The third condition requested by Chevron would require Shell to provide a one grid unit set-back between Significant Discovery Licence SDL019 and lands of differing ownership.

Mosbacher suggested a condition that would direct Shell to include all land in Significant Discovery Licence SDL016 within the commercial

[1] Exploration Licence EL394 has expired and Production Licence PL25 was issued on 17 September 2008 for sections 17, 28 and 39. The current representative interest holder of Production Licence PL25 is MGM Energy Corp.

[2] The *2009 Draft Spacing Requirements* were issued on 31 December 2009 and replaced the *Draft Spacing Unit Regulations*.

[3] The 250 metre off-target area replaces the one grid unit set-back outlined in the *Draft Spacing Unit Regulations*.

discovery declaration area as part of the Niglintgak Development Plan. Secondly, Mosbacher asked for a condition requiring Shell to fully explore joint production arrangements with other interested parties. The third condition requested by Mosbacher would have Shell make available drilling pad space on reasonable commercial terms to allow Mosbacher and other interested parties the opportunity to drill additional wells on a timely basis.

Views of the Board

We are of the view that if the interest holders of the adjacent lands wish to develop their lands a joint and collaborative approach to the development of the Niglintgak field would be advantageous to all parties involved. The benefits would include a minimal duplication of facilities and a minimal environmental footprint within Kendall Island Bird Sanctuary. It is also our view that joint development is best obtained through voluntarily commercial negotiations and agreements between the parties involved. We note that the compulsory unitization[4] provisions in the *Canada Oil and Gas Operations Act* require participation from Shell as it holds a large portion of the lands comprising the Niglintgak commercial discovery declaration area. Shell has stated that it requires that Chevon and Mosbacher drill wells on their lands to demonstrate productivity before serious discussions could occur on joint development or unitization of the Niglintgak field. In this regard, Condition N2 requires the Niglintgak north, central and south well pads to be designed so each may be expanded to allow for the drilling of at least one well by third parties. If the parties involved are able to work out commercial terms including timing, the condition would provide Chevron and Mosbacher the opportunity to drill directional wells to delineate the field on their lands with a minimal environmental footprint in Kendall Island Bird Sanctuary.

As there currently is no joint production arrangement between the interest holders of Significant Discovery Licence SDL016 and Shell, we are of the view that there is no basis for Mosbacher's condition directing Shell to include all sections of land in Significant Discovery Licence SDL016 within the commercial discovery declaration area as part of the Niglintgak Development Plan. As noted, the first step that needs to be taken to commence meaningful discussions on joint production arrangements is the drilling of wells by Chevron and Mosbacher. Without wells on their lands, adjacent interest holders cannot make volume commitments with respect to third party access to Shell's facilities. Therefore, we are not persuaded to include the Mosbacher condition requiring Shell to fully explore joint production arrangements with other interested parties or the Chevron condition requiring field development to take into consideration the area needs when designing and sizing facilities.

In the absence of joint development arrangements, we are of the view that the *2009 Draft Spacing Requirements* are appropriate and provide an approach that balances the optimization of gas recovery with the protection of the correlative rights of adjacent land interest holders. Condition N19 requires Shell to comply with the *2009 Draft Spacing Requirements*. We are not persuaded by Chevron to require a one grid unit set-back between Significant Discovery Licence SDL019 and lands of differing ownership. We consider the 250 metre off-target area for gas wells to be appropriate noting that it is consistent with set-backs used in Alberta, British Columbia, Saskatchewan and Yukon.

The *2009 Draft Spacing Requirements* set a limit of one producing well in spacing units adjacent to lands of differing ownership, but for spacing units not adjacent to lands of differing ownership, there is no off-target area and more than one producing well is permitted[5]. Therefore, we are not persuaded by Chevron to restrict well density to no more than one well per spacing unit for all Shell lands.

[4] Compulsory unitization, sections 39 to 47 of the *Canada Oil and Gas Operations Act* came into force on 31 July 2010. Compulsory unitization requires one or more working interest owners who are parties to a unit agreement and a unit operating agreement and own in the aggregate sixty-five percent or more of the working interests in a unit area to apply for a unitization order with respect to the agreements.

[5] Part IV of the *2009 Draft Spacing Requirements.*

According to the *2009 Draft Spacing Requirements*, Shell would not need a variance for the proposed preliminary well locations. Any future application for a variance would be considered by the National Energy Board at that time and would be assessed in accordance with the *2009 Draft Spacing Requirements*, or any orders dealing with spacing that may supersede it.

We are of the view that the proposed production scheme is appropriate for a conventional gas field such as Niglintgak. With Condition N19 in place requiring compliance with the *2009 Draft Spacing Requirements*, interest holders of Significant Discovery Licence SDL016[6] and Production Licence PL25 have the opportunity to drill wells and develop their lands. We do not consider there to be sufficient grounds to find that the Niglintgak Development Plan is suboptimal in terms of minimizing waste[7], as suggested by Chevron and Mosbacher.

[6] The lands comprising Significant Discovery Licence SDL016 are eligible for a production licence as those lands were included in the NEB's commercial discovery declaration dated 16 September 2004.

[7] Waste as defined in section 18 of the *Canada Oil and Gas Operations Act*.

Geographic and design issues

Permafrost

The Niglintgak field is located within a zone of intermediate discontinuous permafrost. Well operations could produce not only warm natural gas, but also circulate other warm liquids, such as reservoir and drilling fluids, which could thaw the permafrost. Thawing of the permafrost may alter the landscape.

To reduce disturbance to the permafrost, Shell proposes to space the wells a minimum of 15 metres apart, and implement a number of other mitigative measures to reduce thawing of the permafrost by warm fluids from well operations. In addition, the well pads would be constructed on a raised steel deck, and the flow lines would be insulated and elevated.

One reason Shell chose the proposed set-down location for the gas conditioning facility is that the site is underlain by permafrost, which provides several options for excavation of the area. Shell's preferred approach is a combination of winter mechanical excavation and summer dredging. Once the gas conditioning facility is in place, the site would be dammed off and drained to isolate it from the channel to allow the permafrost layer to re-establish naturally.

Did you know?

Horizontal directional drill

A method for installing pipelines or other utilities beneath rivers, streams, channels, roads and other obstacles without requiring a trench and with minimal disruption to the surface. A drill rig is used to bore an underground passage for the pipeline or utility with a directionally controlled drill head. The passage is reamed out to an appropriate size and the pipe or utility is then pulled through.

The location of the gas conditioning facility requires the flow lines from the north and central pads to cross the Kumak Channel, a distance of approximately one kilometre. A feasibility assessment for a horizontal directional drill indicated that ice-rich, thaw-unstable permafrost effectively surrounds the Kumak Channel, but concluded the crossing may be successfully constructed with the application of mitigative measures, such as using chilled drilling fluids, to prevent permafrost thaw.

Shell's alternative to the horizontal directional drill would be a trenched flow line crossing about 900 metres downstream of the proposed horizontal directional drill crossing bordering the Little Kumak Channel.

Views of the Board

We are satisfied with Shell's general approach to addressing permafrost integrity for the Niglintgak development. We note that because warm fluids get circulated up and down the wellbore during drilling and production operations, it is important for safety and environmental protection reasons that the permafrost thaw bulbs around wellbores do not coalesce. Condition N3 requires the interwell spacing on Niglintgak well pads to be no less than 15 metres unless Shell utilizes mitigation measures approved by the National Energy Board.

We are of the view that Shell's preliminary horizontal directional drill design is satisfactory. We note that horizontal directional drill design has been used only once in permafrost areas and that this increases the potential for unforeseen issues during installation. We agree with the use of temperature controlled drilling muds for the horizontal directional drill crossing. When this is not possible, the alternative use of freezing temperature depressants has potential undesirable long term impacts on slope stability and their use as an option in horizontal directional drill must be carefully considered before implementation. Condition N7 requires Shell to provide: a hazard analysis and contingency plan for the proposed horizontal directional drill crossing; detailed final design drawings for the proposed horizontal directional drill crossing and the contingent open cut crossing; a monitoring program of slope stability, scour, drainage impedance and erosion issues for the crossing; and evidence of consultation with other appropriate regulators and government departments.

Subsidence

The reservoir for the Niglintgak field is located in the Reindeer Sands Formation, formed 60 million years ago in the Early Tertiary Period. When natural gas from the Niglintgak field is extracted from the poorly consolidated Reindeer Sands Formation, the sands may become more tightly packed and the surface could settle. This phenomenon is called subsidence. With this subsidence, the Niglintgak field, which is located within the active Mackenzie Delta floodplain, may be more prone to flooding. The low lying terrain of Niglintgak Island presently experiences annual spring floods as snow melt raises water levels in lakes, rivers and their tributaries throughout the Mackenzie Delta.

Shell predicts a maximum subsidence of 0.45 metres at the surface over the centre of the reservoir, which correlates with the centre of the Middle Channel, and predicts subsidence of 0.15 metres at the set-down location of the gas conditioning facility. Shell has indicated that it is considering using global positioning system targets on each of the well sites, the gas conditioning facility, on flow lines and at a number of benchmark locations to monitor subsidence.

Joint Review Panel Report recommendation 6-10 asked us to require Shell to file with the National Energy Board a program to monitor subsidence and flooding due to hydrocarbon extraction for the Niglintgak field. In a letter dated 28 January 2010 responding to the Joint Review Panel Report recommendations the Proponents submitted to us that recommendation 6-10 be rejected as our proposed Condition 7 (dated 5 February 2007) for the Niglintgak field was sufficient. In the Proponents' view, it was unlikely to be technically feasible to monitor flooding due to hydrocarbon extraction since it would be very difficult to differentiate flooding due to hydrocarbon extraction from natural flooding. The Proponents said that flooding at Niglintgak is a natural and annual occurrence.

In argument, Environment Canada suggested the following revisions to the condition:

- clarify and enhance consultation;
- include the monitoring of flooding due to subsidence in order to determine the loss of nesting habitat;
- include monitoring of reservoir compaction in order to differentiate project-induced subsidence from natural changes in ground elevation; and
- allow the use of the most appropriate technology at the time including airborne and remote sensing techniques.

Shell responded in argument by proposing the condition include the terms "best management practices" and "best available technology" in regards to monitoring.

Views of the Board

We are of the view that it will be important to monitor and confirm Shell's estimates of subsidence due to hydrocarbon extraction because the Niglintgak field is located inside Kendall Island Bird Sanctuary and is one of the first proposed developments in the Mackenzie Delta where subsidence due to gas extraction is predicted to occur. Condition N4 requires Shell to submit a program to measure and monitor accumulated subsidence and to monitor flooding for the life of the field.

Environment Canada indicated monitoring of reservoir compaction was needed to differentiate project-induced subsidence from natural changes in ground elevation. Condition N4 requires that elevation benchmarks be located outside of the projected gas-extraction-subsidence-area. We believe that these elevation benchmarks will act as control or reference points to provide data to estimate natural subsidence. We are not persuaded that monitoring of reservoir compaction is necessary.

We agree with Environment Canada that the condition should allow for the use of the most appropriate technology at the time. This is similar to Shell's suggestion to use the terms "best management practices" and "best available technology" in the condition. Condition N4 has been amended to reflect this.

We agree with Environment Canada's suggestion to clarify and enhance consultation and Condition N4 has been revised in this regard.

Flood protection and climate change

Shell's approach to flood protection was to estimate a maximum value for subsidence due to gas extraction and add factors such as the maximum predicted flood level, rising sea levels due to climate change, an increased severity of storm surges, permafrost thaw, and maximum wave height. These factors were all taken into consideration when developing the preliminary design for the well pads, flow lines and the barge-based gas conditioning facilities. Shell determined that permafrost thaw subsidence on areas vulnerable to flooding was much smaller, by an order of magnitude, than subsidence from gas extraction and, therefore, permafrost thaw subsidence was not significant.

Subsidence at the original set-down location of the gas conditioning facility was predicted to be 0.15 metres. A substructure design height of 5.75 metres was determined for the gas conditioning facility, which included consideration of subsidence, foundation settlement, maximum flood level, rise in sea level, storm surge, wave crest and a freeboard of 0.3 metres as additional protection (see Figure 4-7). The well pads would be set between 3 and 4 metres above grade and the flow lines would be elevated a minimum of 2.2 metres above grade.

Shell believes that it has used a conservative approach to estimate the effect of thawing permafrost in its determination of the design height of its facilities. Should the waters of the Mackenzie River ever threaten the facilities, some modification to the facilities and flow lines would be considered. This could include:

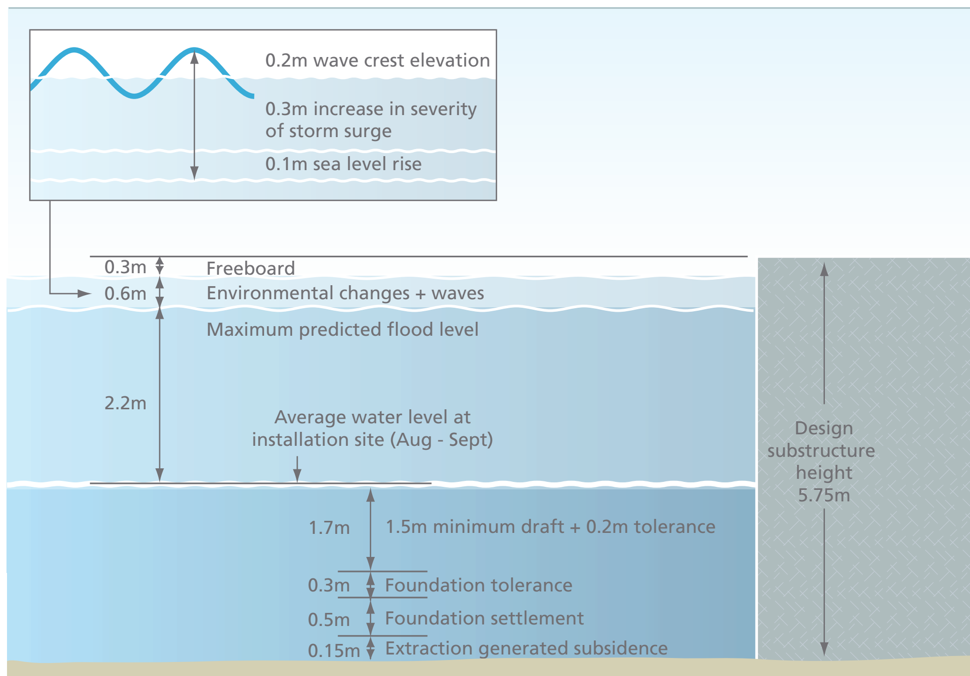
- increasing the height of the equipment platforms and flow lines;
- increasing the number of restraint points on flow lines and certain well site equipment, such as tanks;
- installing a flood barrier around the plant perimeter at deck level;
- increasing the depth of the substructure and raising the elevation of the plant on the gas conditioning facilities; and
- installing ice barriers.

Warming of the global and regional climate could raise sea levels and affect weather patterns. The Niglintgak field is located in the low-lying Mackenzie Delta near the Beaufort Sea. We heard concerns that seasonal flooding and storm surges could affect these facilities during the life of the project. Shell provided evidence that the facilities would be high enough to protect them from storm surges and flooding even if sea levels rise.

The Sierra Club of Canada was concerned about the lack of peer-reviewed research publications on the effects of climate change, specifically for the Mackenzie Delta over the 30 year life span that was used by Shell in the design of the Niglintgak facilities. The Sierra Club of Canada stated that from a design perspective, there is uncertainty regarding the effects of climate change on the permafrost, the rise in sea level and the degree of flooding. The Sierra Club of Canada referred to the Arctic Climate Impact Assessment prepared by the International Arctic Science Committee. The Arctic Climate Impact Assessment states that the Arctic is experiencing the most rapid and severe climate change on earth, including the disappearance of Arctic sea ice which allows higher waves and storm surges.

Shell indicated that the direct impact of sea level rise over 30 years should not exceed 0.1 metre This was based on research from the United States Environmental Protection Agency (September 1995) and the Intergovernmental Panel on Climate Change in 2001.

These documents contain extensive analysis of all the parameters that could influence sea level rise from climate change. Shell noted that the change in the annual average mean sea level, recorded at Tuktoyaktuk between 1971 and 2005 indicates that sea level changes are at a low level (less than 0.1 metres over 35 years). Shell believes previously mentioned research and Environment Canada data endorses its view that the direct impact of sea level rise over 30 years should not exceed 0.1 metres, but that an increase in the magnitude of storm surges needs to be considered. Shell indicated that it will look at whatever evidence and information is available, and if it leads to a different conclusion, Shell would need to increase design margins and would do that. Facility designs



Note: based on preliminary design information

Figure 4-7

Niglintgak substructure design height

will include adaptive management and future mitigations, where appropriate.

The Joint Review Panel was generally satisfied that Shell had taken climate change into account in its design. Nevertheless the Joint Review Panel recommended that the National Energy Board add a condition to the certificate which would require Shell to file final design plans that incorporate further design analysis of the impacts of climate change on permafrost and terrain stability over the design life of the project and post-abandonment. The Joint Review Panel was of the view that this analysis should be conducted for a series of representative locations, conditions and terrain types and should incorporate climate variability, in particular, upper limit temperature scenarios to account for the range of future temperature conditions, including variability and extremes, and the impact of this variability on stream flow regimes. The Joint Review Panel added that the results should be incorporated into monitoring, mitigation and adaptive management plans. The Joint Review Panel thought that this analysis should be provided to other appropriate regulators in sufficient time for review and to provide input to the National Energy Board.

Indian and Northern Affairs Canada suggested in final argument that the Proponents should demonstrate how upper limit temperature scenarios have been considered in their design.

Further specific discussion on climate change regarding project design is found in Chapter 6.

Views of the Board

We are satisfied with Shell's climate change estimates used in the design. Given the uncertainty regarding climate change predictions and the vintage of studies and data used by Shell, a prudent step would be to assess the design using upper limit temperature scenarios as suggested by the Joint Review Panel. As the name implies, upper limit temperature scenarios would be less likely to occur than what has been used by Shell for the design of the project.

Condition N8 requires Shell to provide final detailed design information that incorporates an analysis of the impacts of climate change and variability on permafrost and terrain stability for the Niglintgak facility using potential upper limit temperature scenarios which may occur during the operational life of the facilities. Shell will also provide information about how upper limit temperature scenarios may impact precipitation, rise in sea level, storm surges, ice floes and flood levels, and watercourse crossing designs. We are of the view that government departments such as Environment Canada, Indian and Northern Affairs Canada and Natural Resources Canada should be consulted to benefit from their expertise for the field design.

Air quality issues

Air quality in the North is considered to be of high quality and Northerners are very concerned that it remains that way. Both Environment Canada and the Proponents agreed that existing air quality in the proposed project area is good and, along with other government regulators, emphasized the need to "keep clean areas clean." This principle requires new industrial development to be "planned, constructed and operated in a manner that minimizes the degradation of air quality in these areas."

Air quality issues for the project included project emissions for the pipeline and development fields, monitoring, and greenhouse gases in the context of monitoring climate change. The Joint Review Panel noted that the National Energy Board would be the prime regulator of air emissions from the project and that Environment Canada and the Government of the Northwest Territories would play advisory roles. The Joint Review Panel recognized the National Energy Board's expertise and experience in regulating interprovincial aspects of the oil, gas and electric utility industries, including environmental matters. The Joint Review Panel also recognized the extensive environmental and local knowledge that Environment Canada and the Government of the Northwest Territories can provide.

Air emissions can be related to the project-specific effects of construction, operations, and waste incineration. Air quality impacts can be local to regional in the case of particulate matter and sulphur dioxide, or global in the case of greenhouse gases. Emissions would occur during the construction phase through intermittent flaring during well testing at the Niglintgak field.

Further specific details pertaining to emissions for the pipeline are discussed in Chapter 3 and discussion on air emissions pertaining to facility design is found in Chapter 6.

The Joint Review Panel report indicated that the Proponents' baseline information was compiled from historical data and results of air quality monitoring that was carried out over one year near the communities of Inuvik and Norman Wells, and periodically at the Parsons Lake and Taglu gas fields. The Proponents' monitoring data and other sources indicated that back-ground concentrations of air contaminants are generally below detection levels or applicable guidelines. The one exception that is not below detection levels is ozone; relatively high background levels were monitored in Inuvik and Norman Wells. The Proponents indicated that elevated ozone levels at high latitudes in the northern hemisphere are thought to result from the intrusion of stratospheric ozone. The Proponents stated that all ground-level concentrations of compounds released by the project during operations at the gas fields, the Inuvik Area Facility, and compressor and heater station sites would increase, but would be below those outlined in applicable federal and territorial guidelines at all locations in the production area and along the pipeline corridor.

Environment Canada recommended that the Proponents design and implement suitable air quality monitoring programs with its help. Environment Canada focused its recommendations on pollution prevention and the use of best available technology and best management practices to minimize the degradation of air quality. Further discussion around application of these principles may be found in Chapter 6.

The Dehcho Elders and Harvesters indicated that the project needs to be designed to minimize air quality impacts, with monitoring plans in place to verify the predicted emissions and impacts. Corrective action needs to be taken quickly to avoid impacts upon the land and wildlife from degraded air quality.

Greenhouse gas emissions

Parties were concerned about the impacts of the project on climate change, especially in light of Canada's international efforts under the United Nations Framework Convention on Climate Change and the *Kyoto Protocol*.

Greenhouse gas emissions arising from the project include carbon dioxide, methane and nitrous oxides with each compound having a different climate change potential. During operation, the project would emit greenhouse gases from burning natural gas at combustion related sources such as compressors and methane gas released through normal venting procedures and minor leaks (fugitive emissions). Further specific discussion on air emissions pertaining to facility design is found in Chapter 6.

Alternatives North submitted that the National Energy Board and the Government of Canada have a public interest mandate that requires consideration of greenhouse gas emissions.

Ecology North deemed that high project-specific standards for greenhouse gas emissions based on a robust and strong definition of best available technology and accompanied by penalties in the cases where they do not meet those project standards or targets, would provide the best possible protection in terms of minimizing upstream greenhouse gas emissions associated with the project.

Sierra Club of Canada submitted that we need to specify an actual target and it is not enough to just leave it up to the Proponents. Sierra Club of Canada indicated that the target should at least match the general recommended target in Joint Review Panel recommendation 8-8.

Views of the Board

We understand the importance of clean air in the North and that air quality must be considered in a cumulative manner. We also recognize the need to minimize greenhouse gas emissions resulting from the project. The Joint Review Panel directed several recommendations to us relating to air quality and air emissions. We have addressed air issues through several conditions for the Mackenzie Gas Project. These conditions are focused on the Proponents taking appropriate measures to minimize air emissions and address air quality. We are committed to working collaboratively with Environment Canada and the Government of the Northwest Territories to protect air quality in the North, recognizing the extensive environmental and local knowledge that these agencies can provide.

Conditions N14 and N16 address technologies for reducing emissions, incorporation of best management practices and best available technologies, and facility design. Condition N15 requires the submission of a report evaluating incinerator emissions from camps and station facilities and technologies and practices must be reflected in the waste management plans required by Condition N12. Condition N17 requires Shell to minimize and reduce emissions from flaring. Further specific discussion for these conditions regarding air emissions pertaining to facility design is found in Chapter 6.

Air quality monitoring is part of comprehensive environmental monitoring under an environmental management system. Through environmental management, systems are established to address effects of the project on the environment and of the environment on the project, with the overall goal of minimizing negative impacts. Adaptive management is a systematic process for continually improving management practices by learning from their outcomes.

Environmental monitoring is an important part of environmental management that directly supports adaptive management by observing and evaluating the effects that occur, then changing or adding mitigative measures as appropriate to limit or reverse the environmental effects. Environmental monitoring can include:

- compliance monitoring, to verify that all environmental mitigation is implemented as presented in the Environmental Protection Plan and environmental alignment sheets and that work is in compliance with environmental regulations; and
- effects monitoring, to assess the effects resulting from project-environment interactions and evaluate the effectiveness of approved mitigation measures. This is further discussed in section 3.3.6.

Shell is expected to implement Environmental Protection and Monitoring and Surveillance Programs which include protection of the environment as one of the main goals. A monitoring program may:

- identify any issues or potential concerns that may compromise the protection of the environment;
- include methods for developing measures to prevent or mitigate the impact of the identified issues;
- provide for continued monitoring of sites to evaluate success of mitigative measures undertaken;
- provide a system for implementing additional mitigative measures as necessary; and
- provide a feedback system that allows for adaptation of successful mitigation to future pipeline projects.

Monitoring programs may have specific goals and targets and could include methods for evaluating and interpreting collected data such as air quality or emissions data. Monitoring may include any relevant environmental practices (e.g., vegetation establishment, water quality sampling, waste disposal).

Responsibilities of the National Energy Board regarding monitoring include:

- conducting environmental inspections of facilities, verifying compliance with terms and conditions, and assessing the effectiveness of mitigation;
- monitoring ongoing operation, verifying reclamation and maintenance of the project site to acceptable standards; and
- conducting environmental audits, evaluating environmental management systems and environmental programs.

We generally require the filing of environmental post-construction monitoring reports as a condition of an authorization. The information in monitoring reports should include:

- confirmation of proper implementation of mitigation and reclamation measures used;

- identification of the outstanding environmental issues; and
- discussion of the company's plans for how outstanding issues will be resolved.

Condition N11 requires Shell to submit an Environmental Protection Plan which includes monitoring of activities. Condition N15 includes the requirement for monitoring incinerator emissions.

A commitment to continuous improvement, outlined in Joint Review Panel recommendation 8-6, is expected to be a component of an operator's management system pursuant to paragraph 5(2)(b) of the *Canada Oil and Gas Drilling and Production Regulations*. This is addressed in Condition N11. We are of the view that the commitment to continuous improvement is not limited to greenhouse gas emissions but should apply to all discharges to the environment, which in this case is the atmosphere. Condition N11 also covers the requirements for methods and locations of monitoring.

Condition N16 requires the Proponents to file a report outlining the use of best available technology for station facility construction. Selection of best available technology is the most significant factor in determining achievable air emissions targets. Condition N11 outlines the requirements for an Environmental Protection Plan. The condition requires the Proponents to submit maximum proposed greenhouse gas targets and reduction strategies for air emissions including particulate matter, NOx and greenhouse gases. Condition N11 also addresses other matters from the Joint Review Panel recommendations including employee training, monitoring, public communication, and required consultation with Environment Canada and the Government of the Northwest Territories. With these conditions, we find it acceptable for the Proponents to develop greenhouse gas targets for the project consistent with use of best management practices and in consultation with appropriate government agencies.

Kendall Island Bird Sanctuary

Kendall Island Bird Sanctuary was established in 1961 and is the only protected area in the Mackenzie Delta. It is one of the most significant wetland complexes in North America and the deltaic landscape of the Niglintgak field is a haven for the more than 90 species of birds that migrate to the region annually. The 623 square kilometre Kendall Island Bird Sanctuary provides critical habitat for thousands of songbirds, waterfowl and shore birds that use the area for breeding and staging. Kendall Island Bird Sanctuary has been identified as a Key Habitat Site which is defined as an area that supports at least one percent of the national population of a migratory bird species for any portion of its annual cycle. Kendall Island Bird Sanctuary is considered by Environment Canada to be an important component of Canada's effort to conserve biodiversity. Under the *Migratory Birds Sanctuary Regulations*, Environment Canada has authority over surface developments in Kendall Island Bird Sanctuary and has established a limit of one percent or 600 hectares as the allowable surface disturbance in the Sanctuary for all oil and gas activities. As a result, Environment Canada encourages project design considerations that result in the least possible long-term impact on habitat. To reduce impacts on migratory birds, Environment Canada has indicated that it may restrict or apply special conditions to activities such as construction, operation, monitoring and decommissioning in Kendall Island Bird Sanctuary during the period between May through October when the Sanctuary is occupied by birds. Furthermore, Environment Canada has indicated its preference for Shell to construct above-ground flow lines within Kendall Island Bird Sanctuary. In final argument Shell indicated it is committed to using above-ground flow lines to reduce surface disturbance.

Activity and facility noise levels

The Niglintgak anchor field is located in Kendall Island Bird Sanctuary which is a federally protected area managed for the conservation of migratory birds and protection of habitat for northern-breeding birds. Shell holds Significant Discovery Licence SDL019 that grants it subsurface oil and gas rights. Environment Canada has regulatory authority for activities within Kendall Island Bird Sanctuary, and will issue permit conditions governing noise emissions from development under the *Migratory Bird Sanctuary Regulations*. Environment Canada and the Proponent have both agreed to follow Alberta's Energy Resources Conservation Board Directive 038 for noise regulation. There is currently no legislation or standard in the Northwest Territories governing noise emissions.

Alberta's Energy Resources Conservation Board Directive 038 indicates a recommended noise target for remote areas even if no human residences are present. This is considered the "business as usual" requirement. The Directive has provisions to change the typical target when there are unique circumstances, including if an area is "pristine"—a pure, natural area that might have dwellings but no industrial presence. Environment Canada recommends continuous noise emissions, as measured from the fence line of the facility, not exceed Alberta's Energy Resources Conservation Board Directive 038 "best practices" permissible sound levels during the period from 10 May to 30 September when migratory birds are present in the Sanctuary because Kendall Island Bird Sanctuary is considered a pristine area.

Shell has indicated the primary noise generation sources at the Niglintgak facilities such as compressors, power generation equipment and aerial coolers, will be designed so that the resulting sound levels will be below the maximum permissible noise levels provided in Alberta's Energy Resources Conservation Board Directive 038. The Proponents agree with Environment Canada that the appropriateness, both technically and economically, of the proposed regulatory requirement will be further informed when detailed design progresses and before finalizing Environment Canada permit conditions. For facilities in Kendall Island Bird Sanctuary, the Proponents will continue to evaluate and apply noise mitigation options beyond those required to meet the "business as usual" interpretation of Alberta's Energy Resources Conservation Board Directive 038, provided these are practical. Shell is expected to provide detailed engineering and noise modeling results to Environment Canada.

Shell plans to schedule activities to avoid critical migratory bird nesting periods where practical. Because the Niglintgak field is relatively shallow at 1000 metres, drilling times can be reduced compared to Taglu and Parsons Lake. Shell is proposing a winter-only drilling program, and completions for most wells during winter months over three to four consecutive years. However, two well completions are proposed by Shell in the intervening summer seasons. Other construction activities such as barging, bathymetric work, dredging, transporting and setting of the gas conditioning facility would also occur in summer.

Both the Proponents and Environment Canada shared the view that requirements for noise regulation in Kendall Island Bird Sanctuary, both for the National Energy Board and migratory bird sanctuary requirements, can only be finalized after detailed engineering and design work is completed, after the noise impact analysis is prepared, and after discussions between the parties. Environment Canada will continue to work with the National Energy Board, Proponents and other regulators on issues related to noise in Kendall Island Bird Sanctuary. Shell indicated that it is committed to adhering to requirements in Alberta's Energy Resources Conservation Board Directive 038, as well as continuing evaluation of noise mitigation through detailed engineering and planning in order to arrive at practical solutions to concerns raised by Environment Canada.

Views of the Board

We agree with Environment Canada that regulating impacts of noise in a nationally protected bird sanctuary requires special consideration and application of best practices and the use of best available technology with the intent of "continuous improvement of pipeline safety and environmental protection". Condition N9 applies to regulating noise in the Niglintgak field and is intended to minimize disturbance from facilities inside Kendall Island Bird Sanctuary. The Condition requires meeting Alberta's Energy Resources Conservation Board Directive 038 "business as usual" standard with allowance for achieving the more stringent standard that Environment Canada recommended to the Joint Review Panel and the Joint Review Panel accepted. There is flexibility built in to the condition to adjust the standard as informed by final detailed engineering, an independently verified noise impact analysis report, and continued consultation for final determination of the fence line, which is the measurement base for a distance-based regulatory standard.

Overall footprint

Shell's preliminary design anticipates less than ten hectares of total new disturbance within Kendall Island Bird Sanctuary. This new disturbance includes the entire gas conditioning facility, the three well pads, the above-ground flow lines and modifications to the pre-existing Camp Farewell and a stockpile site.

To prepare a level set-down site for the gas conditioning facility, up to 50 000 cubic metres of silt, mud and other material would need to be excavated. The majority of material would be removed in the winter and, if required, some minor dredging or the removal of mud from the channel floor would occur the following summer. One reason Shell chose the proposed location for the gas conditioning facility is that the site is underlain by permafrost, which provides several options for excavation of the area. Shell's preferred approach is a combination of winter mechanical excavation and summer dredging.

Shell reduced the scope of dredging and made design modifications to avoid or reduce dredging in the delta area. As a result, the gas conditioning facility barge draught was reduced from 1.9 to 1.5 metres, the location was moved outside of Little Kumak Channel, and Shell committed to schedule its dredging activities to avoid impacts on the beluga harvest.

Shell's current plan is to deposit the excavated material adjacent to the gas conditioning facility site within Kendall Island Bird Sanctuary. Environment Canada indicated that it would not allow placement of the excavated stockpile within Kendall Island Bird Sanctuary if it were to result in the permanent loss of habitat. The best placement for these materials will be finalized by Shell after discussions with regulators and stakeholders, including Environment Canada, to reduce the impact on local wildlife.

To reduce the level of permanent disturbance, Shell plans to locate the well pads at previously drilled well locations and would incorporate as much of the previously disturbed land as feasible. Shell also plans to augment the steel pads with temporary ice pads for the drilling equipment. The ice pads would not leave a permanent footprint once drilling is complete.

Access to the field would be by winter road or helicopter from Camp Farewell. Shell does not propose permanent access.

In addition to the permanent footprint, Shell estimates a 17.5 hectare temporary footprint or land disturbed during the construction of ice pads and an ice road.

The disposal of drilling waste is not permitted within the Sanctuary, so Shell's initial plan was to dispose of these drill cuttings in a sump located outside of Kendall Island Bird Sanctuary. However, Shell has since adopted its alternative method which is to transport the cuttings out of the Northwest Territories to an approved landfill in Alberta or British Columbia.

In developing its Development Plan Application, Shell met with a variety of stakeholders including Aboriginal peoples and other Northerners, various government representatives, communities and oil and gas companies. Information from these discussions was used to develop and refine Shell's plans. Examples of community-driven design changes to the Niglintgak Project were discussed during final argument and include reducing overall footprint by locating drilling sites at pre-disturbed locations, preferentially scheduling drilling and construction activities in the winter and using above-ground flow lines to reduce surface disturbance.

Dredging activities will occur within Kendall Island Bird Sanctuary and Environment Canada will not permit the spoil to be placed on undisturbed terrestrial habitat within Kendall Island Bird Sanctuary. Environment Canada requested that we require that Shell's plan for excavation and dredging at the site of the gas conditioning facility at Niglintgak describe the potential impacts associated with dredging, and include spoil management and the site-specific mitigation measures to address adverse impacts.

To address Joint Review Panel Report recommendation 9-9 regarding dredging and excavation of the set-down location for the barge-based gas conditioning facility, we proposed Condition N10 on 9 March 2010. During final argument, Environment Canada suggested that the condition be expanded to require a dredging spoil management plan. Environment Canada and a number of other parties indicated that consultation needed to be defined or clarified. Shell asked that the timing of the condition be adjusted so that the dredging plan is not linked to well pad construction.

Views of the Board

We have considered the various comments regarding Condition N10 and the condition has been amended to require a dredging spoil management plan, to clarify requirements for consultation and to adjust the timing so it is no longer linked to construction of the well pads. The best placement of dredging materials will be finalized by Shell after consultation with regulators and stakeholders, including Environment Canada, to reduce the impact on local wildlife. Environment Canada has authority over activities in Kendall Island Bird Sanctuary under the regulations.

4.3 Taglu

4.3.1 Design of the Taglu facilities

The Taglu field lies above the Arctic Circle near the northern edge of the Mackenzie Delta. Currently the largest onshore gas field ever discovered in the Mackenzie Delta, it is estimated that Taglu contains nearly three trillion cubic feet of recoverable natural gas—enough to fuel all the gas-heated homes in Canada for three years.

The Taglu field is 120 kilometres northwest of Inuvik and 70 kilometres west of Tuktoyaktuk close to the Beaufort Sea. A single development site is proposed near the middle of the field, close to the confluence of the Kuluarpak and Harry channels (see Figure 4-8).

The reservoir reaches under Richards Island and, like the proposed Niglintgak field fifteen kilometres to the southwest, much of the reservoir stretches underneath Kendall Island Bird Sanctuary, a key habitat site for local shore birds and waterfowl. The Taglu field is found within the same geological formation as the Niglintgak field—the Reindeer Sands, a formation that is known to be poorly consolidated.

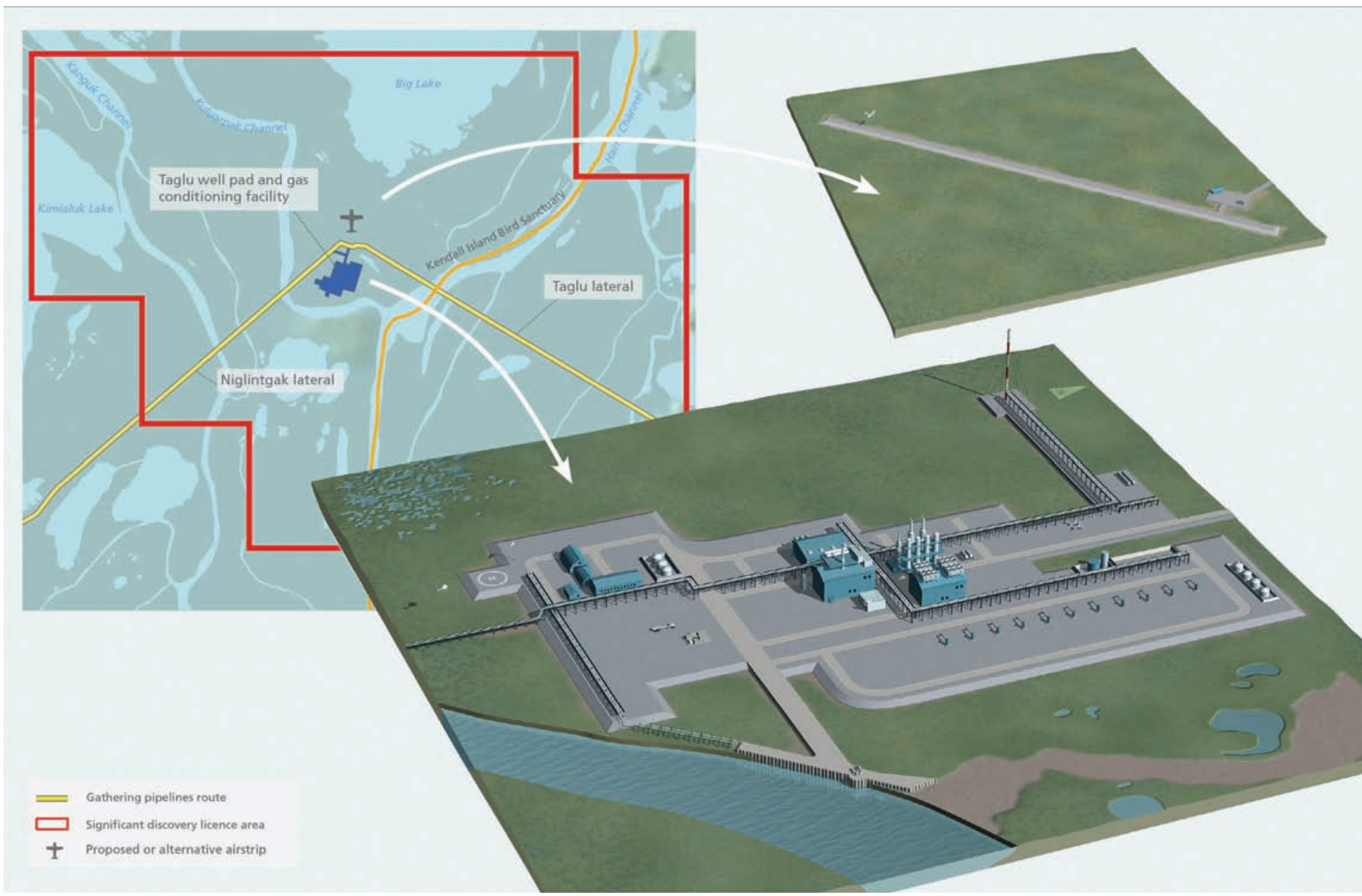


Figure 4-8

Taglu production facilities

Imperial Oil Resources Limited (Imperial) filed a Development Plan for the Taglu field under section 5.1 of the *Canada Oil and Gas Operations Act*. The proposed production facilities include:

- up to 15 production wells drilled from a single pad;
- one or two disposal wells;
- a gas conditioning facility;
- associated infrastructure including pads and foundations;
- a barge landing site;
- an airstrip and helicopter pad;
- buildings; and
- a water treatment system.

The well pad and the gas conditioning facility would be located adjacent to each other (see Figure 4-9).

Construction is planned to take place from 2014 to 2018 with operations commencing in 2018. The cost for developing the field is estimated to be $2,550 million with an estimated average operations and maintenance expenditure of $26 million per year for the period 2019 to 2023.

Imperial proposes to start constructing winter roads and moving equipment onto the site in 2014. Drilling would start in the winter of 2016/17 with production beginning in the summer of 2018. An overview of the construction schedule is provided in Table 4-3.

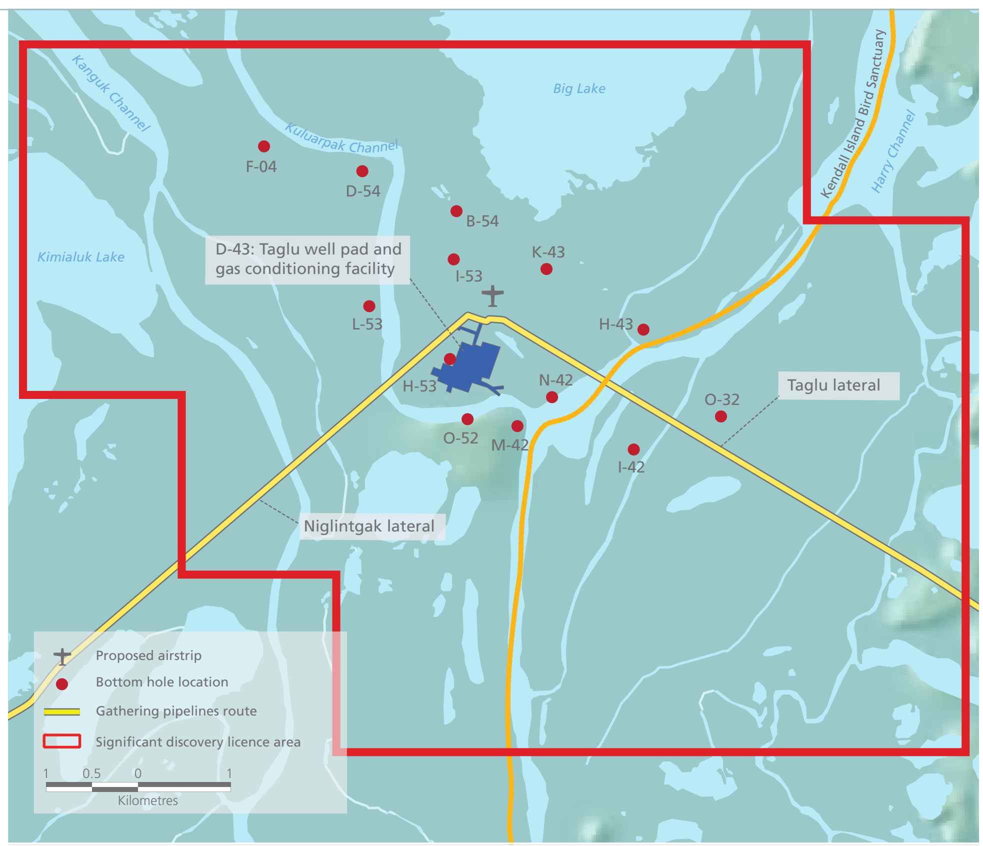


Figure 4-9

Taglu field map

Wells and well pads

Imperial plans to directionally drill 10 to 15 production wells and one or two disposal wells from a single well pad. Figure 4-9 shows the plan view of 11 potential locations of production wells and the preliminary locations of two disposal wells. This well pad would be located near the centre of the reservoir just inside the east boundary of Kendall Island Bird Sanctuary. Once production begins and additional reservoir data becomes available, Imperial may shift the current locations of its contingent wells to optimize production of the field. Imperial plans to build its well pad facilities on elevated pile foundations. Imperial's depletion plan for the Taglu field shows that some wells would incorporate commingled production.

The well pad would be either gravel filled with a matted and fluid sealed surface or a steel deck supported by steel piles. Gravel for the well pad and other facilities will come from existing borrow sites at Yaya Lakes (see Figure 4-1).

Flow lines

The wellheads would be located beneath the surface of the well pad in a long cellar. This cellar would provide personnel with easy access to any well for drilling or servicing with a conventional rig and provides a heated space for the flow lines and other support systems.

Gas would travel above ground on a pipe rack via insulated and heat-traced flow lines to a manifold facility and on to the gas conditioning facility. The manifold facility would direct the flow from each well to either a production line for processing or a line for testing.

Gas conditioning facility

Reservoir fluids would be processed at the gas conditioning facility to remove free water and natural gas liquids and to dehydrate and chill the gas to meet the specifications of the gathering pipeline. Although the gas would not need to be compressed initially, the facility would be designed so that it could do so if compression were needed. Natural gas liquids and gas volumes would be measured and transported to the gathering system and produced water would be injected about one kilometre below the surface into the disposal well.

Imperial would install a safety system in the gas conditioning facility for blowdown and pressure relief to lower the gas conditioning facility pressure and to direct hydrocarbon fluids to the flare system in a safe and controlled manner, when required.

The average daily design capacity for the Taglu gas conditioning facility would be 12.6 Mm^3/d (445 MMcf/d). The facility would be designed to handle a peak maximum design capacity of 14.5 Mm^3/d (510 MMcf/d), about 15 percent above average daily rates, to accommodate scheduled maintenance and production downtime among the development fields.

Infrastructure

The following infrastructure would be provided to support construction, operations and maintenance activities and to access the site:

- pads and foundations;
- barge landing site;
- airstrip and helicopter pad;
- roads;
- living quarters;
- control room;
- office and administration buildings;
- domestic water system;
- sewage treatment system;
- storage; and
- telecommunication facilities.

Barging

Currently, Imperial plans to enter the East Channel of the Mackenzie River through Kittigazuit Bay, where there is a historical shipping channel. Vessel movement through Kittigazuit Bay, which is part of the Kugmallit Bay 1A Beluga Management Zone, would be scheduled in August following prime beluga whale activity in the area. Preliminary engineering indicates dredging is not required in Kittigazuit Bay to successfully transport these modules (see Figure 4-1).

Third-party use and future expansion

The Taglu production facilities are designed to produce and process the Taglu volumes predicted for the Taglu field, however, the gas conditioning facility could accommodate or be expanded to accept additional production volumes. This would depend on the timing and volume of the additional gas, the gas properties, and acceptable commercial arrangements. The well pad may also be extended, but at this point, Imperial does not have a need to extend the well pad.

Table 4-3

Taglu construction highlights schedule

Activity	Season and year
Construct winter roads, gas conditioning facility pad, drilling pad and airstrip	Winter 2014/15
Compact gravel pads and transport construction equipment, materials and fuel	Summer 2015
Construct the dock and complete construction of gravel pads for gas conditioning facility, drilling pad and completions	Winter 2015/16
Barge and install small gas conditioning facility modules	Summer 2016
Begin drilling program	Winter 2016/17
Barge and install large gas conditioning facility modules	Summer 2017
Begin well completions	Winter 2017/18
Startup operations and production	Summer 2018

Views of the Board

We find Imperial's general approach, conceptual design and plan proposed for the Taglu field to be satisfactory. We note that new geological and reservoir data acquired during drilling and production will be used by Imperial to determine if additional faulting and compartmentalization exists and whether any contingent wells would be required. Condition T17 requires that Imperial file an updated resource management plan with the National Energy Board within 18 months after production commences or prior to the drilling of contingent wells.

Condition T18 requires Imperial to comply with the *2009 Draft Spacing Requirements* in order to protect the correlative rights of any adjacent subsurface rights holders. Imperial's preliminary production well locations for the Taglu field comply with the *2009 Draft Spacing Requirements*.

We are of the view that Imperial's conceptual plan whereby some wells would utilize commingled production to achieve maximum gas recovery is acceptable. Commingled production is production of oil and gas from more than one pool or zone through a common well-bore without separate measurement of the production from each pool or zone. The National Energy Board will consider commingled production on an individual well basis during drilling and production operations in accordance with section 66 of the *Canada Oil and Gas Drilling and Production Regulations.*

Condition T30 stipulates that the approval of the Development Plan for the Taglu Field under subsection 5.1(4) of the *Canada Oil and Gas Operations Act* is subject to the Minister of Indian Affairs and Northern Development Canada providing confirmation that Imperial has satisfactorily met the Benefits Plan requirements of section 5.2 of the *Canada Oil and Gas Operations Act*.

4.3.2 Development plan issues

During the hearing, Imperial discussed the following issues associated with developing the Taglu field:

- design issues related to permafrost, subsidence, flood protection and climate change;
- air quality issues and greenhouse gas emissions;
- activity and facility noise levels and environmental footprint in Kendall Island Bird Sanctuary; and
- management of spoil from dredging operations.

The design of the development field facilities is linked to the physical environment. The Taglu field is located in an active delta floodplain, with permafrost under parts of the proposed development. Facility locations are periodically flooded and the effects of flooding are a safety and facility design priority.

Permafrost and design issues

The Taglu field is located within a zone of intermediate discontinuous permafrost. As with the Niglintgak field, if the permafrost thaws, the landscape may be permanently altered. Imperial has proposed using a number of different types of design techniques to prevent the permafrost from thawing beneath its production facilities. One of these methods would be to separate each well by 18 metres. This interwell spacing is similar to the 15 metres Shell has adopted for its wells in Niglintgak. As previously mentioned, wellheads and flow lines would be located in a heated "cellar" below the well pad. To preserve the permafrost, Imperial plans to include an active refrigeration system with the wellbore conductor in their wellsite facility. This system keeps the permafrost from melting by chilling the ground below the wellsite, to about 37 metres deep, during drilling and production. Well pad facilities and flow lines would be constructed on elevated pile foundations to prevent permafrost damage and to avoid seasonal floods during operations.

Views of the Board

We are satisfied with Imperial's approach to addressing permafrost integrity with respect to the Taglu development. We note that all Taglu wells would be located on one well pad and that warm fluids would flow through those wellbores during drilling and production. Condition T2 requires the interwell spacing on the well pad to be no less than 15 metres unless Imperial utilizes mitigation measures approved by the National Energy Board. It is important for safety and environmental protection reasons that the permafrost thaw bulbs around wellbores do not coalesce.

Subsidence

The Taglu reservoir is within the same geological formation as the Niglintgak reservoir, the Reindeer Sands Formation. This formation of poorly consolidated sands from the Early Tertiary Period is nearly 60 million years old. As with Niglintgak, these sands could crumble and partially collapse, or subside, as gas is withdrawn from the field.

Imperial estimates the maximum amount of subsidence resulting from gas extraction would range from 0.20 to 0.42 metres. The deepest subsidence would be a low drainage area to the north of the proposed Taglu gas conditioning facility towards Big Lake. Imperial indicated that the predicted subsidence would not materially change the drainage patterns within the affected area and no "subsidence dish" would be formed.

Subsidence may also occur if the permafrost thaws as a result of climate change. This effect was estimated by Imperial to be much smaller, by an order of magnitude, compared to extraction-induced subsidence described above.

Imperial is considering using a three-dimensional global positioning system survey method to monitor and measure accumulated ground subsidence on the Taglu facilities. Details of such a program are still being assessed by Imperial.

Joint Review Panel Report recommendation 6-10 asked us to require Imperial to file with the National Energy Board a program to monitor subsidence and flooding due to hydrocarbon extraction for the Taglu field. In a letter dated 28 January 2010 responding to the Joint Review Panel Report recommendations the Proponents submitted to us that recommendation 6-10 be rejected as our proposed Condition 7 (dated 5 February 2007) for the Taglu field was sufficient. In the Proponents' view, it was unlikely to be technically feasible to monitor flooding due to hydrocarbon extraction since it would be very difficult to differentiate flooding due to hydrocarbon extraction from natural flooding. The Proponents said that flooding at Taglu is a natural and annual occurrence.

In argument, Environment Canada suggested the following revisions to the condition:

- clarify and enhance consultation;
- include the monitoring of flooding due to subsidence in order to determine the loss of nesting habitat;
- include monitoring of reservoir compaction in order to differentiate project-induced subsidence from natural changes in ground elevation; and
- allow the use of the most appropriate technology at the time including airborne and remote sensing techniques.

Views of the Board

We are of the view that it will be important to monitor and confirm Imperial's estimates of subsidence due to hydrocarbon extraction because the Taglu field is located inside Kendall Island Bird Sanctuary and is one of the first proposed developments in the Mackenzie Delta where subsidence due to gas extraction is predicted to occur. Condition T3 requires Imperial to submit a program to measure and monitor accumulated subsidence and to monitor flooding for the life of the field.

Environment Canada indicated monitoring of reservoir compaction was needed to differentiate project-induced subsidence from natural changes in ground elevation. Condition T3 requires that elevation benchmarks be located outside of the projected gas-extraction-subsidence-area. We believe that these elevation benchmarks will act as control or reference points to provide data to estimate natural subsidence. We are not persuaded that monitoring of reservoir compaction is necessary.

We agree with Environment Canada that the condition should allow for the use of the most appropriate technology at the time. Condition T3 has been amended to reflect this.

We agree with Environment Canada's suggestion to clarify and enhance consultation and Condition T3 has been revised in this regard.

Climate change and flood protection

The Taglu reservoir is found under low lying terrain with a mean elevation of 1.5 to 1.7 metres above sea level. Imperial expects the site to be periodically flooded during spring runoff and later in the season by storm surges from the nearby Beaufort Sea. As a result, Imperial considered the following factors in the design height of the Taglu pad:

- maximum flood level;
- maximum wave height;
- rise in sea level; and
- surface effect of gas extraction induced subsidence on flood depth.

These factors and a safety margin of 0.2 metres were used by Imperial to design a well pad and facility foundation height of 3.1 metres (see Figure 4-10).

Imperial plans to monitor the facilities and implement adaptive management and contingency plans as needed. If Imperial's design height is too low, it is possible to accommodate higher water levels by adding earthen fill material to certain areas of the site to protect them from flooding. In addition, select pile-mounted facilities, such as modules and flow lines, could be raised if flooding becomes a problem. Furthermore, protective measures, such as bumper posts or strengthened pipe supports could be used to protect those parts of the Taglu facility that would be at risk from ice floes.

Although there would be a risk that flood levels during the 30 year operating life of the Taglu field could exceed the design height, Imperial considers this risk to be relatively low. However, if water levels reach an extreme height, it would be possible to shut down production. Onsite activity could cease and some or all personnel would be removed from the site.

Warming of the global and regional climate could raise sea levels and affect weather patterns. The Taglu field is located in the low-lying Mackenzie Delta near the Beaufort Sea. We heard concerns that seasonal flooding and storm surges could affect the facilities during the life of the project. The Taglu airstrip could also be subject to flooding, but in that event workers and equipment would be brought to the site by helicopter. The companies provided evidence that the facilities would be high enough to protect them from storm surges and flooding even if sea levels were to rise.

As with the Niglintgak field, the Sierra Club of Canada was concerned about the lack of peer-reviewed research publications on the effects of climate change, specifically for the Mackenzie Delta over the 30 year life span that was used by Imperial in the design of the Taglu field facilities. The Sierra Club of Canada stated that in designing infrastructure in the Mackenzie Delta there is uncertainty as to the effects of climate change, including the effects on the permafrost, the rise in sea level and the degree of flooding.

The Joint Review Panel was generally satisfied that Imperial had taken climate change into account in its design. Nevertheless the Joint Review Panel recommended that the National Energy Board add a condition to the certificate which would require Imperial to file final design plans that incorporate further analysis of the impacts of climate change on permafrost and terrain stability over the design life of the project and post-abandonment. The Joint Review Panel was of the view that this analysis should be conducted for a series of representative locations, conditions and terrain types and should incorporate climate variability, in particular, upper limit temperature scenarios to account for the range of future temperature conditions, including variability and extremes, and the impact of this variability on stream flow regimes. The Joint Review Panel added that the results should be incorporated into monitoring, mitigation and adaptive management plans. The Joint Review Panel thought that further design analysis should be provided to other appropriate regulators in sufficient time for review and to provide input to the National Energy Board.

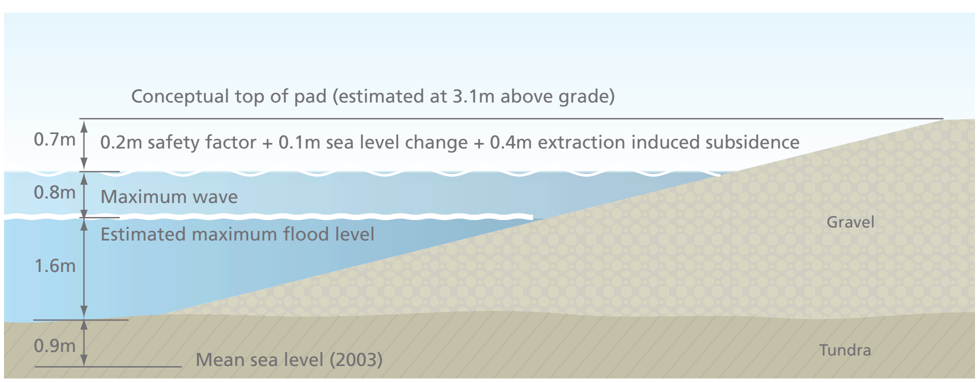
The Taglu field would produce natural gas from relatively shallow underground formations. As the natural gas is removed, the ground could settle by up to almost half a metre due to the removal of natural gas. This possibility was taken into account in the design of the facilities. Imperial also indicates that climate change is implicit in the way it completed its modeling for the facility and pipeline design specifically; that is, trends in climate warming regionally have been incorporated into the modeling.

Indian and Northern Affairs Canada suggested in final argument that the Proponents should demonstrate how upper limit temperature scenarios have been considered in their design.

Further specific discussion on climate change regarding project design is found in Chapter 6.

Figure 4-10

Design height for top of Taglu well pad and facility foundations



Note: Preliminary design. Dimensions shown might be adjusted as design is developed.

Views of the Board

We are satisfied with Imperial's climate change rates used in the design. Given the uncertainty regarding climate change predictions and the vintage of any climate change studies or data used by Imperial, a prudent step would be to assess the design using upper limit temperature scenarios as suggested by the Joint Review Panel. As the name implies, upper limit temperature scenarios would be less likely to occur than what has been used by Imperial for the design of the project.

Condition T7 requires Imperial to provide final detailed design information that incorporates an analysis fo the impacts of climate change and variability on permafrost and terrain stability for the Taglu facility using potential upper limit temperature scenarios which may occur during the operational life of the facilities. Imperial will also provide information about how upper limit temperature scenarios may impact precipitation, rise in sea level, storm surges, ice floes and flood levels. We are of the view that government departments such as Environment Canada, Indian and Northern Affairs Canada and Natural Resources Canada should be consulted to benefit from their expertise for the field design.

Air quality issues

Air quality in the North is considered to be of high quality and Northerners are very concerned that it remains that way. Both Environment Canada and the Proponents agreed that existing air quality in the proposed project area is good and, along with other government regulators, emphasized the need to "keep clean areas clean." This principle requires new industrial development to be "planned, constructed and operated in a manner that minimizes the degradation of air quality in these areas."

Air quality issues for the project included project emissions for the pipeline and development fields, monitoring, and greenhouse gases in the context of monitoring climate change. The Joint Review Panel noted that the National Energy Board would be the prime regulator of air emissions from the project and that Environment Canada and the Government of the Northwest Territories would play advisory roles. The Joint Review Panel recognized the National Energy Board's expertise and experience in regulating interprovincial aspects of the oil, gas and electric utility industries, including environmental matters. The Joint Review Panel also recognized the extensive environmental and local knowledge that Environment Canada and the Government of the Northwest Territories can provide.

Air emissions can be related to the project-specific effects of construction, operations, and waste incineration. Air quality impacts can be local to regional in the case of particulate matter and sulphur dioxide, or global in the case of greenhouse gases. Emissions would occur during the construction phase through intermittent flaring during well testing at the Taglu field.

Further specific details pertaining to emissions for the pipeline are discussed in Chapter 3 and discussion on air emissions pertaining to facility design is found in Chapter 6.

The Joint Review Panel report indicated that the Proponents' baseline information was compiled from historical data and results of air quality monitoring that was carried out over one year near the communities of Inuvik and Norman Wells, and periodically at the Parsons Lake and Taglu gas fields. The Proponents' monitoring data and other sources indicated that background concentrations of air contaminants are generally below detection levels or applicable guidelines. The one exception that is not below detection levels is ozone; relatively high background levels were monitored in Inuvik and Norman Wells. The Proponents indicated that elevated ozone levels at high latitudes in the northern hemisphere are thought to result from the intrusion of stratospheric ozone. The Proponents stated that all ground-level concentrations of compounds released by the project during operations at the gas fields, the Inuvik Area Facility, and compressor and heater station sites would increase, but would be below those outlined in applicable federal and territorial guidelines at all locations in the production area and along the pipeline corridor.

Environment Canada recommended that the Proponents design and implement suitable air quality monitoring programs with its help. Environment Canada focused its recommendations on pollution prevention and the use of best available technology and best management practices to minimize the degradation of air quality. Further discussion around application of these principles may be found in Chapter 6.

The Dehcho Elders and Harvesters indicated that the project needs to be designed to minimize air quality impacts, with monitoring plans in place to verify the predicted emissions and impacts. Corrective action needs to be taken quickly to avoid impacts upon the land and wildlife from degraded air quality.

Greenhouse gas emissions

Parties were concerned about the impacts of the project on climate change, especially in light of Canada's international efforts under the United Nations Framework Convention on Climate Change and the *Kyoto Protocol*.

Greenhouse gas emissions arising from the project include carbon dioxide, methane and nitrous oxides with each compound having a different climate change potential. During operation, the project would emit greenhouse gases from burning natural gas at combustion related sources such as compressors and methane gas released through normal venting procedures and minor leaks (fugitive emissions). Further specific discussion on air emissions pertaining to facility design is found in Chapter 6.

Alternatives North submitted that the National Energy Board and the Government of Canada have a public interest mandate that requires consideration of greenhouse gas emissions.

Ecology North deemed that high project-specific standards for greenhouse gas emissions based on a robust and strong definition of best available technology and accompanied by penalties in the cases where they do not meet those project standards or targets, would provide the best possible protection in terms of minimizing upstream greenhouse gas emissions associated with the project.

Sierra Club of Canada submitted that we need to specify an actual target and it is not enough to just leave it up to the Proponents. Sierra Club of Canada indicated that the target should at least match the general recommended target in Joint Review Panel recommendation 8-8.

Views of the Board

We understand the importance of clean air in the North and that air quality must be considered in a cumulative manner. We also recognize the need to minimize greenhouse gas emissions resulting from the project. The Joint Review Panel directed several recommendations to us relating to air quality and air emissions. We have addressed air issues through several conditions for the Mackenzie Gas Project. These conditions are focused on the Proponents taking appropriate measures to minimize air emissions and address air quality. We are committed to working collaboratively with Environment Canada and the Government of the Northwest Territories to protect air quality in the North, recognizing the extensive environmental and local knowledge that these agencies can provide.

Conditions T13 and T15 address technologies for reducing emissions, incorporation of best management practices and best available technologies, and facility design. Condition T14 requires the submission of a report evaluating incinerator emissions from camps and station facilities and technologies and practices must be reflected in the waste management plans required by Condition T11. Condition T16 requires Imperial to minimize and reduce emissions from flaring. Further specific discussion for these conditions regarding air emissions pertaining to facility design is found in Chapter 6.

Air quality monitoring is part of comprehensive environmental monitoring under an environmental management system. Through environmental management, systems are established to address effects of the project on the environment and of the environment on the project, with the overall goal of minimizing negative impacts. Adaptive management is a systematic process for continually improving management practices by learning from their outcomes.

Environmental monitoring is an important part of environmental management that directly supports adaptive management by observing and evaluating the effects that occur, then changing or adding mitigative measures as appropriate to limit or reverse the environmental effects. Environmental monitoring can include:

- compliance monitoring, to verify that all environmental mitigation is implemented as presented in the Environmental Protection Plan and environmental alignment sheets and that work is in compliance with environmental regulations; and
- effects monitoring, to assess the effects resulting from project-environment interactions and evaluate the effectiveness of approved mitigation measures. This is further discussed in section 3.3.6.

Imperial is expected to implement Environmental Protection and Monitoring and Surveillance Programs which include protection of the environment as one of the main goals. A monitoring program may:

- identify any issues or potential concerns that may compromise the protection of the environment;
- include methods for developing measures to prevent or mitigate the impact of the identified issues;
- provide for continued monitoring of sites to evaluate success of mitigative measures undertaken;
- provide a system for implementing additional mitigative measures as necessary; and
- provide a feedback system that allows for adaptation of successful mitigation to future pipeline projects.

Monitoring programs may have specific goals and targets and could include methods for evaluating and interpreting collected data such as air quality or emissions data. Monitoring may include any relevant environmental practices (e.g., vegetation establishment, water quality sampling, waste disposal).

Responsibilities of the National Energy Board regarding monitoring include:

- conducting environmental inspections of facilities, verifying compliance with terms and conditions, and assessing the effectiveness of mitigation;
- monitoring ongoing operation, verifying reclamation and maintenance of the project site to acceptable standards; and
- conducting environmental audits, evaluating environmental management systems and environmental programs.

We generally require the filing of environmental post-construction monitoring reports as a condition of an authorization. The information in monitoring reports should include:

- confirmation of proper implementation of mitigation and reclamation measures used;
- identification of the outstanding environmental issues; and
- discussion of the company's plans for how outstanding issues will be resolved.

Condition T10 requires Imperial to submit an Environmental Protection Plan which includes monitoring of activities. Condition T14 includes the requirement for monitoring incinerator emissions.

A commitment to continuous improvement, outlined in Joint Review Panel recommendation in 8-6, is expected to be a component of an operator's Management system pursuant to paragraph 5(2)(b) of the *Canada Oil and Gas Drilling and Production Regulations*. This is addressed in Condition T10. We are of the view that the commitment to continuous improvement is not limited to greenhouse gas emissions but should apply to all discharges to the environment, which in this case is the atmosphere. Condition T10 also covers the requirements for methods and locations of monitoring.

Condition T15 requires the Proponents to file a report outlining the use of best available technology for station facility construction. Selection of best available technology is the most significant factor in determining achievable air emissions targets. Condition T10 outlines the requirements for an Environmental Protection Plan. The condition requires the Proponents to submit maximum proposed greenhouse gas targets and reduction strategies for air emissions including particulate matter, NOx and greenhouse gases. Condition T10 also addresses other matters from the Joint Review Panel recommendations including employee training, monitoring, public communication, and required consultation with Environment Canada and the Government of the Northwest Territories. With these conditions, we find it acceptable for the Proponents to develop greenhouse gas targets for the project consistent with use of best management practices and in consultation with appropriate government agencies.

Environmental footprint in Kendall Island Bird Sanctuary

The proposed site of the Taglu development is located near the meeting of the Kuluarpak and Harry channels of the Mackenzie River, and it lies within Kendall Island Bird Sanctuary. As discussed previously, Environment Canada has regulatory authority over the surface of the Sanctuary and has determined that the maximum allowable surface disturbance related to all oil and gas activities within Kendall Island Bird Sanctuary should be no more than one percent of the Sanctuary or 600 hectares. Environment Canada expressed concern with not only the size of the area being disturbed but also with Imperial's plan for continuous drilling and year-round activity. The estimated total area of surface disturbance is approximately 30 hectares, representing 0.05 percent of all of Kendall Island Bird Sanctuary. All production wells would be drilled from the same well pad using directional drilling techniques. This helps to reduce the overall footprint of the development. The well pad is likely to be located just inside the eastern boundary of Kendall Island Bird Sanctuary, just west of the existing D-43 well site (see Figure 4-9). The initial drilling program would occur uninterrupted for about 16 months, with well completions to follow. Imperial is proposing a development plan which is flexible enough to accommodate contingencies that could arise during detailed design, construction and operation of the Taglu field.

The Imperial project management team will continue to look for opportunities to further reduce the footprint of the Taglu development in Kendall Island Bird Sanctuary. For example, Imperial will look at the use of existing disturbed space adjacent to the development site, being the D-43 well site pad and connecting road. The project's engineering team is also investigating the merits of using a wet gas metering system instead of the test separator system in an effort to reduce footprint. The project will also consider tankage requirements for fuel needs, as there may be opportunities for offsite staging, as well as the fabrication and construction of the gas conditioning facilities modules. Imperial hopes that by implementing options such as these, the Taglu footprint could be reduced by approximately 10 percent of the current footprint estimate.

Activity and facility noise levels

The Taglu anchor field is located in Kendall Island Bird Sanctuary which is a federally protected area managed for the conservation of migratory birds and protection of habitat for northern-breeding birds. Imperial holds Significant Discovery Licence SDL063 that grants it subsurface oil and gas rights. Environment Canada has regulatory authority for activities within Kendall Island Bird Sanctuary, and may issue permit conditions governing noise emissions from development under the *Migratory Bird Sanctuary Regulations*. Environment Canada and Imperial have both agreed to follow Alberta's Energy Resources Conservation Board Directive 038 for noise regulation. This provides a solid basis for noise regulation that currently does not exist in the Northwest Territories, in other words, there is currently no legislation or standard in the Northwest Territories governing noise emissions.

Alberta's Energy Resources Conservation Board Directive 038 indicates a recommended noise target for remote areas even if no human residences are present. This is considered the "business as usual" requirement. The Directive has provisions to change the typical target when there are unique circumstances, including if an area is "pristine"—a pure, natural area that might have dwellings but no industrial presence. Environment Canada is recommending continuous noise emissions, as measured from the fence line of the facility, not exceed the Alberta's Energy Resources Conservation Board Directive 038 "best practices" permissible sound levels during the period from 10 May to 30 September when migratory birds are present in the Sanctuary because Kendall Island Bird Sanctuary is considered a pristine area.

Imperial intends to design all equipment at the Taglu gas conditioning facility so that the resulting sound levels would be below the maximum permissible noise levels provided in Alberta's Energy Resources Conservation Board Directive 038. This would include primary sources of noise generation such compressors, power generation equipment and aerial coolers. Environment Canada has also indicated that Imperial has committed to evaluating and applying noise mitigation options beyond those required to meet Alberta's Energy Resources Conservation Board Directive 38 minimum standards provided that such options are practical. Environment Canada is awaiting detailed engineering and noise modeling results from Imperial.

Environment Canada has concerns with the level of noise associated with Imperial's Taglu well drilling operations while birds are present. Unlike Niglintgak, Imperial plans to drill in Taglu for 16 months starting in the winter of 2016 followed by year-round oil and gas activities. However, May to October is the time when birds are typically present in Kendall Island Bird Sanctuary and therefore sensitive to disturbance. As a result, Environment Canada may restrict activity or access within Kendall Island Bird Sanctuary during this period to protect bird habitat.

Imperial indicated that this would not meet its need to service and access personnel year-round for drilling, construction and operational activity. On a related matter, Imperial stated it would consider scheduling planned maintenance flaring outside the migratory birds nesting season.

When we asked how operations would be affected if drilling was restricted from May to October, Imperial indicated it would have to reassess the entire design and execution plan associated with the development. Environment Canada is continuing to have discussions with Imperial on this matter.

Imperial indicated it is committed to adhering, at a minimum, to Alberta's Energy Resources Conservation Board Directive 038. Imperial recognized that operating facilities in Kendall Island Bird Sanctuary requires additional consideration, and Imperial is committed to continuing evaluations of noise mitigation options through detailed engineering and planning, in order to arrive at practical solutions to address concerns raised by Environment Canada. As indicated in previous submissions, Imperial is committed to working with Environment Canada in reducing noise levels of production facilities in Kendall Island Bird Sanctuary, and Imperial will endeavour to reduce noise emissions beyond the requirements of Directive 038 where technically and economically possible.

In final argument both the Proponents and Environment Canada shared the view that requirements for noise regulation in Kendall Island Bird Sanctuary, both for the National Energy Board and migratory bird sanctuary requirements, can only be finalized after detailed engineering and design work is completed, after the noise impact analysis is prepared, and after discussions between the parties. Environment Canada will continue to work with the National Energy Board, Proponents and other regulators on issues related to noise in Kendall Island Bird Sanctuary. Imperial indicated during final argument it is committed to adhering to requirements in Alberta's Energy Resources Conservation Board Directive 038, as well as continuing evaluation of noise mitigation through detailed engineering and planning in order to arrive at practical solutions to concerns raised by Environment Canada.

Views of the Board

We agree with Environment Canada that regulating impacts of noise in a nationally protected bird sanctuary requires special consideration and application of best practices and the use of best available technology with the intent of "continuous improvement of pipeline safety and environmental protection." Condition T8 applies to regulating noise in the Taglu field and is intended to minimize disturbance from facilities inside Kendall Island Bird Sanctuary. The condition requires meeting the Alberta's Energy Resources Conservation Board Directive 038 "business as usual" standard with allowance for achieving the more stringent standard that Environment Canada recommended to the Joint Review Panel, and the Joint Review Panel accepted. There is flexibility built in to adjust the standard as informed by final engineering, an independently verified noise impact analysis document, and final determination of the fence line, which is the measurement base for a distance-based regulatory standard.

We acknowledge the parallel permitting process for Kendall Island Bird Sanctuary and support the need for consistency and clarity between Environment Canada and National Energy Board conditions.

Overall footprint

Many of the proposed facilities for the Taglu field, such as the well pad, gas conditioning facility, flow lines and air strip would be located inside the east boundary of Kendall Island Bird Sanctuary. The total area of permanent surface disturbance would be approximately 30 hectares.

During the project design phase, Imperial incorporated measures to reduce the overall footprint for the proposed Taglu development by:

- locating a single well pad near the centre of the reservoir and using directional drilling techniques to drill all of the proposed wells from one common well pad. This pad would be approximately 70 metres wide by 300 metres in length with 15 metres of road access on both sides and would cause 100 metres of disturbance;
- locating the gas conditioning facility adjacent to the well pad to eliminate the need for a network of connecting roads;
- accessing the site with river barges in the summer and by winter road without adding a substantial number of additional access roads through Kendall Island Bird Sanctuary;
- locating the well pad and gas conditioning facility on already disturbed land;
- using storage areas outside of Kendall Island Bird Sanctuary for some tankage requirements; and
- using staging areas outside of Kendall Island Bird Sanctuary, such as Tununuk Point (Bar C) for drilling materials. Tununuk Point is a previously disturbed lease area located approximately 50 kilometres south of the proposed Taglu site (see Figure 4-1).

Imperial intends to build its facilities offsite, in large modules, and ship them to Taglu for assembly. Based on consultations with area stakeholders, Imperial has identified an opportunity to increase the size of offsite fabricated modules, if the modules can be successfully transported and installed at the site. Based on the construction execution plan descriptions, the concept would reduce:

- the footprint at Taglu within Kendall Island Bird Sanctuary;
- some air traffic support at the site within Kendall Island Bird Sanctuary; and
- barge traffic on the Mackenzie River.

Imperial also indicated that it considered building a barge-based gas conditioning facility, like the one planned for the Niglintgak field; however, this did not reduce the overall footprint.

The proposed location of the Taglu airstrip within Kendall Island Bird Sanctuary was a concern for Environment Canada, as it will occupy approximately seven or eight hectares.

Drilling waste in Taglu can be separated into solids (drill cuttings) and liquids (reserve pit fluids). Typically, these wastes are disposed of in a sump. However, sumps are not permitted in Kendall Island Bird Sanctuary.

Imperial plans to initially inject both solids and liquids into a dedicated disposal well and then, as drilling progresses, into the annuli of a previously drilled production well (see Figure 4-11). With this approach, Imperial would use the dedicated disposal well as a backup if there are any issues with the production well annuli. In addition, Imperial would have a temporary onsite storage area for drill cuttings in case of any equipment or disposal problems with either the production well annuli or the dedicated disposal well.

The solids, or drill cuttings, represent about 20 percent of the total volume to be disposed of in the wells. Before the solids can be injected into a well, they would be mixed with water to create a slurry. Injection of the cuttings is planned as discrete "batch injection operations" for limited volume and discretely scheduled drilling programs. During injection operations, injection pressure and fluid properties would be monitored to verify that the reservoir is behaving as predicted and unexpected fractures are not occurring. Subsurface slurry injection of the scale and extent proposed by Imperial has not been practiced before in the Northwest Territories.

Imperial's alternative method for the disposal of drill cuttings would be to inject the reserve pit fluids into the well annuli and incinerate the drill cuttings. The residual material from incineration would be hauled to an approved disposal facility.

Insofar as air traffic operations are concerned, as the Joint Review Panel noted:

> Environment Canada and the Proponents assessed alternative means of accessing the Taglu site and agreed that the proposed Taglu airstrip would pose the least adverse effects.

The Joint Review Panel similarly agreed that the proposed airstrip was the best option. Imperial will continue to consult with Environment Canada in relation to the details of its proposed air operations at Taglu.

Dredging activities will occur within Kendall Island Bird Sanctuary and Environment Canada will not permit the spoil to be placed on undisturbed terrestrial habitat within Kendall Island Bird Sanctuary. Environment Canada requested that we require that Imperial's plan for dredging the barge landing at the Taglu field should describe the potential impacts associated with dredging, including spoil management and the site-specific mitigation measures proposed to address adverse impacts. As discussed earlier, this is a condition that should also refer to the success of the consultations between the Proponents and Environment Canada.

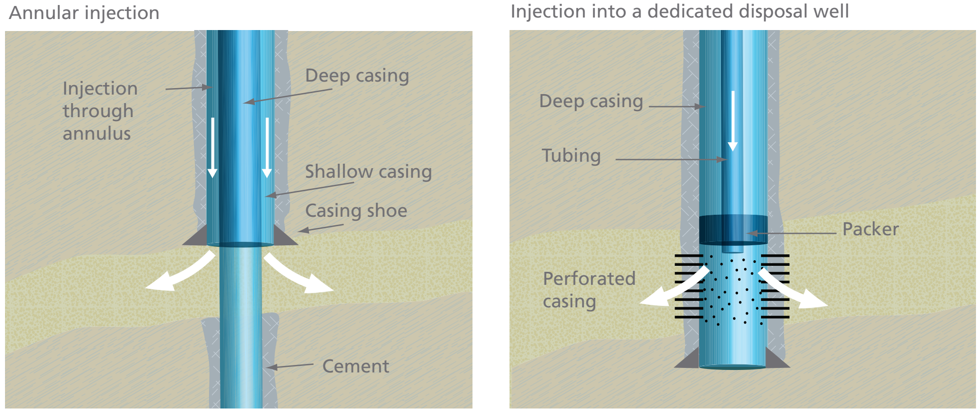
Views of the Board

We accept Imperial's conceptual plan to dispose drill cuttings by subsurface slurry injection as this avoids the use of sumps and would minimize the environmental footprint within Kendall Island Bird Sanctuary. However, as down-hole slurry injection of this scale and extent has not been utilized in the Mackenzie Delta before, Condition T4 requires Imperial to submit a drill cuttings slurry injection management program. The National Energy Board would assess such a program with respect to subsurface containment as well as safety, protection of the environment and conservation of resources.

We have considered the various comments regarding Condition T9 for dredging and the condition has been amended to require a dredging spoil management plan and to clarify requirements for consultation with Environment Canada, Department of Fisheries and Oceans, Indian and Northern Affairs Canada and Transport Canada.

Figure 4-11

Drilling waste disposal



4.4 Parsons Lake

The Parsons Lake field borders the Mackenzie Delta to the east and is located 70 kilometres north of Inuvik and 55 kilometres southwest of Tuktoyaktuk on the Tuktoyaktuk Peninsula. Unlike the neighbouring Niglintgak and Taglu fields to the northwest, the Parsons Lake field is not located within the Mackenzie Delta or Kendall Island Bird Sanctuary.

ConocoPhillips Canada (North) Limited (ConocoPhillips) has requested approval of a Development Plan application for the Parsons Lake field pursuant to section 5.1 of the *Canada Oil and Gas Operations Act*. ConocoPhillips and ExxonMobil Canada Properties (ExxonMobil) propose to develop natural gas and natural gas liquids from Parsons Lake and ship these hydrocarbons with those from the Taglu and Niglintgak fields via the Mackenzie Gathering System to the Inuvik Area Facility.

The capital expenditures for development of the Parsons Lake field are estimated to be $1,550 million with an estimated average operations and maintenance expenditure of $25 million per year for the period 2019 to 2023.

The Parson's Lake development (see Figure 4-12) would include:

- construction of a north pad with nine to nineteen production wells, two disposal wells, and a gas conditioning facility;

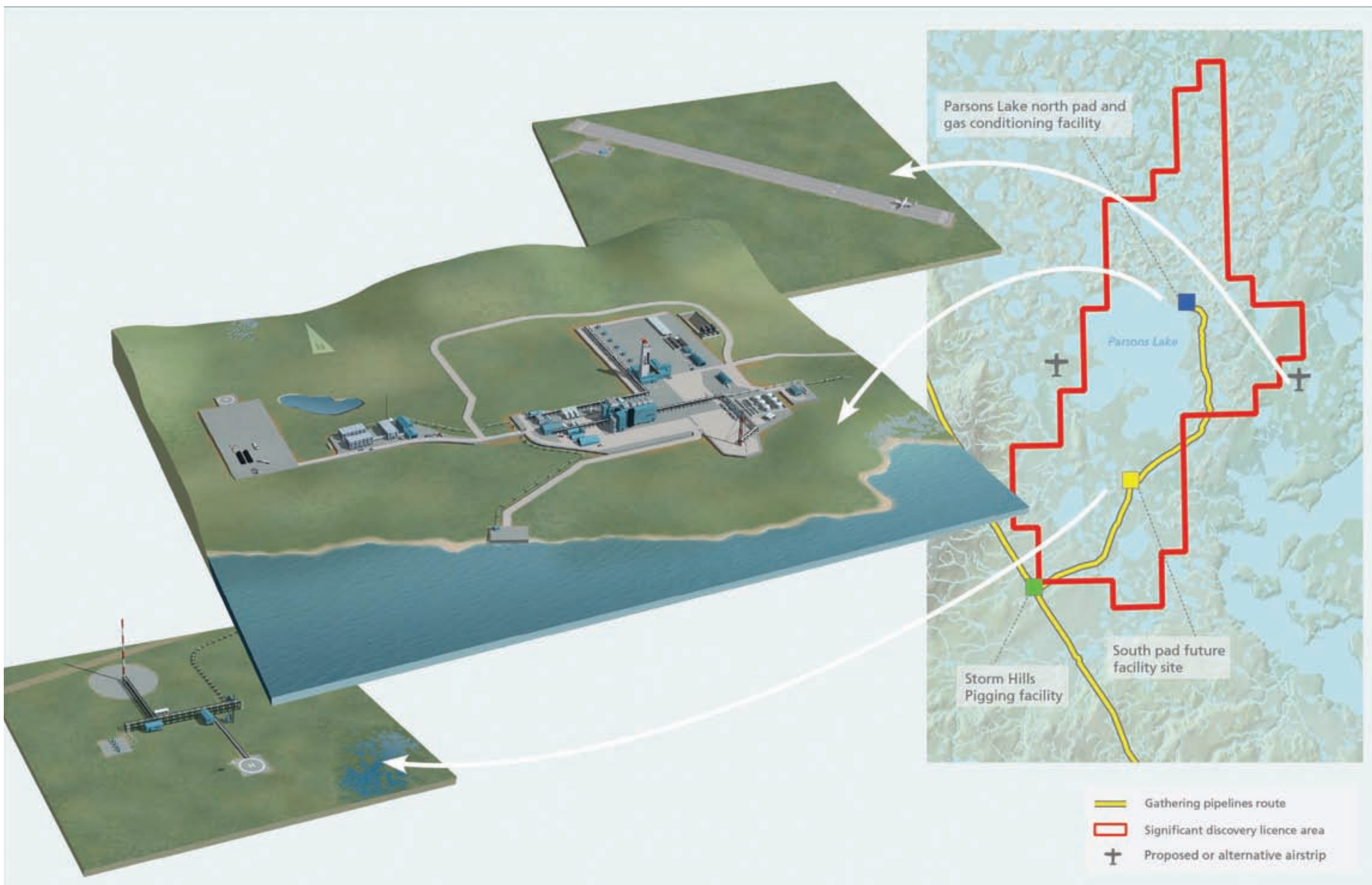


Figure 4-12

Parsons Lake production facilities

- a south pad with three to seven production wells;
- construction and operation of flow lines from the south pad to the north pad; and
- supporting infrastructure, including an all-weather airstrip.

Construction is planned to take place from 2014 to 2018 with production operations commencing in 2018 and expected to continue for 25 or 30 years.

4.4.1 Design of the Parsons Lake facilities

ConocoPhillips plans to transport and stage construction equipment during the summer of 2014 for winter activities. An overview of the construction schedule is shown in Table 4-4.

ConocoPhillips estimates 28 hectares would be required for the development, including the north and south well pads, the airstrip, and a 2.5 kilometre long all-weather road connecting the airstrip to the main road.

Wells and well pads

Proposed phase one development would include constructing well site facilities at the north and south pads and up to three contingent satellite well pads. The north pad would initially house up to nine production wells, one waste disposal well and one cuttings injection well, with the possibility of up to ten contingent production wells.

Phase two, preliminary plans for 2024, includes drilling three production wells and as many as four contingent production wells from the south pad.

ConocoPhillips believes that it may not be able to reach parts of the Parsons Lake field by drilling only from the north or south pads. Therefore, ConocoPhillips has identified three possible sites for contingent satellite well pads, each accommodating up to three wells. ConocoPhillips would develop the contingent wells if drilling and production operations identify and locate faults that compartmentalize the reservoir.

ConocoPhillips' Development Plan provides preliminary bottomhole locations for nine production wells, two contingent wells, one cuttings injection well and one waste disposal well located on the north pad and for three production wells and one contingent well from the south pad (see Figure 4-13). All would be directionally drilled except for the cuttings injection well which would likely be a vertical well. The preliminary total vertical and measured depth of these wells range from 1000 to 3150 metres and from 1000 to 4734 metres, respectively. ConocoPhillips also provided a commingled production strategy for Parsons Lake in order to effectively and economically deplete reservoir compartments.

The north pad would be built on granular material about 1.5 metres thick. The south pad and contingent satellite wells pads would be built on ice pads and with only a small area of granular material around the wellhead. All well pads would include individual wellbores, wellheads and wellhouses. Thermosiphons would be installed to maintain the permafrost below the pads.

Table 4-4

Parsons Lake construction highlights schedule

Activity	Season and year
Transport and stage construction equipment to delta staging location	Summer 2014
Begin construction of winter access road, begin development of borrow sites, transport material to the north pad, all-weather access road and airstrip	Winter 2014/15
Construct and complete commissioning of airstrip	Summer 2016
Construct winter access road for heavy module transport, transport very large modules and begin installing very large modules as part of the gas conditioning facility	Winter 2016/17
Commence drilling program at north pad	Winter 2016/17
Complete north pad drilling and testing program	Winter 2018/19
Start up the gas conditioning facility	Winter 2018
South pad drilling program, construction of the flow line from the south pad to the north pad	Beyond 2019

Flow lines

Once the natural gas and natural gas liquids have been extracted, they would flow through above-ground flow lines from the wells to the gas conditioning facility on the north pad. The 16 kilometre long flow line from the south pad would rest on piled metal supports at least 2.2 metres above the ground, and run parallel to the Parsons Lake lateral of the Mackenzie Gathering System. Hydrocarbons from the south pad would be metered and heated before traveling to the north pad. The flow lines would be insulated to keep temperatures inside the flow lines between 30°C and 50°C. This would help prevent the natural gas, natural gas liquids and any produced water from freezing and plugging the lines.

Production from any satellite well pads would be transported in insulated above-ground flow lines to the north pad and the gas conditioning facility.

Gas conditioning facility

The gas conditioning facility would be able to handle a maximum volume of 9.0 Mm^3/d (324 MMcf/d). It would process the reservoir fluids to meet the specifications of the gathering system and would include components to:

- separate gas from free water and hydrocarbon liquids (natural gas liquids);
- compress and dehydrate the gas;
- chill and meter the hydrocarbons before they enter the gathering system; and
- collect any water and send it to a disposal well.

The gas dehydration unit is designed to reduce the moisture content of the sales gas to 6 mg/m^3 and to neutralize any potential for corrosion caused by the carbon dioxide in the gas stream. ConocoPhillips' design also incorporates a relief and blowdown system, including flare stacks, to handle any emergency relief and flaring at the north and south pads. Equipment to compress the gas so it would flow through the gathering system would be added in stages as the wellhead pressure declines.

Project facilities would be built from very large modules constructed offsite, shipped by barge to Tuktoyaktuk, and transported via winter road to Parsons Lake. Once the modules were onsite, they would be placed on steel piles and elevated about one to two metres above the gravel

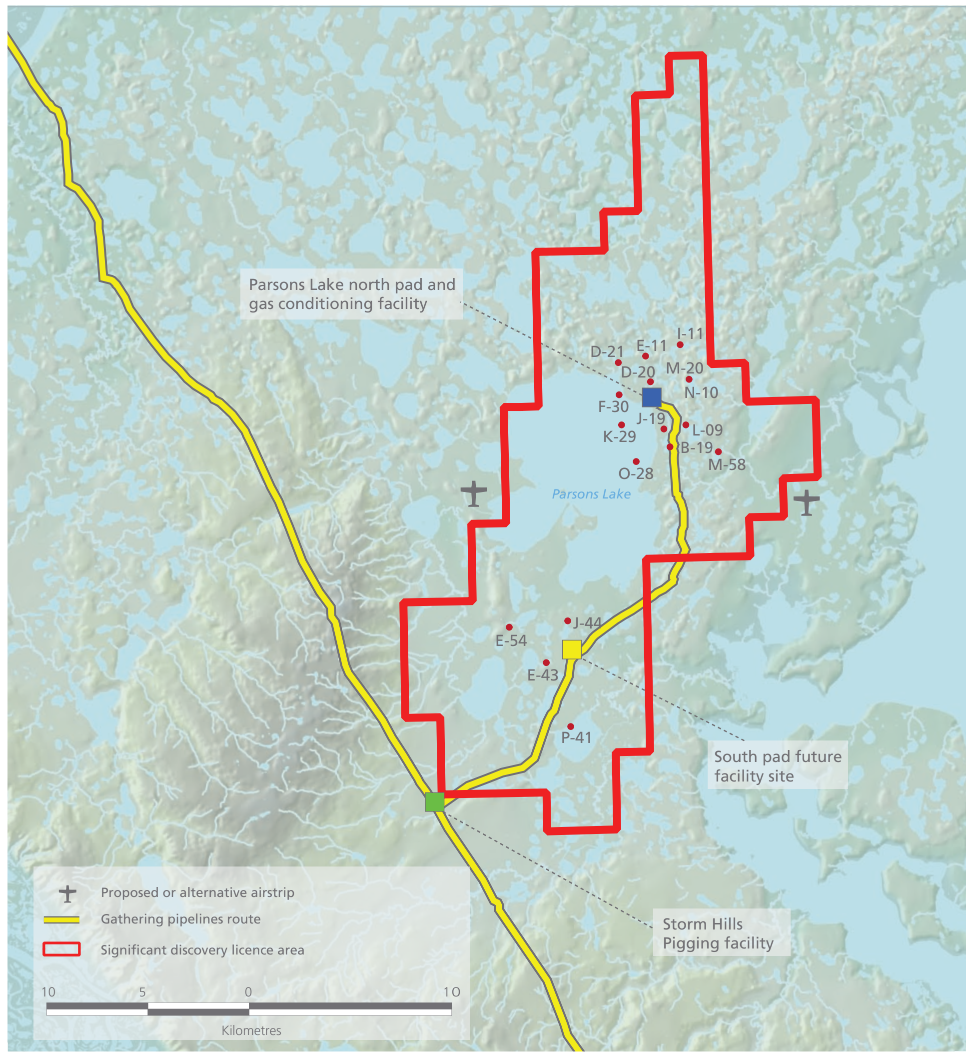


Figure 4-13

Parsons Lake field map

surface. Buildings installed on the gravel pad would have insulated foundations, and thermosiphons.

Alternative production system

ConocoPhillips considered a number of alternative configurations for production such as locating the main gas conditioning facility at the south pad, housing only a minimal satellite facility on the north pad and using a flow line to transport gas from the north pad to the south pad. However, this alternative would require a larger flow line than the current proposal and would be costlier.

Another alternative configuration evaluated by ConocoPhillips was to construct gas conditioning facilities at both north and south pads. This would be costlier and the north pad gas conditioning facility would not be fully utilized.

Because the Parsons Lake north pool contains about three percent carbon dioxide and the south pool about five percent carbon dioxide, ConocoPhillips evaluated whether removal facilities for carbon dioxide would be required. Four different options for removing carbon dioxide were studied, and costs for these options ranged from $80 to $100 million. Rather than design the Parsons Lake facilities to extract the carbon dioxide, ConocoPhillips chose to rely on blending the gas from Parsons Lake with gas from Niglintgak and Taglu that would have lower concentrations of carbon dioxide. Blending would allow ConocoPhillips to meet the Inuvik Area Facility's carbon dioxide content specification.

Winter transportation

ConocoPhillips plans to move the seven pre-assembled gas conditioning facility very large modules from Tuktoyaktuk to Parsons Lake on a purpose-built heavy load ice road the winter before commercial gas production begins. The proposed ice road would be specially prepared with a smooth ice surface and designed to accommodate the heavy-lift trailers carrying the oversized and heavy gas conditioning facility modules. Because of the load's size and weight, the road would need to about 20 metres wide with a 50 metre right of way, have a three percent gradient, contain no tight curves and avoid frozen bodies of water. The wide ice road would be completed late in the season and likely used for six to eight weeks. However, a shortened winter season would mean significant delays to the construction of the gas conditioning facility if the ice road could not be used to transport all seven modules.

Furthermore, ConocoPhillips is proposing to drill the south pool and satellite wells from ice pads. ConocoPhillips is aware that this drilling schedule could be delayed by an unseasonably warm winter. If that happened, the wells would not be drilled until the following winter.

Views of the Board

We are of the view that the general approach and the conceptual design and plan outlined by ConocoPhillips for the Parsons Lake field are reasonable. We note that ConocoPhillips will use new geological and reservoir data acquired from drilling and production to determine if additional faulting and compartmentalization exists and whether any contingent wells would be required. In this regard, Condition P17 requests ConocoPhillips submit an updated resource management plan with the National Energy Board within 18 months after production commences or prior to the drilling of contingent wells.

Condition P5 requires ConocoPhillips to provide adequate gas sampling and analyses during drilling and production operations as the Parsons Lake field is expected to have three to five percent carbon dioxide gas content.

We accept ConocoPhillips' conceptual commingled production strategy to effectively deplete reservoir compartments. The National Energy Board will consider commingled production on an individual well basis during drilling and production operations in accordance with section 66 of the *Canada Oil and Gas Drilling and Production Regulations.*

Condition P30 stipulates that the approval of the Development Plan under for the Parsons Lake field under subsection 5.1(4) of the *Canada Oil and Gas Operations Act* is subject to the Minister of Indian Affairs and Northern Development Canada providing confirmation that ConocoPhillips has satisfactorily met the Benefits Plan requirements of section 5.2 of the *Canada Oil and Gas Operations Act*.

4.4.2 Development plan issues

During the hearing, the issues raised included:

- matters raised by adjacent rights holders;
- geographic and design issues related to permafrost, climate change, subsidence and flooding;
- air quality issues and greenhouse gas emissions; and
- drill cuttings disposal.

Matters raised by adjacent rights holders

The National Energy Board issued a Declaration of Commercial Discovery for the Parsons Lake field on 16 September 2004 which included lands held under Significant Discovery Licence 030, 032 and 062.

The Parsons Lake field is contained within Significant Discovery Licences SDL030 and SDL032. ConocoPhillips, the field operator, holds 75 percent of the working interest of these licences while ExxonMobil holds the other 25 percent. Exploration Licence EL406[8], of which PetroCanada is the representative interest holder, borders Significant Discovery Licence SDL030 and SDL032 to the east and south. Crown land lies to the north and west of Significant Discovery Licence SDL032. Imperial[9] is the registered interest holder and operator of Significant Discovery Licence SDL062 located on the northeast boundary with ConocoPhillips' Significant Discovery Licence SDL032. Other notable interest holders of Significant Discovery Licence SDL062 include ExxonMobil Canada, ConocoPhillips and Mosbacher. ExxonMobil holds between four and eight percent interest in the south, central and north segments of Significant Discovery Licence SDL062. ConocoPhillips holds approximately 1.2 percent interest only in the central segment. Mosbacher holds an average 3.1 percent interest in the central and north segments (see Figure 4-14).

Mosbacher, which holds an interest in lands adjacent to the Parsons Lake field, expressed concern that the proposed development would drain its gas resources. According to Mosbacher, the Parsons Lake Development Plan should not be approved because ConocoPhillips has failed to present plans that would respect the rightful economic interest of holders of adjacent lands.

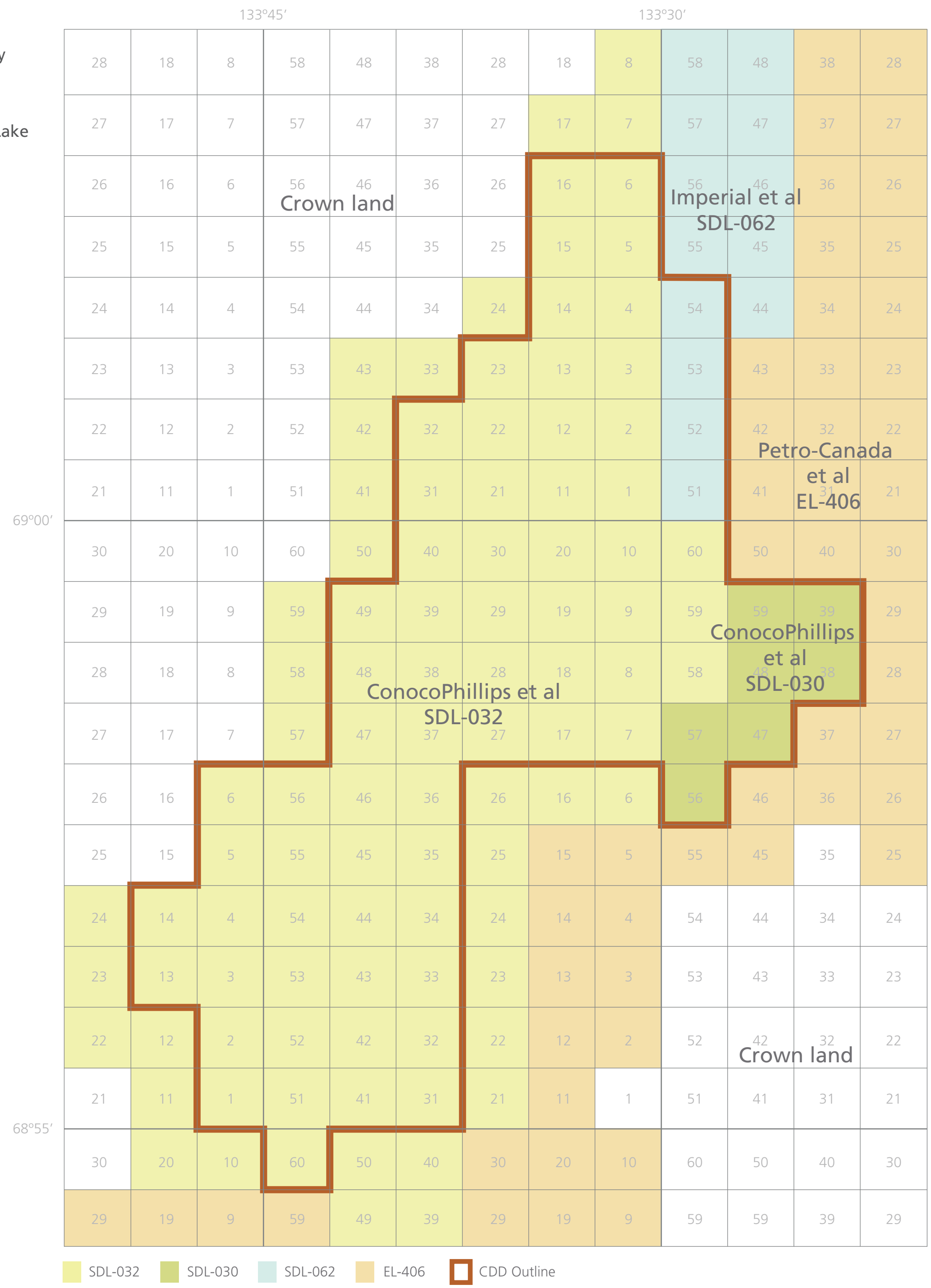
Mosbacher indicated that, although its estimate for gas-in-place for Significant Discovery Licence SDL062 is small compared to the gas-in-place for Significant Discovery Licences SDL030 and SDL032, it believes that approximately 5.4 percent of the total Parsons Lake original gas-in-place lies under Significant Discovery Licence SDL062. According to Mosbacher, the volumes under Significant Discovery Licence SDL062 are commercially producible. Mosbacher stated that the one grid unit buffer offered by ConocoPhillips would not adequately protect its resource from being drained by ConocoPhillips' operations on Significant Discovery Licences SDL030 and SDL032. Without a unitization agreement it is likely that the gas resource on Significant Discovery Licence SDL062 would be lost to the owners of Significant Discovery Licences SDL030 and SDL032.

[8] Exploration Licence EL406 was surrendered in 2007.

[9] In Exhibit MOL-3I, Imperial Oil Resources Limited, Imperial Oil Resources Ventures Limited and Imperial appear to have been used interchangeably.

Figure 4-14

Commercial discovery declaration area and significant discovery licences for Parsons Lake field as of 2006



Mosbacher indicated that it sought cooperative negotiation between the parties. Since its efforts in this regard were not successful, Mosbacher asked us to direct ConocoPhillips to make a comprehensive and compelling case that resources from adjacent lands will not be drained. Mosbacher stated that Imperial, the operator of Significant Discovery Licence SDL062, considered drilling a well, constructing facilities and tying into the proposed Parsons Lake development, but the stand-alone drilling project was not sufficiently robust to meet its internal hurdle rates. Mosbacher stated it then circulated an alternative cost-effective drilling scenario based on the cooperative use of the north pad by all partners of Significant Discovery Licence SDL062. The scenario proposes a single well with a horizontal reach[10] of approximately 7500 metres from the north pad into section 54 of Significant Discovery Licence SDL062 which may be approaching the current theoretical technical limit for the reservoir.

ConocoPhillips stated that Mosbacher has never been prevented from doing work and drilling wells like ConocoPhillips has done. No well has been drilled in Significant Discovery Licence SDL062 and ConocoPhillips believes there is a great deal of uncertainty as to what resources are included in Significant Discovery Licence SDL062. ConocoPhillips stated that serious and meaningful discussions on unitization cannot occur without a well. The gas

[10] Mosbacher stated in the hearing that the length of the drill was "7500 m reach measured depth distance." Measured depth is not horizontal reach, but has been taken to mean horizontal reach because the distance between the north pad and section 54 is approximately 7500 metres.

conditioning facility is designed to process only the gas produced from the Parsons Lake field and offers no spare capacity. Currently, ConocoPhillips has no plans to expand the gas conditioning facility; however, the gas conditioning facility could be upgraded to accommodate third-party gas if the volume, delivery conditions and gas composition were known before detailed engineering plans are finalized. Upgrading would require expansion of the pad size. In addition, ConocoPhillips would consider allowing a third-party to drill a well from the north well pad as this pad was designed to accommodate more wells than ConocoPhillips plans to drill. If Mosbacher were to drill a well into Significant Discovery Licence 062 from the north pad and the well was determined to be commercial, the gas conditioning facility may have to be upgraded.

ConocoPhillips requested approval for a variance to the National Energy Board's *2009 Draft Spacing Requirements* for Significant Discovery Licences SDL030 and SDL032 to allow the appropriate placement of wells to increase gas recovery.

Mosbacher submitted during final argument that the proposed Parsons Lake Development Plan was sub-optimal insofar as it does not address development of the whole field, and it encourages waste. In this regard, Mosbacher referenced sections 18 and 19 of the *Canada Oil and Gas Operations Act*. In the event there is no joint development, Mosbacher requested that we reject ConocoPhillips' applied-for spacing. Mosbacher asked us to consider a condition requiring ConocoPhillips to include all land in Significant Discovery Licence SDL062 within the commercial discovery declaration area as part of the Parsons Lake Development Plan. Another condition requested by Mosbacher would require ConocoPhillips to fully explore joint production arrangements with other interested parties. In addition, Mosbacher suggested a condition requiring ConocoPhillips to make available drilling pad space on reasonable commercial terms to allow Mosbacher and other interested parties the opportunity to drill additional wells on a timely basis.

Views of the Board

We consider joint development of the Parsons Lake field to be the desired approach if the interest holders of Significant Discovery Licence SDL062 agree to develop their lands. This would avoid duplication of facilities and would minimize the environmental footprint. It is also our view that joint development should be attained voluntarily through commercial negotiations and agreements between the interested parties. We note that the compulsory unitization provisions in the *Canada Oil and Gas Operations Act* require participation from ConocoPhillips as it holds a large portion of the lands comprising the Parsons Lake commercial discovery declaration area. ConocoPhillips stated that the first step that needs to be taken to begin meaningful talk on joint development or unitization is Mosbacher proving the extent of field by drilling a well on Significant Discovery Licence SDL062. Condition P2 requires both the north and south well pads to be designed for expansion allowing for the drilling of at least one well by adjacent interest holders. Contingent upon successful discussions between ConocoPhillips and Mosbacher to settle commercial terms including timing, the condition would provide Mosbacher the opportunity to drill directional wells to delineate the field on its lands with a minimal environmental footprint.

We consider there to be no basis for a condition directing ConocoPhillips to include all sections of land in Significant Discovery Licence SDL062 that are within the commercial discovery declaration area as part of the Parsons Lake Development Plan since there is currently no joint development agreement between the interest holders of Significant Discovery Licence SDL062 and ConocoPhillips and ExxonMobil. As the critical action that needs to occur before joint development discussions progress is that Mosbacher drills a well on its land, we are not persuaded to include the condition sought by Mosbacher requiring ConocoPhillips to fully explore joint production arrangements with other interested parties.

We are of the view that the National Energy Board's *2009 Draft Spacing Requirements* are appropriate in the absence of joint development arrangements. The *2009 Draft Spacing Requirements* are intended to provide a fair approach with respect to the optimization of gas recovery and the protection of the correlative rights of adjacent land interest holders. Condition P18 requires ConocoPhillips to comply with the *2009 Draft Spacing Requirements*. The *2009 Draft Spacing Requirements* establish a 250 metre off-target area from adjacent lands of differing ownership for gas wells. Alberta, British Columbia, Saskatchewan and Yukon utilize a similar set-back.

ConocoPhillips would not require a variance for the proposed preliminary well locations for the Parsons Lake field in accordance with the *2009 Draft Spacing Requirements*. The *2009 Draft Spacing Requirements* set a limit of one producing well in spacing units adjacent to lands of differing ownership, but for spacing units not adjacent to lands of differing ownership, there is no off-target area and more than one producing well is permitted[11]. The National Energy Board will consider any future application for a variance at that time and assess it in accordance with the *2009 Draft Spacing Requirements* or any orders dealing with spacing that may supersede it.

In our view, Mosbacher has not provided evidence to support a determination that the proposed Parsons Lake Development Plan encourages waste. We consider the proposed production scheme to be appropriate for a conventional gas field such as Parsons Lake. With Condition P19 in place requiring compliance with the *2009 Draft Spacing Requirements*, Mosbacher has the opportunity to drill wells and develop lands in Significant Discovery Licence SDL062[12].

[11] Part IV of the *2009 Draft Spacing Requirements*.

[12] Those lands of Significant Discovery Licence SDL062 that were included in the National Energy Board's commercial discovery declaration dated 3 November 2004 are eligible for a production licence.

Geographic and design issues

Permafrost and climate change

The Parsons Lake field lies within a zone of continuous permafrost. The permafrost thickness north and east of the lake ranges from 354 metres to 378 metres. Geotechnical drilling on the north pad and adjacent areas in 2004 identified massive ground ice throughout the north pad area. As with the other development fields, development could thaw the permafrost and significantly alter the northern landscape.

ConocoPhillips plans to use a number of measures to preserve the permafrost. These activities are divided into methods for protecting surface sites and methods for protecting the permafrost during drilling and production.

ConocoPhillips plans to insulate the ground from heat sources, such as buildings and flow lines using methods such as:

- piling 1.5 metres of gravel on all well pads and the airstrip to provide thermal stability and protect against contact pressure caused by vehicles. A layer of rigid insulation or geotextile may be incorporated in some areas to further protect the permafrost;
- using adfreeze-type steel pipe piles to elevate the buildings about 1.5 metres above the gravel pads and allow for air flow between the building and the gravel pad;
- using thermsiphons under any slab-on-grade foundations elevating and insulating the flow lines, as mentioned in section 4.4.1; and
- where embankments are created, slopes would be angled to minimize thaw degradation.

Preservation of the permafrost at well sites would be accomplished by:

- spacing all wells, including contingent wells, at least 25 metres apart. This exceeds the 15 metre interwell spacing suggested by the C-FER Technologies and EBA Engineering study of the effect of well spacing on permafrost, which predicted the coalescence of permafrost thaw bulbs in 20 years for wells spaced at 10 metre intervals;
- installing thermosiphons close to each well;
- placing an insulated conductor about 24 metres down each well; and
- using cooled mud to drill the surface holes; using permafrost cement for the conductor and the surface casing on each well; and using gelled diesel fuel in the tubing or casing annulus for insulation.

By using these methods, ConocoPhillips expects heat loss from conduction and convection of produced fluids would be reduced by at least 90 percent compared to using conventional packer fluids.

The Sierra Club of Canada raised questions about the projections of temperature change due to climate change over the life of the project used by ConocoPhillips in the design of the Parsons Lake field facilities.

ConocoPhillips evaluated the risk of surface subsidence caused by the extraction of natural gas and determined that no measurable subsidence is expected because of the nature of the reservoir and its depth (three kilometres). In addition, because ConocoPhillips plans to use a combination of wellbore insulation and thermosiphons it does not expect measurable amounts of well permafrost thaw subsidence.

The north pad sits approximately 45 metres above sea level and there is no evidence the site has been flooded. Accordingly, flooding is not expected at the north pad or, similarly, the south pad.

The Joint Review Panel was generally satisfied that ConocoPhillips had taken climate change into account in its design. Nevertheless the Joint Review Panel recommended that the National Energy Board require ConocoPhillips to file final design plans that incorporate further design analysis of the impacts of climate change on permafrost and terrain stability over the design life of the project and post-abandonment. The Joint Review Panel was of the view that this analysis should be conducted for a series of representative locations, conditions and terrain types and should incorporate climate variability, in particular, upper limit temperature scenarios to account for the range of future temperature conditions, including variability and extremes, and the impact of this variability on stream flow regimes. The Joint Review Panel added that the results should be incorporated into monitoring, mitigation and adaptive management plans. The Joint Review Panel thought that this analysis should be provided to other appropriate regulators in sufficient time for review and to provide input to the National Energy Board.

Indian and Northern Affairs Canada suggested in final argument that the Proponents should demonstrate how upper limit temperature scenarios have been considered in their design.

Further specific discussion on climate change regarding project design is found in Chapter 6.

Views of the Board

Warming of the global and regional climate could raise sea levels and affect weather patterns. Parsons Lake is located on higher ground and further from the sea, so its facilities would be less exposed to possible effects of climate change.

We are satisfied with ConocoPhillips' general approach to addressing permafrost integrity with respect to the Parsons Lake development. As warm fluids will flow through those wellbores during drilling and production operations, it is important for safety and environmental protection reasons that the permafrost thaw bulbs around wellbores do not coalesce. Condition P3 requires the interwell spacing on the Parsons Lake well pads to be no less than 15 metres unless ConocoPhillips utilizes mitigation measures approved by the National Energy Board.

Condition P8 requires ConocoPhillips to provide final detailed design information which incorporates an analysis of the impacts of climate change and variability on permafrost and terrain stability for the Parsons Lake facility using potential upper

limit temperature scenarios which may occur during the operational life of the facilities. ConocoPhillips will also provide information about how upper limit temperature scenarios may impact precipitation and water levels of Parsons Lake and other nearby lakes. We are of the view that government departments such as Environment Canada. Indian and Northern Affairs Canada and Natural Resources Canada should be consulted to benefit from their expertise.

Air quality issues

Air quality in the North is considered to be of high quality and Northerners are very concerned that it remains that way. Both Environment Canada and the Proponents agreed that existing air quality in the proposed project area is good and, along with other government regulators, emphasized the need to "keep clean areas clean." This principle requires new industrial development to be "planned, constructed and operated in a manner that minimizes the degradation of air quality in these areas."

Air quality issues for the project included project emissions for the pipeline and development fields, monitoring, and greenhouse gases in the context of monitoring climate change. The Joint Review Panel noted that the National Energy Board would be the prime regulator of air emissions from the project and that Environment Canada and the Government of the Northwest Territories would play advisory roles. The Joint Review Panel recognized the National Energy Board's expertise and experience in regulating interprovincial aspects of the oil, gas and electric utility industries, including environmental matters. The Joint Review Panel also recognized the extensive environmental and local knowledge that Environment Canada and the Government of the Northwest Territories can provide.

Air emissions can be related to the project-specific effects of construction, operations, and waste incineration. Air quality impacts can be local to regional in the case of particulate matter and sulphur dioxide, or global in the case of greenhouse gases. Emissions would occur during the construction phase through intermittent flaring during well testing at the Parsons Lake field.

Further specific details pertaining to emissions for the pipeline are discussed in Chapter 3 and discussion on air emissions pertaining to facility design is found in Chapter 6.

The Joint Review Panel report indicated that the Proponents' baseline information was compiled from historical data and results of air quality monitoring that was carried out over one year near the communities of Inuvik and Norman Wells, and periodically at the Parsons Lake and Taglu gas fields. The Proponents' monitoring data and other sources indicated that background concentrations of air contaminants are generally below detection levels or applicable guidelines. The one exception that is not below detection levels is ozone; relatively high background levels were monitored in Inuvik and Norman Wells. The Proponents indicated that elevated ozone levels at high latitudes in the northern hemisphere are thought to result from the intrusion of stratospheric ozone. The Proponents stated that all ground-level concentrations of compounds released by the project during operations at the gas fields, the Inuvik Area Facility, and compressor and heater station sites would increase, but would be below those outlined in applicable federal and territorial guidelines at all locations in the production area and along the pipeline corridor.

Environment Canada recommended that the Proponents design and implement suitable air quality monitoring programs with its help. Environment Canada focused its recommendations on pollution prevention and the use of best available technology and best management practices to minimize the degradation of air quality. Further discussion around application of these principles may be found in Chapter 6.

The Dehcho Elders and Harvesters indicated that the project needs to be designed to minimize air quality impacts, with monitoring plans in place to verify the predicted emissions and impacts. Corrective action needs to be taken quickly to avoid impacts upon the land and wildlife from degraded air quality.

Greenhouse gas emissions

Parties were concerned about the impacts of the project on climate change, especially in light of Canada's international efforts under the United Nations Framework Convention on Climate Change and the *Kyoto Protocol*.

Greenhouse gas emissions arising from the project include carbon dioxide, methane and nitrous oxides with each compound having a different climate change potential. During operation, the project would emit greenhouse gases from burning natural gas at combustion related sources such as compressors and methane gas released through normal venting procedures and minor leaks (fugitive emissions). Further specific discussion on air emissions pertaining to facility design is found in Chapter 6.

Alternatives North submitted that the National Energy Board and the Government of Canada have a public interest mandate that requires consideration of greenhouse gas emissions.

Ecology North deemed that high project-specific standards for greenhouse gas emissions based on a robust and strong definition of best available technology and accompanied by penalties in the cases where they do not meet those project standards or targets, would provide the best possible protection in terms of minimizing upstream greenhouse gas emissions associated with the project.

Sierra Club of Canada submitted that we need to specify an actual target and it is not enough to just leave it up to the Proponents. Sierra Club of Canada indicated that the target should at least match the general recommended target in Joint Review Panel recommendation 8-8.

Views of the Board

We understand the importance of clean air in the North and that air quality must be considered in a cumulative manner. We also recognize the need to minimize greenhouse gas emissions resulting from the project. The Joint Review Panel directed several recommendations to us relating to air quality and air emissions. We have addressed air issues through several conditions for the Mackenzie Gas Project. These conditions are focused on the Proponents taking appropriate measures to minimize air emissions and address air quality. We are committed to working collaboratively with Environment Canada and the Government of the Northwest Territories to protect air quality in the North, recognizing the extensive environmental and local knowledge that these agencies can provide.

Conditions P13 and P14 address technologies for reducing emissions, incorporation of best management practices and best available technologies, and facility design. Condition P14 requires the submission of a report evaluating incinerator emissions from camps and station facilities and technologies and practices must be reflected in the waste management plans required by Condition P11. Condition P16 requires the ConocoPhillips to minimize and reduce emissions from flaring. Further specific discussion for these conditions regarding air emissions pertaining to facility design is found in Chapter 6.

Air quality monitoring is part of comprehensive environmental monitoring under an environmental management system. Through environmental management, systems are established to address effects of the project on the environment and of the environment on the project, with the overall goal of minimizing negative impacts. Adaptive management is a systematic process for continually improving management practices by learning from their outcomes.

Environmental monitoring is an important part of environmental management that directly supports adaptive management by observing and evaluating the effects that occur, then changing or adding mitigative measures as appropriate to limit or reverse the environmental effects. Environmental monitoring can include:

- compliance monitoring, to verify that all environmental mitigation is implemented as presented in the Environmental Protection Plan and environmental alignment sheets and that work is in compliance with environmental regulations; and
- effects monitoring, to assess the effects resulting from project-environment interactions and evaluate the effectiveness of approved mitigation measures.

This is further discussed in section 3.3.6.

ConocoPhillips is expected to implement Environmental Protection and Monitoring and Surveillance Programs which include protection of the environment as one of the main goals. A monitoring program may:

- identify any issues or potential concerns that may compromise the protection of the environment;
- include methods for developing measures to prevent or mitigate the impact of the identified issues;
- provide for continued monitoring of sites to evaluate success of mitigative measures undertaken;
- provide a system for implementing additional mitigative measures as necessary; and
- provide a feedback system that allows for adaptation of successful mitigation to future pipeline projects.

Monitoring programs may have specific goals and targets and could include methods for evaluating and interpreting collected data such as air quality or emissions data. Monitoring may include any relevant environmental practices (e.g., vegetation establishment, water quality sampling, waste disposal).

Responsibilities of the National Energy Board regarding monitoring include:

- conducting environmental inspections of facilities, verifying compliance with terms and conditions, and assessing the effectiveness of mitigation;
- monitoring ongoing operation, verifying reclamation and maintenance of the project site to acceptable standards; and
- conducting environmental audits, evaluating environmental management systems and environmental programs.

We generally require the filing of environmental post-construction monitoring reports as a condition of an authorization. The information in monitoring reports should include:

- confirmation of proper implementation of mitigation and reclamation measures used;
- identification of the outstanding environmental issues; and
- discussion of the company's plans for how outstanding issues will be resolved.

Condition P10 requires ConocoPhillips to submit an Environmental Protection Plan which includes monitoring of activities. Condition P13 includes the requirement for monitoring incinerator emissions.

A commitment to continuous improvement, outlined in Joint Review Panel recommendation 8-6, is expected to be a component of an operator's Management system pursuant to paragraph 5(2)(b) of the *Canada Oil and Gas Drilling and Production Regulations*. This is addressed in Condition P10. We are of the view that the commitment to continuous improvement is not limited to greenhouse gas emissions but should apply to all discharges to the environment, which in this case is the atmosphere. Condition P10 also covers the requirements for methods and locations of monitoring.

Condition P15 requires the Proponents to file a report outlining the use of best available technology for station facility construction. Selection of best available technology is the most significant factor in determining achievable air emissions targets. Condition P10 outlines the requirements for an Environmental Protection Plan. The condition requires the Proponents to submit maximum proposed greenhouse gas targets and reduction strategies for air emissions including particulate matter, NOx and greenhouse gases. Condition P10 also addresses other matters from the Joint Review Panel recommendations including employee training, monitoring, public communication, and required consultation with Environment Canada and the Government of the Northwest Territories. With these conditions, we find it acceptable for the Proponents to develop greenhouse gas targets for the project consistent with use of best management practices and in consultation with appropriate government agencies.

Drill cutting disposal

Like the operators of the Taglu field, ConocoPhillips plans to dispose of drill cuttings from the Parsons Lake field into a dedicated disposal well. Drill cuttings would be collected and transported to the cuttings processing station. At the station, the cuttings would be mixed with water, milled and sheared to create slurry. The slurry would then be pumped into the proposed D-20 dedicated cuttings disposal well (see Figure 4-13). Disposal would usually be done in batches at low pump rates. ConocoPhillips is planning a comprehensive program of testing and monitoring of subsurface containment during cuttings injection operations. Annular cuttings injection may be used as a back-up if ConocoPhillips was not able to use the dedicated cuttings injection well.

As mentioned for Taglu, subsurface slurry injection has not been used in the Northwest Territories at this scale before. If cuttings injection is not viable, ConocoPhillips' alternative method for the disposal of drill cuttings would be to stabilize, store and subsequently transport the cuttings to an approved disposal site.

Noise

The Parsons Lake anchor field is located outside of Kendall Island Bird Sanctuary. The physical footprint of the facility, particularly the north pad, is an area of relatively low numbers and diversity of migratory birds compared to the nearby Mackenzie Delta. ConocoPhillips believes that it is appropriate for the Parsons Lake production facility to follow Alberta's Energy Resources Conservation Board Directive 038 "business as usual" Permissible Sound Level.

Views of the Board

We are of the view that the conceptual plan by ConocoPhillips to dispose its drill cuttings by subsurface slurry injection is satisfactory as it avoids the use of sumps and minimizes the environmental footprint. However, as down-hole slurry injection of this scale and extent has not been utilized in the Mackenzie Delta before, Condition P4 requires ConocoPhillips to submit a drill cuttings slurry injection management program. The National Energy Board would assess such a program with respect to subsurface containment as well as safety, protection of the environment and conservation of resources.

Condition P9 requires meeting requirements of Alberta's Energy Resources Conservation Board Directive 038 for noise regulation and filing a post construction noise assessment report 90 days following the start of operation.

Chapter 5 Routing and land matters

5.1 Introduction

The National Energy Board's assessment of a pipeline application under the *National Energy Board Act* includes consideration of the appropriateness of the general route of the proposed pipeline and the general location of associated facilities, the amount of land required, and the proponent's land acquisition approach. If a certificate authorizing a project to be built along the general route is issued, a further process determines the location of the specific or detailed route.

A different legislative scheme applies in relation to facilities approved under the *Canada Oil and Gas Operations Act*. Applications under the *Canada Oil and Gas Operations Act* are usually not filed with the National Energy Board until the route has been established and all required land rights for the project have been secured. However neither the *National Energy Board Act* nor the *Canada Oil and Gas Operations Act* requires that all necessary land rights be acquired prior to a company submitting an application for a project.

Notwithstanding the differing legislative schemes and practices under the *National Energy Board Act* and the *Canada Oil and Gas Operations Act*, we considered similar factors in our assessment of the proposed routes for the Mackenzie Valley Pipeline and the Mackenzie Gathering System.

We recognize that federal and territorial departments and agencies have responsibilities in respect of land authorizations and permitting for the Mackenzie Gas Project. Our assessment may assist those departments and agencies in their consideration of the various applications for land use, land rights acquisition, and other approvals.

Companies typically use surveys, land studies, and other work such as selection criteria and alternatives to identify, assess, and select a proposed pipeline route and facility locations when preparing pipeline applications under both the *National Energy Board Act* and the *Canada Oil and Gas Operations Act*. Refinements are made through further study and consultation with communities and individuals which could be affected by the project.

In addition to the factors referred to above, parties raised issues in respect of land use plan requirements and the status of access agreements. Each of these will be addressed in turn in this chapter.

5.2 General route and facilities site selection

5.2.1 General route selection – Mackenzie Valley Pipeline and Mackenzie Gathering System

The Proponents have identified a general route for the proposed Mackenzie Valley Pipeline and the Mackenzie Gathering System pipelines that consists of a one-kilometre wide corridor. Within this corridor, the Proponents identified a preliminary route which has been and will continue to be subject to refinement through further study and public consultation.

Proposed route of the Mackenzie Gathering System

The upstream gathering pipelines consist of four laterals, one from each field and a fourth extending from the Storm Hills pigging facility south to the Inuvik Area Facility (see Figure 1-2). From the Inuvik Area Facility the natural gas liquids pipeline and the Mackenzie Valley Pipeline would share a common right of way south to Norman Wells, which would be the terminus of the Mackenzie Gathering System (see Figure 1-3).

Niglintgak lateral

This lateral would be located entirely within the Inuvialuit Settlement Region and would extend 14.7 kilometres in a 30-metre wide right of way from the Niglintgak gas conditioning facility to the Taglu gas conditioning facility. The route would traverse the flat delta eastwards, and cross three major channels before reaching the Taglu gas conditioning facility.

On the record

Route and site selection criteria

The criteria used by the Proponents to evaluate the preliminary route and identify alternatives included:

- route placement, including options for reducing the length of the pipeline, potential facility sites, and locating the right of way in order to avoid encroaching on existing habitats, be close to existing infrastructure, and parallel or use existing linear disturbances;
- reducing the number, complexity, and width of watercourse crossings;
- geotechnical considerations such as avoiding springs, perched aquifers and steep, ice rich, or unstable slopes, and the distribution of discontinuous permafrost;
- environmental considerations such as land use plans, socio-economic concerns, and reducing proximity to critical wildlife habitat and important cultural or archaeological sites;
- construction matters such as slopes, muskeg and fen areas, grading, access, ground conditions, crossing linear facilities, and the need for adequate workspace;
- community interests; and
- relative costs of the route alternatives.

On the record
Route and site selection process

The Proponents' stated objectives in the route and site selection process for the Mackenzie Gas Project included:

- avoiding sensitive environmental and cultural areas;
- reducing disturbance to communities and the landscape;
- satisfying engineering and construction requirements; and
- reducing cost.

The Proponents set up multidisciplinary teams of engineering, construction, and environmental specialists to assess potential pipeline routes and facility sites. These teams assessed available information from previous pipeline studies and proposals in the area to determine the potential for using these previously considered locations.

The following methodology was used by the Proponents to select the Mackenzie Gas Project's proposed route and sites for the associated facilities:

- establish route and site selection criteria;
- identify preliminary pipeline routes, sites, and alternatives;
- conduct field investigations involving community representatives;
- revise preliminary site and route locations based on field investigations;
- consult with communities on sites and routes; and
- revise site and route locations, where practical, based on community input.

The selected preliminary route for the Mackenzie Gathering System and Mackenzie Valley Pipeline followed the alignment of the 1984 Polar Gas Project application route from the Mackenzie Delta to Norman Wells, and paralleled the existing Enbridge Pipelines (NW) Inc. Norman Wells Pipeline from Norman Wells to the Northwest Territories /Alberta border.

Alternatives to the preliminary route were identified by the Proponents for further investigation through desktop study, field investigations, and community consultation using the route and site selection criteria set out below.

The preliminary routes and alternatives for the Mackenzie Gas Project were divided for evaluation into 15 segments for the upstream gathering pipelines and 29 segments downstream of the Inuvik Area Facility. Within each segment multiple routes were identified and assessed. After a route within each segment was selected, field reconnaissance and community consultation were carried out to make further routing refinements. These refinements:

- recognized route issues such as the severity of side hill slopes not evident during the desktop study;
- took advantage of more favourable terrain, such as better approaches to water crossings; and
- used other features, such as cut lines.

Did you know?

Definitions

General route – when a pipeline company applies to the National Energy Board under the *National Energy Board Act* for approval of a pipeline longer than 40 kilometres, the first stage involves the assessment of the project. At this stage, the company files an application to the National Energy Board that includes a general route, which may be a corridor that is much wider than the actual right of way that would ultimately accommodate the pipeline. In the case of the Mackenzie Valley Pipeline, the applied-for general route is a one-kilometre wide corridor, within which the much narrower pipeline right of way would be located. At this stage, the National Energy Board, through its public hearing process, considers a variety of factors, including the appropriateness of the general route, to determine whether the project should be approved. If the project is approved, the general route is also approved, and the pipeline company can proceed to the second stage of pipeline route approval, which is approval of the detailed route.

Preliminary or preferred route – in its application for approval of a pipeline project under the *National Energy Board Act*, a pipeline company may include with its proposed general route a preliminary or preferred route for its pipeline. Such a route often serves as the centerline for the corridor used by the company to define its proposed general route. This provides the pipeline company with a specific line of focus for feasibility, design, and impact studies for general route selection, and it can also provide advance opportunities for the company to focus its landowner and community engagement efforts for confirming and securing a final pipeline right of way route in preparation for detailed route approval.

Detailed route – if a pipeline company receives a certificate from the National Energy Board that approves its pipeline project, the company can proceed to the second stage of pipeline route approval, which is approval of its detailed route. At this stage, the pipeline company must prepare plans, profiles, and a book of reference (PPBoR) that describe the precise location of the pipeline right of way in relation to the land properties it crosses. The PPBoR define the pipeline company's proposed detailed route. The pipeline company must make the PPBoR available for public viewing and must serve notice on directly affected landowners as well as publish notices in newspapers in the vicinity of the proposed route. Landowners and persons that may be adversely affected have 30 days to file written statements of opposition to the proposed route. If the National Energy Board receives a written statement of opposition within the 30 day timeframe, the National Energy Board may set the matter down for a detailed route hearing, allowing the affected person to be heard by the National Energy Board before a decision is made on whether to approve that section of the detailed route. The pipeline company cannot start construction of any section of its proposed pipeline until that section of the detailed route has been approved by the National Energy Board.

Taglu lateral

The Taglu lateral would begin at the Taglu gas conditioning facility and extend 80.9 kilometres in a 40-metre wide right of way in a southeasterly direction crossing the east channel of the Mackenzie River to the Storm Hills pigging facility south of Big Lake. This lateral would be entirely within the Inuvialuit Settlement Region.

Parsons Lake lateral

The Parsons Lake lateral would extend 26.4 kilometres in a 30-metre wide right of way from the Parsons Lake gas conditioning facility located at the northeast corner of Parsons Lake, south around the lake, and then in a southwest direction to the Storm Hills pigging facility. All of these facilities would be located within the Inuvialuit Settlement Region.

Storm Hills lateral

The Storm Hills lateral would extend 67.2 kilometres in a 40-metre wide right of way from the Storm Hills pigging facility to the Inuvik Area Facility located in the Gwich'in Settlement Area.

Natural gas liquids pipeline

The proposed 457 kilometre natural gas liquids pipeline route would extend from the Inuvik Area Facility to Norman Wells where it would connect with the Enbridge Pipelines (NW) Inc. Norman Wells Pipeline. It would share a 50-metre wide right of way with the Mackenzie Valley Pipeline for all of its length except for the final one kilometre leading into Norman Wells, which would be located in a 30-metre wide right of way. The natural gas liquids pipeline would begin in the Gwich'in Settlement Area and terminate in the Sahtu Settlement Area.

Proposed route of the Mackenzie Valley Pipeline

The proposed 1196 kilometre Mackenzie Valley Pipeline route (see Figure 1-3) would:

- generally follow the Mackenzie Valley from the proposed Inuvik Area Facility to a pig receiver adjacent to the NOVA Gas Transmission Ltd. interconnect facility, just south of the Northwest Territories-Alberta border;
- pass through the Gwich'in and Sahtu Settlement Areas, and the Dehcho Region including both Crown and Aboriginal private lands;
- follow the existing Enbridge Pipelines (NW) Inc. Norman Wells Pipeline right of way for about 45 percent of its length and parallel previous disturbances, such as cut lines, the winter road, and the Mackenzie Highway;
- be located within the pipeline study corridor identified by the Dehcho First Nations and the Government of Canada; and
- share a common right of way with the natural gas liquids pipeline from the Inuvik Area Facility to Norman Wells, where the natural gas liquids pipeline would connect to the existing Enbridge Pipelines (NW) Inc. Norman Wells Pipeline.

5.2.2 Facilities site selection

The Proponents' site selection process for the Mackenzie Gas Project facilities involved the following activities:

- establishing site selection criteria;
- identifying preliminary sites and alternatives;
- conducting field investigations involving community representatives;
- revising preliminary site locations based on field investigations;
- consulting with communities on sites; and
- revising site locations, where practical, based on community input.

The Proponents initially identified five-kilometre target areas for each of the following facilities required to operate the Mackenzie Valley Pipeline: compressor stations, pig launching and receiving facilities, a heater station, and valve sites.

Similarly, five-kilometre target areas were identified for the Storm Hills pigging facility and the Inuvik Area Facility for the Mackenzie Gathering System.

The target areas were determined by a hydraulic analysis of the Mackenzie Gas Project pipelines. Alternative sites within the target areas were then identified and evaluated based on hydraulic requirements, proximity to the pipeline route, and site-specific environmental, construction, operations, and maintenance considerations, such as access. The assessment of potential pipeline valve sites along the route also considered the requirements for potential future compressor stations. This process led the Proponents to select the initial sites for the Storm Hills pigging facility and the Inuvik Area Facility for the Mackenzie Gathering System and the proposed compressor station sites, along with the heater station site and valve sites, for the Mackenzie Valley Pipeline.

5.2.3 Community and government input into route/site selection

The Proponents submitted that the route and site selection process involved extensive discussion with northern communities, northern regulators, land use planners, and other interested parties. The Proponents plan to continue consulting with stakeholders throughout the regulatory process.

Community representatives provided local knowledge about cultural resources and land use, as well as personal experiences with the Mackenzie Highway, the winter road, construction of the Enbridge Pipeline (NW) Inc. Norman Wells Pipeline, and local resource use. Some representatives provided input to the route evaluation teams, which was used in route selection.

The Proponents reviewed the pipeline route with representatives of the Dehcho First Nations and Indian and Northern Affairs Canada as part of its community consultation. This review was in support of the Dehcho interim land withdrawal process regarding the location and size of a potential pipeline corridor across the Dehcho Region, within which the lands would be identified to accommodate potential pipeline development. This process established a 2.5-kilometre wide pipeline corridor on the east side of the Enbridge Pipeline (NW) Inc. right of way near Trainor Lake, and a two-kilometre wide corridor on the east side of the Enbridge Pipeline (NW) Inc. right of way near Headwater Pond (Deep Lake).

The Proponents undertook two further field studies to assess and refine the route for larger watercourse crossings, such as the Ochre River crossing, and to align it with proposed facility sites, such as compressor stations, interconnections, and valve sites selected for potential future compressor stations.

Information from field studies and community consultation was used by the Proponents to refine the preliminary route and sites prior to filing its application with the National Energy Board. These refinements are summarized in Table 5-1.

Issues raised and route refinements made following filing of application

Subsequent to the Proponents filing their applications, a number of local Aboriginal communities identified routing and siting concerns and raised issues with the Proponents' route selection approach.

Sahtu communities identified key cultural areas, such as Bear Rock, that they believed should be protected in project design.

The Pehdzeh Ki First Nation opposed the proposed pipeline routing and siting of facilities in the Blackwater River area because of its historical, spiritual, and cultural significance. In addition, the Pehdzeh Ki First Nation raised concerns about the Proponents' plan to shift the route away from the existing Enbridge Pipelines (NW) Inc. Norman Wells Pipeline route so that it would be closer to the community of Wrigley. The Pehdzeh Ki First Nation also identified Smith Creek Falls as an important cultural area and recommended the proposed pipeline route be relocated as far away from this area as possible, subject to consultation with Pehdzeh Ki First Nation.

The Sambaa K'e Dene Band recommended that a proposed heater station be relocated to a site identified by the community in order to minimize the overall project footprint.

Local Aboriginal communities also urged that traditional knowledge be used in pipeline routing and selection of related facility sites. For instance, the K'ahsho Got'ine Lands Corporation submitted that traditional knowledge should play a decisive role in designing the routes and sites, and expressed concern that these decisions were being made by engineers which may not be familiar with the land or the traditional way of life.

Table 5-1

Refinements to the preliminary route

Project Change
Moving the proposed route about six kilometres farther east of Travaillant Lake to avoid disrupting areas of cultural and environmental significance to the Tsiigehtchic community and placing the proposed route in an area identified by local land users.
Moving the proposed route 2.5 kilometres east for 39 kilometres of its length to maximize distance from Trainor Lake (or K'eotsee Lake, as it is known) while remaining within the agreed-to Dehcho interim land withdrawal pipeline corridor, as requested by both the Trout Lake community and as identified in the Sambaa K'e Traditional Knowledge report.
Realigning about 4.5 kilometres of the proposed route at the Ochre River crossing to accommodate the preferred method of horizontal directional drilling.
Shifting the proposed route in the Willowlake River area to the east side of the Mackenzie Highway to avoid encroaching upon residences, areas of high archaeological potential, and historical big game mineral licks, as requested by the local community.
Moving about 8 kilometres of the proposed route up to 200 metres to the east to avoid a University of Alberta research plot and to connect into the proposed valve site.

In response to these issues, the Proponents indicated that traditional knowledge has been forthcoming through a variety of methods. Early in the project, the Proponents consulted local communities, particularly Elders and Elders' groups, to provide direction for establishing the pipeline route and some major facility sites. Community involvement helped the Proponents gain an understanding of areas to avoid, areas that would be acceptable, and areas that would be better alternatives. The Proponents also worked with communities to conduct traditional knowledge studies, such as the one conducted in the Gwich'in Settlement Area. The Proponents used the results of this study to assess and refine their project designs, and stated that they have made similar efforts for those areas affected by the project where traditional knowledge studies have been completed. For example, the Sambaa K'e Dene Band traditional knowledge study recommended that the Trout River heater station be moved about three kilometres south of its originally proposed site, and this change was adopted by the Proponents.

Based on further investigations, and in response to issues raised through its consultation program following its initial application filing with the National Energy Board, the Proponents made further changes to their proposed general routing and site locations which are shown in Table 5-2.

The Proponents submitted that the adjustments identified in their November 2005 project update reduce the proposed pipeline length, resulting in reduced footprint, cost, and environmental impact.

Responding to community input, increased costs, and ongoing engineering and construction planning, the Proponents filed another Project Update in May 2007. Although many of the project elements did not change, the Proponents relocated the proposed Great Bear River compressor station about eight kilometres downstream, to the east side of the Great Bear River, in response to requests from the community of Tulita. The Proponents submitted that moving the compressor station closer to Tulita is intended to reduce the cost of potential community access to natural gas and electricity, as well as to increase its distance from the culturally significant Bear Rock. To accommodate this adjustment, the one-kilometre wide pipeline corridor was realigned, which increased its length by 1.4 kilometres.

The Proponents submitted that when a site or proposed route is moved, the rationale for that change is documented, agreed to, properly approved, and recorded so that those involved in subsequent phases of the project have a reference record of commitments, changes, and issues.

In situations where the Proponents have not been able to make routing or siting adjustments to address concerns, they have sought other measures to help mitigate the concerns, such as changing the construction schedule. The Proponents stated that in those cases where agreement cannot be reached, the Proponents contact the concerned parties to explain why an agreement cannot be reached.

Subsequent to the November 2005 and May 2007 project updates filed by the Proponents, some routing and siting concerns were still being raised by Aboriginal communities in the Dehcho Region.

The Dehcho Elders and Harvesters stated that the routing of the pipelines and the siting of all project facilities and activities need to avoid burial and sacred sites.

The Dehcho First Nations submitted concerns that the Proponents' application forces assessment of the project at a very high, conceptual level rather than dealing with the specific concerns of their communities on issues such as pipeline routing and facility locations. As a result, the Dehcho First Nations argued that many community concerns about the project remain unaddressed, and that they are being referred to subsequent regulatory processes rather than being directly dealt with to resolve issues at this stage in the process. For example, the Dehcho First Nations submitted that the Proponents are seeking approval for various block valve locations without any consultations with them as to the acceptability of those proposed locations for future compressor stations.

Table 5-2

Project changes filed in November 2005

Project change
Moving the Inuvik Area Facility about 16 kilometres south, so it will be closer to the Dempster Highway and located on a flatter site.
Reducing the number of initial compressor stations from four to three, and relocating the proposed station sites within the corridor.
Increasing the number of valve sites to 11 and relocating three of the original valve sites to accommodate the revised system hydraulic requirements for potential future compressor stations.
Shortening the pipeline by about 26 kilometres as a result of relocating the Inuvik Area Facility, adjusting the pipeline corridor, and other route adjustments.
Shortening the pipeline by about 3.8 kilometres by straightening two segments of the preliminary route near Travaillant Lake and relocating the corridor to accommodate the rerouting.
Moving a 14.7 kilometre segment of the preliminary route near Wrigley up to two kilometres to the east, and making the necessary adjustments to the one-kilometre wide pipeline corridor, in response to a community request to move the pipeline further away from a sacred spring and burial grounds.
Relocating the Loon River valve site 14 kilometres to the north based on community feedback regarding a nearby hunting area, and converting the site to a compressor station site.
Exchanging the Blackwater River and Trail River compressor station for a single compressor station near River Between Two Mountains, in response to Pehdzeh Ki First Nation concerns about the culturally significant Blackwater River area and due to pipeline hydraulics considerations.

The Proponents submitted that, based on consultations with communities in the Dehcho Region, further project refinements included moving the Willowlake River block valve site, relocating the watercourse crossing on the Mackenzie River further upstream, and relocating the pipeline route near Satellite Lake.

The Proponents stated that consultation has not led to agreement in every case, and in some cases, the outstanding issues can only be addressed at the permitting stage, following the collection of additional information. They submitted that consultation about the project will continue, and that they will continue to strive to address outstanding concerns, although agreement may not be reached in every case.

The latest version of the consultation summary table filed by the Proponents indicates that there will be ongoing discussions with communities and others with regard to a multitude of project related matters. Regarding the proposed location of the pipeline route and related facilities, this table indicates that outstanding concerns remain regarding the proximity of the proposed pipeline right of way to Satellite Lake and the crossing of a possible underground stream in the vicinity of the community of Jean Marie River. The Proponents have committed to continue dialogue with the residents of Jean Marie River to try to address their concerns. The Proponents noted that the Mackenzie Gas Project's consultation program will continue throughout the regulatory process to afford an opportunity for communities to provide input on other project adjustments.

In its report, the Joint Review Panel concluded that, based on available information, it considers the location of the proposed pipeline corridor to be acceptable.

Views of the Board

We find that the general routes of proposed Mackenzie Gas Project pipelines, as defined by the one-kilometre wide corridors put forward by the Proponents, are appropriate. We are of the view that, using relevant information and experience for a Northern pipeline project, the Proponents applied a reasoned, systematic, and suitable methodology for selecting the initial locations of the pipelines and facility sites.

We recognize the concerns raised by some communities and stakeholders regarding the need to consider the presence and protection of culturally and ecologically sensitive features in selecting and adjusting the proposed general pipeline route and related facility locations. We note that the Proponents have demonstrated an ongoing commitment to hear from communities along the proposed route and have made a number of substantial adjustments to their selected pipeline and facility site locations to address community concerns, where possible and appropriate. We find the approach taken by the Proponents to listen to, and to deal with, community and stakeholder concerns in their determination and refinement of the general pipeline route and facility site locations to be acceptable and appropriate for this project.

The location of proposed block valve sites for future compressor stations is determined primarily by the system design of the pipeline. To some extent, their location can be adjusted to accommodate local community concerns. We expect the Proponents to continue consultation with local communities and make adjustments to accommodate their concerns where possible given the system design constraints.

Considering the nature of the lands to be traversed by the Mackenzie Gas Project, we are of the view that the proposed one-kilometre wide corridors provide sufficient flexibility to avoid or minimize impacts to landowners, communities, and sensitive ecological or cultural features in the determination and refinement of the detailed routes of the pipelines.

5.3 General land requirements

The Proponents estimated that the total amount of land required for the Mackenzie Gathering System pipelines, including the 457 kilometre natural gas liquids pipeline and related facilities, is approximately 3055 hectares. For the Mackenzie Valley Pipeline and related facilities, the Proponents estimated that 5265 hectares of land would be required. Land requirements are shown in Table 5-3.

Both the Mackenzie Valley Pipeline and the natural gas liquids pipeline can be accommodated within a 50-metre wide pipeline right of way between the Inuvik Area Facility and the Enbridge Pipelines (NW) Inc. Interconnect Facility at Norman Wells. South of Norman Wells, the Mackenzie Valley Pipeline would continue onward to the NOVA Gas Transmission Ltd. Interconnect Facility within a 40-metre wide right of way. Block valve and cathodic protection sites would be located within the proposed right of way. The proposed 50-metre wide right of way, shared by the Mackenzie Valley Pipeline and the natural gas liquids pipeline, would run for about 456 kilometres, and a 40-metre wide right of way would make up the remainder of the 1196 kilometre Mackenzie Valley Pipeline route.

The Proponents submitted that the different proposed pipeline right of way widths would provide work and travel areas to support safe and efficient construction, including a travel lane for the large construction equipment required (see Figure 5-1). During construction, temporary workspace along or near the right of way would also be required in such locations as:

- watercourse crossings;
- bypasses around ravines and wet areas;
- deep grade or large slope sites;
- construction equipment turnaround areas;
- sharp direction change areas;
- equipment storage areas;
- crossings of roads, highways, and other pipelines;
- valve site installations;
- pig launcher and receiver installations; and
- timber storage areas.

The Proponents estimated that more than 1600 temporary workspace sites, totaling about 420 hectares, would be needed in addition to the proposed right of way during construction. This excludes timber storage and bypass areas, which would be identified as construction planning and engineering progresses. Figure 5-2 shows the Proponents' anticipated typical land requirements, including potential temporary workspace needs, for a conventional open cut watercourse crossing.

The Proponents submitted that three compressor stations and one heater station are initially required for the proposed gas pipeline. The total land requirements for each compressor station would be 9.5 hectares, including allowances for living quarters and helipads. This reflects the size of the area to be cleared. However at the operations stage, each compressor station site would be smaller with an estimated fenced area of between six and seven hectares. The Trout River heater station would require a four hectare area.

Table 5-3

Land requirements by use

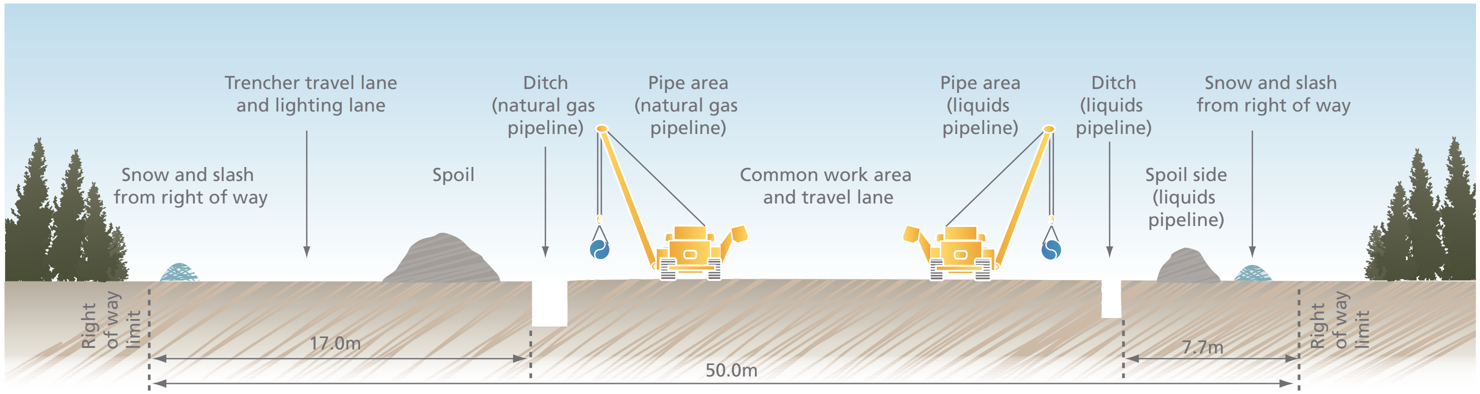
Land use	Total area[1] (ha)	Private land[1,2] (ha)
Gathering pipelines and facilities	770	105
NGL pipeline[3]	2285	1285
Gas pipeline and facilities	5265	1710
Infrastructure[4, 5]	2690	1150
Temporary workspace[4]	420	150
Total	**9150**	**3115**

1. Includes Commissioner's lands
2. Rounded to the nearest 5 ha.
3. Shared right of way with gas pipeline for 456 km, 2280 ha total.
4. The gathering system and gas pipeline share some sites.
5. Infrastructure includes access roads, barge landing sites, camps, pipe storage locations, borrow sites and airstrips, some of which will be required for operations.

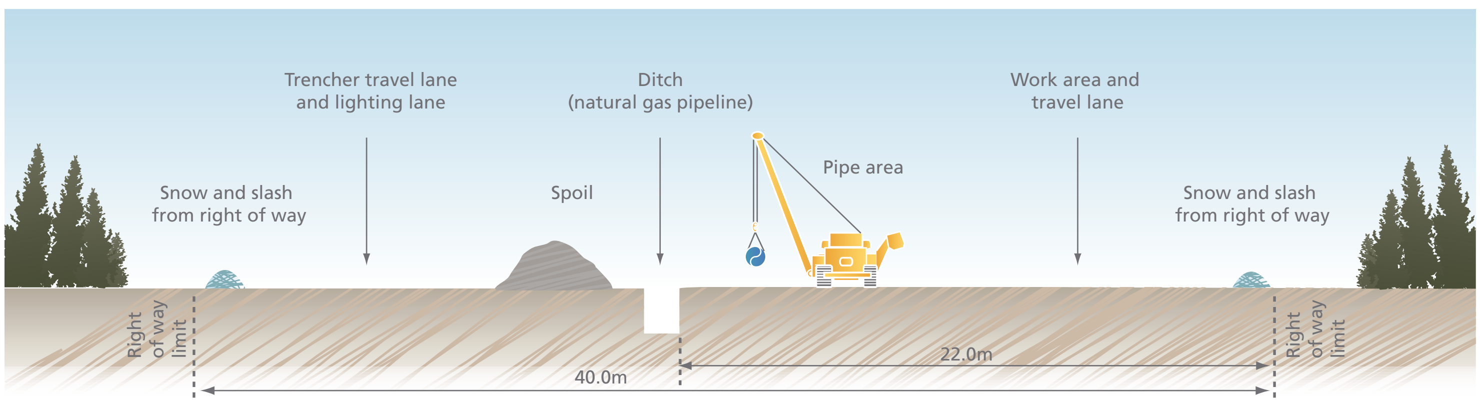
Figure 5-1

Typical right of way cross-sections

Gas and liquids pipelines - Inuvik Area Facility to Norman Wells



Gas pipeline - Norman Wells to Alberta



Some concern was raised about the amount of lands required for the proposed pipelines and related facilities. Alternatives North submitted that particular attention should be paid to minimizing land disturbance by using existing right of ways and minimizing the width of new ones. The Dehcho Elders and Harvesters submitted that too much land is being taken for the proposed right of way. They stated that its width should be reduced to only what is required to safely build the proposed pipeline, rather than taking extra land just to make the construction process easier, faster, and cheaper.

Conversely, the Lidlii Kue First Nation submitted that they would like the right of way to be as wide as is safely required for the Proponents to do their work.

The Proponents submitted that the minimum right of way width required for safe and efficient pipeline construction activities varies depending on terrain, pipeline size, the number of pipelines to be installed, and the access requirements for construction and support equipment. The Proponents stated that the proposed 50-metre and 40-metre right of way widths proposed for the project would allow for:

- stockpiling of loose surface materials removed during the grading operation;
- stockpiling of residue from the clearing operation;
- stockpiling of snow;
- pipe welding, trench excavating, and other pipeline installation activities;
- a travel lane for safely moving crews, equipment, and materials;
- temporary parking areas, primarily for crew transportation vehicles and equipment servicing and maintenance vehicles; and
- emergency shelters.

The Proponents initially considered using some of the existing Enbridge Pipelines (NW) Inc. right of way to reduce the new proposed right of way footprint. However, the much larger pipeline proposed for the Mackenzie Valley Pipeline is not as flexible and, therefore, could not always parallel the same route as the existing pipeline. The proposed route does parallel the existing

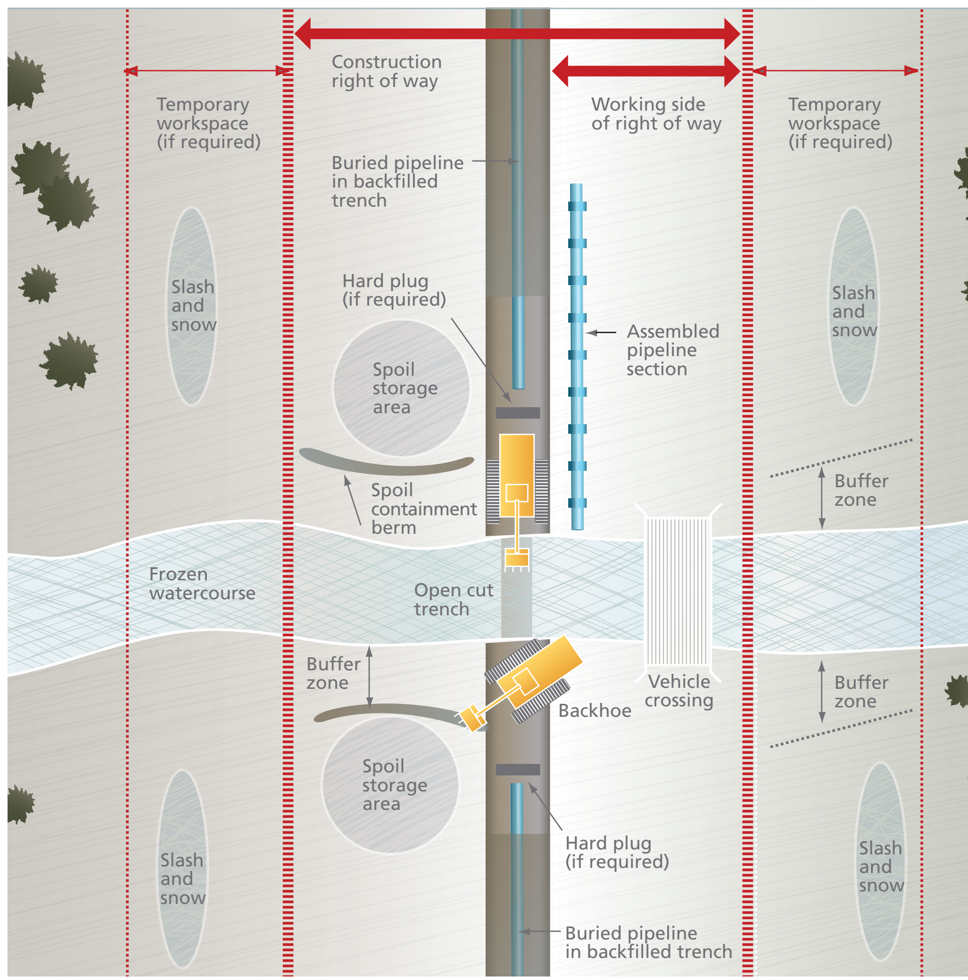


Figure 5-2

Typical land requirements at an open-cut watercourse crossing right of way in many locations, but the Proponents plan to generally maintain an undisturbed 20 to 100-metre wide buffer of native vegetation between the cleared portions of the two right of ways to reduce the potential for soil thaw interaction. In special cases, such as limited construction areas, the two right of ways may be adjacent to each other.

The Joint Review Panel accepted that the proposed widths of the various sections of the right of way are necessary and appropriate for safe and efficient construction. The Joint Review Panel further noted that it heard no evidence that would justify any widening of the right of way sections.

On the record

Narrowing the right of way

To enhance slope stability and reduce the need for reclamation, the Proponents stated that they would consider right of way widths narrower than the typical 50 metre and 40 metre widths at steeper slopes, such as at approaches to watercourse crossings. The Proponents stated that these reduced right of way widths would require additional clearing and temporary off-right of way access routes, known as shoo-flies, to safely move construction equipment. Therefore, the Proponents submitted, narrowing the right of way might not reduce the total amount of cleared land. The Proponents also stated that placing the gas and natural gas liquids pipelines within the same right of way along the proposed route from the Inuvik Area Facility to Norman Wells, was done with the intention of minimizing environmental impact.

Views of the Board

We find that, considering its nature and setting, the amount of land proposed to be required is reasonable and justified for safe and efficient construction of the Mackenzie Gas Project.

We recognize that 29 percent of the total length of the Mackenzie Gas Project and 44 percent of the proposed Mackenzie Valley Pipeline route pass through the Dehcho Region, where there is concern about the proposed width of the pipeline right of way. We note that the Proponents have identified lands in their permanent right of way that may not be needed for the long-term operation of the Mackenzie Valley Pipeline, namely the trencher travel lane and lighting lane as indicated in Figure 5-1. We expect the Proponents to give further consideration to opportunities for minimizing the width of the permanent right of way and maximizing the long-term reclamation of lands adjacent to the permanent right of way post-construction, as long as the safe and efficient operation and maintenance of the Mackenzie Valley Pipeline is not compromised.

5.4 Land use planning considerations

As land governance and regional planning in the Mackenzie Valley are in varying stages of development, we have considered the extent to which the Proponents have recognized and considered known land use planning objectives in their project design.

The *Mackenzie Valley Resource Management Act* establishes the land use planning authorities and frameworks for settlement areas in the Mackenzie Valley, including the Gwich'in and Sahtu Settlement Areas. Section 46 of the *Mackenzie Valley Resource Management Act* requires that federal and territorial bodies having authority to issue authorizations relating to land or water use or the deposit of waste, exercise their authority in accordance with the applicable land use plan in a settlement area.

To date, a land use plan for the Gwich'in Settlement Area has been approved, the Gwich'in Land Use Planning Board is in place, and the land use plan is being implemented. There is a preliminary draft land use plan for the Sahtu Settlement Area, although a land use planning board has not been fully constituted and its current status is unknown. Although a final land claim is not yet in place for the Dehcho Region, the Dehcho Land Use Planning Committee issued an update to its draft land use plan in November 2005. This Committee was established under the Dehcho Interim Measures Agreement, performs most of the roles contemplated for a land use planning board under the *Mackenzie Valley Resource Management Act*, and represents the land use planning views of the Dehcho communities and First Nations in the Dehcho Region.

Section 47 of the *Mackenzie Valley Resource Management Act* requires a planning board to determine whether an activity that has been referred to it or applied for, is in accordance with the land use plan. A referral or application must be made before the *issuance* of any authorization by the federal body. This obligation would also apply to any further land use plans that may be finalized and approved in accordance with *Mackenzie Valley Resource Management Act*.

The Proponents have undertaken to determine whether the Mackenzie Gas Project conforms to existing and draft land use plans in the Mackenzie Valley. On their own, and through the Canadian Association of Petroleum Producers, the Proponents held informal discussions with the applicable land use planning boards and committees before filing their land use permit applications. These meetings helped develop an initial appreciation of the degree to which the Mackenzie Gas Project conforms to the Gwich'in Land Use Plan and is consistent with the two unapproved land use plans. As a result, the Proponents filed applications for amendments and exceptions to the Gwich'in Land Use Plan.

The Proponents noted that, although their amendment and exception applications to the Gwich'in Land Use Planning Board were still in progress, they would require these approvals before deciding to proceed with construction of the proposed pipeline.

The Proponents have had discussions with and provided information to the organizations developing the Sahtu and Dehcho land use plans. The Proponents noted that generally these land use plans recognize and provide for the proposed pipeline through such means as defining a potential pipeline development corridor. The Proponents stated that they are awaiting further progress towards completion of land use plans in the Sahtu and Dehcho regions, and that it was premature to consider any similar applications for amendments to these draft land use plans. However, the meetings with the Sahtu and Dehcho organizations have provided an opportunity to understand and address potential land use plan consistency issues, including conforming to the pipeline corridor interim land withdrawal in the Dehcho Region.

The Proponents stated that they have and will continue to comply with all finalized land use plans. The Proponents also stated that they have addressed and will continue to address land use planning concerns in the Dehcho Region through the Dehcho Land Use Planning Committee until a Dehcho land use planning board is established.

A number of parties submitted that a comprehensive land use planning framework must be finalized and approved in accordance with the *Mackenzie Valley Resource Management Act* either before the Mackenzie Gas Project is approved or before construction commences. Some of these submissions, as well as other submissions, included suggestions to complete other land governance and conservation initiatives currently underway in the project region, including the Northwest Territories Protected Areas Strategy and the Dehcho Process (land claim negotiations in the Dehcho Region). Further, arguments made by Joint Review Panel parties referred to the Joint Review Panel recommendations and supported its view that regional land use plans and a network of protected areas are important and possibly the most effective conservation measures for managing cumulative impacts on areas of ecological and cultural importance.

The Yamoga Land Corporation submitted that until there is substantial progress on land use plans in the Sahtu and Dehcho Regions, no project approvals should be granted.

Alternatives North stated that the *Mackenzie Valley Resource Management Act* is an attempt to put together for the Mackenzie Valley an integrated system of land-use planning and other elements based on the negotiated provisions of constitutionally protected Aboriginal land claim agreements. According to Alternatives North, the problem is that this system has not been fully implemented or funded, and that completing the proper implementation of this system, as set out in many of the Joint Review Panel's recommendations, is required to adequately manage the scale and pace of development that will come with the Mackenzie Gas Project. Alternatives North argued that, while most of the Joint Review Panel's recommendations are aimed at government, we could and should reinforce the need for this work in any approvals we may issue. Consequently, Alternatives North recommended that, if we are not persuaded to adopt the future-oriented Joint Review Panel recommendations, then we should limit the capacity of the Mackenzie Valley Pipeline to 23.5 Mm^3/d (0.83Bcf/d) and make any future expansions subject to full implementation of the Joint Review Panel's recommendations by governments and the Proponents. Alternatives North also submitted that it supports the need for an approved Dehcho Land Use Plan before the Mackenzie Gas Project proceeds, and that the Dehcho Process negotiations should be completed before construction begins.

The Sambaa K'e Dene Band stated that it supports the finalization of a Dehcho land claim agreement, the approval of the Dehcho Land Use Plan, the finalization of protected areas, and establishment of a Dehcho Resource Management Authority as a precondition to construction of the Mackenzie Gas Project.

The Sierra Club of Canada argued that, based on the Joint Review Panel's recommendations, we should set out conditions for the establishment of interim withdrawals to support a network of protected areas and land use plans to incorporate thresholds and limits of acceptable change prior to commencement of construction of the project.

The Dehcho Elders and Harvesters submitted that access to their rights in the Dehcho Territory for the Mackenzie Gas Project should be delayed until the Dehcho Process has been concluded. They stated that conclusion of the Dehcho Process with a final agreement would provide the Dehcho Dene with a clear and necessary authority to ensure that the Mackenzie Gas Project could only proceed in a manner acceptable to them and with their full involvement in all aspects of the project. The Dehcho Elders and Harvesters noted that the draft Dehcho Land Use Plan was ratified by the Dehcho First Nations in 2006, but that the governments of Canada and the Northwest Territories have yet to adopt this plan. They argued that they cannot support the Mackenzie Gas Project approval without a Dehcho Land Use Plan in place to protect their rights and their sovereignty. They stated that the Dehcho Process and the Dehcho Land Use Plan need to be resolved before the Mackenzie Gas Project can be allowed to proceed to construction.

The Dehcho First Nations also maintained the position that the Dehcho Process must be concluded and that the final Dehcho Land Use Plan be in place as soon as possible, and at least before the Mackenzie Gas Project proceeds to construction, as development needs to occur in an orderly fashion with the appropriate and necessary land governance and planning structures in place. The Dehcho First Nations argued that, if the Dehcho Land Use Plan had already been implemented, many of the Dehcho's concerns could have been eliminated. They maintain that having a legally-binding agreement and land use plan in place are the only affordable and secure ways in which Dehcho interests in relation to the Mackenzie Gas Project can be represented and protected.

Canadian Parks and Wilderness Society argued that the National Energy Board, as the primary decision maker for the Mackenzie Gas Project, should consider that as a condition of construction, existing initiatives such as the Protected Areas Strategy be implemented ahead of construction. Understanding that these initiatives are outside of the National Energy Board's legal authority, Canadian Parks and Wilderness Society submitted that we could do this by acknowledging these matters in our certificate conditions as in the best interests of sustainability and construction of the pipeline. Then the National Energy Board could have the ability to monitor and comment on the status of governments' compliance to the Joint Review Panel Report recommendations, to provide encouragement for fulfilling timelines and expectations set out for conservation and community initiatives.

World Wildlife Fund Canada submitted that chief among its concerns was Joint Review Panel recommendation 11-3, which is to complete implementation of the Mackenzie Valley Five-Year Action Plan of the Northwest Territories Protected Areas Strategy prior to commencement of Mackenzie Gas Project construction. World Wildlife Fund Canada recommended that we clearly and publicly state that the Mackenzie

Gas Project would only be in the public interest if all of the Joint Review Panel's recommendations are implemented, even if recommendations such as 11-3 are not within the National Energy Board's authority to implement.

In its report, the Joint Review Panel accepted that taken in isolation, the impacts from the Mackenzie Gas Project on existing and proposed protected areas and on the establishment of a network of protected areas in the Mackenzie Valley would not likely be significantly adverse. The Joint Review Panel stated that it was satisfied that, if the Proponents fulfill their commitments and follow through with a process of ongoing consultation with communities, wildlife management boards, regulators, and Northwest Territories Protected Area Strategy committees during engineering design and refinement, the quantum of those lands that remain undisturbed would still allow for the conditions of land use and conservation plans to be met and the objectives of the Northwest Territories Protected Areas Strategy to be largely realized. The Joint Review Panel noted that the Mackenzie Gas Project would introduce some new development constraints on the conditions for managing conservation and development in the existing and proposed land use and conservation plans. However, this was anticipated to some extent in these plans through identification and reservation of an infrastructure corridor for the pipeline, through interim withdrawal of selected conservation lands, and through procedural arrangements established to accommodate this type and level of development.

The Joint Review Panel also noted its view that, in the absence of a completed settlement agreement under the Dehcho Process or an approved land use plan for the Dehcho Region, Aboriginal interests in managing and protecting traditional and non-traditional land uses and land access in the Dehcho Region may not be fully realized. The Joint Review Panel was of the view that the Dehcho Process land claim negotiations between the Dehcho First Nations and the governments of Canada and the Northwest Territories should continue to be of the highest priority to all negotiating parties. However, the Joint Review Panel agrees with the governments of Canada and the Northwest Territories that final approval and implementation of a land claim agreement with the Dehcho First Nations should not be a condition precedent for approval of the Mackenzie Gas Project.

Views of the Board

We are satisfied that the Proponents have provided reasonable assurance that they are working with the appropriate authorities to ensure that the Mackenzie Gas Project conforms to the land use plans approved or drafted pursuant to the *Mackenzie Valley Resource Management Act*. These plans generally contemplate infrastructure development along the proposed general route of the Mackenzie Valley Pipeline.

We note that the Dehcho land claim process continues and an interim land use plan is in place for the region. Concerns from Dehcho communities also led to a number of route and design changes that now form part of the commitments the National Energy Board will enforce. A number of our conditions respond to Dehcho concerns such as participation in environmental monitoring and wildlife management.

5.5 Land acquisition

5.5.1 Land ownership in the Mackenzie Gas Project area

The Proponents provided the following breakdown of lands crossed by the proposed Mackenzie Gas Project:

- 174.2 kilometres crosses the Inuvialuit Settlement Region, of which 23.4 kilometres (13 percent) is privately owned Aboriginal lands (Inuvialuit private lands) and the remainder is federal Crown land;
- 181.2 kilometres crosses the Gwich'in Settlement Area, of which 106.2 kilometres (59 percent) is privately owned Aboriginal lands (Gwich'in private lands) and the remainder is federal Crown land;
- 231.1 kilometres crosses the K'ahsho Got'ine District of the Sahtu Settlement Area, of which 118.9 kilometres (51 percent) is privately owned Aboriginal lands (Sahtu private lands) and the remainder is mostly federal Crown land and some Government of the Northwest Territories land;
- 270.4 kilometres crosses the Tulita District of the Sahtu Settlement Area, of which 128.3 kilometres (47 percent) is privately owned Aboriginal lands (Sahtu private lands) and the remainder is mostly federal Crown land and some Government of the Northwest Territories land;
- 528 kilometres crosses the Dehcho Region, of which 10.4 kilometres (2 percent) is privately owned Aboriginal land (Sahtu private land) and the remainder is federal Crown land administered by Indian and Northern Affairs Canada pursuant to the Dehcho Interim Measures Agreement; and
- 0.05 kilometres crosses provincial Crown land in Alberta.

The Mackenzie Gas Project's proposed route crosses five major land regions: the Inuvialuit Settlement Region; the Gwich'in Settlement Area; the Sahtu Settlement Area; the Dehcho Region; and Alberta (see Figure 1-7). Land ownership and administration differ in each region. Generally, there are six different types of landowners with which the Proponents would have to acquire land rights. These landowners include:

- Indian and Northern Affairs Canada, which issues tenure on federal Crown land;
- the Government of the Northwest Territories, which issues tenure on Commissioner's and municipal land (both of which comprise about three percent of all land in the Northwest Territories and are concentrated within or near municipal boundaries;
- the Inuvialuit Land Administration, which provides tenure on privately owned lands acquired through the Inuvialuit Final Agreement, 1984;
- the Gwich'in Tribal Council, which provides tenure on privately owned Aboriginal lands acquired through the Gwich'in Comprehensive Land Claim Agreement, 1992;
- District Land Corporations in the Sahtu Settlement Area, which provide tenure on privately owned Aboriginal lands acquired through the Sahtu Dene and Métis Comprehensive Land Claim Agreement, 1993; and
- the Government of Alberta, which allocates tenure on provincial Crown lands.

With the exception of those components in the Inuvialuit Settlement Region and the small Alberta component, the proposed Mackenzie Gas Project route is within the area subject to the *Mackenzie Valley Resource Management Act*. Land and water boards have been established pursuant to the *Mackenzie Valley Resource Management Act*. These boards issue land use permits that provide land tenure on Crown lands for terms of less than five years. They also issue land use permits on privately owned Aboriginal lands once access agreements have been reached with the respective Aboriginal authority. Within the area subject to the *Mackenzie Valley Resource Management Act*, both the necessary land tenure from the landowner and a land use permit from the appropriate land and water board must be obtained. The land use permit authorizes the proposed activity, while the land tenure authorizes access to and occupation of the land requested to carry out that activity.

5.5.2 The Proponents' land acquisition approach

The type of land ownership along the route of the project, particularly the distinction between Crown land and privately owned Aboriginal land, is an important factor in the Proponents' approach to land acquisition for this project.

The Proponents submitted that long-term land rights would be required for the proposed Mackenzie Gas Project pipelines and related facilities. Short-term land rights under several types of land tenure instruments would be required for temporary workspace such as crossing areas and camp sites during construction.

On federal and provincial Crown lands and the Government of the Northwest Territories lands, the Proponents would apply for easements, leases, licences, and permits depending on the need for exclusive or non-exclusive access to the right of way and related facilities. Temporary workspace would be authorized by land use permits, although other surface tenure may also be required for temporary land use. The Proponents noted that easement and right of way agreements are typically used to obtain surface access rights for a pipeline where exclusive possession of the land is not required, and where the surface of the land is reclaimed. However surface leases are typically used to obtain sites for surface facilities such as compressor and heater stations, where a tenure holder requires the right for exclusive, ongoing use of the land surface.

Did you know?

Land tenure instruments

Easement – an easement agreement is the most common agreement that a pipeline company acquires for the right to use the land for a pipeline. Simply put, it is the right that a pipeline company has over the land of another, usually confined to that strip of land which forms the pipeline right of way. The landowner still owns the land, but the pipeline company has acquired certain rights over that land to build and operate a pipeline. In this way, the easement is a written contract that sets out the rights of the company and the rights of the landowner. The easement agreement usually covers things such as: the land area subject to the easement; the size and location of the right of way; protection from liabilities; how the land will be used; terms of payment; legal responsibilities of the pipeline company and the landowner; and any land use restrictions. A pipeline company may offer the landowner a standard easement, but its final form and contents are a matter of negotiation. If the landowner sells its land, any future landowners must also follow the terms and conditions of the easement agreement. The land remains subject to the easement agreement until the pipeline company officially removes it.

Lease – a lease agreement is an agreement whereby the landowner gives the right of possession to another (such as a pipeline company) for a specific period of time and for a specific amount of rent. Similar to easements, the landowner still owns the land, but the pipeline company has acquired the right to occupy and use the land for a certain purpose. The holder of a lease has certain well defined rights which may be enforceable without the agreement of the landowner. Leases are usually acquired by pipeline companies for areas where they need secure, enforceable rights of exclusive use for a long period of time, such as for building and operating surface facilities like compressor stations and heater stations.

Licence – a licence has different meanings, depending on the situation. For instance, in the Mackenzie Valley, a licence may refer to an authorization for the use of waters or the deposit of waste, or both, issued by a board under the *Northwest Territories Waters Act*. Generally, for land tenure purposes, a licence (typically referred to as a licence of occupation) is permission to do something on the land owned by somebody else that, without such permission, would be unlawful. Unlike a lease, a licence is not an estate or an interest in the land and therefore does not carry its own title and cannot be bought or sold like other property. The holder of a licence has fewer legal rights than the holder of a lease. The use of the licence must be limited to the activity or activities authorized by the licence, otherwise the licence holder may be treated as a trespasser. Unlike an easement, a licence can be revoked at will by the landowner. A pipeline company may choose to obtain a licence where it needs to access and use a parcel of land for a shorter period of time and does not need extra measures to maintain exclusive use of that land. An example could be the need to travel on a private road.

Permit – generally, a land use permit is permission granted by the landowner to carry out specific works or activities on a specific area of land for a limited period of time. In the Mackenzie Valley, land use permits are issued by land and water boards for temporary authorization (typically two to five years) of certain activities to be carried out on a certain area of land. In the Inuvialuit Settlement Region, land use permits are issued by the Inuvialuit Land Administration on Inuvialuit private lands and by Indian and Northern Affairs Canada on federal Crown land. These land use permits allow for certain uses of the land but do not convey the permission to enter and occupy that land. A pipeline company must get permission from the landowner before it can carry out its authorized activity on that land as provided for in the land use permit.

Access Agreement – in the Northwest Territories, an access agreement outlines the terms and conditions, including financial arrangements, for access on or through land with Aboriginal interest. Access agreements may also include details on benefits. In some areas, such as the Gwich'in and Sahtu Settlement Areas, these agreements are legislated under land claims, and in other areas, such as the Dehcho Region, they are voluntary agreements between groups. In the Mackenzie Valley, access agreements also constitute permission from the Aboriginal landowner or group to apply to the appropriate land and water board for a permit or licence. Such permission is required before these land and water boards will consider a permit or licence application.

Land tenure agreements would also be required for those privately owned Aboriginal lands crossed by the proposed Mackenzie Gas Project route and facilities. These agreements would either be site-specific authorizations or an initial agreement reserving the right to access lands and establishing a framework within which site-specific authorizations or agreements are obtained.

Access agreements

The Proponents recognized that securing access to privately owned Aboriginal lands, as well as unsettled lands in the Dehcho Region, requires a contract between itself and the landowner called an access agreement.

The Proponents noted that while there are fewer private landowners along the proposed Mackenzie Gas Project route than in other jurisdictions, there is also less process assurance associated with securing site-specific access agreements over privately owned Aboriginal lands. Access to the surface rights legislation, boards and processes needed to secure site-specific access agreements on private land does not exist in the Northwest Territories. Land claim agreements provide for surface rights legislation, but it has not been acted upon.

The Proponents stated that they are negotiating access agreements with all the Aboriginal landowners recognized in land claim agreements, in addition to the Dehcho First Nations, for the areas crossed by the proposed route. The Proponents noted that the Inuvialuit, Gwich'in, and Sahtu Dene and Métis land claim agreements provide for private land ownership by the Inuvialuit, Gwich'in, and Sahtu, respectively. Under the Dehcho Process, land ownership is a matter between the Dehcho First Nations and the Government of Canada. The Proponents submitted that they will comply with, and respect, applicable agreements reached between the Dehcho and the Government of Canada through the Dehcho Process, as well as applicable land claims agreements, treaties, and legislation.

The Proponents noted that typically they would strike an initial agreement with an Aboriginal private landowner, such as a district land corporation, that provides a basis for securing a specific right of way, once its location has been finalized and confirmed.

Issues raised by parties during the proceeding focused on the Proponents' approach for acquiring access agreements on Aboriginal lands. Some parties requested information on or raised concerns regarding the status of access agreement negotiations while others submitted that the Proponents should sign access agreements with the relevant Aboriginal groups before the project is approved. For example:

- The K'ahsho Got'ine District Lands Corporation asked the Proponents how many Aboriginal landowners had signed access agreements and why they chose to file their project application before access agreements were in place. The Corporation submitted that the Proponents are not prepared to modify their standard form access agreements or consider alternative ideas. The K'ahsho Got'ine District Lands Corporation contended that the Proponents have decided to gain access to K'ahsho Got'ine District Lands Corporation's lands through expropriation rather than expending the effort necessary to build a trusting relationship or engage in meaningful two-way dialogue with Aboriginal landowners.
- The Dehgah Alliance Society asked the Proponents if they would continue into the project design and construction phase in the Dehcho Region if they had not signed an access agreement with the Dehcho communities. The Dehgah Alliance Society submitted that the Proponents should be required to conclude an access agreement, including access fees, with the Dehcho First Nations before the National Energy Board approves the project.
- The Sambaa K'e Dene Band argued that neither the Proponents nor Canada has respected the Sambaa K'e Dene Band's right and its stated preference to independently negotiate an area-specific impact benefit agreement with the Proponents. The Sambaa K'e Dene Band submitted that if the Proponents continue to refuse its request to enter into negotiations, then Canada must address section 35 accommodation matters relating to impacts to traditional land use before the issuance of a certificate for the Mackenzie Gas Project, so we can be assured that the project will have unchallenged access to the land required for the project.

- The Dehcho Elders and Harvesters submitted that Dehcho corridor communities must be covered by an access agreement granting permission to use Dehcho traditional lands before the Mackenzie Gas Project is allowed to proceed.
- The Liidlii Kue First Nation stated that we must require as a condition of approval that the Proponents enter into a benefits agreement with Liidlii Kue First Nation and the Dehcho First Nations that meets the needs of all of them fairly.
- The Dehcho First Nations stated that access agreements and benefits agreements are required before the final pipeline route is approved, and that permission for the Proponents to access Dehcho traditional lands will only be granted through an access agreement.

The Proponents stated that they have made some progress on concluding access agreements over these privately owned Aboriginal lands, but that the work is not complete. Access agreements have been executed with the Gwich'in Land Administration and the Tulita District Land Corporation for part of the Sahtu Settlement Area. These two agreements include processes under which site-specific access could be granted. However there is still some process associated with securing site-specific access if and when the Proponents finalize and receive regulatory approval for its pipeline right of way and related facility site locations. The Proponents stated that they are working towards concluding an access agreement with the K'ahsho Got'ine District, and are still in negotiations with the Dehcho First Nations to obtain a similar access agreement for the Dehcho Region.

The Proponents indicated that negotiating access agreements is intended to precede the start of construction, and that site-specific access agreements need to be concluded with all private Aboriginal landowners in order to satisfy regulatory requirements for issuing land use permits. The Proponents stated that they have offered, and continue to offer, to negotiate mutually acceptable access agreements for the Dehcho Region and the K'ahsho Got'ine District in the Sahtu Settlement Area.

The Proponents also submitted that concluding site-specific access agreements with all private Aboriginal landowners would require more time after project approval, if it is granted, than is the case for other pipeline projects because of greater complexity and less certainty in process and timing. The Proponents stated that even if they receive a certificate from us, they must still apply for, and receive, National Energy Board approval for the detailed route of the Mackenzie Valley Pipeline right of way within the identified one-kilometre wide corridor before they can conclude site-specific access agreements with Aboriginal landowners.

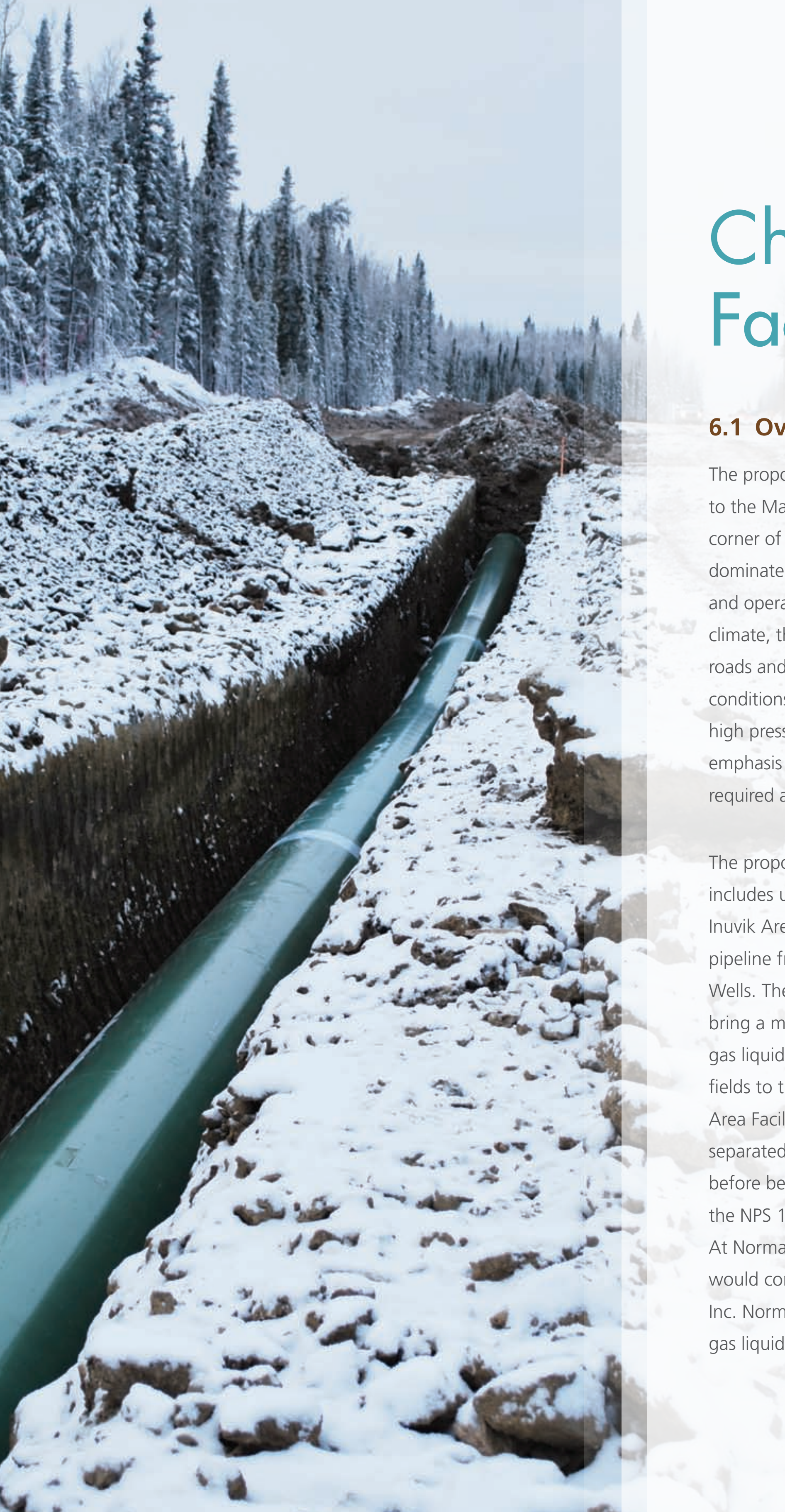
The Proponents stated that, for the Mackenzie Valley Pipeline, notices pursuant to subsection 87(1) of the *National Energy Board Act* would be served on all owners of lands where agreements are required along with copies of any National Energy Board bulletins and guides that outline the rights and remedies available to landowners. The Proponents also submitted that there is no standard access or tenure agreement specific to the Mackenzie Valley Pipeline, and the terms, conditions, and compensation are to be negotiated. These agreements would include the provisions required by subsection 86(2) of the *National Energy Board Act* and applicable land claim agreements.

The Proponents submitted that, as of April 2010, benefit and access agreements have been negotiated in all regions except the Dehcho Region.

Views of the Board

We find the Proponents' land acquisition approach to be appropriate, considering the special circumstances of land ownership and administration in the Mackenzie Valley. We note the Proponents' commitment to negotiate access agreements with all private Aboriginal landowners. Further, we recognize the Proponents' commitment to enter into access negotiations with the Dehcho First Nations.

We recognize the Proponents' efforts to comply with the land acquisition requirements of the *National Energy Board Act.* We are of the view that the Proponents have demonstrated that they will be respectful of landowner rights and concerns.



Chapter 6 Facilities

6.1 Overview of facilities

The proposed Mackenzie Gas Project extends from the three development fields in and adjacent to the Mackenzie Delta (see Chapter 4), south along the Mackenzie River Valley into the northwest corner of Alberta (see Figures 1-2 and 1-3). The land changes along the route from the water-dominated Mackenzie Delta and treeless tundra to boreal forest in Alberta. Design, construction and operation of the pipelines and associated facilities are directly influenced by the harsh northern climate, the presence of permafrost, a unique transportation infrastructure that relies on ice roads and the Mackenzie River and the potential effects of climate change. To address the unique conditions of the project, the Proponents proposed a number of design innovations, including very high pressures, high strength steel, strain-based design, the use of statistical techniques and a greater emphasis on monitoring and subsequent intervention. A fundamental issue was the level of detail required at the approval stage to support our decision on whether or not to approve the project.

The proposed Mackenzie Gathering System includes upstream gathering pipelines, the Inuvik Area Facility and a natural gas liquids pipeline from the Inuvik Area Facility to Norman Wells. The upstream gathering pipelines would bring a mixture of natural gas and natural gas liquids produced at the three development fields to the Inuvik Area Facility. At the Inuvik Area Facility the natural gas liquids would be separated from the natural gas and stabilized before being shipped south to Norman Wells in the NPS 10 (DN 250) natural gas liquids pipeline. At Norman Wells the natural gas liquids pipeline would connect to the Enbridge Pipelines (NW) Inc. Norman Wells Pipeline on which the natural gas liquids would be shipped in batches.

The proposed Mackenzie Valley Pipeline is an NPS 30 (DN 750) natural gas pipeline which would share the same right of way as the natural gas liquids pipeline from the Inuvik Area Facility to Norman Wells. It would then continue in a separate right of way into northern Alberta, where it would connect to facilities to be constructed by NOVA Gas Transmission Ltd.[1]

[1] NOVA Gas Transmission Ltd. filed an application with the Alberta Energy and Utilities Board on 27 June 2006 requesting a permit to construct the proposed Northwest Mainline (Dickins Lake Section), Northwest Mainline Loop (Vardie River Section) and the Northwest Territories Border Meter Station. The Alberta Energy and Utilities Board subsequently announced that it would postpone the establishment of a date for the hearing on these facilities pending the issuance of the Joint Review Panel Report. On 29 April 2009 the NOVA Gas Transmission Ltd. system became subject to the jurisdiction of the National Energy Board. As a result, NOVA Gas Transmission Ltd. must file a new application with the National Energy Board for these facilities.

The Mackenzie Valley Pipeline is designed to operate at a pressure of 18.7 MPa (2,710 psi).

6.2 Assessment of engineering Issues

When assessing an application for proposed facilities, the National Energy Board considers the facilities' design and proposed operation to determine whether the project would be constructed and operated in a safe, reliable and environmentally responsible manner. As mentioned in Chapter 2, pipelines under National Energy Board jurisdiction must be designed in accordance with the National Energy Board's *Onshore Pipeline Regulations, 1999* and the latest versions of relevant design codes, including *Canadian Standards Association Z662, Oil and Gas Pipeline Systems*.

A number of engineering issues were examined in our hearing, some unique to the northern climate, others typical of pipelines in Canada. These issues are grouped into the following categories and discussed in this chapter.

Overall design strategy:

- design process;
- cost estimate;
- stress-based and strain-based design, including consideration of frost heave and thaw settlement; and
- hydraulic design and proposed configuration of the Mackenzie Gathering System, the Mackenzie Valley Pipeline and station facilities.

Specific design issues:

- pipeline operating temperatures;
- pipeline materials;
- joining (including welding and non-destructive examination);
- seismic design;
- slopes;
- watercourse crossings;
- pipeline control systems and leak detection;
- settlement of backfill; and
- geohazards.

Other technical considerations:

- air emissions;
- pressure testing;
- support infrastructure;
- northern logistics and construction;
- right of way protection; and
- monitoring and surveillance plans.

6.3 Overall design strategy

6.3.1 Design process

The Proponents presented a three-phase design process for the Mackenzie Gas Project: conceptual engineering; preliminary engineering; and detailed engineering design (see Figure 6-1). The Proponents stated that the applications submitted to the National Energy Board were based on conceptual engineering and that preliminary engineering started after the applications were filed.

The detailed engineering phase takes into account the information from the previous design phases, inputs from the regulatory phase and additional information collected through field investigation programs. Detailed engineering results in products which can be used to initiate contracting and construction activities and would not start without project approval.

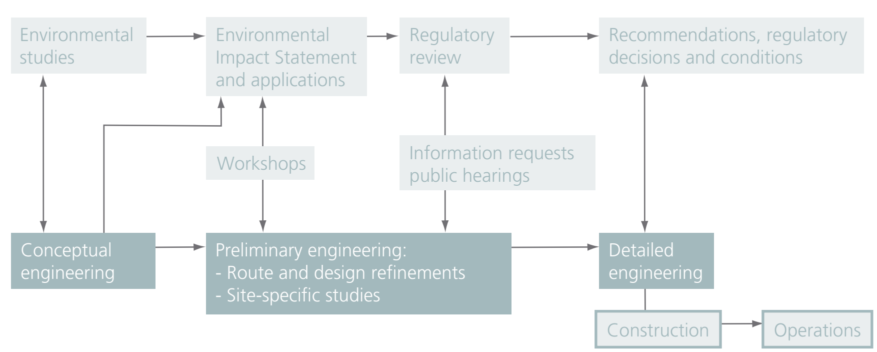


Figure 6-1

Engineering design process

6.3.2 Cost estimate

The initial cost estimate for the Mackenzie Gas Project was prepared by the Proponents based on the proposed scope of work at the completion of the conceptual design phase. After filing the application, the preliminary engineering phase began. This resulted in revised cost estimates, which were based on:

- improved definition of project materials and labour;
- designs for slope stability and watercourse crossings;
- project construction plans; and
- costs of the regulatory process.

These revisions were subsequently filed with us and are shown in Table 6-1 and Figure 6-2. The capital cost estimate included expenditures for engineering design, procurement, owners' costs and construction, but excluded an allowance for funds used during construction.

Table 6-1

Project expenditures 2007 update

Project component	Estimated cost *(2006$ million)*
Niglintgak	800
Taglu	1,750
Parsons Lake	1,200
Mackenzie Gathering System	3,500
Mackenzie Valley Pipeline	7,050
Total initial cost	**14,300**
Future Mackenzie Valley Pipeline facilities	800
Future anchor field investments	1,150
Total cost	**16,250**

Costs for various project components were derived from different sources. The Proponents submitted that materials and equipment costs were based on estimates from suppliers for larger items such as pipe and valves and from the Proponents' own data or manufacturers' price lists for smaller times. The capital costs for spares were estimated on the basis of manufacturers' recommendations. By comparison, construction cost estimates were based on detailed construction industry data for pipelines and infrastructure. Construction cost estimates included allowances for:

- past experience;
- contractor input;
- northern conditions; and
- proposed construction methods.

A specific set of allowances for specific project risks and a contingency allowance based on the level of definition for each major project component were also factored into the cost estimate. The Proponents submitted that the method used to prepare and revise the capital cost estimate is consistent with the Association for the Advancement of Cost Engineering International's recommended practice for process industries.

Did you know?

Definitions

Strain – the deformation or change in pipe dimensions resulting from the applied loads.

Stress – the force per unit area experienced by the pipe at any given location in response to the applied loads.

Frost heave – the upward or outward movement of the ground surface caused by the formation of ice in the soil.

Thaw settlement – the settlement of the ground under its own weight or applied stresses caused by the loss of ice due to melting.

Strain-based design – designing a pipe by setting the limit (or maximum amount) of deformation that it can safely sustain.

Stress-based design – designing a pipe that can safely accommodate the predicted combination of internal and external loads without permanent deformation.

Thermal load – changes in temperature result in expansion or contraction of the pipeline (strain) which in turn induces a stress on the pipeline.

6.3.3 Stress-based and strain-based design

The Mackenzie Gas Project would be constructed and operated in Canada's harsh northern environment through terrain containing varying amounts of permafrost. The design of pipelines in permafrost terrain requires consideration of the thermal properties of the ground, the pipe and the product being shipped, and presents a number of unique geotechnical and structural engineering challenges. Freezing and thawing of the ground can cause frost heave, thaw settlement and slope instability.

These ground movements impose stresses and strains on the pipeline that need to be considered during design, construction and operation. Construction activities can disturb the permafrost and alter terrain conditions.

The conventional approach to pipeline design is based on allowable stresses. This approach measures or predicts the combination of internal and external loads a pipeline can safely withstand without deforming during operation. Information needed for stress-based design includes an understanding of the site-specific geotechnical properties of the soil around the pipe and its potential for interacting with pipe. These properties include soil type, presence of groundwater or permafrost, and the magnitude and likelihood of slope movements, seismic events or other geohazards.

An alternative approach is strain-based design, which focuses on the pipe's material and its behaviour. The pipeline designer sets boundaries or limits, referred to as limit states, which define the maximum amount of strain the pipe can safely tolerate. This approach, however, requires active monitoring to identify where and how fast the pipeline is changing or deforming.

The Proponents stated that they would use a lifespan engineering approach for the Mackenzie Gas Project that includes a combination of stress and strain -based design, construction mitigation and operational monitoring and interventions to ensure the integrity of the pipeline. The primary loads on the Mackenzie Valley Pipeline, such as internal pressure and dead weight, would be designed to meet the stress limits in *Canadian Standards Association Z662-07, Oil and Gas Pipeline Systems* while secondary loads such as frost heave and thaw settlement would be designed using a strain-based limit state design methodology.

The Proponents stated that the overall design approach relies on strain monitoring and mitigation during operation. A Geopig® tool travelling inside the pipe is able to determine longitudinal strains. When the strain at a given location is approaching the serviceability strain limit, the Proponents would take action such as:

- reducing the size and rate of frost bulb growth;
- reducing resistance to pipe movement;
- reducing settlement;
- providing additional pipe support;
- replacing the pipe; or
- relocating the pipe.

The Proponents submitted that specific intervention criteria for pipeline strain would be developed.

Following from this approach to overall project design, two issues arose during the hearing:

- the applicability of using a strain-based design for the Mackenzie Valley Pipeline and the Mackenzie Gathering System; and
- the type, amount and timing of site-specific geotechnical information required by the applicant in the design and regulatory approval processes.

Did you know?

Stress-based and strain-based design

Pipelines are designed to withstand a number of different loads. Some loads are permanent or remain constant for long periods of time, such as the pipeline's weight or that of the soil over the pipe. Operational loads such as internal pressure occur during the pipeline's operation and can vary over time. Environmental loads such as frost heave and thaw settlement can be of short or long duration. These loads are grouped into primary or secondary loads for pipeline design purposes.

Primary loads create stresses or forces within the pipe as long as the load is applied. The loads can be permanent or operational and if the stress in the pipeline were allowed to exceed the peak strength of the steel, the pipe would fail. The pipeline's internal pressure is an example of a primary load. *Canadian Standards Association Z662, Oil and Gas Pipeline Systems* requires that stress combinations resulting from primary loads be limited to a certain percentage of the yield stress of the pipe. This is referred to as stress-based design, and most pipelines in Canada are designed using this method.

Secondary loads are generated within the pipe as it conforms to environmental loads. In order to design pipelines to resist secondary loads, it is necessary to determine the size of the secondary load and the amount of deformation the pipe can safely sustain (called strain capacity or allowable strain). Pipelines designed to resist secondary loads in this way are called strain-based design pipelines.

On the record

Pipeline design temperatures

The Proponents stated that the minimum design temperature for exposed, above ground high pressure piping on the Mackenzie Gathering System without heat tracing would be -53ºC. With insulation and heat tracing the minimum design temperature for above ground piping would be -45ºC. The Proponents reviewed 40 years of Environment Canada climate data for Inuvik, and the lowest minimum average daily air temperature recorded was -53ºC.

Did you know?

Frost heave and thaw settlement

The Mackenzie Valley Pipeline and Mackenzie Gathering System would be buried in areas containing permafrost, giving rise to design issues related to frost heave or thaw settlement depending on local ground conditions. The resulting loads exerted on the pipe would vary depending on the presence of groundwater, the porosity of soil and the temperature of the ground relative to the pipe at a given location. Where the pipe temperature is below 0ºC and the surrounding ground is initially unfrozen, such as in taliks beneath rivers, a frost bulb may grow around the pipe, applying uplift forces over the affected span of pipe. Where the pipe temperature is above 0ºC and the ground is frozen, any thawing may cause the ground to settle, leaving unsupported spans of pipe. If a pipe crosses through ground with varying soil types and ice contents, differential settlement or heave may occur, causing localized stresses and strains on the pipe.

These issues are inter-related and are addressed below in the context of frost heave and thaw settlement along a northern pipeline. The availability of site-specific geotechnical information is also addressed in the context of the specific design issues related to watercourse crossings and geohazards such as seismic risks and slope stability.

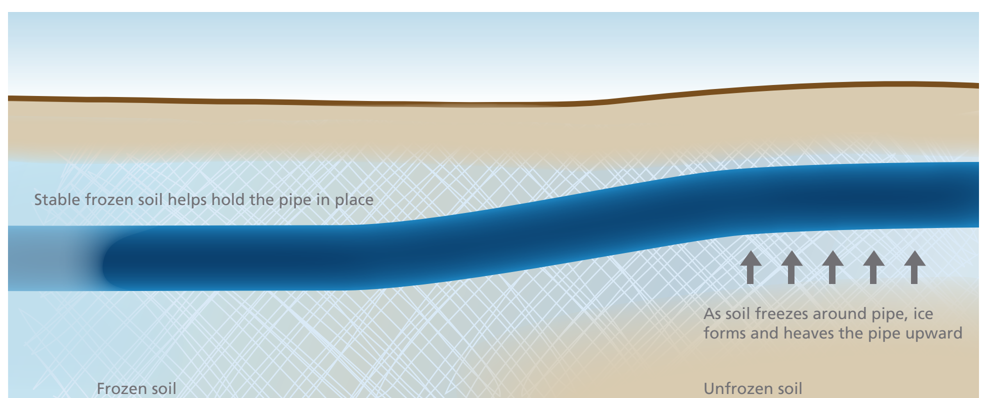
The preliminary design phase, including engineering design calculations such as those for the combination of external forces that could be imposed on the pipe, was ongoing at the time of the hearing. Detailed design and the gathering of the necessary remaining site-specific route information would not start unless the project is approved, and would continue until construction begins on each facility or pipeline construction spread.

Frost heave and thaw settlement

The Mackenzie Gas Project pipelines would be subject to environmental loads, such as large temperature differentials between construction and operation, frost heave and thaw settlement, which are not commonly encountered by conventional onshore pipelines. The Proponents indicated that several factors contribute to the loading conditions, including the unfrozen span length and the number of unfrozen spans per kilometre. The Proponents stated that statistical distributions best characterized these factors, as well as the strain capacity of the pipe. This made probabilistic methods suitable for assessing design safety and estimating the number of operational interventions that may be required during the life of the pipeline. Various simulation programs including finite element analyses were used to determine serviceability strain limits.

Figure 6-2

Frost heave



Strain capacity

The limit state design methodology (Canadian Standards Association Z662-07, Annex C) considers all phases of the pipeline life span, the combination of loads and the properties of the materials to be used. The value of the compressive strain limit for the Mackenzie Gas Project pipes is expected to be 1.5 percent and the tensile strain limit is 2.0 percent. Although these strain limits were determined analytically, the resulting values were confirmed through several laboratory verification tests. The Proponents considered several combinations of internal and external forces during the iterative design process. The most significant forces were internal pressure, frost heave (see Figure 6-2) and thaw settlement (see Figure 6-3).

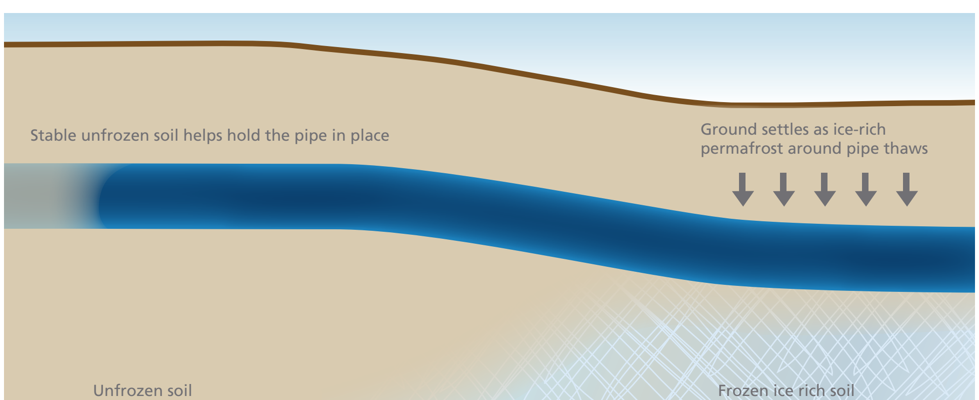
Strain demand

For the overland design, the Proponents submitted that they used pipeline route selection criteria to avoid design and construction challenges (see Chapter 5), and that it was not practicable to collect new geotechnical and geothermal data to further optimize the route. The Proponents mapped geotechnical conditions by terrain class. The soil properties for each terrain class were established using statistical methods. The Proponents submitted that pipeline strain calculations based on this information would not take into account all areas of high frost heave and thaw settlement. As a result, the pipe may be installed in an area with soil properties that produce higher values of frost heave and thaw settlement than established for the terrain class. Limit states would be set for the ultimate tensile strain, within which the pipeline's integrity is maintained, and for serviceable compressive strain, whereby the pipeline would initially buckle but would not leak.

The Proponents submitted that it was not practical to collect detailed soil and temperature

Figure 6-3

Thaw settlement



Did you know?

Definitions

Geopig® – a brand of internal inspection tool that can be used to determine pipe location and deformation.

In-line inspection – the use of internal inspection tools, which travel inside the pipeline, to carry out an inspection.

Longitudinal strains – elongation or compression of the pipe along its length.

Span lengths – the length of pipeline over which the load or deformation occurs.

Probabilistic methods – pipe properties and loads used in design are not discrete numbers but are deemed to be a range of values, each with a certain probability of occurrence based on statistical data. Designers select the design load and pipe properties based on the desired degree of confidence and conservatism and determine the likelihood that a particular limit state will be exceeded.

Strain capacity – the amount of deformation the pipe can safely tolerate.

Strain demand – amount of deformation caused by internal and external forces.

Serviceability strain limit – the point at which a deformity will cause the pipeline to become inoperable, but not cause a loss of containment.

Ultimate strain limit – the point at which a pipeline deformity will cause a loss of containment.

On the record

Iterative design process

The Proponents' pipeline design process for the conceptual and preliminary design phases includes the following steps:

- Conduct hydraulic modeling (system design) to establish the pipe sizes, grade, wall thicknesses, operating temperatures and pressure profiles, and compression requirements.
- Conduct thermal modeling to predict the potential for frost heave and thaw settlement using the temperature profile.
- Conduct structural modeling to predict the potential for frost heave and thaw settlement effects over time. This is known as strain demand.
- Model the capability of the pipe to sustain the tensile and compressive strains predicted by the structural modeling. This is known as strain capacity.
- Compare the calculated strain demand as it varies over time to the design strain demand to ensure pipeline integrity.
- Check the heave and settlement displacements and freeze and thaw bulb growth to assess environmental impacts.
- Evaluate options for design and maintenance and make changes to the temperature limits, pipe sizes, pipe grades and pipe wall thicknesses
- Repeat the above steps until the system design requirements are met, strain demand and strain capacity are balanced and the environmental impacts are acceptable.

data in sufficient detail to support site-specific design. To illustrate, the Proponents pointed out that changes between permafrost and unfrozen ground conditions can occur over tens of metres and changes in ice content can occur within metres. Consequently, the Proponents' design approach incorporated a requirement to monitor pipeline loads which accumulate slowly over several years, such as frost heave and thaw settlement loads. After several years, these loads may reach specific values that would require the Proponents to take action. The Proponents submitted that with this approach, detailed mapping of the geotechnical and geothermal conditions for most of the route would not be necessary for conceptual or preliminary design. Other loads, such as those which may be rapidly applied and those typical of most pipelines would be accounted for in the base design for the pipeline.

Indian and Northern Affairs Canada expressed the view that significant data on actual soil properties and ground temperatures along the pipeline route would be required to accurately model frost heave and thaw settlement on the pipeline. To delineate permafrost along the entire pipeline route, Indian and Northern Affairs Canada recommended that the Proponents use geophysics and additional boreholes, collect ground temperatures at more frequent intervals along the right of way than proposed by the Proponents and develop a detailed characterization of soils in support of frost heave and thaw settlement assessments. Indian and Northern Affairs Canada further

On the record

Effect of heat transfer

Heat transfer between the pipe and the soil will cause water in the soil to freeze or ice in the soil to thaw depending on the pipe temperature, the ground temperature and the time of year. The growth of frost or thaw bulbs around the pipeline over successive years can cause frost heave or thaw settlement forces, respectively, to develop on the pipeline. Disrupting the insulating vegetative mat during pipeline construction will also affect the rate of heat transfer between the air and the soil, further altering the permafrost regime beneath the right of way. In addition to displacement of the pipe by frost heave and thaw settlement, the span over which the displacement occurs also impacts the magnitude of the bending strains (strain demand) imparted to the pipe.

recommended that the geotechnical and thermal data be presented to the National Energy Board prior to pipeline construction.

The Proponents indicated that extensive airborne and ground-based geophysical surveys were planned before the start of construction to delineate the presence of permafrost along the entire route. Furthermore, an extensive borehole program would be undertaken during the geotechnical verification program to be carried out in the two-year period preceding pipe-laying operations. The data on permafrost distribution, ground temperature measurements and soil data would be used to revise the preliminary estimates of frost heave and thaw settlement during final engineering design. It would also be used by the Proponents to identify regions of high heave and settlement potential and to refine monitoring and intervention programs during operations.

The Proponents stated that heavy wall pipe would be used for watercourse crossings but was not being considered as an option for frost heave and thaw settlement mitigation. It would be impractical to delineate all critical permafrost occurrences in time to procure heavy-wall pipe. The Proponents submitted that the approach adopted for the project was to design a pipeline with a tolerance for frost heave and thaw settlement and use monitoring and interventions during operations to detect and address local areas of high-strain demand as they actually occur.

Did you know?

Definitions

Heavy wall pipe – pipe with a greater wall thickness than the general design requirement is capable of tolerating greater stress and is more resistant to deformation (can absorb more strain energy).

LiDAR – a technology that employs an airborne scanning laser to measure the elevation of the ground.

Piezometers – instrumentation used to measure pore water pressure in soil.

Reduced pipe cover – reducing pipeline cover in areas where frost heave is anticipated allows the pipeline to displace more evenly over the entire span length, relieving the heave induced stress and reducing the total strain experienced by any one discrete pipe segment.

Thermistor – a device used to measure temperature, relying on the change in its electrical resistance with changing temperature.

Climate Change

The Proponents found that mean annual soil temperatures are typically about 4.5°C warmer than mean annual air temperatures and surface disturbance can increase the mean ground temperature by about 2°C. At the development fields the ground temperatures vary from about -4°C at Niglintgak to -7.6°C at Parsons Lake. Temperatures rise to the south, where the mean ground temperatures are about -3°C in Fort Good Hope and -2°C in Norman Wells in undisturbed areas.

Climate change data shows a warming trend in the Mackenzie Valley which may affect the distribution of permafrost over the life of the pipeline. The Proponents established values for climate warming for different regions within the project area for consideration in its design, shown in Table 6-2.

Table 6-2

Regional climate-warming rates selected by the Proponents

Region	Climate warming rate *(°C/year)*
Inuvik	0.094
Norman Wells	0.05
Fort Simpson	0.076
Northern Mackenzie Valley	0.072
Southern Mackenzie Valley	0.063

On the record

Data collection

The Proponents submitted that the conceptual design work required a significant amount of information about the route. Data collected using global positioning systems and light detection and ranging (LiDAR) and incorporated into geographic information systems made it unnecessary for the Proponents to clear the centreline of the route for land surveys before construction. The Proponents used the large volume of existing geotechnical and geothermal data from previous highway and pipeline studies, and incorporated some new project boreholes to populate its project borehole database. Information collected from the design and construction of the Enbridge Pipeline (NW) Inc. Norman Wells Pipeline, specifically the geophysical survey and ditch logs, provided nearly continuous profiles of the permafrost south of Norman Wells. Route temperature measurements collected during the 1970s and 1980s were available for conceptual engineering from a Geological Survey of Canada database. This information was supplemented by new information from the Geological Survey of Canada and the Proponents. The Proponents plan to collect additional geotechnical and geothermal information including probe holes, test pits, geotechnical boreholes with sampling and geophysics after the right of way is cleared.

The thermal modeling used in the development of frost heave and thaw settlement predictions was based on historical trends in air temperature warming rates at locations along the route (Inuvik, Norman Wells and Fort Simpson) rather than general climate models. Mr. Doug Ritchie raised concerns that the thermal modeling used did not include rigorous general climate models, as used by other organizations for predicting climate warming in the Arctic. The Proponents responded that historical trends for sites along the route represented the best information for pipeline design and resulted in a higher and therefore more conservative rate of climate warming than the rate predicted by available general climate models.

The Joint Review Panel was generally satisfied that the Proponents had taken climate change into account in their design. Nevertheless the Joint Review Panel recommended that we require the Proponents to file final design plans that incorporate further analysis of the impacts of climate change on permafrost and terrain stability over the design life of the project and post-abandonment. The Joint Review Panel was of the view that this analysis should be conducted for a series of representative locations, conditions and terrain types and should incorporate climate variability and, in particular, upper limit temperature scenarios to account for the range of future temperature conditions, including their variability and extremes, and the impact of this variability on stream flow regimes. The Joint Review Panel added that the results should be incorporated into the monitoring, mitigation and adaptive management plans. The Joint Review Panel thought that this analysis should be provided to other appropriate regulators in sufficient time for review and to provide input to the National Energy Board.

Indian and Northern Affairs Canada argued that the Proponents should consider how these upper limit scenarios influence their predictions regarding pipeline integrity in particular for those areas where permafrost may degrade over the life of the pipeline.

Views of the Board

We are of the view that the Proponents' use of a lifespan engineering approach for the Mackenzie Gas Project that includes a combination of stress and strain-based design, construction mitigation and operational monitoring and interventions to ensure the integrity of the pipeline is acceptable for the project.

As stated in Chapter 3, we are satisfied with the Proponents' climate change estimates used in the design. Given the uncertainty regarding climate change predictions, a prudent step would be to assess the design using upper limit temperature scenarios as recommended by the Joint Review Panel. As the name implies, upper limit temperature scenarios would be less likely to occur than what has been used by the Proponents for the design of the project. Condition 6 requires the Proponents to submit a report which includes an analysis of the impacts of climate change and variability on permafrost and terrain stability for a series of representative locations and conditions using potential upper limit temperature scenarios which may occur along the pipeline. The analysis is to include potential impact on slope and water course crossing design. We have not specified how the study should be structured. We are of the view that, as part of this study, government departments such as Environment Canada, Indian and Northern Affairs Canada and Natural Resources Canada should be consulted to benefit from their expertise.

6.3.4 System design and configuration

To accomplish the stated project objective of delivering natural gas and natural gas liquids from the Mackenzie Delta to existing pipeline infrastructure in Alberta, the Proponents proposed a system of gas and liquids gathering pipelines, station facilities and a large diameter natural gas transmission pipeline. The proposed Mackenzie Gathering System will transport both natural gas and liquids from the anchor fields to the Inuvik Area Facility where receipts will be measured, separated and prepared for transmission south to interconnections with existing pipeline infrastructure. The separated natural gas liquids will be transported to Norman Wells in a dedicated liquids line while natural gas will be compressed and shipped south to an interconnection in Alberta via the Mackenzie Valley Pipeline.

A primary consideration of the system design is selecting an initial system capacity that meets the requirements for immediate hydrocarbon transportation commitments and takes into account requirements for future gas and liquid shipments. The final system design will specify the combination of pipeline diameter, fluid composition, temperature and pressure selected to achieve the desired system capacity. These parameters in turn are used to determine the pipeline materials that will be necessary. The throughput capacity of an existing pipeline can be increased by adding pumps, compressors or pipeline loops during the lifespan of the project.

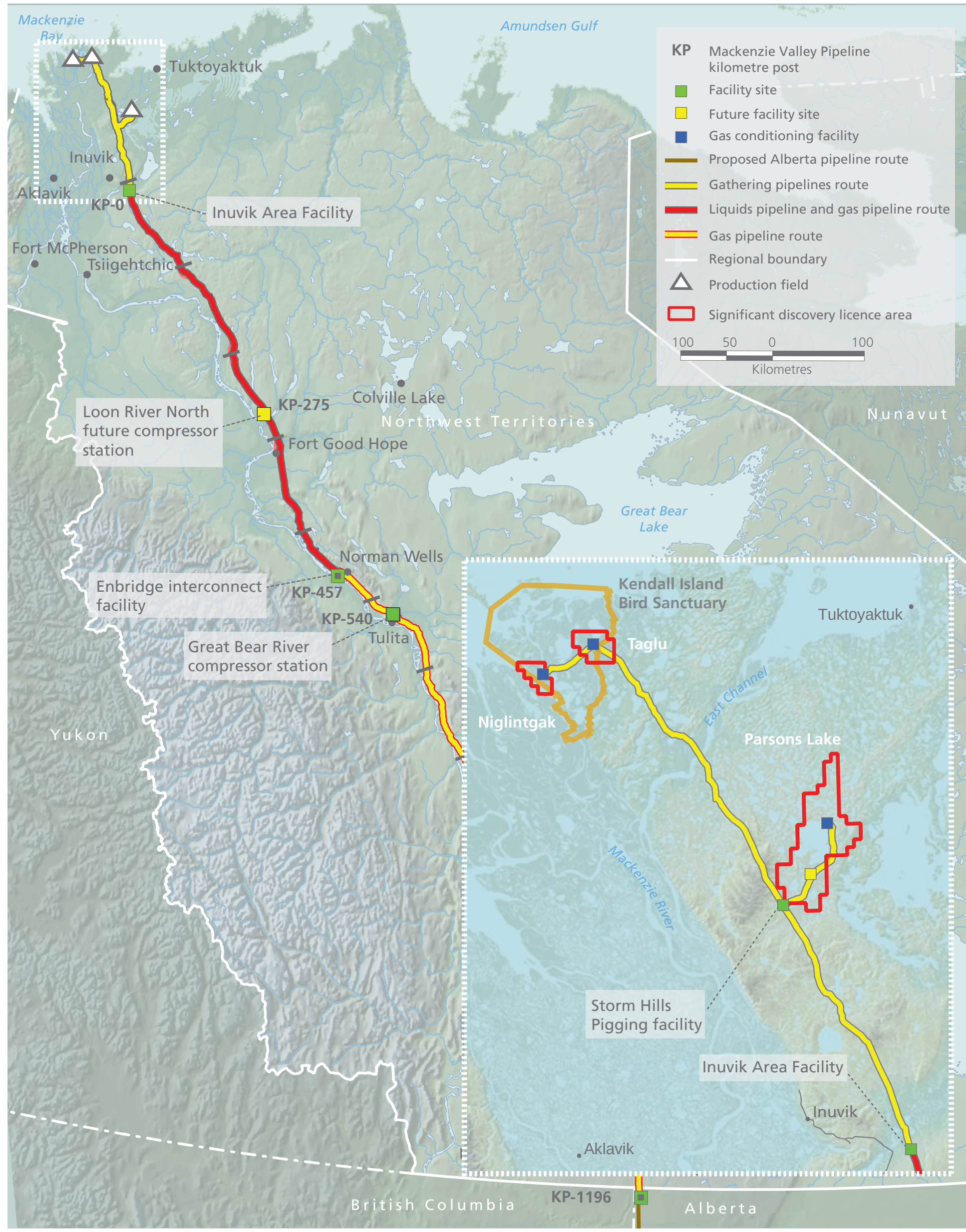


Figure 6-4

Mackenzie Gathering System

On the record

Design considerations

When designing the Mackenzie Gathering System, the Proponents considered:

- historical and existing pipeline routes;
- potential locations for gas processing;
- total costs over the life of the project;
- potential locations of dehydration facilities;
- minimization of the environmental footprint;
- existing infrastructure;
- above-ground and buried pipeline alternatives;
- input from community consultation;
- field delivery pressures;
- delivery pressures entering the gas processing facility;
- accommodation for gas volumes from 24 Mm^3/day (.85Bcf/d) to 34 Mm^3/day (1.2 Bcf/d);
- pipeline operating temperatures in permafrost;
- pipe sizes from NPS 12 to 36 (DN 300 to 900); and
- pipeline material grades up to 483 MPa (X70).

Figures 6-4 and 6-5 illustrate the proposed configuration of the Mackenzie Gathering System and Mackenzie Valley Pipeline, described in greater detail in the following sections. The Proponents submitted that the proposed Mackenzie Gas Project system is expandable through the addition of laterals and facilities on the Mackenzie Gathering System and the addition of up to 11 compressor stations along the Mackenzie Valley Pipeline.

Design of the Mackenzie Gathering System

The Mackenzie Gathering System includes:

- approximately 190 kilometres of NPS 16, 18, 26 and 32 (DN 400, 450, 650 and 800) gathering pipelines to transport production from the Niglintgak, Taglu and Parsons Lake natural gas fields (development fields) and the volumes committed by MGM Energy Corp. to the Inuvik Area Facility;
- the Inuvik Area Facility, which would process the gas produced;
- an approximately 457-kilometre long NPS 10 (DN 250) pipeline to transport natural gas liquids from the Inuvik Area Facility to Norman Wells; and
- block valves, pigging facilities, and meter stations for the gathering pipelines and the natural gas liquids pipeline.

The Mackenzie Gathering System would have the capacity to deliver about 30.9 Mm^3/d (1.1 Bcf/d) of natural gas to the Mackenzie Valley Pipeline and to transport about 4000 m^3/d (25,200 Bbl/d) of natural gas liquids from the Inuvik Area Facility to Norman Wells. The approximate capital cost of the Mackenzie Gathering System is $3.5 billion (2006$). It is scheduled to be in service in 2018.

Mackenzie Gathering System – upstream gathering pipelines

The gathering pipelines upstream of the Inuvik Area Facility (Figure 6-6) consist of:

- the NPS 16 (DN 400) Niglintgak lateral which extends 14.7 kilometres from the outlet of the Niglintgak gas conditioning facility to the Taglu gas conditioning facility with a design pressure of 12.9 MPa (1,870 psi);
- the NPS 26 (DN 650) Taglu lateral which extends 80.9 kilometres from the Taglu gas conditioning facility to the Storm Hills pigging facility with a design pressure of 12.2 MPa (1,770 psi);
- the NPS 18 (DN 450) Parsons Lake lateral which extends 26.4 kilometres from the Parsons Lake gas conditioning facility to the Storm Hills pigging facility with a design pressure of 12.2 MPa (1,770 psi); and
- the NPS 32 (DN 800) Storm Hills lateral which extends 67.2 kilometres from the Storm Hills pigging facility to the Inuvik Area Facility with a design pressure of 12.2 MPa (1,770 psi).

The design of the upstream gathering pipelines is based on natural gas production volumes from the three development fields and other potential sources in the Mackenzie Delta. The natural gas and natural gas liquids mixture would be dehydrated at the development fields and shipped to the Inuvik Area Facility for processing in lateral pipelines designed for two phase flow. The upstream gathering pipelines are designed to carry volumes of up to 30.9 Mm^3/day (1.1 Bcf/d) in the summer. This could be expanded by looping portions of the lateral pipelines or by adding new laterals, additional compression or liquid handling facilities.

Mackenzie Gathering System – natural gas liquids pipeline

The Proponents determined that the best design for the pipelines south of the Inuvik Area Facility would be to use two single-phase pipelines. One pipeline would be for natural gas, as discussed in following sections, and the other would be for the natural gas liquids. The Proponents chose a buried NPS 10 (DN 250), Grade 359 (X52) pipe with a wall thickness of 7.8 millimetres and a maximum operating pressure of 9.93 MPa (1440 psi) for the liquids pipeline. The 457.2-kilometre long natural gas liquids pipeline would terminate at the Enbridge Pipelines (NW) Inc. pump station in Norman Wells where a pig receiver and block valve would be installed. No pump stations would be required between the Inuvik Area Facility and Norman Wells for the initial operation. The line's initial capacity would be about 4000 m^3/day (25,200 Bbl/d), which could be increased to about 6700 m^3/day (42,150 Bbl/d) with two additional pump stations. From Norman Wells, the liquids would be carried further south in batches by the existing Enbridge Pipelines (NW) Inc. Norman Wells Pipeline.

Capacity and expansion of the Mackenzie Gathering System

During the hearing, intervenors questioned the design capacity of the upstream gathering pipelines and how it could be increased. However, no intervenors questioned the design adequacy of the natural gas liquids pipeline or its ability to transport present and future volumes of liquids.

Mackenzie Explorer Group expressed the view that the most likely expansion of the two phase design proposed by the Proponents would be through looping. Mackenzie Explorer Group believes this would probably not be the most cost effective approach especially if new natural gas production comes on line in small increments.

Mackenzie Explorer Group presented evidence which indicated that the nominal capacity of the system would be 30.4 Mm^3/day (1,075 MMcf/d). This would leave 8.65 Mm^3/day (305 MMcf/d) of available, non-contracted capacity of which 5.1 Mm^3/day (180 MMcf/d) is available at Taglu and the remainder is available south of the Storm Hills pigging facility. Mackenzie Explorer Group stated that the design philosophy upstream of the Inuvik Area Facility did not match the downstream design philosophy. Mackenzie Explorer Group noted in its evidence that while the upstream gathering pipelines had a maximum capacity of 30.4 Mm^3/day (1,075 MMcf/d), the Mackenzie Valley Pipeline could be expanded to 48 Mm^3/day (1,695 MMcf/d).

The Proponents and Mackenzie Explorer Group members Chevron Canada Resources and BP Canada Energy Company undertook a joint effort to evaluate alternatives that could increase the capacity on the gathering system north of the Inuvik Area Facility for new natural gas discoveries. Based on this study, Mackenzie Explorer Group supports an option that requires upgraded pipe and components to be pre-installed for future expandability. The Proponents estimated the cost of this pre-installation would be an additional $142 million.

In argument the Mackenzie Explorer Group expressed the view that the higher-pressure design of the two-phase system is superior in terms of total unit of capacity cost, avoiding lumpiness of expansion and minimizing incremental environmental impact.

On the record

Expansion study

For the purposes of the joint Mackenzie Explorers Group/Proponents study, it was assumed there would be three 7.1 Mm^3/day (~250 MMcf/d) expansions north of the Inuvik Area Facility and the fully expanded Mackenzie Gathering System would match the Mackenzie Valley Pipeline's capacity. The study did not consider the potential for gas entering the Mackenzie Valley Pipeline downstream of Inuvik which would use available Mackenzie Valley Pipeline expansion capacity at Inuvik.

The joint Mackenzie Explorers Group/Proponents study submitted by Mackenzie Explorers Group identified seven alternative designs for the gathering pipelines and two alternative designs for the Inuvik Area Facility. Of the seven pipeline alternatives, three allowed for expansion to match the capability of the Mackenzie Valley Pipeline. These alternatives are: installing NPS 36 (DN 900) pipelines between Taglu and the Inuvik Area Facility; increasing the operating pressure of the gathering pipelines to 18 MPa (2,610 psi) to match the design of the Mackenzie Valley Pipeline; and constructing a separate or looped pipeline. Of the three, Mackenzie Explorers Group favoured the 18 MPa (2,610 psi) design option requiring upgraded pipe and components to be pre-installed. As the pressure in the gathering pipelines increases to accommodate new volumes, additional compression would be required at each existing field for the natural gas and natural gas liquids to flow into the upstream gathering system.

Did you know?

Definitions

Batches – quantities of oil/oil products or condensate with particular properties owned by a particular shipper and transported in a pipeline between other batches.

Block valve – a valve that can completely block the flow in a pipeline in both directions.

Dense phase pipeline – under certain conditions of pressure and temperature natural gas liquids and natural gas can be transported in a pipeline in a single phase, referred to as dense phase, which has properties between those of a gas and a liquid. Dense phase pipelines may have higher wall thickness which makes them more resistant to bending stresses.

Lateral – a pipeline that connects a new supply or a new market to the main pipeline.

Looping – expansion of pipeline capacity by building another pipeline adjacent to the existing pipeline.

Mass flow rate – mass of fluid transported by the pipeline over a period of time.

Nominal capacity – the capacity that is available year round and is determined by using historical ambient temperatures in the warmest month (July) since pipeline capacity increases with decreasing air temperature due to the increased driver power of the gas turbines at cooler ambient temperatures.

Pig receiver – a piping arrangement that allows inline tools (pigs) to be removed from a pipeline without stopping the flow of the pipeline.

Pipe grade – the specified minimum yield strength of the steel used in making the pipe, typically expressed in mega Pascals (MPa).

Single phase pipeline – a pipeline that conveys either a liquid or gas but not both at the same time.

Slug catcher – a piping arrangement used in two phase pipelines to separate liquids from gas in the pipeline before it can enter a gas compressor.

Two phase pipeline – a pipeline that conveys both liquid and gas at the same time.

The Proponents rejected the assumption that the ultimate capacity of the Mackenzie Gathering System needed to match the ultimate capacity of the Mackenzie Valley Pipeline. The Proponents pointed to the possibility that gas could enter the Mackenzie Valley Pipeline at locations south of Inuvik from the Colville Hills. The Gilbert Laustsen and Jung Associates supply study forecasted that Colville Hills production could exceed 8.5 Mm^3/d (300 MMcf/d). The Proponents noted that MGM Energy Corp. had requested 5.7 Mm^3/d (200 MMcf/d) of capacity over the 23.5 Mm^3/d (830 MMcf/d) used by the Proponents which left 1.3 Mm^3/d (45 MMcf/d) of capacity for other shippers. The Proponents noted that another 10.6 Mm^3/d (375 MMcf/d) of capacity could be added with the construction of a compressor station at Storm Hills. The Proponents also stated that the capacity of the upstream gathering system could be further expanded by looping.

Design of the Mackenzie Valley Pipeline

The Mackenzie Valley Pipeline includes:

- approximately 1196 kilometres of NPS 30 (DN 750) pipeline from the Inuvik Area Facility to a point of interconnection with the NOVA Gas Transmission Ltd. system just south of the Alberta-Northwest Territories boundary;
- three compressor stations, one at Great Bear River to be installed initially and two others at Loon River North and River Between Two Mountains to be installed when additional shipping commitments are received;
- the Trout Lake heater station to be installed when additional shipping commitments are received;
- a meter station located at the Inuvik Area Facility; and
- a pig receiver and block valve just south of the Alberta-Northwest Territories boundary.

The Mackenzie Valley Pipeline has a design capacity of 27.3 Mm^3/d (0.96 Bcf) with one compressor station and 34.3 Mm^3/d (1.2 Bcf) with three compressors and heater station in operation. The capacity could be expanded to 49.8 Mm^3/d (1.8 Bcf/d) with a total of 14 compressor stations (see Figure 6-5). Only three compressor stations are included in the applications before us. The Mackenzie Valley Pipeline is scheduled to be in service in 2018.

The design selection of the Mackenzie Valley Pipeline was affected by several factors including:

- gas composition;
- operating temperatures in continuous and discontinuous permafrost;
- initial and future volumes; and
- the potential location of station facilities along the route.

The Proponents evaluated three potential design concepts for the Mackenzie Valley Pipeline: a dense phase design, a two phase design and a single phase design. The criteria used to evaluate the designs included:

- flexibility with respect to changes in volume and gas composition caused by potential changes in supply;
- costs over the life of the project;
- constructability; and
- operability.

Figure 6-5

Mackenzie Valley Pipeline design capacity

The Proponents selected a single phase pipeline with a maximum operating pressure of 18.7 MPa (2,710 psi) for the Mackenzie Valley Pipeline. This design was described by the Proponents to best accommodate potential variation and uncertainty in gas volumes, composition, timing and location. Cited advantages of the single phase, high pressure design include lower lifespan costs, simpler facilities and a more flexible operation. Most of the pipe would have a wall thickness of 16.2 millimetres while locations with the potential for higher external loads, such as road crossings and watercourse crossings, would have a wall thickness of 21.6 millimetres. The design parameters are shown in Table 6-3.

Table 6-3

Mackenzie Valley Pipeline design parameters

Pipe type	NPS 30 (DN 750) Line pipe	NPS 30 (DN 750) Heavy wall pipe
Grade	550 MPa (X80)	550 MPa (X80)
Wall thickness	16.2 mm	21.6 mm
Design pressure	18.7 MPa (2,710 psi)	18.7 MPa (2,710 psi)
Estimated quantity	1185 km	19 km

The applied-for design includes three compressor stations and a heater station capable of delivering 34.3 Mm^3/d (1.2 Bcf/d) of natural gas in the summer and 38.4 Mm^3/d (1.35 Bcf/d) in the winter.

On the record

Dense phase, two phase and single phase designs

The Proponents considered a dense phase design where the operating pressures would be increased so the natural gas and natural gas liquids would behave as a single fluid. This concept would result in smaller pipe sizes and fewer compressor stations and would potentially eliminate the need for the natural gas liquids line. The Proponents found that operating pressures of about 40 MPa (5,800 psi) would be required to operate in a dense phase. At pressures less than this, natural gas liquids would be present. The Proponents estimated that it would be necessary to store, sell or dispose of approximately 150 m^3/day (940 Bbl/d) of liquids along the pipeline route, which would be impractical. Also, a processing plant would be required at the end of the Mackenzie Valley Pipeline to remove the liquids from the gas in order to meet downstream gas pipeline specifications. The Proponents chose not to use this design because its operation would be sensitive to gas composition, the presence of liquids at all but the highest operating pressures would increase the need for processing facilities, and the very high operating pressures would increase costs.

In a two phase pipeline, liquids and gas are shipped together. While a two phase pipeline can operate at pressures similar to a single phase pipeline, the liquids must be separated from the gas at compressor stations to prevent them from damaging the compressors. This requires the addition of slug catchers and pumps at each station to collect the liquids and re-inject the liquids into the pipeline after the gas is compressed. The Proponents rejected this design because it was less flexible than a single phase design.

With a single phase pipeline, liquids are separated from the gas and either trucked, flared, re-injected or shipped in a separate pipeline. The Proponents indicated that it selected the single phase gas pipeline option with a separate liquids pipeline because it best accommodated the potential variability between initial and future gas composition, had lower costs over the life of the project, required simpler facilities and allowed for more flexible operation.

Mackenzie Valley Pipeline expansion

No intervenors questioned the adequacy of the design of the Mackenzie Valley Pipeline or its ability to transport present and future volumes of gas. However, there were questions about the initial capacity of the pipeline, how it would be expanded in the future and the design implications of a phased expansion on the thermal regime of the pipeline route.

The development field owners have contracted for 23.5 Mm^3/day (0.83 Bcf/d) of the initial pipeline capacity and the remaining capacity of approximately 11 Mm^3/day (0.39 Bcf/d) is available for contracting. With one compressor station in operation near the Great Bear River, the pipeline is capable of delivering all the initial contracted capacity.

The approximate capital cost of the Mackenzie Valley Pipeline is $7,050 million (2006$) with one compressor station at the Great Bear River. The Loon River North and River Between Two Mountains compressor stations and the Trout Lake heater station would add approximately $800 million to the capital cost. While the Proponents have applied for approval of all of these facilities, they plan to delay construction of two of the three compressors and the heater station until the remaining capacity is contracted for.

The addition of 11 more compressor stations on the Mackenzie Valley Pipeline could increase the nominal capacity to about 49.8 Mm^3/day (1.8 Bcf/d). The Proponents have not applied for approval for these 11 compressor stations in the applications before us.

Design of station facilities

The applied-for station facilities for the Mackenzie Gas Project include:

- receipt metering facilities at each of the development fields where natural gas and natural gas liquids would be metered separately;
- a pigging facility at the junction of the Taglu and Parsons Lake laterals (Storm Hills) consisting of pig receivers and launchers that could be remotely operated from the main control centre;
- the Inuvik Area Facility which would remove natural gas liquids to meet the inlet gas specifications for the Mackenzie Valley Pipeline and natural gas liquids pipelines;
- natural gas liquids and natural gas metering facilities located within the Inuvik Area Facility site;
- compressors to deliver natural gas to the Mackenzie Valley Pipeline and pumps to deliver natural gas liquids to the natural gas liquids pipeline also located within the Inuvik Area Facility site;
- three natural gas compressor stations near Fort Good Hope (Loon River North), the Great Bear River and the River Between Two Mountains; and
- a heater station near Trout River to maintain the pipeline operating temperature within the design limits.

The Proponents state that Mackenzie Gas Project station facilities would be designed to *Canadian Standards Association Z662, Oil and Gas Pipeline Systems* with the exception of the Inuvik Area Facility which would be designed to American Society of Mechanical Engineers Code B31.3.

At the Inuvik Area Facility, the natural gas and natural gas liquids delivered by the upstream gathering pipelines must be separated and processed to meet the inlet gas specifications for the pipelines. The natural gas liquids contain components which vaporize when stored in a conventional oil storage tank. To make it easier to transport natural gas liquids in a pipeline, the unstable components would be removed at the Inuvik Area Facility in a process called stabilization. The removed components would later be re-injected into the Mackenzie Valley Pipeline. The Inuvik Area Facility would use a flare system to burn gaseous streams produced during operational upsets. The design and performance standards would be consistent with Alberta's Energy and Utilities Board Guide G-40.

The natural gas would be compressed by two centrifugal compressors located within the Inuvik Area Facility. These compressors would be driven by two ISO 30 MW gas turbines fuelled by natural gas sourced from within the facility. The compressed natural gas would be cooled using aerial coolers and gas-to-gas heat exchangers. The gas turbines would be commercially available, dry, low nitrogen oxide units. The compressors would be manufactured according to American Petroleum Institute Standard 617. All compressor stations would have a design pressure of 19.8 MPa (2,870 psi) to allow for the maximum discharge pressure of the Mackenzie Valley Pipeline. Primary power production for the compressor stations would be generated by natural gas-fuelled reciprocating engines. Diesel reciprocating engines would be used for standby emergency power generation.

Although not required initially, the Trout River heater station would eventually be needed to maintain pipeline operating temperatures within the design limits established for the three compressor station configuration. The Proponents' preferred design option is to use indirect-fired bath heaters fuelled by pipeline gas. The heater station would be designed for remote operation, with maintenance staff being flown to the station by helicopter. The facility would be designed to operate at a pressure of 19.8 MPa (2,870 psi). Natural gas-fuelled reciprocating engines would be used for primary power production at the heater station. Reciprocating engines would also be used for standby emergency power generation and would be fuelled by diesel.

The Proponents indicated they would select engines with a proven low-emission design and would meet or exceed Alberta Environment's Code of Practice for Compressor and Pumping Stations and Sweet Gas Processing Plants, 1996, which specifies maximum nitrogen oxide emissions of 6 g/kWh for engines over 600 kW.

On the record

Design considerations

After determining that a single phase pipeline was the best design concept for the project, the Proponents considered the following factors:

- historical and existing pipeline routes;
- total costs over the life of the project;
- operating temperatures in continuous and discontinuous permafrost;
- volumes from 24 Mm^3/day to 56 Mm^3/day (0.8 Bcf/d to 2 Bcf/d);
- facility locations along the route;
- initial shipper requirements and potential future expansion;
- input from community consultation; and
- minimizing footprint by using existing infrastructure.

On the record

Location of the Inuvik Area Facility

During the early stages of engineering design, the Proponents had planned to locate the Inuvik Area Facility 16 kilometres to the north of its currently applied-for location. The Proponents submitted that the new location is flatter, requires less imported gravel for the facility and shortens the access road by 14 kilometres. Early design work had established a requirement that all pipeline segments in the continuous permafrost zone should have a constant pipeline inlet gas temperature of -1°C to prevent thawing. To meet this operating requirement, the Inuvik Area Facility needed gas refrigeration units. At the new location of the Inuvik Area Facility, the Proponents found there was little evidence of thaw sensitive soils for some distance downstream. As part of this design refinement, the Proponents investigated the possibility of replacing the gas refrigeration units with heat exchangers which would cool the gas using the surrounding air.

Because of the low temperatures of the product entering the Inuvik Area Facility and the relatively low summertime air temperatures, the Proponents found that without the refrigeration units the Inuvik Area Facility could discharge gas at about 3°C in the summer and at or below 0°C the rest of the year. This would result in approximately 0.3 m of thaw settlement on the right of way at the outlet of the Inuvik Area Facility, decreasing to zero settlement 50 kilometres downstream of the Inuvik Area Facility.

Views of the Board

We are of the view that the system design undertaken by the Proponents for the single phase gas pipeline and the natural gas liquids line between the Inuvik Area Facility and Norman Wells is consistent with good design practice and provides sufficient expansion capability for future volumes. We are also of the view that there is uncertainty in regards to volume, composition, timing and location of future gas supplies. Because of this uncertainty, we do not share the view of Mackenzie Explorer Group that pre-investing in heavy wall pipe and other facilities to permit a future increase in operating pressure is warranted for the two-phase gathering system. We note that in the event that new capacity is required from the Mackenzie Delta, the option to construct compression facilities at Storm Hills is a viable potential alternative to looping. It also has the advantage of not requiring changes to compressor facilities at other receipt points.

6.4 Specific design issues

6.4.1 Overview

Specific issues arose as a result of the project's location in a northern environment and on the proposed engineering design approach. Our focus in the hearing was to ensure that the facilities could be designed and operated in a safe and environmentally responsible manner, while maintaining system reliability.

6.4.2 Geohazards

Geohazards are naturally occurring or project-induced geological, geotechnical, geothermal or hydrological phenomena that could lead to pipeline or other component failure, causing adverse environmental impacts, or that could affect the right of way, causing environmental concerns.

The Proponents indicated that the principal geohazards to the project are well known from the previous studies and projects in the Mackenzie Valley. The Proponents were of the view that the initial consideration of geohazards did not require detailed information on the location or the quantification of risk associated with each specific geohazard occurrence. During the conceptual and preliminary design the Proponents used route selection approaches to avoid potentially difficult terrain and unstable slopes. The Proponents indicated that credible worst case scenarios had been used to develop conservative estimates of the effects of geohazards on the pipelines, pipeline ditch or pipeline right of way. These estimates were used to develop a pipeline design that was relatively insensitive to ground conditions along the route, thus reducing the need for very detailed and precise data (i.e., the pipe wall thickness for overland portions of each pipeline is predominately one thickness). A monitoring and mitigation tool box was developed to address geohazards during construction and operation.

The Proponents stated that a more formalized geohazard assessment approach would be beneficial for the detailed design phase in terms of systematically organizing available information on geohazards, verifying preliminary design assumptions, and obtaining information about the distribution and potential effects of various individual and combined geohazards along the pipeline route.

The Proponents plan a three-phased approach consisting of: a geohazard inventory and assessment using terrain mapping and LiDAR; a field geotechnical program and detailed design engineering to develop mitigation; and a construction and operations monitoring phase where expected conditions would be further verified during ditch excavation and later upgraded based on in-line inspection and monitoring of the right of way.

In order to assess the geohazards which act alone or in combinations the Proponents propose to use a semi-quantitative index based approach to rank the susceptibility of individual geohazards along the route. As part of this approach the values and rankings associated with each geohazard would be based on expert judgment. To facilitate the assessment of possible combined geohazards the route would be segmented based on the extent of each individual geohazard.

In undertaking their geohazard assessment the Proponents would consider only those geohazards within the pipeline corridor that may directly affect the pipe, the pipeline ditch, or the right of way. The Proponents referred to these as "credible probable geohazards." The Proponents identified 31 geohazards which could result from:

- the freezing of unfrozen ground;
- the thawing of permafrost terrain;
- landslides impacting the right of way;
- tectonics/seismicity;
- watercourse hydraulics resulting in exposed pipe;
- erosion;
- geochemical concerns such as the occurrence of acid-generating rock; and
- soil structure issues such as the presence of large rocks which could damage the pipe.

The Proponents are of the view that these naturally occurring or project-induced geohazards could load the pipeline causing a pipeline integrity concern, could affect the pipeline or ditch causing an operational concern, or could affect the right of way causing an environmental concern.

The Proponents assembled a Senior Advisory Team consisting of four external experts experienced in northern engineering and pipeline design to evaluate its proposed approach and made modifications in response to the comments received. A workshop was held in Calgary on 10 and 11 July 2006 where the Proponents, the Senior Advisory Team and staff from Indian and Northern Affairs Canada and Natural Resources Canada met and discussed the Proponents' semi-quantitative geohazard assessment approach. Following the July workshop four more geohazards were identified by the Proponents. The results of these workshops were submitted in our hearing.

Indian and Northern Affairs Canada indicated that the success of any geohazard risk assessment will depend on the adequacy of the database and acknowledged the Proponents' efforts at organizing existing data and its preparations to accommodate anticipated data in a geographic information system. Indian and Northern Affairs Canada was of the view that the geohazard list was adequate for the preliminary stage of the assessment and that the Proponents' work may benefit from broader input by geoscientists with northern mapping experience. Indian and Northern Affairs Canada indicated that it was not possible to fully assess the Proponents' methodology at the July meeting because much of the presentation was conceptual. Indian and Northern Affairs Canada noted that the assessment approach outlined was adequately structured and in conformity with other semi-quantitative methodologies described in the literature but that in its view significant challenges remain. Indian and Northern Affairs Canada cautioned that

On the record

Inuvik Area Facility, compressor stations and heater station equipment

The Inuvik Area Facility includes:

- a liquid slug catcher;
- liquid stabilization;
- pumping and storage facilities;
- residue gas processing and compression equipment;
- propane refrigerant equipment;
- safety and control systems; and
- utility systems.

Liquid processing and storage equipment includes:

- stabilizer and associated equipment;
- heat exchangers;
- aerial coolers;
- pumps;
- storage tanks; and
- a pressure vessel.

The liquid storage in the Inuvik Area Facility would be protected by a foam-based fire protection system and the tank farm would be designed to meet Alberta's Energy Resources Conservation Board's Guide G-55 requirements. The tanks would be constructed within a bermed containment area with an impermeable liner.

The three downstream compressor stations would all contain similar equipment, including:

- pipe and pipeline components such as mainline block valve assemblies;
- pig launcher and receiver;
- inlet scrubber;
- gas turbine compressor package;
- aerial coolers;
- gas-to-gas heat exchangers;
- utility gas equipment;
- fuel gas equipment;
- station power generating equipment;
- controls and communication equipment; and
- safety equipment.

The centrifugal compressor at each of the compressor stations would be driven by an ISO 15 MW gas turbine fuelled by natural gas sourced from the pipeline. The gas turbines would be commercially available, dry low nitrous oxide units. The compressor units would be manufactured according to API Standard 617.

Equipment at the heater station site includes:

- line heaters;
- fuel gas and metering equipment;
- glycol storage tanks;
- electrical power generating equipment;
- controls and communication equipment; and
- safety equipment.

As noted above, the heater station piping would comply with *Canadian Standards Association Z662, Oil and Gas Pipeline Systems*; however, the line heaters would be designed and manufactured in accordance with *American Society of Mechanical Engineers Boiler and Pressure Vessel Code, Section VIII, Division 1, as permitted by Canadian Standards Association Z662*.

a semi-quantitative approach, such as the one adopted by the Proponents could "easily stray from good science regardless of the best intentions of those involved" and that the individual geohazard scores obtained from the Proponents' methodology would be difficult to compare and sum, and thus integrate into risk assessment.

The Proponents are of the view that their semi-quantitative index-based geohazard assessment approach allows geohazards to be identified and ranked in terms of the associated susceptibility (i.e., high, medium, low, very low, or negligible) relative to specific pipeline elements. The Proponents stated that the spatial distribution and sorting of individual and combined geohazards by susceptibility provides sufficiently detailed information to guide decisions regarding design, field activities, specialized engineering analysis and testing, operations monitoring and operations mitigation maintenance. The Proponents characterized their approach as adaptable and well-suited to the abundance of regional data available to the project. The Proponents also noted that their approach allowed for more site specific information to be incorporated into it as the project progresses.

The Proponents stated that a quantitative risk assessment for all geohazards was neither required at the preliminary engineering stage of project nor meaningful, given the lack of site-specific information required to support the engineering judgment of probabilities required in a quantitative approach. The Proponents indicated that during operations, integrity management decisions for specific locations might be suited to the quantitative or probabilistic site-specific treatment of geohazards.

Indian and Northern Affairs Canada suggested that the geohazard risk assessment should be conducted using a quantitative risk assessment approach on a segment-by-segment basis and that the preferable approach would be a geohazard risk assessment which examined every segment of the pipeline route. Indian and Northern Affairs Canada was of the view that the segments should be small. Indian and Northern Affairs Canada stated that in the least, the assessment should include a relative risk rating and analyses of geohazards acting in combination where applicable. Indian and Northern Affairs Canada was of the view that we should consider a condition specifically listing the geohazards and specific combinations of geohazards which the Proponents would be required to analyze.

Views of the Board

We note that there was general agreement that a geohazard assessment of the project would be beneficial in providing useful information for the detailed design and the implementation of geohazard mitigation during construction. There was disagreement however on whether the semi-quantitative approach described by the Proponents is adequate or whether the quantitative approach suggested by Indian and Northern Affairs Canada is required. Both require a significant level of expertise to implement.

We are satisfied that the semi-quantitative geohazard approach described by the Proponents is a suitable design tool for the detailed design phase of the project. Therefore we will not require the Proponents to undertake a quantitative geohazard assessment. Condition 45 requires the Proponents to file a geohazard assessment of the project prior to pipe-laying operations. This report shall:

- detail its geohazard assessment methodology and the specific and combined geohazards identified along the route;
- describe specific measures to be implemented to mitigate individual and combined geohazards;
- provide decision criteria for implementation of mitigation for geohazards identified during construction;

- outline the qualifications of the staff making decisions regarding design and implementation; and
- outline the ongoing monitoring requirements for geohazards identified during the detailed design and construction phases.

6.4.3 Pipeline operating temperatures

The operating temperature of a pipeline is an important design consideration as heat is exchanged between the pipeline and the surrounding ground. The difference in temperature of the pipeline compared to the surrounding ground could result in a change of temperature in the ground around the pipeline as well as how the surrounding ground exchanges heat with the atmosphere (the thermal regime). In permafrost environments the structural and physiographic properties of the ground are dependent on the thermal regime. A change in ground temperature could cause the formation of a frost or thaw bulb around the pipeline, a change in the depth of the active layer or a change in the timing of active layer freeze-thaw cycles, resulting in loading and, in some cases, deformation of the pipe.

Did you know?

Joule-Thompson effect

As natural gas moves downstream in a pipeline, energy is lost mostly due to friction and this causes a drop in pressure. When pressure decreases the gas expands and the temperature of the natural gas. decreases The decrease in temperature is referred to as the Joule-Thompson effect.

Mackenzie Gathering System – upstream gathering pipelines

The Proponents stated that the gathering pipelines north of the Inuvik Area Facility would be operated cold since they are located in continuous permafrost. These pipelines would be subject to frost heave where unfrozen pockets of ground referred to as taliks occur. The Proponents indicated that design mitigation would be used as required on a site-specific basis to limit the strain demand on the gathering pipelines to below 0.5 percent, so that common line pipes that comply with *Canadian Standards Association Z245.1, Steel Pipe*, can be used.

Mackenzie Gathering System – natural gas liquids pipeline

The temperature of a liquids pipeline is affected by the mass flow rate and the transfer of heat between the pipe and the soil. The Proponents determined that since the mass flow rate in the natural gas liquids pipeline is low, the pipe temperature would be close to the soil temperature anywhere along the pipeline. Natural gas liquids entering the liquids pipeline from the Inuvik Area Facility would be designed to have a constant inlet temperature of -1^{o}C. The Proponents stated operating temperature guidelines are based on the criteria that the average annual temperature will not increase long-term thaw of the right of way compared to the effects of just clearing without pipeline operation.

Mackenzie Valley Pipeline

The Proponents indicated that they intend to limit the compressor station discharge temperature to ensure that the pipeline temperature does not cause long-term thawing of the permafrost beyond that caused by clearing the right of way. The Proponents selected an average annual station discharge temperature of -1^{o}C in continuous permafrost areas. Figure 6-6 shows the expected temperature profiles at different times of year for the one compressor station configuration and the three compressor stations plus a heater station configuration.

In their May 2007 updated evidence the Proponents indicated that the Mackenzie Valley Pipeline would begin operation with only one compressor station between the Inuvik Area Facility and the Alberta border, at Great Bear River. The full potential capacity of the Mackenzie Valley Pipeline could be reached in the future with a total of 14 compressor stations in operation. Figure 6-7 shows the different temperature profiles for the Mackenzie Valley Pipeline with different compressor arrangements. The variation in the temperature profile with added compressor stations is a consideration in the overall design of the pipeline. Areas which would begin operation with average pipeline temperatures well below 0^{o}C could operate with temperatures above 0^{o}C in the fully expanded case. For example, near kilometre 400, the annual average temperature with one station operating would be about -6^{o}C but with 14 stations operating the annual average temperature would be 2^{o}C.

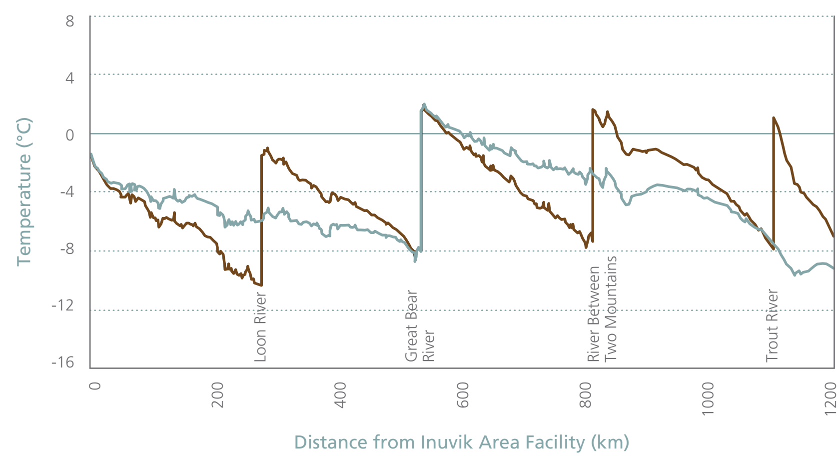
To monitor the effects of changes in ground temperature on the pipeline, the Proponents stated that ground temperatures would be monitored with thermistors and pipeline strain would be monitored with high resolution in-line inspection tools (such as the Geopig®). The Proponents discussed several mitigation measures against thermally induced pipeline deformation including the use of heavy wall pipe, thermosiphons, pipe insulation, reduced pipe cover, and backfill of the trench with non frost-susceptible soils at locations of high frost heave and thaw settlement potential.

Views of the Board

The pipeline operating temperatures for the gas pipeline are significantly influenced by the system configuration. We are of the view that the Proponents' approach of developing a pipeline design which is relatively insensitive to pre-existing ground conditions is prudent. Nevertheless, we have added requirements to Conditions 46, 48 and 51 for further assessments of the potential impact of changing pipe operating temperatures associated with increases in compressor stations. Monitoring of pipeline strain will be important to maintaining pipeline integrity. Conditions regarding monitoring are discussed in Section 6.6.

Figure 6-6

Temperature profiles for configurations with one and three compressor stations



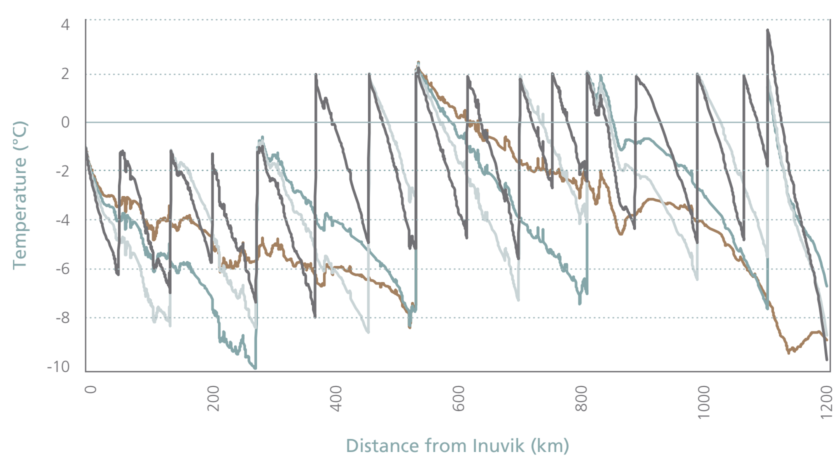
Annual average pipeline operating temperatures

1 compressor station

3 compressor stations and Trout River heater station

Figure 6-7

Temperature profiles for various compressor configurations



Annual average pipeline operating temperatures

1 compressor station with no heater station

3 compressor stations

7 compressor stations

14 compressor stations

6.4.4 Pipeline materials

The Proponents' approach to pipeline design for the project, as discussed in Section 6.3, includes using a strain-based design methodology for secondary loads such as ground movement. The Proponents would then use monitoring during operation to identify locations where loads are accumulating, and would intervene to repair or maintain the pipe at these locations. The materials selected for the project must be suitable for strain-based design and operation at high pressures in an environment with limited seasonal access for pipeline repair and maintenance. The materials must also be able to withstand cold temperatures during construction and potentially high external loads.

The line pipe, components and plant-applied external coating would be designed and manufactured in accordance with the Canadian Standards Association Z245 series requirements. Line pipe specifications are shown in Table 6-4. Qualified suppliers would be selected to produce the pipe and apply external coating in accordance with the Canadian Standards Association Z245.1 and Z245.20/Z245.21, and the Proponents' specification and quality assurance program.

Table 6-4

Line pipe specifications

Parameter	Manufacturing specifications
Pipe material	Low carbon, high strength, low alloy steel
Steel grade	550 (X80)
Skelp (plate)	Thermo-mechanically rolled
Welds	Longitudinally or helically double submerged arc
Notch toughness	160 Joules

The Proponents performed ductile fracture arrest analysis using the Battelle method and conducted a full-scale burst test. Based on the results of the analysis and verification test the Proponents would specify a notch toughness of 160 Joules to provide for a positive ductile fracture arrest in the Mackenzie Valley Pipeline.

Pipeline components such as valves, fittings, flanges, and induction bends would be manufactured in accordance with Canadian Standards Association Z245.15, Z245.11, Z245.12, and the Proponents' specification and quality assurance program. Components would be of Grade 483 (X70), PN250 and Category II to provide sufficient strength and fracture resistance for reliable operation in the northern environment.

Views of the Board

The design specifications will require material properties able to meet the requirements for operation in cold temperatures at high pressures and subjected to secondary loads such as ground movement. We are of the view that the current piping manufacturing technology exists to enable the Proponents to select and test the appropriate piping materials to ensure they meet the design specifications. The Proponents have indicated that they will be using a quality control and assurance process to ensure that the piping materials will be selected, manufactured, tested, transported and installed to ensure they continually meet the design specifications. Condition 18 requires the filing of specifications, mill joining programs and project-specific quality assurance programs to facilitate National Energy Board audits. Condition 58 requires summary reports of non-compliances with design, materials and construction specifications and the disposition of these non-conformances.

6.4.5 Joining – welding and non-destructive examination

Individual pipe sections are factory manufactured using either longitudinal welding or spiral welding techniques. Sections of pipe are then joined together at the pipe mill or the project site by welding the circumference joint using girth welds. The factory and field welding procedures are critical to ensuring pipeline integrity. To ensure quality control the welds are tested using non-destructive examination techniques.

Did you know?

Definitions

Arc weld – a welding process where metal is joined by using a power supply to create an electric arc between a consumable electrode and the base metal to melt the metals.

Ductile fracture arrest – the ability of pipe, which fails in a ductile manner, to resist or arrest crack propagation.

Full-scale burst test – burst testing of sections pipe to validate material behaviour models, such as crack propagation.

Girth weld – the circumferential weld used to join two pipe joints together.

Helically double submerged weld – the welding process used to join spiral pipe; the pipe is manufactured from steel coils formed helically into cylinders.

Longitudinal weld – the weld used to join U and O formed pipe; the pipe is manufactured from steel coils or plate formed into a cylinder and then the length of the joint is welded.

Notch toughness – the ability of pipe steel to resist crack initiation and propagation.

Skelp – a piece or strip of metal produced to a specified thickness and width during the pipe manufacturing process.

The Proponents indicated that a combination of stress and strain-based design would be used on the pipeline portion of the project and a conventional stress-based design would be used for the station and facility construction. The specific components identified in the welding and non-destructive examination programs are related and form part of an overall joining program. The successful implementation of an effective joining program is necessary to provide the required weld quality.

Welding

Strain-based design calls for a higher degree of weld quality and more stringent mechanical properties than stress-based design. The integrity and strain bearing capacity of the weld and the area adjacent to the weld, known as the heat affected zone, are important factors. In addition to any flaws which may be introduced during the welding process, heat from this process may change the micro-structure of the parent metal adjacent to the welding material in the heat affected zone. This in turn may affect the strength and ductility of the original parent metal. Therefore, it is important that the welding procedure minimizes the potential for flaws and ensures any changes in the parent material properties are still within the design parameters. The welding procedure design should not only consider flaws and mechanical property requirements, but also balance the need for acceptable construction productivity in the challenging northern environment. Verification that a welding procedure can achieve the predicted and desired results is critical when the project involves the use of unconventional design methods or state of the art joining techniques.

The Proponents have developed a framework for weld qualification requirements which they would use to develop final girth weld procedure specifications. The Proponents stated that all welding procedure specifications would meet *Canadian Standards Association Z662, Oil and Gas Pipeline Systems* requirements and any additional project-specific requirements.

The objective for the Proponents' strategy for developing welding procedures for the project is to achieve weld properties critical to a strain-based design. These welding procedures relate to:

- weld strength overmatch;
- appropriate consumable selection;
- bevel design; and
- the appropriate welding process selection.

The Proponents indicated that all circumferential field and pipe mill welds would be required to meet the same weld performance criteria, based on their intended application in either a stress or strain-based design. The identified performance criteria include mechanical properties and maximum allowable flaw sizes. In addition, the Proponents indicated that the target weld overmatch yield strength value is five percent higher than the yield strength of the parent metal.

The Proponents indicated that they would use a combination of stress and strain-based design for all pipeline applications on the Mackenzie

Gas Project and a stress-based design for the Inuvik Area Facility, compressor station and the facility construction. The weld quality requirements for these two design approaches are different due to the different operating and loading regimes. The Proponents submitted that the Canadian Standards Association Z662 flaw acceptance criterion is very conservative and would be impractical to use on the strain-based design piping, due to the high cost associated with repairing defects which may have excess stress and strain capacity for the intended loading regime. Canadian Standards Association Z662 provides the option of using fracture mechanic principles to develop alternative acceptance criteria. Therefore, the Proponents developed a curved wide plate test program to perform large-scale proof testing to determine the critical flaw sizes for the various proposed pipe sizes and to verify the preliminary estimates of tensile strain capacity of the welds.

Under the curved wide plate test program, a total of 60 curved wide plate tests were performed on UOE (longitudinally welded pipe) and spiral welded pipe which had undergone a simulated coating heat treatment to represent the aged heat condition. The Proponents indicated that additional curved wide plate tests may be considered during detailed design to further enhance the design and to identify areas which could reduce construction costs. Some of the identified follow-up testing may include confirmation of weld procedure strain capacity and critical flaw size. In addition, the Proponents would consider additional testing on buried flaws or interacting flaws to determine if the acceptable flaw criteria could be expanded to accommodate actual field production welding.

The Proponents stated that they are attempting to leverage new technology or process initiatives they are involved in. Welding related improvements contemplated on the project, such as dual torch metal arc weld or single torch tandem (dual wire) welding process, may enable the Proponents to find efficiencies during pipeline production and to complete more, higher quality welds in a shorter time frame.

Non-destructive examination

Once welding procedures and flaw acceptance criteria that meet the design requirements have been established, the next step is to choose a reliable method for identifying and fully characterizing any flaws. The weld inspection method must be able to non-destructively examine the finished weld to determine whether the weld integrity meets specified flaw acceptance criteria requirements. The chosen non-destructive examination technique must be proven to accurately characterize potential flaws in terms of vertical height, depth and circumferential location.

A solid understanding of the types of potential flaws associated with the welding process, and their anticipated size, location and orientation is required when choosing and proving the effectiveness of the non-destructive examination technique. In addition, knowledge of the potential weld flaw characteristics is also required when developing non-destructive examination procedures and related quality checks.

To aid in the preparation of a joining program, the Proponents developed a non-destructive examination strategy framework to inspect the estimated 80,000 circumferential girth and facility welds. The main purpose of the non-destructive examination strategy is to identify any flaws in the weld metal which

Did you know?

Testing of welds

Since the early 1980s considerable work has gone into testing and analysis to determine the tensile strain capacity of pipe and girth welds. The driver for this work was the potentially high strains associated with offshore piping installation and operation. A reliable means to analyze strain capacity of a pipeline weld and the associated heat affected zone was required because traditional fracture mechanics methods have not been fully validated for higher strain demands.

The mechanical properties required to achieve high tensile strain capacity in pipeline girth welds include weld metal yield strength overmatch (where the weld metal has higher strength properties than the parent metal) yield to tensile strength ratio and uniform elongation in both the pipe and weld metal and, in addition, adequate toughness in both the heat affected zone and the weld metal. Currently, the only method to obtain these properties accurately is through empirical testing with methods such as curved wide plate testing. The curved wide plate test (a large-scale tensile test of a piece of pipe which may include a girth weld) has been used within both the offshore and onshore pipeline industry to better represent actual pipe behaviour under strain conditions compared to transverse tensile testing.

would reduce the strength of the weld joint during the anticipated loading.

The Proponents are planning to use a zonal discrimination approach to determine the flaw sizes using either focused probes or phased array technology. Prior to detailed engineering, the Proponents would implement an automated ultrasonic testing vendor qualification program along with an automated ultrasonic testing flaw size verification program to determine the accuracy of the automated ultrasonic testing system under cold climate conditions.

The stress-based design used for station and facility construction would employ flaw acceptance criteria specified in either the applicable Canadian Standards Association Z662 or American Society of Mechanical Engineers B31.3 standards. The Proponents confirmed that they would comply with *Onshore Pipeline Regulations, 1999* requirements which stipulate 100 percent non-destructive examination inspection of all welds. However, the Proponents stated that they intend to request an exemption from the *Onshore Pipeline Regulations, 1999* non-destructive examination requirement for welds in the auxiliary systems of the Mackenzie Valley Pipeline.

The Proponents plan to develop a project-wide data management system designed specifically for the Mackenzie Gas Project to manage the large amount of data resulting from over 80,000 pipeline welds. The Proponents indicated that a weld management and materials system would be developed during detailed engineering to ensure each weld is uniquely identified and traceable during all stages of construction and over the operating life of the pipeline.

Views of the Board

Due to the anticipated strain-based design and the associated loads we are of the view that joining of the piping is an important consideration in meeting the material design specifications. Instances of localized low fracture toughness properties are known to have occurred in or adjacent to the weld. Currently there is no requirement in the piping manufacturing standard to perform testing such as crack tip opening displacement that would identify areas of localized low fracture toughness. Instances of localized low fracture toughness could affect the integrity of the weld or the base metal adjacent to the weld during any pipeline deformation associated with a strain-based design at low operating temperatures. Therefore, in addition to determining the crack tip opening displacement values for the alternative flaw acceptance criteria we are of the view that it would be prudent to determine the crack tip opening displacement values for the heat affected zone and the weld metal of the pipe mill circumferential, helical and longitudinal welds. Condition 17 requires the Proponents to undertake testing to determine the susceptibility to areas of localized low fracture toughness associated with welds.

Pursuant to the *Onshore Pipeline Regulations, 1999* the Proponents must file a joining program with the National Energy Board prior to conducting welding procedure qualification tests for the field circumferential production, tie-in and repair pipeline welds and welding of project facilities. In addition, the Proponents must file the non-destructive examination procedure qualification records shortly after the completion of qualification tests. Conditions 52, 53 and 54 address these requirements.

6.4.6 Seismic design

Indian and Northern Affairs submitted that the occurrence of earthquakes could impose significant environmental loads and subsequent strain on the pipeline. A recommendation was made that the Proponents should satisfy us that seismic related hazards had been incorporated into the design of the pipelines and associated facilities. The Proponents submitted that earthquakes and other seismic related geohazards were to be considered as part of the final design and would be addressed during detailed engineering.

6.4.7 Slopes

If the soil surrounding a pipeline moves after a pipeline is built, as in the case of an unstable slope, the movement can cause stresses and strains in the pipe, expose the line, damage the pipe coating, or possibly cause the pipe to fail. The Proponents submitted that the structural integrity of the proposed pipelines is such that rupture and leakage would be unlikely in the case of soil movement. The Proponents expressed the view that the objective for slope design for the project is essentially one of environmental protection and, in particular, one of protecting watercourses from the ingress of soils from slope movement or soil erosion caused by pipeline construction and operation.

Did you know?

Definitions

Cross slopes – slopes that dip perpendicular to the pipeline.

Longitudinal slopes – slopes that dip roughly parallel to the pipeline.

Pore water pressure – the pressure of groundwater at a given location within the soil.

On the record

Threshold slope angles

The Proponents define threshold slope angles as the angles below which a particular slope will be stable regardless of surface disturbance and permafrost thaw. The method was adopted based on its successful utilization for the Norman Wells to Zama Pipeline.

The Proponents submitted that the Mackenzie Valley is very active in terms of slope movement and the pipeline route would cross terrain susceptible to slope movement and other geological hazards. Permafrost has a significant influence on slope stability design in northern regions. When permafrost thaws, the ice in the ground melts, causing the pore water pressure to rise until the water is able to drain. The Proponents' goal is to manage pore water pressures in the slopes so that thawing permafrost does not cause the calculated factor of safety for the slope to fall below a predetermined value, and the slope to become potentially unstable.

Slopes were categorized on the basis of slope angle and orientation in relation to the pipeline. The Proponents estimated that the Mackenzie Gathering System and Mackenzie Valley Pipeline would cross 372 and 822 longitudinal slopes, respectively, as well as 64 kilometres and 339 kilometres of cross slopes, respectively. Of these slopes, the Proponents identified 246 that required stability mitigation. Based on preliminary geothermal and pore water pressure modeling and preliminary soil data, the Proponents developed threshold slope angles for three types of frost susceptible soils and four geographical regions. The Proponents plan to update the threshold angles during final design.

Slope design

Where LiDAR measurements of slope angle exceed the threshold angle, the Proponents propose the use of slope stability mitigation techniques. The primary methods proposed to increase slope stability and reduce the rate of permafrost thaw are:

- installing pipe insulation;
- using right of way passive cooling systems such as thermosiphons;
- employing surface erosion control measures; and
- using surface insulation.

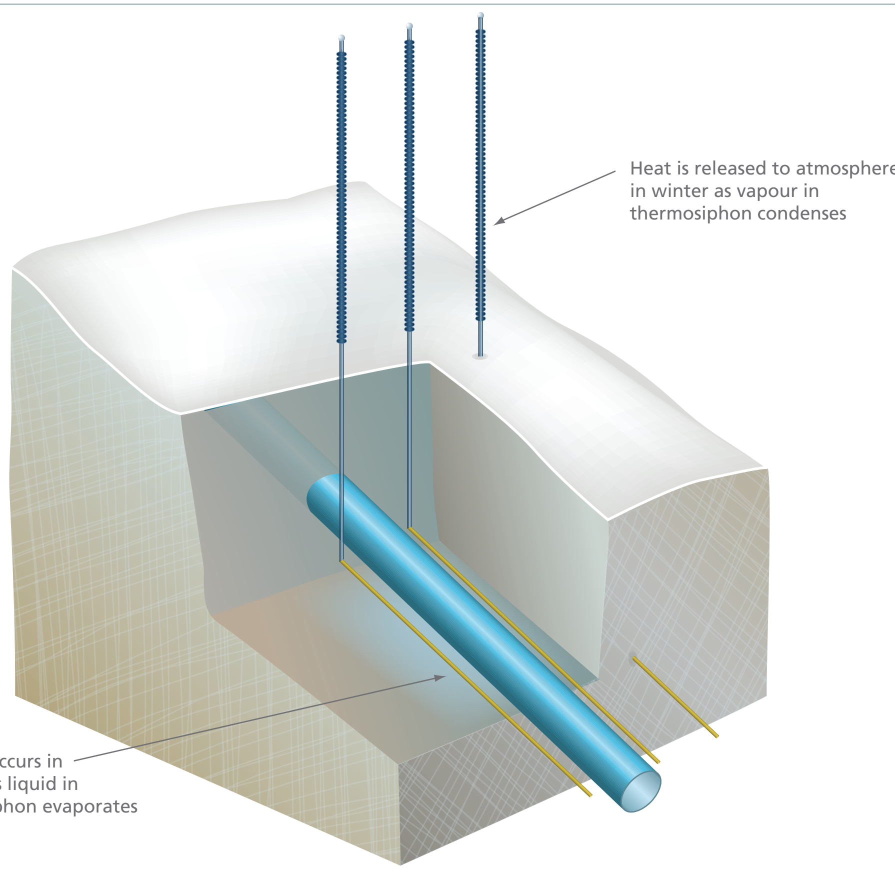
Other proposed slope stability mitigation methods include re-grading the slope to a lesser angle or installing friction-reducing wrap on the pipeline to prevent damage during slope movement. Studies to determine the suitability of carbon dioxide versus ammonia refrigerant thermosiphons and the available types of surface insulation (flax straw, wood chips and synthetic sheeting) were ongoing during the hearing. The Proponents submitted preliminary analysis of data from the surface insulation field trials indicating that straw bales provided the best thermal protection of materials tested, but were subject to shrinkage and would require further study to determine if the effects were material.

The Proponents submitted that the risk of potentially rapid events such as slope movements would be reduced in design and construction by identifying rapid loading mechanisms and then avoiding these areas (rerouting and directional drilling) or stabilizing the site using secondary mitigation measures such as slope grading or thermosiphons. The Proponents described the buildup of strain due to earth movement from frost heave, thaw settlement and soil creep as a gradual process that could be identified prior to reaching threshold intervention values for pipeline strain. In addition, the Proponents plan to install slope monitoring equipment, including piezometers and thermistor cables on the right of way. Slope movement indicators would be installed at sites with stability concerns such as ice rich slopes, slopes with evidence of soil movement or slopes where large toe excavations are required. The Proponents stated that intervention criteria other than pipeline strain, such as thaw depth or slope movement, would not be developed for monitored slope parameters.

To address the expected variation in ground conditions along the proposed route, the Proponents' preliminary slope design method incorporates a field change manual with contemplated design responses to foreseeable changes in ground conditions from those assumed in final design.

Figure 6-8

Thermosiphon (left) and wood chips used as surface insulation (right)



Indian and Northern Affairs Canada reviewed preliminary documents submitted by the Proponents and made several recommendations as outlined in Section 6.4.8. Indian and Northern Affairs Canada and the Proponents participated in a series of meetings and technical workshops and reached a general agreement on a design approach for slopes and geohazards.

Indian and Northern Affairs Canada was of the view that the Proponents should assess the effects of changes in ground thermal regime due to the addition of compressor stations or selected slopes where those effects could occur. Indian and Northern Affairs Canada also suggested that the Proponents prepare a complete inventory of all slopes along the right of way, especially lesser slopes, and not just those requiring site-specific slope designs.

Indian and Northern Affairs Canada indicated that further detail was required regarding the remedial actions the Proponents would take should monitoring indicate that the factor of safety for a slope falls below the design factor of safety. Indian and Northern Affairs Canada was concerned over who would make this determination and what kind of training or expertise they would have. Indian and Northern Affairs Canada suggested that there needs to be specific requirements for the technical ability and skills of the individuals making this determination and suggested that this should be specified in a condition.

Views of the Board

We find the Proponents' preliminary design methodology for slopes to be satisfactory. We note however that there appears to be an exhaustive inventory of slopes on the project in the report submitted in evidence which will require revision when the final route is determined. We also note that the Proponents have proposed a field change manual for slopes in anticipation of the need for changes during construction. We are of the view that such a manual should be approved by the National Energy Board prior to use so that changes made in accordance with the manual would not require amendments to submitted final designs. Indian and Northern Affairs Canada's concern regarding the effects of changes in ground thermal regime due to the addition of compressor stations is valid and should be considered by the Proponents during the final design phase to preserve their ability to safely add compression in the future.

We are of the view that the Proponents understand the importance of ensuring competent design staff for the final slope design and we are not persuaded that this needs to be specified in a condition. However we will make adequate training a requirement of the field changes manual since the presence of qualified geoscientists on each pipeline spread is not a typical requirement.

Conditions 48 and 49 require the submission of a slope design methodology final report and a field changes manual for slopes.

On the record

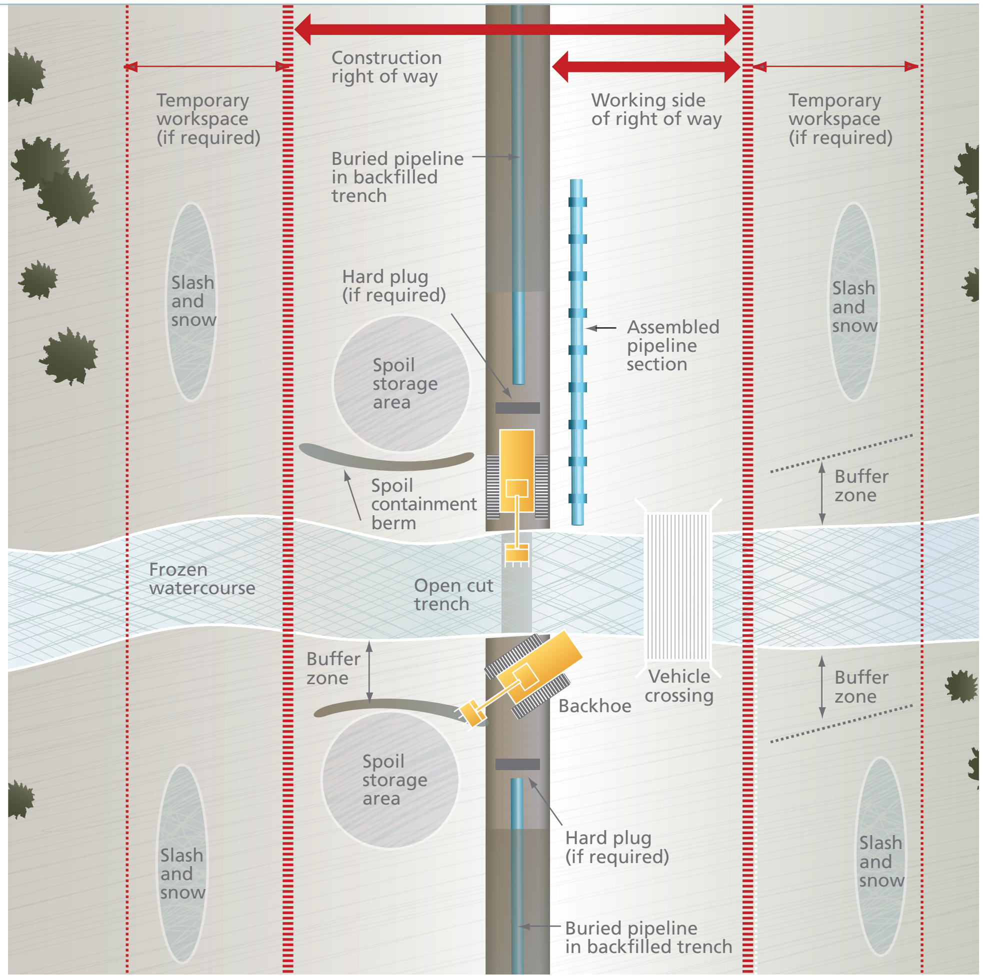
Thermosiphons

The Proponents filed an April 2006 report entitled *Slope Design Methodology Report – Preliminary Engineering Design* which described the use of thermosiphons. Thermosiphons are passive devices (require no power source) designed to remove heat from the ground during winter when the air temperature is lower than both the ground temperature and the boiling point of the heat exchange agent. The thermosiphons considered for the project are sealed systems containing a pressurized heat transfer agent. This agent would be either pressurized carbon dioxide or ammonia. Heat is removed from the ground in winter, when the heat transfer agent boils within the buried portion of the thermosiphon and the gas rises and condenses in the radiator segment above ground. The heat exchange process stops in summer when the air temperature is warmer than the ground temperature. The Proponents indicated that manufacturers currently favour carbon dioxide as the heat transfer agent but that ammonia had not been ruled out.

The Proponents indicated that ammonia had been used in the 120,000 thermosiphons, called heat pipes, installed on the Alyeska Pipeline which carries crude oil from Prudhoe Bay, Alaska. Ammonia was found to have the best thermal performance and a lower working pressure, meaning that thinner-walled pipe could be used for the thermosiphons. The Proponents noted, however, that these thermosiphons had operational problems due to non-condensing gas accumulating within the pipes, and the company was converting these pipes to carbon dioxide. During preliminary engineering the Proponents had not yet considered the corrosion protection requirements for thermosiphons but acknowledged that the loss of containment of the heat transfer agent due to corrosion would be undesirable.

Figure 6-9

Watercourse crossing – open trench



6.4.8 Watercourse crossings

Where a pipeline crosses a watercourse, there is a possibility that the water quality, aquatic habitat and navigable waterways could be degraded. Watercourses are a dynamic component of the physical environment and are subject to floods, debris flows, ice jams, erosion, and changing banks which can damage or trigger slope instability or expose the pipe. In permafrost regions, taliks present the potential for very large frost bulbs to form around the pipe which could cause frost heave and disrupt the surface and groundwater flow patterns at watercourse crossings.

The Proponents submitted that the Mackenzie Gathering System and Mackenzie Valley Pipeline would cross 643 water bodies. The shorter natural gas liquids pipeline would cross 260 water bodies. These watercourses range from unmapped, vegetated drainage features to named, navigable corridors including the Mackenzie River. The project route also crosses bodies of standing water and peatlands, which are typically areas of significant shallow groundwater flow. The Proponents anticipate taliks to be present beneath perennial watercourses in areas of continuous or discontinuous permafrost. With the exception of the major watercourses, there is limited flow data from northern regions for use in the hydrologic design of watercourse crossings.

The Proponents selected the proposed crossing locations to minimize the number and width of crossings and to avoid areas prone to channel migration, local scour and ice jams. The Proponents plan to use a generic design template based on company best practices and a minimum burial depth of two metres for the majority of crossings. Site-specific designs for all large watercourse crossings would be based on local stream characteristics, the 1:100 year flood event, or the 1:200 year flood event where hydraulic data is limited.

Generally, watercourse crossings would be constructed using an open trench method when the watercourses are frozen (see Figure 6-9). Where winter flows occur, the flows would be controlled and watercourse crossings would be constructed using isolation methods (see Figure 6-10). The Proponents intend to install the pipe in horizontal directionally drilled bores (see Figure 6-12) to cross 17 perennial watercourses where fish habitat is present and isolation methods are not feasible.

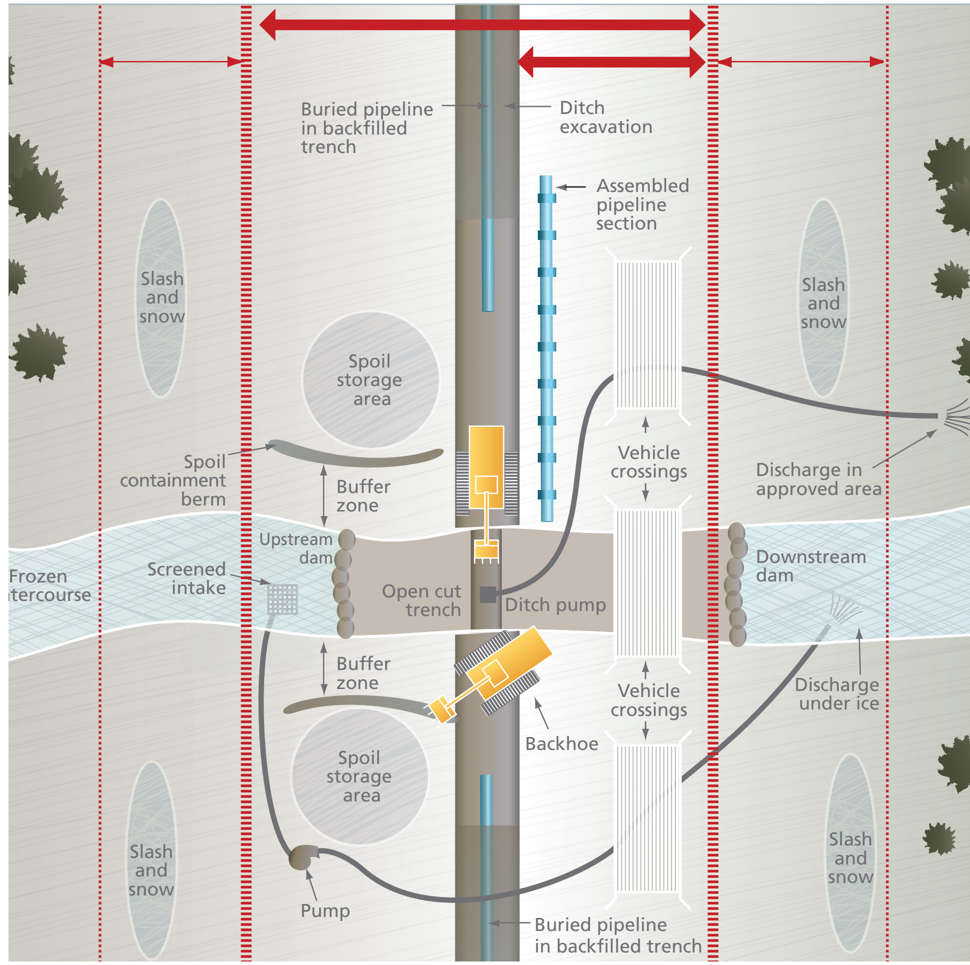
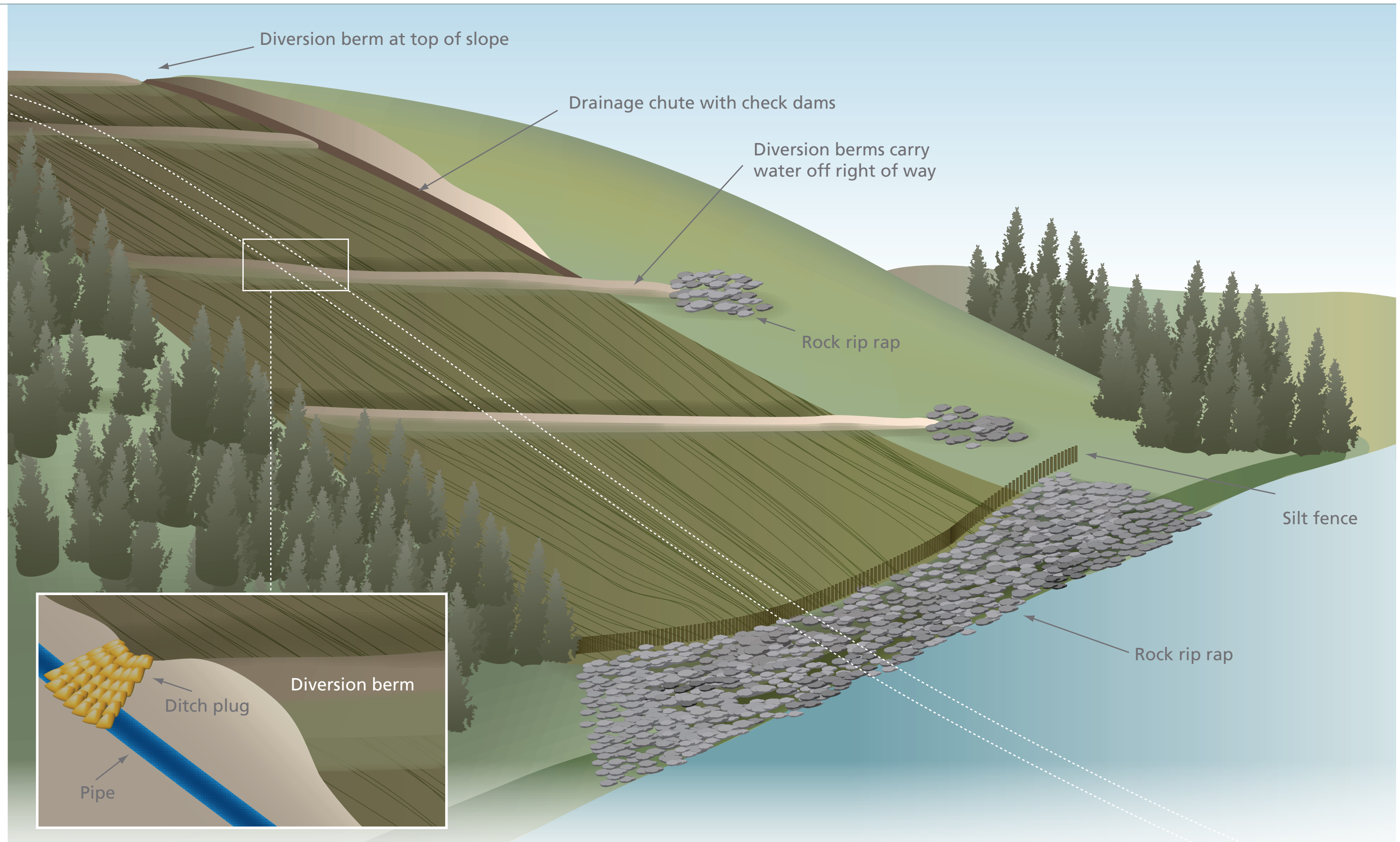


Figure 6-10

Watercourse crossing – isolated method

Figure 6-11

Diversion berms and ditch plugs



The Proponents propose to control groundwater flow and seepage along the pipelines using ditch plugs and diversion berms for overland areas (see Figure 6-11). In areas of high groundwater flow, such as watercourse crossings and fens, the Proponents expect pipe strain related to frost bulb growth to be manageable, and intend to monitor frost bulb growth at these locations using aerial patrols and in-line inspection tools.

Did you know?

Definitions

Ditch plug – a section of ditch filled with a material intended to prevent the flow of ground water in the backfill along the ditch.

Diversion berm – a berm constructed on the surface of a slope which is intended to direct surface water off the right of way in order to minimize erosion.

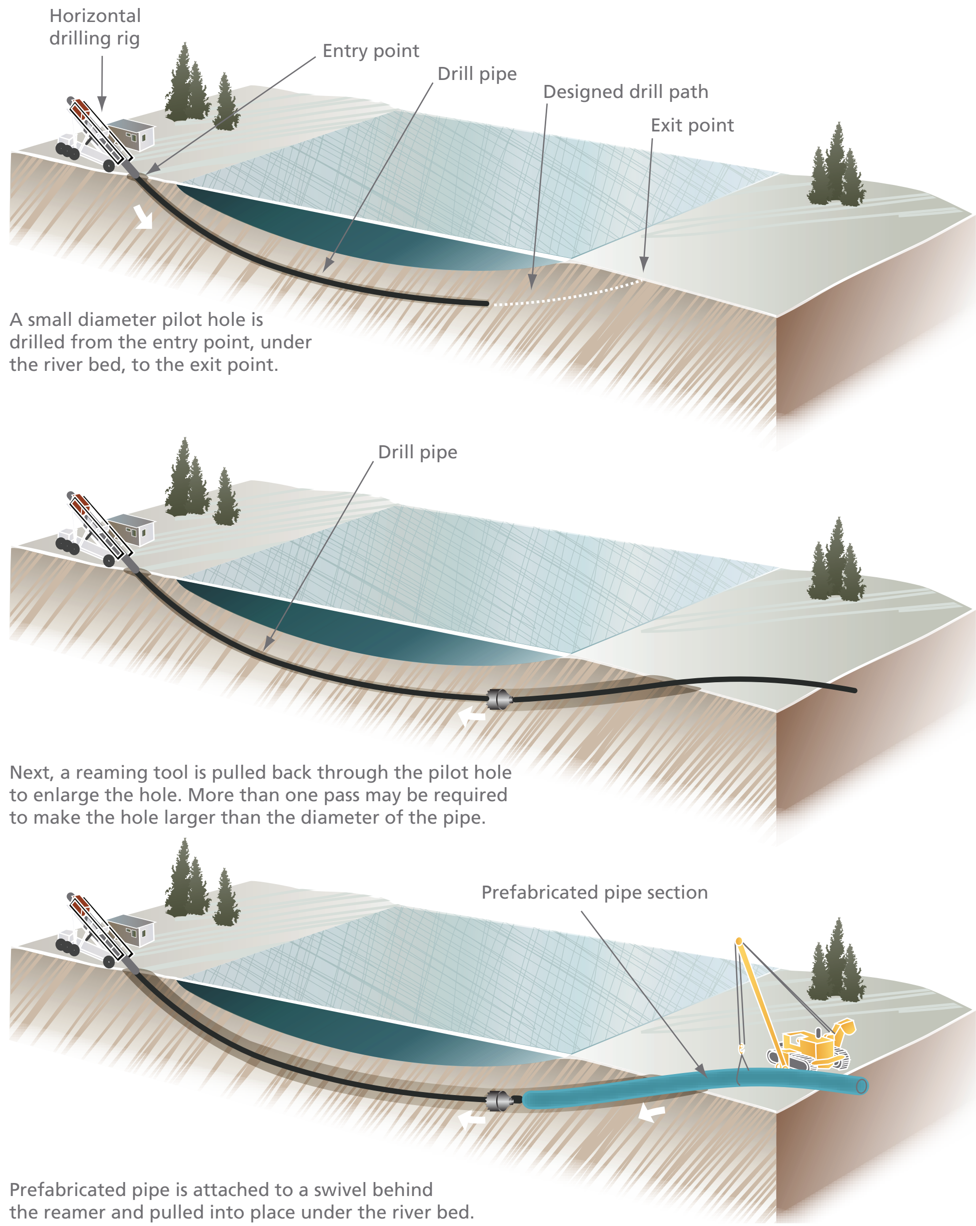
Horizontal directionally drilled crossings

Feasibility assessments were carried out for all proposed horizontal directionally drilled crossings based on subsurface data from existing boreholes in the vicinity of the crossings. Additional field work is planned for each horizontal directional drill location before drilling begins to confirm soil types, ice content and the presence of any ice lenses.

Drilling muds are used during directional drill operations to remove drill cuttings, cool and lubricate the drill bit, provide fluid loss control and create pressure on the walls of the borehole for stability. The Proponents stated that muds with freezing temperature depressant additives have a lasting impact on the environment and increase the complexity of the horizontal directional drill operation compared to using chilled muds without freezing temperature depressant additives. Therefore, using temperature controlled (5°C) drilling fluids without freezing temperature depressant additives is preferable due to restrictions placed on the disposal of freezing temperature depressant muds. The Proponents stated that using freezing temperature depressant additives would be assessed further during detailed design and would only be considered where there is significant concern about hole instability during drilling. While freezing temperature depressant muds remain an option, the Proponents expressed confidence that the directional drill operations can be successfully completed using drilling muds chilled to within a few degrees above freezing.

Figure 6-12

Watercourse crossing – horizontal directional drill using backreaming method



On the record

Horizontal directional drilling in Arctic environments

The Proponents indicated that there is little precedent for horizontal directional drilling operations in permafrost and Arctic environments. A horizontal directional drilling comprehensive review undertaken by the Proponents identified several key issues which could affect the success of the overall horizontal directional drilling operations including:

- limited numbers of horizontal directional drilling contractors with Arctic experience;
- logistical planning;
- continuous operation in an extreme cold environment; and
- the need for tight control of drilling fluid properties.

A significant challenge identified by the Proponents is the development of a drilling mud that will not freeze when used in permafrost environments, yet will remain viscous enough to remove drill cuttings, provide lubrication and prevent hole collapse. In ice rich soils the circulation of warm drilling muds will cause the permafrost to thaw, which could lead to the collapse of the borehole, surface subsidence or slope instability.

The horizontal directional drilling study made a number of recommendations including:

- investigating the use of non-toxic, biodegradable methyl glucoside as a freezing temperature depressant mud additive;
- use of temperature controlled (cooled) drilling fluids;
- investigating mud disposal requirements;
- the calculation of frost heave at crossings; and
- the completion of an extensive geotechnical field investigation to identify and delineate horizontal directional drilling unfavourable substrates, high ice content soils and taliks.

Additional mitigative measures proposed by the Proponents to prevent the degradation or thaw of unstable or ice rich permafrost include insulated work pads, temporary surface drill casing and auxiliary mud chilling systems.

During the course of the hearing Indian and Northern Affairs Canada reviewed the watercourse crossing conceptual designs and recommended that the Proponents collect and incorporate into the design additional data on:

- distribution of ground ice;
- thermal regime of river sediments;
- extent of taliks;
- soil properties; and
- slope characterization at stream crossings.

Indian and Northern Affairs Canada further recommended that prior to construction, the Proponents should submit to the National Energy Board:

- detailed stream crossing designs for the Mackenzie Valley Pipeline and natural gas liquids pipeline;
- a comprehensive river engineering analysis;
- revised frost bulb predictions; and
- a typical crossing design for an ice rich slope.

The Proponents submitted that the proposed field investigations and final design requirements would address the recommendations made by Indian and Northern Affairs Canada during the oral hearing.

The Joint Review Panel expressed concerns regarding the potential release of sediments at stream crossings during construction and the post-construction phase and the potential negative effects of the formation of frost bulbs and aufeis at stream crossings. The Joint Review Panel recommended that measures must be in place to avoid the creation of frost bulbs and aufeis at stream crossings through effective design and mitigation. Frost bulbs in streams could have an impact on the physical environment if the flow in certain streams is blocked. The biological community in these streams, particularly fish and their habitat could be negatively affected. The Joint Review Panel heard that frost bulb formation can be reduced by using pipe insulation however the effectiveness of that insulation could degrade over time. Impacts at stream crossings can be further reduced by deeper burial of pipe but that burial by itself requires substantial depth to be effective.

The Joint Review Panel was generally satisfied that the Proponents have adequately addressed potential impacts of the Project on groundwater flow, subject to a number of recommendations.

Views of the Board

We are satisfied with the design approach adopted by the Proponents. The design approach and construction techniques, for the most part, are conventional and have been used on other projects successfully. We note that horizontal directional drilling has been used only once in permafrost areas and that this increases the potential for unforeseen issues during installation. We agree with the use of temperature controlled drilling muds for the majority of the horizontal directional drilling crossings. When this is not possible, the alternative use of freezing temperature depressants has potential undesirable long term impacts on slope stability and their use as an option in horizontal directional drilling must be carefully considered before implementation. Condition 47 requires the Proponents to undertake a hazard analysis and prepare contingency plans for each horizontal directional drilling crossing.

Condition 51 requires an inventory of all watercourse and water body crossings, design information, drawings, information regarding frost bulb analysis, evidence demonstrating the prevention of aufeis and unacceptable pipe strains, information regarding thermal, erosion, scour control and ground water flow mitigation measures, and evidence of consultation with the Department of Fisheries and Oceans.

Surveillance and monitoring is a requirement of the *Onshore Pipeline Regulations, 1999* and all pipeline monitoring and surveillance programs incorporate the monitoring of watercourse crossings and their approach slopes. Condition 39, which is discussed later, requires the monitoring of water course crossings for scour, aufeis, drainage impedance and erosion issues.

6.4.9 Pipeline control systems and leak detection

Project facilities would be remotely monitored and operated using Supervisory Control and Data Acquisition Systems (SCADA) from a main control centre in Calgary. Emergency shutdown systems capable of being initiated remotely or locally would be installed. A leak detection system is an important complement to SCADA because it uses the information SCADA collects to help detect leaks earlier than surveillance programs such as aerial patrols. According to the Proponents, the leak detection system's performance is important to the integrity of the entire system. Therefore, they would develop a leak detection quality program to annually review the system's performance. The Proponents added that a typical quality program would use direct methods, such as liquid withdrawals, and inferred methods, such as inputting false data into the system, to evaluate both the system's performance and the response of operating personnel. The Proponents indicated that as part of the quality program alarm statistics, actual leak data and system performance information would be reviewed annually to improve system performance.

The Proponents plan to use computational pipeline monitoring with statistical process control technology on the Mackenzie Valley Pipeline and Mackenzie Gathering System pipelines. The Proponents noted that this technology would not be able to detect leaks as effectively in multi-phase lines such as the gathering system upstream of the Inuvik Area Facility; however, potential performance improvements were possible with additional operational experience. The Proponents would also develop a project-specific plan to address the full implications of process control network security.

Did you know?

Leak detection systems

Leak detection capabilities depend on the accuracy of the measurement devices, the design and location and capabilities of the SCADA. At the time of the hearing, the overall system design had not progressed to the point where the Proponents could accurately determine the necessary leak detection system capabilities. The Proponents' decision criteria would be based on API 1155 *Evaluation Methodology for Software-based Leak Detection Systems*. The Proponents confirmed that its leak detection system for the natural gas liquids pipeline would comply with Canadian Standards Association Z662-03, Annex E *Recommended Practice for Liquid Hydrocarbon Pipeline System Leak Detection*; however, it would test the leak detection system's effectiveness annually by inferred methods and not by annually removing the liquids.

Views of the Board

In order to minimize potential damage from spills during operation, early detection of leaks and breaks is paramount. Given the remoteness of the pipeline we are of the view that it is important to ensure the system can be adequately controlled and the leak detection capability is sensitive but not prone to false alarms. Conditions 63 and 64 require the submission of data regarding the expected capabilities of the system and reports detailing the actual performance of the system and how the Proponents have addressed performance issues.

6.4.10 Settlement of backfill

After a pipeline is built, the earth along the right of way and ditch line may settle. This settlement can disrupt drainage and promote erosion if not addressed. Furthermore, if the backfill thickness and strength decreases, the pipe may become buoyant. Experience from the construction of other northern pipelines demonstrates that localized settlement occurs primarily in the first spring and summer after winter construction.

In planning their mitigation for ditch settlement, the Proponents drew on the knowledge gained by others during the construction of the Ikhil Pipeline. They plan to import thaw stable fill to supplement or replace the local backfill at the time of construction. The Proponents stated that granular fill material (e.g., sand or gravel) would be best; however, they recognized that granular material is in short supply along the pipeline route. The Proponents indicated that the only quality requirement for replacement backfill was that it be of low ice content so that thaw settlement would be limited. The Proponents intend to mine the material at borrow sites, and deliver and backfill the pipe trench soon after the pipe is placed in the trench. They would use equipment which could process the backfill into smaller lumps at the borrow site and on the right of way so that large lumps would not be placed over top of the pipe.

To help protect the pipe, the Proponents indicated that the three millimetre, three-layer pipeline coating would protect against the expected backfill conditions. In addition to the pipeline coating, foam pillows and imported fill for bedding and padding purposes would be used. Pipe protection products such as Rockshield and wood lagging (*i.e.*, lumber strapped around the circumference of the pipe) might also be used to protect the pipe as required.

The requirement for slope trench backfill is more stringent than the requirement for overland replacement backfill due to the potential for slope instability during thawing. The Proponents identified the need to replace or improve trench backfill as a function of slope angle, soil type and method of excavation in their preliminary slope design.

The Joint Review Panel considered the Proponents' plans for remediating ditch fill settlement satisfactory for most of the terrain likely to be encountered but remained concerned about the effectiveness of the ditch fill settlement remediation for areas of massive ice. The Joint Review Panel recommended that we require the Proponents to file:

- methods for determining the quality and quantity of imported fill requirements;
- the timing and methods for hauling and stockpiling those fill requirements;
- the methods for monitoring for and remediating ditch subsidence; and
- the methods for disposal of excavated material not required for backfill.

Views of the Board

We note that the Proponents filed a report during our hearing which presented the method used to estimate the settlement of backfill material that might be required. The ditch settlement values calculated were used as the basis for the preliminary designs and estimates of replacement backfill. The imported backfill quantities were based on route soil information obtained from geotechnical information available to the Proponents during preliminary design. We are confident that these estimates will improve as a result of the planned Geotechnical Verification Program. However, measures are required to ensure that the Proponents' efforts to remediate backfill settlement do not lead to other impacts which may be caused by excess backfill material being left on the right of way. Condition 44 addresses these concerns and implements the Joint Review Panel's recommendations. The condition requires the Proponents to consult with land managers and the appropriate regulators to ensure they are aware of the project backfill requirements for the project and

On the record

Ditch settlement

Localized ditch settlement is primarily the result of three factors. First, excavated material tends to increase in volume to the extent that it cannot all be graded back into the ditch. Inevitably some of this excavated soil remains along the ditch. Second, in areas of permafrost the soil immediately below the active layer can be ice rich, and this material will lose some volume after it has melted. Third, freshly exposed earth will absorb more solar radiation and would tend to thaw faster than the adjacent less disturbed soil.

the need for potential disposal sites for unused material.

Condition 43 requires the approval of backfill and padding specifications. The purpose of this requirement is to ensure that this material is not injurious to the pipe and its coating. There is a potential that some of this material will be sourced from areas where acid-bearing rock may be present. It is our expectation that the specification will contain a requirement that quarried material be screened for this possibility.

6.4.11 Right of way protection during construction

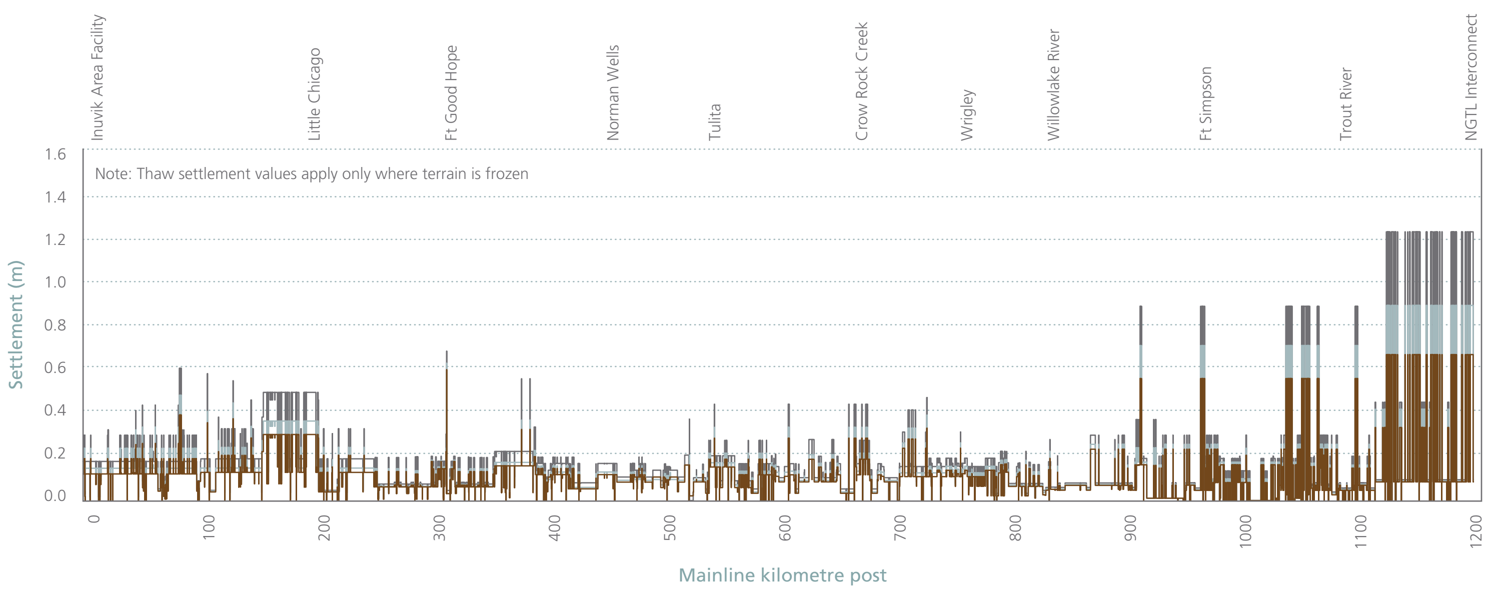
Thaw-sensitive terrain along the pipeline route may be affected by thaw-induced erosion, slope instability, or excessive settlement. Disturbance of the vegetative cover specifically on thaw-sensitive overland areas could lead to ponding and possible sustained thawing.

Based on expected terrain conditions developed from available data, the Proponents plan to build snow-ice pads, where practical, north of the tree line, and at specific locations along about 50 kilometres of sensitive terrain between the Inuvik Area Facility and Fort Good Hope. The Proponents are of the view that available borehole and terrain mapping data from previous ground disturbances in the Mackenzie Valley as well as experience gained from building earlier northern pipelines, suggests a combination of conventional surface leveling and cut and fill techniques can be used successfully south of Inuvik.

The Proponents indicated that existing borehole data is sufficient to determine the expected average amount of thaw settlement for a terrain group. The average settlement for each terrain

Figure 6-13

Anticipated right of way settlement for different clearing techniques



Locations of thick peat and predicted five-year thaw settlement for various levels of surface disturbance in frozen terrain – mainline route

- Thaw settlement – clearing and removed surface organics
- Thaw settlement – clearing and disturbed surface organics
- Thaw settlement – clearing and undisturbed surface organics

group between Inuvik and Norman Wells is predicted to be less than about 0.5 metres after five years. Figure 6-13 shows the anticipated right of way settlement between Inuvik and the Nova Gas Transmission Ltd. interconnection in Northern Alberta for three different clearing and right of way preparation techniques in areas of thick peat. The Proponents added that long-term terrain effects would be acceptable provided the necessary rehabilitation and re-vegetation is carried out. Where grading is necessary and high-ice content soil is exposed, special protective measures would be applied before the construction season ends.

Mitigative measures being considered by the Proponents include:

- using surface insulation, such as a layer of stripped organics, wood chips or board stock insulation under a layer of soil, to limit seasonal thaw;
- installing berms and breakers for erosion control; and
- stabilizing the right of way through re-vegetation.

Views of the Board

Based on the successful use of conventional surface leveling techniques on the Norman Wells Pipeline we are satisfied with the Proponents' proposed right of way preparation plans south of the tree line. North of the tree line and in limited areas north of Fort Good Hope, where construction from snow pads is required, pursuant to Condition 44(d), we will verify that the Proponents' plans to remove excess replacement backfill from the right of way will incorporate measures to limit disturbance of the surface organics.

6.5 Other technical considerations

6.5.1 Overview

In addition to the design issues discussed above, a number of technical issues were raised during the hearing related to construction and operation. The following issues are included in this section:

- air emissions;
- pressure testing;
- northern logistics and construction;
- right of way protection during construction; and
- preliminary plans for integrity monitoring and surveillance

6.5.2 Air emissions

During operation the project would emit greenhouse gases including carbon dioxide from combustion-related sources such as compressors, along with methane gas released through normal venting procedures and minor leaks (fugitive emissions). Annual equivalent carbon dioxide emissions during operation are estimated at 812.8 kt/a. Construction activities are expected to generate up to 487.6 kt/a of equivalent carbon dioxides. Other air contaminants which may be emitted, such as oxides of nitrogen, fine particulate matter, carbon monoxide and volatile organic compounds could have a direct impact on human health, wildlife and vegetation. Oxides of nitrogen and volatile organic compounds are precursors to the formation of secondary particulate matter and ozone. Oxides of nitrogen also contribute to acid rain.

Environment Canada noted that air quality in the project area is good and recommended pollution prevention measures to minimize negative effects on air quality. Recommendations were made for both the pipeline and the facilities and included ways to reduce methane emissions during operation including:

- reducing oxides of nitrogen and sulphur oxide emissions from gas turbines;
- minimizing greenhouse gas emissions; and
- reducing benzene and other emissions.

Methane emissions

Environment Canada provided examples of pipeline best management practices that address operational methane emissions. These examples included:

- dry gas seals on compressors;
- unit isolation valve systems;
- electric or air starting systems for gas turbines;
- optimized maintenance and pigging schedules;
- regular leak detection and aerial surveys;
- line break controls;
- computational leak detection;
- pre-installed connecting tees for future gathering pipelines and compressor stations;

- hot tapping;
- operator training; and
- an emergency response plan.

The Proponents stated they would implement the best management practices that are currently being developed by the Canadian Association of Petroleum Producers, Environment Canada, the Canadian Energy Partnerships for Environmental Innovation and the Canadian Gas Association, once these are adopted by Alberta's Energy Resources Conservation Board Directive 60. This document is called *Best Management Practice: Management of Fugitive Emissions at Upstream Oil and Gas Facilities* and is expected to:

- identify large versus small fugitive emission sources, to allow operators to focus on sources with larger volume emissions;
- provide a tiered approach for developing leak detection and repair programs;
- recommend a framework for establishing guidelines, such as leak definition, sampling protocols, leak detection frequency, repair and maintenance and other monitoring methods;
- describe methods of flow indication to determine leakage, and to determine how this information would be used to guide repair and maintenance decisions; and
- provide a method for collecting and benchmarking fugitive emissions information resulting from any leak detection and repair program implemented.

Environment Canada supported the implementation of these best management practices by the Proponents, but added that it was not necessary as a prerequisite that the best management practices be adopted by Alberta's Energy Resources Conservation Board.

Oxides of nitrogen and sulphur oxides emissions

Environment Canada stated that using dry low oxides of nitrogen gas turbines that meet the 1992 Canadian Council of Ministers of the Environment *National Emission Guidelines for Stationary Combustion Turbines* along with reciprocating engines that meet or exceed the requirements for such engines in Alberta's Energy Resources Conservation Board Directive 56 would meet Environment Canada's recommendations regarding the appropriate application of best available technology and best management practices in order to reduce the project's oxides of nitrogen and sulphur oxide emissions. Alberta's Energy Resources Conservation Board Directive 56 requires compliance with Alberta Environment's *Code of Practice for Compressor and Pumping Stations and Sweet Gas Processing Plants, 1996*.

The Proponents intend to specify the requirement that gas turbines meet or exceed Canadian Council of Ministers of the Environment guidelines in the purchase agreements. The Proponents added that vendors would be required to guarantee emissions performance and fuel efficiency. The Proponents indicated that natural gas fuelled reciprocating engines would be used as primary power production for the Storm Hills pigging facility, compressor stations, and the Trout Lake heater station. Diesel engines would be used for standby emergency power generation. Engines would be selected using proven low emission design criteria and would meet or exceed the requirements of Alberta Environment's *Code of Practice for Compressor and Pumping Stations and Sweet Gas Processing Plants, 1996*, which specify a maximum oxides of nitrogen level of 6 grams/kilowatt-hour for engines over 600 kW.

Greenhouse gas emissions

Environment Canada stated that maintaining an efficient gas processing and pipeline system is important factor in minimizing greenhouse gas emissions and conserving natural gas. Environment Canada cited waste heat recovery as a method of achieving this goal. The Proponents' preliminary designs incorporate waste heat recovery in the Inuvik Area Facility. Environment Canada recommended that the Proponents provide details concerning the design choices for waste heat recovery at the Inuvik Area Facility prior to construction.

Benzene emissions

Natural gas produced at the development fields would be dehydrated before entering the gathering pipelines. Glycol dehydrators typically used in the upstream oil and gas industry have the potential to emit benzene gas. Benzene can cause harmful effects at any level of exposure and available evidence indicates that it is a carcinogen. Accordingly, benzene emissions

On the record

Best available technologies and best management practices

Environment Canada stated that the intent of the phrase "best available technology" varies according to the specific application. For the Mackenzie Gas Project, Environment Canada understood the phrase to refer to the continuous improvement of pipeline safety and environmental protection and would expect any best available technology to achieve that intent. In addition, Environment Canada pointed to certain criteria guiding its assessment of whether a particular proposed technology is best available technology. These criteria are that:

- it must be a technology with superior emissions performance;
- it must be commercially available at the time it is required for the project;
- the cost for the technology must be reasonable; and
- the best available technology includes the goals of pollution prevention and energy efficiency.

Environment Canada expressed the view that best management practices are innovative, dynamic, and improved environmental protection practices that help ensure development is conducted in an environmentally responsible manner. Environment Canada indicated that best management practices may exist as formal guidelines or generally accepted procedures recognized by regulators and industry associations as best practices. Best management practices for this project refer to both system design and operating practice for all activities and operations from the wellhead to the product's final destination, using overall system optimization, energy efficiency, reliability and air emissions prevention.

were a concern for Environment Canada.

The Proponents indicated that molecular sieve dehydration units would be used where required. Environment Canada expressed the view that glycol dehydrators could be specified during final design and suggested implementing a condition requiring glycol dehydrators be designed, installed and operated in accordance with recommended practice *Control of Benzene Emissions from Glycol Dehydrators* (Canadian Association of Petroleum Producers, 2000) and comply with Alberta's Energy Resources Conservation Board *Directive 39: Revised program to Reduce Benzene Emissions from Glycol Dehydrators*.

Other emissions

Environment Canada noted that incinerators operating at work camps and other project-related facilities could emit mercury, dioxins and furans. Environment Canada recommended that all incinerators be required to meet emission limits in the Canada-wide Standards for Mercury Emissions and the Canada-wide Standards for Dioxins and Furans. Environment Canada stated that using best available incineration technologies and best management practices would also minimize emissions of particulate matter and precursors to pollution management and ozone. Environment Canada added that best management practices for incineration focus on waste segregation, reducing the amount of waste to be incinerated and proper operation and maintenance of incineration equipment. Dual chamber and controlled air technologies are considered best available technology for incineration.

Views of the Board

Addressing emissions issues begins with making appropriate design decisions to minimize energy use, implementing best available technologies and using best available management practices. The Proponents made undertakings during our hearing which indicate their intention to implement these measures. Conditions 11 and 13 require the Proponents to submit reports that will confirm the implementation of their undertakings. Condition 67 requires the Proponents to minimize and reduce emissions from flaring.

We agree with the measures proposed by Environment Canada to limit mercury, dioxin and furan emissions. Condition 12 requires the submission of a report evaluating technologies and practices the Proponent will implement to reduce these emissions from camps and station facilities. These technologies and practices must be reflected in the waste management plans required by Conditions 16 and 59.

6.5.3 Pressure testing

Prior to final commissioning, testing is conducted on the assembled pipeline to verify at the outset that the pipeline does not have undetected leaks and that the pipeline is capable of containing its design pressure plus an appropriate safety margin. While water is generally considered to be the most acceptable testing medium, freezing temperature depressants must be added to prevent freezing in the pipeline or test facilities in cold climates. For alternative test mediums such as air, operators may need to address additional safety risks and demonstrate that an equivalent degree of accuracy, as compared to hydrostatic fluids, can be achieved.

The Proponents stated that the installed pipelines and facilities would be pressure tested in segments to confirm the strength and to check for leaks in accordance with Canadian Standards Association Z662 requirements. Potential test media evaluated by the Proponents include:

- heated water;
- water with freeze depressants;
- air;
- nitrogen; and
- hydrocarbons.

The Proponents indicated that their plan is to use a mixture of water and methanol to pressure test the natural gas liquids pipeline and Mackenzie Valley Pipeline. The mixture of water with freeze depressants could be reused to minimize the volume of fluid required for testing and for eventual disposal. For the upstream gathering pipelines, water mixed with freeze depressants and air are both being assessed. The Proponents indicated that air testing was also being considered as an option because of difficulties with water testing such as drying pipelines and managing the different volumes required by each test section (with varying pipeline lengths and diameters), as well as cost and schedule considerations. In order to compensate for the air test's lack of sensitivity, it was suggested that test section volumes and hold period durations could be adjusted. Further, odorant could be added to increase the ability to detect small leaks. If a leak occurs, the segment identified by the test would be uncovered and repaired or replaced.

Views of the Board

Due to its ability to detect leaks and for safety reasons we consider hydrostatic testing to be the preferred method of ensuring pipeline integrity prior to operation. We recognize that there may be circumstances where air testing may be necessary. Condition 57 requires the filing of the Pressure Testing Program required by section 23 of the *Onshore Pipeline Regulations, 1999* which specifies additional requirements for air testing should its use be necessary.

6.5.4 Support infrastructure

The Proponents submitted that construction of the project facilities will involve the construction of extensive off right of way support infrastructure including roads, borrow sources, camps, barge landings and staging areas. The project would require new roads to transport materials, equipment and personnel to and from camps, facility and pipeline construction sites. The Proponents estimate they would need 60 kilometres of all-weather roads and 820 kilometres of winter roads for the project. Of the 820 kilometres of winter, roads 235 kilometres would be ice roads over rivers and lakes. Approximately 80 percent of the winter roads would be needed to access water and borrow sources for the project.

The borrow requirements for the project are estimated at 7.6 Mm^3 and would be sourced from 68 primary sites in the Mackenzie Delta and Mackenzie Valley. This material is required for development field facility sites, the Inuvik Area Facility, pipeline facilities, infrastructure development and pipeline backfill.

Winter roads for the project must be durable enough to support the expected construction equipment needed to transport 7.6 Mm^3 of borrow material, as well as project equipment and materials. The Proponents indicated this would require developing similar, but more stringent, design specifications than the Government of the Northwest Territories winter road construction standards. The Proponents stated that maintenance would comply with local regulatory approvals and would generally conform to *Environmental Guidelines for the Construction, Maintenance and Closure of Winter roads in the NWT*, a handbook used by the Northwest Territories Department of Transportation. The Proponents also indicated that ice thickness requirements for ice crossings would be similar to the Government of the Northwest Territories ice bearing assessments.

Views of the Board

The construction, operation and closure of winter roads require regulatory measures to reduce the off right of way impacts of the project. There are also safety concerns since 235 kilometres of these winter roads would be over lakes and rivers. The Northwest Territories Department of Highways has experience constructing and operating these roads and the handbook used by the Northwest Territories Department of Transportation is sufficient for their needs. However, is likely that most of the workers constructing, operating, using and closing the project's winter roads, many of whom will come from outside of the Northwest Territories, will not have the benefit of this experience. We are of the view that a single manual encompassing both safety and environmental requirements of winter road management is required for the project to minimize off right of way environmental impacts and promote safety. Conditions 9 and 10 require the filing of winter road manual as well as the permits, authorizations and letters of advice issued by governments and regulators which have a bearing on winter road construction, operation and closure.

6.5.5 Northern logistics and construction

Logistics

The Mackenzie River would be the primary transportation corridor for the project. Most of the material required to build the pipeline would be shipped by rail from the south to Hay River where it would be transferred to barges for travel north in the summer. Pipeline construction would take place mostly in winter when the ground surface is sufficiently frozen to support the movement of vehicles. Trucks would use existing highways, winter roads and new project roads. Construction crews would travel to the camps by aircraft, which would limit private vehicle use by the workforce. Substantial improvements to existing infrastructure and new project-specific infrastructure such as barge landings, camps and temporary winter roads would be required to accommodate construction activities. Some very large processing and compressor modules for the Inuvik Area Facility would be shipped by sea to Inuvik where specialized carriers would transport them to the site on purpose-built gravel and winter roads.

Schedule

The Proponents' construction plan assumes four years of construction for infrastructure, pipelines, and associated facilities. To address potential issues related to the availability of labour and increased costs, the construction plan distributed pipeline construction activities over three full winter seasons.

Construction Activities by Season

First Summer

- Mobilize some equipment, small camps and fuel for initial site development.
- Develop borrow sites and stockpile borrow material.
- Begin to develop barge landing sites.
- Begin to install main construction camp pads and stockpile pads.
- Mobilize equipment, small camps and fuel for right of way clearing.
- Transport fuel by barge and truck to support future construction.

First Winter

- Continue borrow site development work.
- Develop barge landing sites.
- Install main construction camp pads, stockpile pads and facilities pads.
- Begin installing main infrastructure, including camps and field-erected tanks.
- Survey, clear and, potentially, grade the right of way and facility sites.
- Geotechnical Verification Program.

Second Summer

- Mobilize pipe, equipment, camps and fuel to support main construction.
- Install construction camps.
- Clear pipeline right of way, where practical.
- Continue developing and operating borrow sites.
- Continue installing infrastructure and facility pads.

Second Winter (First pipe-laying season)

- Construct pipeline sections with multiple construction spreads.
- Continue surveying and clearing right of way and facility sites.
- Continue developing and operating borrow sites and installing infrastructure, including camps and field-erected tanks.
- Install pile foundations at facility sites.
- Begin pipeline right of way construction cleanup.
- Geotechnical Verification Program.

Third Summer

- Mobilize pipe, equipment, camps and fuel to support main construction.
- Install construction camps.
- Clear pipeline right of way, where practical.
- Transport facility modules from Hay River.
- Install pile foundations at facility sites.
- Begin facility assembly at sites and continue construction.
- Continue developing and operating borrow sites and installing infrastructure.

Third Winter (Second pipe-laying season)

- Construct pipeline sections with multiple construction spreads.
- Continue surveying and clearing right of way and facility sites, where required.
- Continue developing and operating borrow sites and installing infrastructure, including camps and field-erected tanks.
- Install pile foundations at facility sites.
- Continue pipeline right of way construction cleanup and reclamation.

Fourth Summer

- Mobilize pipe, equipment, camps and fuel to support main construction.
- Install construction camps.
- Clear pipeline right of way, where practical.
- Transport facility modules from Hay River and offshore locations.
- Continue installing facility modules and construction.
- Continue developing and operating borrow sites and installing infrastructure.

Fourth Winter (Third pipe-laying season)

- Complete surveying and clearing right of way and facility sites, where required.
- Construct remaining pipeline sections with multiple construction spreads.
- Transport facility modules to remote sites.
- Complete pipeline construction.
- Continue operating borrow sites.
- Continue facility construction.
- Continue pipeline right of way construction cleanup and reclamation.
- Begin demobilizing camps and equipment.

Fifth Summer

- Complete facility construction.
- Begin commissioning and start-up activities for pipelines and facilities.
- Begin infrastructure and borrow site reclamation.
- Continue pipeline right of way construction cleanup and reclamation.
- Continue demobilizing camps and equipment.

Fifth Winter

- Complete commissioning and start-up activities.
- Start up and begin operating facilities and pipelines in Q4 2018.
- Continue pipeline right of way construction cleanup and reclamation.
- Continue demobilizing camps and equipment.

Sixth Summer

- Complete pipeline right of way construction cleanup and reclamation.
- Complete reclamation of infrastructure sites not required for operations.
- Complete demobilization.

Construction Safety

Pipeline construction projects in winter conditions similar to those in the project area have been successfully completed in the past. To ensure the Mackenzie Gas Project is equally successful, the Proponents have incorporated the following mitigation measures in construction planning:

- providing shelters for welding, horizontal directional drilling and pressure testing;
- using electric resistance and propane flame heating to meet preheat, inter-pass and post heating requirements for welding and the field application of weld joint coatings;
- fitting construction machinery for arctic service;
- installing cooling and lubricating system heater devices to allow equipment to be shut down for extended periods;
- developing activity shutdown criteria; and
- sizing crews and equipment to allow work to continue during warm-up breaks.

The Proponents' planning assumes pipeline construction crews would work seven days a week, 12 hours per day. Some activities such as directional drilling and ditching may be carried out around the clock. The Proponents estimated that 15 to 20 percent of scheduled working days may end up being weather days, resulting in little or no productivity.

The Proponents stated that one of the primary project priorities is to provide an injury-free, incident-free, healthy workplace and that, regardless of the labour supply and demand situation, contractors participating in project construction must meet safety requirements. The Proponents added that safety training must be completed before workers are assigned to a work site and that supplemental safety training would also be provided, both before and during construction, to ensure workers have the required safety related qualifications.

In order to maintain worker safety in northern working conditions, the Proponents indicated that the personal protective equipment provided for each worker would be appropriate for their work assignments. This equipment would typically include a hooded arctic parka, insulated coveralls, lined leather mitts, insulated arctic work boots, face protection and headgear. In addition, the Proponents stated it would provide crew transportation buses and emergency shelters with heaters so that warm-up breaks could be taken depending on working conditions.

Views of the Board

Conditions 3, 4, 7, 8, 9, 10, 15, 16, 19, 20, 21, 29 to 36, 39, 42, 49 and 56 require the Proponents to construct the Mackenzie Gas Project with due consideration of safety, the environment, and logistical and scheduling difficulties in the North. Some of these conditions have been elaborated elsewhere in this volume. Implementation of these conditions during construction of the project will promote worker safety, protect the environment and help maintain the project schedule.

These conditions include the filing of:

- Environmental Protection Plans (EPP) and corresponding environmental alignment sheets;
- a waste management plan;
- an emergency response plan;
- a construction safety manual;
- construction schedules;
- a manual for the construction operation, maintenance and closure of winter roads;
- permits, authorizations and letters of advice from federal departments, the Government of the Northwest Territories and local regulatory organizations;
- project organization details of the Proponent;
- engineering alignment sheets;
- field change manual for slope design;
- heritage resources management plans;
- wildlife management plans;
- air quality monitoring program; and
- project progress reports.

There is also a requirement to provide logistical support to the National Energy Board staff undertaking construction inspection and reclamation.

Did you know?

Integrity management program

An Integrity Management Program is a proactive program which typically incorporates the tools, technologies, procedures and strategies needed to ensure pipelines are safe, reliable and environmentally responsible. The included management system defines the scope of the program, organizational lines of responsibility, personnel training and qualification requirements, change management and program monitoring. An Integrity Management Program incorporates a records management system to provide timely access to important integrity information. The program would also typically include hazard identification and condition monitoring using methods such as in-line inspection tools (pigs) and a mitigation program to correct integrity issues identified. The monitoring of pipeline strain, corrosion and geotechnical hazards is within the scope of an Integrity Management Program.

6.6 Preliminary plans for integrity monitoring and surveillance

The Proponents outlined preliminary plans for monitoring and surveillance as well as its proposed frequency of inspection. These preliminary plans are listed in Table 6-5.

The Proponents expressed the view that strain accumulation from frost heave and thaw settlement would occur over several years before they would approach critical strain levels. During the operating phase, inline strain monitoring would be required so that the Proponents can undertake appropriate maintenance before the onset of the limiting strains. Therefore it is particularly important to the project to construct a suitable in-line inspection tool or tools that can detect strain accumulation in the Mackenzie Gas Project pipelines and would work under the anticipated conditions. Also required is a detailed survey of as-constructed base line conditions in order to measure strain that develops following construction. The Proponents indicated that the baseline survey of the pipe would be undertaken during construction instead of running the inspection tool immediately after the start of pipeline operation.

The Proponents assessed the pipeline operating parameters of temperature, pressure, fluid speed, fluid composition and multiphase flow against the operating capabilities of currently available in-line inspection tools and discovered challenges that would limit pipeline inspection capability. The most difficult challenge is overcoming low operating temperatures, although high operating pressures and long inspection lengths would also limit certain tools. In-line inspection tools perform better within certain speed ranges. Another challenge is developing speed control that would minimize impacts on throughput while allowing accurate inspection of the pipeline. The Proponents were of the view that, although these constraints would pose challenges for in-line inspection tool vendors, these are not vastly different from other challenges that have been solved in the past with enough lead time and planning.

Because the pipelines will be buried for approximately two years prior to operation and in-line inspection monitoring can only be done in the first year of operation, Indian and Northern Affairs Canada suggested that the Proponents be required to survey the location of the pipe after it is lowered into the trench to determine its precise location prior to line fill. Indian and Northern Affairs Canada suggested that In-line inspection monitoring of the pipeline be conducted twice in the first year of pipeline operation, with the frequency thereafter based on those results and as directed by the National Energy Board, with a minimum of one In-line inspection per year.

The Joint Review Panel recommended that we require the Proponents to implement an effects monitoring plan that includes, in addition to pipeline integrity monitoring, monitoring of permafrost, terrain and geotechnical parameters relevant to thaw and frost bulb impact assessment.

Table 6-5

Proponents' preliminary plans for monitoring and surveillance

Mechanism	Preliminary monitoring method options	Indicator	Preliminary monitoring frequency
Frost heave	Curvature in-line inspection (ILI)	Strain accumulation	Baseline is the construction as-built survey. Annual in-line inspection runs for the first three years of operation. Frequency of subsequent runs based on projected strain accumulation.
	Remote sensing methods	Ground deformation	Quarterly, at identified sites.
Thaw settlement	Inertial ILI	Strain accumulation	Baseline is the construction as-built survey. Annual in-line inspection runs for the first three years of operation. Frequency of subsequent runs based on projected strain accumulation.
	Aerial patrol	Ground deformation	Monthly.
	Remote sensing methods	Ground deformation	Quarterly, at identified sites.
Upheaval displacement	Inertial ILI	Strain accumulation	Baseline is the construction as-built survey. Annual in-line inspection runs for the first three years of operation. Frequency of subsequent runs based on in-line inspection trends.
	Aerial patrol	Ground deformation	Monthly.
Slope instability	Inertial ILI	Strain accumulation	Baseline is the construction as-built survey. Annual in-line inspection runs for the first three years of operation. Frequency of subsequent runs based on projected strain accumulation.
	Aerial patrol	Ground deformation	Monthly.
	Slope monitored by inclinometers, thermistors, piezometers	Ground deformation	As required.
	Remote sensing	Ground deformation	Quarterly, at identified sites.
Frost bulb growth-crossings	Aerial patrol	Icings	Monthly.
Frost bulb growth-general	Aerial patrol	Drainage impedance	Monthly.
Buoyancy	Aerial patrol	Loss of cover	Monthly.
River scour-lateral	Aerial patrol	Loss of cover	Monthly.
River scour-vertical	Diver survey	Loss of cover	As required.
Right of way performance	Aerial patrol	Drainage and erosion integrity	Monthly.
Corrosion	Magnetic flux leakage or ultrasonic ILI	Metal loss	Initial run in years 5 to 7 of operations. Frequency of subsequent runs based on in-line inspection trends.
	Investigative digs	Cracking	As required.
Third party damage	Aerial patrol	Encroachment on rights of way	Monthly.
Seismicity	Aerial patrol	Slope movement	Monthly.
		Loss of support	

Views of the Board

Given the importance of strain monitoring in the current design, Condition 60 requires the Proponents to have the necessary in-line inspection tools available to inspect the pipeline during operation.

We agree with Indian and Northern Affairs Canada that establishing a base line for future in-line inspection monitoring of a pipeline's position is important. Condition 70 requires the Proponents to survey the position of the pipelines after they are lowered in the trench. We are not persuaded that Indian and Northern Affairs Canada's suggestion of running the in-line inspection twice in the first year is warranted given the pipelines will be in the ground two seasons prior to operation; however we are of the view that requiring a high resolution in-line inspection to determine their position within one month of operation has merit. Condition 70 requires that the Proponents monitor geotechnical and thermal effects on the Mackenzie Gathering System and Mackenzie Valley Pipeline with respect to thaw subsidence, frost heave and slope stability using inertial in-line inspection within one month of the start of operation and on an annual basis thereafter.

Condition 39 requires the development of an effects monitoring program. We have specified that the program's scope, objectives, monitoring methodologies, frequencies and criteria for the selection of instrumented sites be determined prior to the first of the pipe-laying activities to facilitate the early selection of sites to be monitored, the acquisition of detailed data on pre-disturbance/ pipeline operation conditions, and early installation of instrumentation.

To facilitate effects monitoring, and adaptive management during operation Conditions 66 and 68 to 72 require the submission of as-built slope information, post-construction environmental reports, ditch wall logs and the stream flow, ice thickness and ground temperature data used for project planning and design. Condition 37 which requires the filing of the Geotechnical Verification Program data and Condition 45 which requires the filing of the Proponents' geohazard assessments would also inform the effects monitoring program. In keeping with the National Energy Board's usual practice, these submissions will be available to the public by way of the National Energy Board's regulatory repository.

6.7 Emergency response

The *Onshore Pipeline Regulations, 1999* requires pipeline companies to develop, regularly review and update, as required, an emergency procedures manual. A company must take all reasonable steps to inform all persons who may be associated with an emergency response activity on the pipeline of the practices and procedures to be followed, and make available to them the relevant information that is consistent with that which is specified in the emergency procedures manual. A company must also develop a continuing educational program for the police, fire departments, medical facilities, other appropriate organizations and agencies and the public residing adjacent to the pipeline to inform them of the location of the pipeline, potential emergency situations involving the pipeline and the safety procedures to be followed in the case of an emergency.

The Joint Review Panel recommended that we require the Proponents to provide, prior to the commencement of construction, and as part of the an emergency preparedness and response plan for all forms of transportation associated with the Mackenzie Gas Project, an assessment of the potential for the establishment of local, community-based spill response teams. This assessment would include their commitment to build community spill response and a discussion of the opportunities and constraints in establishing local spill response teams.

Views of the Board

Safely responding to a transportation emergency or spill requires coordination, training, knowledge of the products involved, the appropriate personal protective equipment and spill response equipment.

To address worker and public safety and environmental protection during construction, Condition 4 requires the Proponents to file an Emergency Response Plan at least 60 days prior to pre-construction. During construction, the Proponents and their contractors will be on the scene for incidents on the right of way, on project winter roads and at camps and they will be required to have the necessary resources to respond appropriately. We have therefore decided local, community-based spill response teams are not necessary for the construction phase of the project.

To ensure that the Proponents are prepared for an emergency on the first day of operation Condition 61 requires the submission of emergency procedures manuals at least 30 days prior to operation. We believe that local communities could be involved in pipeline emergencies occurring during operation as they may be the closest to the incident. Condition 61 requires an assessment of the potential for local community-based spill response teams, opportunities and constraints of establishing these teams and a commitment to work with local communities to build and maintain capacity. Condition 62 requires the Proponents to confirm that they have completed an emergency response exercise to evaluate the effectiveness of their response plans prior to operation.

Government departments have responsibility for emergencies occurring on territorial highways, winter roads and on the Mackenzie River. They will have the responsibility for emergency response training and equipment needs at these locations.

6.8 Other requirements specific to the Mackenzie Gathering System

Views of the Board

We are of the view that the requirements for the Mackenzie Gathering System, regulated under the *Canada Oil and Gas Operations Act,* should be consistent with the requirements for the Mackenzie Valley Pipeline, regulated under the *National Energy Board Act*. In this regard, for the Mackenzie Gathering System, Condition 77 requires the Proponents to comply with the *Onshore Pipelines Regulations*, *1999*, as amended from time to time; the *National Energy Board Processing Plant Regulations*, as amended from time to time; and those sections of the *National Energy Board Pipeline Crossing Regulations Part I* and *Part II* as amended from time to time. Similarly, Condition 78 requires the Proponents to file for approval the information referred to in the National Energy Board Filing Manual, 2004, for opening the pipeline for operation.

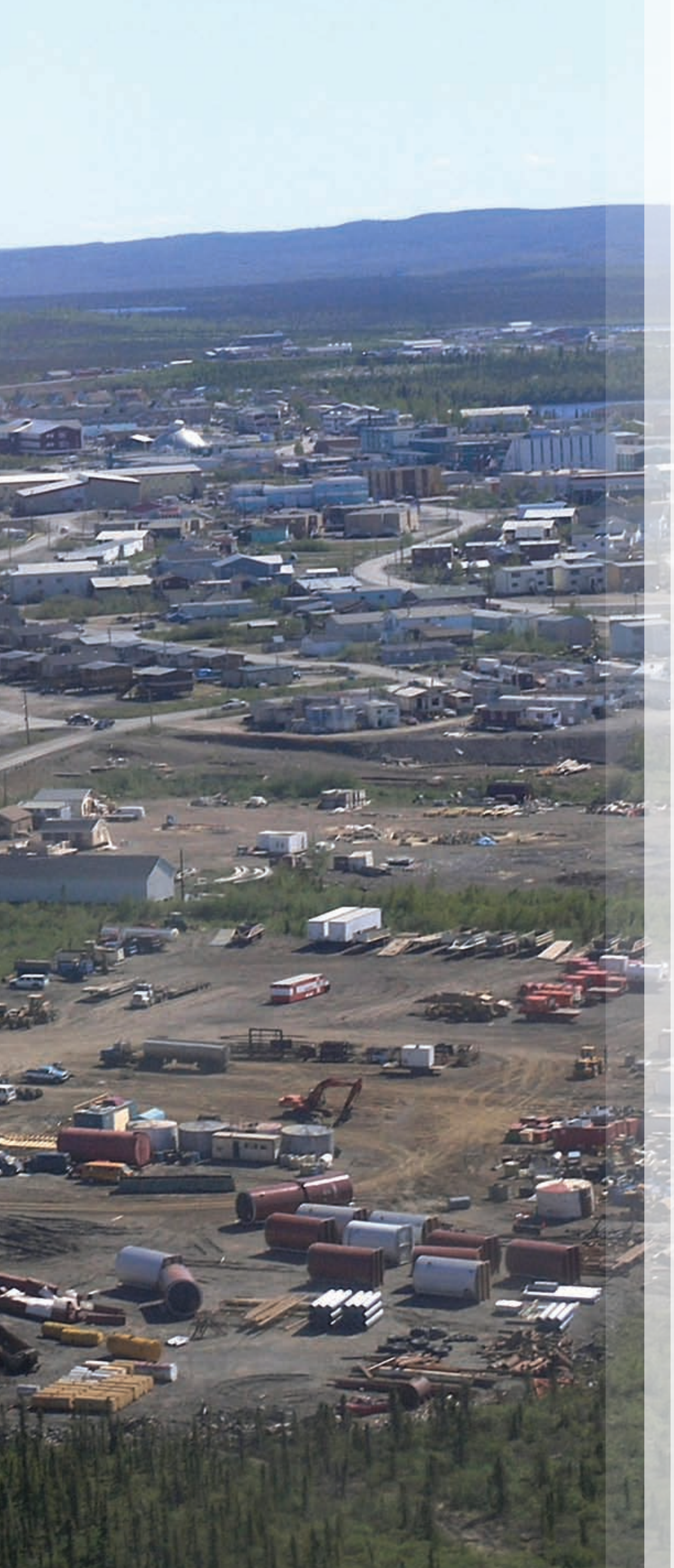
There are also requirements under the *Canada Oil and Gas Operations Act* that apply to the Mackenzie Gathering System.

Condition 76 requires the Proponents to provide financial responsibility pursuant to the *Canada Oil and Gas Spills and Debris Liability Regulations* and pursuant to subsection 27(1) of the *Canada Oil and Gas Operations Act* in the amount of $25,000,000 in a form satisfactory to the National Energy Board prior to commencement of pre-construction activities and that will remain in place until all facilities are abandoned in accordance with National Energy Board requirements.

Condition 79 stipulates that the authorization for the Mackenzie Gathering System under paragraph 5(1)(b) of the *Canada Oil and Gas Operations Act* is subject to the Minister of Indian Affairs and Northern Development Canada providing confirmation that the Proponents have satisfactorily met the Benefits Plan requirements of section 5.2 of the *Canada Oil and Gas Operations Act*.

Condition 80 requires the Proponents to provide a declaration pursuant to subsection 5.11(1) of the *Canada Oil and Gas Operations Act* in a form satisfactory to the National Energy Board prior to commencement of pre-construction activities.

Condition 81 requires the Proponents to provide any necessary certificates pursuant to subsection 5.12(1) of the *Canada Oil and Gas Operations Act* in a form satisfactory to the National Energy Board prior to commencement of the related activities.



Chapter 7
Economic feasibility

7.1 Public convenience and necessity

The National Energy Board must be satisfied that any facilities it approves pursuant to section 52 of the *National Energy Board Act* are required by the present and future public convenience and necessity. In making that determination, the National Energy Board considers the economic feasibility of the project. This involves determining the likelihood of the facilities being used at a reasonable level over their economic life and the likelihood of the demand charges being paid.

The National Energy Board takes the following criteria into consideration when considering economic feasibility for facilities built under the *National Energy Board Act*:

- the availability of markets for the gas flowing on the pipeline (will the gas be purchased?);
- the availability of downstream pipeline capacity (will there be sufficient pipeline capacity to move the gas from the end of the Mackenzie Valley Pipeline to ultimate markets?);
- the long-term gas supply which is available to the pipeline (is there sufficient gas to be transported?);
- the contractual commitments underpinning the project (will the fixed cost component of the pipeline tolls be paid?); and
- the ability of the project to be financed (will investors fund the pipeline?).

7.2 Economic setting

Development of the large natural gas deposits that lie buried under the Mackenzie Delta has had a unique history. The resources were discovered in the early 1970s when natural gas prices were not high enough to justify building costly pipeline infrastructure. Growing natural gas consumption and decreasing production from conventional sources in North America have enticed producers back to the Mackenzie Valley in search of hydrocarbons. While a small amount of gas is currently produced in the Mackenzie Delta for local use, producers will need access to the larger markets in southern Canada and the lower 48 U.S. states in order to support the significant development of these resources. The Mackenzie Gas Project would provide northern producers with access to the North American pipeline network and markets.

The Mackenzie Gas Project would be:

- largely owned and operated by producers;
- opening access to a previously little-developed basin;
- located a great distance away from natural gas markets and existing transportation infrastructure; and
- located in an environmentally unique and sensitive area.

The project must meet a threshold or minimum size; otherwise the cost to bring that gas to market could be far more than the value of the gas. Due to significant economies of scale, services would be more efficiently provided by one larger pipeline operated by one firm than by competing firms operating separate smaller pipelines.

Given these circumstances, it is important that the facilities are the right size for the available supply, that the cost of shipping the gas is fair, and that the pipeline is accessible by all parties. There are two main economic questions for us to answer when assessing this project:

1. Is the project economically feasible?
   - Are the facilities, as they are proposed, right for the circumstances?
   - What is the supply?
   - Is there sufficient demand?
   - Can the project be financed?
   - Will it be paid for?
2. Are the proposed tolls and services (i.e., the shipping arrangements) fair and reasonable?
   - Will other parties have fair access to the facilities in the future?
   - Is there "open access" so that any producer that meets the tariff requirements is able to use the pipeline?

The first question is discussed here in Chapter 7 and the second in Chapter 8.

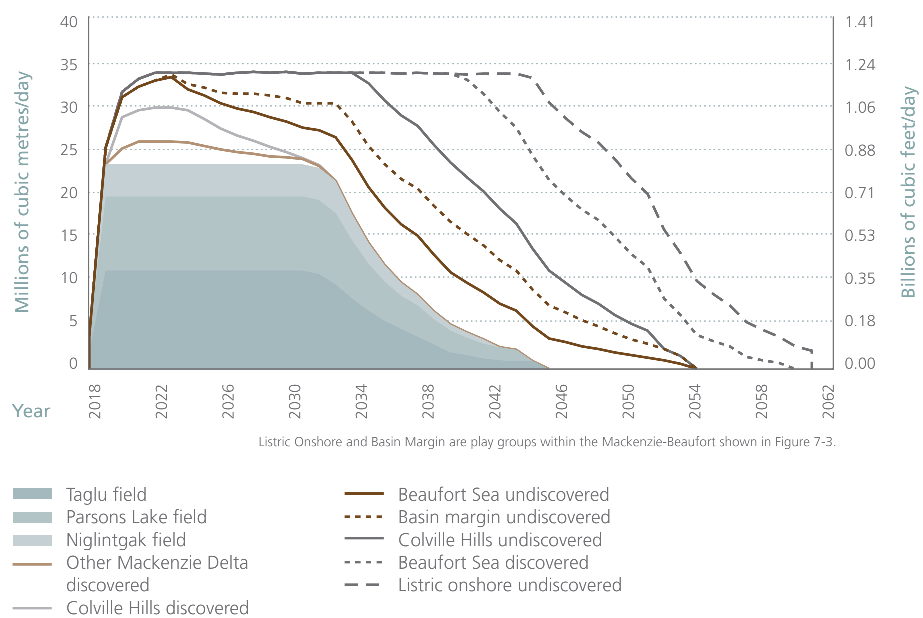
7.3 Supply

For many new natural gas pipelines, the main challenge is ensuring that there will be enough natural gas to supply the pipeline for its economic life. However, the more significant concern in this proceeding has been the question of whether the facilities will be large enough to transport present and future volumes. Estimating future volumes is full of uncertainty and must account for issues such as:

- uncertainty in resource estimates, both discovered and undiscovered;
- the timing of the development of these resources; and
- whether resources will be large enough to allow them to be connected economically.

The natural gas resources in the area are shown in Figure 7-1.

The Proponents assume that three years after they begin producing natural gas from the Niglintgak, Parsons Lake and Taglu development fields, other producers will begin producing both the remaining discovered onshore fields in the Mackenzie Delta and fields in the Colville Hills region. The Proponents concluded there are sufficient gas resources to fill a 34 Mm³/d (1.2 Bcf/d) pipeline for 25 years, given a reasonable pace of exploration and development. The Mackenzie Valley Pipeline



Listric Onshore and Basin Margin are play groups within the Mackenzie-Beaufort shown in Figure 7-3.

Figure 7-1

Natural gas resources

Table 7-1

Comparison of available natural gas supply forecasts

		GLJ Supply Study for the Proponents (sales gas volumes)		Sproule Supply Study for Mackenzie Explorer Group (sales gas volumes)	
Resource type	**Area**	**Metric** *(Gm^3)*	**Imperial** *(Bcf)*	**Metric** *(Gm^3)*	**Imperial** *(Bcf)*
Discovered	Development fields	161.3	5694	161.3	5694
	Non-anchor onshore	7.7	272	21.9	772
	Offshore shallow (</= 100 m)	64.4	2275	57.5	2028
	Offshore deep (> 100 m)	0.0	0	0.0	0
	Colville Hills	10.7	379	15.2	537
	Total discovered	244.1	8620	255.9	9031
Undiscovered	Onshore	86.9	3069	226.4	7993
	Offshore shallow	47.6	1679	198.6	7010
	Offshore deep	0.0	0	256.0	9036
	Colville Hills	45.3	1599	71.3	2517
	Total undiscovered	179.8	6347	752.3	26556

as applied for has a design capacity of 27.3 Mm^3/d (964 MMcf/d) with one compressor and 34.3 Mm^3/d (1.2 Bcf/d) with three compressors, and is expandable to 49.8 Mm^3/d (1.8 Bcf/d) with the installation of fourteen compressor stations.

Gilbert Laustsen Jung Associates Ltd. prepared the gas supply study for the Proponents (the GLJ Supply Study) and Sproule Associates Limited prepared the gas study submitted by Mackenzie Explorer Group (the Sproule Supply Study). These studies show a minor difference in estimates for discovered resources but a major difference in estimates for undiscovered resources for the Mackenzie Valley and Colville Hills areas (See Table 7-1).

Both studies supported the prediction that sufficient resources would be available to keep a 34.3 Mm^3/d (1.2 Bcf/d) pipeline full throughout its economic life.

Figure 7-2 illustrates the productive capacity forecasts of the Proponents and Mackenzie Explorer Group along with the proposed contract profile and the pipeline capacities at the sizes of 27.3 Mm^3/d (964 MMcf/d), 34.3 Mm^3/d (1.2 Bcf/d) and 49.8 Mm^3/d (1.8 Bcf/d).

The Sproule Supply Study examined scenarios in which different sized pipelines would remain full for a 20 year period. The study concluded that it is likely that resources could be developed in the future that would support the construction of a 34.3 Mm^3/d (1.2 Bcf/d) pipeline or a larger 49.8 Mm^3/d (1.8 Bcf/d) pipeline. For example, there is a 75 percent probability that a 62.3 Mm^3/d (2.2 Bcf/d) pipeline would be fully used for 20 years.

Based on the results of the Sproule Supply Study, Mackenzie Explorer Group supported the design of the Mackenzie Valley Pipeline because it could be expanded to 49.8 Mm^3/d (1.8 Bcf/d) by adding compression. Mackenzie Explorer Group anticipates that demand for space on the natural gas pipeline would increase significantly as the basin is opened by further exploration and development. It also supported the size of the liquids line from Inuvik to Norman Wells, which is part of the Mackenzie Gathering System.

Figure 7-2

Capacity forecasts

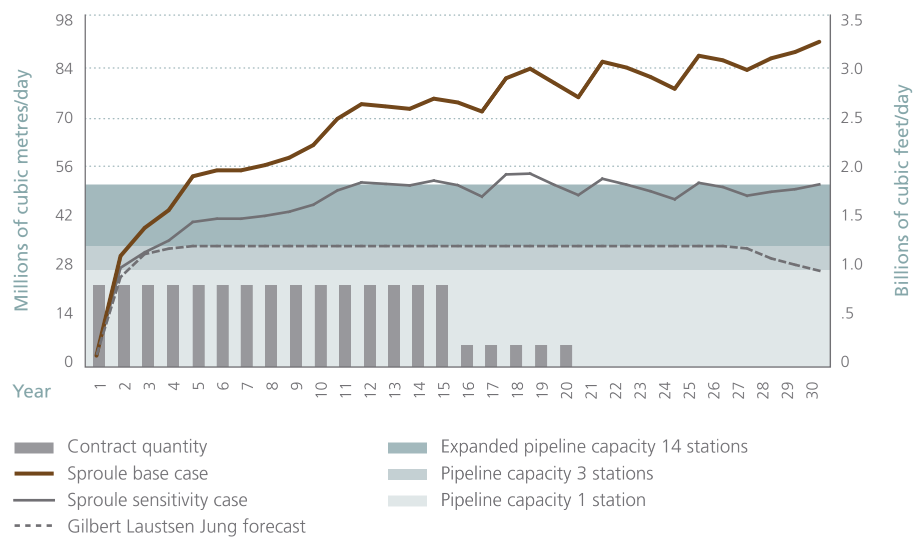
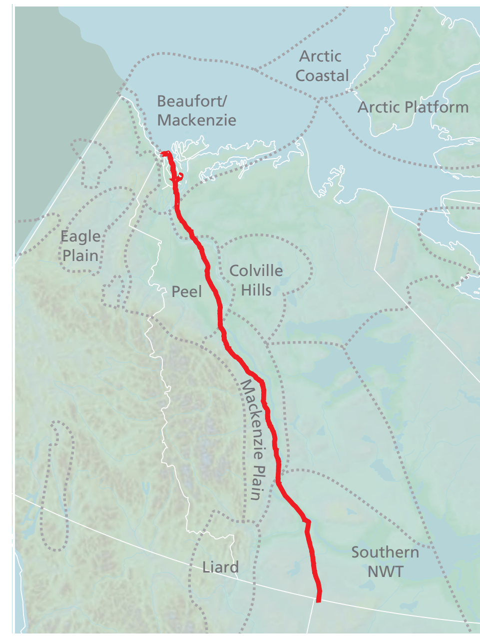


Figure 7-3

Supply basins and sub basins



Natural gas flowing from the Mackenzie Delta to southern markets must pass through the Mackenzie Gathering System as well as the Mackenzie Valley Pipeline. Mackenzie Explorer Group contends that the Mackenzie Gathering System north of Inuvik could not be expanded to the same extent as the Mackenzie Gas Project. A discussion of the appropriate design of the Mackenzie Gathering System facilities can be found in Section 6.3.4.

The Government of Yukon also prepared a gas supply study that focused on the Eagle Plain region (see Figure 7-3) in Yukon – the Geological Survey of Canada Supply Study (GSC Supply Study). According to this study, production from the Eagle Plain region is currently uneconomic but could become viable with adequate gas prices and pipeline access to markets. Table 7-2 provides a comparison of Eagle Plain resource estimates used in the GLJ Supply Study and the GSC Supply Study.

Table 7-2

Eagle Plain basin resource estimates

	Discovered *Gm³ (Bcf)*			Potential resource estimates *Gm³ (Bcf)*
GLJ Supply Study	2.37 (83.7)	(P_{90}) 10.8 (382)	(P_{50}) 21.3 (751)	(P_{10}) 39.7 (1401)
GSC Supply Study	2.37 (83.7)	(P_{95}) 67.4 (2379)	(P_{50}) 152.7 (5392)	(P_{05}) 339.8 (12000)

On the Record

Market supply and demand cases

The Proponents submitted the *Mackenzie Valley Pipeline Market Demand, Supply and Infrastructure Analysis Final Report*, by Navigant Consulting, Inc. and Energy and Environmental Analysis, Inc. (the Navigant Study). In the report, four cases were studied:

- The Base Case – studied the impact of the Mackenzie Delta region delivering 34 Mm^3/d (1.2 Bcf/d) of gas to the marketplace by the end of 2009.
- The Mackenzie Expansion Case – identified the impact of expanded Mackenzie Delta production to 42.5 Mm^3/d (1.5 Bcf/d) in 2015 and to 51 Mm^3/d (1.8 Bcf/d) in 2020.
- The North American Economic Slowdown Case – identified the impact on gas markets from a North American economic slowdown.
- The Alaskan Pipeline Development Case – identified the impacts of Alaska gas coming onstream, ultimately reaching a level of 113.3 Mm^3/d (4.0 Bcf/d) in 2014.

Conclusions of the report:

- There is an adequate market for gas supplies from the Mackenzie Gas Project in all cases.
- With small increments to the NOVA Gas Transmission Ltd. system, there is sufficient capacity on NOVA Gas Transmission Ltd. and on other pipelines leaving Alberta except in the Alaska Case. Under that scenario, 85 Mm^3/d (3 Bcf/d) of additional export capacity would be required.

7.4 Markets/demand

There are two traditional considerations when assessing markets for natural gas. The first consideration is whether there is sufficient demand for the gas that would be transported by the proposed project. The second consideration is whether there would be sufficient space on connecting downstream pipelines to receive and move the gas to market.

In its original evidence, the Proponents submitted the *Mackenzie Valley Pipeline Market Demand, Supply and Infrastructure Analysis Final Report,* prepared by Navigant Consulting, Inc. and Energy and Environmental Analysis, Inc. – April 13, 2004 (the Navigant Study). The Navigant Study assessed the long-term ability of the market to accept natural gas from the Mackenzie Valley using four different scenarios.

The Navigant Study focused on market regions that are connected via gas pipelines to the Western Canada Sedimentary Basin and looked at forecasted consumption over the period 2010 to 2030, which was expected to cover the Mackenzie Valley Pipeline's first 20 years of operation at the time the study was prepared. The forecasts projected strong growth in gas demand in Canada, particularly Alberta, and the United States for electrical power generation, residential and commercial consumption and for use in industrial and resource development. However, the study anticipated only modest growth in gas production in Canada and the United States and suggested that a significant shift to currently untapped resources would be needed over the next 20 years to meet growing natural gas demand. Therefore, according to the study, markets would need the proposed 34.3 Mm^3/d (1.2 Bcf/d) of gas to be transported on the Mackenzie Valley Pipeline.

Even with the increase in capital costs and cost of service filed in the spring of 2007, the Proponents' view was that there would be adequate markets for the natural gas from the project, and Mackenzie Delta gas would be required to offset the expected decline in conventional gas production.

Mackenzie Explorer Group noted that the forecasts are subject to some uncertainty. Regardless, the favourable results obtained in all of the sensitivity cases that were studied suggest that "market risk" would not be a significant issue for the Mackenzie Gas Project.

The Government of the Northwest Territories submitted that the Mackenzie Basin reserves are a long-term resource that, over time, will find their way to very diverse markets. The Government of the Northwest Territories position was that the Mackenzie Gas Project should provide access to as much of the North American market as possible and market economics should be allowed to determine the use of the reserves thereafter.

In March 2010, the Proponents filed updated projections for North American natural gas markets and supply in a report prepared by Angevine Economic Consulting Ltd. (the Angevine Report) *An Updated Natural Gas Market Demand and Supply Analysis for Canada and the U.S. Lower 48 States.* The author of the Angevine Report was also a co-author of the Navigant Study. Gas modelling analysis for the Angevine Report was performed by ICF International, which acquired Energy and Environmental Analysis Inc. in 2007. The Angevine Report concluded that in spite of increasing shale gas production, the North American market remains sufficient to absorb incremental gas volumes from northern gas projects and would support the construction of the Mackenzie Valley Pipeline.

The Angevine Report assumed that the Mackenzie Pipeline would be constructed and put in service by October 2018, and that a gas pipeline from Alaska's North Slope would also be constructed and would be in service by October 2023. The updated projections for North American natural gas consumption and domestic gas production suggested that incremental gas volumes would be required from other sources such as northern gas or imports of liquefied natural gas to meet growing North American requirements (see Figure 7-4).

The approach used by both the Angevine Report and the Navigant Study did not assess the competitiveness of Mackenzie Valley gas relative to other sources of gas supply. The reports assessed the impact of incremental gas volumes from the proposed project into the market and left the Proponents to determine if the project would be economic at the resultant natural gas prices which are predicted by the modelling analysis. Both reports concluded that the North American market would be sufficient and able to absorb the 34.3 Mm³/d (1.2 Bcf/d) from the Mackenzie Gas Pipeline.

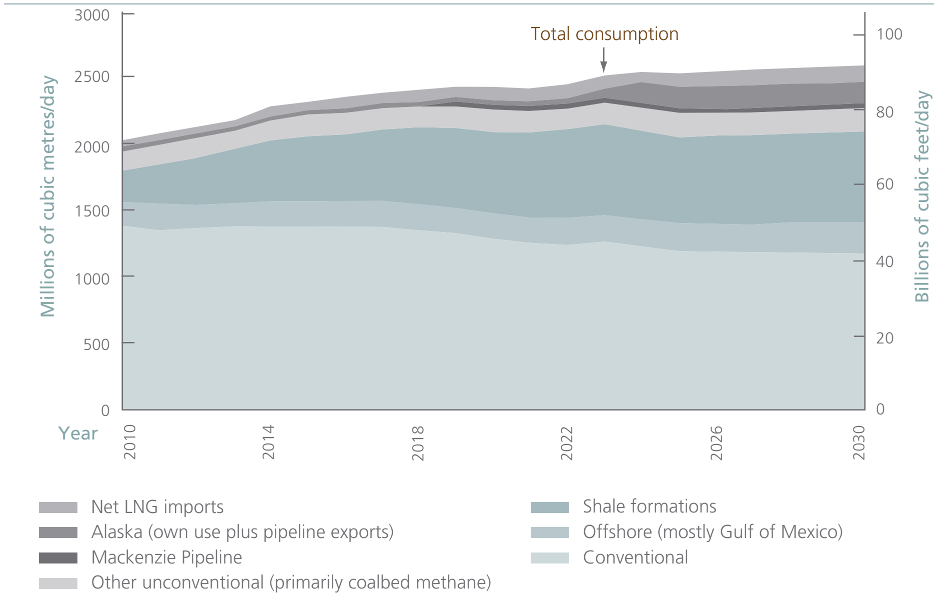


Figure 7-4

Projected North American natural gas supply and consumption

In the Navigant Study, the Proponents also assessed the capability of the Alberta pipeline system and the main export pipelines from the Western Canada Sedimentary Basin to deliver Mackenzie Delta gas to markets in central Canada and the United States. These markets are currently served by five export pipeline corridors from the Western Canada Sedimentary Basin (see Figure 7-5 and Table 7-3).

The Navigant study concluded that with a forecasted increase in natural gas consumption in western Canada along with an expected drop in conventional gas production in the Western Canada Sedimentary Basin, there will be no pipeline capacity constraints on gas exports from the Western Canada Sedimentary Basin. Furthermore, no export pipeline facility expansions would be required to accommodate the delivery of 34.3 Mm³/d (1.2 Bcf/d) from the Mackenzie Valley Pipeline. However, in the case where the Alaska Pipeline is also built, additional downstream pipeline capacity would be required.

With respect to intra-Alberta infrastructure, the Canadian Arctic Resources Committee expressed concern that the Proponents did not accurately or sufficiently assess the requirements and costs of constructing additional infrastructure in Alberta to ship Mackenzie Valley gas via the existing NOVA Gas Transmission Ltd. system. The Proponents submitted that the Mackenzie Valley Pipeline volumes can be accommodated in the NOVA Gas Transmission Ltd. system with a modest expansion in the northwest part of the system.

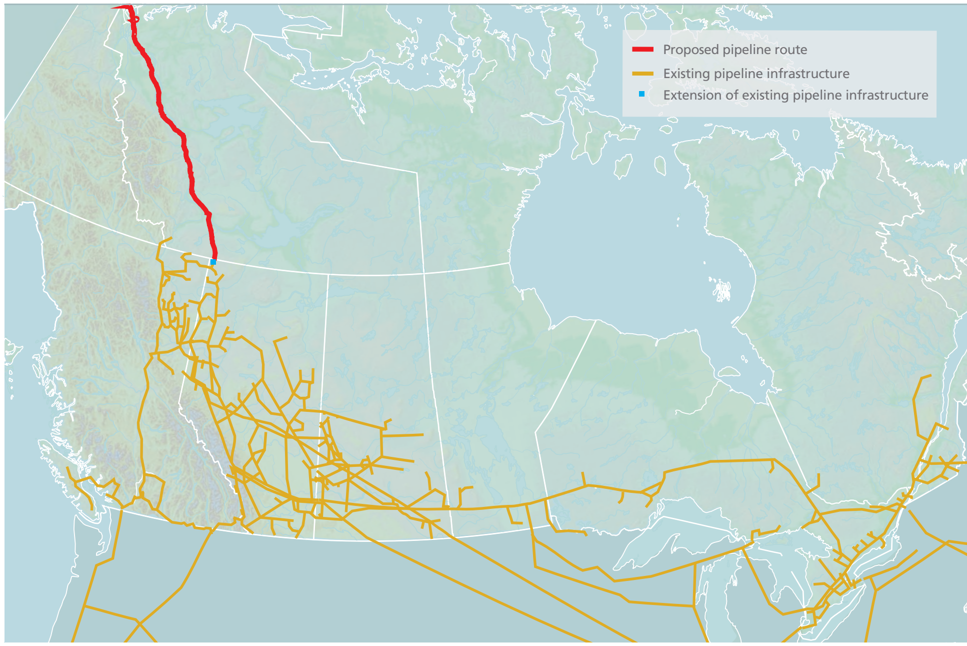


Figure 7-5

Existing export pipeline corridors from the Western Canada Sedimentary Basin

Table 7-3

Western Canada Sedimentary Basin export pipeline capacity and projected gas flows

Mm³/d (Bcf/d)	2003		2010		2020		2030		
Pipeline Corridor	**Capacity**	**Projected Flow**	**Capacity**	**Projected Flow**	**Capacity**	**Projected Flow**	**Capacity**	**Projected Flow**	
Northwest Pipeline	**39.92 (1.41)**	**28.61 (1.01)**	**49.58 (1.75)**	**29.12 (1.03)**	**49.58 (1.75)**	**32.32 (1.14)**	**49.58 (1.75)**	**21.95 (0.78)**	**Base Case**
					60.91 (2.15)	42.10 (1.49)	60.91 (2.15)	33.80 (1.19)	Alaska Case
Gas Transmission Northwest	**77.05 (2.72)**	**59.24 (2.09)**	**77.05 (2.72)**	**63.43 (2.24)**	**77.05 (2.72)**	**64.08 (2.26)**	**77.05 (2.72)**	**59.77 (2.11)**	**Base Case**
					94.05 (3.32)	80.68 (2.85)	94.05 (3.32)	68.36 (2.41)	Alaska Case
Foothills and Northern Border	**62.04 (2.19)**	**60.28 (2.13)**	**62.04 (2.19)**	**60.31 (2.13)**	**62.04 (2.19)**	**60.96 (2.15)**	**62.04 (2.19)**	**35.52 (1.25)**	**Base Case**
					70.54 (2.49)	68.73 (2.43)	70.54 (2.49)	67.56 (2.39)	Alaska Case
Alliance Pipeline	**43.54 (1.54)**	**42.41 (1.50)**	**43.54 (1.54)**	**42.69 (1.51)**	**43.54 (1.54)**	**42.18 (1.49)**	**43.54 (1.54)**	**40.82 (1.44)**	**Base Case**
					52.04 (1.84)	51.02 (1.80)	52.04 (1.84)	49.72 (1.76)	Alaska Case
TransCanada	**203.12 (7.17)**	**152.66 (5.39)**	**203.12 (7.17)**	**171.47 (6.05)**	**203.12 (7.17)**	**136.37 (4.81)**	**203.12 (7.17)**	**112.44 (3.97)**	**Base Case**
					242.78 (8.57)	182.46 (6.44)	242.78 (8.57)	145.55 (5.14)	Alaska Case

7.5 Transportation contracts

7.5.1 Mackenzie Valley Pipeline

When considering economic feasibility, the National Energy Board evaluates whether there is adequate contractual support for the pipeline from prospective shippers. The National Energy Board is also mindful of the desire for capacity to be available for third-party shippers.

To date, only the owner-shippers have signed contracts for capacity on the Mackenzie Valley Pipeline. The capacity available for third-party shippers is shown in Table 7-4 under three scenarios, with one, three and fourteen compressor stations in place. As noted previously, this application seeks approval for construction of three compressor stations.

If additional shippers do not sign contracts for capacity on the pipeline, the installation of two of the compressor stations would be delayed. Table 7-5 shows the volumes that have been contracted by each of the shipper-owners.

Table 7-4

Contracted and available capacity on Mackenzie Valley Pipeline

System design	System capacity (summer)	Owner-shipper contracted capacity	Owner-shipper contracted capacity	Uncontracted capacity	Uncontracted capacity
1 compressor station	27.3 Mm^3/d (964 MMcf/d)	23.5 Mm^3/d (830 MMcf/d)	86%	3.8 Mm^3/d (134 MMcf/d)	14%
3 compressor stations	34.3 Mm^3/d (1.2 Bcf/d)	23.5 Mm^3/d (830 MMcf/d)	69%	10.8 Mm^3/d (380 MMcf/d)	31%
14 compressor stations	49.8 Mm^3/d (1.8 Bcf/d)	23.5 Mm^3/d (830 MMcf/d)	47%	26.3 Mm^3/d (928 MMcf/d)	53%

Table 7-5

Contracted volumes by shipper

Shipper	15 year term *(GJ/d)*	20 year term *(GJ/d)*	Total *(GJ/d)*	Total *(Bcf/d)*
Imperial	361 821	90 455	452 276	.400
ConocoPhillips	197 255	49 314	246 569	.225
ExxonMobil	65 752	16 438	82 190	.75
Shell	111 040	27 760	138 800	.130
Total	735 868	183 967	919 835	.830

Note: energy content assumed is 39.1 MJ/m^3

7.5.2 Mackenzie Gathering System

The Mackenzie Gathering System owners have been allocated rights to capacity in various functional units under the Mackenzie Gas Gathering and Processing Facilities Development and Operating Agreement. In October 2007, the Proponents filed contracts signed with MGM Energy Corp. for 5.66 Mm^3/d (200 MMcf/d) of capacity on segments of the Mackenzie Gathering System. These were the first third-party contracts executed for capacity on the Mackenzie Gathering System. MGM Energy Corp. did not sign a corresponding contract for capacity on the Mackenzie Valley Pipeline at that time.

Did you know?

Volume and energy measurements for natural gas

Natural gas can be measured in several different ways. It can be measured by volume which is stated in cubic metres or cubic feet. One cubic metre equals approximately 35.3 cubic feet under standard temperature and pressure conditions. (Standard is defined as 15 degrees Celsius (60 degrees Fahrenheit) and 101.325 kPa (14.7 pounds per square inch)).

Natural gas can also be measured in terms of energy. One gigajoule (GJ) is equal to one billion joules (or 10^9 joules) and, in terms of volume, is equivalent to approximately 26.8 cubic metres (or 946 cubic feet) of natural gas, depending on the heat content of the gas stream. One gigajoule is approximately 950,000 British thermal units (Btus), where one Btu is the amount of heat needed to raise the temperature of one pound of water by one degree Fahrenheit.

Refer to Appendix E for a conversion chart of volume measurements and energy measurements.

7.6 Financing

The National Energy Board has an obligation to satisfy itself that the proponents of a project can obtain the necessary funds to pay for their facilities. In this case, the Proponents have proposed a joint venture structure for owning and operating the Mackenzie Valley Pipeline. The final ownership interests would be determined once the group decides to proceed with construction. The ownership interest of each development field owner, or its affiliate, would be the ratio of its development field firm service transportation agreement to the total firm service transportation agreement commitments at that time. Predevelopment interests are shown in Table 7-6.

Ultimately, the Mackenzie Valley Aboriginal Pipeline Limited Partnership could own up to 33.3 percent of the Mackenzie Valley Pipeline. Its actual ownership interest in the facilities would be calculated as the ratio of third-party contracts to the total contracts in place on the Mackenzie Valley Pipeline when the Proponents make their decision to construct the pipeline. If no shippers, other than the owner-shippers, have signed contracts before the decision is made to construct the facilities, then the Mackenzie Valley Aboriginal Pipeline Limited Partnership would be given a minimum interest in the pipeline. The minimum interest is calculated as the ratio of the Mackenzie Valley Aboriginal Pipeline Limited Partnership's predevelopment phase spending, which is being funded by TransCanada PipeLines Limited, to the total construction costs, plus all predevelopment phase costs for the gas pipeline. It is expected that the minimum interest could be in the range of two to three percent. However, the Mackenzie Valley Aboriginal Pipeline Limited Partnership would have the option to increase its ownership interest up to the maximum of one third within the first 10 years from pipeline start-up as additional contracts are entered into.

Table 7-6

Predevelopment interests of owner-shippers

Owner-shipper	Predevelopment interest
Imperial Oil Resources Ventures Limited	34.2%
Mackenzie Valley Aboriginal Pipeline Limited Partnership	33.3%
ConocoPhillips	16.0%
Shell	11.2%
ExxonMobil	5.3%

Once the Proponents decide to construct the facilities, TransCanada PipeLines Limited would have the option to acquire from the development field owners an interest in the pipeline equivalent to five percent of the total development field capacity.

According to the Proponents, the joint venture structure was selected because it allowed for financing flexibility, tax efficiency and efficient use of overhead resources. The development field owners will arrange financing for their own share of the project costs, most of which will probably come from internally generated funds. The Proponents argued that the pipeline owners are all part of organizations that are very financially strong and highly credit worthy. The Mackenzie Valley Aboriginal Pipeline Limited Partnership intends to raise debt and equity in conventional capital markets and can access, if necessary, backstop funding from the owners of the development fields for its equity share of the Mackenzie Valley Pipeline's construction costs.

As noted at the beginning of the chapter, when considering the economic feasibility of an application, the National Energy Board considers all of the evidence dealing with markets, downstream facilities, supply, contracts and financing to assess whether the pipeline is likely to be used and useful and whether the pipeline's costs will be paid.

Alternatives North argued that it is not good enough to say the decision on economic viability lies with the Proponents alone as financial, environmental and socio-economic costs and impacts would be borne by others. Alternatives North also argued that the Proponents had failed to prove the need for, and the economic feasibility of, the pipeline.

Views of the Board

Financing

If the shipper-owners decide to construct the facilities, we agree they will be able to finance the project from internally generated funds or other sources as business conditions may dictate. We note that the Mackenzie Valley Aboriginal Pipeline Limited Partnership would be able to access backstop funding from the owners of the development fields if not through conventional capital markets.

Supply

We note that no evidence was filed which was contrary to the Proponents' long-term forecasts for the supply and consumption of natural gas in North America. In our view, the evidence demonstrates that there is, and there will be, adequate natural gas supply to support the use of the project over its expected economic life.

Transportation contracts and markets

We are satisfied that the forecasted growth in the North American market would be sufficient to absorb the expected gas volumes from the Mackenzie Valley Pipeline. We note the forecasted growth in natural gas consumption and the continued decline in gas production from conventional sources in western Canada. We accept that this supports the conclusion that adequate pipeline capacity exists to accommodate the delivery of 34.3 Mm^3/d (1.2 Bcf/d) of natural gas from the Mackenzie Valley Pipeline to downstream markets.

Although the Angevine Report did not specifically re-assess the availability of pipeline capacity, the updated projections for combined production from British Columbia, Alberta and Saskatchewan in the updated evidence are significantly lower than the original projections for natural gas production in the Navigant Study. Consequently, the evidence of the Angevine Report would support the Navigant Study conclusion that no export pipeline expansions would be required to accommodate the delivery of 34.3 Mm^3/d (1.2 Bcf/d) from the Mackenzie Valley Pipeline.

For the Mackenzie Valley Pipeline to be successful, the natural gas moved through it would need to compete with other sources of gas supply in the North American market. In final argument some parties raised concerns that the evidence on the record does not prove that Mackenzie gas could successfully compete in the market. We note that it is impossible to know how markets and circumstances will change over time.

If the pipeline is built it would take several years for construction and the pipeline would be expected to operate for at least 25 years. The Proponents estimated that 2018 is the earliest the pipeline could commence service. Therefore, the pipeline could be in operation until 2043 and beyond. Economic conditions will inevitably change over that time as they have in the past several years. More specifically, supply and demand forecasts and gas prices will continue to change over time. We do not agree that these are reasons to deny the project. Our approval gives Mackenzie gas an opportunity to compete. Denial would block that opportunity indefinitely.

Although the shipper-owners have entered into Precedent Agreements, these agreements are only in effect until a Firm Service Transportation Agreement is entered into. Either party to the agreement has the option of terminating the agreement if the Proponents have not provided start up notice by 1 November 2012 or such later date as may be agreed to by the parties. In final argument the Proponents indicated they would not be prepared to make a decision to construct until after that date. Therefore, all existing Precedent Agreements could theoretically be terminated. Accordingly, we require the Proponents to demonstrate to the National Energy Board's satisfaction that the necessary long-term transportation service contracts have been executed for the Mackenzie Valley Pipeline before construction starts.

The Proponents and shippers have made significant financial commitments and will have to make further commitments by signing Firm Service Transportation Agreements. If they do, we are satisfied this will demonstrate that parties have determined Mackenzie Valley gas would be competitive in the market and that the pipeline would be useful. If producers are confident that Mackenzie gas can compete in the market they will enter into the required long-term contracts for service on the Mackenzie Gas Pipeline. These contracts provide necessary assurance that the demand charges for the pipeline will be paid. It is an important indicator that the proposed pipeline will be used.

Economic feasibility

Given our views on financing, supply, contracts and markets we believe that if long-term contracts are signed as required, the pipeline is likely to be sufficiently well utilized over its economic life.

Chapter 8 Toll, tariff and access provisions

8.1 Regulation of tolls, tariffs and access

The Mackenzie Valley Pipeline is a producer owned, basin opening pipeline in an environmentally sensitive area. The gas must flow through the Mackenzie Gathering System before reaching the Mackenzie Valley Pipeline. Each of these system components, the Mackenzie Gathering System and the Mackenzie Valley Pipeline, has a different ownership structure, different contractual arrangements and will operate under a slightly different regulatory framework.

The Mackenzie Valley Pipeline is regulated under the *National Energy Board Act* which provides for regulation of the physical facilities as well as the applicable tolls, tariffs and access provisions. The tolls and tariffs on National Energy Board regulated pipelines must conform to Part IV of the *National Energy Board Act*. A requirement of the *National Energy Board Act* is that a company cannot charge for service on a pipeline unless it has a tariff on file with the National Energy Board. The *National Energy Board Act* also requires that tolls be just and reasonable and charged equally to all shippers using the same services.

The Mackenzie Gathering System was applied for under the *Canada Oil and Gas Operations Act* and we subsequently found this to be appropriate.[1] During the evidentiary portion of the hearing in 2006, the *Canada Oil and Gas Operations Act* did not have provisions for toll, tariff and access regulation. Therefore the appropriate means of addressing these topics was a key issue in our hearing. On 14 December 2007 legislation was passed which amended the *Canada Oil and Gas Operations Act* to allow the National Energy Board to regulate the tolls and

[1] Mackenzie Explorer Group filed a motion on 7 April 2006 asking us to declare that once in service both the Mackenzie Gathering System and the Mackenzie Valley Pipeline would be a single "pipeline" under the *National Energy Board Act* and entirely subject to regulation under Part IV of that Act. They also asked us to direct the Proponents to prepare, file, and serve the toll principles and the tariff(s) that would apply to both systems for approval in this proceeding. On 10 July 2006 we determined that the Mackenzie Gathering System was appropriately applied for under the *Canada Oil and Gas Operations Act* and denied the motion. However, we noted that we remained concerned about the tolls, access and tariff provisions for the Mackenzie Gathering System and the methods for resolving disputes on these matters. Our decision was upheld by the Federal Court of Appeal.

tariffs of these facilities in a manner similar to regulation under the *National Energy Board Act*.

In Canada, economic regulation of federal pipelines by the National Energy Board is intended to produce outcomes that are similar to what would happen in a competitive market. Traditionally, pipelines have been regulated using a "cost of service" approach, although there are alternatives such as use of negotiated settlements and complaint-based regulation. The cost of service methodology basically involves a two step process. In the first step, a pipeline company calculates the cost to deliver the gas (the throughput) in the following year. This is referred to as determining the annual cost of service or the revenue requirement. The second step is to distribute these total costs among the different customers and the different types of services offered by the pipeline. This step is commonly referred to as toll design. The Proponents propose to use this general approach for the Mackenzie Valley Pipeline, although not for the Mackenzie Gathering System.

In this proceeding, parties raised a number of concerns with specific costs, the methodology for their distribution among customers and the method to review costs. Specifically, the following issues were discussed for the Mackenzie Valley Pipeline:

- method of regulation;
- cost of capital including capital structure, return on equity and the deemed cost of debt;
- depreciation;
- tolling methodology;
- access issues;
- laterals and service to northern communities; and
- the Code of Conduct.

For the Mackenzie Gathering System, issues centered around the need for economic regulation, methods for collecting fees and setting tolls, and codes of conduct.

8.2 Mackenzie Valley Pipeline

8.2.1 Timing of decision on toll and tariff matters

The Proponents applied under Part IV of the *National Energy Board Act* for an order approving the toll and tariff principles that are to apply to service on the Mackenzie Valley Pipeline. Various parties, including Mackenzie Explorer Group, raised issues related to these principles throughout the hearing. In argument Mackenzie Explorer Group took the position that we should leave the toll and tariff issues to be determined through some future process once the economic parameters are better known. They suggested that there would be ample time to resolve these issues.

The Proponents responded that they need to know the toll and tariff principles prior to making the decision to construct.

Did you know?

Why there is economic regulation of the pipeline sector in Canada

Most industries in Canada have some form of regulation that governs what they can and cannot do. However, the pipeline sector is subject to more economic regulation than most because of the unique features of energy supply and delivery.

A market allows sellers and buyers to exchange their goods or services. In a fully competitive market, there are many buyers and sellers competing for the same goods or services. This competition motivates buyers to keep their prices down and drives the innovation of new products or services. Pipeline markets are different. They are often natural monopolies with a limited number of companies providing the product or service. In some cases, there is only one provider. Pipelining of natural gas is a necessary service, but because the construction of major pipelines and associated facilities can take many years and be extremely costly, there can be significant economic barriers to entry. Once a single pipeline is built, it often becomes more difficult for other companies to provide the same service. This economic barrier becomes even higher because the existing company can often expand its system at a lower price than what it would cost another company to build a new pipeline. Yet buyers often do not have a substitute service – there is nothing else to take the place of the pipeline. As a result, the existing company can control the market, and there is no pressure from competitors for prices to become lower, or for innovation in the market place.

At the same time, companies are unwilling to undertake the massive investments that are often required without reasonable assurance that they will be able to recoup their money and earn a reasonable return on investment.

In a monopoly situation, markets are not fully competitive and would not function efficiently on their own. Regulation can be used as a non-market force to set prices for the goods or services. Pipeline regulation in Canada therefore is a substitute for the competitive economic forces that would normally work in a fully functioning market. The goal of economic regulation is that the public good (in this case pipeline infrastructure) is provided at a price, and in amounts, that would be expected from a competitive market.

Views of the Board

Although the Mackenzie Valley Pipeline will not go into service before 2018 at the earliest, we find that it is appropriate to make a decision on the toll and tariff principles at this time. This will give the Proponents, potential third-party shippers, and others a clearer understanding of the terms of service that will prevail as they make decisions concerning the project.

8.2.2 Method of economic regulation

The Proponents have proposed that tolls be established based on the best estimate of the Mackenzie Valley Pipeline's costs for the coming year. Any differences between the original estimates and the actual amounts at the end of the year would be recorded in deferral accounts and included in the following year's tolls. The Proponents also committed to providing each shipper with the annual revenue requirement and the applicable tolls at least 30 days prior to the beginning of the new toll year.

According to MGM Energy Corp. this form of regulation includes little incentive to control costs since there is little or no risk of non-recovery of actual costs incurred. Higher than anticipated costs can be recovered through the following year's tolls. MGM Energy Corp. contends that this form of regulation might be appropriate for a pipeline without third-party shippers since, as both the owners of and shippers on the Mackenzie Valley Pipeline, the Proponents would be relatively indifferent to tolling costs. However, for third-party shippers that would be competing with the owner-shippers for access to markets, this approach is contrary to the concept of an open access pipeline system.

In addition to the lack of incentive to control costs, MGM Energy Corp. stated that there is no opportunity to review costs and the onus is placed on third-party shippers to file a complaint with respect to the prudence and level of any costs. In order for the tolls to be considered fair and transparent, third-party shippers must have sufficient notice of the incurred costs and the opportunity in a public forum, if necessary, to adequately assess these costs before the Mackenzie Valley Pipeline begins operation. MGM Energy Corp. supported a public hearing process once the Mackenzie Valley Pipeline is in service that would occur on a regular basis, whether annually or over some specific negotiated period, for example every three to five years.

Group 1 versus Group 2

For the purpose of economic regulation (not safety or environmental regulation) the National Energy Board has divided pipeline companies into two groups. Group 1 companies own the major pipeline systems. Those companies that own smaller pipelines or pipelines with relatively few shippers are classified as Group 2 companies. Group 2 companies and certain Group 1 companies are regulated on a complaint basis. Under complaint-based regulation, the pipeline company is responsible for providing their shippers and other interested groups with sufficient information so that they may determine whether the tolls are reasonable. The tariffs and the resulting tolls are effective once filed unless a complaint is filed or the National Energy Board, on its own motion, decides to review the toll.

The Proponents have not specifically asked to be classified as either a Group 1 or Group 2 company. They noted that they expect the Mackenzie Valley Pipeline to be classified as a Group 1 company but would be satisfied if we found that a Group 2 designation was more appropriate.

Did you know?

Definitions

Access provisions – the provisions in a tariff which allow third parties to contract for the use of the pipeline facilities.

Tariff – the list of rules for transporting (moving) gas on a pipeline company's facilities. This list of rules sets out the terms and conditions under which the service of a pipeline are offered or provided, including the tolls, the rules and regulations, and the practices relating to specific services.

Tariff principles – the general principles that will be used to define the tariff.

Toll – the price charged by a pipeline company for the use of its facilities.

Toll principles – the general principles outlining how the tolls will be determined.

Views of the Board

Imperial Oil Resources Ventures Limited will be designated as a Group 1 company. It will be required to file Quarterly Surveillance Reports as outlined in the *Toll Information Regulations* and *Section BB, Financial Surveillance Reports* in the National Energy Board's *Filing Manual*.

Given that, as a Group 1 company, both shippers and the National Energy Board will have the opportunity to review the Mackenzie Valley Pipeline's costs and any concerns can be brought to the National Energy Board, we accept the Proponents' proposed method of regulation.

8.2.3 Cost of capital

Capital structure and return on equity

Capital structure is the mix of debt and equity that a company uses to finance projects, such as a pipeline. Ideally, the capital structure should minimize the cost of capital while meeting the objectives of a fair return. Debt is generally cheaper than equity financing because, unlike equity, it is tax deductible and because it is less risky. In the event of bankruptcy, it is the lenders, not the company shareholders, who have the first call on cash. However, the determination of the optimal capital structure can be a fine balance – too much debt and the pipeline's financial risk increases along with its cost of capital.

Did you know?

RH-2-94 formula for calculating return on equity

In 1995, the National Energy Board started using a formula for setting the annual return on equity for a hypothetical or benchmark pipeline. This could be used as the standard for determining the return on equity for pipelines that did not have an alternative, negotiated arrangement. This National Energy Board formula was based on the forecast interest rate for long-term Government of Canada bonds, plus a risk premium. Each year, the formula was adjusted by 75% of the change in 30 year Government of Canada bonds. In October 2009, the National Energy Board decided that the formula would no longer be in effect.

The Proponents originally proposed a capital structure that combines 30 percent equity with 70 percent debt and a return on equity for the first 10 years of operation that is equal to the return on equity derived from the National Energy Board's RH-2-94 formula return on equity[2], plus 221 basis points. For example, if the formula return on equity were 9.0 percent, the return on equity for the Mackenzie Valley Pipeline would be 11.21 percent. When the Proponents originally filed their application to build the Mackenzie Gas Project, the return on equity derived by the RH-2-94 formula was 9.79 percent. At that time, the Proponents chose a 221 basis point premium on the premise that a 12 percent return on equity was reasonable for the Mackenzie Valley Pipeline. After the initial 10 years, the return on equity would be determined either through a negotiated settlement with Mackenzie Valley Pipeline shippers or the Proponents would apply to the National Energy Board to set the allowed rate.

Mackenzie Explorer Group asked us to approve a different capital structure and return on equity for the Mackenzie Valley Pipeline than what the Proponents applied for. Specifically, Mackenzie Explorer Group contended that the cost of capital for the Mackenzie Valley Pipeline should vary according to risk so we should approve a capital structure and return on equity that vary with the different phases of the project. The proposal using this approach is shown in Table 8-1. Alternatively, Mackenzie Explorer Group stated that if it had to recommend one premium for the entire project, it would suggest a premium of 70 basis points over the RH-2-94 formula return on equity.

Table 8-1

Mackenzie Explorer Group's proposed return on equity capital for the Mackenzie Valley Pipeline

	Deemed equity	Premium above the RH-2-94 formula *(basis points)*
The Proponents	30%	221
Mackenzie Explorer Group (Option 1)		
Predevelopment	80%	150
Construction	25%	150
Operations	30%	50
Mackenzie Explorer Group (Option 2)	–	70

[2] In the RH-2-94 Decision, the National Energy Board established a mechanism to annually adjust the return on equity for several Group 1 pipelines.

These differing positions on what the Mackenzie Valley Pipeline's capital structure and return on equity should be are based on different determinations of the risk related to the project.

The Proponents submitted that the risks for the Mackenzie Valley Pipeline are significantly different than the risks for the established National Energy Board regulated pipelines accessing the well-proven Western Canada Sedimentary Basin. The fact that it is a greenfield pipeline accessing a new and untested supply basin increases the risk of the project, thereby necessitating a higher return for investors compared to other National Energy Board regulated gas pipelines. A greenfield pipeline is a new pipeline built on undeveloped land or where a pipeline has not yet been located.

The Proponents also noted that, on a stand-alone basis, if the Mackenzie Valley Pipeline were being financed in its entirety in the public markets, or if the National Energy Board's formula for return on equity had applied, it would require a higher equity component than that of established pipelines because of the greenfield characteristics of the Mackenzie Valley Pipeline combined with the magnitude of the investment. The Proponents contended that the proposed return on equity capital for the Mackenzie Valley Pipeline is reasonable when compared to other Canadian greenfield transmission pipelines, Canadian local distribution companies and American gas pipelines. Table 8-2 compares the common equity ratios and equity returns of major National Energy Board regulated pipelines in 2005 as provided in evidence.

Table 8-2

Comparison of 2005 returns on equity capital

	Deemed equity	ROE
Alliance	30%	11.3%
Maritimes & Northeast	25%	13.0%
Mackenzie Valley Pipeline proposed	30%	11.7%
TransCanada Mainline	33%	9.5%

Mackenzie Explorer Group disagreed with the Proponents' assessment of the risks for the Mackenzie Valley Pipeline. According to Mackenzie Explorer Group's analysis of the business risks facing the Mackenzie Valley Pipeline:

- supply risk is low;
- market risk is not significant and there will be no direct competitors;
- construction risk is immaterial; and
- there is little regulatory risk for the Mackenzie Valley Pipeline once it is in service.

Once in operation, Mackenzie Explorer Group contended that the Mackenzie Valley Pipeline faces no more risk than any of the mature pipelines accessing the Western Canada Sedimentary Basin.

On 8 October 2009, the National Energy Board issued a decision stating that the formula, which the Proponents had used as the basis of their return on equity calculation, would no longer be in effect. At that time, the only National Energy Board regulated pipelines which were subject to the formula were the TransCanada Mainline, Foothills Pipe Lines Ltd., and Westcoast Energy Inc. Transmission.

In argument, the Proponents noted that Subsection 3.5 of the Toll Principles contemplated the possibility that the formula would be eliminated prior to the end of the 10th year of service. In such a case, the principle stated that the return on equity will be determined through a negotiated settlement or as a result of an application to the National Energy Board in a manner which preserves the principle that the return on equity will reflect a 2.21 percent premium over the National Energy Board prescribed rates of other Group 1 pipelines to which the formula had been applied immediately prior to 9 October 2009.

The Government of the Northwest Territories' position in argument was that determining the return on equity at least eight years prior to commencement of service and based on a formula, the main component of which already no longer existed, did not make sense. Consequently, the Government of the Northwest Territories, as had Mackenzie Explorer Group, asked us not to fix the return on equity for the Mackenzie Valley Pipeline at this time.

Deemed cost of debt

The cost of debt for a pipeline is typically determined when the pipeline goes to the capital markets to borrow funds. However, the Proponents would not access debt markets to directly finance the project. Instead, each of the Proponents would provide the funds needed to cover its share of the debt. The development field owners, all of which have strong credit ratings, expect that this would likely come from internally generated funds. However, the Mackenzie Valley Aboriginal Pipeline Limited Partnership plans to access the capital markets to raise the funds it would need to finance both debt and equity.

Since the cost of debt for the Mackenzie Valley Pipeline would not be determined directly by the market, the Proponents proposed to deem the debt rate. Parties in the hearing agreed that the appropriate cost of debt would be the rate that would apply if the Mackenzie Valley Pipeline, as a stand-alone entity, borrowed funds. As a proxy for this rate, the Proponents proposed that the debt cost to be included in Mackenzie Valley Pipeline tolls be deemed as the weighted, average interest rate of the project debt financing provided by the senior lenders for the Mackenzie Valley Aboriginal Pipeline Limited Partnership. At the time of application, the cost of this debt was estimated to be 6.1 percent.

The Proponents contended that the Mackenzie Valley Aboriginal Pipeline Limited Partnership cost of debt is a reasonable proxy for the cost of debt because:

- both the Mackenzie Valley Aboriginal Pipeline Limited Partnership and the Mackenzie Valley Pipeline have been given a provisional credit rating of A (low) by DBRS[3];
- the Mackenzie Valley Aboriginal Pipeline Limited Partnership's sole business is to invest in the Mackenzie Valley Pipeline;
- the Mackenzie Valley Aboriginal Pipeline Limited Partnership's debt would be serviced by the same pool of cash flows that would service the Mackenzie Valley Pipeline stand-alone debt;
- the Mackenzie Valley Aboriginal Pipeline Limited Partnership's debt would be secured directly against the Mackenzie Valley Pipeline; and
- the Mackenzie Valley Aboriginal Pipeline Limited Partnership partners would be taxable—therefore the coverage ratios, debt ratings and cost of debt for the Mackenzie Valley Aboriginal Pipeline Limited Partnership should be similar to those of the Mackenzie Valley Pipeline.

The Proponents noted that if specific circumstances caused the Mackenzie Valley Aboriginal Pipeline Limited Partnership's debt rating to differ from that of the Mackenzie Valley Pipeline as a stand-alone pipeline, they would deal with that situation when it arose.

Assuming the financial forecasts unfolded as planned, the Proponents' evidence suggested that the proposed capital structure, return on equity and cost of debt would be aligned with an 'A' credit rating from Standard & Poor's and DBRS. If the cost of debt were closer to 7.0 percent when it is issued, interest coverage ratios and fixed charge coverage ratios could be lower, weakening the Mackenzie Valley Pipeline's credit profile. The Proponents stated that a credit rating lower than A- may impact the ability of an issuer to access the debt capital markets to raise the debt required for this project on a stand-alone basis. A rating lower than A- would also impact the cost of financing.

Mackenzie Explorer Group stated that deeming the debt cost of the development field owners as proposed by Proponents could be unfair and unreasonable because:

- the Mackenzie Valley Aboriginal Pipeline Limited Partnership's share of Mackenzie Valley Pipeline ownership could be very small and therefore Mackenzie Valley Aboriginal Pipeline Limited Partnership's cost of debt may not be reflective of the true debt costs for a venture the size of the Mackenzie Valley Pipeline;
- the Mackenzie Valley Aboriginal Pipeline Limited Partnership's equity may be funded by a loan from the development field owners and therefore the investment takes on the characteristics of a 100 percent margin loan. While it may be low risk, it will still be more risky and expensive than debt backstopped by genuine equity; and

[3] DBRS and Standard & Poor's are rating agencies which provide credit ratings on issuers of various types of debt including bonds, commercial paper and preferred shares.

The March 2005 credit rating was subject to a number of assumptions such as that the project be completed without cost overruns, that the Mackenzie Valley Pipeline capacity is 28.3 Mm^3/d (1 Bcf/d) to 34.3 Mm^3/d (1.2 Bcf/d) and fully subscribed and that there is no change in the current shippers, owners, or agreements throughout the entire term of the debt.

- the Mackenzie Valley Aboriginal Pipeline Limited Partnership is a limited partnership which may not pay corporate income taxes so the financial parameters such as interest coverage ratios may be worse than if the Mackenzie Valley Pipeline were operating as a conventional limited liability corporation. (After this evidence was filed, the Proponents clarified that the current Mackenzie Valley Aboriginal Pipeline Limited Partnership partners will be taxable.)

Mackenzie Explorer Group proposed that the Mackenzie Valley Pipeline's cost of debt should be the lowest equivalent term issue cost for NOVA Gas Transmission Ltd., TransCanada PipeLines Limited, and Enbridge Gas Distribution, which Mackenzie Explorer Group contended are more appropriate proxies. This proposal would apply to the operating stage of the Mackenzie Valley Pipeline. For the predevelopment and construction stages, Mackenzie Explorer Group proposed different debt rates as follows:

- predevelopment – 30 year Government of Canada bond yield plus 60 basis points; and
- construction – three to five year Government of Canada bond yield plus 50 basis points.

Mackenzie Explorer Group submitted that the option is "always on the table" for the National Energy Board to review the Mackenzie Valley Aboriginal Pipeline Limited Partnership's cost of debt if there was evidence that it was not the same cost of debt that would apply to a stand-alone Mackenzie Valley Pipeline.

Views of the Board

The specific return on equity for the Mackenzie Valley Pipeline will be set closer to the in-service date, either through a negotiated settlement subject to National Energy Board approval, or as a result of an application brought to the National Energy Board. We accept the Proponents' approach of preserving the 221 basis point premium over other Group 1 companies that were subject to the formula. However, we cannot make future National Energy Board decisions and, as noted in RH-2-2004 (TransCanada PipeLines Limited Phase II), when determining the appropriate returns for a pipeline, the National Energy Board looks at the total return taking into account both return on equity and equity thickness, not one factor in isolation.

With respect to the deeming of the debt rate, if there is evidence in the future that the Mackenzie Valley Aboriginal Pipeline Limited Partnership's cost of debt is different than the cost of debt that would apply to a stand-alone Mackenzie Valley Pipeline, a party can bring the issue to the National Energy Board in the usual fashion. We do not accept Mackenzie Explorer Group's proposal for a different capital structure, allowed return on equity or debt rate for each phase of the project. We find the approach to be unnecessarily complicated and inconsistent with typical regulatory practice in Canada.

8.2.4 Depreciation

The Proponents plan to use a depreciation method that would allow them to recover 80 percent of their asset costs over the first 20 years of operation of the Mackenzie Valley Pipeline. The owners would only recover the remaining 20 percent of the initial costs if there were shippers beyond year 20. Using this method, the annual depreciation rate would be between four and five percent, depending on the ratio of 15 year and 20 year Firm Service Transportation Agreements. Based on the initial contracts signed by the owner shippers, the proposed depreciation rate would be 4.8 percent for the first 15 years of the Mackenzie Valley Pipeline's operating life and 1.6 percent in years 16 to 20. This would result in a significant reduction in tolls for the last five years of the Mackenzie Valley Pipeline's 20 year economic life.

Mackenzie Explorer Group submitted that the proposed overall depreciation rate is too high

Did you know?

Depreciation

Depreciation for accounting purposes is a method of distributing the costs of assets, such as a pipeline, over their estimated useful lives by allocating annual amounts as an expense. For example, if a project's capital costs were $20 million and the depreciation rate was five percent, then each year $1 million would be included in tolls to allow the owner to recover the original capital. For toll making purposes, this depreciation expense is part of the company's annual cost of providing transportation service. By including depreciation in the cost of service, the company can recover the costs of its investment over time. In addition to this return of capital, there is also a return on capital.

and that it would be inappropriate at this time for us to fix the system's allowed depreciation rates for a 20 year period. Mackenzie Explorer Group stated that the perceived economic life of the system would be tied to a number of factors such as the discovered and likely to be discovered gas supply, as well as supply and demand conditions in the entire North American gas market. Mackenzie Explorer Group proposed that given the current knowledge and understanding of the resource base, it would not object to us approving a forecasted 25 year economic life with an initial depreciation rate of four percent.

Mackenzie Explorer Group also contended that, every five years after commissioning, the Proponents should be required to file a review of the allowed depreciation rates, including an evaluation of the economic life of the facilities based on gas supply forecasts at the time.

Views of the Board

We accept the Proponents' proposed depreciation method but note that circumstances may change over the 20 years, necessitating a review of the economic life of the project and therefore the appropriate depreciation rates. While noting that we cannot bind future panels of the National Energy Board, if the National Energy Board reviews the depreciation method during the first 20 years of operation it would have regard to the effect of any change in depreciation on the ability of the Mackenzie Valley Aboriginal Pipeline Limited Partnership to finance its interest.

8.2.5 Tolling methods (zonal versus volume distance tolling)

The three main cost of service tolling methods are zonal, volume distance, and postage stamp. Depending on the circumstances, any of these methods can produce just and reasonable tolls.

The Proponents have proposed two tolling zones for the Mackenzie Valley Pipeline:

- a long haul zone for gas coming into the Mackenzie Valley Pipeline upstream of Little Chicago at approximately kilometre post 203; and
- a short haul zone for gas entering at or downstream of that point.

The 20 year short haul toll is proposed to be fixed at 72.4 percent of the firm service transportation toll. This would allow shippers of gas from Colville Hills to pay the reduced rate. This rate was originally fixed at 80 percent but was revised downward to reflect the distance from the midpoint between Little Chicago and Norman Wells to the NOVA Gas Transmission Ltd. interconnect in Alberta relative to the total length of the Mackenzie Valley Pipeline.

The Proponents indicated that two zones, each with a single toll, would be reasonable for the Mackenzie Valley Pipeline. This approach recognizes that the large quantities of gas flowing into the Mackenzie Valley Pipeline at Inuvik make it economically possible to move gas from more southern Northwest Territory locations. The Proponents did not support volume-distance based tolls as a stand-alone tolling method. The Proponents were concerned that applying highly distance-sensitive rates could allocate too many benefits of economies

Did you know?

Toll design

Zonal tolls – all receipts from, or deliveries within, the same zone pay the same toll, regardless of exactly where the product is received or delivered within the zone. For example, on the TransCanada Mainline the province of Saskatchewan comprises a zone. Therefore all gas received in Saskatchewan pays the same rate whether it was received on the west side of the province or the east side.

Volume-distance tolls – the further the gas moves, the higher the charge. For example, the charge could be per kilometre. (If the contracts are negotiated in energy units, such as $/GJ or $/MMBtu rather than volumetric units such as $/Mcf or $/cubic metre, then the term "energy-distance tolls" is sometimes used.)

Postage stamp tolls – a toll that is charged per volumetric unit transported regardless of the distance traveled and the points of origin and destination. This is similar to the charge for a postage stamp where the rate is the same whether the letter goes to the next block or the other side of the country.

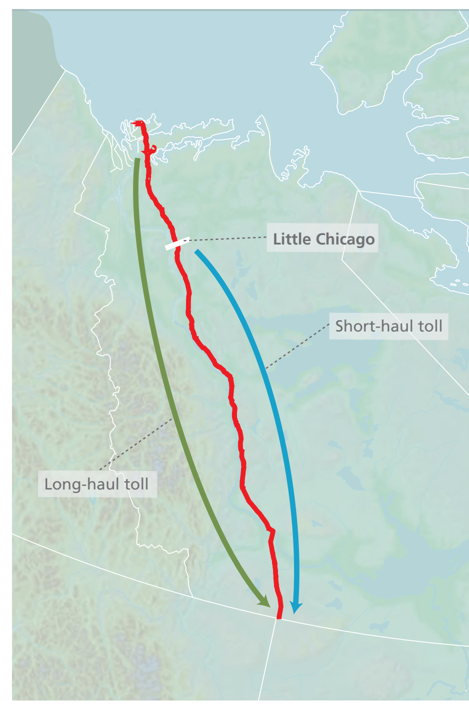


Figure 8-1

Proposed toll zones for the Mackenzie Valley Pipeline of scale and scope to future short haul shippers and thereby undermine the willingness of the initial anchor shippers to proceed with the project.

While there are currently no plans to establish any other zones, the Proponents would consider doing so if transportation was requested for gas produced south of Colville Hills. In such a case, the appropriate tolling arrangements would be considered at that time. The Proponents would consider any benefits from the additional commitments, the availability of competitive alternatives, any stranding of upstream capacity, and all other relevant factors in making a decision. They further noted that it would ultimately be up to the National Energy Board to decide what tolls would be just and reasonable.

The Government of Yukon submitted that the Proponents' toll design is not economically efficient and may lead to less than optimal pipeline development and use. Specifically, they were concerned that a short haul zone of 994 kilometres (the distance from Little Chicago to Alberta) is a very long distance over which to apply a single toll and would discourage potential shippers from using the southern portion of Mackenzie Valley Pipeline. The Government of Yukon submitted that we should find a volume-distance (or energy-distance) toll design to be appropriate and in the public interest for the Mackenzie Valley Pipeline. Further, we should direct that it be implemented using a single rolled-in revenue requirement that includes the cost of the initial pipeline, future expansions of that pipeline, and future extensions and laterals connecting with the Mackenzie Valley Pipeline. (See Section 8.2.8 for a further discussion of these topics.)

The Government of Yukon noted that a volume-distance toll design in differing formats is used on many Canadian pipeline systems, including on the TransCanada Mainline, TransCanada's British Columbia system and Westcoast's T-South. A volume-distance cost method would result in tolls that are efficient, fair and equitable, well understood by shippers and the National Energy Board, and flexible and durable over a wide range of future circumstances. The Government of Yukon also stated that the tolling method would not have to be purely volume-distance tolls. Toll zones could be created along a pipeline that uses energy-distance or volume-distance toll design.

MGM Energy Corp. and Apache Canada Ltd. both supported a pipeline toll method with a toll based on distance as this reflects a shipper's proportionate share of costs for use. MGM Energy Corp. wanted the volume-distance method to be applied to both the Mackenzie Valley Pipeline and the natural gas liquids transmission facilities and was not opposed to the use of a zonal method. They and other parties supported distance-sensitive tolls in final argument.

The Proponents are also offering a separate tolling arrangement for service to northern communities (see Section 8.2.9).

Views of the Board

It would be most economically efficient from a pipeline perspective for the entire pipeline from Inuvik to the Alberta border to be filled to capacity at all times. If this were the case, it would make sense to use a postage stamp methodology and have only one toll zone. However, this is not the case. The Mackenzie Valley Pipeline, as proposed, has spare capacity available and attracting additional shippers would increase economic efficiency and generally result in lower tolls for everyone.

In accordance with the principles of cost-causation and user-pay, we find it desirable that tolls would be distance sensitive. However, we find using a pure volume-distance based toll would be unnecessarily complicated. Based on the location of the gas reserves noted in evidence, we approve the Proponents' initial tolling method with two zones. However, we expect that additional zones (over and above the two proposed zones) would be considered in the future, and expect the tolls in each zone to be distance sensitive. Considerations in determining the location and timing of future zones should include:

- distance;
- capital expenditure;
- the benefit of the additional commitments;
- the availability of competitive alternatives;
- any stranding of upstream capacity; and
- all other relevant factors.

8.2.6 Open access

Producers of other natural gas resources in the region need access to the Mackenzie Valley Pipeline to reach the North American market. Open access means that shippers willing to meet the toll and tariff conditions have the right to access service where it is economically feasible for the Proponents to provide that service. Without this access, natural gas supplies in the Northwest Territories could not be economically developed.

Parties who could be potential third-party shippers raised the following issues with regard to access to the Mackenzie Valley Pipeline:

- access and expansion policy, which includes the process for addressing expansions and toll treatment for future expansions;
- precedent agreements;
- minimum contract term; and
- interruptible service for gas which fails to meet specifications.

Access and expansion policy

During our hearing two key issues were discussed regarding the access and expansion policy. The first concerned the process for, and timeliness of, expansions and the second the appropriate toll treatment for future expansions.

Process for addressing future expansions

The Proponents submitted that when future requests for service on the Mackenzie Valley Pipeline are received, capacity could be found in a number of different ways. The Proponents could ask existing shippers to give up ("turn back") any unneeded capacity. Alternatively, the Proponents could conduct an open season to determine if other producers needed capacity. Once there were sufficient precedent agreements, the Proponents would then make the necessary applications to expand the Mackenzie Valley Pipeline. Finally, potential shippers would retain the right to ask the National Energy Board to order the Mackenzie Valley Pipeline to provide the service. The Proponents also noted that it is not possible to be definitive at this stage about the circumstances and timing of future Mackenzie Valley Pipeline expansions.

Mackenzie Explorer Group sought a degree of assurance that when resources are discovered, processing capacity and pipeline capacity can be economically accessed or developed within a reasonable period of time. They submitted that this could be provided by developing an expansion policy for both the Mackenzie Valley Pipeline and the Mackenzie Gathering System. In Mackenzie Explorer Group's view, an expansion policy should include, among other things, a clear procedure for existing and prospective shippers to request service, as well as a public and transparent open-access process to solicit other requests. Further, the Mackenzie Valley Pipeline operator should be required to make information such as expansion volumes, costs and expected tolls available on a timely basis. Mackenzie Explorer Group also requested that the Proponents consider and execute any expansion in a timely manner.

The Government of Yukon also contended that if the access conditions are met, the Proponents should be required to proceed with an application.

Toll treatment for future expansions

The second issue, the appropriate toll treatment of expansions, addresses the question of whether the costs of expansions should be rolled into the Mackenzie Valley Pipeline's existing rate base.

The Proponents' Toll Principles stated that, as all foreseeable expansions are expected to reduce existing tolls, it is currently contemplated that the tolls for an expansion would be determined on a rolled-in basis. However, the Proponents also stated that they cannot establish a definite tolling method that would apply for every circumstance and it would not be appropriate for them or us to make such a guarantee.

The Government of the Northwest Territories contended that, as a matter of principle, potential shippers on an expanded Mackenzie Gas Project should receive categorical assurance that tolls would be determined on a rolled-in basis, whether or not the costs of that expansion would reduce existing tolls. The Government of the Northwest Territories noted that it has been the National Energy Board's practice for every major gas pipeline under its jurisdiction to roll in all of the capital costs associated with its facilities to one rate base, and therefore to one cost of service. This rolled-in approach was challenged in the 1980s. At that time the National Energy Board chose this approach based on a large body of evidence and argument. An indication of intended or required conformity to rolled-in tolling would be valuable for parties which expect to contract for the Mackenzie Valley Pipeline's services in the future. It would also provide a long-term signal to encourage exploration and development of gas resources, particularly in respect of a basin opening pipeline.

The Government of Yukon also asserted that we should find that the costs of expansions, as well as extensions and supply laterals, should be rolled in as long as they meet standard economic tests to ensure the facility would be used and that shippers would be held accountable through contracts with sufficient primary terms.

Did you know?

Definitions

Demand charges – a monthly charge that typically covers the fixed costs of a pipeline. The demand charge is based on the daily contracted quantity and is payable regardless of whether the quantities of gas are transported.

Open season – a process in which a pipeline company offers either existing or new capacity to the market and receives bids for that capacity from market participants.

Precedent agreements – a formal understanding between a potential shipper and the pipeline company saying that once capacity is available the companies will sign a Service Agreement if certain conditions are met. The Precedent Agreement commits the shipper to using that pipeline to transport specific volumes of gas and commits the pipeline company to making that amount of space available to the shipper for moving the gas if the conditions are satisfied.

Pro forma contract or pro forma precedent agreement – a sample contract or sample precedent agreement.

Revenue requirement – the total cost of providing service, including operating and maintenance expenses, depreciation and amortization, taxes, and return on rate base.

The Proponents replied that the National Energy Board is not strictly bound by its earlier decisions and must consider each case on its own merits based on the record before it. It can therefore only decide the tolling treatment of a particular expansion when an application for that expansion is made. However, they agreed to remove the clause in section 20.4 of the Tariff Principles that caused concern about the willingness to undertake expansions which would result in higher tolls. That clause states: "As all foreseeable expansions are expected to reduce existing tolls…"

Precedent agreements

As discussed previously, the only parties that have signed Precedent Agreements for the Mackenzie Valley Pipeline to date are the owner-shippers, which have signed contracts for capacity totaling 23.5 Mm^3/d (830 MMcf/d). This leaves 10.8 Mm^3/d (380 MMcf/d) of capacity available in the summer with three compressor stations, as in the base case design, or 3.8 Mm^3/d (134 MMcf/d) with only a single compressor station at Great Bear River. While additional capacity would be available during the winter because of the effect of ambient temperature on capacity, firm contracts are based on the level of flow that can be achieved during the lowest flow period which is the summer. The number of third-party contracts is important because it influences, among other things, the number of compressor stations that would be required, the level of tolls on the system and the share of the project that would be owned by the Mackenzie Valley Aboriginal Pipeline Limited Partnership.

In order to obtain the right to capacity on the Mackenzie Valley Pipeline, potential shippers must first sign a Precedent Agreement. As the Proponents have structured the agreements, the pro forma Precedent Agreement contains the proposed Firm Service Transportation Agreement, the Toll Principles and the Tariff Principles.

The Proponents are not requesting our approval of the Precedent Agreement or the Firm Service Transportation Agreement but they are requesting approval of the toll and tariff principles. The Proponents' position is that an agreement on the tolling principles provides greater certainty for both shippers and the Proponents as to how tolls will be determined. This increased certainty allows shippers to make plans to develop their gas resources and it allows the Proponents to obtain financing. It also reduces the need for, and cost of, annual rate hearings.

The Proponents stated that, once we release our Reasons for Decision, each Mackenzie Gas Project shipper will have to sign a Firm Service Transportation Agreement at which time the Precedent Agreement will terminate. Within 75 days of our Reasons for Decision date, the Proponents will issue Firm Service Transportation Agreements to all shippers and shippers will have 15 days after the Firm Service Transportation Agreement is received, or 45 days after our decision date, whichever is later, to sign the contracts. The Firm Service Transportation Agreement will be signed before the Proponents decide to go ahead with the project.

The Precedent Agreement gives parties the right to terminate the agreement for any reason within 30 days of us issuing our Reasons for Decision. However, if a shipper wishes to terminate the agreement it would have to pay a termination fee of $285 for each gigajoule of daily contract quantity. For example, a party which signed a Precedent Agreement for 2.83 Mm^3/d (100 MMcf/d) would pay approximately $30 million in termination fees. The Proponents may terminate all Firm Service Transportation Agreements within one year of our Reasons for Decision date if the Proponents decide not to proceed with construction of the Mackenzie Valley Pipeline.

Because the Toll and Tariff Principles are embedded in the Precedent Agreement, any shipper that signed a Precedent Agreement contractually agrees that the tariff for the Mackenzie Valley Pipeline should reflect these toll and tariff provisions. In effect, they would be contractually precluded from raising concerns about these issues before us and would be contractually obliged to support the Proponents' position in proceedings before the National Energy Board.

A specific exception was made within the Precedent Agreement which would give signatories the right to challenge the prudence of predevelopment costs and capital expenditures, as well as the prudence of operating costs. This right to challenge would allow shippers to question whether or not the costs claimed by the Proponents were reasonable.

According to Mackenzie Explorer Group the requirement for shippers that entered into a Firm Service Transportation Agreement to support aspects of the Mackenzie Gas Project application with which they do not agree discourages parties from signing contracts before our hearing process is complete. Mackenzie Explorer Group asserted that this is unreasonable to shippers which are not owner-shippers.

Mackenzie Explorer Group notes that the Precedent Agreement and the Firm Service Transportation Agreement lay out numerous items which would normally be addressed in a pipeline tariff or determined by the National Energy Board in tolls and tariff proceedings such as:

- capital structure;
- return on equity;
- cost of debt;
- depreciation;
- taxes;
- toll design;
- renewal rights;
- force majeure;
- services offered by the pipeline;
- authorized overrun service;
- restrictions on the availability of interruptible transportation service; and
- various other matters.

In addition, Mackenzie Explorer Group contends that parties are discouraged from signing the Precedent Agreement because it contains no provisions protecting the shipper against adverse events before signing a Firm Service Transportation Agreement, other than a right to "buy out" its transportation obligations by paying $285 per gigajoule of contract demand. Adverse events could include unreasonable escalation of projected rate base, an adverse National Energy Board decision, regulatory delays, and the lack of available downstream pipeline capacity. Other impediments to signing contracts include the lack of assurances that access to other segments of the Mackenzie Gas Project would be made available on reasonable terms and conditions during the term of the Firm Service Transportation Agreement, and the lack of a Code of Conduct during the construction and operation phases of the pipeline.

To address the concerns regarding the Precedent Agreement, Mackenzie Explorer Group contends that the Proponents should be required to file a proposed tariff with the National Energy Board within three months of the date our decision is issued. After reviewing that filing, including a public hearing if required, the National Energy Board would approve an appropriate tariff and Firm Service Transportation Agreement. This tariff would reflect the National Energy Board's determinations in this proceeding on the toll and tariff principles.

MGM Energy Corp. also noted that it was not surprising no third-party shippers had yet signed a Precedent Agreement given the lack of agreement on tariff and tolling methods, the lack of an operating Code of Conduct and the lack of tolling and tariff information on the natural gas liquids pipeline.

Minimum contract term

The Proponents have offered two contract terms, 20 years and 15 years, provided that at least 20 percent of the contracts are for 20-year terms to satisfy financing requirements. The toll for a 15-year term would be higher than the toll for a 20-year term. For gas flowing the full distance this premium would be $0.15 per gigajoule. The Proponents also noted that consideration of any other term lengths would be determined after deliveries start and would depend on many factors including volume, timing and cost.

Mackenzie Explorer Group and the Government of the Northwest Territories both expressed concerns with the lack of shorter-term contracts. Mackenzie Explorer Group accepts that 15 years is an appropriate minimum contract term for initial contracts. However, it notes that the Mackenzie Valley Pipeline, when it files its proposed tariff, should be required to clarify that minimum contract terms of one year for firm service are acceptable for existing uncontracted capacity.

The Government of the Northwest Territories is concerned that no transportation service is currently planned for shippers which cannot commit to the minimum 15-year term. Shippers which need shorter-term service will have to wait a number of years to find out whether or not this service will be available. Further, they may be left in a disadvantageous position of contracting in the secondary market for transportation on the Mackenzie Valley Pipeline, if one develops. The Government of the Northwest Territories expressed the belief that these deficiencies will discourage the economic development of further gas reserves in the region. To address this concern, the Government of the Northwest Territories submitted that it would be just and reasonable for us to ensure, even if only as a fallback, that primary capacity on the Mackenzie Valley Pipeline would be available from the start of operations for terms shorter than the 15-year minimum, perhaps 10 years. As with the 15-year term, the pricing of shorter-term service would also reflect a term toll differentiation.

Interruptible service for gas which fails to meet specifications

Suncor requested in written argument that the Mackenzie Valley Pipeline be required to offer a special interruptible service for gas which fails to meet the tariff specifications for minimum heat content. Suncor Energy Inc. noted in its request, that there would be a long lead time to redesign its gas plant so that its gas could meet the minimum specifications.

As background, in June 2006, the Proponents and potential shippers negotiated a provision which would allow gas which did not meet the minimum heat content to be shipped as long as a surcharge was paid. The Tariff Principles also provide for gas to flow even if it exceeds the CO_2 limits as long as various conditions are met. However, if the conditions are not met, the pipeline can curtail those flows and the shipper is still obligated to pay the tolls under its firm service agreement. Also related to interruptible service, Mackenzie Explorer Group asserted that interruptible service should not be restricted to firm service shippers.

The Proponents responded that they don’t intend to offer interruptible service to shippers that don’t hold firm service contracts so Suncor Energy Inc. will in any event be required to enter a Firm Service Transportation Agreement. It is through firm service contracts that the Mackenzie Valley Aboriginal Pipeline Limited Partnership will earn its interest in the Mackenzie Valley Pipeline. The Proponents noted that since it will be at least eight years until natural gas flows, Suncor Energy Inc. would have time to redesign its plant so that its gas meets specifications.

Views of the Board

We find it fundamental to our decision that the Mackenzie Valley Pipeline be accessible to all shippers that meet the terms of the tariff. There are a number of principles which enhance open access on a pipeline. For example, it is essential that shippers know the terms and conditions of access to a pipeline in advance of negotiations. In GH-2-87 the National Energy Board stated:

> **The Board, however, considers it essential that all terms and conditions of access to a pipeline be clearly reflected in the tariff in order to ensure that there are no undue**

> service restrictions imposed by pipeline companies involved in the marketing or producing sectors of the natural gas industry. In the National Energy Board's view, prospective shippers are entitled to know the conditions of access to a pipeline system in advance of contract negotiations, as this knowledge will allow market participants to make informed supply and market decisions thereby contributing to the efficient functioning of the natural gas market.[4]

As elaborated in RH-3-2004:

> This ensures transparency and puts the pipeline and its customers on an equal footing in negotiating a business arrangement.[5]

To provide this transparency and clarity, the Proponents are directed to include in the tariff all terms and conditions of access to the Mackenzie Valley Pipeline including a clear procedure for shippers and potential shippers to request service and the specific process that will be used for open seasons.

Regarding future expansions, we cannot provide the degree of assurance sought by Mackenzie Explorers Group and the Government of Yukon absent the information that would accompany a specific request for service.

With respect to toll treatment for future expansions, we note the concerns about the clause in the tariff which states: "As all foreseeable expansions are expected to reduce existing tolls…" With the removal of this clause as offered by the Proponents in final argument, the governments of the Northwest Territories and Yukon agreed that, while it has been the National Energy Board's practice to roll in the capital costs of an expansion, the appropriate toll treatment would be determined at the time of the expansion after considering the specific circumstances.

Certain provisions of the Precedent Agreements purport to require that potential shippers support all aspects of the toll and tariff principles and therefore preclude potential shippers from raising concerns with the National Energy Board. This provision is contrary to the National Energy Board's principles and to the fundamental tenets of open access. The Proponents are directed to remove these words from any document that relates to access to the Mackenzie Valley Pipeline. We expect the clause to be removed as soon as possible but, in any event, no later than 31 December 2011. In the meantime, any potential shipper can approach the National Energy Board to resolve a dispute.

The Proponents are also directed to file a tariff as soon as reasonably possible but, in any event, no later than 31 December 2011.

We acknowledge the preference of Mackenzie Explorer Group and the Government of the Northwest Territories for flexibility with respect to minimum contract terms when capacity emerges. We also note that no party disputed the need for minimum 15-year contracts to support the construction of the project and for the Mackenzie Valley Aboriginal Pipeline Limited Partnership to obtain financing. We wish to focus at this stage on the arrangements that will put the Mackenzie Valley Pipeline on a sound commercial footing between now and the in-service date. For this reason, we will not require a shorter minimum contract term at this time. We expect that the Proponents would investigate shorter contract terms once the project becomes operational.

The proposal by the Proponents to offer interruptible service only to parties that have signed a Firm Service Transportation Agreement is acceptable at this time given the need to establish a firm commercial foundation for the Mackenzie Valley Pipeline. The specific proposal for a special interruptible service for gas which fails to meet minimum specifications is not required, particularly given the long lead time for Suncor Energy Inc. to address this issue at its facilities.

[4] GH-2-87 Reasons for Decision, p 92.

[5] RH-3-2004 Reasons for Decision, p. 9.

8.2.7 Term-related toll differential

As mentioned in the previous section, the toll for a 15-year term would be higher than the toll for a 20-year term. For gas flowing the full distance this premium would be $0.15 per gigajoule. Mackenzie Explorer Group argued that the $0.15 per gigajoule premium had not been justified on a cost basis, and should not be approved.

The Proponents argued that the differential was not intended to reflect costs and was arrived at as a matter of judgment intended to reflect the different values that shippers would place on 15- and 20-year contracts.

Views of the Board

We find that the proposed toll differential reflects different services and is reasonable. Potential shippers will have the choice of entering into a longer-term contract with a slightly lower toll or a shorter-term contract with a higher toll. We expect they will make the choice that best meets their needs.

8.2.8 Lateral policy

The Proponents, for business reasons, do not intend to build extensions or laterals either for tying in supply or for delivering natural gas to market. They will, however, accommodate the tie-in of interconnecting pipelines built by others.

The Government of Yukon argued that we should find that lateral and extension services must be provided by the Mackenzie Valley Pipeline. Allowing the Proponents to limit their investment to the mainline is inconsistent with the public interest in achieving economies of scale and scope that can lower system-wide costs upon which tolls are based. The Government of Yukon contended that if these economies, both of scale and of scope, were not realized, some extensions or laterals which would otherwise be of economic value may not be constructed and the regional development of natural gas would almost certainly be reduced. Such an approach would establish an unnecessary barrier to developing gas resources located away from, but dependent on, the Mackenzie Valley Pipeline for transportation to southern markets.

On the record

Economies of scale and scope with laterals

Economies of scale occur when a single product, such as pipeline transportation services, can be offered for a lower unit cost by one large diameter pipeline than by several smaller pipelines built along the same route. Instead of each shipper building and operating facilities for its own needs, the transmission company can combine demand from several shippers and build a single, larger pipeline.

Economies of scope occur when there is a reduction in costs if two or more services, such as provision of pipeline services and provision of lateral services, are produced by a single company rather than a number of companies.

On the record

Transportation-by-others model

A separate company could construct, own and operate the extension or lateral facility that interconnects with the mainline. Parties wishing to use those facilities would contract with the Mackenzie Valley Pipeline which would in turn contract with the company that owns the laterals. The cost of that contracted service would be combined with the costs of the mainline to form a single annual revenue requirement. Shippers would see a seamless service despite using facilities of two different owners.

If the Proponents will not build extensions or laterals, the Government of Yukon submitted that a transportation-by-others model could be used to achieve the economies of scope. Integral to this solution is the Government of Yukon's request for volume-distance tolls. Although the cost per kilometre would be the same across the mainline and lateral or extension, an extension shipper would incur a higher total toll because it would be going further since it would use the extension or lateral in addition to the mainline.

The Government of Yukon noted that another variation of the transportation-by-others structure would be for the Mackenzie Valley Pipeline to operate and administer the upstream interconnected facilities, instead of the facility owner. The facility owner would not need its own operating and administration function since these functions would be undertaken by the Proponents.

Did you know?

Definitions

Distribution system – the pipeline facilities which transport the fuel from the mainline to the end users, including homes and businesses.

Gathering system – the pipeline facilities which collect gas from producing fields.

Mainline – the main transportation line(s) of a pipeline system.

The Government of the Northwest Territories stated that the Proponents' policy of not investing in supply laterals is unfortunate since the Proponents were probably in the best position to construct and integrate these facilities. The Government of the Northwest Territories noted that the Proponents cannot, by declaring that they will not invest in laterals, escape the requirement of the *National Energy Board Act* which states that the National Energy Board can, upon request, require extension of the Mackenzie Valley Pipeline facilities, if required and if no undue burden is imposed on the pipeline.

The Proponents argued in reply that section 71(3) of the *National Energy Board Act* did not appear to give the National Energy Board authority to direct a pipeline owner to build supply laterals or extensions, but section 72(1) authorizes the National Energy Board to direct a pipeline company to extend its transmission facilities to the junction with local distribution companies.

Views of the Board

We will not require the Proponents to construct supply extensions and laterals or roll in the costs of those facilities. In order for the National Energy Board to make these decisions, even if it has the authority to do so, it would have to have a specific application before it. Without the detail contained in an application, we cannot assess the circumstances, public interest or burden.

Our views with respect to delivery laterals are discussed in Section 8.2.9 below.

8.2.9 Service to northern communities

Four issues on the record related to community access to gas flowing on the Mackenzie Valley Pipeline:

- a rebate for shippers selling gas to northern communities;
- the allocation of capital costs for metering and related facilities;
- laterals to communities; and
- community access to gas supply.

Rebate for shippers selling gas to northern communities

When shippers on the Mackenzie Valley Pipeline sell gas to small gas users in the Northwest Territories, the Proponents propose to give those shippers a rebate of 50 percent of the applicable 20-year toll. The program is called the Northwest Territories Small Market Delivery Rebate Expense. The rebate would apply to:

- residential, commercial or institutional users, including power generators that serve these users;
- small industrial companies that consume less than 100,000 gigajoules per year; and
- power generators that produce less than the amount of electricity that could be generated from 100,000 gigajoules annually.

Did you know?

Definitions

Community gas pipeline – a lateral from the main pipeline to a local distribution system.

Local distribution company – a legal entity that distributes natural gas throughout a community or area, for example, to homes, businesses, institutions or power generators. The legal entity may be a private company, an entity owned by a municipality, or a cooperative. The term local distribution company can also be used for a company that distributes electricity.

After small industrial companies and power generators were included in the program, the Government of the Northwest Territories withdrew evidence raising concerns about the program.

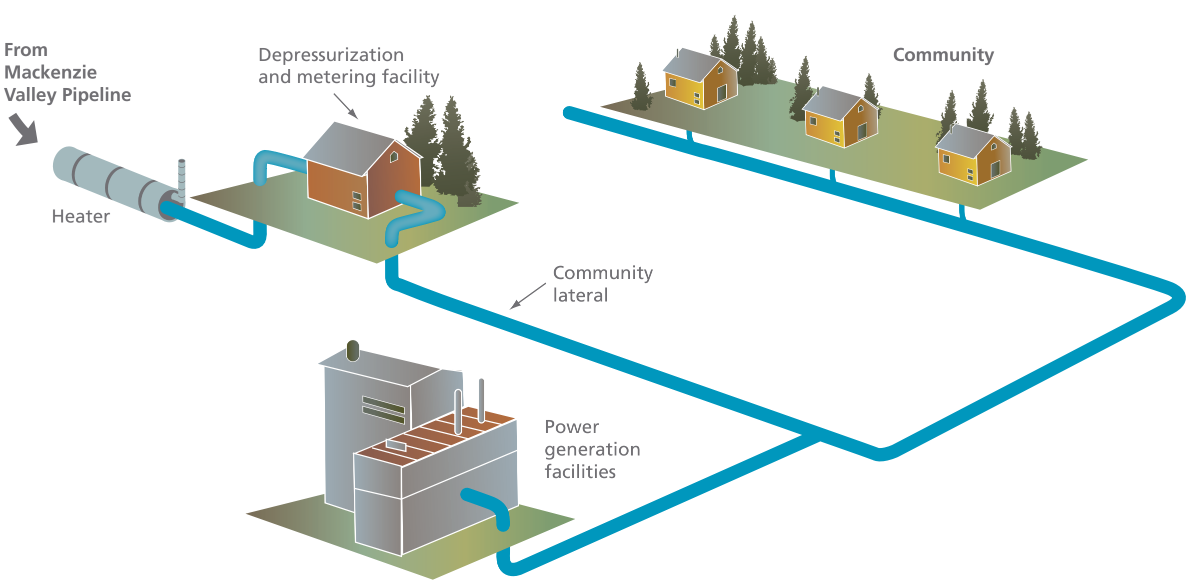
Capital costs for metering and related facilities

Communities requesting access to natural gas flowing on the Mackenzie Valley Pipeline would require an agreement with a pipeline shipper to purchase the gas, an agreement with the Proponents for an interconnection, and regulatory approvals for facilities and gas distribution. A number of facilities would need to be installed to access gas from the Mackenzie Valley Pipeline including a depressurization and metering facility at each access point. Depressurization would be necessary because the pressure of the Mackenzie Valley Pipeline would be much higher than the pressure of a distribution system going into the community. The natural gas would also need to be heated so that liquid hydrocarbons do not form when the gas goes from a higher pressure to a lower pressure. The facilities would also include valves, vessels and safety control equipment.

After leaving the depressurization and metering facility, the gas would flow on a community gas pipeline, or lateral, to a local distribution system serving homes, businesses, institutions and, potentially, power generators. The length of the lateral would depend on the distance between the community and the Mackenzie Valley Pipeline. See Figure 8-2 for an example of a community gas pipeline connection.

Figure 8-2

Community gas pipeline



The Proponents plan to include the cost of valve access points in the Mackenzie Valley Pipeline's rate base. However, they propose that the community or developer would be responsible for all costs downstream of these valves. These costs could include metering and associated interconnection facilities as well as any transportation, distribution, processing or other facilities needed to bring gas from the pipeline to the users. The Proponents intend to construct and own the meter station and all associated interconnection facilities and would charge communities for these facilities at cost. These facilities would not be part of the rate base for the Mackenzie Valley Pipeline and therefore would not be included in the Mackenzie Valley Pipeline's tolls. The details of how these costs would be passed on to the communities have not yet been determined but would be subject to regulatory approval.

This arrangement was agreed to in the Mackenzie Gas Project Socio-Economic Agreement between the Government of the Northwest Territories and the Proponents. However, the Socio-Economic Agreement recognized that these commitments are subject to the tariffs, tolls, terms and conditions of service approved by us.

The Proponents estimated that the capital cost of the metering and related facilities for eight communities along the line (Inuvik, Fort Good Hope, Norman Wells, Tulita, Déline, Wrigley, Fort Simpson and Jean Marie River) would total $27 million if all communities received service (see Table 8-3). The Proponents also estimated operating costs of $3.0 million per year, two thirds of which would be spent on weekly visits by operations staff to each of these communities.

Table 8-3

Estimated capital costs for metering and related facilities by community

Community	Capital cost *($millions)*
Inuvik	6.0
Fort Good Hope	2.8
Norman Wells	4.2
Tulita	2.8
Déline	2.8
Wrigley	2.1
Fort Simpson	4.2
Jean Marie River	2.1
Total	**27.0**

The Proponents' proposed treatment of the metering and related facilities costs for downstream communities differs from the way these costs are handled on most National Energy Board regulated pipelines. Typically, metering and related costs associated with sales to local communities have been rolled into the rate base and included in the pipeline's tolls rather than in the cost of distribution. The exception has been some laterals on the Maritimes and Northeast Pipeline system. Where Maritimes and Northeast Pipeline built laterals that failed to meet an economic viability test, the costs of those facilities, including both the pipe and the metering facilities, were paid for by the local distribution company.

The Proponents stated that the requirement for the downstream community to pay for metering and related facilities was driven by cost considerations.

Laterals to communities

The Proponents provided a screening level evaluation of the cost to construct a lateral from the Mackenzie Valley Pipeline to eight different communities. The Proponents based their cost estimate on the expected gas demand, distance and any site specific considerations such as horizontal directional drilling costs for river crossings as required for Fort Simpson and Déline. The estimates do not include the cost of the community gas distribution system or the cost of converting the power generation system to use natural gas. The capital costs, distance, estimated gas demand, and average annual increase in the Mackenzie Valley Pipeline toll are shown in Table 8-4.

Community access to gas supply

The Pehdzeh Ki First Nation submitted that a condition of any approval must be a requirement to supply natural gas for local use in the community of Wrigley. The Ayoni Keh Land Corporation argued that the Proponents should be required to guarantee the availability of a minimum gas supply of 10,000 MMBtu/day for domestic use in communities of the Northwest Territories at no commodity cost to these communities.

The Proponents replied that it isn't contrary to the public interest for the Mackenzie Gas Project gas producers to receive a market based price for the gas they produce.

Table 8-4

Estimated cost of service to northern communities

Community	Distance to Community *(km)*	Estimated Gas Demand *(m^3/d)*	*(MMcf/d)*	Estimated Capital Cost *($millions)*	Incremental Cost of Service 20 year Average *($millions/year)*
Inuvik	28	130,000	4.6	41.8	4.7
Fort Good Hope	5	24,000	.8	4.8	.5
Norman Wells	1	36,000	1.3	1.0	.1
Tulita	7	14,000	.5	6.7	.8
Déline	110	20,000	.7	97.7	11.1
Wrigley	5	6,000	.2	3.2	.4
Fort Simpson	23	43,000	1.5	36.2	4.1
Jean Marie River	25	3,000	.1	12.9	1.5
Total	**204**	**276,000**	**9.7**	**204.3**	**23.1**

Views of the Board

Northerners should have a reasonable opportunity to benefit from this project by obtaining access to clean-burning natural gas for use in their communities when it makes economic sense to do so. The Proponents' commitment to a 50 percent rebate of the 20-year toll for shippers selling to communities is valuable. However, we feel that the public interest requires that more be done to give residents of the Northwest Territories a chance to access this gas.

We have decided that it is in the public interest to require the Proponents to construct, own and roll into rate base the cost of laterals to communities that meet an economic test. If a proposed lateral does not meet the economic test, the Proponents could require a contribution ("aid to construct") to cover the shortfall. To put this into effect, the Proponents are directed to develop and file the details of the economic test by 31 December 2011, following consultation with potential shippers and the Government of the Northwest Territories.

With respect to metering and pressure reducing facilities, in most cases in Canada these facilities are rolled into the pipeline's mainline cost of service. We see no reason why a similar toll treatment should not apply to the Mackenzie Valley Pipeline. Accordingly, the Proponents are directed to incorporate this toll methodology in their toll and tariff principles.

With respect to gas supply to communities, we expect natural gas markets to continue to function effectively. As long as communities are paying market prices which provide shippers with a netback comparable to what they would receive if the gas was sold in Alberta, there should not be difficulty in obtaining gas supply. Therefore, there is no need to guarantee a minimum gas supply to communities.

We are interested in monitoring the ability of communities to access Mackenzie Valley gas supplies. To this end, Condition 76 for the Mackenzie Valley Pipeline requires the Proponents to file a report identifying details of any community's expression of interest in connecting to a delivery lateral or in having a delivery lateral constructed to connect to a local gas distribution system. Condition 76 has been modified since it was floated 9 March 2010 to accommodate the circumstance where the Mackenzie Valley Pipeline is asked to build a lateral to a community.

8.2.10 Codes of conduct

The purpose of a Code of Conduct is to guide company officials by setting out the standards and conditions for the interaction between a company, staff, owners, affiliates, and potential and actual shippers. The Proponents established a Code of Conduct for all predevelopment activities of the Mackenzie Valley Pipeline. The Code covers topics such as confidentiality of information, separation of activities of Mackenzie Valley Pipeline staff and Mackenzie Valley Pipeline owners, staff, appropriate cost allocation, acquisition of services at fair market value and arrangements to ensure there is no preferential treatment for owners.

The Code of Conduct was to apply to all activities on the Mackenzie Valley Pipeline from 1 July 2002, until either 1 January 2011, or the date that a decision to construct the Mackenzie Valley Pipeline has been made, whichever is earlier. At that point the Proponents would upgrade the Code of Conduct to include the construction and operating phases of the Mackenzie Valley Pipeline. The Proponents committed to develop such a Code, in consultation with shippers and prospective shippers, before the next project phase proceeds.

The Proponents believed there was no reason to develop a new Code covering the construction and operation phases prior to our decision, nor would it be an efficient use of resources to do so. Codes of Conduct are highly evolutionary documents and highly specific to any particular pipeline, organization or project. The Proponents proposed to defer the detailed Code of Conduct finalization process for future project phases until it could be accomplished in a timely and efficient manner.

While the Proponents filed the Code of Conduct for information only, they did not have a problem with the National Energy Board adjudicating the adequacy of the Operating Code of Conduct for the Mackenzie Valley Pipeline that is ultimately developed.

A Code of Conduct was not filed for the Mackenzie Gathering System. However, according to the Proponents they have been following the principles of the Mackenzie Valley Pipeline Code of Conduct for all matters relating to the Mackenzie Gathering System.

Two interveners, Mackenzie Explorer Group and MGM Energy Corp., expressed concerns with the Proponents' Code of Conduct. Mackenzie Explorer Group wanted to ensure that arm's length shippers would be treated fairly and appropriately relative to the facility owners and their affiliated shippers. Issues concerning appropriate standards of conduct for utility owners in their dealings with affiliates have been extensively canvassed in other jurisdictions. Regulators have prescribed standards and enforcement mechanisms that are intended to ensure affiliates gain no unfair advantage as a result of their relationship with utility owners. Mackenzie Explorer Group expressed concern that some of the provisions of the Code of Conduct are too permissive.

Mackenzie Explorer Group is also concerned that the proposed Firm Service Transportation Agreements require prospective shippers to disclose extensive and detailed information about their resources and forecasts of their deliverability to the Proponents. The appropriateness of this disclosure requirement would presumably be addressed in the context of the tariff filings the Proponents should be required to make with the National Energy Board. However, if it were to be approved by the National Energy Board, then significant issues would arise relating to the possibility of improper disclosure or use of that information, including to, or by, affiliates of the Proponents. They submitted that we must take all necessary steps to ensure that any such information a shipper may be required to provide will not be improperly used or disclosed.

Regulated utilities are often required to implement a Code of Conduct. The TransCanada PipeLines Limited Mainline Code of Conduct was filed in response to the RH-2-2004 decision and approved by the National Energy Board on 7 July 2005. Mackenzie Explorer Group contends that a Code of Conduct should apply to all portions of the Mackenzie Valley Pipeline and Mackenzie Gathering System and throughout all phases, i.e., pre-construction, construction and operation. It should be included as part of the filed tariffs and be subject to approval by the National Energy Board.

MGM Energy Corp. was concerned that the Proponents did not believe the National Energy Board is required to approve the Operating Code of Conduct; that they did not plan to submit the Operating Code of Conduct until after our decision; and that the operating owner would continue to transfer staff between the pipeline and related facilities and the owners' producing and operating companies.

MGM Energy Corp. believed the Proponents' position was inappropriate and did not meet the minimum operating standards for potential third-party customers for a regulated pipeline in Canada. The Operating Code of Conduct should have been filed with the Application or submitted prior to the start of the hearing. Regulators have required pipeline companies under their jurisdiction to file Codes of Conduct. MGM Energy Corp. reviewed the Codes of Conduct developed for the Maritimes & Northeast Pipeline and TransCanada's Alberta system. It believed these Codes of Conduct, developed in conjunction with industry participants, provided the Proponents with a good framework for the development and implementation of its own Code of Conduct. MGM Energy Corp. cited the National Energy Board's decision in RH-3-2004 where the National Energy Board reiterated the principle that shippers are to know in advance of negotiations the terms and conditions of access to a pipeline. (See Views of the Board in 8.2.6 for elaboration.)

Views of the Board

Hesitancy about the terms and conditions of access on the Mackenzie Valley Pipeline and the Mackenzie Gathering System has impaired the ability for non-owner shippers to negotiate contracts for service. This is to the detriment of potential shippers with stranded gas in the Mackenzie Delta and the public interest to which a successful project could contribute.

We note that several existing Codes of Conduct could serve as examples for the Proponents in drafting a thorough and appropriate Code of Conduct for an open-access pipeline system.

The Proponents are directed to file, for approval, a Code of Conduct for the Mackenzie Valley Pipeline and the Mackenzie Gathering System for all phases of development including pre-construction, construction and operation. The Code(s) of Conduct are to be filed as soon as possible but in any event not later than 31 December 2011. At a minimum, the Code(s) of Conduct should address in detail:

- prevention of undue preferential treatment;
- governance of the interactions between shippers and transporters;
- independence of transmission operations from affiliate operations;
- governance of separation of business;
- protection of confidential and commercially-sensitive information;
- mechanisms and methodologies related to the design of an acceptable transfer pricing mechanism;
- a Code of Conduct compliance plan with independent audits; and
- penalties for breaches of the Code of Conduct and recourse to a third-party arbitrator.

8.2.11 Tolls and tariff task force

In written argument Suncor Energy Inc. recommended that, as a condition of approval, the Proponents be required to file with the National Energy Board formal procedures regarding the conduct of business at a Mackenzie Valley Pipeline shipper committee in a form similar to the formal procedures filed with the National Energy Board regarding NOVA Gas Transmission Ltd.'s Tolls, Tariff, Facilities & Procedures Committee. Suncor Energy Inc. asserted that such procedures would be a significant aid in conducting the work required to compile the tariff, as well as addressing many other issues which will likely arise over time.

The Proponents responded that this condition is unnecessary and there is no reason to formalize the procedures for consultation with potential shippers at this stage. They noted that development of a final tariff is not a near term critical path activity.

Views of the Board

While we have directed the Proponents to file a tariff no later than 31 December 2011, we do not see the need to direct the Proponents to file formal procedures for a toll and tariff task force at this time. However, the Proponents may wish to do so in the future.

8.3 Mackenzie Gathering System

8.3.1 Overview

Mackenzie Explorer Group contends that, although the Proponents describe the liquids line, the Inuvik Area Facility and the facilities upstream of the Inuvik Area Facility as a "gathering system", it is difficult to conceive of a large diameter pipeline with a capacity near 31.1 Mm^3/d (1.1 Bcf/d) as a "gathering pipeline" in any conventional sense. The same could be said for the 476 kilometre natural gas liquids pipeline and the Inuvik Area Facility. The Government of the Northwest Territories notes that these Mackenzie Gathering System facilities are more correctly described as "supply laterals". The discussion of whether or not these facilities are appropriately characterized as a gathering system speaks to the issue of whether the methods used elsewhere for determining fees on a gathering system are suitable in this context.

During our hearing, the issues discussed around toll, tariff and access provisions on the Mackenzie Gathering System included:

- the need for economic regulation and dispute resolution;
- tolls on the system (excluding the natural gas liquids pipeline);
- tolls on the natural gas liquids pipeline; and
- the Code of Conduct.

8.3.2 The need for economic regulation on the Mackenzie Gathering System

The Proponents submitted their application for the Mackenzie Gathering System under the *Canada Oil and Gas Operations Act*. This legislation did not include any provision for the regulation of tolls, tariffs and access to the systems at the time the project was applied for and through the course of the hearings in 2006. However, we felt that this was an important matter and added "the appropriate tolls, access and tariff provisions for the Mackenzie Gathering System and the methods for resolving disputes on these matters" as Issue 13 on the List of Issues in the proceeding. In response to Mackenzie Explorer Group's motion which sought to have the Mackenzie Gathering System regulated under the *National Energy Board Act*, we ruled that the facilities were appropriately applied for under the *Canada Oil and Gas Operations Act*. However, we noted in our ruling that we remained concerned about Issue 13.

Mackenzie Explorer Group, the Government of the Northwest Territories and MGM Energy Corp. contended that regulatory oversight was needed on significant portions of the Mackenzie Gathering System. Their reasons included the following:

- the Proponents could exercise significant market power for each component of the Mackenzie Gathering System and therefore in the provision of transmission services for northern gas supplies;
- the market power would be manifested in both higher fees/tolls for use of the various components of the Mackenzie Gas Project and an inefficiently small set of facilities;
- access to the natural gas pipeline would be essentially meaningless without similar access to the liquids pipeline;
- the public interest is served by regulation, or the threat of regulation, to discourage the potential abuse of a dominant position;
- the tolling and tariff principles proposed by the Proponents are not adequately transparent nor predictable;
- the anchor field producers would enjoy considerable economies of scale and together may acquire a dominant position in the regional market for gathering and processing services to the disadvantage of developers which have smaller volumes needing those services;
- by focusing expansion, to the extent technically possible, on the applied-for gathering and processing facilities, the unnecessary duplication of facilities could be avoided, thereby minimizing the project's environmental "footprint";
- the efficient development of the basin demands that potential producers have confidence the tolls and tariffs applicable to all of the Mackenzie Valley Pipeline, the natural gas liquids line, the Inuvik Area Facility and the gathering pipelines (supply laterals) will be developed in a transparent manner consistent with sound principles of pipeline

rate design including that tolls be just and reasonable, non-discriminatory, fair, and charged equally to all persons at the same rate under substantially similar circumstances;
- there needs to be open access to pipeline services; and
- commercial processes should be transparent.

The Proponents agreed that these facilities have characteristics of a monopoly. However, they also noted the opportunity for others to acquire ownership in the Mackenzie Gathering System including the natural gas liquids pipeline, the opportunity to subscribe for transportation and processing services, and their proposal for dispute resolution would ensure that they could not exercise market power.

To address the concerns about the absence of financial regulation for *Canada Oil and Gas Operations Act* facilities including the lack of provision for dispute resolution, and to be responsive to Issue 13, the Proponents put in place the Access Process in May of 2005. The Access Process would be used to resolve disputes involving non-owner access to the facilities, terms of facilities ownership, fees and other terms of service. This Access Process was intended to provide the Proponents with sufficient certainty about how fees would be set in the future.

The Access Process contained a provision stating it would be in effect until amendments were effective to the *Canada Oil and Gas Operations Act* legislation or other legislative was enacted or amended which addresses access and fees related to *Canada Oil and Gas Operations Act* facilities in the Northwest Territories.

When the amendments to the *Canada Oil and Gas Operations Act* were passed by Parliament on 14 December 2007 giving the National Energy Board power to regulate tolls, tariffs and access on *Canada Oil and Gas Operations Act* regulated facilities, issues related to the need for economic regulation of these facilities were fully addressed. The Access Process terminated as it was no longer required and it was subsequently removed from the record of this proceeding.

8.3.3 Proposed method for setting Mackenzie Gathering System fees (excluding the natural gas liquids pipeline)

The Proponents believed the traditional cost of service method is not appropriate for producer-built gathering and processing facilities like the Mackenzie Gathering System. Rather, the Proponents have structured the project so that the fees for owners are set in a different manner than the fees for third-party shippers. The fees for shippers are a consequence of individual negotiations that occur at different times. Therefore, fees can vary significantly between owners and shippers as well as between various shippers.

At the time of the hearing the Proponents proposed to use the principles of the 2005 Jumping Pound Formula (Jumping Pound-05) as the basis for tolling negotiations on the Mackenzie Gathering System, other than the liquids line. Jumping Pound-05 provisions include, among other things, a capital structure based on 100 percent equity, a 20 percent before-tax return on equity, no depreciation and an investment cost base for tolls negotiated between the historical cost and replacement cost.

However in October 2007, MGM Energy Corp. signed contracts for 2.83 Mm^3/d (100 MMcf/d) on each of the Niglintgak and Taglu laterals. At that time, the fee principles for the Mackenzie Gathering System were revised to reflect the new principles for third-party use of the system. The after-tax return on equity was set at 150 basis points above the Mackenzie Valley Pipeline return on equity. While Jumping Pound-05 provided for the investment cost base used in the calculation of tolls to be negotiated between historical and replacement cost, the Proponents' fee principles were revised to set the investment cost base at actual historical cost. The capital structure was maintained at 100 percent equity.

The revised fee principles form a basis for negotiation between the Proponents and potential shippers. The Proponents noted that if negotiations fail and the National Energy Board is asked to adjudicate a process, the National Energy Board can decide at that time what principles will be used to determine the fee.

In its evidence and testimony, MGM Energy Corp. did not accept the use of JP-05. It stated that the Mackenzie Gathering System tolls should be cost-based and the system should be regulated as a Group 2 company which means that it would be regulated on a complaint basis. Mackenzie Explorer Group suggested that the Proponents have not shown that the Mackenzie Gathering System is distinguishable from the

Mackenzie Valley Pipeline in terms of cost of capital. It recommends the same cost of service parameters for the Mackenzie Gathering System as are recommended for the Mackenzie Valley Pipeline including a capital structure of 70 percent debt and 30 percent equity, the same return on equity and a four percent depreciation rate. The impact of Mackenzie Explorer Group's assumptions would be to reduce Mackenzie Gathering System tolls by about 45 percent. Mackenzie Explorer Group asserts that the use of Jumping Pound-05 results in much higher tolls than under conventional cost of service regulation. (It should be noted that the evidence of both of these parties was provided prior to the fee principles being revised in October 2007 as a result of negotiations between the Proponents and MGM Energy Corp.)

On the record

The Jumping Pound Formula

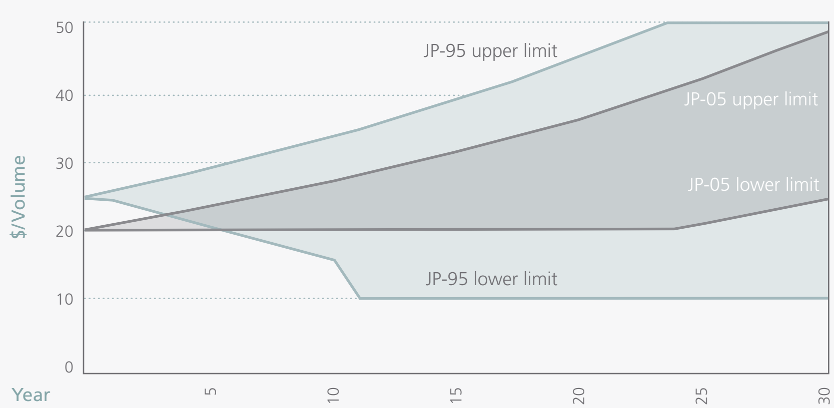
Jumping Pound-05 and its predecessors, Jumping Pound-95 and Jumping Pound-90 were originally developed as a framework for negotiating gathering and processing fees in Alberta. Jumping Pound-05 contains provisions for determining the level of fees and emphasizes the use of negotiation and alternative dispute resolution among facility owners and potential users of the facilities. In Alberta, if parties are unable to reach agreement, they can take their dispute to the regulator, Alberta's Energy Resources Conservation Board, for adjudication.

Initially, the Proponents had proposed to use the Jumping Pound-95 formula but changed to Jumping Pound-05 when it was adopted as the industry standard. Both Jumping Pound-05 and Jumping Pound-95 provide for a range of fees with the intent that parties would settle on a fee within those ranges. The difference between the ranges of Jumping Pound-95 and Jumping Pound-05 are shown in the figure below which is drawn from the Jumping Pound-05 document. While Jumping Pound-95 has a lower and upper limit, the Proponents had formulated their fee structure based on the lower limit.

There are two major differences between Jumping Pound-95 and Jumping Pound-05 in terms of the effect on tolls. The first is the elimination of the depreciation component of the capital charge in Jumping Pound-05 so that tolls no longer decrease over time as a result of depreciation. The second major difference is the return on investment, which is fixed at 20 percent before tax in Jumping Pound-05 versus a formula-based return in Jumping Pound-95. However, the Proponents have agreed to an after-tax return on equity which is set at 150 basis points above the return on the Mackenzie Valley Pipeline, rather than the before-tax return of 20 percent provided for in JP-05.

Figure 8-3

JP-05 / JP-95 fee comparison (20 year life)



Mackenzie Explorer Group contended that under the Proponents' proposal, the owners of the Mackenzie Gathering System will be in a fundamentally different relationship with the Mackenzie Valley Pipeline than will either the sponsors or their affiliates. In order to avoid unjust discrimination, and to ensure that tolls for using the Mackenzie Gathering System appropriately reflect the cost of providing service, it is essential that all shippers, including the sponsors and their affiliates, receive service on terms that are verifiably the same. The only way to ensure this result is to require all shippers to enter the same form of service agreement, be subject to the same tariff, and pay tolls that are verifiably the same for all shippers receiving the same service.

The Government of the Northwest Territories stated that Jumping Pound-05 is "very rich" compared to the return parameters for the Mackenzie Valley Pipeline, particularly when there does not appear to be any fundamental difference in supply risk, market risk, natural risk, completion risk, regulatory risk and so on.

Views of the Board

In response to concerns about the lack of toll and tariff regulation and our concern that this pipeline be accessible to third-party shippers, we added Issue 13 to the List of Issues. Issue 13 is:

> The appropriate tolls, access and tariff provisions for the Mackenzie Gathering System and the methods for resolving disputes on these matters.

On this topic, things evolved over the course of the proceeding and events overtook the discussion in a number of ways. The issue of the need for regulation of the Mackenzie Gathering System was addressed when Parliament amended the *Canadian Oil and Gas Operations Act* in December 2007 allowing us to regulate tolls, tariffs and access on these facilities. In addition, the Proponent's proposed basis for negotiations of the fees moved from Jumping Pound-95 to Jumping Pound-05 to the fee principles established in October 2007 as a result of negotiations with MGM Energy Corp.

We acknowledge that the Proponents did not ask for approval of the toll principles for the Mackenzie Gathering System as they did for the Mackenzie Valley Pipeline. We also note that the Proponents expected us to address any concerns about the proposed methodology in our decision. Mackenzie Explorer Group sought a more traditional cost of service regulation reflecting risks for the Mackenzie Gathering System and the Mackenzie Valley Pipeline which were similar. The Government of the Northwest Territories did not see any fundamental difference in risks between the two systems. However, we are of the view that the risks, and therefore the cost of service parameters for the two systems are not necessarily the same. Potential differences include the character of the physical facilities, contract terms and dependence of some components of the Mackenzie Gathering System on specific fields.

Given the unique features of the Mackenzie Gathering System, we accept the Proponents' proposal to negotiate fees for use of the Mackenzie Gathering System which will be regulated on a complaint basis. If parties are not successful in their negotiations, then any party has recourse to the National Energy Board. The National Energy Board would at that time decide what principles would be used to determine fees.

We note Mackenzie Explorer Group's concern about owners and third parties being under different forms of service agreements, not subject to the same tariff and not necessarily paying the same fee. However, parties have the option at any time of bringing a complaint to the National Energy Board. We also note in this case that contracting shippers have the same priority of access to capacity on the Mackenzie Gathering System as the owner-shippers. In addition, all parties have the option of becoming either owners or shippers.

8.3.4 Proposed method for tolls on the natural gas liquids pipeline

Similar to the contractual arrangements for the rest of the Mackenzie Gathering System, a potential shipper on the natural gas liquids pipeline would sign a Capacity Request Agreement and could then choose either an ownership option or third-party transportation option for use of the Mackenzie Gathering System. If they chose the ownership option, they would be subject to the Development and Operating Agreement. The transportation option would be subject to the Natural Gas Liquids Pipeline Firm Transportation Agreement.

Rather than using the Jumping Pound framework, the Proponents proposed to use traditional cost of service regulation on the natural gas liquids pipeline and assumed a 65/35 debt equity ratio, a 12 percent return on equity and five percent depreciation. However, these parameters would form the basis of negotiation, meaning that the fees on the natural gas liquids pipeline could also be negotiable.

Although the Proponents are proposing to use a conventional cost of service method on the natural gas liquids pipeline, subject to negotiation, Mackenzie Explorer Group does not accept the Proponents' proposed parameters. Mackenzie Explorer Group asserts that the debt equity ratio and the return on equity should be the same as is applicable to the Mackenzie Valley Pipeline and the depreciation rate should be four percent. This formula would reduce the toll on the natural gas liquids pipeline by 22 percent.

MGM Energy Corp. contends that there needs to be adequate disclosure of information and data on tolls and tariffs on the natural gas liquids line.

Views of the Board

As with the other components of the Mackenzie Gathering System, we accept the Proponents' proposal to negotiate fees for the natural gas liquids pipeline. If parties are not successful in their negotiations, then any party has recourse to the National Energy Board. The National Energy Board would at that time decide what principles would be used to determine fees.

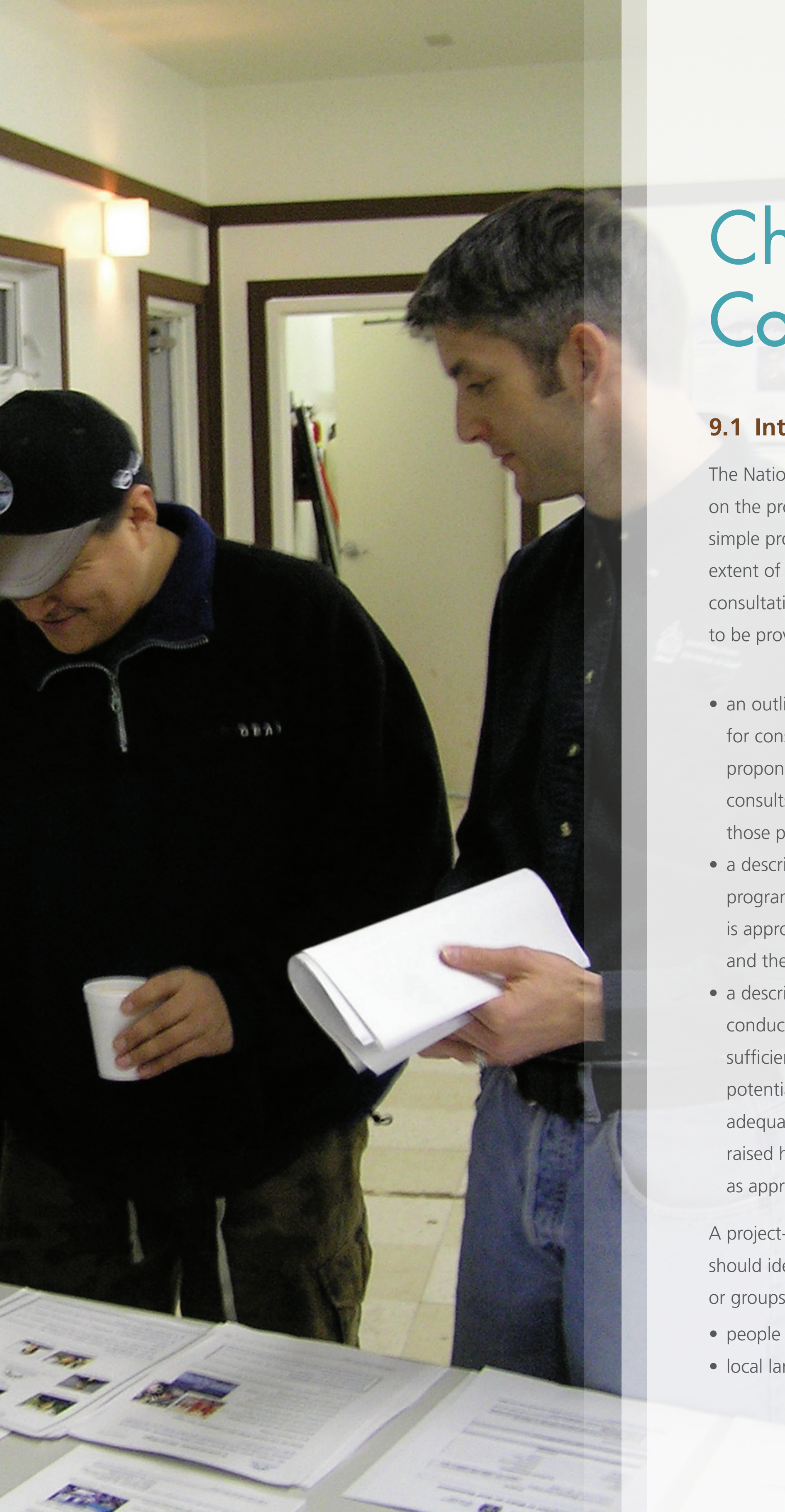
In accordance with the National Energy Board's publication entitled *Financial Regulation of Pipeline Companies under the Board's Jurisdiction,* it is the responsibility of a company regulated on a complaint basis to provide its shippers and interested parties with sufficient information to enable them to determine whether a complaint to the National Energy Board is warranted.

8.3.5 Code of Conduct

As discussed previously, the Proponents established a Code of Conduct for all predevelopment activities of the Mackenzie Valley pipeline but not for the construction and operating phases, nor for any phase on the Mackenzie Gathering System. The Proponents stated they had been following the principles of the Mackenzie Valley Pipeline Code of Conduct for all matters relating to the Mackenzie Gathering System. The concerns of intervenors discussed in Section 8.2.10 applied to the Mackenzie Gathering System as well as the Mackenzie Valley Pipeline.

Views of the Board

As explained in Section 8.2.10, the Proponents are directed to file, for approval, a Code of Conduct for the Mackenzie Valley Pipeline and the Mackenzie Gathering System.



Chapter 9 Consultation

9.1 Introduction

The National Energy Board expects proponents to consider consultation for all projects. Depending on the project scope, this could mean carrying out a very extensive consultation program or a very simple program such as notifying a single landowner. Proponents are responsible for justifying the extent of consultation carried out for each project. For complex projects that require an extensive consultation program, such as the Mackenzie Gas Project, the following information is expected to be provided within an application to the National Energy Board:

- an outline of the principles and goals for consultation by which the project proponent will ensure that it adequately consults with, and respects the rights of, those potentially affected;
- a description of the project's consultation program and an indication why its design is appropriate for the nature of the project and the type of application; and
- a description of the results of the consultation conducted to date for the project, with sufficient detail to demonstrate that those potentially affected by the project have been adequately consulted and that any concerns raised have been considered and addressed as appropriate.

A project-specific consultation program should identify all potentially affected persons or groups to be consulted, including:

- people living near the proposed pipeline;
- local land users;
- Aboriginal people;
- local, territorial and federal government authorities; and
- others who might have an interest in the project such as community associations and environmental groups.

Proponents are required in their applications to describe the results of the consultation carried out, including how the consultation program was undertaken, a summary of the comments and concerns raised, how comments and concerns have been addressed by the proponents, and how outstanding concerns will be addressed. Proponents should also be able to demonstrate how public input influenced the design, construction, or operation of the project. When an application is filed with the National Energy Board, it is reviewed to assess whether or not the company has taken into consideration the comments and concerns raised about the project.

The National Energy Board provides members of the public with information on how they may participate in the National Energy Board process through various publications and community information sessions to ensure that all interested individuals and groups have an opportunity to make their views on a project known to the National Energy Board.

This process is designed to provide the National Energy Board with a full understanding of the concerns that governments, Aboriginal people and the public in general may have with the project so that the National Energy Board may appropriately consider and address those concerns in its decision making.

In addition to consultations undertaken by the Proponents and the opportunities for participation by parties in the Joint Review Panel and National Energy Board hearing processes, the federal government established the Crown Consultation Unit to coordinate its consultation with Aboriginal people about the project. The Crown Consultation Unit included representatives from Environment Canada, Indian and Northern Affairs Canada, Natural Resources Canada, Department of Fisheries and Oceans, and Transport Canada. In addition, the Government of the Northwest Territories consulted extensively with the territories' residents and Aboriginal people about the project. Consultation with Aboriginal people by the Crown for the Mackenzie Gas Project will continue as the project progresses.

9.2 The Proponents' consultation program

9.2.1 Overview

The Proponents define public consultation as the process of involving all affected parties in the design, planning and operation of a project. This process requires the Proponents to give the parties to be consulted notice of the matter in sufficient form and detail and with a reasonable amount of time to allow them to prepare their views on the matter.

The Proponents stated their goal for the Mackenzie Gas Project is to conduct consultation that is meaningful and effective. Consultation activities are to be well documented, inclusive and dynamic, and provide transparent engagement with communities affected by the project. The Proponents also noted that consultation would continue throughout the lifespan of the project.

The Proponents indicated that their public consultation efforts for the project have been primarily focused on Aboriginals and other Northerners. Most of the interactions with the public, governments, regulatory authorities, local businesses, non-government organizations and people directly affected by the project development have involved Aboriginal people of Inuit, Dene and Métis heritage.

The public consultation program for the Mackenzie Gas Project was conducted by representatives of the:

- Mackenzie Gathering System and Mackenzie Valley Pipeline operator;
- Environmental Impact Statement consultants;
- development field operators; and
- engineering consultants.

9.2.2 Consultation for the Mackenzie Gathering System and Mackenzie Valley Pipeline

The Proponents undertook consultations related to the Mackenzie Gathering System and Mackenzie Valley Pipeline. Some initiatives were undertaken jointly with the development field operators. In addition, each development field operator conducted separate consultations for their respective field developments. (For more information see Section 9.2.3.)

The Proponents stated their consultation and community affairs group provides a multi-layered support system which is structured to provide consistent activities and information exchange in all regions and communities throughout the project area. This includes resident community representatives in the pipeline corridor, regional representatives who are beneficiaries of and live within the region, and Calgary-based representatives who routinely travel within the region.

The Proponents stated that public consultation was an integral part of the project. They have been consulting with Aboriginal and non-Aboriginal people in communities that might be affected by the project since January 2002. They have also consulted with governments, regulatory authorities, potential shippers and suppliers, labour groups, non-government organizations and industry representatives, and members of the public

On the record

Consultation methods

The Proponents used various methods to address the broad range of interests, levels of understanding and needs of potentially affected parties, including establishing three regional offices with open door policies. Consultation methods and activities were also selected to address the needs of stakeholders in more remote locations. To provide opportunities for community input, regional liaison staff, community representatives, Proponents' and contractors' consultation staff have:

- conducted one-on-one visits;
- contacted community leaders, individually and collectively;
- provided written materials such as letters, brochures, project website materials, posters and advertisements and third-party items such as the Cooperation Plan;
- conducted interviews with local media, including stations that broadcast local language programs;
- created audio-visual materials;
- held workshops, public meetings and open houses;
- made project presentations at many community events and conferences;
- sponsored project-focused events, such as an organized tour of a pipeline construction site, for community residents;
- visited schools, made presentations and attended career fairs; and
- met with various representative groups within the communities and regions.

The Proponents have conducted over 1500 meetings with northern residents and community organizations, the results of which have been recorded and documented. There have been more than 350,000 visits to the project website. The information and feedback gathered from affected communities and organizations during the consultation program identified a number of concerns, some expressed by more than one group. Other concerns were more localized and affected only one group or area. In many cases, the concerns raised were dealt with by the Proponents. In a few cases, additional study and consultation was required to develop satisfactory solutions.

throughout the Northwest Territories and Canada. Consultation was used to explain the purpose, needs and limitations of the project. At the same time, the Proponents were seeking to understand local concerns and to use this information in project planning. The primary goals of the ongoing consultation program were stated to be:

- to increase public awareness of the project by providing timely information and soliciting comments from affected members of the public about proposed development and activities that might affect their communities, including the potential environmental and socio-economic effects;
- to respond to public input and concerns, and take them into account during project planning, design and implementation;
- to encourage the participation of Aboriginal and other northern residents, as well as other Canadians, in the employment and business opportunities created by the project; and
- to identify, and reduce or mitigate, any negative effects the project might have on the biophysical or socio-economic environment.

Formal mechanisms were developed to share the information obtained during the consultation program with the different consultation groups working on the Mackenzie Gas Project. One mechanism is an issues database, which the Proponents use to capture meeting notes and any follow-up items that arise. Everyone working on the Mackenzie Gas Project can view this issues database. Another mechanism is a system that the Proponents use to track commitments, to ensure that the staff members involved in subsequent phases of the project have an accurate record of commitments that are made.

In addition the Proponents' engineering contractors worked with the Proponents' consultation staff to communicate information on the design, site and route selection, and initial site investigation in support of the project. Community consultation activities have been coordinated through local project offices in Inuvik, Norman Wells, Fort Simpson and Hay River. The project's public consultation program will continue throughout the regulatory process, and throughout the construction and operations phases of the project.

Environmental Impact Statement consultation program

The consultants that prepared the Environmental Impact Statement developed and implemented a complementary, but distinct, program of biophysical and socio-economic public participation. This program was conducted to obtain input for the Environmental Impact Statement prepared for the three development field plans — Niglintgak, Taglu, and Parsons Lake, the Mackenzie Gathering System and the Mackenzie Valley Pipeline.

A separate team was responsible for designing and completing the public participation program for the Proponents' Environmental Impact Statement. This team worked closely with the Proponents' consultation and community affairs group in developing and implementing stakeholder participation opportunities. Staff from the Proponents' consultation and community affairs group was directly involved in many of the meetings that were held specifically to discuss the Environmental Impact Statement. The meeting notes and any follow-up items from the meetings with the Environmental Impact Statement public participation team were recorded in the Proponents' issue database.

Two main rounds of activity occurred. The first round consisted of identifying and scoping issues, with communications centering on introducing the project and identifying community concerns. Consultation efforts during the second round focused on assessing mitigation and management measures to mitigate the effects of the project. During both rounds, meetings were held in potentially affected communities to seek input on identifying possible impacts. These meetings were followed by workshops in regional centres. All of these meetings and workshops helped the Proponents identify potential impacts associated with the Mackenzie Gas Project for which mitigation measures had to be considered. A number of changes were made to the project design as a result of this input.

The Proponents submitted that, while all suggested mitigation measures were considered, not all were adopted. The Proponents must also consider other factors including technical feasibility, safety and cost in determining which mitigation measures to adopt. In this way, the Proponents have stated that mitigation measures are considered within a sustainability framework.

9.2.3 Consultation for the development fields

Each of the development field operators conducted its own public consultation program. Each operator was responsible for consultation on its own particular field and staffed its project team to facilitate consultation objectives, methods, activities and materials. Where possible, activities were combined and coordinated to include the Mackenzie Gathering System. In order to share information from the consultation programs that might affect their venture partners, the Proponents had both:

- a formal process (i.e., meetings of development field partners every two weeks to discuss matters related to consultation and regulatory affairs to ensure a common understanding of the issues they are each facing); and
- an informal process (i.e., development field partners working with the Proponents' regional staff to ensure they are informed about each other's activities and any matters that have come up in their meetings).

Shell – Niglintgak

Shell stated that working with stakeholders is a key principle in its commitment to sustainable development, and that it developed a coordinated consultation plan for all of its activities in the Mackenzie Delta. For the Niglintgak field, Shell submitted that emphasis had been placed on consultation, and concerns raised in these discussions were considered while preparing the Niglintgak Development Plan Application and subsequent filings. Stakeholder input helped Shell focus on specific items to ensure full understanding of the potential impacts before making a decision. Shell met with Aboriginal and non-Aboriginal Northerners; municipal, territorial and federal representatives; communities; regulators and agencies; and other oil and gas companies. During consultation, specific concerns regarding Niglintgak were raised, including:

- the size and nature of the development's land footprint;
- the biophysical and socio-economic effects of the proposed gas conditioning facility concept;
- the drilling waste disposal method; and
- the use of drilling sumps.

Shell submitted that information arising from these discussions was used to develop and refine its plans. Design changes for the Niglintgak field that resulted from community consultations included:

- reducing the development footprint by locating drilling sites at pre-disturbed locations and using above ground flow lines;
- reducing the draught of the proposed barge-mounted gas conditioning facility, moving the barge set down location outside the Little Kumak Channel, and committing to schedule dredging activities to avoid impacts to the beluga whale harvest;
- eliminating the remote sump and committing to transport drilling waste to a waste management facility outside of the Northwest Territories; and
- scheduling most of Shell's activities during winter months when wildlife is less abundant in the area.

Shell committed to ongoing consultation with stakeholders and interested parties.

Imperial – Taglu

Imperial's consultation activities for the Taglu field development were, for the most part, integrated into the Proponents' consultation program. Imperial's participation in Mackenzie Gas Project consultation activities included:

- developing printed material and brochures;
- exchanging information at workshops;
- public meetings and open houses;
- seeking input from community representatives and regulators; and
- communicating with community leaders.

Imperial submitted that many of the concerns raised at Mackenzie Gas Project public meetings, particularly in the Beaufort Delta region, were common to the Mackenzie Gathering System, the Mackenzie Valley Pipeline, and the Taglu field. Specific concerns raised by stakeholders in the Beaufort Delta region included land disturbance and footprint in Kendall Island Bird Sanctuary, and the disposal of drilling waste. In response to these concerns, Imperial proposed a number of mitigation measures, including:

- use of a single well pad;
- staging materials and supplies offsite at an existing disturbed area at Tununuk Point; and
- using a disposal well for drilling waste.

Imperial stated that consultation activities for the Taglu field will continue throughout the construction, operation, abandonment, and reclamation phases.

ConocoPhillips – Parsons Lake

ConocoPhillips stated that responsible business involves listening and responding to the needs of its stakeholders. ConocoPhillips said it consulted throughout the evolution of the Development Plan for Parsons Lake and concerns raised by stakeholders were considered while preparing the Development Plan Application. ConocoPhillips met with Aboriginal and non-Aboriginal Northerners; municipal, territorial and federal representatives; communities; regulators and agencies; and other oil and gas companies. ConocoPhillips further submitted that information from these discussions has been used to develop and refine the plans for the Parsons Lake field development. Design changes to the Parsons Lake field that resulted from community consultations included:

- in response to concerns that above ground pipelines would negatively impact caribou migration patterns, changing the design of the lateral line from the north pad to be a buried line, and designing the flow lines from the south pad to be 2.2 metres above ground to allow for the passage of caribou and harvesters below;
- reducing the size of the north and south pads;
- strapping together two required flare stacks to minimize overall land required;
- utilizing two levels of lighting so that a lower intensity lighting level is normally used, and a higher intensity will only be used during maintenance activities; and
- optimizing distance between wellbores to prevent coalescence of well permafrost thaw bulbs.

ConocoPhillips committed to conducting consultation in a manner that is consistent with its Stakeholders Relations Policy, by providing stakeholders with project information, and listening to and considering their input, throughout the life of the development.

9.2.4 Consultation with government

Representatives from territorial and federal agencies were invited by the Proponents to participate in Mackenzie Gas Project workshops specific to the Environmental Impact Statement and open house activities related to the project. In addition, the Proponents held regular meetings with territorial and federal government departments and agencies to provide activity updates, discuss emerging issues, and develop plans to manage the issues and coordinate schedules for activities of interest to all parties.

The Proponents also advised in evidence that they kept the relevant government agencies apprised of any concerns raised that were beyond the ability of the Proponents to address.

The Proponents also noted that the scope of Crown involvement included:

- working with the Dehcho First Nations to establish a pipeline study corridor, as specified in the Interim Measures Land Withdrawal Agreement between the Dehcho First Nations and the Government of Canada;
- participating as observers in regional Mackenzie Gas Project Environmental Impact Statement workshops and in non-governmental organization workshops;

- corresponding with Aboriginal Leaders in the Inuvialuit Settlement Region, Gwich'in Settlement Area, Sahtu Settlement Area and Dehcho regions in the Northwest Territories and with the Dene Tha' in Northeastern Alberta; and
- announcing a Crown Consultation Unit to facilitate and report to the National Energy Board on Crown consultation with Aboriginal Groups.

9.3 Participation by parties in the Joint Review Panel hearing process

As discussed in Chapters 2 and 3, parties had the opportunity to raise socio-economic and environmental concerns in the Joint Review Panel hearings.

The overarching purpose of the Joint Review Panel, as described in the *Agreement for an Environmental Impact Review of the Mackenzie Gas Project* (Agreement), was to conduct an Environmental Impact Review of the Mackenzie Gas Project, having regard to:

> the protection of the environment from the significant adverse impacts of proposed developments, and to the protection of the existing and future social, cultural and economic well-being of residents and communities.

As set out in the Agreement, the Joint Review Panel was required to conduct its review in a manner that would promote and facilitate public participation, and ensure that the concerns of Aboriginal people and the general public were taken into account in that process. To fulfill this mandate, the Joint Review Panel held public hearings in the Northwest Territories and Alberta. Persons or groups were allowed to participate fully in the Joint Review Panel's review process as intervenors, and the Joint Review Panel granted intervenor status to 103 individuals, groups or organizations. Persons or groups who were not intervenors were given other opportunities to participate in the public hearings, and any individual, group or organization could file written comments at any time throughout the review.

The Joint Review Panel held hearing sessions between 14 February 2006 and 29 November 2007. The Joint Review Panel held a total of 115 days of hearings in 26 centres and northern communities. The Joint Review Panel heard directly from 558 presenters, either as individuals or as representatives of groups or organizations. Matters presented to the Joint Review Panel related primarily to the potential environmental, social and cultural impacts of the project, but also included aspects related to project design and construction, geohazards, accidents, malfunctions and emergency response. These matters were addressed in the Joint Review Panel Report filed with us for consideration in our decision.

9.4 Participation by parties in our hearing process

In order to ensure that its record is as complete as possible about the potential impacts of a project, and to ensure that these factors can be considered in its final decision, the National Energy Board relies on evidence provided in accordance with the requirements of its *Filing Manual*, and on its hearing process. The National Energy Board encourages those with an interest in a project to participate in the hearing process in order to make the National Energy Board aware of their views and concerns. To facilitate participation, we held community information sessions and pre-hearing conferences and had staff available in the hearing room to assist parties.

Our hearings for the Mackenzie Gas Project focused on safety, engineering and economic issues, but other matters were also heard including social, cultural and environmental issues and concerns. We heard directly from people potentially affected by the project in the Mackenzie Delta and along the Mackenzie River, in larger communities such as Yellowknife, and in High Level, Alberta. Our hearing process provided members of the public, governments, Aboriginal people and other interested parties with a number of opportunities to participate in hearing sessions, and to provide input into the review of the project. Opportunities that were available included filing a letter of comment, making an oral statement at a hearing session, providing written evidence, offering oral testimony by elders and members of Aboriginal groups, cross-examination of the Proponents and other parties, and presenting final argument.

A total of 129 individuals, groups and organizations applied to be intervenors in our hearings. We also received eight letters of comment and 21 requests to make oral statements. All of our hearings were broadcast live by audio webcasting, and were also available to participants via a toll-free telephone service. Hearings were interpreted live, as appropriate, into English, French, Inuvialuktun, Gwich'in, and the North Slavey, South Slavey and Dene Tha' languages.

We held public sessions of our hearings in 15 communities between 25 January and 14 December 2006. Subsequent sessions were also held in 2007 and 2010, including sessions on the Proponents' 2007 updated evidence and evidence relating to the activities of the Crown Consultation Unit. We also heard final argument directly from parties, with some parties providing written final argument. A range of views and concerns were expressed by individuals, organizations, governments and Aboriginal groups through our hearing.

Several parties raised a number of consultation-related issues and requests with us. Alternatives North and Indian and Northern Affairs Canada recommended that we define 'consultation' for the purposes of our conditions, and that we adopt the definition of consultation described in Section 3 of *the Mackenzie Valley Resource Management Act*. Environment Canada requested that for conditions requiring the Proponents to consult with Environment Canada, that evidence of Environment Canada's level of satisfaction regarding consultation should be provided. The Government of Yukon requested that Condition 27 be amended so that the plans for a formal issues resolution program would be prepared in consultation with the Government of Yukon.

9.5 Consideration of Aboriginal concerns

Given the importance of Aboriginal concerns and considerations, this section discusses more fully the concerns and issues raised by Aboriginal groups.

9.5.1 Accommodation by the Proponents

The List of Issues contained in the Hearing Order for our GH-1-2004 proceeding identified the adequacy of Aboriginal consultation as an issue to be considered by us. Consultation efforts by the Proponents for the Mackenzie Gas Project primarily involved Aboriginal people, as members of communities, governments, Aboriginal authorities, regulatory bodies, local businesses and as land claim beneficiaries.

The Proponents submitted detailed tables and periodic updates summarizing all of their project-related consultation efforts, including the concerns that were raised during these consultations in the Inuvialuit, Gwich'in, Sahtu and Dehcho regions and northern Alberta. Their record of consultation highlighted the measures that were taken, or will be taken, by the Proponents to address the concerns raised by Aboriginal groups as well as other affected parties. The consultation record also indicated how these concerns and the Proponents' responses have influenced the design of the Mackenzie Gas Project, and whether any concerns remain outstanding. Examples of the changes that have been made to the design of the Mackenzie Gas Project by the Proponents in response to concerns and community input are listed in Table 9-1.

Table 9-1

Changes to project design

Changes in the Inuvialuit Settlement Region
• modifying the construction plan and schedule near Storm Hills • eliminating Storm Hills facility requirements • reducing the number of borrow sites • reducing the number of water sources • relocating access roads
Changes in the Gwich'in Settlement Area
• moving the pipeline farther east of Travaillant Lake • eliminating infrastructure requirements near the Travaillant Lake–Thunder River Area • reducing the number of borrow sites • reducing the number of water sources • relocating access roads
Changes in the Sahtu Settlement Area
• withdrawing two borrow sites at Bear Rock • reducing the number and size of borrow sites • moving the Great Bear River compressor station
Changes in the Dehcho Region
• moving the Blackwater River compressor station and associated infrastructure • rerouting the pipeline near Wrigley and Willowlake River • moving the Willowlake River block valve site • eliminating the Trail River compressor station and associated all-weather road • relocating the watercourse crossing on the Mackenzie River upstream • relocating the McGill station camp and storage area • rerouting the pipeline near Satellite Lake • relocating the Trout River heater station • withdrawing a borrow site in Shihndaakaa Tselaa • rerouting the pipeline and relocating the camp at Trainor (K'eotsee) Lake • using an existing cutline as access to Trainor (K'eotsee) Lake

Some of the concerns raised by Aboriginal people were related specifically to the proposed general routing and the locations of proposed facilities. Details of these concerns, and the measures proposed by the Proponents to address them, are found in Chapter 5.

In addition to the Proponents' specific measures to address concerns raised by Aboriginal groups, the Proponents noted that they have concluded benefits and access agreements for the Inuvialuit Settlement Region and for the Gwich'in and Sahtu Settlement Areas. The Proponents noted that such agreements have not been concluded for the Dehcho region, and stated they are committed to concluding benefits and access agreements for the Dehcho.

9.5.2 Concerns raised in our hearing

A number of Aboriginal groups and organizations presented their views and concerns directly to us during our hearing.

Gwich'in Tribal Council

The Gwich'in Tribal Council stated that the Mackenzie Gas Project can contribute to a sustainable economy in the North, and provide a greater and fulfilling role for the Aboriginal peoples of the Dehcho, Sahtu and Mackenzie Delta regions. Gwich'in Tribal Council President Richard Nerysoo stated that:

> the Gwich'in Tribal Council supports the Mackenzie Gas Project as a means to enable the Gwich'in to become self-sufficient and full participating members in a global society.

The Gwich'in Tribal Council noted the Mackenzie Gas Project will provide a range of benefits to the Gwich'in, Northerners and other Canadians, including economic benefits, job creation, revenues and taxes to all levels of government, and will help reinforce Canada's sovereignty in the North.

The Gwich'in Tribal Council encouraged us to grant a Certificate for the Mackenzie Gas Project, but requested that we review the Gwich'in Tribal Council's comments on the Joint Review Panel recommendations, and the concerns raised with the Joint Review Panel relating to environmental protection, cultural preservation, and economic development. Finally, the Gwich'in Tribal Council recommended that the Proponents be required to commence project construction within three years of receiving a Certificate, and that the Mackenzie Gas Project be available on appropriate commercial terms to all potential shippers.

Inuvialuit Regional Corporation

Ms. Nellie Cournoyea, Chair and Chief Executive Officer of the Inuvialuit Regional Corporation stated that throughout the public hearings of the National Energy Board and the Joint Review Panel:

> the Inuvialuit Regional Corporation has been consistent in its recognition of the extensive economic opportunities this project would provide to not only the Inuvialuit and other residents of the Beaufort Delta, but also to the residents of other regions along the pipeline route, and Canadians in general.

The Inuvialuit Regional Corporation noted that economic opportunity is limited in Beaufort Delta communities, and the Inuvialuit want to be self-reliant and enjoy the benefits of a thriving and sustainable economic base. The Inuvialuit Regional Corporation stated the Mackenzie Gas Project and ongoing exploration and development would provide such economic opportunity to Beaufort Delta communities and other regions. Ms. Cournoyea also noted:

> I don't believe it's in the Canadian interest that one group, or part of one group, can hold up the economic opportunities of a lot of other people…

in the absence of a land claim settlement for the Dehcho region. The Inuvialuit Regional Corporation encouraged us to include in our approval terms that would direct the federal government to support ongoing planning processes in the Beaufort region through the release of the Mackenzie Gas Project Impacts Fund.

Mackenzie Valley Aboriginal Pipeline Limited Partnership

The Mackenzie Valley Aboriginal Pipeline Limited Partnership (otherwise known as the Aboriginal Pipeline Group), representing the one-third Aboriginal ownership interest in the project, also expressed its support for the Mackenzie Gas Project. Mr. Fred Carmichael, Chair of the Mackenzie Valley Aboriginal Pipeline Limited Partnership noted the Mackenzie Gas Project is the first step to regaining economic self-sufficiency for the regions. He stated that:

> our youth are dependent on a wage economy, like your own sons and daughters. They need quality education, training and meaningful employment and business opportunities. The Aboriginal Pipeline Group is supporting this project to make sure they have those opportunities.

North Slave Métis Alliance

The North Slave Métis Alliance stated they were not identified as an Aboriginal group for consultation in the Proponents' Environmental Impact Statement, that they should have been included in the Proponents' list of non-corridor communities, and that consultation by the Proponents was not adequate.

Dehcho communities

The Dehcho Elders and Harvesters Councils, Dehcho First Nations, the Sambaa K'e Dene Band and the Liidlii Kue First Nation raised a number of unresolved concerns about the project in their submissions to us. Some concerns were raised by more than one group from the Dehcho region, while other concerns were unique to the interests of specific communities. Overall, the concerns encompassed several broad issues related to the potential impacts and benefits arising from the approval, construction and operation of the Mackenzie Gas Project.

Those issues raised by Dehcho communities relating to socio-economic and environmental concerns are addressed in Chapter 3.

Agreements and settlements

Concerns were raised by the Dehcho Elders and Harvesters Councils and the Dehcho First Nations regarding the status of key settlements and agreements for the Dehcho Region. On behalf of the Dehcho Elders and Harvesters Councils, Mr. Herb Norwegian noted that:

> unlike other regions in the Northwest Territories affected by this project, the Dehcho Dene have not resolved our outstanding land and self-government relationships with Canada.

Mr. Norwegian further stated that:

> the conclusion of the Dehcho Process with a final agreement would provide the Dehcho Dene with a clear and necessary authority to ensure that this project could only proceed in a manner acceptable to us and with our full involvement.

The Dehcho Elders and Harvesters Councils also expressed their disappointment and frustration with the Government of Canada and the Government of the Northwest Territories for delay in adopting the Dehcho Land Use Plan, which was ratified by the Dehcho First Nations in 2006. The Dehcho Elders and Harvesters Councils stated that the land use plan is an expression of the values and aspirations of the Dehcho Dene, and they have placed a high priority on the formal adoption and implementation of the land use plan.

The Dehcho Elders and Harvesters Councils and the Dehcho First Nations stated that they cannot support the approval of the Mackenzie Gas Project without a land use plan in place for the Dehcho Region, and recommended that access for construction in the Dehcho territory be delayed until the Dehcho Process has been concluded and the Dehcho Land Use Plan has been implemented. This view was supported by the Sambaa K'e Dene Band. The Dehcho Elders and Harvesters Councils further recommended that the project not proceed to construction until the Proponents have concluded an Access Agreement and a Benefits Agreement for the Dehcho communities. The Dehcho First Nations noted that the Proponents' updated project schedule indicated that a decision to construct the project would be made in approximately 2013. Dehcho First Nations Grand Chief Samuel Gargan noted that, in the Dehcho First Nations' view:

> three and half years between now and then is more than what is needed to conclude the Dehcho Process, have a final land use plan in place and resolve other outstanding matters.

Consultation by the Proponents

The Sambaa K'e Dene Band and the Dehcho First Nations raised concerns regarding the adequacy of the Proponents' consultation. The Dehcho First Nations stated that the Proponents' efforts were inadequate, and that many regional and community concerns about the project remain unaddressed. Dehcho First Nations Grand Chief Samuel Gargan expressed concern that the Proponents were "frequently referring us to subsequent regulatory processes rather than directly dealing with us to resolve these issues" such as consultation regarding future block valve locations.

The Sambaa K'e Dene Band stated that the Proponents did not respect the Sambaa K'e Dene Band's stated preference to independently negotiate an area-specific impact benefit agreement, and expressed concern that the Proponents avoided their consultation obligations within the National Energy Board's regulatory process.

In response, the Proponents noted that, as a consequence of consultation, many changes were made to the design of the Mackenzie Gas Project in the Dehcho region. The Proponents also noted consultation did not lead to agreement in every case, and that some remaining issues can only be addressed at the permitting stage, following the collection of additional information. Finally, the Proponents affirmed that consultation for the project will continue, and the Proponents will continue to strive to address outstanding concerns.

Adequacy of Crown consultation

Concerns were raised by the Dehcho First Nations, the Sambaa K'e Dene Band and the North Slave Métis Alliance about the adequacy of Crown consultation for the project. The Dehcho First Nations stated that Canada's consultation efforts were inadequate, and that Canada's evidence submitted to us failed to acknowledge the submissions and recommendations made to the Joint Review Panel by the Dehcho First Nations.

The Sambaa K'e Dene Band stated Canada did not fulfill its legal obligation to consult with the intent of finding accommodation, including compensation for the infringement of Section 35 rights and interests on Crown lands. The Sambaa K'e Dene Band recommended that we not issue a Certificate for the project until Canada has concluded its consult to modify process in relation to the Joint Review Panel recommendations, particularly with respect to Section 35 issues, and has concluded the process of substantive consultation with the Sambaa K'e Dene Band to accommodate outstanding rights issues.

The North Slave Métis Alliance stated that it should be consulted regarding the Mackenzie Gas Project, and that the North Slave Métis Alliance was not adequately consulted by the Crown.

Dene Tha'

We held a hearing session in High Level, Alberta on 27 September 2006 to hear concerns from Northern Alberta communities. Although the Dene Tha' registered as an intervenor and filed evidence, they did not participate in this session or our other hearing sessions. In November 2006 the Dene Tha' First Nation entered into a Settlement Agreement with Canada as settlement of litigation in relation to the project. In that agreement Canada would provide $25,000,000 to the Dene Tha' First Nation to, among other things, assist the Dene Tha' First Nation in addressing the socio-economic impacts associated with the project.

Views of the Board

The Proponents' consultation program

When an application is filed, the National Energy Board's *Filing Manual* requires companies to demonstrate that they have identified, contacted and consulted with potentially affected groups and individuals prior to filing their application. Companies must learn about the concerns of people, and attempt to address those concerns to the fullest extent possible. They are also expected to continue their discussions with those who will be affected by their project as the regulatory process unfolds, and during the construction and operation phases of their project. The project application must contain detailed information on all aspects of company's consultation work, including a description of any unresolved issues or concerns.

The Proponents provided extensive details of their consultations with those groups, individuals, organizations, governments and Aboriginal people that will be affected by the Mackenzie Gas Project. They documented more than 1,500 meetings, described the concerns that were raised over years of consultation, and provided details on how they have already or will address the concerns they heard. The Proponents responded to the concerns and input they received through their consultations with numerous changes to the design of the project, and through a range of commitments in the Socio-Economic Agreement. They have committed to continuing consultation throughout the life of the Mackenzie Gas Project.

We find that the Proponents designed and implemented an effective consultation program for the Mackenzie Gas Project. We accept that agreement on how to address concerns that were raised was not possible in all instances, and we are confident that some remaining issues will be further addressed by other regulatory institutions, federal departments and Aboriginal authorities at the permitting stage. In this regard, we will continue to work cooperatively with and support northern institutions and federal departments throughout subsequent approval phases.

Where our own conditions require further consultation by the Proponents, or require the Proponents to provide the National Energy Board with evidence of consultation, the National Energy Board will continue to evaluate the appropriateness and effectiveness of their efforts, including how any concerns have been addressed. With respect to defining consultation in our conditions, we consider the recommendation by Alternatives North and Indian and Northern Affairs Canada to be helpful. The definition of consultation contained in Section 3 of the *Mackenzie Valley Resource Management Act* is broadly consistent with the full guidance we provide to all applicants and regulated companies in our Filing Manual. A preamble that defines consultation has therefore been included in our conditions. Regarding Environment Canada's request that evidence of their level of satisfaction for consultation be provided, we note that all interested and affected parties may contact us at any time regarding the Proponents' activities, and we would give appropriate consideration to any submission as it is received. In response to the Government of Yukon's request, we have amended Condition 27 so that the Government of Yukon will be included in consultations for the preparation of plans for a formal issues resolution program.

Potential impacts of the project

We rely on those with an interest in a project to participate in our hearing process, so that we can hear directly from them and consider their views and concerns. We also encourage all those who might be affected by a project to engage early in the project planning and assessment stages with proponents, so that they may work collaboratively to address any interests and concerns, including concerns related to the potential impacts of a project.

We heard directly from a number of parties about the potential impacts and benefits of the Mackenzie Gas Project, including the views and concerns of people in the Inuvialuit, Gwich'in, Sahtu and Dehcho regions. The Dehcho organizations and communities told us they would prefer that approval of the project be delayed until their land claim is settled, and their land use plan has been implemented. But we also heard about the social and economic aspirations of the people in the Inuvialuit, Gwich'in and Sahtu regions, and the benefits the Mackenzie Gas Project would bring to them. As Gwich'in Tribal Council President Richard Nerysoo told us, the Mackenzie Gas Project will "enable the Gwich'in to become self-sufficient and full participating members in a global society". From the Government of the Northwest Territories, we also heard that the project will allow the residents of the North to move toward economic self-sufficiency.

We are encouraged by Grand Chief Gargan's view that sufficient time is available before the project is constructed to make concrete progress on, and perhaps to finalize, a land claim agreement for the Dehcho Region, and to implement a Dehcho land use plan. We are further encouraged that sufficient opportunity would also be available before the project proceeds to construction for the Proponents and Dehcho organizations and communities to make progress toward concluding any additional agreements, such as access and benefits agreements, to address remaining mutual interests and concerns.

Through their commitments and adjustments to the project, the Proponents have addressed many, but not all, of the concerns raised with them. We were also made aware of unresolved concerns during our hearing and through the Joint Review Panel Report, including the specific concerns raised by Aboriginal groups.

Throughout its hearing process, the National Energy Board requires an applicant to consult with Aboriginal groups in order to determine their concerns, and to attempt to address them to the extent possible. If there are concerns that remain unaddressed after consultation, the National Energy Board can impose conditions to address them. In our hearing, we considered the concerns of Aboriginal people when making our decision, and our conditions address these concerns. With the Proponents' measures and commitments, and the requirements contained in our conditions, we believe the concerns raised by parties and Aboriginal groups have been or will be adequately addressed, and identified impacts will be effectively mitigated.

Through this process, as also discussed in section 1.3 of Volume 1, and the Board's assessment of the information it has received throughout, we have determined that our decision is consistent with section 35 of the *Constitution Act, 1982*.

Chapter 10 National Energy Board lifespan regulation

The National Energy Board is committed to doing all it can in overseeing every stage of this project, if it is built. This means that the National Energy Board will to see to it that the Proponents keep their promises and that all conditions attached to the approvals will be implemented. If people of the Northwest Territories have any concerns with the project, the National Energy Board will be there to resolve those concerns. The National Energy Board will be there to inspect, audit and work in collaboration with Northern agencies while the pipeline is operated and will still be there many years from now when the pipeline needs to be abandoned. Abandonment will be approved when it can be done safely while protecting the environment.

If people have concerns throughout the life of the project, and cannot resolve a matter directly with the company, they can speak to a National Energy Board inspector or call toll free, 1-800-899-1265. Regulatory documents including those filed as a result of National Energy Board conditions can be found on the National Energy Board's website at: www.neb-one.gc.ca. On the right side of the page under the heading "Regulatory Documents" click on "View".

Details on the National Energy Board's lifespan approach to regulation follow.

10.1 Regulation under the *National Energy Board Act*

The National Energy Board is responsible for assessing applications for pipeline projects to determine if they are in the public interest. If a project is approved, the National Energy Board then regulates it throughout its entire lifespan, from the application phase, through construction and operation, and finally to the abandonment phase (see Figure 10-1).

The primary tools used by the National Energy Board to regulate the over 71,000 kilometres of pipeline within its jurisdiction are the *Onshore Pipeline Regulations, 1999,* the *National Energy Board Processing Plant Regulations;* the *National Energy Board Pipeline Crossing Regulations Part I* and *Part II*; the *Toll Information*

Regulations, and the *Gas Pipeline Uniform Accounting Regulations* or *Oil Pipeline Uniform Accounting Regulations.* These regulations require that a number of programs, plans and manuals be established and information be provided. As part of its overall responsibility for regulating energy facilities the National Energy Board also:

- issues safety advisories;
- conducts inquiries or formal investigations into safety issues;
- addresses landowner complaints;
- inspects; and
- conducts financial, safety, environment and security audits.

In addition to the regulations, the National Energy Board's Filing Manual provides guidance to companies on what information must be filed in a project application and in financial surveillance reports.

10.1.1 The application stage

Applications for major projects are generally heard by way of oral public hearing. This allows the company proposing the project, and any other interested people or groups, a chance to provide information on the project and to provide input in support of or against a project. A hearing gives all of the people interested in a project an opportunity to provide evidence, ask or answer questions and express their point of view on the project. It also provides the National Energy Board with the information needed to make a fair and objective decision.

When assessing an application the National Energy Board considers what additional measures should be required of a company during construction and operation of the project if it were to be approved. These measures become conditions to an approval issued by the National Energy Board. The company must meet all of the conditions set by the National Energy Board. Some examples of conditions include:

- restrictions on the timing of construction;
- imposing measures which limit impacts on the land;
- requiring a noise level report;
- conducting a rare plant study; and
- requiring the filing of a joining program.

During the hearing, the National Energy Board considers all information that is relevant to the question of whether or not the application should be approved.

10.1.2 Monitoring and enforcement

Pre-construction and construction

If the National Energy Board approves a project, its oversight is directed toward ensuring that the project is built in compliance with regulations and the conditions that were placed on the

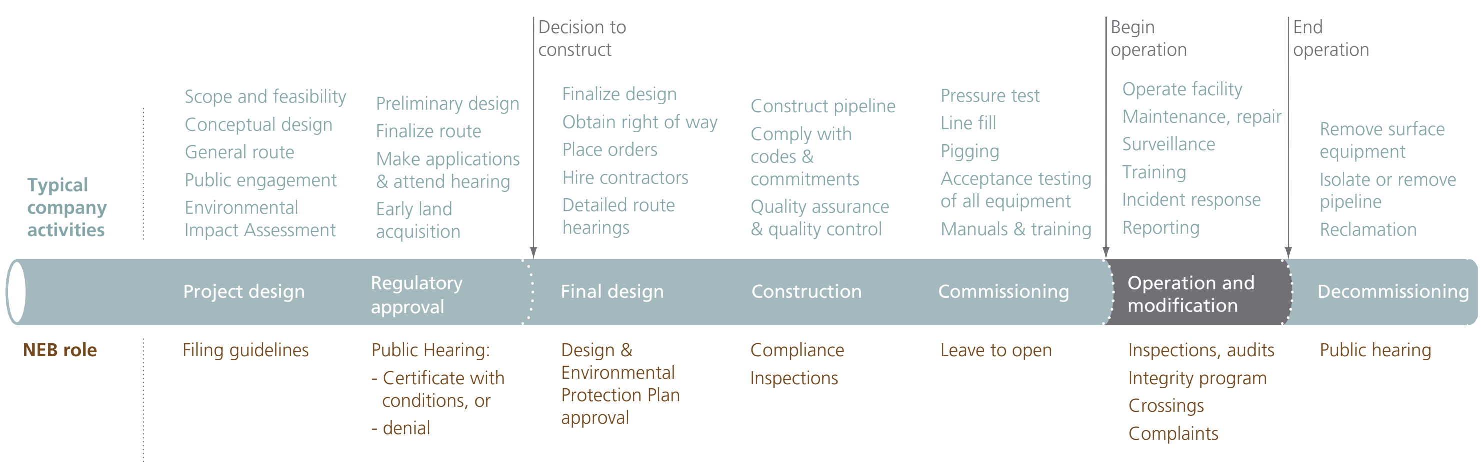


Figure 10-1

Regulation by the National Energy Board throughout a project's lifespan approval. Conditions of approval are project-specific and based on the hearing's evidentiary record and the experience of the National Energy Board in dealing with pipeline matters. The company is obligated to follow through with all of these conditions and the National Energy Board makes sure it does through various means including the review of submitted plans, reports, and manuals. If input is required from another party the nature of that input is specified in the conditions and regulations. The company is expected to confirm that this input has been received and incorporated as appropriate. The company's submissions and the correspondence of the National Energy Board are accessible from the regulatory repository.

During the construction stage, the National Energy Board conducts inspections to verify that approved facilities meet the requirements of the Acts, regulations, and conditions associated with approvals. National Energy Board inspectors document the results of the inspections, follow-up on outstanding issues, and provide feedback on observations in the field.

The frequency and type of inspections depend on several factors, including the:

- complexity of the project;
- safety and environmental issues identified during the application and the construction phase;
- observed compliance history of the company; and
- the performance of the company on the specific construction spread at hand.

Inspections are focused on the right of way and above-ground facility locations. Inspectors work in collaboration with other regulators to ensure that there are no regulatory gaps and to minimize regulatory overlap.

Inspections and monitoring activities by the National Energy Board include:

- verifying compliance with, and assessing the effectiveness of, mitigation measures, conditions, and environmental protection plans;
- verifying compliance with the appropriate standards and regulations; and
- monitoring construction and operations, including verifying construction progress reports.

If inspectors find that the company is not meeting the conditions or the regulations, the National Energy Board takes action to enforce them.

The National Energy Board enforces safety and environmental commitments and requirements. If we find a company is not meeting its commitments and requirements we immediately ask the company to voluntarily correct the situation. If a situation cannot be corrected immediately, or if additional information is required from a company, the National Energy Board's Inspection Officers may ask for a written assurance of voluntary compliance from the company. The company must later confirm that compliance was achieved.

Inspection Officers appointed under the *National Energy Board Act* can also issue an order where there are reasonable grounds to believe that a hazard to the safety of the public or employees of a company, or a detriment to property or the environment, is being or will be caused by the construction, operation, maintenance or abandonment of a pipeline. The order may direct the company to undertake certain work or stop its construction until that work has been completed. These orders may be converted into court orders to be enforced in the same manner as an order of that court if the company does not comply.

Public concerns can vary throughout the different stages of a project's life. For example, a potential environmental issue may be noticed first by people in the vicinity of the facilities. People who have concerns with a pipeline project may contact the National Energy Board at any time for information on how to work through their concerns with the company. The National Energy Board provides various ways that these concerns can be brought forward for resolution.

The National Energy Board's Complaint Resolution Program and the Appropriate Dispute Resolution process are options for resolving outstanding issues. Appropriate Dispute Resolution could take the form of a meeting between a concerned person and the company, which may be facilitated by our National Energy Board staff or by another neutral third party. During construction, National Energy Board staff is often out in the field inspecting the project and can be contacted directly. As well, the National Energy Board can be contacted by phone, mail, fax or e-mail.

After completion of construction, the National Energy Board will continue to monitor the right of way to verify the ongoing success of environmental and geotechnical mitigation measures. This is usually done using inspections in the field as well as reviewing reports submitted by the company.

Did you know?

Physical monitoring and surveillance program

A monitoring and surveillance program consists of two parts. The monitoring is aimed at identifying any issues or potential concerns that may compromise the pipeline, property, persons and the environment (e.g., pipeline integrity or erosion, and security). It may include methods for developing measures to prevent or mitigate the impact of the identified issue(s). The program may also dictate:

- follow-up monitoring of sites where mitigative measures have been undertaken, in order to determine their success or failure;
- a system for implementing additional mitigative measures as needed; and
- a feedback system that allows for successful mitigation to be adapted to future pipeline projects.

The surveillance component of the monitoring program focuses on the company's activities, its contractors or the public. For example, ensuring that contractors adhere to the environmental requirements of a task, that encroachments upon rights-of-way are detected, and that adjacent construction activities are known. A monitoring and surveillance program can include aerial patrols, in-line inspection, soil-to-pipe surveys, erosion monitoring, and slope stability monitoring. Relevant environmental practices such as those for managing materials storage and waste, monitoring air quality and water quality can all be contained within the monitoring and surveillance program.

Operations

Requirements for companies operating National Energy Board regulated pipelines are set out in the *Onshore Pipeline Regulations, 1999*. As mentioned previously, specific programs, plans and manuals are required under these regulations. For example, creating and implementing a Monitoring and Surveillance Program and an Integrity Management Program are mandatory requirements of the *Onshore Pipeline Regulations, 1999*.

Monitoring activities by National Energy Board staff during the operations phase include:

- inspections of the facilities and right of way;
- conducting management system audits to verify that National Energy Board regulatory requirements have been and will continue to be met;
- assessment of safety practices and procedures under the National Energy Board mandate as well as through the *Canada Labour Code Part II* on behalf of Human Resources Skills Development Canada;
- review and assessment of a company's integrity management and environmental protection programs;
- conducting financial audits to verify compliance with financial regulations and other National Energy Board requirements; and
- review of financial surveillance reports and annual filings.

The National Energy Board is as accessible to the public during operations activities as it is during construction, and will follow up on any issues that are brought forward.

10.1.3 Abandonment

When a facility under the National Energy Board's jurisdiction comes to the end of its useful life the company must apply for permission to abandon it. A public hearing is required for an abandonment application. This gives the public an opportunity to express their views about whether the proposed abandonment procedures would provide for adequate safety and protection of the environment. Before allowing the abandonment to proceed the National Energy Board must be satisfied that the abandonment will be carried out in a way that is safe, protects property and protects the environment. The National Energy Board expects that companies will discuss abandonment plans with landowners to ensure that concerns are dealt with at the planning stage.

In order to abandon a facility the company must comply with all regulations and conditions imposed by the National Energy Board. Abandonment procedures typically involve the removal of surface installations and the restoration of the land. Buried pipe may either be removed or left in place, depending on the best way of addressing safety and environmental concerns. The procedures are different for each abandonment depending on the location of

Did you know?

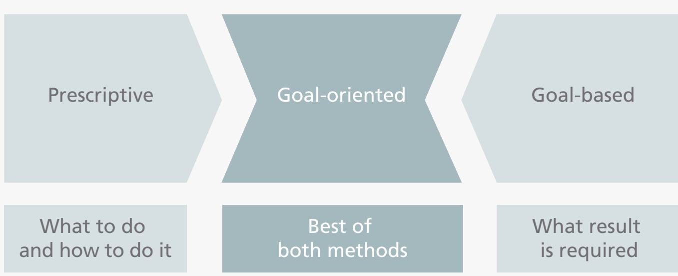
Goal-oriented regulation

Methods of regulation are often characterized as either prescriptive or goal-based. Both methods have strengths and weaknesses and both are in common use. The choice between them can depend on the nature of the activity being regulated.

Prescriptive regulation works well to set compulsory requirements, such as design or the reporting of incidents where, regardless of the circumstances or the location of the facilities, the requirements should not vary. The main weakness of prescriptive regulation is its inflexibility. It can block the introduction of innovative new ideas and technology and can be insensitive to unique or changing circumstances.

Goal-based regulation allows the company to adapt required programs and manuals to suit its business and the environment in which it operates. It also encourages innovation and can lead to safer systems. Weaknesses include higher costs to enforce and the potential lack of transparency to the public.

The National Energy Board has taken the best from both methods and called it goal-oriented regulation. Prescription is used when compulsory means of compliance are desired. Goals are used when circumstances can differ greatly among the regulated companies or where superior outcomes are likely to be achieved through innovation or new technology. For example, the National Energy Board's *Onshore Pipeline Regulations, 1999* rely on *CSA Standard Z662 – Oil and Gas Pipeline Systems*, in which most of the technical requirements are set out in prescriptive terms. Specific programs, manuals and plans must be in place but the content of these documents is guided by goals. The National Energy Board evaluates the company's compliance with regulations using audits and inspections.



the facility, the operating history of the facility, and the future uses proposed for the land. The company's abandonment plan would typically address key issues that relate to public safety, environmental protection, and future land use. These include:

- land use management;
- ground settling;
- soil and groundwater contamination;
- pipe cleanliness;
- water crossings;
- soil erosion;
- utility and pipeline crossings;
- creation of water conduits, where water travels through the pipeline; and
- related pipeline equipment (e.g. risers, valves, piping, etc.).

When the National Energy Board is satisfied with what the company has done, the abandonment order takes effect. At this point the facility is considered abandoned and is no longer under the jurisdiction of the National Energy Board.

To guide the development of abandonment plans, the National Energy Board has several proposed principles for the end state of land, as shown in Table 10-1.

In January 2008 as part of its Land Matters Consultative Initiative, the National Energy Board convened a public hearing, RH-2-2008, to consider the financial issues related to pipeline abandonment. As a result, all pipeline companies regulated under the *National Energy Board Act* will be required to file, for approval, a proposed process and mechanism to set aside funds for abandonment. Pipeline companies are expected to demonstrate to the National Energy Board how the mechanism they have chosen meets the goal of ensuring that adequate funds will be set aside to cover all pipeline abandonment activities. Since the Mackenzie Valley Pipeline was applied for pursuant to the *National Energy Board Act*, these requirements would automatically apply to it.

The Mackenzie Gathering System was applied for pursuant to the *Canada Oil and Gas Operations Act* rather than under the *National Energy Board Act*. Our Condition 4 in the Miscellaneous Order for Mackenzie Gathering System Tolls (Appendix N) requires that, at least 18 months prior to the Mackenzie Gathering System being placed in service, the Proponents must prepare and file for approval, an estimate of abandonment costs, a proposal for the collection of funds and a proposed process and mechanism to set aside the funds. The requirements are therefore the same for both the Mackenzie Gathering System and the Mackenzie Valley Pipeline.

Table 10-1

Principles for the end state of land post-retirement

Concern	Principle
Responsibility	Facility owners and operators are responsible for the retirement of facilities and reclamation of the right of way as well as any liabilities arising from those facilities post-retirement.
Retirement and reclamation planning	Persons and groups potentially affected by the retirement of facilities are invited to be involved in the development of retirement and reclamation plans specific to those facilities.
	A retirement and reclamation plan deals with the retired facility in such a manner that the risk to public safety, property and the environment is at a level that is acceptable in the public interest, with the agreement of affected parties where possible, but ultimately as determined by the Board.
	Consideration is given to reuse and recycling of facilities in identifying retirement options.
End state of land	Retirement and reclamation returns the right of way to a state comparable with the surrounding environment. Facility owners and operators should accommodate the desired land use of those who are affected when it is reasonable to do so.
	In natural environment areas, or where rare or sensitive native plant species and communities are present, reclamation promotes the eventual re-establishment of habitat quality on lands affected by right-of-way development to as native a state as is consistent with the current and surrounding land use.
Performance measurement	Measuring the performance of retirement and reclamation plans is required to facilitate continual improvement and to assess effectiveness.

10.2 Economic regulation

Once a pipeline is approved, the National Energy Board regulates the tolls and rules for transportation on the pipeline. Some of the costs that can be included in tolls include operating expenses, depreciation, return on capital, and income and other taxes. Tolls can be set for a year or for multi-year periods. The National Energy Board adjudicates and sets tolls when there is a disagreement between shippers and the pipeline company, or it can accept a negotiated settlement. However, the existence of a negotiated settlement does not limit the authority of the National Energy Board. The National Energy Board will determine that the tolls are just and reasonable before it will accept them. At any time, applications and complaints about tolls, tariffs and access to the pipeline may be filed with the National Energy Board.

The National Energy Board's *Gas Pipeline Uniform Accounting Regulations* and *Oil Pipeline Uniform Accounting Regulations* establish a uniform system of accounts for Group 1 companies. Group 1 companies are required to file a surveillance report four times a year, on the basis of the *Toll Information Regulations*. These reports provide details of financial performance and explain any significant variations from approved amounts. The National Energy Board will audit a pipeline company's records to verify the accuracy of filed documents and compliance with the National Energy Board's decisions, regulations and other directives.

10.3 Regulation, monitoring and enforcement under the *Canada Oil and Gas Operations Act*

The Mackenzie Gathering System, including gathering pipelines upstream of the Inuvik Area Facility, the Inuvik Area Facility and the natural gas liquids pipeline, has been applied for under paragraph 5(1)(b) of the *Canada Oil and Gas Operations Act.* By use of conditions these facilities would be regulated in a manner that is similar to regulation of the Mackenzie Valley Pipeline under the *National Energy Board Act*. The National Energy Board would regulate the tolls and rules on the Mackenzie Gathering System under the *Canada Oil and Gas Operations Act* with toll and tariff legislation that is very similar to the *National Energy Board Act*.

The Development Plans for the Niglintgak, Taglu and Parsons Lake fields have also been applied for under the *Canada Oil and Gas Operations Act*. Upon National Energy Board approval of a Development Plan and consent of the Governor in Council in relation to Part I of the Development Plan pursuant to paragraph 5.1(4) of the *Canada Oil and Gas Operations Act*, any work or activity relating to that field can only commence after the operator submits an application under paragraph 5(1)(b) of the *Canada Oil and Gas Operations Act* for that work or activity and obtains authorization from the National Energy Board.

An authorization under paragraph 5(1)(b) of the *Canada Oil and Gas Operations Act* is required for work and activities in relation to a Development Plan which may include drilling, well completions, facilities construction, production operations, and decommissioning. In accordance with section 6 of the *Canada Oil and Gas Drilling and Production Regulations*, an application for an authorization under paragraph 5(1)(b) of the *Canada Oil and Gas Operations Act* should contain the following:

- a description of the scope of activities;
- an environmental protection plan;
- a safety plan; and
- a contingency plan.

In accordance with section 5 of the *Canada Oil and Gas Drilling and Production Regulations*, an applicant for an authorization under paragraph 5(1)(b) is required to develop an effective management system that includes processes for setting goals for the improvement of safety, environmental protection and waste prevention.

The National Energy Board would assess each application for work or activity submitted under paragraph 5(1)(b) including assessment of the accompanying environmental protection plan, safety plan and contingency plan to verify that the work or activity:

- is within the scope of and consistent with the approved Development Plan;
- complies with terms and conditions outlined in the National Energy Board's approval of the Development Plan;
- complies with the *Canada Oil and Gas Operations Act* and its regulations, which promote, for the exploration for and exploitation of oil and gas:
  - safety, particularly by encouraging persons exploring for and exploiting oil and gas to maintain a prudent regime for achieving safety;
  - protection of the environment;
  - conservation of oil and gas resources;
  - joint production arrangements; and
  - economically efficient infrastructures.

Depending on the work or activity, the environmental review of the proposed paragraph 5(1)(b) work or activity may be coordinated with other appropriate regulatory bodies. A National Energy Board authorization under paragraph 5(1)(b) of the *Canada Oil and Gas Operations Act* would include any appropriate terms and conditions.

In order to drill, re-enter, work over, complete or recomplete a well or suspend or abandon a well or part of a well a company requires a well approval from the National Energy Board in accordance with section 10 of the *Canada Oil and Gas Drilling and Production Regulations*. The National Energy Board would assess each application for a well approval to verify the following:

- compliance with the terms and conditions of the authorization under paragraph 5(1)(b) of the *Canada Oil and Gas Operations Act;*

- it is within the scope of and consistent with the Environmental Protection Plan, safety plan and contingency plan;
- it is within the scope of and consistent with the approved Development Plan;
- compliance with terms and conditions outlined in the National Energy Board's approval of the Development Plan;
- compliance with the *Canada Oil and Gas Operations Act,* the *Canada Oil and Gas Drilling and Production Regulations* and other *Canada Oil and Gas Operations Act* regulations.

Any well approval granted under section 10 of the *Canada Oil and Gas Drilling and Production Regulations* by the National Energy Board would contain appropriate terms and conditions.

After the National Energy Board issues an authorization for a work or activity under paragraph 5(1)(b) of *Canada Oil and Gas Operations Act* including a well approval under section 10 of the *Canada Oil and Gas Drilling and Production Regulations*, the National Energy Board will periodically conduct inspections and audits of field operations to verify compliance with the applicable *Canada Oil and Gas Operations Act* regulations, terms and conditions of the Development Plan approval, the 5(1)(b) authorization and/or well approval, and other matters relating to environmental protection, safety, and conservation of oil and gas resources.

Enforcement of the *Canada Oil and Gas Operations Act* and its regulations for safety are carried out by the Chief Safety Officer and Safety Officers. Verifying compliance for environmental protection and oil and gas conservation matters is within the mandate of the Chief Conservation Officer and Conservation Officers. Conservation Officers and Safety Officers work in collaboration with other regulators to ensure that there are no regulatory gaps and to minimize regulatory overlap.

Throughout the lifespan of a project, the National Energy Board will monitor drilling, completions, facilities construction, production operations, and decommissioning with inspections and management system audits. Information on condition tracking, inspection reports and other compliance information is used by the National Energy Board to improve its internal processes, track condition compliance and non-compliances, and to establish the need and frequency of future inspections and audits.

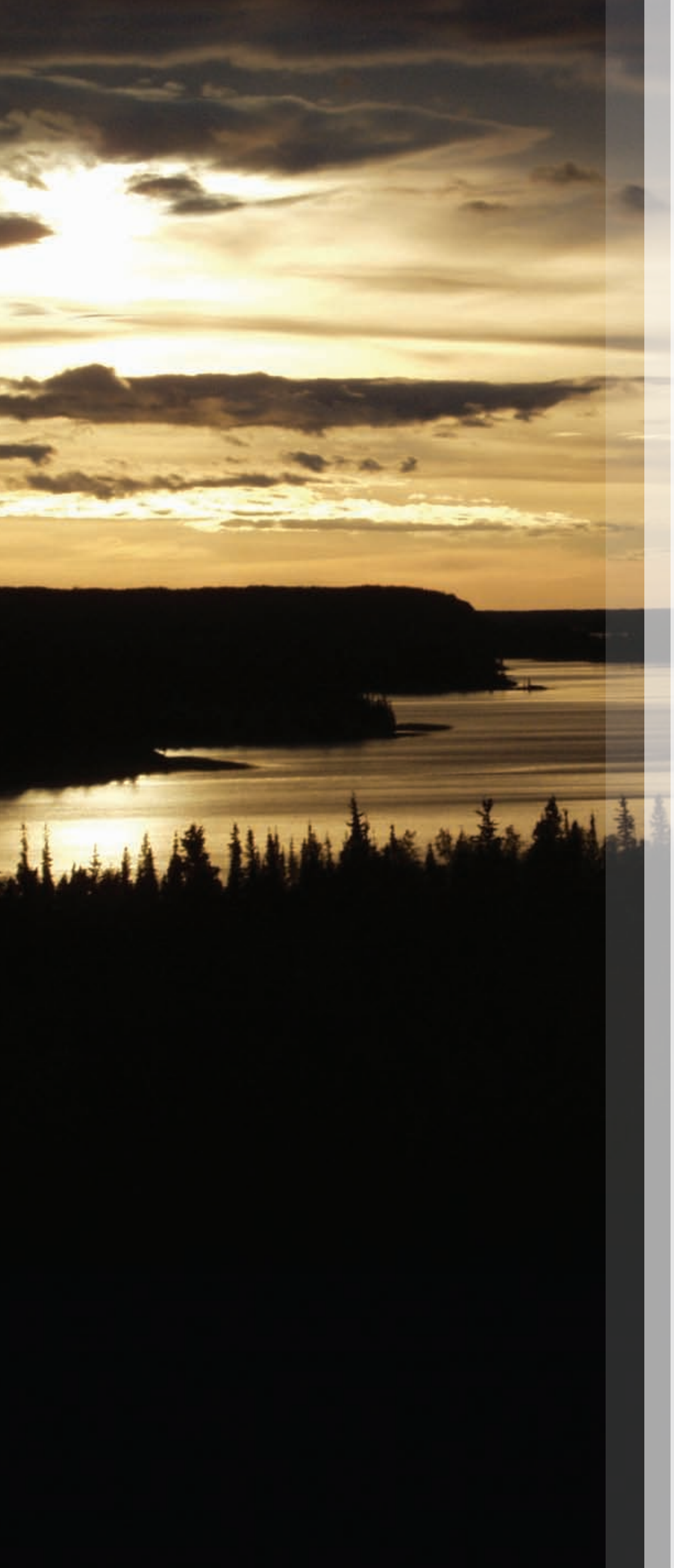
The frequency and type of inspections depend on several factors, including the:

- complexity of the project;
- safety and environmental issues identified during the application and prior activity phases; and
- observed compliance history of the company.

Inspections and monitoring activities by the National Energy Board include:

- verifying compliance with, and assessing the effectiveness of, mitigation measures, conditions, and Environmental Protection Plans and safety plans;
- verifying compliance with the appropriate standards and regulations; and
- monitoring drilling, facilities construction, production operations, and decommissioning.

If cooperative approaches to compliance are not successful, Safety Officers may issue orders about safety and the Chief Conservation Officer may order operations to be shut down, if necessary, to prevent damage to persons or property, to protect the environment or to prevent waste.



Chapter 11
Disposition

Volumes 1 and 2 constitute our Reasons for Decision approving the Mackenzie Gas Project applications.

We are satisfied that the proposed Mackenzie Valley Pipeline is, and will be, required by the present and future public convenience and necessity provided the terms and conditions outlined in Appendix K of these Reasons are met. Therefore, subject to the approval of the Governor in Council, a certificate will be issued pursuant to Part III of the *National Energy Board Act*. We have also made an Order setting toll and tariff principles for the Mackenzie Valley Pipeline as set out in Appendix L.

We find that the Mackenzie Gathering System promotes safety, environmental protection and conservation of oil and gas resources. Accordingly, we will issue an authorization for the Mackenzie Gas System under paragraph 5(1)(b) of the *Canada Oil and Gas Operations Act.* This authorization will be issued once the proponents have complied with the necessary provisions of the *Canada Oil and Gas Operations Act*. This authorization will be subject to the conditions outlined in Appendix M. We have also made an Order setting toll principles for the Mackenzie Gathering System that are contained in Appendix N.

We find that the Development Plans submitted by Shell Canada Limited as managing partner of Shell Canada Energy for the Niglintgak field, Imperial Oil Resources Limited for the Taglu field and ConocoPhillips Canada (North) Limited and ExxonMobil Canada Properties for the Parsons Lake field promote safety, environmental protection and conservation of oil and gas resources. Accordingly, we will issue approvals of the Development Plans for the Niglintgak, Taglu and Parsons Lake fields once the proponents have complied with the necessary provisions of the *Canada Oil and Gas Operations Act*. These approvals will each be subject to the consent of the Governor in Council in relation to Part I of each Development Plan. In addition we will require that:

a) the conditions set out in Appendix O be met for the Niglintgak field;

b) the conditions set out in Appendix P be met the Taglu field; and

c) the conditions set out in Appendix Q be met for the Parsons Lake field.

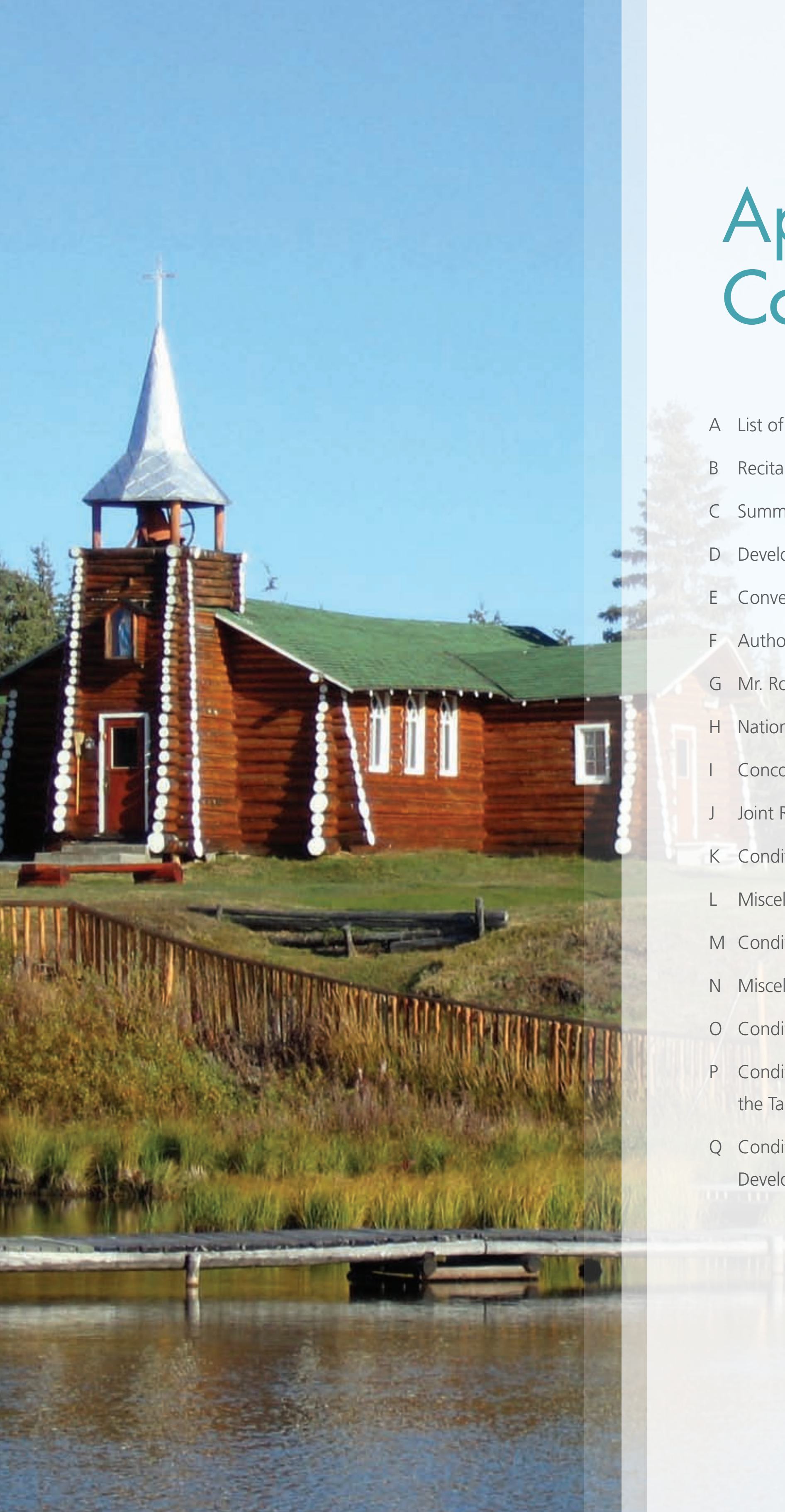
In making our decision we have considered the *Governments of Canada & of the Northwest Territories Final Response to the Joint Review Panel Report* for the Proposed Mackenzie Gas Project and the comments received from parties on that Response.

K.W. Vollman
Presiding Member

G. Caron
Member

D. Hamilton
Member

December 2010



Appendices Contents

Appendix A
List of Issues for Hearing GH-1-2004

1. The need for the proposed project.
2. The economic feasibility of the proposed project.
3. The potential commercial impacts of the proposed project.
4. The appropriateness of the general routes of the proposed pipelines.
5. The toll and tariff regulation of the proposed Mackenzie Gas Pipeline.
6. The suitability of the design of the proposed project.
7. The terms and conditions to be included in any approval the NEB may issue.
8. The appropriateness of the Applicants' public consultation program and the adequacy of aboriginal consultation.
9. The ability of the Proponents to manage risk and financial liabilities related to the construction, operation and decommissioning of the proposed project.
10. The appropriateness of the Development Plans for the Taglu, Parsons Lake and Niglintgak fields.
11. The estimated cost of construction of the Mackenzie Valley Pipeline for the purpose of subsection 5.2(1) of the *National Energy Board Cost Recovery Regulations*.
12. For the purpose of Phase 6 of the NEB process, the reports from the Joint Review Panel process.
13. The appropriate tolls, access and tariff provisions for the Mackenzie Gathering System and the methods for resolving disputes on these matters.

Appendix B
Recital and appearances

IN THE MATTER OF the *National Energy Board Act* (Act) and the Regulations made thereunder: and

IN THE MATTER OF an application filed with the National Energy Board on 7 October 2004 under file PA-IOR 2004-001, for a Certificate of Public Convenience and Necessity under Parts III and IV of the Act by Imperial Oil Resources Ventures Limited (IORVL) on behalf of itself, Mackenzie Valley Aboriginal Pipeline Limited Partnership (APG), ConocoPhillips Canada (North) Limited (ConocoPhillips), Shell Canada Limited (Shell) and ExxonMobil Canada Properties (ExxonMobil); and

IN THE MATTER OF an application filed with the National Energy Board on 7 October 2004 under file FacPipe IRL MGS-04 for authorization for the Mackenzie Gathering System, pursuant to paragraph 5(1)(b) of the *Canada Oil and Gas Operations Act* (COGO Act). The application was filed by Imperial on behalf of itself, ConocoPhillips, Shell and ExxonMobil; and

IN THE MATTER OF an application filed with the National Energy Board on 7 October 2004 under file FieldOp IRL Taglu-07 for approval of the Development Plan for the Taglu field, pursuant to section 5.1 of the COGO Act, filed by Imperial Oil Resources Limited; and

IN THE MATTER OF an application filed with the National Energy Board on 7 October 2004 under file FieldOp CPN Parsons-07 for approval of the Development Plan for the Parsons Lake field, pursuant to section 5.1 of the COGO Act, filed by ConocoPhillips on behalf of itself and ExxonMobil; and

IN THE MATTER OF an application filed with the National Energy Board on 20 October 2004 under file FieldOp SCL Niglintgak-07 for approval of the Development Plan for the Niglintgak field, pursuant to section 5.1 of the COGO Act, filed by Shell; and

IN THE MATTER OF National Energy Board Hearing Order GH-1-2004 dated 24 November 2004;

HEARD in Inuvik, N.W.T. on 25, 26, 27, 28, 30, 31 January and 1 February 2006; Norman Wells, N.W.T. on 24, 25 and 26 April 2006; Fort Good Hope, N.W.T. on 29 and 30 May 2006; Tulita, N.W.T. on 1 June 2006; Yellowknife, N.W.T. on 2 June, 24, 25, 26, 27, 28, 29, 31 July and 1 August 2006; Fort Providence, N.W.T. on 25, 26 September 2006; High Level, Alberta on 27 September 2006; Hay River, N.W.T. on 29 and 30 September 2006; Deline, N.W.T. on 2 October 2006; Wrigley, N.W.T. on 3 October 2006; Fort Simpson, N.W.T. on 4 and 5 October 2006; Inuvik, N.W.T. on 22, 23, 24, 25, 27, 28, 29, 30 November and 1 December 2006; Tuktoyaktuk, N.W.T. on 4 December 2006; Fort MacPherson, N.W.T. on 5 December 2006; Tsiigehtchic, N.W.T. on 6 December 2006; Inuvik, N.W.T. on 11, 12, 13 and 14 December 2006; Yellowknife, N.W.T. on 10 and 11 October 2007, 29 March and 12, 13, 14, 15, 16 April 2010; and Inuvik, N.W.T on 20, 21 and 22 April 2010.

BEFORE:

K.W. Vollman	Presiding Member
G. Caron	Member
D. Hamilton	Member

APPEARANCES:

Imperial Oil Resources Ventures Limited (IORVL): D.G. Davies, B. Ho, T. Hughes, W. Shalagan
Witnesses: Dr. G. Angevine, B. Bleaney, R. Boivin, K.M. Braaten, D. Brandes, D. Coolidge, B.J. Cunningham, K. Drysdale, R. Falconer, D. Gough, D.G. Harris, C.E. Heuer, K. Johnson, L. Kennedy, J. Kingsbury, B. Kohrs, G.L. Lee, R. Luckasavitch, H. Marreck, A. Martinson, D. Mazurek, K. McShane, J. Oswell, R. Ottenbreit, G. Penrose, Dr. A. Safir, C. Saunders, E. van Beurden, W. Veldman, A. Watson, W. Williams, M.M. Zhang

Imperial Oil Resources Limited: D.G. Davies, B.Ho
Witnesses: M. Curtin, D. Haeberle, B. Parent, M. Sykes, F. Yurkiw

Shell Canada Limited: S.H.T. Denstedt, M. Henderson, B. Gilmour, R. Rodier
Witnesses: P.M. Davies, P. Johnson, R.K. Johnson, M.A. Read, R.J. Ritchie

ConocoPhillips Canada (North) Limited: S.H.T. Denstedt, G. Teixeira, R. Rodier
Witnesses: R. Bleaney, A. Duguid, S. Kennedy, B. Plesuk, G. Prost

Alternatives North: K. O'Reilly

Apache Canada Ltd: A.W. Carpenter, S. Carpenter
Witnesses: B. Jackson, B. Kalynchuk

Ayoni Keh Land Corporation: L.D. Rae

France Benoit: F. Benoit

BP Canada Energy Company: B. Wallace

Canadian Parks & Wilderness Society: K. Brekke

Government of Canada – Justice Canada: J.M. Shaw, R. Mack
Witnesses: C.A. Brumwell, M. Chenier, L. Clayton, W. Fenton, C. Gibson, R. Hurst, F. Lefebvre, C. Leowen, B. MacDonald, P. Szkwarok

Canadian Association of Petroleum Producers: N. Schultz

Chevron Canada Resources: K.F. Miller
Witnesses: R. Maier, M. Morand, K. Nahm, K. Starkey

Dehcho Elders Council: Grand Chief H. Nowegian

Dehcho First Nations: Grand Chief S. Gargan, J. Acorn

Dehcho Harvesters Council: Grand Chief H. Nowegian

Ecology North: D. Ritchie

EnCana Corporation: R.K. Powell

Environment Canada: B. Rattan, C.J. Thomas, J.R. Harvey

Fort Simpson Métis Local No. 52: M. Lafferty

Gwich'in Tribal Council: R. Nerysoo

Indian and Northern Affairs Canada: S. Duke, R. Graw
Witnesses: Dr. A. Baumgard, Dr. C. Burn, T. Kaiser, D. Livingstone, Dr. B. Roggensack, Dr. W. Savigny, E. Yaremko

Inuvialuit Regional Corporation: N. Cournoyea

Ka'a'Gee Tu First Nation: Chief L. Chicot

Lidlii Kue First Nations: Chief J. Antoine

Mackenzie Explorer Group: D.E. Crowther, J. Farrell, R. Neufeld
Witnesses: Dr. L. Booth, J. Chipperfield, N. Deyell, M. Drazen, N. Dustan, L. Germiquet, G. Hiltz, R. Maier, K. Milne, M. O'Blenes, R.K. Powell, M. Scott, S. Willis

Mackenzie Valley Aboriginal Pipeline Limited Partnership: L.E. Smith, Q.C., F. Carmichael

MGM Energy Corp. (formerly Paramount Resources Ltd.): A.S. Hollingworth, N. Dilts, G. Bunio
Witnesses: R. DeWolf, W. Rausch

Mosbacher Operating Ltd.: L.L. Manning
Witnesses: H. Baird, R.G. Dingwall

North Slave Métis Alliance: S. Grieve

Northern Pipeline Projects Ltd.: D. Anguish

Pehdzeh Ki First Nation: Chief T. Lannie

Government of Northwest Territories:
C.W. Sanderson, Q.C., K. Bergner, C. Ferguson, J. Fulford
Witnesses: Hon. B. Bell, R. Priddle, P. Vician

Sahdae Energy Ltd.: D. Evanchuk
Witnesses: A. Chung, D. Grabke, R. Lawrence

Sambaa K'e Dene Band: J. Lojek, S. Morgan, P. Redvers

Sierra Club of Canada: P. Falvo, K. Ferguson, S. Hazell
Witnesses: E. May; M. McCulloch

Talisman Energy: F.C. Basham

World Wildlife Fund – Canada: P. Falvo, M. Hummel, Dr. R. Powell

Government of Yukon: J.H. Smellie, R.E. Smith, G.M. Nettleton
Witnesses: G. Engbloom; B. Love; K. Osadetz

National Energy Board: P. Enderwick, A. Hudson, D. Saumure

Written Final Argument: Acho Dene Koe First Nation, Alberta Department of Energy, Apache Canada Ltd., Ayoni Keh Land Corporation, Chevron Canada Ltd., North Slave Métis Alliance, Suncor Energy Marketing Inc.

Opening Remarks and Oral Statements: A. Andre, G. Andre, J. Andre, L. André, Chief F. Andrew, J. Antoine, J. Arsenault, L. Azzolini, G. Barbaby, D. Bayha, A. Beaudin, J. Bernard, P. Bhuggins, C. Brown, D. Campbell, S. Carle, B. Clement, D. Codzi, L. Cooke, M. Cox, M. Dubeau, Mayor D. Ehman, A. Elanik, J. Elleze, S. Elleze, M. Ellton, E. Erutse, D. Etchinelle, E. Freeland Ballantyne, Chief C. Furlong, M. Gannon, S. Gargan, D. Gaudet, G. Gibson, R. Gordon, G. Grandjambe, J. Grandjambe, R. Grandjambe, T. Grandjambe, F. Gruben, R. Gruben, L. Jackson, W. Jackson, J. Kakfwi, T. Kakfwi, Chief J. Kay, I. Katz, C. Kochon, G. Kochon, Chief R. Kochon, E. Koe, B. Kotchile, T.-L. Kuptana, J. Lacorn, E. Lamothe, W. Landry, M. Lavigne, P. Lélorey, L. Lennie, Chief T. Lennie, L. Little, I. Manuel, T. Manuel, A. Martel, A. Masuzumi, H. McCauley, R. McCord, G. McMeekin, E. Menicoche, K. Menicoche, L. Menicoche Moses, Mayor M. Mihaly, Elder E. Mitchell, D. Nelner, Chief C. Neyelle, B. Nind, J. Norbert, Chief K. Norwegian, J. Paulson, M. Phelan, F. Pierrot, Chief R. Pierrot, J. Pokiak, B. Ritias, T. Remy-Sawyer, Chief P. Ross, B. Saunders, D.L. Simmons, D. Sipos, D. Sonfrere, J.A. Snowshoe, S. Snowshoe, V. Teddy, M. Teya, J. Thomas, A. Tobac, C. Tobac, Jim Tutcho, John Tutcho, A. Tuninge, D. Vital, J. Vital, A. Williams, A. Yellee, A. Yallee for D'Arcy Moses

Appendix C
Summary of events

Date	Event
June 2002	The *Cooperation Plan for the Environmental Impact Assessment and Regulatory Review of a Northern Gas Pipeline Project through the Northwest Territories* (Cooperation Plan) was issued. The Cooperation Plan set out a joint environmental impact assessment process to meet the requirements of the *Canadian Environmental Assessment Act*, the *Mackenzie Valley Resource Management Act* and the Inuvialuit Final Agreement.
February 2003	The *Plan for Public Involvement in the Environmental Assessment of the Proposed Mackenzie Valley Gas Pipeline in the Northwest Territories* was issued. The Plan provided general information to the public about opportunities to participate in the environmental impact assessment and regulatory review of an anticipated gas pipeline project through the Northwest Territories.
18 June 2003	The Preliminary Information Package for the Mackenzie Gas Project was submitted by the Proponents.
17 July 2003	The Mackenzie Gas Project was referred to the Minister of the Environment for the establishment of a review panel under the *Canadian Environmental Assessment Act*.
21 July 2003	An application for a Type A Land Use Permit and Type B Water License for the Camsell Bend Development was filed with the Mackenzie Valley Land and Water Board, triggering the environmental review process.
21 August 2003	The Minister of the Environment referred the Mackenzie Gas Project to a Joint Review Panel under the *Canadian Environmental Assessment Act*.
October 2003	The Draft Terms of Reference for the Environmental Impact Assessment of the Mackenzie Gas Project was released for comment by the Joint Secretariat for the Inuvialuit Settlement Region, the Mackenzie Valley Environmental Impact Review Board and the Canadian Environmental Assessment Agency.
December 2003	A Memorandum of Agreement was signed by the National Energy Board, the Mackenzie Valley Land and Water Board, the Northwest Territories Water Board, the Mackenzie Valley Environmental Impact Review Board, the Inuvialuit Game Council, the Canadian Environmental Assessment Agency, and the Department of Indian Affairs and Northern Development. The Agreement served to establish the Northern Gas Project Secretariat.
22 April 2004	The Agreement for the Coordination of the Regulatory Review of the Mackenzie Gas Project was released, setting out details for the environmental impact assessment by a Joint Review Panel, the coordination of hearings between regulatory agencies, and the maintenance of a public registry.
August 2004	The Environmental Impact Statement Terms of Reference for the Mackenzie Gas Project was issued by the Joint Secretariat for the Inuvialuit Settlement Region, the Mackenzie Valley Environmental Impact Review Board and the Canadian Environmental Assessment Agency.

Date	Event
9 August 2004	The seven-member Joint Review Panel was created.
16 September 2004	The Joint Review Panel released its Rules of Procedure for the conduct of the Environmental Impact Assessment of the Mackenzie Gas Project by a Joint Review Panel.
7 October 2004	The Environmental Impact Statement was submitted to the Joint Review Panel by the Proponents.
7 October 2004	Proponents submitted all but one of the applications for the Mackenzie Gas Project to the National Energy Board.
20 October 2004	Shell Canada Limited submitted its Niglintgak Development Plan Application to the National Energy Board.
24 November 2004	The National Energy Board issued Hearing Order GH-1-2004 including a schedule of events covering the technical review phase of the proceeding.
November 2004 to January 2006	The National Energy Board, Joint Review Panel and Northern Gas Project Secretariat conducted public information sessions in communities along near the proposed pipeline route. Also during this period the National Energy Board and Joint Review Panel carried out several rounds of information requests in their respective hearings.
23 December 2004	The National Energy Board finalized and issued its List of Issues for the proceeding.
13 July 2005	Imperial Oil Resources Ventures Limited announced that it would advise the National Energy Board in late summer of its readiness to proceed to hearing.
15 September 2005	Imperial Oil Resources Ventures Limited stated it would advise the National Energy Board and the Joint Review Panel in November 2005 of its willingness to proceed to hearing.
23 November 2005	Imperial Oil Resources Ventures Limited announced that it was willing to proceed to public hearings.
December 2005	The National Energy Board held a pre-hearing planning conference to assist parties in preparing for the National Energy Board public hearing. The conference was held in Inuvik, Yellowknife, Fort Good Hope, and Fort Simpson.
20 December 2005	A coordinated hearing schedule was released for the National Energy Board and Joint Review Panel hearings.
25 January 2006 to 14 December 2006	The National Energy Board held 47 days of hearings in 15 communities, starting and ending in Inuvik. The other locations were Norman Wells, Fort Good Hope, Tulita, Fort Providence, Yellowknife, High Level, Hay River, Déline, Wrigley, Fort Simpson, Colville Lake, Tuktoyaktuk, Fort McPherson and Tsiigehtchic.
14 February 2006 to 29 November 2007	The Joint Review Panel held 117 days of hearings in 26 communities, starting and ending in Inuvik.
7 April 2006	The Mackenzie Explorer Group filed a motion with the National Energy Board for an order that, when constructed and placed into service, the Mackenzie Gathering System and Mackenzie Valley Pipeline will be a single pipeline subject to regulation under Part IV of the *National Energy Board Act* and that Imperial Oil Resources Ventures Limited prepare, file and serve the toll principles and the tariff(s) for this single pipeline for approval under Part IV of the *National Energy Board Act*.
2 June 2006	An oral hearing was held in Yellowknife on the Mackenzie Explorer Group's motion.
10 July 2006	The National Energy Board issued Ruling No. 16, denying The Mackenzie Explorer Group's motion. The Mackenzie Explorer Group subsequently appealed the National Energy Board's decision to the Federal Court of Appeal in August 2006.
14 December 2006	The National Energy Board completed its initially scheduled evidentiary hearing in Inuvik.

Date	Event
5 February 2007	The National Energy Board issued a list of potential conditions for comment by parties.
12 March 2007	Imperial Oil Resources Ventures Limited filed a project cost estimate and schedule update.
30 March 2007	Imperial Oil Resources Ventures Limited filed updated costs, tolls and fees.
15 May 2007	Imperial Oil Resources Ventures Limited filed supplemental information to its project updates.
10-11 October 2007	The National Energy Board held a hearing session in Yellowknife to examine updated evidence filed in the National Energy Board hearing.
28-29 November 2007	The Joint Review Panel heard closing statements in Inuvik.
22 April 2008	In *Anadarko Canada Corp. v. (National Energy Board)* [2008] F.C.J. No. 664, the Federal Court of Appeal dismissed Mackenzie Explorer Group's appeal of the National Energy Board's decision to dismiss the Mackenzie Explorer Group's motion that the Mackenzie Gathering System when built should be regulated under the *National Energy Board Act.*
7 October 2009	The National Energy Board issued information on the next steps in its hearing in anticipation of the Joint Review Panel issuing its report.
30 December 2009	The Joint Review Panel issued its report.
30 December 2009	Mr. Rowland J. Harrison, Q.C. issued his subsection 15(1) report.
6 January 2010	The National Energy Board established a process to consult on the Joint Review Panel recommendations.
28 January 2010	The Proponents sent comments on the Joint Review Panel recommendations to National Energy Board and parties to both hearings.
11 February 2010	Parties to both hearings sent comments on the Joint Review Panel recommendations to the National Energy Board, the Proponents and other parties.
18 February 2010	The Proponents sent reply comments on the Joint Review Panel recommendations to National Energy Board and parties to both hearings.
9 March 2010	The National Energy Board provided proposed modifications to the Joint Review Panel for written response.
9 March 2010	The National Energy Board issued a revised list of potential conditions for comment by parties.
15 March 2010	Updated evidence, including evidence on economic feasibility and further evidence on the adequacy of Aboriginal consultation was filed with the National Energy Board.
29 March 2010	The Joint Review Panel responded to the National Energy Board's proposed modifications to the Joint Review Panel recommendations.
29 March 2010	National Energy Board held a hearing session in Yellowknife to examine the updated evidence that was filed in its hearing.
8 April 2010	Written final argument was filed with the National Energy Board.
12-16 April 2010	The National Energy Board heard final argument in Yellowknife.
20-22 April 2010	The National Energy Board heard final argument in Inuvik. The hearing ended after a total of 58 days of hearing in 15 communities.

Appendix D

Development field reservoirs: characteristics and exploration history

The Niglintgak and Taglu reservoirs are both located in the Reindeer Sands formed 60 million years ago during the Early Tertiary Period. This rock is considered to be fairly young, or immature, and poorly consolidated. This means that as gas is extracted, the rock may compress and crumble and the earth can slowly sink. Gas from Parsons Lake reservoir is found in the Kamik Formation of the Early Cretaceous Period, which was formed 140 million years ago. The Kamik Formation is more mature than the Reindeer Sands, and is consolidated. Although the fields share some similar geological characteristics, the reservoirs are all quite different. In the Niglintgak field, the gas is only about one kilometre below the surface, making it a relatively shallow field. In comparison, the Taglu and Parsons Lake fields contain gas about three kilometres below the surface. Characteristics of the gas in each reservoir also differ.

The Parsons Lake field covers a large widespread area with Significant Discovery Licence 030 and 032 covering 104 sections of land. The Niglintgak field's Significant Discovery Licence 019 and Taglu's Significant Discovery Licence 063 cover 12 and 20 sections of land respectively. The Niglintgak and Parsons Lake fields are expected to produce water immediately after gas production commences. Imperial does not anticipate producing any water with its gas production until approximately five years after the Taglu begins production. The natural gas from both the Taglu and Parsons Lake fields is rich containing large amounts of natural gas liquids whereas natural gas from the Niglintgak field is lean. In addition, natural gas from the Parsons Lake field contains significant amounts of carbon dioxide, 3 to 5 percent, which may present corrosion issues. The gas from the Niglintgak and Taglu fields contains small amounts of carbon dioxide.

Table D-1

Gas characteristics for the development fields

Parameter	Niglintgak field	Taglu field	Parsons Lake field
Project life, years	25	30	25
Initial daily raw natural gas production, Mm^3/d (MMcf/d)	4.3 (150)	12.6 (445)	9.0 (324)
Initial daily natural gas liquids production, m^3/d (Bbl/d)	6 (40)	1,230 (7,700)	520 (3,271)
Expected commencement of water production	12th year of production	5th year of production	1st year of production
Carbon dioxide, CO_2, content (%) of gas	0.90%	0.27%	3.00% north pool 5.00% south pool
Hydrogen Sulphide, H_2S, content (%) of gas	0.00%	0.00%	0.00%
Projected depth of production wells, mTVD (ft)	850-2,100 (2,789-6,890)	2,992-3,335 (9,816-10,941)	2,923-2,943 (9,590-9,655)
Expected initial flowing wellhead pressure, MPa (psi)	9.65[1] (1,400)	17.80 (2,580)	23.00[2] (3,336)
Significant discovery licence(s)	SDL-019	SDL-063	SDL-030, SDL-032
Sections of land	12 sections of land	20 sections of land	104 sections of land

[1] Estimate for all wells except for the deep L, M and N sand well which is estimated to be 15.45 MPa (2,241 psi).

[2] Estimate for the north pool. The south pool is estimated to be 19.00 MPa (2,756 psi).

A brief description of the history of exploration and the approach to gas production follows for each field. Oil and gas companies have been exploring Canada's North since the 1950s. However, despite the lure of rich deposits of hydrocarbons, exploration and discovery in the harsh Arctic environment has proven to be a challenge.

Niglintgak

Shell first obtained exploration land in the Mackenzie Delta in 1958. The history of exploration for the Niglintgak field is shown in Table D-2.

Table D-2

Niglintgak exploration history

Year	Activity
1960s and 1970s	2-D seismic surveys
1973	Drilling of discovery well H-30
1974 – 1977	Drilling of four additional exploratory and delineation wells
1988	SDL-019 issued
1988 – 1989	3-D seismic survey
2000	Declaration of a Commercial Discovery issued

The current model of the reservoir is based on information obtained from seismic surveys and exploratory wells. Results of the model for Significant Discovery Licence 019, which covers most of the Niglintgak field, are shown in Table D-3.

Shell, the operator of the Niglintgak field, subdivided the Niglintgak Reindeer Sands into 26 units, or layers, labeled sands A to Z. In some other layers there is no gas present or not in quantities large enough to be commercially extracted. Of the 26 units, Shell plans to produce, or extract gas, from the gas bearing A sands, D to G sands and the L to N sands. The model also indicates the reservoir is broken into several compartments as a result of faulting.

Did you know?

Commercial discovery, significant discovery and significant discovery licence

A commercial discovery is a discovery of petroleum that demonstrates petroleum reserves to justify the investment of capital and effort to bring the discovery to production (*Canada Petroleum Resources Act*).

A production licence is a licence for oil and gas rights issued in respect of all portions of the commercial discovery area that are subject to an exploration licence and/or a significant discovery licence by the Minister of Indian Affairs and Northern Development Canada upon application of an interest holder of the exploration licence and/or significant discovery licence where a commercial discovery is in force.

A significant discovery is a discovery indicated by the first well on a geological feature that demonstrates by flow testing the existence of hydrocarbons in that feature and, having regard to geological and engineering factors, suggests the existence of an accumulation of hydrocarbons that has potential for sustained production (*Canada Petroleum Resources Act*).

A significant discovery licence is a licence for oil and gas rights issued in respect of all portions of the significant discovery area that are subject to an exploration licence by the Minister of Indian Affairs and Northern Development Canada upon application of an interest holder of the exploration licence where a declaration of significant discovery is in force.

Table D-3

Reservoir model results for Significant Discovery Licence 019

Parameter	Unit	
Original gas-in-place	34.0 Gm^3	(1.2 Tcf)
Recoverable gas	27.0 Gm^3	(0.95 Tcf)
Recoverable natural gas liquids	40,000 m^3	(250,000 Bbl)
Initial raw gas production rate	4.3 Mm^3/d	(150 MMcf/d)

Taking into account this compartmentalization, Shell concluded that six production wells could efficiently produce the reservoir. These six wells would range in vertical depth from 850 to 2100 metres and from 1050 to 2550 metres in length and they would be directionally drilled from three well pads. The well locations and the plan and cross-section views of the well pad are shown in Figures 4-5 and D-1.

Four wells would produce the A sand, one well would produce the D to G sands, and one well would produce the L to N sands. Usually, gas from each unit is produced independently of the other units. However, in some cases it is more efficient to mix, or commingle, gas from several units when it is being extracted. Shell plans to make an application to commingle production from the D to G sands and from the L to N sands because of enhanced wellbore flow performance, improved ultimate recovery and economic reasons. The four A sands wells and the D to G sands well are expected to produce a lean sweet gas with little or no natural gas liquids. The L to N sands well would produce a richer gas. Shell estimates the average gas composition to be lean, 98 percent methane with the liquid-rich gas making up less than 5 percent of the total flow.

The locations for these initial six wells were chosen by Shell to optimize gas recovery with minimal water production. However, as wells begin to produce, the operators will have new reservoir data from flow tests and well analysis. This information will be used to determine if additional faulting and compartmentalization exist and whether any contingent wells would be required. This monitoring program would help ensure the Niglintgak field operates effectively and that gas recovery and production are optimized.

All original Niglintgak exploration and delineation wells were abandoned in 1996.

Did you know?

Definitions

Condensate – a liquid hydrocarbon mixture that may be separated from natural gas.

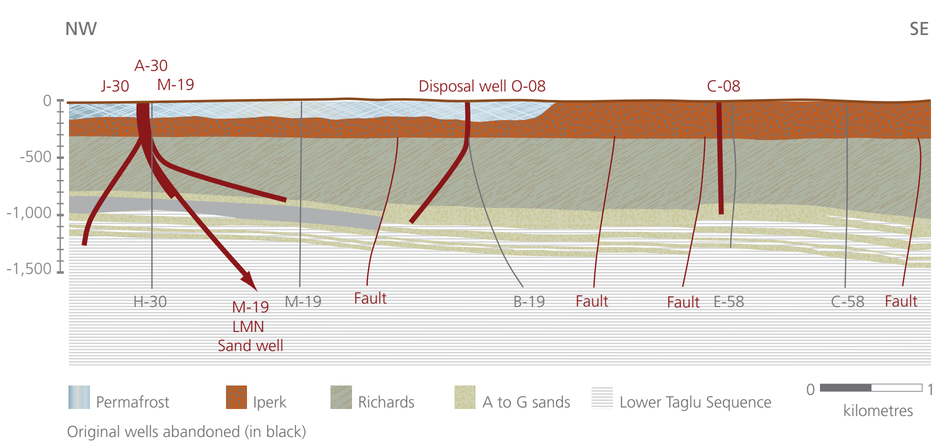
Natural gas liquids – a liquid hydrocarbon mixture that may be extracted from natural gas.

Rich or wet gas – natural gas that contains significant amounts of condensate or natural gas liquids.

Lean or dry gas – natural gas that contains little or no condensate or natural gas liquids.

Figure D-1

A NW-SE cross-section of the Niglintgak reservoir and proposed initial well locations



Taglu

Natural gas in the Taglu field is found in three sand units, or layers, known as the A, B, and C units of the Reindeer Formation in the Tertiary Period. The A sands, the Upper C and the Lower C sands are estimated to contain 95 percent of the original gas-in-place.

The history of exploration for the Taglu field is shown in Table D-4.

Table D-4

Taglu exploration history

Year	Activity
1969	Start of 2-D seismic surveys
1971	Drilling of discovery well G-33
1971 – 1985	Drilling of seven additional exploratory and delineation wells
1987	SDL-063 issued
1987 – 1988	3-D seismic survey
2004	Declaration of a Commercial Discovery issued

Imperial used a computer model to estimate volumes of gas, natural gas liquids and water from its proposed wells. Results are shown in Table D-5.

Table D-5

Reservoir model results for the Taglu field

Parameter	Unit	
Original gas-in-place	109.0 Gm^3	(3.8 Tcf)
Recoverable gas	81.0 Gm^3	(2.8 Tcf)
Recoverable natural gas liquids	4.85 Mm^3	(30.0 MMBbl)
Initial raw gas production rate	12.6 Mm^3/d	(445 MMcf/d)

Imperial's reservoir modeling results describe the Taglu field as being one fault block with minor faulting which is too small to compartmentalize the reservoir. This means the Taglu field is not anticipated to be partitioned and as a result Imperial is proposing to develop 10 to 15 production wells from a single well pad located near the centre of the reservoir. Imperial has provided 11 potential well locations including four wells that would produce from the A sands, four wells that would produce the B2, upper C, lower C and LC2 sands, and three wells that would produce the A and C sands. The vertical depth of these wells would range from about 2992 to 3335 metres. Imperial has indicated if production were not commingled, the field would have a lower gas recovery, a decelerated production profile and a negative economic impact. Imperial also plans to monitor the production wells to confirm the current reservoir model. If faults are located that compartmentalize the reservoir, then contingent wells would be developed. The original Taglu exploration and delineation wells have been abandoned.

Parsons Lake

The history of exploration for the Parsons Lake field is shown in Table D-6.

Table D-6

Parsons Lake exploration history

Year	Activity
1950s, 1960s, 1970s	2-D seismic surveys
1972	Drilling of discovery well F-09
1973 – 1977	Drilling of 17 additional exploratory and delineation wells
1988	SDL-030 & SDL-032 issued
2002	3-D seismic survey
2004	Declaration of a Commercial Discovery issued

Currently, ConocoPhillips believes the Parsons Lake field contains two main natural gas pools. The larger north pool contains approximately 85 percent of the reservoir's natural gas and is partially located under Parsons Lake itself while the rest of the pool stretches northeast of Parsons Lake. The smaller south pool is found southwest of Parsons Lake. The main gas bearing interval in both pools is the Kamik Formation of the Lower Cretaceous Period. ConocoPhillips plans to produce from the Kamik A, A1, B and C sands. The A1, B and C sands each contain roughly a third of the original gas-in-place for the entire Parsons Lake field. The results of reservoir simulation are shown in Table D-7.

Table D-7

Reservoir model results for Parsons Lake

Parameter	Unit	
Original gas-in-place	97.7 Gm^3	(3.45 Tcf)
Recoverable gas	64.0 Gm^3	(2.3 Tcf)
Recoverable natural gas liquids	3.0 Mm^3	(18.7 MMBbl)
Initial raw gas production rate	9.0 Mm^3/d	(324 MMcf/d)

ConocoPhillips is planning to drill the field in two phases. In phase one, crews would drill nine production wells, two disposal wells and 10 contingent production wells from the north pad. Phase two would occur a few years later and would involve drilling three production wells and four contingent production wells from the south pad. If drilling results and further exploration activities indicate additional surface locations are required, ConocoPhillips is proposing three contingent satellite well pads, each holding up to three wells. The vertical depth of these wells would be about 3000 metres.

ConocoPhillips[1] reservoir model of the Parsons Lake field shows it is subdivided into 42 compartments because of multiple faults and multiple sands. Original gas-in-place estimates from the 19 compartments containing gas range from 0.9 to 16.4 Gm^3 (32 to 580 Bcf). Like the other operators, ConocoPhillips is proposing to commingle production from the lower permeability sands of the Kamik Formation to effectively and economically deplete these compartments. This would include three wells commingling the A, A1 and B sands, and, three wells commingling the A1 and B sands from the north pad. The north pad would also include two wells which would produce from the C sands only and one well which would produce from the A1 sands only. Two wells are proposed to commingle the A1 and B sands in the south pool. The third well from the south pad would initially produce the C sands and then be re-completed to produce from the B sands. The advantages of commingling as outlined by ConocoPhillips include reduced costs and longer production life. Commingling would reduce costs because of a lower well count, a smaller project footprint and fewer re-completion programs and associated production downtime. Commingling would enable recovery from smaller reserve compartments and tighter and thinner sands. In addition, ConocoPhillips estimates the pressure differences are less than 0.30 MPa (43 psi) in the sands that would be commingled.

ConocoPhillips has indicated that uncertainty in geological, geophysical and reservoir engineering interpretations means the locations of wells drilled after start-up depend on production and drilling results. Despite the significant amount of information already known about the field, production data is needed to verify much of the geological modeling. Like Shell and Imperial, ConocoPhillips plans to monitor production and evaluate the need for any contingent wells.

As all original wells have been abandoned, new wells would need to be drilled to develop the Parsons Lake field.

[1] ConocoPhillips has proposed that the B-19 well initially produce from the C sands and be then recompleted to produce the A1 and B sands, commingled.

Appendix E
Conversion factors and energy content

Abbreviation table

Metric prefixes		Equivalent
k	kilo	10^3
M	mega	10^6
G	giga	10^9
T	tera	10^{12}
P	peta	10^{15}
E	exa	10^{18}

Metric to Imperial conversion table

Physical units		Equivalent
m	metre	3.2808 feet
km	kilometre	0.621 mile
m^3	cubic metre	6.292 barrels (oil or NGL),
		35.301 cubic feet (gas)
MPa	megapascal	145.037 psi
GJ	gigajoule	0.95 million Btu
ha	hectare	2.47 acres

Energy content table

	Energy measures	Energy content
Electricity		
MW.h	megawatt hour	3.6 GJ
GW.h	gigawatt hour	3600 GJ
TW.h	terawatt hour	3.6 PJ
Natural gas		
MMBtu	million British thermal units	1.05 GJ
Mcf	thousand cubic feet	1.05 GJ
MMcf	million cubic feet	1.05 TJ
Bcf	billion cubic feet	1.05 PJ
Tcf	trillion cubic feet	1.05 EJ
Natural gas liquids		
m^3	ethane	18.36 GJ
m^3	propane	25.53 GJ
m^3	butanes	28.62 GJ

Appendix F
Authorization MO-13-2004

IN THE MATTER OF Subsection 15(1) of the *National Energy Board Act*

AND IN THE MATTER OF an Authorization of a National Energy Board Member to Report and Make Recommendations to the National Energy Board on Matters relating to the Mackenzie Gas Project Application

BEFORE the Board on 15 October 2004.

A. Background

Imperial Oil Resources Ventures Limited, the Aboriginal Pipeline Group, ConocoPhillips Canada (North) Limited, ExxonMobil Canada Properties and Shell Canada Limited (Proponents) have applied or will be applying to the National Energy Board (the Board) for a certificate under section 52 of the *National Energy Board Act* (NEBA) for the natural gas transmission pipeline, an approval under section 5.1 of the *Canada Oil and Gas Operations Act* (COGOA) for the production facilities at the Taglu, Parsons Lake and Niglintgak natural gas fields and for authorizations under paragraph 5(1)(b) of the COGOA for the Mackenzie gathering system, collectively the Mackenzie Gas Project (MGP).

The Board will designate a Panel (NEB Panel) to consider the Mackenzie Gas Project application pursuant to the NEBA.

A Joint Review Panel (JRP) of seven members has been established by agreement of the Mackenzie Valley Environmental Impact Review Board, the Inuvialuit as represented by the Inuvialuit Game Council and the Minister of the Environment to conduct an environmental impact review of the Mackenzie Gas Project that will meet the requirements of the *Canadian Environmental Assessment Act*, the *Mackenzie Valley Resource Management Act* and the *Inuvialuit Final Agreement*.

A Board Member, Mr. Rowland Harrison, has been appointed as a member of the JRP.

The Board desires to authorize Mr. Harrison under subsection 15(1) of the NEBA to report and make recommendations on certain aspects of the application.

B. Authorization

In accordance with the provisions of subsection 15(1) of the NEBA, the Board hereby authorizes Mr. Harrison to report and make recommendations to the NEB Panel regarding the matters set out in Section C below for use by the NEB Panel in its consideration of the Mackenzie Gas Project .

Mr. Harrison has all the powers of the Board for the purpose of taking evidence and acquiring the necessary information for the purpose of making the report and recommendations on the Mackenzie Gas Project application.

This authorization allows Mr. Harrison to utilize the Joint Review Panel process to compile the evidence and information necessary for him to make his report and recommendations to the NEB Panel. Mr. Harrison will consider the matters identified in the Environmental Impact Statement Terms of Reference for the Mackenzie Gas Project dated August 2004 and any other matter that comes within

Section C upon which information or evidence is presented to the Joint Review Panel.

By virtue of this authorization, Mr. Harrison will consider all evidence and material presented to or obtained by the Joint Review Panel regarding the matters set out in Section C below in preparing and presenting his report and recommendations to the NEB Panel.

C. Matters for Report and Recommendations

In relation to the facilities described in Annex 1 to the Schedule: Project Description (which Schedule is appended to the Agreement for an Environmental Impact Review of the Mackenzie Gas Project executed July 27 to August 3 2004), Mr. Harrison's report and recommendations will have regard to the protection of the social, cultural and economic well-being of residents and communities and will include a consideration of the factors as set out in Annex 2 to the said Schedule: Joint Review Panel Mandate.

This authorization was approved by the Board on the 15th of October, 2004.

National Energy Board

[original signed by]

Michel L. Mantha
Secretary

Appendix G
Mr. Rowland J. Harrison's subsection 15(1) report

30 December 2009

Ms. Anne-Marie Erickson
Acting Secretary
National Energy Board
444 – 7th Avenue S.W.
Calgary, Alberta
T2P OX8

Dear Ms. Erickson:

Mackenzie Gas Project Hearing Order GH-1-2004
NEB Authorization Order MO-13-2004

I refer to the above Authorization approved by the National Energy Board (NEB or Board) on October 15, 2004, in accordance with the provisions of subsection 15 (1) of the *National Energy Board Act* (NEB Authorization).

On September 2, 2004, I was appointed by the federal Minister of Environment (Minister) as a member of the Joint Review Panel for the Mackenzie Gas Project (JRP), pursuant to the *Agreement for an Environmental Impact Review of the Mackenzie Gas Project* (JRPA), between the Mackenzie Valley Environmental Impact Review Board, the Inuvialuit Game Council and the Minister.

In accordance with the terms of the NEB Authorization and of the JRPA, I participated fully in the joint review of the Mackenzie Gas Project undertaken by the JRP and in preparing *Foundation for a Sustainable Northern Future: Report of the Joint Review panel for the Mackenzie Gas Project* (JRP Report).

On December 30, 2009, the JRP Report was posted to the JRP Registry. It can be accessed at http://www.ngps.nt.ca/registryDetail_e.asp.

I am a signatory to the JRP Report and agree with its conclusions and recommendations.

I adopt the JRP Report as my report to the NEB for the purpose of fulfilling the requirements of the NEB Authorization. Insofar as the JRP Report recommendations are directed to and address matters within the jurisdiction of the NEB, I recommend them for the Board's consideration.

Yours truly,

[original signed by]

Rowland J. Harrison, Q.C.

Appendix H
National Energy Board's letter to Joint Review Panel regarding modifications

9 March 2010

Mr. Robert Hornal
Chair
Joint Review Panel for the Mackenzie Gas Project
c/o Northern Gas Project Secretariat
5114 – 49th Street
Yellowknife, NWT X1A 1P8

Mackenzie Gas Project (MGP) – Hearing Order GH-1-2004 Consult to Modify Process for the Recommendations Identified in the Joint Review Panel (JRP) Report on the Environmental Impact Review of the Mackenzie Gas Project

The National Energy Board (NEB) is considering the JRP report (Report) issued on 30 December 2009. Pursuant to section 137 of the *Mackenzie Valley Resource Management* Act (MVRMA), the purpose of this letter is to consult with the JRP on possible modifications to the specific recommendations in the Report that were directed to the NEB. The NEB will make final decisions in these matters after final argument.

On 6 January 2010 the NEB set out a comment process regarding the Report and the JRP recommendations that were within the NEB's mandate. On 28 January 2010 the NEB received comments from the Proponents of the Mackenzie Gas Project . On 11 February 2010 the NEB received comments from parties to the NEB Hearings and the JRP Hearings. On 18 February 2010 the NEB received reply comments from the Proponents[1]. In accordance with subsection 137(2) of the MVRMA, the NEB is identifying the comments received as new information the NEB is considering that was not before the JRP.

The attached Table of Concordance for JRP Recommendations and NEB Proposed Conditions (Appendix 1) indicates how the NEB proposes to address each JRP recommendation that was addressed to the NEB. Some of the proposed modifications apply to more than one recommendation as described in the following categories.

Clarification of the Desired End Result

When the NEB prepares conditions it does so with a desired end result (DER) in mind. The DER is the goal or specific outcome expected in response to a condition. This way, the proponent can understand the intent of the condition and the NEB can verify compliance. The NEB prefers to use a goal-oriented approach in describing the DER, whereby the NEB is clear as to the specific outcomes that must be produced. The Proponent is left with flexibility in choosing how to best achieve these outcomes. Verification of compliance with statutes, regulations and conditions continues throughout the project lifespan from the approval stage and continuing through construction, operation and abandonment.

The NEB is considering modifying some of the recommendations to create conditions that have clearly stated desired end results, can be measured for compliance, and are goal-oriented.

---

[1] Documents from the comment process can be found on the National Energy Board's website by clicking on this hyperlink. Alternatively go to www.neb-one.gc.ca. On the right side of the page under "Major Applications (s. 52)" click on Mackenzie Gas Project, then click on the link under the heading "Regulatory Documents". Go into the "6 - Joint Review Panel Report, Mr. Harrison's s. 15 Report and Consult to Modify Process" folder and choose "C - Comments to NEB on Joint Review Panel Recommendations".

Prevailing Statutes and Regulations

Every certificate, authorization or approval issued by the NEB under the *National Energy Board Act* (NEBA) or the *Canada Oil and Gas Operations Act* (COGOA) must comply with the prevailing statutes and regulations. Regulations have been issued requiring companies to:

- follow specified technical standards for the safety, security and protection of people, the environment and property (for example, the *Onshore Pipeline Regulations, 1999* and the latest versions of relevant design codes, including the *Canadian Standards Association Z662, Oil and Gas Pipeline Systems)*
- follow toll and tariff requirements (for example, the *Toll Information Regulations* and *Gas Pipeline Uniform Accounting Regulations);*
- develop manuals, programs and plans to manage the operations of pipelines, plants and field developments.

The NEB expects to see these requirements reflected in environmental protection plans, design drawings and specifications filed pursuant to any approvals.

Flexible and goal-oriented regulations such as those made under the NEBA and COGOA allow regulatory requirements and industry practices to improve and adapt efficiently over the life span of a facility.

The Board issues guidance notes for its goal oriented-regulations which provide assistance to interested parties in understanding the requirements of the regulations and how requirements could be met. The NEB verifies compliance through audits and inspections.

In a number of instances recommendations require information to be filed which would come to the NEB through prevailing statutes and regulations. In these cases, a condition would be duplicative. Accordingly the NEB is considering not including such recommendations as conditions.

Adjustments to the Timing for Implementation

The NEB regulates safety, security, environmental and economic matters throughout a project's life span. The NEB is considering reorganizing several recommendations to reflect the normal sequence of project activities and, accordingly, the filing of related manuals and plans.

Within the Jurisdiction of Other Regulatory Authorities

In the NEB's view, some recommendations fall within the jurisdiction of other regulatory authorities. Conditions imposed by the NEB in such cases could conflict with existing and future regulatory requirements. Duplication serves no useful purpose and undermines an effective and efficient regulatory process. Therefore, the NEB is considering not including such recommendations as conditions.

The NEB will continue to work in collaboration with the organizations created by the land claim agreements in the Northwest Territories when matters of mutual interests arise in the implementation of the respective conditions attached to the various permits which may be issued in respect of the Mackenzie Gas Project .

Delegation of Authority

Some of the JRP's recommendations require other persons, groups or agencies to approve something in order for a proposed NEB condition to be satisfied. In monitoring compliance with conditions it is important to be clear on who is accountable for specific outcomes. The NEB is charged by statute with making the decisions on whether the Mackenzie Gas Project , taking into account the conditions that would be imposed, is in the public interest. If the satisfaction of conditions must be approved by others, accountability becomes unclear. Multiple approvals for the same requirement do not contribute to achieving concrete results. Accordingly, the NEB considers it inappropriate to delegate these decisions to others by requiring their approval for conditions to be satisfied.

However, the NEB strongly promotes consultation with those affected by the decisions it makes and with those who have relevant expertise and information. Therefore the NEB is considering an approach whereby the Proponents are required to consult with appropriate parties and file the results of consultation with the NEB, rather than requiring other parties to approve the Proponents' filings to the NEB.

Outside the Scope of the Mackenzie Gas Project Applications

Some JRP recommendations relate to future facilities for which applications have not yet been made to the NEB. Although some of these facilities were within the scope of the JRP's environmental review, they are not within the scope of the applications the NEB is currently considering. The NEB is considering not including conditions that relate to future applications in the decisions it must make in the GH-1-2004 proceeding. These recommendations will be available for consideration by the NEB when applications for the future facilities come before it.

Operational Matters

Some JRP recommendations are directed to NEB operational matters rather than to the Proponents of the Mackenzie Gas Project . The NEB will consider these recommendations if it approves the project and if the Proponents decide to proceed, but they are not being considered for inclusion as conditions.

Closing

Should the Mackenzie Gas Project be approved, the JRP recommendations directed to the NEB with the possible modifications set out herein could be included as conditions in any approvals granted. For your reference a complete list of potential NEB conditions for the Mackenzie Gas Project is attached (Appendix 2).

The NEB will proceed to final argument on 12 April 2010 and requests that the JRP provide any comments it may have on the proposed modifications by 31 March 2010.

Yours truly,

[Original signed by J. Morales]

for

Anne-Marie Erickson
Acting Secretary of the Board

Attachments

cc: Parties to the JRP Hearing
Parties to the GH-1-2004 Hearing

Appendix I

Concordance table

JRP No.	Title of JRP Recommendation	NEB Condition	
5-1	Proponents' Commitments	1, N1, T1, P1	Since the National Energy Board (NEB) may not adopt all of the recommendations in the Joint Review Panel (JRP) report, it proposes removing the phrase "or except where the Joint Review Panel for the Mackenzie Gas Project (the Panel) has recommended otherwise."
5-2	NGTL Approval Conditions	–	Outside the scope of the Mackenzie Gas Project (MGP) applications as it involves future application(s).
6-1	Baseline	37	Addressed in Condition 37. Timing adjusted to require earlier submission of information. Adjusted to clarify desired end result.
6-2	Final Designs, Impact Assessments, Mitigation Plans	3, 6, 7, 14, 38, 39, 41, 42, 44, 45, 46, 47, 48, 49, 51, 70, N7	The elements of this recommendation are addressed in the NEB conditions listed or through prevailing statutes and regulations [monitoring and ongoing mitigation of integrity and environmental issues would be dealt with during operation by the requirements of the *Onshore Pipeline Regulations, 1999* (OPR) sections 39, 40 and 48]. Timing adjusted to require earlier submission of information.
6-3	Impacts of Climate Change	6, 70, 72, N8, T7, P8	Addressed in the conditions listed. Timing adjusted to allow for earlier submission of information. Adjusted to clarify desired end result.
6-4	Construction and Operations Plan – KIBS/Fish Island	3, 38, N11, T10, P10	Addressed in the conditions listed. Kendall Island Bird Sanctuary (KIBS) – falls within the jurisdiction of other regulatory authorities [Environment Canada]. Fish Island – addressed through prevailing statutes and regulations [sections 39 & 48 of the OPR]. This recommendation will also be addressed in the Environmental Protection Plan.
6-5	Fill and Ditch Subsidence	44	Addressed in Condition 44.
6-6	Frost Bulb and Aufeis Mitigation	51	Addressed in Condition 51, which requires Proponents' consultation with Department of Fisheries and Oceans. Timing adjusted to allow for consultation.

JRP No.	Title of JRP Recommendation	NEB Condition	
6-7	Groundwater Mitigation	48, 49	Addressed in Conditions 48 and 49. To be incorporated into the slope design report required in Condition 48. The NEB has the required expertise to assess adequacy.
6-8	Sediment Mitigation	3, 38	Sediment control is routine for stream crossing design and construction and the NEB would expect it to be part of stream crossing designs and incorporated within the Environmental Protection Plan as required by Conditions 3 and 38. Addressed through prevailing statutes and regulations [post-construction monitoring for issues would be by overflights of the right of way undertaken as part of the monitoring and surveillance requirements of OPR section 39].
6-9	Acid Rock Drainage Mitigation	3, 38, 43	Timing adjusted to obtain the information earlier. Conditions 3 and 38 incorporate the need for an acid rock drainage prevention plan. Condition 43 includes consideration of the environment in the replacement backfill and padding specifications.
6-10	Taglu/Niglintgak Subsidence and Flooding	N4, T3	Addressed in Conditions N4 and T3. Adjusted to clarify desired end result.
6-11	Permafrost and Terrain Research and Monitoring Program	39, 71, 72, N7	Although this recommendation is not directed at the NEB, the effects monitoring plan from recommendation 6-2 (Condition 39) as well as Conditions 71 and 72 will support any government program.
6-12	Adoption of Proposed NEB Conditions	9, 10, 37, 39, 43, 45, 46, 47, 48, 49, 51, 66, 70, 71, 72, N4, T3	Addressed in the conditions listed. Outside the scope of the Mackenzie Gas Project applications to the extent it involves future application(s).
7-2	Spill Contingency Planning and Reporting	4, N20, T19, P19	The listed conditions require an Emergency Response Plan for the construction phase of the project of a greater scope than what is proposed in this recommendation. Addressed through prevailing statutes and regulations [OPR sections 32 to 35 address the operations phase]. *Canada Oil and Gas Operations Act* (COGOA) paragraph 5(1)(b) requires a contingency plan.
7-3	Spill Prevention and Response – Highways	–	Falls within the jurisdiction of other regulatory authorities [Government of the Northwest Territories].
7-4	Spill Prevention and Response – Hazardous Materials	4	Addressed in Condition 4. Addressed through prevailing statutes and regulations [the construction safety manual (OPR section 18) contains training and handling requirements]. The Environmental Protection Plan required for construction addresses the remaining issues as part of the general environmental protection measures. During the operating phase, the training, handling and monitoring requirements for hazardous materials are dealt with as part of the Environmental Protection Program and Operations and Maintenance manuals. COGOA paragraph 5(1)(b) requires safety plan, environmental protection plan and contingency plan.

JRP No.	Title of JRP Recommendation	NEB Condition	
7-5	Spill Prevention and Response – Bulk Fuel Storage on Ice or Water	–	Falls within the jurisdiction of other regulatory authorities [Transport Canada].
7-6	Spill Prevention and Response – Bulk Fuel Storage on Land	–	Falls within the jurisdiction of other regulatory authorities [Indian and Northern Affairs Canada].
7-7	Environmental Emergency Plans	4, 61, 62, N20, N21, T19, T20, P19, P20	Addressed in conditions listed. Incorporated in Emergency Response Plans. Timing adjusted to allow for earlier filing of plans. Adjusted to clarify desired end result. Addressed through prevailing statutes and regulations [OPR sections 32 to 35 address the Operations phase]. COGOA paragraph 5(1)(b) requires safety plan, environmental protection plan and contingency plan.
7-8	Accident and Malfunction Plans –Earthquakes	4, 61, 62, N20, T19, P19	Addressed in the conditions listed. Addressed through prevailing statutes and regulations [accidents and malfunction caused by an earthquake would be addressed in the Emergency Response Plan required by OPR section 32 and Conditions 61 and 62].
7-9	Transportation Emergency Preparedness and Response Plan	4, N20, T19, P19	Addressed in the conditions listed. Incorporated in the Emergency Response Plans. Adjusted to clarify desired end result.
7-10	Local Spill Response Teams	61	The proponent would be required to assess the potential for local spill response teams for pipeline operation as part of Condition 61.
7-11	Spills Management – Mackenzie River	–	This will be considered in collaboration with the other parties to the Northwest Territories/ Nunavut Spills Working Agreement.
8-1	Regional Air Quality Management Strategy	–	Outside the scope of the Mackenzie Gas Project applications as it involves future application(s).
8-2	Final Design, Construction and Operations Procedures	13, N14, N16, T13, T15, P13, P15	Addressed in the conditions listed.
8-3	Air Quality and Emissions Management Plan	11, 12, 13, 15, 59, 67, N10, N11, N14, N15, N16, N17, T10, T13, T14, T15, T16, P10, P13, P14, P15, P16	Addressed in the conditions listed.

JRP No.	Title of JRP Recommendation	NEB Condition	
8-4	Air Quality Impacts Monitoring Program	15, 16, 59, N11, N12, T10, T11, P10, P11	Addressed in the conditions listed.
8-5	Waste Management Plan – Incineration	12, 16, 59, N11, N12, N15, T10, T11, T14, P10, P11, P14	Addressed in the conditions listed. A waste management plan is also part of the Environmental Protection Program during operation.
8-6	Greenhouse Gas Emissions Targets	11, 13, 59, N11, N14, N16, T10, T13, T15, P10, P13, P15	Addressed in the conditions listed.
8-7	Greenhouse Gas Emissions Monitoring	59, N11, T10, P10	Addressed in the conditions listed.
9-1	Fish and Fish Habitat Decision Trees	50, N26, T25, P25	Addressed in the conditions listed. Timing adjusted to allow Proponent more time for design and consultation. Adjusted to clarify the desired end result. Adjusted to replace the delegation of authority with consultation.
9-3	Stream Flow Mitigation	39, 51, 69	Addressed in the conditions listed. Addressed through prevailing statutes and regulations [OPR 39 and 48]. Adjusted to replace the delegation of authority with consultation.
9-4	Fish Habitat Compensation Plan	–	Falls within the jurisdiction of other regulatory authorities [Department of Fisheries and Oceans].
9-6	Fish and Fish Habitat Inspection and Enforcement	–	The NEB would work with other responsible agencies as appropriate to develop an enforcement and inspection strategy.
9-7	Dredging and Barge Landings Plans	T9	Mackenzie Gas Project - Falls within the jurisdiction of other regulatory authorities [Transport Canada, Environment Canada & Department of Fisheries and Oceans]. Development plan applications - addressed in Condition T9 for the proposed Taglu barge landing.
9-8	Dredging Plans – VLMs	–	Falls within the jurisdiction of other regulatory authorities [Environment Canada and Department of Fisheries and Oceans].
9-9	Excavation/Dredging Plan – Niglintgak	N10	Addressed in Condition N10.
9-10	Marine Mammal Protection Plan	–	Falls within the jurisdiction of other regulatory authorities [Transport Canada, Environment Canada & Department of Fisheries and Oceans].

JRP No.	Title of JRP Recommendation	NEB Condition	
10-1	Wildlife Protection and Management Plans	29, 30, 31, N22, N23, N24, N25, T21, T22, T23, T24, P21, P22, P23, P24	To address the recommendations in chapter 10 of the JRP's report, a systematic approach to laying out the conditions is warranted to aid effective implementation and future compliance verification. The NEB has included a condition that sets out the framework for a Wildlife Protection and Management Plan based on the recommendations of the JRP, with species-specific details found in subsequent conditions. Together, this set of conditions is intended to address the JRP's recommendations related to wildlife protection and management. Timing adjusted to allow for earlier filing of data. Adjusted to clarify desired end result. Adjusted to replace delegation of authority with consultation. Outside the scope of the Mackenzie Gas Project applications to the extent that it involves future application(s).
10-2	Yellow Rail and Western Toad	34	Included as species-specific details to Wildlife Protection and Management Plan(s) (see 10-1). Adjusted to replace the delegation of authority with consultation.
10-4	Listed Species Assessments	29, N22, T21, P21	Addressed in the conditions listed (see 10-1). Adjusted to clarify the desired end result. Outside the scope of the Mackenzie Gas Project applications to the extent that it involves future application(s).
10-6	Future Development and Woodland Caribou	–	Outside the scope of the Mackenzie Gas Project applications as it involves future application(s).
10-7	Parsons Lake Airstrip Operating Procedures	P21	Addressed in Condition P21. Addressed in the Wildlife Protection and Management Plan(s) (see 10-1).
10-8	Porcupine Caribou Herd Protection Plan	31, N23, T22, P22	Addressed in the conditions listed. Included as species-specific details to Wildlife Protection and Management Plan(s) (see 10-1). Adjusted to replace delegation of authority with consultation.
10-11	Grizzly Bear Den Surveys	32, N27, T26, P26	Addressed in the conditions listed. Included as species-specific details to Wildlife Protection and Management Plan(s) (see 10-1).
10-15	Future Development and Polar Bears	–	Outside the scope of the Mackenzie Gas Project applications as it involves future application(s).
10-16	Wildlife Protection and Management Plans – Listed Species	29, N22, T21, P21	Addressed in the conditions listed (see 10-1). Outside the scope of the Mackenzie Gas Project applications to the extent that it involves future application(s).
10-17	Wood Bison Plan	33	Addressed in Condition 33. Included as species-specific details to Wildlife Protection and Management Plan(s) (see 10-1). Adjusted to replace delegation of authority with consultation.

JRP No.	Title of JRP Recommendation	NEB Condition	
10-18	Short-Eared Owls and Rusty Blackbirds Surveys	35, N24, T23, P23	Addressed in the conditions listed. Included as species-specific details to Wildlife Protection and Management Plan(s) (see 10-1).
10-19	Peregrine Falcon Protection and Management Plan	36, N25, T24, P24	Addressed in the conditions listed. Included as species-specific details to Wildlife Protection and Management Plan(s) (see 10-1).
10-20	Raptor Protection and Management Plan	36, N25, T24, P24	Addressed in the conditions listed. Included as species-specific details to Wildlife Protection and Management Plan(s) (see 10-1).
10-24	Air Operations Plan – Taglu	T21	Addressed in Condition T21. Addressed in the Wildlife Protection and Management Plan(s) (see 10-1).
10-25	De-Icing Fluid Management	16, N12, T11, P11	Addressed in the conditions listed. Addressed in Waste Management Plan (see 14-3)
10-26	Noise Emissions – KIBS	N9, T8	Addressed in Conditions N9 and T8. Alberta's Energy Resources Conservation Board Directive 038 permissible sound level of 40 dBA at 1.5 km may be adjusted to reflect "best management practices" and "best available technologies".
11-8	Approval of Community Conservation Plans and land use plans that incorporate socio-cultural and ecological thresholds	–	Outside the scope of the Mackenzie Gas Project applications as it involves future application(s).
11-10	Legal enforceability of approved Community Conservation Plans in the Inuvialuit Settlement Region	–	Outside the scope of the Mackenzie Gas Project applications as it involves future application(s).
11-15	Interim protection of Sahtu Settlement Area lands identified as having high conservation value or traditional and cultural importance	–	Outside the scope of the Mackenzie Gas Project applications as it involves future application(s).
11-16	Approval of the Sahtu Land Use Plan	–	Outside the scope of the Mackenzie Gas Project applications as it involves future application(s).
11-18	Approval of the Dehcho Land Use Plan	–	Outside the scope of the Mackenzie Gas Project applications as it involves future application(s).
12-2	Harvester Compensation Agreements (NWT) – Communication	–	Falls within the jurisdiction of other regulatory authorities [specified within the various Land Claim Agreements].

JRP No.	Title of JRP Recommendation	NEB Condition	
12-5	Harvester Compensation Agreements (Alberta) – Communication	–	Outside the scope of the Mackenzie Gas Project applications as it involves future application(s).
12-6	Worst-Case Scenarios	MGS1, MGS75, N1, N5, T1, T5, P1, P6	Addressed in the conditions listed.
13-2	Granular Management Plan	–	Outside the scope of the Mackenzie Gas Project applications as it involves future application(s).
13-3	Merchantable Timber	MVP75	Addressed in Condition 75 for the Mackenzie Valley Pipeline. Adjusted to clarify desired end result.
13-6	Heritage Resources Management Plan	21	Addressed in Condition 21. Adjusted to clarify desired end result.
14-1	Transportation and Logistics Plan	–	Falls within the jurisdiction of other regulatory authorities [GNWT].
14-2	Community Services/ Infrastructure	22	Addressed in Condition 22. Adjusted to clarify desired end result.
14-3	Waste Management Plan	16, N12, T11, P11	Addressed in the conditions listed.
15-9	Diversity Plans	23, N28, T27, P27	Addressed in the conditions listed. Adjusted to clarify desired end result.
15-10	Employee Travel to Work Sites	–	Outside the scope of the Mackenzie Gas Project applications as it involves future application(s).
16-1	Closed Work Camps	24	Addressed in Condition 24.
16-2	Existing Camps	25	Addressed in Condition 25. Adjusted to replace delegation of authority with consultation.
16-3	Worker Interactions – Fort Good Hope and Tulita	26	Addressed in Condition 26.

JRP No.	Title of JRP Recommendation	NEB Condition	
16-4	Noise Monitoring	15, 68, N9, N11, T8, T10, P9, P10	Addressed in the conditions listed.
16-23	Issues Resolution Program	27, N29, T28, P28	Addressed in the conditions listed. Outside the scope of the Mackenzie Gas Project applications to the extent it involves future application(s).
17-1	Extension of NEB Decommissioning and Abandonment Principles	MGS77, MGS78, MGSTolls4, N5, N6, T5, T6, P6, P7	Addressed in the conditions listed. Adjusted to clarify desired end result.
17-2	Coordination of Decommissioning and Abandonment Approvals	MGS77, MGS78, MGSTolls4, N5, N6, T5, T6, P6, P7	Addressed in the conditions listed. Adjusted to clarify desired end result. The NEB will continue to work collaboratively with Northern agencies to develop a coordinated and effective approach.
18-5	Adaptive Management Components	–	The NEB subscribes to the principles of adaptive management.
18-7	Local NEB Office	–	This is an operational matter that the NEB will consider should the applications be approved and the Proponents decide to proceed.
18-8	NEB Reports	–	The NEB will continue to work collaboratively with Northern agencies to develop a coordinated and effective approach regarding compliance and inspection activities for the project. All reports filed in compliance with conditions will be available on the NEB's website.
18-9	Comprehensive Environmental Management Plans	3, 38, 59, N11, T10, P10	Addressed in the conditions listed. Addressed through prevailing statutes and regulations [OPR and *Canada Oil and Gas Drilling and Production Regulations]*.
18-10	Coordination of Compliance Monitoring	–	The NEB will continue to work collaboratively with Northern agencies to develop a coordinated and effective approach regarding compliance and inspection activities for the project.
18-11	Local Monitors	28, N30, T29, P29	Addressed in the conditions listed.
18-21	Future Developments	–	Outside the scope of the Mackenzie Gas Project applications as it involves future application(s).

Appendix J
Joint Review Panel's response to NEB's consult to modify process

March 29, 2010

Ms. Anne-Marie Erickson
Secretary
National Energy Board
444 – 7th Avenue S.W.
Calgary, Alberta
T2P 0X8

Dear Ms. Erickson:

Mackenzie Gas Project (MGP) – Hearing Order GH-1-2004

Consult to Modify Process for the Recommendations Identified in the Joint Review Panel (JRP) Report on the Environmental Impact Review of the Mackenzie Gas Project

The Joint Review Panel for the Mackenzie Gas Project (JRP or Panel) acknowledges receipt of the letter of March 9, 2010 from the National Energy Board (NEB) for the purpose of "consult[ing] with the JRP on possible modifications to the specific recommendations in the [JRP] Report that were directed to the NEB" (the "NEB letter to consult").

The JRP has considered the NEB letter to consult and provides the following comments.

The JRP first notes that neither the Panel's Terms of Reference nor the *Mackenzie Valley Resource Management Act* (MVRMA) provide the Panel with any guidance on the Panel's role in the "consult to modify" process, which, the Panel notes, is unique to the MVRMA. The Panel has considered the Mackenzie Valley Environmental Impact Review Board Reference Bulletin of June 5, 2005 but has found it to be of limited assistance in guiding the Panel.

In the absence of guidance, the Panel has concluded that its role is to provide overall comments directed at whether, in the Panel's view, any modifications that are proposed to be made to the Panel's recommendations would have the effect of nullifying or undermining the Panel's overall conclusions with respect to the likely significance of the impacts of the Mackenzie Gas Project and its contribution to sustainability. In the Panel's view, it is not the Panel's role to "pass judgment" on the drafting of measures that appear to be directed at implementing the Panel's recommendations.

It appears to the Panel that, generally, and subject to the following two paragraphs, the NEB Proposed Conditions have not rejected any of the Panel's recommendations that are directed to the NEB and that the modifications proposed by the NEB are primarily for the purpose of ensuring that the implementation of those recommendations conforms to established NEB protocols and procedures, operational requirements and other statutes and regulations. Where the proposed modifications might affect the interests of other parties (for example, where information is to be provided to other regulators), the Panel notes that those parties may present their views to the NEB.

In the Table of Concordance forwarded with the NEB letter to consult, the NEB has noted in several instances that the relevant JRP recommendation is "[o]utside the scope of the Mackenzie Gas Project (MGP) applications as it involves future application(s)." The JRP does not understand this notation to be a rejection by the NEB of the relevant recommendation. The relevant JRP recommendations stand and the Panel expects that they would, accordingly, be considered by the NEB in the specific context of any future applications.

In several other instances, the NEB has noted in its Table of Concordance that certain JRP recommendations are "within the jurisdiction of other regulatory authorities…" In these instances, the substance of the Panel's recommendations stands and the specific recommendations should be read as being directed to the relevant regulatory authority.

The Panel understands that the Government of Canada will, pursuant to section 135 of the MVRMA, consult the Panel in the event the Government proposes to make any modifications or rejections to the Panel's recommendations. The Panel may make further comments at that time.

The Panel reaffirms its overall conclusion that the adverse impacts of the Mackenzie Gas Project and the Northwest Alberta Facilities would likely not be significant and that the project and those Facilities would likely make a positive contribution towards a sustainable northern future, **"subject to the full implementation of the Panel's recommendations."**

Sincerely,

[Original signed by]

Robert Hornal
Joint Review Panel Chair

cc: All Parties to the Environmental Impact Review conducted
by the Joint Review Panel for the proposed Mackenzie Gas Project
Mr. Joe Acorn

Appendix K
Conditions for the Mackenzie Valley Pipeline

Unless otherwise specified in the condition, *pre-construction activities* include activities such as: clearing and grading for infrastructure development; construction and operation of camp facilities; the development of borrow pits, roads, and airstrips; snow pad construction; the transportation and stockpiling of fuel and material; and geotechnical investigations necessary for the construction of the pipeline project. Pre-construction activities may include other activities such as clearing of the right of way if approved by the National Energy Board. Pre-construction activities do not include activities associated with normal surveying operations or data collection activities.

Unless otherwise specified in the condition, *pipe-laying operations* include the clearing of vegetation in proximity of water crossings and on thaw sensitive slopes, as well as grading and trenching and other forms of right of way and station site preparation that may have an effect on the environment through to final clean-up and reclamation.

Unless otherwise specified, Proponent *consultation* referred to in a condition must be carried out in a manner that includes the Proponent:

a) providing, to the party to be consulted,
   - i) notice of the matter in sufficient form and detail to allow the party to prepare its views on the matter,
   - ii) a reasonable period for the party to prepare those views, and
   - iii) an opportunity to present those views to the party conducting the consultation; and

b) considering, fully and impartially, any views so presented.

Unless otherwise specified in a condition *best available technology* (BAT) means technology with superior emissions performance which is commercially available at a reasonable cost at the time it is required for the project which meets the goals of pollution prevention and energy efficiency.

Unless otherwise specified in a condition *best management practices* (BMP) are innovative, dynamic, and improved environmental protection practices and procedures that help ensure that development is conducted in an environmentally responsible manner. BMP may exist as formal guidelines or generally accepted procedures that are recognized by regulators and industry associations as best practices.

Conditions that correspond for the Mackenzie Valley Pipeline and the Mackenzie Gathering System

General

1. Unless the NEB otherwise directs, the Proponent shall cause the approved facilities to be designed, located, constructed, installed and operated in accordance with the commitments, specifications, standards, policies, mitigation measures, procedures, and other information referred to in its application or in the Environmental Impact Statement or other filings, or as otherwise agreed to during the GH-1-2004 Hearing and during the review by the Joint Review Panel.

2. Unless the NEB otherwise directs, the Proponent shall comply with all filing timelines and completion dates set out in these conditions.

Prior to Pre-Construction Activities

3. To compile and communicate all of the Proponent's environmental protection procedures, mitigation measures, and monitoring commitments pertaining to pre-construction activities to its field staff and to the NEB inspectors, the Proponent shall file with the NEB an Environmental Protection Plan (EPP) for approval at least 90 days prior to the start of pre-construction activities. The EPP may be divided into separate plans by region or project area as deemed necessary.

   The pre-construction EPP shall include:

   a) the scope and area of application of the EPP;
   b) environmental protection procedures and measures, including decision criteria for timing and implementation of these measures, site-specific plans and drawings, mitigation measures, and monitoring applicable to pre-construction activities;
   c) an acid rock drainage prevention plan incorporating the testing of quarried and exposed rock during infrastructure, borrow pit and quarry development and provisions for the safe disposal or treatment of unsuitable material if required;
   d) references to other plans and manuals for environmental protection required by field staff and inspectors; and
   e) evidence of consultation with appropriate regulatory authorities and government subject matter experts in the area of application of the EPP.

4. To address worker and public safety and environmental protection during construction in the unique northern environment, the Proponent shall file an Emergency Response Plan with the NEB at least 60 days prior to the start of pre-construction activities which shall address 24-hour medical evacuation, fire response and hazardous chemical and fuel spill response and security issues. The Emergency Response Plan shall be prepared in consultation with Indian and Northern Affairs Canada, the Canadian Coast Guard, Transport Canada, Environment Canada, the Government of the Northwest Territories and the Inuvialuit Land Administration, as applicable, and shall include:

   a) the scope of the plan detailing the project infrastructure, geographic and time period covered by the plan;
   b) training and orientation requirements of company and contractor staff;
   c) an inventory of petroleum products, chemicals and other hazardous substances, together with corresponding MSDS sheets, that will be transported, stored and/or used during the pre-construction and construction phases;
   d) storage facilities and locations of the above inventoried products and substances;
   e) identification of resources (equipment and staff) to be on-site and/or available to respond to emergencies;
   f) identification of mutual aid partners and the location of their resources (equipment and staff) available to respond to emergencies;
   g) procedures for responding to spills, releases, fires, medical emergencies and security issues including the incident reporting and notification system;
   h) location of fire and spill response equipment stores and the spill kit requirements for vehicles;
   i) a phone list of company, contractor, government agency and community representatives outlining their respective roles and information needs;
   j) clean-up and disposal procedures for generated clean-up wastes;
   k) identification of muster points for emergency evacuations from camps and facilities;
   l) location of emergency medical treatment locations and capabilities;
   m) the requirement for 24-hour emergency medical evacuation capability; and
   n) maps showing the location of the right of way and infrastructure such as camps, access roads, material storage areas, barge landing sites and borrow pits to facilitate the dispatch of first responders.

5. To address worker and public safety in the unique northern environment, the Proponent shall file a construction safety manual with the NEB at least 60 days prior to the start of pre-construction activities.

6. To confirm consideration of the effects of climate change on specific geohazard mitigation, slope and stream crossing designs and terrain stability for the overall design life of the project, the Proponent shall file a report six months prior to the start of pre-construction activities which includes:
   a) an analysis of the impacts of climate change and variability on permafrost and terrain stability for a series of representative locations and conditions using potential upper limit temperature scenarios which may occur along the Mackenzie Valley;
   b) a description of how these upper limit temperature scenarios may impact precipitation and stream flows along the Mackenzie Valley;
   c) a description of how the Proponent will account for the potential change in precipitation patterns in the detailed design of slopes and water course crossings for the project; and
   d) the results of consultation with other appropriate regulators and government departments.

7. To facilitate NEB inspections, the Proponent shall file with the NEB updated environmental alignment sheets at least 90 days prior to pre-construction activities, and shall file with the NEB any modifications as they become available.

8. To facilitate NEB inspections, the Proponent shall file with the NEB a detailed construction schedule or schedules identifying major activities at least 30 days prior to pre-construction activities and pipe-laying operations, and shall notify the NEB of any modifications to the schedule or schedules as they occur.

9. To demonstrate that project winter roads will be constructed and operated in a safe and environmentally acceptable manner, the Proponent shall file with the NEB a manual for the construction, operation, maintenance and closure of project winter roads at least 30 days prior to the start of project winter road construction.

   The manual shall include:
   a) required road width, clearing and grading requirements, grade, allowable speed, signage, maximum vehicle weight;
   b) objective and measurable environmental and engineering criteria to determine when the winter road will be ready for use;
   c) safe ice thickness criteria for lake, river and stream crossing including the frequency of ice profiling;
   d) local regulatory requirements;
   e) installation and removal requirements for snow fills, culverts, corduroy and temporary bridges; and
   f) objective and measurable environmental and engineering criteria for closure.

10. To demonstrate that the pipeline and project winter roads will be constructed and operated in a safe and environmentally acceptable manner, the Proponent shall file with the NEB a copy of any applicable permits, authorizations and letters of advice issued by the Federal departments, the Government of the Northwest Territories, or local regulatory organizations that are referred to in an EPP or winter road manual at least 90 days prior to pre-construction activities.

11. The Proponent shall evaluate the technologies and practices available to reduce emissions of particulate matter (PM) and PM and ozone precursors from its facilities and construction related activities, and incorporate the BMP and BAT to reduce emissions of PM and precursors of PM and ozone to the extent practicable. The Proponent shall file a report of its findings and how it will implement its findings to the NEB at least six months prior to construction of the Inuvik Area Facility, compressor stations and heater stations.

12. The Proponent shall evaluate and implement technologies and practices available to reduce mercury, dioxin and furan emissions from incinerators operating at construction camps and its station facilities to the extent practicable. The Proponent shall file a report of its findings and how it intends to implement its findings to the NEB at least 60 days prior to the operation of its construction camps and station facilities.

13. The Proponent shall file with the NEB at least 60 days prior to the start of station facility construction, a report outlining:
    a) the specific design and operational measures it has implemented and will implement to minimize methane leakage and venting through the system's operation taking into account BMP developed by CAPP, Environment Canada, the Canadian Energy Partnerships for Environmental Innovation and the Canadian Gas Association;
    b) how the Proponent has utilized waste heat energy to minimize natural gas fuel consumption in the design of the Inuvik Area Facility;
    c) the use of BAT when specifying compressor units used on the project including size, efficiency and their conformity with Canadian Council of Ministers of the Environment National Emissions Guidelines for Stationary Combustion Turbines (CCME,1992); and
    d) results of consultation with Environment Canada and the Government of Northwest Territories.

14. To demonstrate that the design is experimentally verified and that the inputs and outputs of the design calculations are clearly determined for overland, slope and water crossing designs, the Proponent shall file with the NEB at least six months prior to the start of pipe manufacture:
    a) a stress/strain analysis, including all inputs, assumptions, outputs, methods, and outline of process of calculation;
    b) a detailed description and results of all verification tests performed in support of the stress/strain analysis;
    c) an explanation and reconciliation of any differences and uncertainties that may result among:
        i) stress/strain analysis inputs and outputs;
        ii) results of verification tests;
        iii) final material properties specifications; and
        iv) loads, stresses and strains pipelines may experience during transportation, construction, and operation; and
    d) a description of the processes for the implementation of changes that may occur between the design information and material specifications submitted to the NEB as a result of Conditions 14 and 18, and the detailed design and the actual material properties.

15. The Proponent shall file with the NEB for approval, at least 30 days prior to the start of pre-construction activities an Air Quality Monitoring Program developed in consultation with Environment Canada, Health Canada and the Government of the Northwest Territories, to be undertaken immediately prior to and during construction. This program shall include:
    a) identification of the baseline, pre-construction conditions;
    b) the location of monitoring sites on a map or diagram, the purpose for the locations selected, and the timing for installation;
    c) methods and schedule of constituent monitoring (PM, O_3, NO_2 and noise);
    d) data recording, processing and reporting details;
    e) the process for public communication and complaint response; and
    f) details of the additional measures that would be implemented as a result of monitoring data or ongoing concern, and the criteria or thresholds that would require these measures.

    The Proponent shall include a legacy plan detailing the measures that would be continued through the operation phase as a result of monitoring undertaken or ongoing concern and the criteria or thresholds that are used to determine when they would no longer be required.

16. In order that the right of way, camps and supporting infrastructure are maintained, operated and left in an environmentally acceptable condition following the construction phase of the project, the Proponent shall file a Waste Management Plan with the NEB for approval 90 days prior to the start of pre-construction activities. This plan shall be developed in consultation with the Government of the Northwest Territories, Indian and Northern Affairs Canada

and Environment Canada. The Waste Management Plan shall address all wastes associated with the construction of the project with the objectives of minimizing impacts to the environment and ensuring worker and public safety. The plan shall address air, land and water quality; measures to minimize animal attraction; and preventing uncontrolled fires. The scope of the plan shall include:

a) disposal or treatment of potentially hazardous and dangerous materials, including petroleum products, toxic or persistent chemicals, oily wastes, de-icing fluids and fuel barrels;

b) solid waste management including metals, plastics, recyclables, incinerator ash, equipment, equipment parts, batteries, building materials and construction waste;

c) food waste management;

d) management of contaminated soil, snow and ice from spills and de-icing activities;

e) treatment and disposal of waste water (including domestic sewage and grey water); and

f) incinerator emissions monitoring.

The plan shall address:

i) incineration and evaporator technology choices and rationale for selection;

ii) training requirements for operators;

iii) waste segregation requirements;

iv) interim waste storage;

v) treatment;

vi) testing method for waste streams proposed for release to the environment (e.g. air and water);

vii) disposal method for waste streams proposed for release to the environment; and

viii) final off-site waste disposal locations and facilities including evidence of facility approvals and compliance with regulations.

17. To mitigate potential localized low fracture toughness in or adjacent to the welds which could be detrimental during anticipated pipeline deformation at low operating temperatures, the Proponent shall:

a) determine the minimum acceptable value for the crack tip opening displacement (CTOD) for weld metal and heat affected zone of mill circumferential, helical (if practicable) and longitudinal welds, for the lowest installation temperature and the most severe deformation during construction or operation. The CTOD tests shall be conducted for all combinations of pipe steel producers and pipe mill manufacturers and be representative of applicable project pipe with the maximum Carbon Equivalent (CE) heat;

b) determine the minimum acceptable value for the CTOD for field circumferential welds for the lowest installation temperature and the most severe deformation during construction or operation. The CTOD tests shall be conducted at the welding procedure development phase, for all combinations of pipe steel producers and pipe mill manufacturers and be representative of applicable project pipe with the maximum CE heat. Deviations in the essential changes as specified in CSA Z662-07, Table 7.3 and Table K1 will require weld procedure requalification and retesting to determine the minimum acceptable value for the CTOD; and

c) file with the NEB minimum acceptable CTOD values and results of the tests:

i) for the mill qualification welds, at least 60 days prior to the pipe manufacture; and

ii) for the field circumferential qualification welds, at least 60 days prior to the field welding.

18. To demonstrate compliance with appropriate regulations, standards and engineering practices and to facilitate NEB audits, the Proponent shall file with the NEB the following documents, to be finalized prior to the procurement of materials:

a) project-specific material specifications for pipe, fittings, valves, and pig launchers and receivers, at least 90 days prior to the start of manufacture of each of these elements;

b) specifications for plant-applied coatings for buried and exposed pipeline(s) and valves, at least 90 days prior to the application of each coating. The specifications shall include coating materials, application methods, and verification test results;

c) specifications for materials to be used for the manufacture of stations, the Inuvik Area Facility, and the Trout Lake Heater Station, including applicable standards, and non-destructive examination methods and frequency, at least 60 days prior to the start of the manufacture of each of these facilities;

d) joining program for mill welding, at least 90 days prior to the start of manufacture of pipe, components or facilities in the plant;

e) non-destructive examination specifications for the mill non-destructive examinations at least 90 days prior to the start of each non-destructive examination; and

f) project-specific quality assurance programs for all materials, components, and processes at least 90 days prior to manufacture of pipe components and facilities.

19. Unless the NEB otherwise directs, to facilitate NEB monitoring, the Proponent shall file with the NEB project progress reports that summarize major activities by construction spread, as follows:

a) every month during active construction periods; and

b) every two months during pre-construction and inactive construction periods.

These reports shall also provide:

i) the description of any significant pipeline and facilities design changes;

ii) the list of any current and cumulative number of incidents, accidents, or hazardous occurrences as defined in regulations pursuant to the *National Energy Act* and the *Canada Labour Code Part II*;

iii) a description of any major activities planned for the next reporting period;

iv) locations and proposed timing of any planned pressure tests; and

v) locations of any unsuccessful pressure tests and their cause.

20. To demonstrate the effective management of safety and environmental protection matters during pre-construction and construction, the Proponent shall file with the NEB at the start of field pre-construction activities, a diagram of the project's organization, clearly identifying roles, responsibilities and reporting structure.

21. The Proponent shall file with the NEB, at least 30 days prior to the start of pre-construction activities, the Heritage Resources Management Plan as reviewed by the Prince of Wales Northern Heritage Centre.

22. The Proponent shall file with the NEB, at least 90 days prior to the start of pre-construction activities, the results of consultations regarding the conclusion of fee-for-service agreements with affected communities respecting the use of community services or infrastructure facilities.

23. The Proponent shall file, at least 90 days prior to the start of pre-construction activities, diversity plans, inclusive of gender equality, for both the construction and operations phases of the Mackenzie Gas Project. The plans shall include:

a) methods for determining diversity goals;

b) identification of diversity goals;

c) steps to achieve the identified goals;

d) commitments to the provision of a healthy and safe work environment;

e) steps to create a Diversity Management Committee; and

f) a monitoring and reporting system.

The Proponent shall require its contractors and subcontractors to comply with the Proponent's diversity plans.

24. To minimize and address adverse impacts of any interactions between the construction workforce on the Mackenzie Gas Project and the communities in proximity to the project, the Proponent shall implement closed work camps. This requirement shall apply to all new work camps proposed by the Proponent, its contractors and subcontractors.

25. To minimize and address adverse impacts of any interactions between workers in existing open camps that may be used for the project and the communities in proximity to those camps, the Proponent shall identify to the NEB whether any of the existing open construction camps will be used, either directly or indirectly, in relation to project construction. Where existing open camps are to be used and are to remain open, the Proponent shall develop a plan to minimize and address adverse impacts of any interactions. The plan should be developed in consultation with affected communities, identify the specific measures to be employed to address adverse impacts, and comply with the commitments made by the Proponent. The plan shall be filed with the NEB at least six months prior to the start of pre-construction activities.

26. To minimize and address potential adverse impacts of any interactions between the construction workforce on the Mackenzie Gas Project and the communities of Fort Good Hope and Tulita, the Proponent shall file with the NEB, at least six months prior to the start of pre-construction activities, a plan to monitor the interactions between the construction workforce and the communities. The plan shall be developed in consultation with the leadership of Fort Good Hope and Tulita, and include:

    a) plans for monitoring interactions;

    b) the specific measures that will be employed to address adverse interactions, should any be identified; and

    c) plans for regular consultation and reporting on interactions with both potentially affected communities.

27. The Proponent shall file with the NEB, at least six months prior to the start of pre-construction activities, plans for a formal issues resolution program that will be implemented during construction and operations of the Mackenzie Gas Project. The plans shall be prepared in consultation with the government of the Northwest Territories, the Government of Yukon and Aboriginal authorities, and include:

    a) a description of the process by which any complaints or issues related to the Mackenzie Gas Project would be raised with the Proponent or governments;

    b) a description of the process by which any received complaints or issues would be allocated among those with responsibility for action and a description of the roles and responsibilities of any party involved in assessing or responding to any complaint or issue;

    c) a description of the process by which any received complaints or issues would be resolved;

    d) a description of any protocols developed for referral and resolution of any complaints or issues;

    e) a description of the recourse mechanisms for any unresolved complaints or issues or any unsatisfactorily resolved complaints or issues; and

    f) a description of the process for communicating and informing communities about the issues resolution program.

28. The Proponent shall file, prior to the start of pre-construction activities, information related to the hiring of local residents as monitors to carry out compliance and environmental impact monitoring for the Mackenzie Gas Project including:

    a) the nature of the activities to be monitored;

    b) clearly defined job descriptions for the positions as monitors;

    c) identification of the training that will be offered to monitors to enable them to perform their duties; and

    d) confirmation that monitors have been hired.

29. To minimize project-related impacts on wildlife species, the Proponent shall file with the NEB for approval, before the detailed pipeline route is filed with the NEB and at least 90 days prior to the start of pre-construction activities, a Wildlife Protection and Management Plan or Plans to address general wildlife protection and specific protection of woodland caribou, barren ground caribou, grizzly bear, polar bear and wolverine. The Wildlife Protection and Management Plan(s) shall specify goals, area covered by the plan(s), and assumed zones of influence of project activities and rationales for these assumptions. The Wildlife Protection and Management Plan(s) may be divided into separate plans by region or project area as deemed necessary.

    The Wildlife Protection and Management Plan(s) shall include:

    a) results of pre-construction surveys, including surveys for species at risk listed on Schedule 1 of the *Species at Risk Act* public registry (listed species) except where the Minister has determined that recovery for the species is not feasible, and locations of any observations of species classified as at risk or may be at risk on the most recent Committee on the Status of Endangered Wildlife in Canada assessment and NWT General Status Ranks;
    b) updated impact assessments for listed species in consideration of the *Species at Risk Act*, conducting the impact assessments directly on the listed species where possible rather than using one or more indicator species;
    c) mitigation measures including:
        i) measures to avoid or minimize disturbances including linear disturbance and effects of habitat fragmentation, sensory disturbance, and barriers to movement;
        ii) scheduling of project activities to minimize wildlife disturbance;
        iii) measures to minimize the development footprint in habitats known to support listed species;
        iv) measures to limit predator travel along right of ways;
        v) procedures to avoid disturbance of potential maternal denning areas;
        vi) access management, including provisions for public consultation;
        vii) protocols and education/awareness activities for managing human-wildlife interactions, including measures to limit harvesting and to deter wildlife, especially bears, from entering camps and other facilities;
        viii) measures to reduce the impacts of access road, right of way, and other project-related vehicle and air traffic on wildlife and migratory birds; and
        ix) any wildlife protection measures included in other project management plans, or references to those measures;
    d) protocols for monitoring and adaptive management including:
        i) establishing and maintaining linkages to regional programs;
        ii) survey protocols to be employed to avoid or prevent impacts to wildlife;
        iii) plans for monitoring responses of wildlife to project activities during all phases of the project;
        iv) protocols for documenting habitat loss and habitat change as well as wildlife incidents, interactions and mortality; and
        v) measures to determine the effectiveness of mitigation measures, criteria to determine when and how mitigation measures should be adapted, as well as the responses proposed to address unforeseen effects;
    e) implementation plans, including:
        i) details on how the plans will be implemented by the Proponent;
        ii) the measures the Proponent will take to enable the participation of local monitors; and
        iii) the process for updating the protection plan as information gaps are addressed, including listed species’ recovery strategies and action plans;

f) processes for oversight and reporting with respect to the Wildlife Protection and Management Plan(s) and how those processes will be implemented; and

g) evidence of consultation with the Government of the Northwest Territories, Environment Canada and appropriate wildlife management boards or comparable organizations.

To support the Wildlife Protection and Management Plan(s), the Proponent shall implement the following species-specific requirements, set out in Conditions 30 to 36, in addition to the specifications of Condition 29.

30. The Proponent shall include in its Wildlife Protection and Management Plan(s) (Condition 29) with respect to woodland caribou:

a) timing and dates during which project-related activities would occur so as to avoid or minimize conflict with caribou movement or sensitive feeding or calving time; and

b) evidence of consultation with the Dehcho Boreal Caribou Working Group.

31. The Proponent shall include in its Wildlife Protection and Management Plan(s) (Condition 29) with respect to barren ground caribou:

a) timing and dates during which project-related activities would occur so as to avoid or minimize conflict with caribou movement or sensitive feeding or calving time;

b) plans to address any impacts from the project on the Porcupine caribou herd resulting from increased use of the Dempster Highway by project-related traffic; and

c) evidence of consultation with the Porcupine Caribou Management Board and the Government of Yukon.

32. The Proponent shall include in its Wildlife Protection and Management Plan(s) (Condition 29) with respect to grizzly bear:

a) a plan to conduct annual grizzly bear den surveys during pre-construction activities and pipe-laying operations prior to the commencement of work planned for the coming season;

b) proposed mitigation measures for avoiding disturbance to grizzly bear dens; and

c) a commitment to file the results of the surveys annually during pre-construction activities and pipe-laying operations, prior to the commencement of work planned for the coming season, with the Government of the Northwest Territories and appropriate wildlife management boards.

33. The Proponent shall include in its Wildlife Protection and Management Plan(s) (Condition 29):

a) mitigation measures to avoid creation of preferred bison habitat; and

b) a monitoring program to detect wood bison use of the Mackenzie Gas Project's right of way and a process to develop mitigation measures in consultation with the Government of the Northwest Territories if wood bison start using the project right of way.

34. The Proponent shall include in its Wildlife Protection and Management Plan(s) (Condition 29):

a) the results of a survey in those parts of the Local Study Area where, based on the most recent assessment by the Committee on the Status of Endangered Wildlife in Canada, the yellow rail and western toad might occur, to confirm the presence or absence of those species;

b) proposed mitigation and monitoring measures specific to yellow rail and western toad, based on the results of this survey; and

c) evidence of consultation with Environment Canada and the Government of the Northwest Territories.

35. The Proponent shall include in its Wildlife Protection and Management Plan(s) (Condition 29) a commitment to conduct pre-construction, construction and post-construction surveys and monitoring programs in relation to short-eared owls and rusty blackbirds and to file this information with the Government of the Northwest Territories.

36. The Proponent shall include in its Wildlife Protection and Management Plan(s) (Condition 29) mitigation measures specific to raptors, including peregrine falcon and bald and golden eagles, that include the following restrictions on project-related activities or facilities, unless the NEB otherwise directs:

    a) for permanent structures, long-term habitat disturbance including pipeline right of way, road, quarry, camp, etc., ground and air access, and blasting maintain a setback of 1000 m from nest sites between April 15 and September 1 for peregrine falcons and between March 30 and July 31 for all other raptors; and

    b) for aircraft overflight, maintain a setback of 760 m above ground level from nest sites between April 15 and September 1 for peregrine falcons and between March 30 and July 31 for all other raptors.

Prior to Pipe-laying Operations

37. The Proponent shall undertake a geotechnical verification program to support the final design and construction of the project facilities and shall file with the NEB 90 days prior to pipe-laying operations or station construction:

    a) copies of all borehole logs and the results of geophysical surveys completed; and

    b) an updated assessment of permafrost, ground ice and terrain conditions along the Mackenzie Valley Pipeline including, as applicable, copies of all published information regarding permafrost conditions, ground ice and terrain conditions used in the assessment.

38. To compile and communicate all of the Proponent's environmental protection procedures, mitigation measures, and monitoring commitments pertaining to pipe-laying operations to its field staff and to the NEB inspectors, the Proponent shall file with the NEB an Environmental Protection Plan (EPP) for approval at least 90 days prior to the start of pipe-laying operations. The EPP may be divided into separate plans by region or project area as deemed necessary.

    The EPP for pipe-laying operations shall include:

    a) the scope and area of application of the EPP;

    b) environmental protection procedures and measures, including decision criteria for timing and implementation of these measures, site-specific plans and drawings, mitigation measures, and monitoring applicable to pipe-laying operations;

    c) an acid rock drainage prevention plan incorporating the testing of quarried and exposed rock during trenching, borrow pit and quarry development and provisions for the safe disposal or treatment of unsuitable material if required;

    d) a reclamation plan which includes a description of the condition to which the Proponent intends to reclaim and maintain the right of way, a description of measurable goals for reclamation, methods to minimize invasive plant introduction and measures to maximize vegetation recovery;

    e) references to other plans and manuals for environmental protection required by field staff and inspectors; and

    f) evidence of consultation with appropriate regulatory authorities and government subject matter experts in the area of application of the EPP.

39. To promote safety of the pipeline and protection of the environment and to advance knowledge of the effects of pipeline construction and operation in permafrost environments the Proponent shall develop an effects monitoring program for the project. The purpose of this program is to:

    a) monitor the effects of the environment on pipeline integrity;

    b) monitor the long-term effects of the construction and operation of pipeline on the physical environment; and

    c) validate design assumptions and approaches and monitor the effects of construction and operations practices used on the project.

    This program shall take into account the results of the geotechnical verification program, the geohazard assessment and observations made during construction and shall be developed in consultation with Indian and Northern Affairs Canada, Natural Resources Canada and the Department of Fisheries and Oceans. The program shall address and identify changes in thermal regimes and their environmental effects, including existing and potential thaw settlement, frost heave, slope stability, river crossing scour, aufeis, drainage and fish passage impedance and erosion issues, and how these would be affected by successive changes in compressor station configuration. The program shall outline the monitoring methods to be used, instrumentation locations and the frequency of monitoring. The results shall be integrated into the Proponent's integrity management program and environmental protection program. The Proponent shall file with the NEB:

i) a report for approval, at least 90 days prior to the start of pipe-laying operations, which outlines the scope, objectives, monitoring methodologies and frequencies and the criteria for the selection of instrumentation sites for the program;

ii) on 1 April of each subsequent year of pipeline construction, locations it has chosen to monitor, the rationale for selection, the instrumentation required and the time of its installation; and

iii) a report by 30 November of each year describing the results of this program, and its mitigation/intervention plans to address issues identified.

40. The Proponent shall file with the NEB for approval the Construction Safety Manual at least 60 days prior to the start of pipe-laying operations.

41. The Proponent shall file with the NEB the final Pipeline Construction and Facility Specifications at least 60 days prior to the start of construction. The specifications shall be of sufficient scope and detail to demonstrate the suitability of the specifications prior to the start of pipe-laying operations and facility construction.

42. To facilitate NEB inspections, the Proponent shall file with the NEB updated engineering and environmental alignment sheets at least 90 days prior to the start of pipe-laying operations, and shall file with the NEB any modifications as they become available.

43. The Proponent shall file with the NEB for approval the replacement backfill and padding specifications at least 60 days prior to the start of pipe-laying operations. The specifications shall include provisions to ensure the replacement backfill and padding do not contain materials injurious to the pipeline, its coating and the environment.

44. Unless the NEB otherwise directs, to determine the effectiveness of the Proponent's plans for remediating ditch fill settlement for the project, the Proponent shall file a report with the NEB 90 days prior to the start of pipe-laying operations, which addresses:

a) its methods for determining the quality and quantity of imported fill required to remediate excess ditch settlement;

b) the timing and methods for hauling and stockpiling the fill materials;

c) the methods it will use to assess and address the need for additional replacement backfill or manage any excess backfill during final clean up and reclamation;

d) methods and locations for the disposal of excess excavated material not required for backfill; and

e) evidence of consultation with land managers and appropriate regulators.

45. To demonstrate that it has adequately assessed and mitigated against geohazards and to facilitate NEB monitoring during operations, the Proponent shall file with the NEB, at least 90 days prior to the start of pipe-laying operations, a Geohazard Assessment for the project describing:

a) its geohazard assessment methodology and the specific and combined geohazards identified along the route that have a reasonable probability of impacting the project;

b) specific measures to be implemented to mitigate individual and combined geohazards;

c) decision criteria for the implementation of mitigation for geohazards identified during construction;

d) the qualifications of the staff making decisions regarding design and implementation; and

e) the ongoing monitoring requirements.

46. To demonstrate that the pipeline design can accommodate an increase in compressor stations over time and is sufficient to withstand anticipated frost heave and thaw settlement loadings, the Proponent shall file with the NEB at least 90 days prior to the start of pipe-laying operations:

a) a report summarizing the findings of the final design frost heave and thaw settlement analysis for overland areas demonstrating that the pipeline design is sufficient to withstand anticipated frost heave and thaw settlement loadings. Where analysis indicates that the strain demand over the design life may exceed the strain capacity of the pipeline materials (omitting the effect of secondary mitigation measures), the report shall describe the site specific secondary measures incorporated into the design or integrity management program to prevent the pipeline from exceeding the critical threshold strain limits.

b) an assessment of the impacts of changing pipe operating temperatures associated with an increase in compressor stations over time, on the right of way. Where the assessment indicates that significant impacts may occur, the secondary measures required to mitigate these impacts shall be identified and reflected in the design prior to construction.

47. The Proponent shall undertake a hazard analysis identifying reasonably foreseeable hazards or problems with horizontal directionally drilled (HDD) activities, based on site specific data, and develop specific contingency plans for each HDD crossing. The Proponent shall file the hazard analysis and contingency plans with the NEB at least 60 days prior to the start of construction of an HDD watercourse crossing. The plans shall identify and address, where applicable, site-specific concerns such as the presence of ice-rich permafrost and other potentially unfavorable geotechnical conditions.

48. To facilitate NEB inspection during construction and monitoring during operations, and to confirm that there have been no significant changes to the slope design methodology, the Proponent shall file for approval with the NEB a Slope Design Methodology Final Report following the completion of final design and at least 90 days prior to the start of pipe-laying operations.
The Slope Design Methodology Final Report shall include:

a) the slope design methodology, data requirements, assessment techniques and pre-construction slope inventory;

b) revisions to threshold slope angles, critical longitudinal and critical cross slope criteria based on findings from final design and further geotechnical investigations;

c) target Factor of Safety for longitudinal and cross slope designs;

d) details of selected passive ground cooling systems including the proposed number, location, type, refrigerant, typical drawings, corrosion protection and installation method;

e) details of the selected surface insulation(s) including type, source, thickness and specified mitigation against the introduction of noxious weeds (if applicable);

f) details of erosion control requirements including typical drawings and spacing requirements for berms, plugs and ditches;

g) results of thermal analysis showing 10 and 25 year thaw depth predictions for the startup, 3, 7 and 14 station configurations based on selected thermal mitigation options for thaw sensitive slopes exceeding critical slope length, slopes identified as potential concerns from a stability perspective which cannot be avoided by route refinements, and slopes that have or will have slope instrumentation installed during the construction phase;

h) typical design drawings for various slope conditions;

i) specific designs for thaw sensitive slopes exceeding critical slope length;

j) a tabular summary of sites requiring site-specific slope designs, indicating the location and identification number of the slope, slope angle, slope length, slope height, orientation, actual or assumed soil conditions, nature of the site-specific issue and proposed mitigation measures; and

k) a slope stability response plan describing the actions the Proponent shall take, and the timing of those actions, should monitoring indicate that the Factor of Safety for a slope falls below the design Factor of Safety or thaw depth exceeds predicted values.

49. The Proponent shall file with the NEB for approval a Field Changes Manual, for Slopes at least 90 days prior to the start of pipe-laying operations. The manual shall include:

a) specific criteria for the implementation of changes to the designs, grading, materials, installation procedures, thermal stabilization measures, erosion mitigation measures and monitoring;

b) details regarding the required qualifications of its field staff implementing the manual; and

c) consultation required with other experts and regulatory authorities and the scope of that consultation.

50. To protect traditional harvesting of fish from adverse impacts related to project stream crossings, the Proponent shall file with the NEB, at least 90 days prior to the start of pipe-laying operations, the final suite of decision trees proposed to manage the impacts of the Mackenzie Gas Project on fish and fish habitat including:

a) an explanation of the decision-making process, the criteria for decision-making and the mitigation options;

b) a description of how the Proponent will address the importance of fish habitat and fish populations to local communities and harvesters; and

c) evidence of consultation with Fisheries and Oceans Canada and the relevant management boards and agencies with regard to the decision trees.

51. To demonstrate the adequacy of scour protection and thermal mitigation measures of watercourse crossing designs and facilitate NEB inspection during construction, the Proponent shall file for approval with the NEB at least 90 days prior to the start of pipe-laying operations:

a) a revised Watercourse/Waterbody Crossing Inventory, in both PDF and MS Excel spreadsheet format, describing the watercourse name and numerical identifier, coordinates, stream class, width of wetted channel, construction method, design type, minimum pipeline cover, navigability and fish habitat status and level of assessment;

b) detailed final design drawings and plans for all watercourse and waterbody crossings requiring site specific designs, including HDD crossings, showing the design flood level, calculated vertical and lateral scour potential and detailing proposed thermal, erosion, scour control and ground water flow mitigation measures;

c) detailed final design drawings of typical designs for open cut and isolated crossings of Lakes, Active I, Active II and Vegetated Channel watercourses detailing proposed thermal, erosion, scour control and ground flow mitigation measures;

d) 25 year frost bulb growth/thaw settlement analysis (for the start up, 3, 7 and 14 station configuration), including predicted strain demand/ available strain capacity and frost bulb dimensions, for all Large, HDD, Active I and Active II watercourse crossings which demonstrates that changes in the thermal regime of the pipe associated with changes in compressor station configurations or degraded insulation effectiveness will not result in aufeis conditions or unacceptable pipe strains; and

e) evidence of consultation with the Department of Fisheries and Oceans in regards to the design of stream crossings.

52. To facilitate NEB monitoring, the Proponent shall notify the NEB at least 30 days prior to qualifying the automated ultrasonic non-destructive examination procedures for mill and field circumferential welds.

53. The Proponent shall develop the joining program and file it with the NEB at least 30 days prior to conducting welding procedure qualification tests for:

    a) field circumferential production, tie-in and repair pipeline welds; and

    b) welding of project facilities.

    The joining program shall include:

    i) requirements for the qualification of welders;

    ii) requirements for the qualification and duties of welding inspectors;

    iii) welding procedure specifications;

    iv) non-destructive examination specifications;

    v) quality assurance program for field welds and welding procedures; and

    vi) any additional information which supports the joining program.

54. To facilitate NEB inspection, the Proponent shall file with the NEB procedure qualification records for welding and non-destructive examination within 30 days of the completion of procedure qualification tests.

55. To facilitate NEB inspection, the Proponent shall file with the NEB the specifications for field applied coatings at least 60 days prior to the start of pipe-laying operations.

During Construction

56. To facilitate NEB inspection of all phases of construction, the Proponent shall provide when requested, logistical support to NEB staff undertaking inspection of construction and reclamation, at a reasonable cost to the NEB. (For clarity, the scope of this support is limited to transportation of NEB staff and vehicles to isolated camp locations, vehicle fuel and maintenance, meals and accommodation, office space and communications support.)

57. Unless the NEB otherwise directs the Proponent shall pressure test the approved facilities with a liquid medium and submit the Pressure Testing Program, demonstrating compliance with applicable codes, standards and regulatory requirements, to the NEB for approval at least 60 days prior to the start of pressure testing; or in the event that a hydrostatic test is not practicable, the Proponent shall file with the NEB for approval, at least 60 days prior to the start of any air testing activities, the Proponent's air testing measures. The program shall include:

    a) information demonstrating the ability of the leak test to detect the same size leak as a comparable hydrostatic test;

    b) information demonstrating that the pipeline has adequate notch toughness;

    c) a description of the specific safety precautions to be implemented during the pressure test; and

    d) a confirmation of successful leak test of pipeline sections prior to their installation under watercourses, lakes and ponds.

58. To verify implementation of the Proponent's quality assurance and control plans and procedures, the Proponent shall file monthly summary reports during construction outlining non-conformances with its design, materials, and construction specifications and the disposition of these non-conformances.

Prior to Operation

59. The Proponent shall file with the NEB for approval, at least 90 days prior to the planned start of operation, the elements of the Environmental Protection Program for the operation and maintenance of the pipeline pursuant to section 48 of the *Onshore Pipeline Regulations, 1999.* The elements to be submitted include

but are not limited to policies, practices and procedures for:

a) ongoing environmental training for employees/operators;

b) handling and disposal of all wastes associated with the operation and maintenance of the project;

c) management of air emissions, including:

   i) maximum Proponent-identified and/or legislated discharge limits for PM and NOx;

   ii) maximum Proponent-identified greenhouse gas targets;

   iii) reduction strategies for air emissions including PM, NOx, and greenhouse gases;

   iv) monitoring and measurement methods; and

   v) record keeping including annual reporting of greenhouse gases to the NEB;

d) public communication program (non-emergency); and

e) program review and consultation with Environment Canada and the Government of Northwest Territories.

60. To demonstrate that in-line inspection tools will be able to support effective integrity management programs, the Proponent shall submit to the NEB at least 90 days prior to the start of system operation:

a) the type, description, specifications, operating limits and detection limits of all in-line inspection tools which can be used by the Proponent during operation of its pipelines;

b) data on the inertial curvature in-line inspection tool(s) developed for the project indicating the detectable level of displacement and associated strain, the recommended pig velocity, and the relationship between pig velocity and strain resolution; and

c) intervention values for all parameters that will be monitored by in-line inspection tools.

61. The Proponent shall prepare:

a) an Emergency Preparedness and Response Plan for the project prior to the start of system operation and file with the NEB the Emergency Procedures Manual at least 30 days prior to the start of operation; and

b) a report, to be filed with the Emergency Procedures Manual, which outlines:

   i) the potential for the establishment of local, community-based spill response teams to assist in responses to Mackenzie Gas Project incidents;

   ii) a discussion of the opportunities and constraints of establishing local spill response teams including a training and equipment needs assessment; and

   iii) the Proponent's commitment to work with local communities to build and maintain community spill response capacity.

In preparing its Emergency Preparedness and Response Plan, the Proponent shall have regard to:

1) the NEB letter dated 24 April 2002 entitled Security and Emergency Preparedness Programs addressed to all oil and gas companies under the jurisdiction of the NEB and subsequent amendments made thereafter; and

2) emergency responses required as a result of significant earthquakes which may require a broader scope of response.

62. To demonstrate that it is prepared to respond to an emergency at the outset of operation, the Proponent shall hold an emergency response exercise to evaluate the effectiveness of the Emergency Preparedness and Response Plan at least 10 days prior to the start of system operation and file a letter of notification with the NEB upon the successful completion of the exercise.

63. Unless the NEB otherwise directs the Proponent shall file with the NEB a report describing the final design of the SCADA and leak detection system for the Mackenzie Valley Pipeline at least 90 days prior to the start of operation of the Mackenzie Valley Pipeline. The report shall include information suitable for establishing a base line for the quality program for its SCADA and leak detection system and shall include:

a) a description of the SCADA and leak detection system;

b) the location and type of pressure, temperature and flow monitoring and control devices and remote terminal units;

c) the location of remotely operated valves;

d) the target detect ability (e.g., amounts leaked, time to detect, leakage rate);

e) the target sensitivity (i.e., minimum leak size);

f) the target reliability (i.e., false alarm rate, failure to alarm rate);

g) the expected system robustness (i.e., system availability in light of the system operating conditions);

h) the target accuracy (i.e., size and location of a detected leak); and

i) a description of the quality program using both direct and inferred methods that the Proponent shall implement during the operational phase of the project to ensure optimal performance.

64. To demonstrate that the SCADA and leak detection system are calibrated to actual system conditions, the Proponent shall file with the NEB, reports describing the results of the Proponent's quality program for its SCADA and leak detection system and how identified issues were addressed. Unless the NEB otherwise directs, the reports shall be filed one year, three years and five years after the start of system operation.

During Operation

65. Within 30 days of the date that the approved project is placed in service, the Proponent shall file with the NEB a confirmation, by an officer of the company, that the approved project was completed and constructed in compliance with all applicable conditions in this Certificate. If compliance with any of these conditions cannot be confirmed, the officer of the company shall file with the NEB details as to why compliance cannot be confirmed. The filing required by this condition shall include a statement confirming that the signatory to the filing is an officer of the company.

66. To facilitate monitoring during operation, the Proponent shall file with the NEB, within six months of the start of system operation, a geotechnical construction report including maps and drawings, which identifies and describes:

a) longitudinal and cross slopes identified during construction as requiring ongoing monitoring;

b) locations where passive cooling systems were installed;

c) locations where slope instrumentation including thermistors, piezometers and slope inclinometers were installed;

d) slopes exceeding the critical slope length which were identified during construction as being thaw sensitive or exhibiting evidence of soil movement;. and

e) locations where slope design changes were made in accordance with the Field Change Manual for Slopes and the reasons for the design change.

67. To minimize or reduce air emissions from flaring, the Proponent shall meet the Guideline for Ambient Air Quality Standards in the Northwest Territories and Alberta's Energy Resources Conservation Board Directive 60: *Upstream Petroleum Industry Flaring, Incinerating and Venting*.

68. To minimize noise disturbance from pipeline facilities, the Proponent shall:

a) design pipeline facilities to meet the requirements of Alberta's Energy Resources Conservation Board Directive 038; and

b) file with the NEB, 90 days following the start of operation, a post construction noise assessment report.

69. To aid NEB inspectors in confirming the effectiveness of mitigation techniques and any adaptation required, as well as to identify effects that were not predicted and appropriate adaptive management to address these effects, the Proponent shall file with the NEB a post-construction environmental report that reflects any monitoring or follow-up program developed, including:

a) identification on a map or diagram of any environmental issues which arose during construction;

b) the criteria used or to be used to verify the accuracy of the environmental assessment predictions;

c) the determination of the accuracy of the environmental assessment predictions;

d) discussion of the effectiveness of the mitigation applied pre-, during and post- construction and where adaptive management was necessary;

e) identification of the current status of the issues identified describing whether those issues are resolved or unresolved; and

f) proposed measures and schedule that the Proponent shall implement to address any unresolved concerns.

The report shall be filed on or before the 31 of January of each of the first, third, fifth and tenth years following the start of project operation, unless the NEB otherwise directs.

70. Unless the NEB otherwise directs, to demonstrate the management of pipeline integrity and thermal effects on the right of way the Proponent shall monitor geotechnical and thermal effects on the pipeline(s) with respect to thaw subsidence, frost heave and slope stability by:

a) undertaking a detailed as-built survey prior to backfill which documents the position of the pipeline for comparison with future in-line inertial inspection data, the location of pipe specification changes, the location of each circumferential weld, buoyancy control devices, depth of cover; and

b) undertaking an inertial in-line inspection within one month of the start of operations and on an annual basis thereafter.

71. To facilitate monitoring, the Proponent shall record ditch wall geotechnical information during construction and shall file the ditch wall logs with the NEB within one year of the start of system operation.

72. To facilitate monitoring, the Proponent shall file with the NEB, within one year of the start of system operation, copies of all stream flow monitoring, ice thickness measurements and ground temperature monitoring data collected during project planning and design. Numerical records shall be submitted in both PDF and MS Excel spreadsheet format.

Planning Clause

73. The Proponents shall file updated cost estimates and report on their decision to construct by 31 December 2013.

Sunset Clause

74. Unless the NEB otherwise directs, this Certificate shall expire on 31 December 2015 unless construction in respect of the Mackenzie Gas Project has commenced by that date.

Conditions that apply only to the Mackenzie Valley Pipeline

75. The Proponent shall notify and consult with Aboriginal and municipal authorities in each community proximate to the Mackenzie Valley Pipeline right of way with regard to community use of merchantable timber that would be cleared along the Mackenzie Valley Pipeline right of way, and shall provide the NEB with a report on its consultations and any agreements that have been reached 90 days prior to the start of pre-construction activities for the relevant spread.

76. To facilitate local access to gas, the Proponent shall file with the NEB at least 90 days prior to the start of pipe-laying operations a report identifying:

a) details of any expressions of interest it has received for connections to a gas delivery lateral or in having a delivery lateral constructed to connect to a local gas distribution system;

b) technical details regarding the tie-in, valves, regulating and metering equipment required to satisfy the request; and

c) the expected timing for the installation of the facilities.

Appendix L
Miscellaneous Order for Mackenzie Valley Pipeline Tolls and Tariff

National Energy Board

Office national de l'énergie

ORDER MO-17-2010

IN THE MATTER OF Part IV of the *National Energy Board Act* and

IN THE MATTER OF the applications by Imperial Oil Resources Ventures Limited (the Proponent), on behalf of Imperial Oil Resources Ventures Limited, the Mackenzie Valley Aboriginal Pipeline Limited Partnership, ConocoPhillips Northern Partnership, ExxonMobil Canada Properties and Shell Canada Limited as managing partner of Shell Canada Energy filed with the National Energy Board (Board) for the Mackenzie Valley Pipeline under file numbers: OF-Fac-Gas-I017-2004-1, OF-EP-FacPipe-I003-MAC 04, OF-EP-FieldOp-I003-TL 07, OF-EP-FieldOp-C648-PL 07, OF-EP-FieldOp-S245-NIG 07.

WHEREAS the Proponent filed an application in October 2004 under Part III of the *National Energy Board Act* for the 1196 kilometre long, 750 millimetre (30 inch) diameter Mackenzie Valley Pipeline to carry natural gas from the a processing plant near Inuvik, Northwest Territories to northwestern Alberta;

AND WHEREAS the Proponent applied for approval of toll and tariff principles for the Mackenzie Valley Pipeline pursuant to Part IV of the *National Energy Board Act*;

AND WHEREAS the application was set down for hearing in Hearing Order GH-1-2004;

AND WHEREAS the National Energy Board has issued, subject to the approval of the Governor in Council, a certificate of public convenience and necessity for the Mackenzie Valley Pipeline;

IT IS ORDERED pursuant to Part IV of *National Energy Board Act* that the toll and tariff principles for the Mackenzie Valley Pipeline proposed by the Proponent in the GH-1-2004 proceedings be approved subject to the following:

1. The Mackenzie Valley Pipeline shall be accessible to all shippers that meet the terms of the tariff.

2. The Proponent shall file, for Board approval, a Code of Conduct for the Mackenzie Valley Pipeline for all phases of development including pre-construction, construction and operation. The Code of Conduct is to be filed as soon as possible but in any event no later than 31 December 2011. At a minimum, the Code of Conduct should address in detail:
   a) prevention of undue preferential treatment;
   b) governance of the interactions between shippers and transporters;
   c) independence of transmission operations from affiliate operations;
   d) governance of separation of business;
   e) protection of confidential and commercially-sensitive information;
   f) mechanisms and methodologies related to the design of an acceptable transfer pricing mechanism;
   g) a Code of Conduct compliance plan with independent audits; and
   h) penalties for breaches of the Code of Conduct and recourse to a third party arbitrator.
3. At least 90 days prior to the start of pre-construction activities the Proponent shall demonstrate to the National Energy Board's satisfaction that the necessary long-term transportation service contracts have been executed for the Mackenzie Valley Pipeline.
4. The Proponent shall be designated as a Group 1 company and shall file quarterly Surveillance Reports as outlined in the Toll Information Regulations and Section BB, Financial Surveillance Reports in the National Energy Board's Filing Manual.
5. The return on equity for the Mackenzie Valley Pipeline shall be set reflecting the principle of a 221 basis point premium over other Group 1 companies that were subject to the formula immediately prior to 9 October 2009. The total return will be set taking into account both return on equity and equity thickness.
6. The cost of debt shall be deemed as the weighted average interest rate of the project debt financing provided by the senior lenders for the Mackenzie Valley Aboriginal Pipeline Limited Partnership as long as this reflects the cost of debt that would apply to a stand-alone Mackenzie Valley Pipeline.
7. The Proponent shall use a depreciation method that would allow it to recover 80 percent of its asset costs for the Mackenzie Valley Pipeline over the first 20 years of the Mackenzie Valley Pipeline's operation unless the Board determines that this methodology no longer reflects the economic life of the Mackenzie Valley Pipeline.
8. The Proponent shall initially establish two tolling zones for the Mackenzie Valley Pipeline.
9. The appropriate toll treatment for future expansions shall be determined at the time of the expansion after considering the specific circumstances.
10. The Proponent shall remove the clause in Section 20.4 of the Tariff Principles that states "As all foreseeable expansions are expected to reduce existing tolls".
11. As soon as possible but, in any event, no later than 31 December 2011, the Proponent shall remove from any document the words that preclude shippers from raising concerns about the toll and tariff principles before the Board.

12. Prior to operation, the minimum contract term for service on the Mackenzie Valley Pipeline is not required to be shorter than 15 years.

13. The Proponent may choose to offer interruptible service only to shippers with firm service contracts on the Mackenzie Valley Pipeline.

14. A specific proposal for a special interruptible service for gas which fails to meet the tariff specifications for minimum heat content is not required.

15. For gas flowing the full distance under a 15 year contract, the Proponent shall charge a toll premium of $0.15 per gigajoule over the toll for a 20 year contract.

16. By 31 December 2011, and following consultation with potential shippers and the Government of the Northwest Territories, the Proponent shall develop and file the details of an economic test for delivery laterals which are to be constructed and owned by the Mackenzie Valley Pipeline and rolled into its rate base.

17. The Proponent shall incorporate in its toll and tariff principles the requirement that metering and pressure reducing facilities will be rolled into the Mackenzie Valley Pipeline's cost of service.

18. The Proponent shall file a tariff as soon as reasonably possible but, in any event, no later than 31 December 2011.

NATIONAL ENERGY BOARD

Anne-Marie Erickson
Secretary of the Board

Appendix M
Conditions for the Mackenzie Gathering System

Unless otherwise specified in the condition, *pre-construction activities* include activities such as: clearing and grading for infrastructure development; construction and operation of camp facilities; the development of borrow pits, roads, and airstrips; snow pad construction; the transportation and stockpiling of fuel and material; and geotechnical investigations necessary for the construction of the pipeline project. Pre-construction activities may include other activities such as clearing of the right of way if approved by the National Energy Board. Pre-construction activities do not include activities associated with normal surveying operations or data collection activities.

Unless otherwise specified in the condition, *pipe-laying operations* include the clearing of vegetation in proximity of water crossings and on thaw sensitive slopes, as well as grading and trenching and other forms of right of way and station site preparation that may have an effect on the environment through to final clean-up and reclamation.

Unless otherwise specified, Proponent *consultation* referred to in a condition must be carried out in a manner that includes the Proponent:

a) providing, to the party to be consulted,

   i) notice of the matter in sufficient form and detail to allow the party to prepare its views on the matter,

   ii) a reasonable period for the party to prepare those views, and

   iii) an opportunity to present those views to the party conducting the consultation; and

b) considering, fully and impartially, any views so presented.

Unless otherwise specified in a condition *best available technology* (BAT) means technology with superior emissions performance which is commercially available at a reasonable cost at the time it is required for the project which meets the goals of pollution prevention and energy efficiency.

Unless otherwise specified in a condition *best management practices* (BMP) are innovative, dynamic, and improved environmental protection practices and procedures that help ensure that development is conducted in an environmentally responsible manner. BMP may exist as formal guidelines or generally accepted procedures that are recognized by regulators and industry associations as best practices.

Conditions that correspond for the Mackenzie Valley Pipeline and the Mackenzie Gathering System

General

1. Unless the NEB otherwise directs, the Proponent shall cause the approved facilities to be designed, located, constructed, installed and operated in accordance with the commitments, specifications, standards, policies, mitigation measures, procedures, and other information referred to in its application or in the Environmental Impact Statement or other filings, or as otherwise agreed to during the GH-1-2004 Hearing and during the review by the Joint Review Panel.

2. Unless the NEB otherwise directs, the Proponent shall comply with all filing timelines and completion dates set out in these conditions.

Prior to Pre-Construction Activities

3. To compile and communicate all of the Proponent's environmental protection procedures, mitigation measures, and monitoring commitments pertaining to pre-construction activities to its field staff and to the NEB inspectors, the Proponent shall file with the NEB an Environmental Protection Plan (EPP) for approval at least 90 days prior to the start of pre-construction activities. The EPP may be divided into separate plans by region or project area as deemed necessary.

   The pre-construction EPP shall include:

   a) the scope and area of application of the EPP;

   b) environmental protection procedures and measures, including decision criteria for timing and implementation of these measures, site-specific plans and drawings, mitigation measures, and monitoring applicable to pre-construction activities;

   c) an acid rock drainage prevention plan incorporating the testing of quarried and exposed rock during infrastructure, borrow pit and quarry development and provisions for the safe disposal or treatment of unsuitable material if required;

   d) references to other plans and manuals for environmental protection required by field staff and inspectors; and

   e) evidence of consultation with appropriate regulatory authorities and government subject matter experts in the area of application of the EPP.

4. To address worker and public safety and environmental protection during construction in the unique northern environment, the Proponent shall file an Emergency Response Plan with the NEB at least 60 days prior to the start of pre-construction activities which shall address 24-hour medical evacuation, fire response and hazardous chemical and fuel spill response and security issues. The Emergency Response Plan shall be prepared in consultation with Indian and Northern Affairs Canada, the Canadian Coast Guard, Transport Canada, Environment Canada, the Government of the Northwest Territories and the Inuvialuit Land Administration, as applicable, and shall include:

   a) the scope of the plan detailing the project infrastructure, geographic and time period covered by the plan;

   b) training and orientation requirements of company and contractor staff;

   c) an inventory of petroleum products, chemicals and other hazardous substances, together with corresponding MSDS sheets, that will be transported, stored and/or used during the pre-construction and construction phases;

   d) storage facilities and locations of the above inventoried products and substances;

   e) identification of resources (equipment and staff) to be on-site and/or available to respond to emergencies;

   f) identification of mutual aid partners and the location of their resources (equipment and staff) available to respond to emergencies;

   g) procedures for responding to spills, releases, fires, medical emergencies and security issues including the incident reporting and notification system;

   h) location of fire and spill response equipment stores and the spill kit requirements for vehicles;

   i) a phone list of company, contractor, government agency and community representatives outlining their respective roles and information needs;

   j) clean-up and disposal procedures for generated clean-up wastes;

   k) identification of muster points for emergency evacuations from camps and facilities;

   l) location of emergency medical treatment locations and capabilities;

   m) the requirement for 24-hour emergency medical evacuation capability; and

   n) maps showing the location of the right of way and infrastructure such as camps, access roads, material storage areas, barge landing sites and borrow pits to facilitate the dispatch of first responders.

5. To address worker and public safety in the unique northern environment, the Proponent shall file a construction safety manual with the NEB at least 60 days prior to the start of pre-construction activities.

6. To confirm consideration of the effects of climate change on specific geohazard mitigation, slope and stream crossing designs and terrain stability for the overall design life of the project, the Proponent shall file a report six months prior to the start of pre-construction activities which includes:

   a) an analysis of the impacts of climate change and variability on permafrost and terrain stability for a series of representative locations and conditions using potential upper limit temperature scenarios which may occur along the Mackenzie Valley;

   b) a description of how these upper limit temperature scenarios may impact precipitation and stream flows along the Mackenzie Valley;

   c) a description of how the Proponent will account for the potential change in precipitation patterns in the detailed design of slopes and water course crossings for the project; and

   d) the results of consultation with other appropriate regulators and government departments.

7. To facilitate NEB inspections, the Proponent shall file with the NEB updated environmental alignment sheets at least 90 days prior to pre-construction activities, and shall file with the NEB any modifications as they become available.

8. To facilitate NEB inspections, the Proponent shall file with the NEB a detailed construction schedule or schedules identifying major activities at least 30 days prior to pre-construction activities and pipe-laying operations, and shall notify the NEB of any modifications to the schedule or schedules as they occur.

9. To demonstrate that project winter roads will be constructed and operated in a safe and environmentally acceptable manner, the Proponent shall file with the NEB a manual for the construction, operation, maintenance and closure of project winter roads at least 30 days prior to the start of project winter road construction. The manual shall include:

   a) required road width, clearing and grading requirements, grade, allowable speed, signage, maximum vehicle weight;

   b) objective and measurable environmental and engineering criteria to determine when the winter road will be ready for use;

   c) safe ice thickness criteria for lake, river and stream crossing including the frequency of ice profiling;

   d) local regulatory requirements;

   e) installation and removal requirements for snow fills, culverts, corduroy and temporary bridges; and

   f) objective and measurable environmental and engineering criteria for closure.

10. To demonstrate that the pipeline and project winter roads will be constructed and operated in a safe and environmentally acceptable manner, the Proponent shall file with the NEB a copy of any applicable permits, authorizations and letters of advice issued by the Federal departments, the Government of the Northwest Territories, or local regulatory organizations that are referred to in an EPP or winter road manual at least 90 days prior to pre-construction activities.

11. The Proponent shall evaluate the technologies and practices available to reduce emissions of particulate matter (PM) and PM and ozone precursors from its facilities and construction related activities, and incorporate the BMP and BAT to reduce emissions of PM and precursors of PM and ozone to the extent practicable. The Proponent shall file a report of its findings and how it will implement its findings to the NEB at least six months prior to construction of the Inuvik Area Facility, compressor stations and heater stations.

12. The Proponent shall evaluate and implement technologies and practices available to reduce mercury, dioxin and furan emissions from incinerators operating at construction camps and its station facilities to the extent practicable. The Proponent shall file a report of its findings and how it intends to implement its findings to the NEB at least 60 days prior to the operation of its construction camps and station facilities.

13. The Proponent shall file with the NEB at least 60 days prior to the start of station facility construction, a report outlining:

    a) the specific design and operational measures it has implemented and will implement to minimize methane leakage and venting through the system's operation taking into account BMP developed by CAPP, Environment Canada, the Canadian Energy Partnerships for Environmental Innovation and the Canadian Gas Association;

    b) how the Proponent has utilized waste heat energy to minimize natural gas fuel consumption in the design of the Inuvik Area Facility;

    c) the use of BAT when specifying compressor units used on the project including size, efficiency and their conformity with Canadian Council of the Ministers of the Environment National Emissions Guidelines for Stationary Combustion Turbines (CCME,1992); and

    d) results of consultation with Environment Canada and the Government of Northwest Territories.

14. To demonstrate that the design is experimentally verified and that the inputs and outputs of the design calculations are clearly determined for overland, slope and water crossing designs, the Proponent shall file with the NEB at least six months prior to the start of pipe manufacture:

    a) a stress/strain analysis, including all inputs, assumptions, outputs, methods, and outline of process of calculation;

    b) a detailed description and results of all verification tests performed in support of the stress/strain analysis;

    c) an explanation and reconciliation of any differences and uncertainties that may result among:

       i) stress/strain analysis inputs and outputs;

       ii) results of verification tests;

       iii) final material properties specifications; and

       iv) loads, stresses and strains pipelines may experience during transportation, construction, and operation; and

    d) a description of the processes for the implementation of changes that may occur between the design information and material specifications submitted to the NEB as a result of Conditions 14 and 18, and the detailed design and the actual material properties.

15. The Proponent shall file with the NEB for approval, at least 30 days prior to the start of pre-construction activities an Air Quality Monitoring Program developed in consultation with Environment Canada, Health Canada and the Government of the Northwest Territories, to be undertaken immediately prior to and during construction. This program shall include:

    a) identification of the baseline, pre-construction conditions;

    b) the location of monitoring sites on a map or diagram, the purpose for the locations selected, and the timing for installation;

    c) methods and schedule of constituent monitoring (PM, O_3, NO_2 and noise);

    d) data recording, processing and reporting details;

    e) the process for public communication and complaint response; and

    f) details of the additional measures that would be implemented as a result of monitoring data or ongoing concern, and the criteria or thresholds that would require these measures.

    The Proponent shall include a legacy plan detailing the measures that would be continued through the operation phase as a result of monitoring undertaken or ongoing concern and the criteria or thresholds that are used to determine when they would no longer be required.

16. In order that the right of way, camps and supporting infrastructure are maintained, operated and left in an environmentally acceptable condition following the construction phase of the project, the Proponent shall file a Waste Management Plan with the NEB for approval 90 days prior to the start of pre-construction activities. This plan shall be developed in consultation with the Government of the Northwest Territories, Indian and Northern Affairs Canada

and Environment Canada. The Waste Management Plan shall address all wastes associated with the construction of the project with the objectives of minimizing impacts to the environment and ensuring worker and public safety. The plan shall address air, land and water quality; measures to minimize animal attraction; and preventing uncontrolled fires. The scope of the plan shall include:

a) disposal or treatment of potentially hazardous and dangerous materials, including petroleum products, toxic or persistent chemicals, oily wastes, de-icing fluids and fuel barrels;

b) solid waste management including metals, plastics, recyclables, incinerator ash, equipment, equipment parts, batteries, building materials and construction waste;

c) food waste management;

d) management of contaminated soil, snow and ice from spills and de-icing activities;

e) treatment and disposal of waste water (including domestic sewage and grey water); and

f) incinerator emissions monitoring.

The plan shall address:

i) incineration and evaporator technology choices and rationale for selection;

ii) training requirements for operators;

iii) waste segregation requirements;

iv) interim waste storage;

v) treatment;

vi) testing method for waste streams proposed for release to the environment (e.g. air and water);

vii) disposal method for waste streams proposed for release to the environment; and

viii) final off-site waste disposal locations and facilities including evidence of facility approvals and compliance with regulations.

17. To mitigate potential localized low fracture toughness in or adjacent to the welds which could be detrimental during anticipated pipeline deformation at low operating temperatures, the Proponent shall:

a) determine the minimum acceptable value for the crack tip opening displacement (CTOD) for weld metal and heat affected zone of mill circumferential, helical (if practicable) and longitudinal welds, for the lowest installation temperature and the most severe deformation during construction or operation. The CTOD tests shall be conducted for all combinations of pipe steel producers and pipe mill manufacturers and be representative of applicable project pipe with the maximum Carbon Equivalent (CE) heat;

b) determine the minimum acceptable value for the CTOD for field circumferential welds for the lowest installation temperature and the most severe deformation during construction or operation. The CTOD tests shall be conducted at the welding procedure development phase, for all combinations of pipe steel producers and pipe mill manufacturers and be representative of applicable project pipe with the maximum CE heat. Deviations in the essential changes as specified in CSA Z662-07, Table 7.3 and Table K1 will require weld procedure requalification and retesting to determine the minimum acceptable value for the CTOD; and

c) file with the NEB minimum acceptable CTOD values and results of the tests:

i) for the mill qualification welds, at least 60 days prior to the pipe manufacture; and

ii) for the field circumferential qualification welds, at least 60 days prior to the field welding.

18. To demonstrate compliance with appropriate regulations, standards and engineering practices and to facilitate NEB audits, the Proponent shall file with the NEB the following documents, to be finalized prior to the procurement of materials:

a) project-specific material specifications for pipe, fittings, valves, and pig launchers and receivers, at least 90 days prior to the start of manufacture of each of these elements;

b) specifications for plant-applied coatings for buried and exposed pipeline(s) and valves, at least 90 days prior to the application of each coating. The specifications shall include coating materials, application methods, and verification test results;

c) specifications for materials to be used for the manufacture of stations, the Inuvik Area Facility, and the Trout Lake Heater Station, including applicable standards, and non-destructive examination methods and frequency, at least 60 days prior to the start of the manufacture of each of these facilities;

d) joining program for mill welding, at least 90 days prior to the start of manufacture of pipe, components or facilities in the plant;

e) non-destructive examination specifications for the mill non-destructive examinations at least 90 days prior to the start of each non-destructive examination; and

f) project-specific quality assurance programs for all materials, components, and processes at least 90 days prior to manufacture of pipe components and facilities.

19. Unless the NEB otherwise directs, to facilitate NEB monitoring, the Proponent shall file with the NEB project progress reports that summarize major activities by construction spread, as follows:

a) every month during active construction periods; and

b) every two months during pre-construction and inactive construction periods.

These reports shall also provide:

i) the description of any significant pipeline and facilities design changes;

ii) the list of any current and cumulative number of incidents, accidents, or hazardous occurrences as defined in regulations pursuant to the *National Energy Act,* the *Canada Oil and Gas Operations Act* and the *Canada Labour Code Part II*;

iii) a description of any major activities planned for the next reporting period;

iv) locations and proposed timing of any planned pressure tests; and

v) locations of any unsuccessful pressure tests and their cause.

20. To demonstrate the effective management of safety and environmental protection matters during pre-construction and construction, the Proponent shall file with the NEB at the start of field pre-construction activities, a diagram of the project's organization, clearly identifying roles, responsibilities and reporting structure.

21. The Proponent shall file with the NEB, at least 30 days prior to the start of pre-construction activities, the Heritage Resources Management Plan as reviewed by the Prince of Wales Northern Heritage Centre.

22. The Proponent shall file with the NEB, at least 90 days prior to the start of pre-construction activities, the results of consultations regarding the conclusion of fee-for-service agreements with affected communities respecting the use of community services or infrastructure facilities.

23. The Proponent shall file, at least 90 days prior to the start of pre-construction activities, diversity plans, inclusive of gender equality, for both the construction and operations phases of the Mackenzie Gas Project. The plans shall include:

a) methods for determining diversity goals;

b) identification of diversity goals;

c) steps to achieve the identified goals;

d) commitments to the provision of a healthy and safe work environment;

e) steps to create a Diversity Management Committee; and

f) a monitoring and reporting system.

The Proponent shall require its contractors and subcontractors to comply with the Proponent's diversity plans.

24. To minimize and address adverse impacts of any interactions between the construction workforce on the Mackenzie Gas Project and the communities in proximity to the project, the Proponent shall implement closed work camps. This requirement shall apply to all new work camps proposed by the Proponent, its contractors and subcontractors.

25. To minimize and address adverse impacts of any interactions between workers in existing open camps that may be used for the project and the communities in proximity to those camps, the Proponent shall identify to the NEB whether any of the existing open construction camps will be used, either directly or indirectly, in relation to project construction. Where existing open camps are to be used and are to remain open, the Proponent shall develop a plan to minimize and address adverse impacts of any interactions. The plan should be developed in consultation with affected communities, identify the specific measures to be employed to address adverse impacts, and comply with the commitments made by the Proponent. The plan shall be filed with the NEB at least six months prior to the start of pre-construction activities.

26. To minimize and address potential adverse impacts of any interactions between the construction workforce on the Mackenzie Gas Project and the communities of Fort Good Hope and Tulita, the Proponent shall file with the NEB, at least six months prior to the start of pre-construction activities, a plan to monitor the interactions between the construction workforce and the communities. The plan shall be developed in consultation with the leadership of Fort Good Hope and Tulita, and include:
    a) plans for monitoring interactions;
    b) the specific measures that will be employed to address adverse interactions, should any be identified; and
    c) plans for regular consultation and reporting on interactions with both potentially affected communities.

27. The Proponent shall file with the NEB, at least six months prior to the start of pre-construction activities, plans for a formal issues resolution program that will be implemented during construction and operations of the Mackenzie Gas Project. The plans shall be prepared in consultation with the government of the Northwest Territories, the Government of Yukon and Aboriginal authorities, and include:
    a) a description of the process by which any complaints or issues related to the Mackenzie Gas Project would be raised with the Proponent or governments;
    b) a description of the process by which any received complaints or issues would be allocated among those with responsibility for action and a description of the roles and responsibilities any party involved in assessing or responding to any complaint or issue;
    c) a description of the process by which any received complaints or issues would be resolved;
    d) a description of any protocols developed for referral and resolution of any complaints or issues;
    e) a description of the recourse mechanisms for any unresolved complaints or issues or any unsatisfactorily resolved complaints or issues; and
    f) a description of the process for communicating and informing communities about the issues resolution program.

28. The Proponent shall file, prior to the start of pre-construction activities, information related to the hiring of local residents as monitors to carry out compliance and environmental impact monitoring for the Mackenzie Gas Project including:
    a) the nature of the activities to be monitored;
    b) clearly defined job descriptions for the positions as monitors;
    c) identification of the training that will be offered to monitors to enable them to perform their duties; and
    d) confirmation that monitors have been hired.

29. To minimize project-related impacts on wildlife species, the Proponent shall file with the NEB for approval, before the detailed pipeline route is filed with the NEB and at least 90 days prior to the start of pre-construction activities, a Wildlife Protection and Management Plan or Plans to address general wildlife protection and specific protection of woodland caribou, barren ground caribou, grizzly bear, polar bear and wolverine. The Wildlife Protection and Management Plan(s) shall specify goals, area covered by the plan(s), and assumed zones of influence of project activities and rationales for these assumptions. The Wildlife Protection and Management Plan(s) may be divided into separate plans by region or project area as deemed necessary.

The Wildlife Protection and Management Plan(s) shall include:

a) results of pre-construction surveys, including surveys for species at risk listed on Schedule 1 of the *Species at Risk Act* public registry (listed species) except where the Minister has determined that recovery for the species is not feasible, and locations of any observations of species classified as at risk or may be at risk on the most recent Committee on the Status of Endangered Wildlife in Canada assessment and NWT General Status Ranks;

b) updated impact assessments for listed species in consideration of the *Species at Risk Act*, conducting the impact assessments directly on the listed species where possible rather than using one or more indicator species;

c) mitigation measures including:

   i) measures to avoid or minimize disturbances including linear disturbance and effects of habitat fragmentation, sensory disturbance, and barriers to movement;

   ii) scheduling of project activities to minimize wildlife disturbance;

   iii) measures to minimize the development footprint in habitats known to support listed species;

   iv) measures to limit predator travel along right of ways;

   v) procedures to avoid disturbance of potential maternal denning areas;

   vi) access management, including provisions for public consultation;

   vii) protocols and education/awareness activities for managing human-wildlife interactions, including measures to limit harvesting and to deter wildlife, especially bears, from entering camps and other facilities;

   viii) measures to reduce the impacts of access road, right of way, and other project-related vehicle and air traffic on wildlife and migratory birds; and

   ix) any wildlife protection measures included in other project management plans, or references to those measures;

d) protocols for monitoring and adaptive management including:

   i) establishing and maintaining linkages to regional programs;

   ii) survey protocols to be employed to avoid or prevent impacts to wildlife;

   iii) plans for monitoring responses of wildlife to project activities during all phases of the project;

   iv) protocols for documenting habitat loss and habitat change as well as wildlife incidents, interactions and mortality; and

   v) measures to determine the effectiveness of mitigation measures, criteria to determine when and how mitigation measures should be adapted, as well as the responses proposed to address unforeseen effects;

e) implementation plans, including:

   i) details on how the plans will be implemented by the Proponent;

   ii) the measures the Proponent will take to enable the participation of local monitors; and

iii) the process for updating the protection plan as information gaps are addressed, including listed species' recovery strategies and action plans;

f) processes for oversight and reporting with respect to the Wildlife Protection and Management Plan(s) and how those processes will be implemented; and

g) evidence of consultation with the Government of the Northwest Territories, Environment Canada and appropriate wildlife management boards.

To support the Wildlife Protection and Management Plan(s), the Proponent shall implement the following species-specific requirements, set out in Conditions 30 to 36, in addition to the specifications of Condition 29.

30. The Proponent shall include in its Wildlife Protection and Management Plan(s) (Condition 29) with respect to woodland caribou:

a) timing and dates during which project-related activities would occur so as to avoid or minimize conflict with caribou movement or sensitive feeding or calving time; and

b) evidence of consultation with the Dehcho Boreal Caribou Working Group.

31. The Proponent shall include in its Wildlife Protection and Management Plan(s) (Condition 29) with respect to barren ground caribou:

a) timing and dates during which project-related activities would occur so as to avoid or minimize conflict with caribou movement or sensitive feeding or calving time;

b) plans to address any impacts from the project on the Porcupine caribou herd resulting from increased use of the Dempster Highway by project-related traffic; and

c) evidence of consultation with the Porcupine Caribou Management Board and the Government of Yukon.

32. The Proponent shall include in its Wildlife Protection and Management Plan(s) (Condition 29) with respect to grizzly bear:

a) a plan to conduct annual grizzly bear den surveys during pre-construction activities and pipe-laying operations prior to the commencement of work planned for the coming season;

b) proposed mitigation measures for avoiding disturbance to grizzly bear dens; and

c) a commitment to file the results of the surveys annually during pre-construction activities and pipe-laying operations, prior to the commencement of work planned for the coming season, with the Government of the Northwest Territories and appropriate wildlife management boards.

33. The Proponent shall include in its Wildlife Protection and Management Plan(s) (Condition 29):

a) mitigation measures to avoid creation of preferred bison habitat; and

b) a monitoring program to detect wood bison use of the Mackenzie Gas Project's right of way and a process to develop mitigation measures in consultation with the Government of the Northwest Territories if wood bison start using the project right of way.

34. The Proponent shall include in its Wildlife Protection and Management Plan(s) (Condition 29):

a) the results of a survey in those parts of the Local Study Area where, based on the most recent assessment by the Committee on the Status of Endangered Wildlife in Canada, the yellow rail and western toad might occur, to confirm the presence or absence of those species;

b) proposed mitigation and monitoring measures specific to yellow rail and western toad, based on the results of this survey; and

c) evidence of consultation with Environment Canada and the Government of the Northwest Territories.

35. The Proponent shall include in its Wildlife Protection and Management Plan(s) (Condition 29) a commitment to conduct pre-construction, construction and post-construction surveys and monitoring programs in relation to short-eared owls and rusty blackbirds and to file this information with the Government of the Northwest Territories.

36. The Proponent shall include in its Wildlife Protection and Management Plan(s) (Condition 29) mitigation measures specific to raptors, including peregrine falcon and bald and golden eagles, that include the following restrictions on project-related activities or facilities, unless the NEB otherwise directs:

    a) for permanent structures, long-term habitat disturbance including pipeline right of way, road, quarry, camp, etc., ground and air access, and blasting maintain a setback of 1000 m from nest sites between April 15 and September 1 for peregrine falcons and between March 30 and July 31 for all other raptors; and

    b) for aircraft overflight, maintain a setback of 760 m above ground level from nest sites between April 15 and September 1 for peregrine falcons and between March 30 and July 31 for all other raptors.

Prior to Pipe-Laying Operations

37. The Proponent shall undertake a geotechnical verification program to support the final design and construction of the project facilities and shall file with the NEB 90 days prior to pipe-laying operations or station construction:

    a) copies of all borehole logs and the results of geophysical surveys completed; and

    b) an updated assessment of permafrost, ground ice and terrain conditions along the Mackenzie Gathering System including, as applicable, copies of all published information regarding permafrost conditions, ground ice and terrain conditions used in the assessment.

38. To compile and communicate all of the Proponent's environmental protection procedures, mitigation measures, and monitoring commitments pertaining to pipe-laying operations to its field staff and to the NEB inspectors, the Proponent shall file with the NEB an Environmental Protection Plan (EPP) for approval at least 90 days prior to the start of pipe-laying operations. The EPP may be divided into separate plans by region or project area as deemed necessary.

    The EPP for pipe-laying operations shall include:

    a) the scope and area of application of the EPP;

    b) environmental protection procedures and measures, including decision criteria for timing and implementation of these measures, site-specific plans and drawings, mitigation measures, and monitoring applicable to pipe-laying operations;

    c) an acid rock drainage prevention plan incorporating the testing of quarried and exposed rock during trenching, borrow pit and quarry development and provisions for the safe disposal or treatment of unsuitable material if required;

    d) a reclamation plan which includes a description of the condition to which the Proponent intends to reclaim and maintain the right of way, a description of measurable goals for reclamation, methods to minimize invasive plant introduction and measures to maximize vegetation recovery;

    e) references to other plans and manuals for environmental protection required by field staff and inspectors; and

    f) evidence of consultation with appropriate regulatory authorities and government subject matter experts in the area of application of the EPP.

39. To promote safety of the pipeline and protection of the environment and to advance knowledge of the effects of pipeline construction and operation in permafrost environments the Proponent shall develop an effects monitoring program for the project. The purpose of this program is to:

    a) monitor the effects of the environment on pipeline integrity;

    b) monitor the long-term effects of the construction and operation of pipeline on the physical environment; and

    c) validate design assumptions and approaches and monitor the effects of construction and operations practices used on the project.

This program shall take into account the results of the geotechnical verification program, the geohazard assessment and observations made during construction and shall be developed in consultation with Indian and Northern Affairs Canada, Natural Resources Canada and the Department of Fisheries and Oceans. The program shall address and identify changes in thermal regimes and their environmental effects, including existing and potential thaw settlement, frost heave, slope stability, river crossing scour, aufeis, drainage and fish passage impedance and erosion issues, and how these would be affected by successive changes in compressor station configuration. The program shall outline the monitoring methods to be used, instrumentation locations and the frequency of monitoring. The results shall be integrated into the Proponent's integrity management program and environmental protection program. The Proponent shall file with the NEB:

i) a report for approval, at least 90 days prior to the start of pipe-laying operations, which outlines the scope, objectives, monitoring methodologies and frequencies and the criteria for the selection of instrumentation sites for the program;

ii) on 1 April of each subsequent year of pipeline construction, locations it has chosen to monitor, the rationale for selection, the instrumentation required and the time of its installation; and

iii) a report by 30 November of each year describing the results of this program, and its mitigation/intervention plans to address issues identified.

40. The Proponent shall file with the NEB for approval the Construction Safety Manual at least 60 days prior to the start of pipe-laying operations.

41. The Proponent shall file with the NEB the final Pipeline Construction and Facility Specifications at least 60 days prior to the start of construction. The specifications shall be of sufficient scope and detail to demonstrate the suitability of the specifications prior to the start of pipe-laying operations and facility construction.

42. To facilitate NEB inspections, the Proponent shall file with the NEB updated engineering and environmental alignment sheets at least 90 days prior to the start of pipe-laying operations, and shall file with the NEB any modifications as they become available.

43. The Proponent shall file with the NEB for approval the replacement backfill and padding specifications at least 60 days prior to the start of pipe-laying operations. The specifications shall include provisions to ensure the replacement backfill and padding do not contain materials injurious to the pipeline, its coating and the environment.

44. Unless the NEB otherwise directs, to determine the effectiveness of the Proponent's plans for remediating ditch fill settlement for the project, the Proponent shall file a report with the NEB 90 days prior to the start of pipe-laying operations, which addresses:

a) its methods for determining the quality and quantity of imported fill required to remediate excess ditch settlement;

b) the timing and methods for hauling and stockpiling the fill materials;

c) the methods it will use to assess and address the need for additional replacement backfill or manage any excess backfill during final clean up and reclamation;

d) methods and locations for the disposal of excess excavated material not required for backfill; and

e) evidence of consultation with land managers and appropriate regulators.

45. To demonstrate that it has adequately assessed and mitigated against geohazards and to facilitate NEB monitoring during operations, the Proponent shall file with the NEB, at least 90 days prior to the start of pipe-laying operations, a Geohazard Assessment for the project describing:

a) its geohazard assessment methodology and the specific and combined geohazards identified along the route that have a reasonable probability of impacting the project;

b) specific measures to be implemented to mitigate individual and combined geohazards;

c) decision criteria for the implementation of mitigation for geohazards identified during construction;

d) the qualifications of the staff making decisions regarding design and implementation; and

e) the ongoing monitoring requirements.

46. To demonstrate that the pipeline design is sufficient to withstand anticipated frost heave and thaw settlement loadings, the Proponent shall file with the NEB a report summarizing the findings of the final design frost heave and thaw settlement analysis for overland areas at least 90 days prior to the start of pipe-laying operations. Where analysis indicates that the strain demand over the design life may exceed the strain capacity of the pipeline materials (omitting the effect of secondary mitigation measures), the report shall describe the site specific secondary measures incorporated into the design or integrity management program to prevent the pipeline from exceeding the critical threshold strain limits.

47. The Proponent shall undertake a hazard analysis identifying reasonably foreseeable hazards or problems with horizontal directionally drilled (HDD) activities, based on site specific data, and develop specific contingency plans for each HDD crossing. The Proponent shall file the hazard analysis and contingency plans with the NEB at least 60 days prior to the start of construction of an HDD watercourse crossing. The plans shall identify and address, where applicable, site-specific concerns such as the presence of ice-rich permafrost and other potentially unfavorable geotechnical conditions.

48. To facilitate NEB inspection during construction and monitoring during operations, and to confirm that there have been no significant changes to the slope design methodology, the Proponent shall file for approval with the NEB a Slope Design Methodology Final Report following the completion of final design and at least 90 days prior to the start of pipe-laying operations. The Slope Design Methodology Final Report shall include:

a) the slope design methodology, data requirements, assessment techniques and pre-construction slope inventory;

b) revisions to threshold slope angles, critical longitudinal and critical cross slope criteria based on findings from final design and further geotechnical investigations;

c) target Factor of Safety for longitudinal and cross slope designs;

d) details of selected passive ground cooling systems including the proposed number, location, type, refrigerant, typical drawings, corrosion protection and installation method;

e) details of the selected surface insulation(s) including type, source, thickness and specified mitigation against the introduction of noxious weeds (if applicable);

f) details of erosion control requirements including typical drawings and spacing requirements for berms, plugs and ditches;

g) results of thermal analysis showing 10 and 25 year thaw depth predictions for the start up configurations based on selected thermal mitigation options for thaw sensitive slopes exceeding critical slope length, slopes identified as potential concerns from a stability perspective which cannot be avoided by route refinements, and slopes that have or will have slope instrumentation installed during the construction phase;

h) typical design drawings for various slope conditions;

i) specific designs for thaw sensitive slopes exceeding critical slope length;

j) a tabular summary of sites requiring site-specific slope designs, indicating the location and identification number of the slope, slope angle, slope length, slope height, orientation, actual or assumed soil conditions, nature of the site-specific issue and proposed mitigation measures; and

k) a slope stability response plan describing the actions the Proponent shall take, and the timing of those actions, should monitoring indicate that the Factor of Safety for a slope falls below the design Factor of Safety or thaw depth exceeds predicted values.

49. The Proponent shall file with the NEB for approval a Field Changes Manual, for Slopes at least 90 days prior to the start of pipe-laying operations. The manual shall include:
    a) specific criteria for the implementation of changes to the designs, grading, materials, installation procedures, thermal stabilization measures, erosion mitigation measures and monitoring;
    b) details regarding the required qualifications of its field staff implementing the manual; and
    c) consultation required with other experts and regulatory authorities and the scope of that consultation.
50. To protect traditional harvesting of fish from adverse impacts related to project stream crossings, the Proponent shall file with the NEB, at least 90 days prior to the start of pipe-laying operations, the final suite of decision trees proposed to manage the impacts of the Mackenzie Gas Project on fish and fish habitat including:
    a) an explanation of the decision-making process, the criteria for decision-making and the mitigation options;
    b) a description of how the Proponent will address the importance of fish habitat and fish populations to local communities and harvesters; and
    c) evidence of consultation with Fisheries and Oceans Canada and the relevant management boards and agencies with regard to the decision trees.
51. To demonstrate the adequacy of scour protection and thermal mitigation measures of watercourse crossing designs and facilitate NEB inspection during construction, the Proponent shall file for approval with the NEB at least 90 days prior to the start of pipe-laying operations:
    a) a revised Watercourse/Waterbody Crossing Inventory, in both PDF and MS Excel spreadsheet format, describing the watercourse name and numerical identifier, coordinates, stream class, width of wetted channel, construction method, design type, minimum pipeline cover, navigability and fish habitat status and level of assessment;
    b) detailed final design drawings and plans for all watercourse and waterbody crossings requiring site specific designs, including HDD crossings, showing the design flood level, calculated vertical and lateral scour potential and detailing proposed thermal, erosion, scour control and ground water flow mitigation measures;
    c) detailed final design drawings of typical designs for open cut and isolated crossings of Lakes, Active I, Active II and Vegetated Channel watercourses detailing proposed thermal, erosion, scour control and ground water flow mitigation measures;
    d) 25 year frost bulb growth analysis for the start up configuration, including predicted strain demand/available strain capacity and frost bulb dimensions, for all Large, HDD, Active I and Active II watercourse crossings; and
    e) evidence of consultation with the Department of Fisheries and Oceans in regards to the design of stream crossings.
52. To facilitate NEB monitoring, the Proponent shall notify the NEB at least 30 days prior to qualifying the automated ultrasonic non-destructive examination procedures for mill and field circumferential welds.
53. The Proponent shall develop the joining program and file it with the NEB at least 30 days prior to conducting welding procedure qualification tests for:
    a) field circumferential production, tie-in and repair pipeline welds; and
    b) welding of project facilities.

    The joining program shall include:
    i) requirements for the qualification of welders;
    ii) requirements for the qualification and duties of welding inspectors;
    iii) welding procedure specifications;
    iv) non-destructive examination specifications;
    v) quality assurance program for field welds and welding procedures; and

vi) any additional information which supports the joining program.

54. To facilitate NEB inspection, the Proponent shall file with the NEB procedure qualification records for welding and non-destructive examination within 30 days of the completion of procedure qualification tests.

55. To facilitate NEB inspection, the Proponent shall file with the NEB the specifications for field applied coatings at least 60 days prior to the start of pipe-laying operations.

During Construction

56. To facilitate NEB inspection of all phases of construction, the Proponent shall provide when requested, logistical support to NEB staff undertaking inspection of construction and reclamation, at a reasonable cost to the NEB. (For clarity, the scope of this support is limited to transportation of NEB staff and vehicles to isolated camp locations, vehicle fuel and maintenance, meals and accommodation, office space and communications support.)

57. Unless the NEB otherwise directs the Proponent shall pressure test the approved facilities with a liquid medium and submit the Pressure Testing Program, demonstrating compliance with applicable codes, standards and regulatory requirements, to the NEB for approval at least 60 days prior to the start of pressure testing; or in the event that a hydrostatic test is not practicable, the Proponent shall file with the NEB for approval, at least 60 days prior to the start of any air testing activities, the Proponent's air testing measures. The program shall include:

    a) information demonstrating the ability of the leak test to detect the same size leak as a comparable hydrostatic test;

    b) information demonstrating that the pipeline has adequate notch toughness;

    c) a description of the specific safety precautions to be implemented during the pressure test; and

    d) a confirmation of successful leak test of pipeline sections prior to their installation under watercourses, lakes and ponds.

58. To verify implementation of the Proponent's quality assurance and control plans and procedures, the Proponent shall file monthly summary reports during construction outlining non-conformances with its design, materials, and construction specifications and the disposition of these non-conformances.

Prior to Operation

59. The Proponent shall file with the NEB for approval, at least 90 days prior to the planned start of operation, the elements of the Environmental Protection Program for the operation and maintenance of the pipeline pursuant to section 48 of the *Onshore Pipeline Regulations, 1999*. The elements to be submitted include but not be limited to policies, practices and procedures for:

    a) ongoing environmental training for employees/operators;

    b) handling and disposal of all wastes associated with the operation and maintenance of the project;

    c) management of air emissions, including:

        i) maximum Proponent-identified and/or legislated discharge limits for PM and NOx;

        ii) maximum Proponent-identified greenhouse gas targets;

        iii) reduction strategies for air emissions including PM, NOx, and greenhouse gases;

        iv) monitoring and measurement methods; and

        v) record keeping including annual reporting of greenhouse gases to the NEB;

    d) public communication program (non-emergency); and

    e) program review and consultation with Environment Canada and the Government of Northwest Territories.

60. To demonstrate that in-line inspection tools will be able to support effective integrity management programs, the Proponent shall submit to the NEB at least 90 days prior to the start of system operation:

    a) the type, description, specifications, operating limits and detection limits of all in-line inspection tools which can be used by the Proponent during operation of its pipelines;

b) data on the inertial curvature inline inspection tool(s) developed for the project indicating the detectable level of displacement and associated strain, the recommended pig velocity, and the relationship between pig velocity and strain resolution; and

c) intervention values for all parameters that will be monitored by in-line inspection tools.

61. The Proponent shall prepare:

a) an Emergency Preparedness and Response Plan for the project prior to the start of system operation and file with the NEB the Emergency Procedures Manual at least 30 days prior to the start of operation; and

b) a report, to be filed with the Emergency Procedures Manual, which outlines:

i) the potential for the establishment of local, community-based spill response teams to assist in responses to Mackenzie Gas Project incidents;

ii) a discussion of the opportunities and constraints of establishing local spill response teams including a training and equipment needs assessment; and

iii) the Proponent's commitment to work with local communities to build and maintain community spill response capacity.

In preparing its Emergency Preparedness and Response Plan, the Proponent shall have regard to:

1) the NEB letter dated 24 April 2002 entitled Security and Emergency Preparedness Programs addressed to all oil and gas companies under the jurisdiction of the NEB and subsequent amendments made thereafter; and

2) emergency responses required as a result of significant earthquakes which may require a broader scope of response.

62. To demonstrate that it is prepared to respond to an emergency at the outset of operation, the Proponent shall hold an emergency response exercise to evaluate the effectiveness of the Emergency Preparedness and Response Plan at least 10 days prior to the start of system operation and file a letter of notification with the NEB upon the successful completion of the exercise.

63. Unless the NEB otherwise directs the Proponent shall file with the NEB a report describing the final design of the SCADA and leak detection system for the Mackenzie Gathering System at least 90 days prior to the start of operation of the Mackenzie Gathering System. The report shall include information suitable for establishing a base line for the quality program for its SCADA and leak detection system and shall include:

a) a description of the SCADA and leak detection system;

b) the location and type of pressure, temperature and flow monitoring and control devices and remote terminal units;

c) the location of remotely operated valves;

d) the target detect ability (e.g., amounts leaked, time to detect, leakage rate);

e) the target sensitivity (i.e., minimum leak size);

f) the target reliability (i.e., false alarm rate, failure to alarm rate);

g) the expected system robustness (i.e., system availability in light of the system operating conditions);

h) the target accuracy (i.e., size and location of a detected leak); and

i) a description of the quality program using both direct and inferred methods that the Proponent shall implement during the operational phase of the project to ensure optimal performance.

64. To demonstrate that the SCADA and leak detection system are calibrated to actual system conditions, the Proponent shall file with the NEB, reports describing the results of the Proponent's quality program for its SCADA and leak detection system and how identified issues were addressed. Unless the NEB otherwise directs, the reports shall be filed one year, three years and five years after the start of system operation.

During Operation

65. Within 30 days of the date that the approved project is placed in service, the Proponent shall file with the NEB a confirmation, by an officer of the company, that the approved project was completed

and constructed in compliance with all applicable conditions in this Certificate. If compliance with any of these conditions cannot be confirmed, the officer of the company shall file with the NEB details as to why compliance cannot be confirmed. The filing required by this condition shall include a statement confirming that the signatory to the filing is an officer of the company.

66. To facilitate monitoring during operation, the Proponent shall file with the NEB, within six months of the start of system operation, a geotechnical construction report including maps and drawings, which identifies and describes:
    a) longitudinal and cross slopes identified during construction as requiring ongoing monitoring;
    b) locations where passive cooling systems were installed;
    c) locations where slope instrumentation including thermistors, piezometers and slope inclinometers were installed;
    d) slopes exceeding the critical slope length which were identified during construction as being thaw sensitive or exhibiting evidence of soil movement;. and
    e) locations where slope design changes were made in accordance with the Field Change Manual for Slopes and the reasons for the design change.

67. To minimize or reduce air emissions from flaring, the Proponent shall meet the Guideline for Ambient Air Quality Standards in the Northwest Territories and Alberta's Energy Resources Conservation Board Directive 60: "Upstream Petroleum Industry Flaring, Incinerating and Venting".

68. To minimize noise disturbance from pipeline facilities, the Proponent shall:
    a) design pipeline facilities to meet the requirements of Alberta's Energy Resources Conservation Board Directive 038; and
    b) file with the NEB, 90 days following the start of operation, a post construction noise assessment report.

69. To aid NEB inspectors in confirming the effectiveness of mitigation techniques and any adaptation required, as well as to identify effects that were not predicted and appropriate adaptive management to address these effects, the Proponent shall file with the NEB a post-construction environmental report that reflects any monitoring or follow-up program developed, including:
    a) identification on a map or diagram of any environmental issues which arose during construction;
    b) the criteria used or to be used to verify the accuracy of the environmental assessment predictions;
    c) the determination of the accuracy of the environmental assessment predictions;
    d) discussion of the effectiveness of the mitigation applied pre-, during and post- construction and where adaptive management was necessary;
    e) identification of the current status of the issues identified describing whether those issues are resolved or unresolved; and
    f) proposed measures and schedule that the Proponent shall implement to address any unresolved concerns.

    The report shall be filed on or before the 31 of January of each of the first, third, fifth and tenth years following the start of project operation, unless the NEB otherwise directs.

70. Unless the NEB otherwise directs, to demonstrate the management of pipeline integrity and thermal effects on the right of way the Proponent shall monitor geotechnical and thermal effects on the pipeline(s) with respect to thaw subsidence, frost heave and slope stability by:
    a) undertaking a detailed as-built survey prior to backfill which documents the position of the pipeline for comparison with future in-line inertial inspection data, the location of pipe specification changes, the location of each circumferential weld, buoyancy control devices, depth of cover; and
    b) undertaking an inertial in-line inspection within one month of the start of operations and on an annual basis thereafter.

71. To facilitate monitoring, the Proponent shall record ditch wall geotechnical information during construction and shall file the ditch wall logs with the NEB within one year of the start of system operation.

72. To facilitate monitoring, the Proponent shall file with the NEB, within one year of the start of system operation, copies of all stream flow monitoring, ice thickness measurements and ground temperature monitoring data collected during project planning and design. Numerical records shall be submitted in both PDF and MS Excel spreadsheet format.

Planning Clause

73. The Proponents shall file updated cost estimates and report on their decision to construct by 31 December 2013.

Sunset Clause

74. Unless the NEB otherwise directs, this Certificate shall expire on 31 December 2015 unless construction in respect of the Mackenzie Gas Project has commenced by that date.

Conditions that apply only to the Mackenzie Gathering System

75. Prior to leave to open, the Proponent shall provide financial responsibility pursuant to subsection 13(14) of the *Inuvialuit Final Agreement* in the amount of $6,028,200 to be held in trust by the NEB in a form satisfactory to the NEB and to remain in place until all facilities located within the Inuvialuit Settlement Region are abandoned in accordance with NEB requirements.

76. Prior to the start of pre-construction activities, the Proponent shall provide financial responsibility pursuant to the *Canada Oil and Gas Spills and Debris Liability Regulations* and subsection 27(1) of *Canada Oil and Gas Operations Act* in the amount of $25,000,000 in a form satisfactory to the NEB, to remain in place until all facilities are abandoned in accordance with NEB requirements.

77. Unless the NEB otherwise directs, to ensure that safety, integrity, and environmental protection will be at an equivalent level for the Mackenzie Gathering System as for the Mackenzie Valley Pipeline, the Proponent shall comply with the following regulations:
    a) the *Onshore Pipeline Regulations, 1999*, as amended from time to time;
    b) the *National Energy Processing Plant Regulations*, as amended from time to time; and
    c) those sections of the *National Energy Board Pipeline Crossing Regulations Part I* and *Part II* and as amended from time to time that would be applicable to the Proponent.

78. To ensure the NEB is satisfied that the pipeline may be safely opened for transmission the Proponent shall file for approval the information referred to in NEB Filing Manual, 2004, for opening the pipeline for operation (Guide "T").

79. The authorization for the Mackenzie Gathering System under paragraph 5(1)(b) is subject to the Minister of Indian Affairs and Northern Development Canada providing confirmation that the Proponents have satisfactorily met the Benefits Plan requirements of section 5.2 of the *Canada Oil and Gas Operations Act.*

80. Prior to commencement of pre-construction activities, the Proponents shall provide a declaration pursuant to subsection 5.11(1) of the *Canada Oil and Gas Operations Act* in a form satisfactory to the NEB.

81. Prior to commencement of the related activities, the Proponents shall provide any necessary certificates pursuant to subsection 5.12(1) of the *Canada Oil and Gas Operations Act* in a form satisfactory to the NEB.

Appendix N
Miscellaneous Order for Mackenzie Gathering System Tolls

National Energy Board | Office national de l'énergie

ORDER MO-18-2010

IN THE MATTER OF Part 0.1 of the *Canada Oil and Gas Operations Act*; and

IN THE MATTER OF an application by Imperial Oil Resources Ventures Limited (the Proponent), on behalf of Imperial Oil Resources Ventures Limited, ConocoPhillips Canada (North) Limited, ExxonMobil Canada Properties and Shell Canada Limited as managing partner of Shell Canada Energy filed with the National Energy Board (Board) for the Mackenzie Gathering System under file numbers: OF-Fac-Gas-I017-2004-1, OF-EP-FacPipe-I003-MAC 04, OF-EP-FieldOp-I003-TL 07, OF-EP-FieldOp-C648-PL 07, OF-EP-FieldOp-S245-NIG 07.

WHEREAS the Proponent filed an application in October 2004 under the *Canada Oil and Gas Operations Act* for the Mackenzie Gathering System which consists of:

- 190 kilometres of pipeline to carry the natural gas and natural gas liquids from the Niglinktak, Taglu and Parsons Lake fields to a processing plant near Inuvik, Northwest Territories;
- the processing plant near Inuvik, Northwest Territories; and
- a 457 kilometre long, 250 millimetre (10 inch) diameter pipeline to carry natural gas liquids from the processing plant near Inuvik, Northwest Territories to the existing crude oil pipeline at Norman Wells operated by Enbridge Pipelines (NW) Inc.;

AND WHEREAS the application was set down for hearing in Hearing Order GH-1-2004;

AND WHEREAS the appropriate tolls, access and tariff provisions for the Mackenzie Gathering System and the methods for resolving disputes on these matters was on the List of Issues for the Hearing;

AND WHEREAS the National Energy Board has indicated that it intends to issue an authorization for the Mackenzie Gathering System;

IT IS ORDERED pursuant to Part 0.1 of the *Canada Oil and Gas Operations Act* that the method for determining tolls for the Mackenzie Gathering System agreed to by the Proponent in the GH-1-2004 proceedings be approved subject to the following:

1. The Mackenzie Gathering System shall be accessible to all shippers that meet the terms of the contractual arrangements.

2. Tolls for the Mackenzie Gathering System, including the natural gas liquids line, shall be negotiated and regulated on a complaint basis.

3. The Proponent shall file, for National Energy Board approval, a Code of Conduct for the Mackenzie Gathering System for all phases of development including pre-construction, construction and operation. The Code of Conduct is to be filed as soon as possible but in any event no later than 31 December 2011. At a minimum, the Code of Conduct should address in detail:

   a) prevention of undue preferential treatment;

   b) governance of the interactions between shippers and transporters;

   c) independence of transmission operations from affiliate operations;

   d) governance of separation of business;

   e) protection of confidential and commercially-sensitive information;

   f) mechanisms and methodologies related to the design of an acceptable transfer pricing mechanism;

   g) a Code of Conduct compliance plan with independent audits; and

   h) penalties for breaches of the Code of Conduct and recourse to a third-party arbitrator.

4. Consistent with the requirements for all pipelines to set aside funds to cover all abandonment activities as set out in RH-2-2008, at least 18 months prior to the pipelines being placed in service the Proponent shall prepare and file for approval:

   a) an estimate of abandonment costs and the amount required to be set aside using pipeline-specific assumptions or a combination of pipeline-specific assumptions and Base Case assumptions from the National Energy Board's RH-2-2008 proceeding; and

   b) a proposal for the collection of funds and a proposed process and mechanism to set aside the funds.

NATIONAL ENERGY BOARD

Anne-Marie Erickson
Secretary of the Board

Appendix O
Conditions for the Shell Canada Limited (Shell) Development Plan for the Niglintgak field

Many of the proposed conditions reference an application for an authorization under paragraph 5(1)(b) of the *Canada Oil and Gas Operations Act* (COGOA). Before any drilling or construction activity relating to a development plan may commence, authorizations under paragraph 5(1)(b) would be required. Section 6 of the *Canada Oil and Gas Drilling and Production Regulations* states that an operator shall provide the following in an application for an authorization under paragraph 5(1)(b): a description of the scope of activities; an environmental protection plan; a safety plan; and a contingency plan. The activities in relation to a development plan may include drilling, completions, facilities construction, production, and decommissioning.

Unless otherwise specified, Proponent *consultation* referred to in a condition must be carried out in a manner that includes the Proponent:

a) providing, to the party to be consulted,
   - i) notice of the matter in sufficient form and detail to allow the party to prepare its views on the matter,
   - ii) a reasonable period for the party to prepare those views, and
   - iii) an opportunity to present those views to the party conducting the consultation; and

b) considering, fully and impartially, any views so presented.

Unless otherwise specified in a condition *best available technology* (BAT) means technology with superior emissions performance which is commercially available at a reasonable cost at the time it is required for the project which meets the goals of pollution prevention and energy efficiency.

Unless otherwise specified in a condition *best management practices* (BMP) are innovative, dynamic, and improved environmental protection practices and procedures that help ensure that development is conducted in an environmentally responsible manner. BMP may exist as formal guidelines or generally accepted procedures that are recognized by regulators and industry associations as best practices.

N1. Unless the National Energy Board (NEB) otherwise directs, Shell shall design, implement or cause to be implemented all of the policies, mitigation measures, procedures, specifications, standards and recommendations for any work or activity referred to in the Development Plan application or in the Environmental Impact Statement or other filings with the Joint Review Panel or as otherwise agreed to during the GH-1-2004 Hearing and during the review by the Joint Review Panel.

N2. To promote potential joint development with a minimal environmental footprint, the north, central and south well pads of the Niglintgak field shall each be designed so they may be expanded to allow for the drilling of at least one well by third party adjacent subsurface rights interest holders.

N3. To prevent coalescence of the well permafrost thaw bulbs, the interwell spacing on a well pad shall not be less than 15 m unless Shell utilizes mitigation measures approved by the NEB.

N4. To confirm the estimates of subsidence due to gas extraction, Shell shall submit a program employing BMP and BAT to quantitatively measure and monitor accumulated subsidence, and to monitor flooding for the life of the field with the initial application for an authorization under paragraph 5(1)(b). For this condition BAT means technology with superior accuracy and measurement performance which is commercially available at a reasonable cost at the time it is required for the project which meets the goals of pollution prevention and energy efficiency. The program shall include:

a) a description of proposed survey area or the proposed number and the proposed locations of the elevation survey points within the projected gas-extraction-subsidence-area;

b) the proposed number and the proposed locations of the elevation benchmarks to be situated outside the projected gas-extraction-subsidence-area in order to estimate natural subsidence;

c) the expected elevation accuracy of the surveys;

d) a proposed baseline survey to be conducted prior to the commencement of natural gas production;

e) the proposed measurement frequency and the proposed reporting frequency to the NEB; and

f) the results of consultation with Environment Canada.

N5. Prior to the commencement of drilling, Shell shall provide financial responsibility pursuant to subsection 13(14) of the *Inuvialuit Final Agreement* in the amount of $30,072,000 to be held in trust by the NEB in the form satisfactory to the NEB and to remain in place until all wells and facilities are abandoned in accordance with NEB requirements.

N6. All financial responsibility provided pursuant to the *Canada Oil and Gas Spills and Debris Liability Regulations* and subsection 27(1) of *Canada Oil and Gas Operations Act* shall remain in place until all wells and facilities are abandoned in accordance with NEB requirements.

N7. To promote safety of the pipeline and protection of the environment with respect to the design, construction and operation of the proposed flow line crossing of the Kumak Channel, Shell shall provide the following with the corresponding application for an authorization under paragraph 5(1)(b) of COGOA:

a) a hazard analysis and contingency plan for the proposed horizontal directional drill crossing. The plan shall identify and address site-specific concerns such as the presence of ice-rich permafrost and other potentially unfavourable geotechnical conditions;

b) detailed final design drawings of the proposed HDD showing the design flood level, calculated vertical and lateral scour potential and detailing proposed thermal, erosion, scour control and ground water flow mitigation measures;

c) detailed final design drawings of the contingent open cut detailing proposed thermal, erosion, scour control and ground water flow mitigation measures;

d) a monitoring program for slope stability, scour, drainage impedance and erosion issues for the crossing; and

e) evidence of consultation with other appropriate regulators and government departments.

N8. To confirm adequate consideration of the effects of climate change has been incorporated into the facilities design, Shell shall submit the following information with the initial application for an authorization under paragraph 5(1)(b):

a) an analysis of the impacts of climate change and variability on permafrost and terrain stability for the Niglintgak facility using potential upper limit temperature scenarios which may occur during the operational life of the facilities;

b) a description of how these upper limit temperature scenarios may impact precipitation, rise in sea level, storm surges, ice floes and flood levels;

c) a description of how the proposed facilities design, including water course crossing design, accounts for the potential changes outlined in b); and

d) the results of consultation with appropriate regulators and government departments.

N9. To minimize noise disturbance from facilities inside the Kendall Island Bird Sanctuary, Shell shall:

a) design the facilities to meet, as a minimum, the requirements of Alberta's Energy Resources Conservation Board Directive 038;

b) incorporate BMP and BAT related to noise abatement into the facilities design;

c) continue to evaluate noise mitigation options in consultation with Environment Canada and submit the results of consultation with the corresponding application for an authorization under paragraph 5(1)(b); and

d) submit an independent noise impact analysis report on the proposed design and the feasibility of further reductions in noise emissions with the corresponding application for an authorization under paragraph 5(1)(b).

N10. Shell shall provide the following with the corresponding application for an authorization under paragraph 5(1)(b):

a) the plans for excavation and dredging at the site of the barge-based gas conditioning facility set-down location;

b) a dredging spoil management plan;

c) the results of consultation with Environment Canada, Department of Fisheries and Oceans and Transport Canada.

N11. To compile and communicate all of Shell's environmental protection procedures, mitigation measures, and monitoring commitments pertaining to the facilities operations, to its field staff, and to the NEB inspectors, Shell shall file with the NEB an Environmental Protection Plan (EPP). The EPP is to be submitted with the initial application for an authorization under paragraph 5(1)(b) and shall include policies, practices and procedures for:

a) the scope and area of application of the EPP;

b) environmental protection procedures and measures, including decision criteria for timing and implementation of these measures, site-specific plans and drawings, mitigation measures, and monitoring applicable to construction and drilling operations;

c) ongoing environmental training for employees/operators;

d) references to other plans and manuals for environmental protection required by field staff and inspectors;

e) a reclamation plan which includes a description of the condition to which Shell intends to reclaim, a description of measurable goals for reclamation, methods to minimize invasive plant introduction, and measures to maximize vegetation recovery.

f) management of air emissions, including:

i) maximum Proponent-identified and/or legislated discharge limits for particulate matter (PM) and NOx;

ii) maximum Proponent-identified greenhouse gas targets;

iii) reduction strategies for air emissions including PM, NOx, and greenhouse gases;

iv) monitoring and measurement methods;

v) location of monitoring sites on a map or diagram, the purpose for the locations selected, and timing of installation;

vi) details of the additional measures that would be implemented as a result of monitoring data or ongoing concern, and the criteria or thresholds that would require these measures; and

vii) record keeping including annual reporting of greenhouse gases to the NEB;

g) public communication program (non-emergency);

h) program review and consultation with Environment Canada and the Government of Northwest Territories; and

i) evidence of consultation with appropriate regulatory authorities and government subject matter experts in the area of application of the EPP.

N12. In order that the facilities, camps and supporting infrastructure are maintained and operated in an environmentally acceptable condition during construction and production operations, Shell shall submit a Waste Management Plan with the initial application for the authorization under paragraph 5(1)(b). This plan shall be developed in consultation with the Government of the Northwest Territories, Indian and Northern Affairs Canada and Environment Canada.

The plan shall address:

a) all wastes associated with construction and production operations with the objectives of minimizing impacts to the environment and ensuring worker and public safety;

b) training requirements for company and contractor staff;

c) the prevention of uncontrolled fires;

d) disposal or treatment of potentially hazardous and dangerous materials, including petroleum products, toxic or persistent chemicals, oily wastes, aircraft de-icing fluids and fuel barrels;

e) solid waste management including metals, plastics, recyclables, incinerator ash, equipment, equipment parts, batteries, building materials and construction waste;

f) food waste management including measures to minimize animal attraction;

g) management of contaminated soil, snow and ice from spills and aircraft de-icing;

h) treatment and disposal of domestic sewage and grey water;

i) incineration/evaporator technology choices and rationale for selection;

j) waste segregation requirements, interim storage and treatment;

k) testing methods and disposal for waste streams proposed for release to the environment; and

l) the results of consultation.

N13. To demonstrate that winter roads will be constructed and operated in a safe and environmentally acceptable manner, Shell shall submit a manual for the construction, operation, maintenance and closure of winter roads with the initial application for an authorization under paragraph 5(1)(b). The manual shall include:

a) required road width, clearing and grading requirements, grade, allowable speed, signage, maximum vehicle weight;

b) objective and measurable environmental and engineering criteria to determine when the winter road will be ready for use;

c) safe ice thickness criteria for lake, river and stream crossing including the frequency of ice profiling;

d) local regulatory requirements;

e) installation and removal requirements for snow fills, culverts, corduroy and temporary bridges; and

f) objective and measurable environmental and engineering criteria for closure.

N14. Shell shall evaluate the technologies and practices available to reduce emissions of particulate matter (PM) and precursors of PM and ozone from its facilities and construction related activities, and incorporate BMP and BAT to reduce emissions of PM and precursors of PM and ozone to the extent practicable. Shell shall file a report of its findings and how it will implement its findings with the initial application for an authorization under paragraph 5(1)(b).

N15. Shell shall evaluate and implement technologies and practices available to reduce mercury, dioxin and furan emissions from incinerators operating at construction camps and facilities to the extent practicable. Shell shall file a report of its findings and how it intends to implement its findings with the initial application for an authorization under paragraph 5(1)(b).

N16. Shell shall file with the initial application for an authorization under paragraph 5(1)(b) a report outlining:

a) the specific design and operational measures it has implemented and will implement to minimize methane leakage and venting through the system's operation taking into account BMP developed by Canadian Association of Petroleum Producers, Environment Canada, the Canadian Energy Partnerships for Environmental Innovation and the Canadian Gas Association;

b) how Shell has utilized waste heat energy to minimize natural gas fuel consumption in the design of the facilities;

c) the use of BAT when specifying compressor units used including size, efficiency and their conformity with Canadian Council of Ministers of the Environment National Emissions Guidelines for Stationary Combustion Turbines (CCME,1992); and

d) the results of consultation with Environment Canada and the Government of the Northwest Territories.

N17. To minimize or reduce air emissions from flaring, Shell shall meet the Guideline for Ambient Air Quality Standards in the Northwest Territories and Alberta's Energy Resources Conservation Board Directive 60: *Upstream Petroleum Industry Flaring, Incinerating and Venting*.

N18. Unless the NEB otherwise directs, Shell shall submit an updated resource management plan within 18 months after production commences or prior to the drilling of contingent wells.

N19. To protect the correlative rights of adjacent subsurface rights interest holders, Shell shall comply with to the NEB's *Draft Spacing Requirements* dated 31 December 2009 or any orders dealing with spacing units that may supersede it.

N20. To address worker and public safety and environmental protection, Shell shall prepare its contingency plans in consultation with Indian and Northern Affairs Canada, the Canadian Coast Guard, Transport Canada, Environment Canada, the Government of the Northwest Territories and the Inuvialuit Land Administration. The contingency plans shall include:

a) training and orientation requirements of company and contractor staff;

b) an inventory indicating storage facility locations for petroleum products, chemicals and other hazardous substances, together with corresponding material safety data sheets (MSDS) sheets, that will be transported, stored and/or used during construction and operational phases;

c) identification of resources (equipment and staff) to be on-site and/or available to respond to emergencies;

d) identification of mutual aid partners and the location of their resources (equipment and staff) available to respond to emergencies;

e) procedures for responding to spills, releases, fires, medical emergencies and security issues including the incident reporting and notification system;

f) location of fire and spill response equipment stores and the spill kit requirements for vehicles;

g) a phone list of company, contractor, government agency and community representatives outlining their respective roles and information needs;

h) clean-up and disposal procedures for generated clean-up wastes;

i) identification of muster points for emergency evacuations from camps and facilities;

j) location of emergency medical treatment locations and capabilities;

k) the requirement for 24-hour emergency medical evacuation capability;

l) maps showing the location of infrastructure such as camps, access roads, material storage areas, aircraft landing sites, barge landing sites and borrow pits to facilitate the dispatch of first responders;

m) consideration of high flood and high ice floe scenarios;

n) consideration of earthquakes; and

o) the results of consultation.

N21. To demonstrate that it is prepared to respond to an emergency at the outset of production, unless the NEB otherwise directs, Shell shall hold an emergency response exercise to evaluate the effectiveness of the contingency plan at least 10 days prior to the commencement of production and file a letter of notification with the NEB upon the successful completion of the exercise.

N22. To minimize field development-related impacts on wildlife species, Shell shall file with the NEB for approval, with the initial application for an authorization under paragraph 5(1)(b), a Wildlife Protection and Management Plan(s) to address general wildlife protection and specific protection of barren ground caribou, grizzly bear, polar bear and wolverine. The Wildlife Protection and Management Plan(s) shall specify goals, area covered by the plan(s), and assumed zones of influence of activities and rationales for these assumptions. The Wildlife Protection and Management Plan(s) shall include:

a) results of pre-construction surveys, including surveys for species at risk listed on Schedule 1 of the *Species at Risk Act* public registry (listed species) except where the Minister has determined that recovery for the species is not feasible, and locations of any observations of species classified as at risk or may be at risk on the most recent Committee on the Status of Endangered Wildlife in Canada assessment and NWT General Status Ranks;

b) updated impact assessments for listed species in consideration of the *Species at Risk Act*, conducting the impact assessments directly on the listed species where possible rather than using one or more indicator species;

c) mitigation measures including:

i) measures to avoid or minimize disturbances including linear disturbance and effects of habitat fragmentation, sensory disturbance, and barriers to movement;

ii) scheduling of activities to minimize wildlife disturbance;

iii) measures to minimize the development footprint in habitats known to support listed species;

iv) procedures to avoid disturbance of potential maternal denning areas;

v) access management, including provisions for public consultation;

vi) protocols and education/awareness activities for managing human-wildlife interactions, including measures to limit harvesting and to deter wildlife, especially bears, from entering camps and other facilities;

vii) measures to reduce the impacts of access road and other field development-related vehicle and air traffic on wildlife and migratory birds; and

viii) any wildlife protection measures included in other management plans, or references to those measures;

d) protocols for monitoring and adaptive management including:

i) establishing and maintaining linkages to regional programs;

ii) survey protocols to be employed to avoid or prevent impacts to wildlife;

iii) plans for monitoring responses of wildlife to activities during all phases of the development;

iv) protocols for documenting habitat loss and habitat change as well as wildlife incidents, interactions and mortality; and

v) measures to determine the effectiveness of mitigation measures, criteria to determine when and how mitigation measures should be adapted, as well as the responses proposed to address unforeseen effects;

e) implementation plans, including:

i) details on how the plans will be implemented and linked to Shell's Wildlife Protection and Management Plan;

ii) the measures taken to enable the participation of local monitors; and

iii) the process for updating the protection plan as information gaps are addressed, including listed species' recovery strategies and action plans;

f) processes for oversight and reporting with respect to the Wildlife Protection and Management Plan(s) and how those processes will be implemented; and

g) evidence of consultation with the Government of the Northwest Territories, Environment Canada and appropriate wildlife management boards.

N23. Shell shall include in its Wildlife Protection and Management Plan(s) (Condition N22) with respect to barren ground caribou:

a) timing and dates during which activities would occur so as to avoid or minimize conflict with caribou movement or sensitive feeding or calving time;

b) plans to address any impacts on the Porcupine caribou herd resulting from increased use of the Dempster Highway by field development-related traffic; and

c) evidence of consultation with the Porcupine Caribou Management Board and the Government of Yukon.

N24. Shell shall include in its Wildlife Protection and Management Plan(s) (Condition N22) a commitment to conduct pre-construction, construction and post-construction surveys and monitoring programs in relation to short-eared owls and rusty blackbirds and to file this information with the Government of the Northwest Territories.

N25. Shell shall include in its Wildlife Protection and Management Plan(s) (Condition N22) mitigation measures specific to raptors, including peregrine falcon and bald and golden eagles, that include the following restrictions on activities or facilities, unless the NEB otherwise directs:

a) for permanent structures, long-term habitat disturbance including road, quarry, camp, etc., ground and air access, and blasting maintain a setback of 1000 m from nest sites between April 15 and September 1 for peregrine falcons and between March 30 and July 31 for all other raptors; and

b) for aircraft overflight, maintain a setback of 760 m above ground level from nest sites between April 15 and September 1 for peregrine falcons and between March 30 and July 31 for all other raptors.

N26. To protect traditional harvesting of fish from adverse impacts related to construction, Shell shall file with the NEB, with the initial application for an authorization under paragraph 5(1)(b), the final suite of decision trees proposed to manage the impacts on fish and fish habitat including:

a) an explanation of the decision-making process, the criteria for decision-making and the mitigation options;

b) a description of how Shell will address the importance of fish habitat and fish populations to local communities and harvesters; and

c) evidence of consultation with the Department of Fisheries and Oceans and the relevant management boards and agencies with regard to the decision trees.

N27. Shell shall include in its Wildlife Protection and Management Plan(s) (Condition N22) with respect to grizzly bear:

a) a plan to conduct annual grizzly bear den surveys during pre-construction activities and construction operations prior to the commencement of work planned for the coming season;

b) proposed mitigation measures for avoiding disturbance to grizzly bear dens; and

c) a commitment to file the results of the surveys annually during pre-construction activities and construction operations, prior to the commencement of work planned for the coming season, with the Government of the Northwest Territories and appropriate wildlife management boards.

N28. Shell shall file with the initial application for an authorization under paragraph 5(1)(b), diversity plans, inclusive of gender equality, for both the construction and operations phases. The plans shall include:

a) methods for determining diversity goals;

b) identification of diversity goals;

c) steps to achieve the identified goals;

d) commitments to the provision of a healthy and safe work environment;

e) steps to create a Diversity Management Committee; and

f) a monitoring and reporting system.

Shell shall require its contractors and subcontractors to comply with the diversity plans.

N29. Shell shall file with the initial application for an authorization under paragraph 5(1)(b), plans for a formal issues resolution program that will be implemented during construction and operations. The plans shall be prepared in consultation with the Government of the Northwest Territories and Aboriginal authorities, and include:

a) a description of the process by which any complaints or issues would be raised with Shell or governments;

b) a description of the process by which any received complaints or issues would be allocated among those with responsibility for action and a description of the roles and responsibilities of any party involved in assessing or responding to any complaint or issue;

c) a description of the process by which any received complaints or issues would be resolved;

d) a description of any protocols developed for referral and resolution of any complaints or issues;

e) a description of the recourse mechanisms for any unresolved complaints or issues or any unsatisfactorily resolved complaints or issues; and,

f) a description of the process for communicating and informing communities about the issues resolution program.

N30. Shell shall file with the initial application for an authorization under paragraph 5(1)(b), information related to the hiring of local residents as monitors to carry out compliance and environmental impact monitoring including:

a) the nature of the activities to be monitored;

b) clearly defined job descriptions for the positions as monitors;

c) identification of the training that will be offered to monitors to enable them to perform their duties; and

d) confirmation that monitors have been hired.

N31. The approval of the Development Plan for the Niglintgak field under subsection 5.1(4) of the *Canada Oil and Gas Operations Act* is subject to the Minister of Indian Affairs and Northern Development Canada providing confirmation that Shell has satisfactorily met the Benefits Plan requirements of section 5.2 of the *Canada Oil and Gas Operations Act*.

Appendix P

Conditions for the Imperial Oil Resources Limited (IORL) Development Plan for the Taglu field

Many of the proposed conditions reference an application for an authorization under paragraph 5(1)(b) of the *Canada Oil and Gas Operations Act* (COGOA). Before any drilling or construction activity relating to a development plan may commence, authorizations under paragraph 5(1)(b) would be required. Section 6 of the *Canada Oil and Gas Drilling and Production Regulations* states that an operator shall provide the following in an application for an authorization under paragraph 5(1)(b): a description of the scope of activities; an environmental protection plan; a safety plan; and a contingency plan. The activities in relation to a development plan may include drilling, completions, facilities construction, production, and decommissioning.

Unless otherwise specified, Proponent *consultation* referred to in a condition must be carried out in a manner that includes the Proponent:

a) providing, to the party to be consulted,

   i) notice of the matter in sufficient form and detail to allow the party to prepare its views on the matter,

   ii) a reasonable period for the party to prepare those views, and

   iii) an opportunity to present those views to the party conducting the consultation; and

b) considering, fully and impartially, any views so presented.

Unless otherwise specified in a condition *best available technology* (BAT) means technology with superior emissions performance which is commercially available at a reasonable cost at the time it is required for the project which meets the goals of pollution prevention and energy efficiency.

Unless otherwise specified in a condition *best management practices* (BMP) are innovative, dynamic, and improved environmental protection practices and procedures that help ensure that development is conducted in an environmentally responsible manner. BMP may exist as formal guidelines or generally accepted procedures that are recognized by regulators and industry associations as best practices.

T1. Unless the National Energy Board (NEB) otherwise directs, IORL shall design, implement or cause to be implemented all of the policies, mitigation measures, procedures, specifications, standards and recommendations for any work or activity referred to in the Development Plan application or in the Environmental Impact Statement or other filings with the Joint Review Panel or as otherwise agreed to during the GH-1-2004 Hearing and during the review by the Joint Review Panel.

T2. To prevent coalescence of the well permafrost thaw bulbs the interwell spacing on a well pad shall not be less than 15 m unless IORL utilizes mitigation measures approved by the NEB.

T3. To confirm the estimates of subsidence due to gas extraction, IORL shall submit a program employing BAT and BMP to quantitatively measure and monitor accumulated subsidence and to monitor flooding for the life of the field with the initial application for an appropriate authorization under paragraph 5(1)(b). For this condition BAT means technology with superior accuracy and measurement performance which is commercially available at a reasonable cost at the time it is required for the project which meets the goals of pollution prevention and energy efficiency. The program shall include:

a) a description of proposed survey area or the proposed number and the proposed locations of the elevation survey points within the projected gas-extraction-subsidence-area;

b) the proposed number and the proposed locations of the elevation benchmarks to be situated outside the projected gas-extraction-subsidence-area in order to estimate natural subsidence;

c) the expected elevation accuracy of the surveys;

d) a proposed baseline survey to be conducted prior to the commencement of natural gas production;

e) the proposed measurement frequency and the proposed reporting frequency to the NEB; and

f) the results of consultation with Environment Canada.

T4. To confirm adequate consideration for subsurface containment, IORL shall submit a drill cuttings slurry injection management program with the corresponding application for an authorization under paragraph 5(1)(b). The program shall include:

a) a description of the proposed cuttings slurry injection methodologies and proposed wells;

b) a description of the proposed injection zones;

c) a description of the any step-rate or injectivity tests that would be conducted prior to operations; and

d) a description of how the vertical migration of injection and/or formation fluid out of the injection zone and the potential contamination of fresh water aquifers, permafrost intervals and hydrocarbon bearing formations would be prevented during subsurface cuttings slurry injection operations.

T5. Prior to the commencement of drilling, IORL shall provide financial responsibility pursuant to subsection 13(14) of the *Inuvialuit Final Agreement* in the amount of $30,045,600 to be held in trust by the NEB in the form satisfactory to the NEB and to remain in place until all wells and facilities are abandoned in accordance with NEB requirements.

T6. All financial responsibility provided pursuant to the *Canada Oil and Gas Spills and Debris Liability Regulations* and subsection 27(1) of *Canada Oil and Gas Operations Act* shall remain in place until all wells and facilities are abandoned in accordance with NEB requirements.

T7. To confirm adequate consideration of the effects of climate change has been incorporated into the facilities design, IORL shall submit the following information with the initial application for an authorization under paragraph 5(1)(b):

a) an analysis of the impacts of climate change and variability on permafrost and terrain stability for the Taglu facility using potential upper limit temperature scenarios which may occur during the operational life of the facilities;

b) a description of how these upper limit temperature scenarios may impact precipitation, rise in sea level, storm surges, ice floe and flood levels;

c) a description of how the proposed facilities design accounts for the potential changes outlined in b); and

d) the results of consultation with appropriate regulators and government departments.

T8. To minimize noise disturbance from facilities inside the Kendall Island Bird Sanctuary, IORL shall:

a) design the facilities to meet, as a minimum, the requirements of Alberta's Energy Resources Conservation Board Directive 038;

b) incorporate BMP and BAT related to noise abatement into the facilities design;

c) continue to evaluate noise mitigation options in consultation with Environment Canada and submit the results of consultation with the corresponding application for an authorization under paragraph 5(1)(b); and

d) submit an independent noise impact analysis report on the proposed design and the feasibility of further reductions in noise emissions with the corresponding application for an authorization under paragraph 5(1)(b).

T9. IORL shall provide the following with the application for an authorization under paragraph 5(1)(b) that encompasses the construction of the well pad:

a) the plans for dredging and installing the barge landing located at the Taglu field; and

b) the results of consultation with Environment Canada, Department of Fisheries and Oceans, Indian and Northern Affiars Canada and Transport Canada.

T10. To compile and communicate all of Imperial's environmental protection procedures, mitigation measures, and monitoring commitments pertaining to the facilities operations, to its field staff, and to the NEB inspectors, Imperial shall file with the NEB an Environmental Protection Plan (EPP). The EPP is to be submitted with the initial application for an authorization under paragraph 5(1)(b) and shall include policies, practices and procedures for:

a) the scope and area of application of the EPP;

b) environmental protection procedures and measures, including decision criteria for timing and implementation of these measures, site-specific plans and drawings, mitigation measures, and monitoring applicable to construction and drilling operations;

c) ongoing environmental training for employees/operators;

d) references to other plans and manuals for environmental protection required by field staff and inspectors;

e) a reclamation plan which includes a description of the condition to which IORL intends to reclaim, a description of measurable goals for reclamation, methods to minimize invasive plant introduction, and measures to maximize vegetation recovery;

f) management of air emissions, including:

i) maximum Proponent-identified and/or legislated discharge limits for particulate matter (PM) and NOx;

ii) maximum Proponent-identified greenhouse gas targets;

iii) reduction strategies for air emissions including PM, NOx, and greenhouse gases;

iv) monitoring and measurement methods;

v) location of monitoring sites on a map or diagram, the purpose for the locations selected, and timing of installation;

vi) details of the additional measures that would be implemented as a result of monitoring data or ongoing concern, and the criteria or thresholds that would require these measures; and

vii) record keeping including annual reporting of greenhouse gases to the NEB;

g) public communication program (non-emergency);

h) program review and consultation with Environment Canada and the Government of Northwest Territories; and

i) evidence of consultation with appropriate regulatory authorities and government subject matter experts in the area of application of the EPP.

T11. In order that the facilities, camps and supporting infrastructure are maintained and operated in an environmentally acceptable condition during construction and production operations, IORL shall submit a Waste Management Plan with the initial application for the authorization under paragraph 5(1)(b). This plan shall be developed in consultation with the Government of the Northwest Territories, Indian and Northern Affairs Canada and Environment Canada. The plan shall address:

a) all wastes associated with construction and production operations with the objectives of minimizing impacts to the environment and ensuring worker and public safety;

b) training requirements for company and contractor staff;

c) the prevention of uncontrolled fires;

d) disposal or treatment of potentially hazardous and dangerous materials, including petroleum products, toxic or persistent chemicals, oily wastes, aircraft de-icing fluids and fuel barrels;

e) solid waste management including metals, plastics, recyclables, incinerator ash, equipment, equipment parts, batteries, building materials and construction waste;

f) food waste management including measures to minimize animal attraction;

g) management of contaminated soil, snow and ice from spills and aircraft de-icing;

h) treatment and disposal of domestic sewage and grey water;

i) incineration/evaporator technology choices and rationale for selection;

j) waste segregation requirements, interim storage and treatment;

k) testing methods and disposal for waste streams proposed for release to the environment; and

l) the results of consultation.

T12. To demonstrate that winter roads will be constructed and operated in a safe and environmentally acceptable manner, IORL shall submit a manual for the construction, operation, maintenance and closure of winter roads with the initial application for an authorization under paragraph 5(1)(b). The manual shall include:

a) required road width, clearing and grading requirements, grade, allowable speed, signage, maximum vehicle weight;

b) objective and measurable environmental and engineering criteria to determine when the winter road will be ready for use;

c) safe ice thickness criteria for lake, river and stream crossing including the frequency of ice profiling;

d) local regulatory requirements;

e) installation and removal requirements for snow fills, culverts, corduroy and temporary bridges; and

f) objective and measurable environmental and engineering criteria for closure.

T13. IORL shall evaluate the technologies and practices available to reduce emissions of particulate matter (PM) and precursors of PM and ozone from its facilities and construction related activities, and incorporate BMP and BAT to reduce emissions of PM and precursors of PM and ozone to the extent practicable. IORL shall file a report of its findings and how it will implement its findings with the initial application for an authorization under paragraph 5(1)(b).

T14. IORL shall evaluate and implement technologies and practices available to reduce mercury, dioxin and furan emissions from incinerators operating at construction camps and facilities to the extent practicable. IORL shall file a report of its findings and how it intends to implement its findings with the initial application for an authorization under paragraph 5(1)(b).

T15. IORL shall file with the initial application for an authorization under paragraph 5(1)(b) a report outlining:

a) the specific design and operational measures it has implemented and will implement to minimize methane leakage and venting through the system's operation taking into account BMP developed by Canadian Association of Petroleum Producers, Environment Canada, the Canadian Energy Partnerships for Environmental Innovation and the Canadian Gas Association;

b) how IORL has utilized waste heat energy to minimize natural gas fuel consumption in the design of the facilities;

c) the use of BAT when specifying compressor units used including size, efficiency and their conformity with Canadian Council of Ministers of the Environment (CCME) National Emissions Guidelines for Stationary Combustion Turbines (CCME,1992); and

d) the results of consultation with Environment Canada and the Government of the Northwest Territories.

T16. To minimize or reduce air emissions from flaring, IORL shall meet the Guideline for Ambient Air Quality Standards in the Northwest Territories and Alberta's Energy Resources Conservation Board Directive 60: *Upstream Petroleum Industry Flaring, Incinerating and Venting*.

T17. Unless the NEB otherwise directs, IORL shall submit an updated resource management plan within 18 months after production commences or prior to the drilling of contingent wells.

T18. To protect the correlative rights of adjacent subsurface rights interest holders, IORL shall comply with to the NEB's *Draft Spacing Requirements* dated 31 December 2009 or orders dealing with spacing units that may supersede it.

T19. To address worker and public safety and environmental protection, IORL shall prepare its contingency plans in consultation with Indian and Northern Affairs Canada, the Canadian Coast Guard, Transport Canada, Environment Canada, the Government of the Northwest Territories and the Inuvialuit Land Administration. The contingency plans shall include:

a) training and orientation requirements of company and contractor staff;

b) an inventory indicating storage facility locations for petroleum products, chemicals and other hazardous substances, together with corresponding material safety data sheets (MSDS) sheets, that will be transported, stored and/or used during construction and operational phases;

c) identification of resources (equipment and staff) to be on-site and/or available to respond to emergencies;

d) identification of mutual aid partners and the location of their resources (equipment and staff) available to respond to emergencies;

e) procedures for responding to spills, releases, fires, medical emergencies and security issues including the incident reporting and notification system;

f) location of fire and spill response equipment stores and the spill kit requirements for vehicles;

g) a phone list of company, contractor, government agency and community representatives outlining their respective roles and information needs;

h) clean-up and disposal procedures for generated clean-up wastes;

i) identification of muster points for emergency evacuations from camps and facilities;

j) location of emergency medical treatment locations and capabilities;

k) the requirement for 24-hour emergency medical evacuation capability;

l) maps showing the location of infrastructure such as camps, access roads, material storage areas, aircraft landing sites, barge landing sites and borrow pits to facilitate the dispatch of first responders;

m) consideration of high flood and high ice floe scenarios;

n) consideration of earthquakes; and

o) the results of consultation.

T20. To demonstrate that it is prepared to respond to an emergency at the outset of production, unless the NEB otherwise directs, IORL shall hold an emergency response exercise to evaluate the effectiveness of the contingency plan at least 10 days prior to the commencement of production and file a letter of notification with the NEB upon the successful completion of the exercise.

T21. To minimize field development-related impacts on wildlife species, IORL shall file with the NEB for approval, with the initial application for an authorization under paragraph 5(1)(b), a Wildlife Protection and Management Plan(s) to address general wildlife protection and specific protection of barren ground caribou, grizzly bear, polar bear and wolverine. The Wildlife Protection and Management Plan(s) shall specify goals, area covered by the plan(s), and assumed zones of influence of activities and rationales for these assumptions. The Wildlife Protection and Management Plan(s) shall include:

a) results of pre-construction surveys, including surveys for species at risk listed on Schedule 1 of the *Species at Risk Act* public registry (listed species), except where the Minister has determined that recovery for the species is not feasible and locations of any observations of species classified as at risk or may be at risk on the most recent Committee on the Status of Endangered Wildlife in Canada assessment and NWT General Status Ranks;

b) updated impact assessments for listed species in consideration of the *Species at Risk Act*, conducting the impact assessments directly on the listed species where possible rather than using one or more indicator species;

c) mitigation measures including:

   i) measures to avoid or minimize disturbances including linear disturbance and effects of habitat fragmentation, sensory disturbance, and barriers to movement;

   ii) scheduling of activities to minimize wildlife disturbance;

   iii) measures to minimize the development footprint in habitats known to support listed species;

   iv) procedures to avoid disturbance of potential maternal denning areas;

   v) access management, including provisions for public consultation;

   vi) protocols and education/awareness activities for managing human-wildlife interactions, including measures to limit harvesting and to deter wildlife, especially bears, from entering camps and other facilities;

   vii) measures to reduce the impacts of access road, and other field development-related vehicle and air traffic on wildlife and migratory birds; and

   viii) any wildlife protection measures included in other management plans, or references to those measures;

d) protocols for monitoring and adaptive management including:

   i) establishing and maintaining linkages to regional programs;

   ii) survey protocols to be employed to avoid or prevent impacts to wildlife;

   iii) plans for monitoring responses of wildlife to activities during all phases of the development;

   iv) protocols for documenting habitat loss and habitat change as well as wildlife incidents, interactions and mortality; and

   v) measures to determine the effectiveness of mitigation measures, criteria to determine when and how mitigation measures should be adapted, as well as the responses proposed to address unforeseen effects;

e) implementation plans, including:

   i) details on how the plans will be implemented and linked to IORL's Wildlife Protection and Management Plan;

   ii) the measures taken to enable the participation of local monitors; and

   iii) the process for updating the protection plan as information gaps are addressed, including listed species' recovery strategies and action plans;

f) processes for oversight and reporting with respect to the Wildlife Protection and Management Plan(s) and how those processes will be implemented; and

g) evidence of consultation with the Government of the Northwest Territories, Environment Canada and appropriate wildlife management boards.

T22. IORL shall include in its Wildlife Protection and Management Plan(s) (Condition T21) with respect to barren ground caribou:

a) timing and dates during which activities would occur so as to avoid or minimize conflict with caribou movement or sensitive feeding or calving time;

b) plans to address any impacts on the Porcupine caribou herd resulting from increased use of the Dempster Highway by field development-related traffic; and

c) evidence of consultation with the Porcupine Caribou Management Board and the Government of Yukon.

T23. IORL shall include in its Wildlife Protection and Management Plan(s) (Condition T21) a commitment to conduct pre-construction, construction and post-construction surveys and monitoring programs in relation to short-eared owls and rusty blackbirds and to file this information with the Government of the Northwest Territories.

T24. IORL shall include in its Wildlife Protection and Management Plan(s) (Condition T21) mitigation measures specific to raptors, including peregrine falcon and bald and golden eagles, that include the following restrictions on activities or facilities, unless the NEB otherwise directs:

a) for permanent structures, long-term habitat disturbance including road, quarry, camp, etc., ground and air access, and blasting maintain a setback of 1000 m from nest sites between April 15 and September 1 for peregrine falcons and between March 30 and July 31 for all other raptors; and

b) for aircraft overflight, maintain a setback of 760 m above ground level from nest sites between April 15 and September 1 for peregrine falcons and between March 30 and July 31 for all other raptors.

T25. To protect traditional harvesting of fish from adverse impacts related to construction, IORL shall file with the NEB, with the initial application for an authorization under paragraph 5(1)(b), the final suite of decision trees proposed to manage the impacts on fish and fish habitat including:

a) an explanation of the decision-making process, the criteria for decision-making and the mitigation options;

b) a description of how IORL will address the importance of fish habitat and fish populations to local communities and harvesters; and

c) evidence of consultation with the Department of Fisheries and Oceans and the relevant management boards and agencies with regard to the decision trees.

T26. IORL shall include in its Wildlife Protection and Management Plan(s) (Condition T21) with respect to grizzly bear:

a) a plan to conduct annual grizzly bear den surveys during pre-construction activities and construction operations prior to the commencement of work planned for the coming season;

b) proposed mitigation measures for avoiding disturbance to grizzly bear dens; and

c) a commitment to file the results of the surveys annually during pre-construction activities and construction operations, prior to the commencement of work planned for the coming season, with the Government of the Northwest Territories and appropriate wildlife management boards.

T27. IORL shall file with the initial application for an authorization under paragraph 5(1)(b), diversity plans, inclusive of gender equality, for both the construction and operations phases. The plans shall include:

a) methods for determining diversity goals;

b) identification of diversity goals;

c) steps to achieve the identified goals;

d) commitments to the provision of a healthy and safe work environment;

e) steps to create a Diversity Management Committee; and

f) a monitoring and reporting system.

IORL shall require its contractors and subcontractors to comply with the diversity plans.

T28. IORL shall file with the initial application for an authorization under paragraph 5(1)(b), plans for a formal issues resolution program that will be implemented during construction and operations. The plans shall be prepared in consultation with the Government of the Northwest Territories and Aboriginal authorities, and include:

a) a description of the process by which any complaints or issues would be raised with IORL or governments;

b) a description of the process by which any received complaints or issues would be allocated among those with responsibility for action and a description of the roles and responsibilities of any party involved in assessing or responding to any complaint or issue;

c) a description of the process by which any received complaints or issues would be resolved;

d) a description of any protocols developed for referral and resolution of any complaints or issues;

e) a description of the recourse mechanisms for any unresolved complaints or issues or any unsatisfactorily resolved complaints or issues; and

f) a description of the process for communicating and informing communities about the issues resolution program.

T29. IORL shall file with the initial application for an authorization under paragraph 5(1)(b), information related to the hiring of local residents as monitors to carry out compliance and environmental impact monitoring including:

a) the nature of the activities to be monitored;

b) clearly defined job descriptions for the positions as monitors;

c) identification of the training that will be offered to monitors to enable them to perform their duties; and

d) confirmation that monitors have been hired.

T30. The approval of the Development Plan for the Taglu field under subsection 5.1(4) of the *Canada Oil and Gas Operations Act* is subject to the Minister of Indian Affairs and Northern Development Canada providing confirmation that IORL has satisfactorily met the Benefits Plan requirements of section 5.2 of the *Canada Oil and Gas Operations Act*.

Appendix Q

Conditions for the ConocoPhillips Canada (North) Limited (ConocoPhillips) Development Plan for the Parsons Lake field

Many of the proposed conditions reference an application for an authorization under paragraph 5(1)(b) of the *Canada Oil and Gas Operations Act* (COGOA). Before any drilling or construction activity relating to a development plan may commence, authorizations under paragraph 5(1)(b) would be required. Section 6 of the *Canada Oil and Gas Drilling and Production Regulations* states that an operator shall provide the following in an application for an authorization under paragraph 5(1)(b): a description of the scope of activities; an environmental protection plan; a safety plan; and a contingency plan. The activities in relation to a development plan may include drilling, completions, facilities construction, production, and decommissioning.

Unless otherwise specified, Proponent *consultation* referred to in a condition must be carried out in a manner that includes the Proponent:

a) providing, to the party to be consulted,

   i) notice of the matter in sufficient form and detail to allow the party to prepare its views on the matter,

   ii) a reasonable period for the party to prepare those views, and

   iii) an opportunity to present those views to the party conducting the consultation; and

b) considering, fully and impartially, any views so presented.

Unless otherwise specified in a condition *best available technology* (BAT) means technology with superior emissions performance which is commercially available at a reasonable cost at the time it is required for the project which meets the goals of pollution prevention and energy efficiency.

Unless otherwise specified in a condition *best management practices* (BMP) are innovative, dynamic, and improved environmental protection practices and procedures that help ensure that development is conducted in an environmentally responsible manner. BMP may exist as formal guidelines or generally accepted procedures that are recognized by regulators and industry associations as best practices.

P1. Unless the National Energy Board (NEB) otherwise directs, ConocoPhillips shall design, implement or cause to be implemented all of the policies, mitigation measures, procedures, specifications, standards and recommendations for any work or activity referred to in the Development Plan application or in the Environmental Impact Statement or other filings with the Joint Review Panel or as otherwise agreed to during the GH-1-2004 Hearing and during the review by the Joint Review Panel.

P2. To promote potential joint development with a minimal environmental footprint, the north and south well pads of the Parsons Lake field shall each be designed so they may be expanded to allow for the drilling of at least one well by third party adjacent subsurface rights interest holders.

P3. To prevent coalescence of the well permafrost thaw bulbs, the interwell spacing on a well pad shall not be less than 15 m unless ConocoPhillips utilizes mitigation measures approved by the NEB.

P4. To confirm adequate consideration for subsurface containment, ConocoPhillips shall submit a drill cuttings slurry injection management program with the corresponding application for an authorization under paragraph 5(1)(b). The program shall include:

a) a description of the proposed cuttings slurry injection methodologies and proposed wells;

b) a description of the proposed injection zones;

c) a description of the any step-rate or injectivity tests that would be conducted prior to operations; and

d) a description of how the vertical migration of injection and/or formation fluid out of the injection zone and the potential contamination of fresh water aquifers, permafrost intervals and hydrocarbon bearing formations would be prevented during subsurface cuttings slurry injection operations.

P5. To monitor carbon dioxide (CO_2) content in the Parsons Lake field gas production, ConocoPhillips shall provide adequate gas sampling and analysis in the field data acquisition program and in the well data acquisition programs.

P6. Prior to the commencement of drilling, ConocoPhillips shall provide financial responsibility pursuant to subsection 13(14) of the *Inuvialuit Final Agreement* in the amount of $40,062,500 to be held in trust by the NEB in the form satisfactory to the NEB and to remain in place until all wells and facilities are abandoned in accordance with NEB requirements.

P7. All financial responsibility provided pursuant to the *Canada Oil and Gas Spills and Debris Liability Regulations* and subsection 27(1) of *Canada Oil and Gas Operations Act* shall remain in place until all wells and facilities are abandoned in accordance with NEB requirements.

P8. To confirm adequate consideration of the effects of climate change has been incorporated into the facilities design, ConocoPhillips shall submit the following information with the initial application for an authorization under paragraph 5(1)(b):

a) an analysis of the impacts of climate change and variability on permafrost and terrain stability for the Parsons Lake facility using potential upper limit temperature scenarios which may occur during the operational life of the facilities;

b) a description of how these upper limit temperature scenarios may impact precipitation, and the water levels of Parsons Lake and other nearby lakes;

c) a description of how the proposed facilities design accounts for the potential changes outlined in b); and

d) the results of consultation with appropriate regulators and government departments.

P9. To minimize noise disturbance from facilities located at Parsons Lake, ConocoPhillips shall:

a) design the facilities to meet the requirements of Alberta's Energy Resources Conservation Board Directive 038; and

b) file with the NEB, 90 days following the start of operation, a post construction noise assessment report.

P10. To compile and communicate all of ConocoPhillip's environmental protection procedures, mitigation measures, and monitoring commitments pertaining to the facilities operations, to its field staff, and the NEB inspectors, ConocoPhillips shall file with the NEB an Environmental Protection Plan (EPP). The EPP is to be submitted with the initial application for an authorization under paragraph 5(1)(b) and shall include policies, practices and procedures for:

a) the scope and area of application of the EPP;

b) environmental protection procedures and measures, including decision criteria for timing and implementation of these measures, site-specific plans and drawings, mitigation measures, and monitoring applicable to construction and drilling operations;

c) ongoing environmental training for employees/operators;

d) references to other plans and manuals for environmental protection required by field staff and inspectors;

e) a reclamation plan which includes a description of the condition to which ConocoPhillips intends to reclaim, a description of measurable goals for reclamation, methods to minimize invasive plant introduction, and measures to maximize vegetation recovery;

f) management of air emissions, including:

   i) maximum Proponent-identified and/or legislated discharge limits for particulate matter (PM) and NOx;

   ii) maximum Proponent-identified greenhouse gas targets;

   iii) reduction strategies for air emissions including PM, NOx, and greenhouse gases;

   iv) monitoring and measurement methods;

   v) location of monitoring sites on a map or diagram, the purpose for the locations selected, and timing of installation;

   vi) details of the additional measures that would be implemented as a result of monitoring data or ongoing concern, and the criteria or thresholds that would require these measures; and

   vii) record keeping including annual reporting of greenhouse gases to the NEB.

g) public communication program (non-emergency);

h) program review and consultation with Environment Canada and the Government of Northwest Territories; and

i) evidence of consultation with appropriate regulatory authorities and government subject matter experts in the area of application of the EPP

P11. In order that the facilities, camps and supporting infrastructure are maintained and operated in an environmentally acceptable condition during construction and production operations, ConocoPhillips shall submit a Waste Management Plan with the initial application for the authorization under paragraph 5(1)(b). This plan shall be developed in consultation with the Government of the Northwest Territories, Indian and Northern Affairs Canada and Environment Canada. The plan shall address:

a) all wastes associated with construction and production operations with the objectives of minimizing impacts to the environment and ensuring worker and public safety;

b) training requirements for company and contractor staff;

c) the prevention of uncontrolled fires;

d) disposal or treatment of potentially hazardous and dangerous materials, including petroleum products, toxic or persistent chemicals, oily wastes, aircraft de-icing fluids and fuel barrels;

e) solid waste management including metals, plastics, recyclables, incinerator ash, equipment, equipment parts, batteries, building materials and construction waste;

f) food waste management including measures to minimize animal attraction;

g) management of contaminated soil, snow and ice from spills and aircraft de-icing;

h) treatment and disposal of domestic sewage and grey water;

i) incineration/evaporator technology choices and rationale for selection;

j) waste segregation requirements, interim storage and treatment;

k) testing methods and disposal for waste streams proposed for release to the environment; and

l) the results of consultation.

P12. To demonstrate that project winter roads will be constructed and operated in a safe and environmentally acceptable manner, ConocoPhillips shall submit a manual for the construction, operation, maintenance and closure of project winter roads with the initial application for an authorization under paragraph 5(1)(b). The manual shall include:

a) required road width, clearing and grading requirements, grade, allowable speed, signage, maximum vehicle weight;

b) objective and measurable environmental and engineering criteria to determine when the winter road will be ready for use;

c) safe ice thickness criteria for lake, river and stream crossing including the frequency of ice profiling;

d) local regulatory requirements;

e) installation and removal requirements for snow fills, culverts, corduroy and temporary bridges; and

f) objective and measurable environmental and engineering criteria for closure.

P13. ConocoPhillips shall evaluate the technologies and practices available to reduce emissions of particulate matter (PM) and PM and ozone precursors from its facilities and construction related activities, and incorporate BMP and BAT to reduce emissions of PM and precursors of PM and ozone to the extent practicable. ConocoPhillips shall file a report of its findings and how it will implement its findings with the initial application for an authorization under paragraph 5(1)(b).

P14. ConocoPhillips shall evaluate and implement technologies and practices available to reduce mercury, dioxin and furan emissions from incinerators operating at construction camps and facilities to the extent practicable. ConocoPhillips shall file a report of its findings and how it intends to implement its findings with the initial application for an authorization under paragraph 5(1)(b).

P15. ConocoPhillips shall file with the initial application for an authorization under paragraph 5(1)(b) a report outlining:

a) the specific design and operational measures it has implemented and will implement to minimize methane leakage and venting through the system's operation taking into account BMP developed by Canadian Association of Petroleum Producers, Environment Canada, the Canadian Energy Partnerships for Environmental Innovation and the Canadian Gas Association;

b) how ConocoPhillips has utilized waste heat energy to minimize natural gas fuel consumption in the design of the facilities;

c) the use of BAT when specifying compressor units used including size, efficiency and their conformity with Canadian Council of Ministers of the Environment National Emissions Guidelines for Stationary Combustion Turbines (CCME,1992); and

d) the results of consultation with Environment Canada and the Government of the Northwest Territories.

P16. To minimize or reduce air emissions from flaring, ConocoPhillips shall meet the Guideline for Ambient Air Quality Standards in the Northwest Territories and Alberta's Energy Resources Conservation Board Directive 60: *Upstream Petroleum Industry Flaring, Incinerating and Venting*.

P17. Unless the NEB otherwise directs, ConocoPhillips shall submit an updated resource management plan within 18 months after production commences or prior to the drilling of contingent wells.

P18. To protect the correlative rights of adjacent subsurface rights interest holders, ConocoPhillips shall comply with to the NEB's *Draft Spacing Requirements* dated 31 December 2009 or any orders dealing with spacing units that may supersede it.

P19. To address worker and public safety and environmental protection, ConocoPhillips shall prepare its contingency plans in consultation with Indian and Northern Affairs Canada, the Canadian Coast Guard, Transport Canada, Environment Canada, the Government of the Northwest Territories and the Inuvialuit Land Administration. The contingency plans shall include:

a) training and orientation requirements of company and contractor staff;

b) an inventory indicating storage facility locations for petroleum products, chemicals and other hazardous substances, together with corresponding material safety data sheets (MSDS) sheets, that will be transported, stored and/or used during construction and operational phases;

c) identification of resources (equipment and staff) to be on-site and/or available to respond to emergencies;

d) identification of mutual aid partners and the location of their resources (equipment and staff) available to respond to emergencies;

e) procedures for responding to spills, releases, fires, medical emergencies and security issues including the incident reporting and notification system;

f) location of fire and spill response equipment stores and the spill kit requirements for vehicles;

g) a phone list of company, contractor, government agency and community representatives outlining their respective roles and information needs;

h) clean-up and disposal procedures for generated clean-up wastes;

i) identification of muster points for emergency evacuations from camps and facilities;

j) location of emergency medical treatment locations and capabilities;

k) the requirement for 24-hour emergency medical evacuation capability;

l) maps showing the location of infrastructure such as camps, access roads, material storage areas, aircraft landing sites, barge landing sites and borrow pits to facilitate the dispatch of first responders;

m) consideration of earthquakes; and

n) the results of consultation.

P20. To demonstrate that it is prepared to respond to an emergency at the outset of production, unless the NEB otherwise directs, ConocoPhillips shall hold an emergency response exercise to evaluate the effectiveness of the contingency plan at least 10 days prior to the commencement of production and file a letter of notification with the NEB upon the successful completion of the exercise.

P21. To minimize field development-related impacts on wildlife species, ConocoPhillips shall file with the NEB for approval, with the initial application for an authorization under paragraph 5(1)(b), a Wildlife Protection and Management Plan(s) to address general wildlife protection and specific protection of barren ground caribou, grizzly bear, polar bear and wolverine. The Wildlife Protection and Management Plan(s) shall specify goals, area covered by the plan(s), and assumed zones of influence of activities and rationales for these assumptions. The Wildlife Protection and Management Plan(s) shall include:

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v) measures to determine the effectiveness of mitigation measures, criteria to determine when and how mitigation measures should be adapted, as well as the responses proposed to address unforeseen effects;

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a) timing and dates during which activities would occur so as to avoid or minimize conflict with caribou movement or sensitive feeding or calving time;

b) plans to address any impacts on the Porcupine caribou herd resulting from increased use of the Dempster Highway by field development-related traffic; and

c) evidence of consultation with the Porcupine Caribou Management Board and the Government of Yukon.

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a) for permanent structures, long-term habitat disturbance including road, quarry, camp, etc., ground and air access, and blasting maintain a setback of 1000 m from nest sites between April 15 and September 1 for peregrine falcons and between March 30 and July 31 for all other raptors; and

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a) an explanation of the decision-making process, the criteria for decision-making and the mitigation options;

b) a description of how ConocoPhillips will address the importance of fish habitat and fish populations to local communities and harvesters; and

c) evidence of consultation with the Department of Fisheries and Oceans and the relevant management boards and agencies with regard to the decision trees.

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a) a plan to conduct annual grizzly bear den surveys during pre-construction activities and construction operations prior to the commencement of work planned for the coming season;

b) proposed mitigation measures for avoiding disturbance to grizzly bear dens; and

c) a commitment to file the results of the surveys annually during pre-construction activities and construction operations, prior to the commencement of work planned for the coming season, with the Government of the Northwest Territories and appropriate wildlife management boards.

P27. ConocoPhillips shall file with the initial application for an authorization under paragraph 5(1)(b), diversity plans, inclusive of gender equality, for both the construction and operations phases. The plans shall include:

a) methods for determining diversity goals;

b) identification of diversity goals;

c) steps to achieve the identified goals;

d) commitments to the provision of a healthy and safe work environment;

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ConocoPhillips shall require its contractors and subcontractors to comply with the diversity plans.

P28. ConocoPhillips shall file with the initial application for an authorization under paragraph 5(1)(b), plans for a formal issues resolution program that will be implemented during construction and operations. The plans shall be prepared in consultation with the government of the Northwest Territories and Aboriginal authorities, and include:

a) a description of the process by which any complaints or issues would be raised with ConocoPhillips or governments;

b) a description of the process by which any received complaints or issues would be allocated among those with responsibility for action and a description of the roles and responsibilities of any party involved in assessing or responding to any complaint or issue;

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a) the nature of the activities to be monitored;

b) clearly defined job descriptions for the positions as monitors;

c) identification of the training that will be offered to monitors to enable them to perform their duties; and

d) confirmation that monitors have been hired.

P30. The approval of the Development Plan for the Parsons Lake field under subsection 5.1(4) of the *Canada Oil and Gas Operations Act* is subject to the Minister of Indian Affairs and Northern Development Canada providing confirmation that ConocoPhillips has satisfactorily met the Benefits Plan requirements of section 5.2 of the *Canada Oil and Gas Operations Act*.