Diane Roy
Director, Regulatory Affairs

FortisBC Energy
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

October 25, 2013

Via Email
Original via Mail

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI or the Company)

Application for a Certificate of Public Convenience and Necessity (CPCN) for the Huntingdon Station Bypass (the Application)

Pursuant to sections 45 and 46 of the *Utilities Commission Act* (the Act), FEI files the attached application (the Application) for approval from the British Columbia Utilities Commission (the Commission) for a CPCN for the Huntingdon Station Bypass (the Project). FEI also requests Commission approval under sections 59-61 of the Act for deferral treatment of costs for preparing this Application and for prefeasibility costs for assessing the potential design and alternatives, and to amortize these costs over a subsequent three-year period.

FEI owns and operates the Huntingdon Station (the Station), which is located south of Abbotsford, British Columbia, approximately 3 km east of the Huntingdon/Sumas border crossing. The Huntingdon Station is the sole source of natural gas supply for FEI's Coastal Transmission System and FortisBC Energy (Vancouver Island) Inc. system. FEI has identified the Huntingdon Station as a "single-point-of-failure" facility because several critical components and sections of piping within the Station lack redundancy and failure of one of the components can lead to the shutdown of the Station. The proposed bypass will provide the necessary redundancy to the Station, which, in turn, will remove the "single-point-of-failure" risk and reduce the risk of loss of gas supply to approximately 600,000 customers downstream of the Station in the event of a failure.

The estimated capital cost for the Project is $8.0 million (in as-spent dollars).

Requests for Confidential Treatment of Certain Appendices

To support the Application, FEI has filed several appendices, with the following ones being filed confidentially in accordance with the Practice Directive of the British Columbia Utilities Commission "Confidential Filings":

Appendix B - GHD Phase 1 Risk Assessment Report

Appendix C1- DRAS Quantitative Risk Assessment Report March 30, 2011

Appendix C2- DRAS Consideration of In-Station Bypass Report July 15, 2011

Appendix C3- DRAS Consideration of In-Station Bypass – Revised Report July 18, 2013

Appendix F3 - Capital Cost Estimate

Additionally, there are three figures in the Application that are also filed confidentially:

Figure 3-4 - The Huntingdon Station Single Points of Failure

Figure 4-1 - Internal Station Upgrades

Figure 4-2 Bypass Pipeline Option

FEI respectfully requests that the Commission file the above listed documents confidentially, and believes that such information shall remain confidential even after the regulatory process for this Application is completed. Below, FEI will outline the reasons for keeping the information confidential.

Appendix B

Appendix B is a risk assessment report provided by GHD Consulting. In the report, GHD Consulting identified the Company's transmission system vulnerabilities and riskiest system assets based on the probability of failure, consequence of failure, and redundancy factors, and ranked ten of FEI's assets it believes to present the highest risks. Further explanation of the report is in section 3.4.3 of the Application.

Appendix B should be kept confidential on the basis that it contains sensitive technical information pertaining to the Company's assets. In particular, it identifies the most vulnerable points on the Company's transmission system. FEI believes that there is a reasonable expectation that the release of such information can potentially jeopardize the safety and security of the Company's system. Furthermore, this report was developed for FEI's internal uses, and not meant for public review.

Appendices C1, C2 and C3

Similar to Appendix B, Appendices C1, C2, and C3 provide an assessment of the risk and vulnerability of the Huntingdon Station. The information contained in these documents provides detailed facility drawings and details on specific components or equipment within the Huntingdon Station which are the most vulnerable from an operational risk aspect. FEI believes the release of these details can potentially jeopardize the Station and the Company's system. Additionally, these reports were developed for FEI's internal uses, and not meant for public review.

Appendix F3

This appendix contains the capital cost estimate for the Project. The information should be kept confidential as FEI will be going to the market for competitive bids for the materials and construction work. If the estimated costs for the material and construction work are disclosed, it can be reasonably expected that FEI's negotiating position may be prejudiced. For instance, the bidding parties with knowledge about the estimated costs may use the estimate costs as a reference for their bidding. Because there are limited contractors due to high demand in the market in recent years, FEI's negotiating position may be further prejudiced if the bidders know about the Company's estimated costs for materials and construction work.

Figures 3-4, 4-1 and 4-2

These figures are station schematics showing internal system details of the Huntingdon Station. In particular, they show the most vulnerable points, i.e., the critical non-redundant parts, within the Station. The release of such information to the public can potentially raise a safety and security concern for the Huntington Station.

FEI does not object to customer group interveners such as the British Columbia Public Interest Advocacy Centre on behalf of the British Columbia Pensioners' and Seniors' Organization *et al* (BCPSO), and the Commercial Energy Consumers Association of British Columbia (CEC), being provided with these appendices and figures upon executing standard form undertakings of confidentiality.

FEI proposes that information requests relating to these confidential appendices be filed separately from other information requests, with a copy circulated only to FEI and other parties that have signed the confidentiality undertaking. This process will ensure that confidential information is not inadvertently disclosed in answers to questions posed.

If there are any questions regarding this Application, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Interveners in the FEI 2010-2011 RRA proceeding

FORTIS BC™

FortisBC Energy Inc.

Application for a Certificate of Public Convenience and Necessity for Approval to Construct and Operate the Huntingdon Station Bypass

Volume 1 - Application

October 25, 2013

Table of Contents

List of Appendices

Index of Tables and Figures

1. APPLICATION

1.1 EXECUTIVE SUMMARY

FortisBC Energy Inc. (the Company or FEI), pursuant to sections 45 and 46 of the *Utilities Commission Act* (the Act), applies (the Application) to the British Columbia Utilities Commission (the BCUC or the Commission) for a Certificate of Public Convenience and Necessity (CPCN) to construct and operate a bypass pipeline immediately around FEI's Huntingdon Flow and Pressure Control Station (the Huntington Station or the Station). The bypass as proposed will significantly reduce the risk of gas supply disruption to approximately 600,000 customers residing in the Lower Mainland and in Whistler, Squamish, the Sunshine Coast, and Vancouver Island in the event of a failure of the Huntingdon Station.

In particular, FEI seeks approval under sections 45 and 46 for:

1. Construction of a new Nominal Pipe Size (NPS) 36 (inch) transmission pressure bypass pipeline by conventional construction methods; and

2. Installation of an in-line pressure control valve and four isolation valves to tie into the existing FEI NPS 30 and NPS 42 pipelines, and to tie into the existing pipeline of Westcoast Energy Inc., doing business as Spectra Energy Transmission (Spectra), adjacent to the Huntingdon Station;

collectively referred to as the "Project". The estimated capital cost for the Project is $8.0 million.

FEI is also seeking Commission approval under sections 59-61 of the Act for deferral treatment of costs for preparing this Application and to amortize these costs over the subsequent three year period. The Application costs include expenses for consultant reports, legal review, costs for archaeological assessments, Commission costs and Commission approved intervener costs. Also, under sections 59-61 of the Act, FEI is seeking approval from the Commission to defer prefeasibility costs that cover expenses for project management, engineering, and consultants' costs for assessing the potential design and alternatives and associated costs prior to Commission approval of the Project. FEI is seeking Commission approval to amortize these deferred prefeasibility costs over three years starting in 2016. The prefeasibility costs would be recorded in a Non-Rate Base deferral account on a net-of-tax basis attracting AFUDC. At the beginning of 2016, the deferral account would be included in Rate Base, ending any further AFUDC addition.

FEI owns and operates the Huntingdon Station, which is located south of Abbotsford, British Columbia, approximately 3 km east of the Huntingdon/Sumas border crossing. Immediately east of the Huntingdon Station is a metering facility operated by Spectra, which serves facilities of FEI and Williams Northwest Pipeline LLC, a subsidiary of the Williams Company Inc. (Williams). Williams has a major compression facility immediately across the Canada-US border.

The Huntingdon Station is the sole source of natural gas supply for FEI's Coastal Transmission System (CTS) and FortisBC Energy (Vancouver Island) Inc. (FEVI) system. Through operational experience and risk assessments (further discussed in Section 3 below), the Huntingdon Station has been identified as a single-point-of-failure facility because several critical components and sections of piping within the Station lack redundancy. This means that failure of one of these components can cause the entire Station to stop operating, which, in turn, will cause the complete shutdown of gas flow from the Huntingdon Station to both the CTS and FEVI system. As the Huntingdon Station is the sole source for these two systems, the shut-down of the Station will cause the gas supply service outage to approximately 600,000 customers downstream of the Station within a short period of time. For instance, in the event of a failure of the Huntingdon Station, the CTS would survive for less than one hour of line pack during a peak winter day and between two to four hours on an average winter day before an eventual service disruption of gas supply to all customers in the Lower Mainland, as further explained in Section 3.4.2.1.

The potential risk of single point of failure of the Huntingdon Station can result from various events, including:

- Failures of facility components resulting from lack of ability to perform maintenance or repairs;
- Failures of non-visible facility piping caused by corrosion or imperfections; and
- Potential equipment failures resulting from natural hazards.

Recovery from a significant failure and complete shutdown of the Huntingdon Station would require a complex, large scale plan for shutdown, repair, and service restoration to be undertaken. To fully restore service to the customers in the Lower Mainland, Sunshine Coast and on Vancouver Island following a complete shutdown of the Huntingdon Station, FEI estimates that it would take approximately 4 months and would cost an estimated $34 million. The total economic loss from the complete service outage at the Huntingdon Station could be in the range of $1 billion, including estimated economic losses because of service disruption, shut in and relight costs, and loss of revenue. As detailed in Section 3 below, the magnitude of potential consequences from large-scale service disruption and damage from failure of the Station is the primary justification for the Project.

In order to significantly reduce the single-point-of-failure risk, FEI has evaluated numerous options ranging from additional valving within the Huntington Station to various bypass pipeline alignments near the Huntingdon Station. The Company has determined a bypass immediately around the Huntingdon Station is the preferred option. This is further discussed in Section 4 of the Application.

The proposed bypass will remove the single-point-of-failure risk by providing the necessary redundancy to the Station. This, in turn, will reduce the risk of loss of gas supplies to approximately 600,000 customers in the event that one of the critical components within the Station fails, leading to the shut-down of the Station.

Additionally, by building the bypass, the Company will have the ability to maintain and repair (if necessary) any of the non-redundant components or sections of piping within the Station without the need of shutting down the entire Station. This will increase the reliability of the Station as discussed further in Section 4 of the Application.

The Company has identified a number of Project stakeholders, including residents, businesses and government entities, and has in place a communication plan for consultation with the public during the construction of the Project. Initial communications with the public about the Project have already taken place, and all issues identified have been resolved or a plan is in place to address them.

The Project will be completely on private land. However, during the earlier, preliminary stage of considering alternatives, as further explained in Section 9 of this Application, the Company had informed twenty (20) First Nations, plus two Tribal Councils, Sto:lo Nation Tribal Council and Sto:lo Tribal Council, about the Company's intent to construct a bypass pipeline near the Huntingdon Station. The Company subsequently updated the First Nations of the Company's preferred bypass solution, the proposed Project, which will be confined to private land. The Sto:lo Tribal Council has expressed concern about the archaeological/cultural impacts of the Project. FEI plans to use the Sto:lo Nation Research and Resource Management Centre (SRRMC) for the next stage Archaeological Impact Assessment, to have a qualified archaeologist onsite during ground-disturbing activities, and to work with the Sto:lo Tribal Council regarding the criteria to be used in conducting the Archaeological Impact Assessment. The British Columbia Oil and Gas Commission (OGC) will be the Crown agency responsible for First Nations consultation. FEI will work with the OGC if any further First Nation consultation is required.

Based on the information summarized above, provided in the following discussions and potentially further expanded in the Information Request process, FEI has shown and will continue to show that the Project is in the public interest and should be approved.

1.2 FEI 2014-2018 MULTI-YEAR PERFORMANCE BASED RATEMAKING APPLICATION

The Huntingdon Station bypass was presented in FEI's Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 (FEI 2014-2018 PBR Application) as an anticipated CPCN.[1]

1.3 REQUESTED REGULATORY REVIEW OF CPCN APPLICATION

The information presented in this Application accords with the guidelines set out in the Commission's *2010 Certificates of Public Convenience and Necessity Application Guidelines* (the Guidelines). Draft Procedural and Final Orders are included as Appendix K.

[1] FEI 2014-2018 PBR Application, at pages 250-251.

FEI believes that a written hearing process, with one round of Information Requests from the Commission and interveners, provides appropriate and efficient review for this Application. The Project is of a nature that falls within the traditional natural gas infrastructure construction and is confined to private land with limited impact to the surrounding communities and First Nations during the construction and operation. Additionally, the Project is of relatively small scale, with the total forecast capital cost to be $8.0 million.

FEI proposes the following regulatory timetable:

Table 1-1: Proposed Regulatory Timetable

ACTION	DATES (2013 and 2014)
FEI files CPCN Application	Friday, October 25
Commission Information Request No. 1	Thursday, November 28
Intervener and Interested Party Registration	Monday, December 9
Intervener Information Request No. 1	Monday, December 9
FEI Response to Information Requests No. 1	Friday, January 10
FEI Written Final Submission	Friday, January 17
Intervener Written Final Submission	Friday, January 24
FEI Written Reply Submission	Friday, January 31

FEI respectfully requests that the Commission complete its process to review this Application and reach a decision by mid-March 2014 in order to meet the proposed materials procurement and construction schedule outlined in Section 5 of the Application.

2. APPLICANT

2.1 NAME, ADDRESS AND NATURE OF BUSINESS

FEI is a company incorporated under the laws of the Province of British Columbia and is a wholly-owned subsidiary of FortisBC Holdings Inc., which, in turn, is a wholly-owned subsidiary of Fortis Inc. FEI maintains an office and place of business at 16705 Fraser Highway, Surrey, British Columbia, V4N 0E8.

FEI is the largest natural gas distribution utility in British Columbia and provides sales and transportation services to residential, commercial, and industrial customers in more than 100 communities throughout British Columbia, with approximately 840,000 customers served throughout British Columbia. FEI's distribution network delivers gas to more than eighty percent of the natural gas customers in British Columbia.

FEI is regulated by the BCUC.

2.2 FINANCIAL CAPABILITY

FEI is capable of financing the Project either directly or through its parent, FortisBC Holdings Inc. FEI has credit ratings for senior unsecured debentures from Dominion Bond Rating Service and Moody's Investors Service of A and A3 respectively. FortisBC Holdings Inc. has credit ratings for senior unsecured debentures from Dominion Bond Rating Service and Moody's Investors Service of BBB (High) and Baa2 respectively.

2.3 TECHNICAL CAPABILITY

FEI has designed and constructed a system of integrated high, intermediate and low-pressure pipelines and operates more than 40,900 kilometres of natural gas transmission and natural gas distribution mains and service lines in British Columbia. FEI's transmission and distribution infrastructure serves approximately 840,000 customers in British Columbia.

The Project will be managed by a team from the Company. Figure 5-1 is the organization chart of the Project team. FEI will employ a qualified contractor for the construction of the Project, which is discussed in detail in Section 5.5.3 of the Application.

2.4 NAME, TITLE AND ADDRESS OF COMPANY CONTACT

Diane Roy
Director
Regulatory Affairs - Gas
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, B.C. V4N 0E8

Phone: (604) 576-7349
Facsimile: (604) 576-7074
E-mail: diane.roy@fortisbc.com
Regulatory Matters: gas.regulatory.affairs@fortisbc.com

2.5 NAME, TITLE AND ADDRESS OF LEGAL COUNSEL

Song Hill
Legal Counsel
FortisBC Holdings Inc.
1111 West Georgia Street
Vancouver, BC V6E 4M3

Phone: (604) 443-6510
Facsimile: (604) 443-6540
E-mail: song.hill@fortisbcholdings.com

3. PROJECT JUSTIFICATION

In this section, FEI will discuss the three main related reasons for the Project:

1. The potential severe consequence of large-scale service disruption to 600,000 customers and economic loss resulting from failure of the Huntingdon Station is the primary driver for the Project. The Huntingdon Station is the sole source of natural gas supply to both FEI's CTS and the interconnected FEVI transmission system, and controls natural gas supply to 600,000 customers residing in the communities in the Lower Mainland, Squamish, Whistler, the Sunshine Coast, and Vancouver Island. Disruption of natural gas supply to these customers and communities has both significant safety and economic consequences.

2. The Huntingdon Station is a single-point-of-failure facility. This is caused by certain critical components and sections of piping within the Huntingdon Station lack redundancy. This means that failure of one of these components or sections of piping within the Station can lead to a Station shutdown and cause the complete outage on both the CTS and the FEVI system within a short period of time. Building redundancy, such as the proposed Project, will avoid single point of failure and significantly reduce the consequence of large-scale service disruption.

3. Lack of redundancy within the Huntingdon Station prevents the Company from performing complete maintenance and inspection of critical components and sections of piping unless the entire Station is taken out of service. This is because there is no duplication of these critical components or section piping. The ability to perform complete maintenance and necessary repair is critical for ensuring the reliability and integrity of the Station.

This section provides further information on the Huntingdon Station to demonstrate that the Station is:

- a sole source of gas supply to approximately 600,000 customers;
- a single-point-of-failure facility;
- a reliability concern because of the Company's inability to complete full Station inspection and maintenance; and
- a high risk facility considering the consequence of failure of the Station and the risk to the Company and customers.

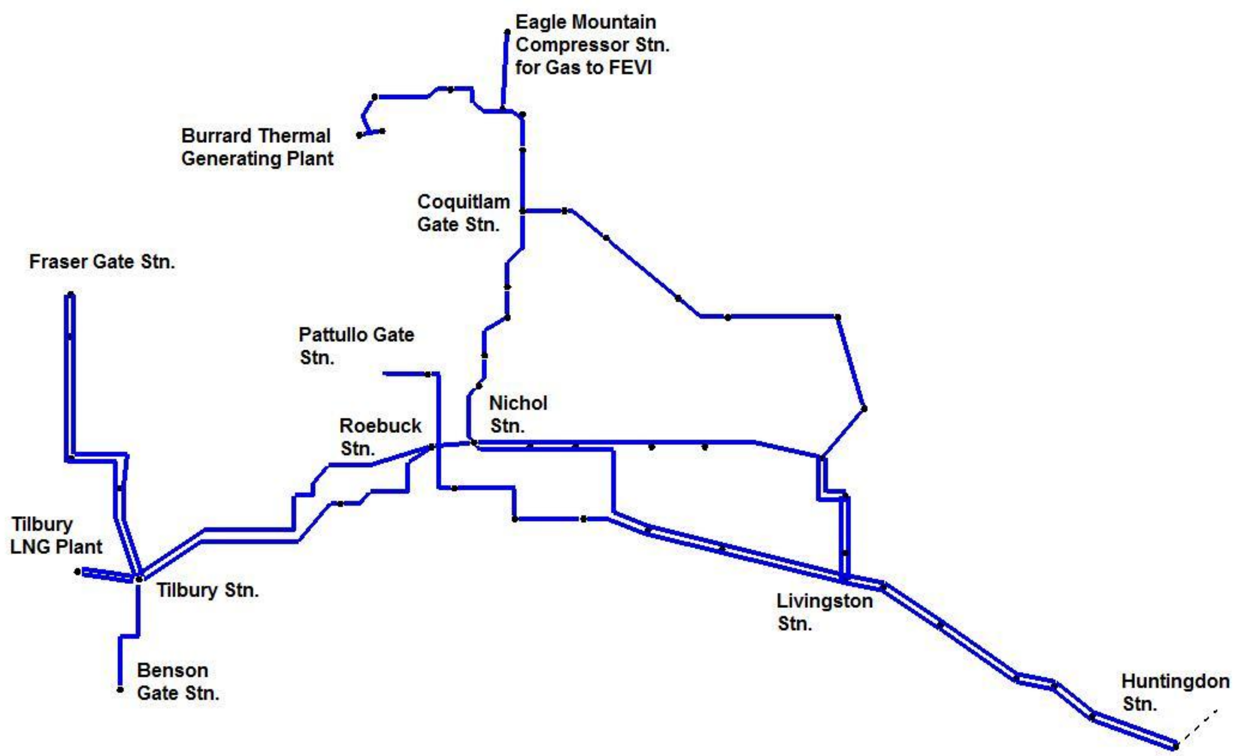
3.1 *SOLE SOURCE OF GAS SUPPLY TO CTS AND FEVI SYSTEM*

The Huntingdon Station is located on the Canada/US border, south of Abbotsford, British Columbia, and approximately 3 km east of the Huntingdon/Sumas border crossing. The

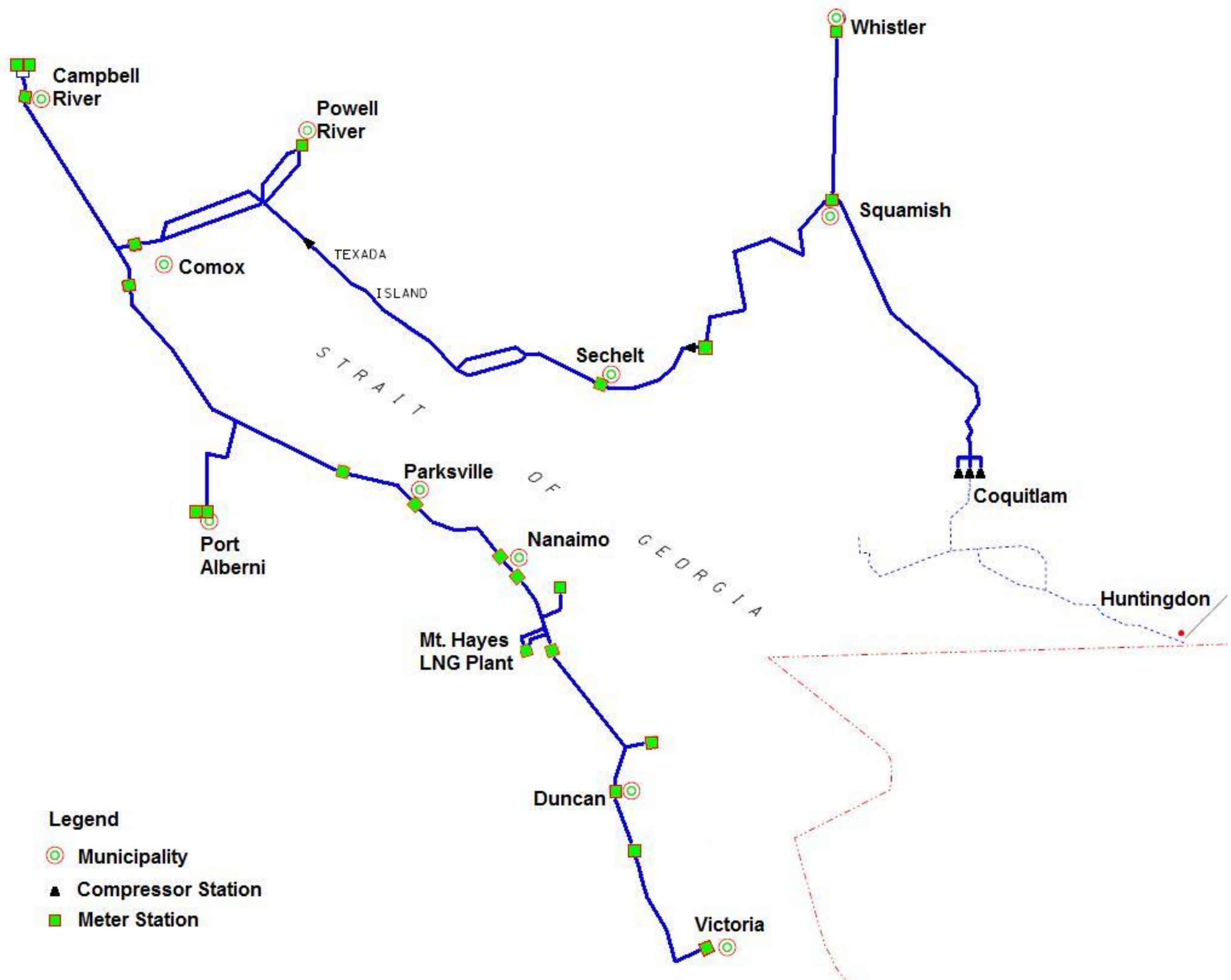
Huntingdon Station was constructed and commissioned in 1956. It currently contains two flow and pressure control stations and feeds the NPS 30 and NPS 42 CTS pipelines.

The Huntingdon Station is part of FEI's Coastal Transmission System and interconnects with FEVI's transmission system. Figures 3-1 and 3-2 below are system maps of the CTS and FEVI system respectively.

Figure 3-1: FortisBC Energy Coastal Transmission System (CTS)



1 **Figure 3-2: FortisBC Energy Vancouver Island Transmission System (FEVI)**

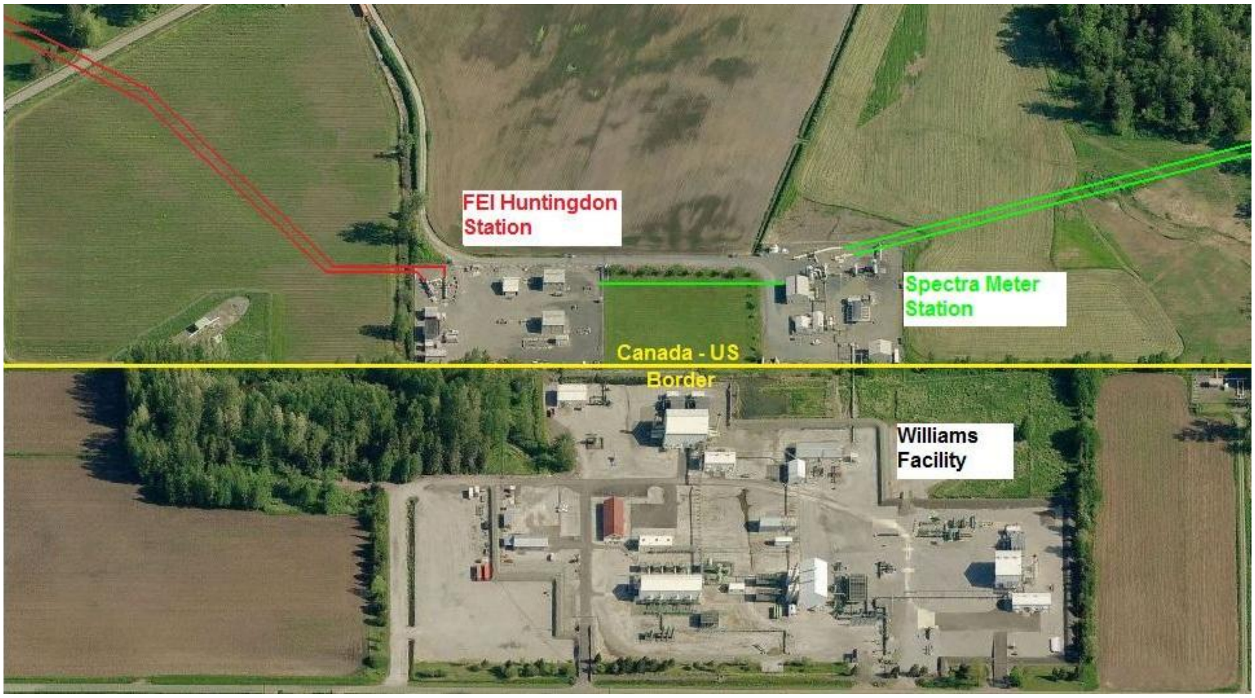


2

3 Immediately east of the Huntingdon Station is the southern terminus of Spectra's Transportation
4 South Mainline, which transports natural gas from northeast British Columbia and supplies gas
5 via the Huntingdon/Sumas trading hub to both the Huntingdon Station and the Williams facility
6 immediately across the border from the Spectra facility. The Spectra facility consists of various
7 equipment to meter the gas delivered to FEI and Williams. The Williams facility is considerably
8 larger and more complex and includes significant compression equipment. Figure 3-3 below is
9 an aerial image showing the Huntingdon Station, the Spectra facility, and the Williams facility.

10

Figure 3-3: Aerial Photo of the Huntingdon Station and Surrounding Facilities



As reflected in the above figures, the Huntingdon Station is the sole source of supply to the CTS and the FEVI system. Natural gas is received from the Spectra facility at the Huntingdon Station and continues to flow west on these systems towards end points at Whistler, Sunshine Coast and Vancouver Island, serving along the way approximately 600,000 customers in the communities in Lower Mainland, Whistler, Squamish, the Sunshine Coast, and Vancouver Island.

3.2 *A SINGLE-POINT-OF-FAILURE FACILITY*

The Huntingdon Station is a single point of failure because it has to be taken out of service if one of the critical, non-redundant of components or piping of the Station fails and cannot be isolated for repair or replacement. This is further explained in this section.

The Huntingdon Station is a complex station because it contains numerous, large components (i.e. valves, pressure regulators, in-line inspection tool launchers, odourant pumps and injection points) and large diameter piping to handle high (transmission) pressures. However, the design of several critical components and sections of piping within the Huntington Station lacks redundancy.

Redundancy refers to the duplication of critical components or sections of piping of a system, designed and built into the system to increase reliability of the system, usually by way of backup. If a failure occurs to one of these critical components, there is no redundancy to compensate for it. Lack of redundancy or backup of certain critical components in the instance of a station can mean that the entire station would have to be shut down if any of these non-redundant critical components or piping segments fails and there is no way to isolate for in-service repair, replacement or reconfigure for an alternate feed without taking the entire station out of service.

This is the situation of the Huntingdon Station. Within the Huntingdon Station, with the exception of the two independent control valve stations and the portions of mainline downstream of the in-line inspection tool launchers, all portions of the Huntingdon Station are non-redundant, as shown in confidential Figure 3-4. With so many components and sections of piping within the Station being non-redundant, there are many potential points of failure. Depending on the nature, location, and time of the failure of any of these critical components, repair or replacement may require shutting down of the Station and may take hours, days, or weeks to complete the necessary work. For instance, a number of components, such as valves, cannot be taken out of service for repair or replacement because they cannot be isolated. If a failure occurs to one of these components that precludes in-service repair, the Huntingdon Station will need to shut down. Additionally, if an unforeseen failure occurs to one of these components, resulting in a release of gas and/or spontaneous fire, the entire Station may have to be taken out of service if it is not safe or practical to address the failure without stopping the flow of gas.

Shutting down the Station even for a relatively short period of time (as further explained in Section 3.4.2.1) can cause gas supply disruption to customers on both CTS and the FEVI system. FEI's current internal design standard, the practice of other major gas utilities and good utility practice all require that a single-point-of-failure station that cannot easily be taken out service have provisions for a station bypass. The Huntingdon Station is one of those stations that cannot easily be taken out of service because it is the sole source of gas supply to the CTS and the FEVI system,

FEI has thus proposed the Project to build redundancy on the system – a bypass – to avoid the single point of failure of the Station and to increase the system reliability. This, in turn, will ensure continuous natural gas service to the 600,000 customers downstream of the Station.

Figure 3-4: The Huntingdon Station Single Points of Failure CONFIDENTIAL

This Figure redacted and filed confidentially.

3.3 A FURTHER RELIABILITY CONCERN

Lack of redundancy in critical components and sections of piping within the Huntingdon Station presents a further reliability concern as it prevents the Company from conducting a complete, fulsome inspection and maintenance of these components and of the whole Station. Although the Company can maintain, and has maintained, these components, to perform a complete inspection and maintenance will require the shutdown of the Station because these components cannot be easily isolated. For example, routine valve maintenance is performed; however, a major repair or replacement of a critical valve would not be possible without a temporary Station shutdown.

Without the ability to perform complete maintenance of critical components, the reliability of the entire Station is further reduced.

3.4 *A HIGH RISK FACILITY*

Risk is generally defined as follows:

Risk = Probability of Failure x Consequence of Failure

The Huntingdon Station is a high risk facility mainly because of the potential severe consequences of service interruption to the Lower Mainland and FEVI customers and resultant business and economic loss if the Station fails. The Probability of Failure and Consequence of Failure are further explained below.

3.4.1 Potential Causes of Failure at the Huntingdon Station

There are several events at the Station that can lead to the failure of the Station, including:

- Failures of facility components resulting from lack of ability to perform maintenance or repairs;
- Failures of non-visible facility piping caused by corrosion or imperfections; and
- Potential equipment failures resulting from natural hazards.

Each failure event is described below in greater detail.

- <u>Failures of Facility Components</u>

  The failure of the facility components can result from lack of maintenance or repair. FEI has an Integrity Management Program that is used to ensure the integrity of the gas system assets by taking a comprehensive and systematic approach to providing effective prevention, detection and remediation activities. However, as mentioned above, many components or sections of piping within the Huntingdon Station lack redundancy, which prevents FEI's ability to perform complete maintenance or repair functions.

- <u>Failures of Facility Piping</u>

  A substantial amount of non-redundant piping within the Huntingdon Station is sub-surface and is not readily accessible for inspection. Corrosion, material imperfections, and weld flaws are primary threats to this asset, with corrosion creating the highest risk. Corrosion is the loss of metal thickness of the pipe wall due to iron oxide formation and the integrity of the piping gradually reduces over time, increasing the risk of piping failure.

  Currently, there are limited methods of maintaining gas supply if a defect is discovered on a non-redundant section of the piping that requires immediate repair or replacement. The entire Station may have to be shut down in order to repair.

- <u>Natural Hazards</u>

  The Huntingdon Station is located in a flood zone and an active seismic zone. A failure resulting from a major seismic or flood event could also lead to a release of gas or a gas cloud ignition, which could consequently shut down the Huntingdon Station.

Currently, FEI mitigates the probable occurrence of these events mentioned above through Integrity Management Program activities (such as inspections, patrols and leak surveys). However, these mitigation measures are limited in that the Company cannot perform a full, complete inspection of all critical, non-redundant sections or components unless the entire Station is shut down. As explained in the following section, shutting down the Station, even for a relatively short period of time, will result in complete gas service outage to approximately 600,000 customers relying on the CTS and FEVI system for gas supply.

3.4.2 Consequences of Failure of the Huntingdon Station

The risk posed by the Huntingdon Station is primarily driven by the Consequence-of-Failure factor - the potential complete shutdown of the Station and the loss of natural gas supply to approximately 600,000 customers in the Lower Mainland and on Vancouver Island. The magnitude of service interruption and the potential business and economic loss, in the Company's view, make the risk posed by the Station unacceptable. As such, the Company is proposing the Project to mitigate the Consequence of Failure by creating system redundancy and removing the Huntingdon Station as a single point of failure.

3.4.2.1 Rapid Loss of Natural Gas Supply to Customers

As discussed above, the failure of a critical component or section of piping within the Huntingdon Station can lead to the complete shutdown of the Station. In the event that the Huntingdon Station is shutdown, supply to customers can only be temporarily maintained through transmission pipeline system line pack. A number of other mitigation measures may also be employed to extend system survival time, but none of these measures is sufficient to maintain continuous supply to all the customers served by the CTS and FEVI system. These measures are discussed below.

Line pack is defined as the quantity of gas in a gas transmission and/or distribution system between the maximum allowable and the minimum required operating pressures at any point in time. Line pack varies within a system depending on supply and demand factors. Often line pack is used as a means of storage for natural gas during low demand periods. FEI's CTS has limited usable line pack due to the narrow range between its low maximum allowable and minimum required operating pressure and the relatively short length of the transmission pipelines. To preserve the line pack, the FEVI system will also be isolated at the Eagle Mountain V1 Compressor Station in Coquitlam (see Figure 3-1) to prevent gas flow onto FEVI system.

Because of this limited line pack, if the Huntingdon Station is shutdown, customers downstream of the Station will suffer a very rapid loss of natural gas supply. As an example, it is estimated that should a complete outage of gas flow from the Huntingdon Station occur there is less than one hour of line pack during a peak winter day and between two to four hours on an average winter day in the CTS before an eventual service disruption of gas supply to all customers in the Lower Mainland.

Due to the much higher operating pressure of the FEVI system (thus much higher line pack) as well as the presence of Mount Hayes Liquefied Natural Gas (LNG) facility on Vancouver Island, that system can survive for a longer period of time after the loss of continuous gas supply from the Huntingdon Station occurs. It is estimated that the FEVI system can currently continue to feed FEVI customers for approximately 10 to 20 days depending on time of the year and level of storage available at the Mount Hayes LNG facility.

In case of a complete shutdown of the Huntingdon Station, the following additional mitigation measures may also be employed to extend system survival time:

1. Lower Mainland Industrial customer curtailment;
2. LNG sendout from the Tilbury LNG facility; and
3. Reverse flow of FEVI line pack into the CTS via the Eagle Mountain Reverse Flow Facility.

However, these additional measures all have limitations. For instance, the Tilbury LNG facility is intended for peak load conditions and may be used to extend system survival time where possible, but is insufficient to sustain the CTS by itself. Additionally, all of them are short-term measures to extend CTS system survival time, and all require one to several hours to put into effect, which may not be available during a sudden outage of the Huntingdon Station. Thus, none of the measures can replace the Huntingdon Station as a supply source.

3.4.2.2 Critical Customer Impact

As discussed above, the Huntingdon Station is the sole supply source of natural gas to the CTS and also to the FEVI system, which together serve about 600,000 customers. Thus, a complete outage at the Huntingdon Station will prevent gas flows potentially for a relatively prolonged period of time to those customers, including critical service customers such as hospitals and senior and critical care homes. A high level, approximate breakdown of critical customer accounts affected by such an outage is as follows:

- 125 hospital and emergency facilities;
- 375 care homes; and
- 2,000 schools and public assembly facilities.

The Huntingdon Station is located in a rural area, so the immediate risk to public safety due to a gas leak and possible ignition is lower than it would be if it were situated in an urban area. The risk is therefore more driven by the potential economic or financial consequences to these critical customers resulting from a complete outage, as opposed to public safety risk in the surrounding area.

3.4.2.3 Potential Business and Economic Losses

FEI estimates that recovery from the complete service outage of the CTS and FEVI system caused by failure of the Huntingdon Station would take several months and require a complex, large scale plan for shutdown of stations and meter sets, repair, restoration of gas service and re-lighting appliances to be undertaken. To fully restore service following a complete shutdown it has been estimated to take approximately 4 months and $34 million in cost.

Of the 600,000 customers potentially impacted by the gas supply service disruption, many are commercial and industrial customers. These customers usually require natural gas service to operate. The loss from potential commercial downtime can result in a significant economic loss to these customers.

FEI expects that the total economic loss resulting from a complete service outage at the Huntingdon Station to be in the magnitude of $1 billion. Factors considered in this economic loss include damages and losses from both commercial and industrial plant outages such as loss wages, equipment damage and loss of revenue. This figure was based on economic losses caused by the 1998 Esso Longford Gas Plant Accident in Australia (refer to Appendix A). In the Company's view, the impact assessed in that incident provides a reasonable basis for estimating the consequences of failure at the Huntingdon Station because the number of customers that may be affected is roughly in the same range. The 1998 incident in Australia affected 1.4 million households and 89,000 businesses, and the estimated impact to the economy at the time was $1.3 billion AUD.

3.4.3 Risk Assessments by Third Parties

FEI retained experts to conduct a risk assessment on all transmission assets as well as a specific risk assessment of the Huntingdon Station that evaluates the Probability of Failure (PoF), the Consequence of Failure (CoF), and risks to the customers and the Company.

FEI retained GHD Consulting[2] (GHD) to prepare a series of risk assessments of its transmission assets. As a first step, GHD performed an initial, high level qualitative Risk Assessment (RA) of all transmission assets, and reported its findings in a document titled "Phase 1 Risk Assessment Report" (Confidential Appendix B). In this report, GHD aimed to identify the highest risk assets and establish a risk management framework that can be progressively expanded and refined over time as more comprehensive information becomes available. For each asset, GHD

[2] GHD Consulting: A multidiscipline engineering consulting company that with strong understanding of risk assessment and asset management principles. http://www.ghd.com/global/about-us/

considered the PoF, CoF and redundancy factors to determine risk. In the report, GHD identified and ranked the top ten FEI's assets from three perspectives – Business Risk Exposure (BRE), PoF, and CoF. BRE, as expressed in the GHD Risk Assessment, accounts for the PoF, CoF and redundancy factors. For CoF, equal weightings of social, environmental and financial factors were used.

Based on GHD's report, the Huntingdon Station was ranked the highest in terms of BRE due to the highest CoF. The CoF was high because of the Huntingdon Station being a single point of failure and the financial losses based on the estimated 1,375 mmcfd of lost throughput and 2009/2010 peak day simulations. GHD recommended a bypass around the Huntingdon Station to mitigate the risk[3].

Following GHD's qualitative assessment, FEI engaged Dynamic Risk Assessment Systems[4] (DRAS) to conduct three quantitative risk assessments of the Huntingdon Station (Confidential Appendices C1, C2 and C3 respectively). The objective of the quantitative risk assessments was to determine the impact that the installation of the bypass around the Huntingdon Station would have on operational risk. The approach includes processes for quantifying the consequences of a piping section or component failure, the likelihood of its occurrence, and the overall risk that is derived by combining consequences of a failure with the failure likelihood. Numerous categories of consequences were factored into the assessment, including health and safety, physical damages, economic losses, environment, and corporate image. The primary unmitigated consequence drivers identified in the study are service disruption, relight costs and loss of revenue from energy sales. Different from the qualitative assessment, the study quantifies the consequences of failure with an impact value. This is a sum of the quantitative risk value of each pipe section and component per year of operation, based on failure frequency per year and financial cost per event.

The quantitative RA considered two scenarios: the Huntingdon Station without the bypass in place; and with the bypass in place. Risk calculations were performed for each of the major pressure retaining equipment items in the Huntingdon Station. The assessment concludes that:

> *The overall risk of all equipment items combined that is associated with current operation (without the bypass in place) is $3,275,000 per year of operation. The corresponding risk value for the scenario with the bypass in place is $2,100 per year of operation. The risk differential between the two scenarios is $3,272,900 per year of operation. This analysis illustrates that the installation of a bypass around Huntingdon Station would result in significant savings in operational risk.* [5]

---

[3] Appendix B: GHD Consulting "Terasen Transmission Phase 1 Risk Assessment Report", Report submitted to FortisBC Energy Inc. by GHD Consulting, Inc., February 2010.,Section 7, Page 27.

[4] Dynamic Risk Assessment Systems, Inc. – a multidiscipline consulting company whose services include risk and engineering assessments. http://www.dynamicrisk.net/

[5] Appendix C1 Mihell, J.N. and Len, N. "Quantitative Risk Assessment of Huntingdon Control Station", Report submitted to FortisBC Energy Inc. by Dynamic Risk Assessment Systems, Inc., March 30, 2011.,Section 1, Page 4.

The risk differential between the without-bypass scenario and with-bypass scenario represents only a snapshot in time. As the equipment within the Huntingdon Station ages, the risk differential will increase due to the Company's inability to perform complete inspection and maintenance. More specifically, as discussed in the DRAS report[6] (refer to Confidential Appendix C1, at page 46), deferring the Project will increase the overall risk to operations in five years by 275 percent, from $3,275,000 to $9,116,200 per year of operation.

3.5 *CONCLUSION OF JUSTIFICATION*

The Huntingdon Station is the sole natural gas supply source to the CTS and the FEVI system, together serving approximately 600,000 customers. The customers include hospitals, care homes, and also schools.

However, the design of many critical components and sections of piping within the Huntington Station lacks redundancy, thereby making them single points of failures within the Station. Because these critical non-redundant components cannot be easily isolated for repair or replacement if a failure occurs, the entire Station would have to be shut down. In the event that the Huntingdon Station is out of service, the gas supply on the CTS and FEVI system will be disrupted within a relatively short period of time. The 600,000 customers will experience potentially a prolonged period of gas service outage as described in Section 3.4.2 above. The anticipated economic losses due to the outage of the Huntingdon Station are roughly estimated to be in the range of $1 billion.

As previously stated, the magnitude of the potential service disruption and associated business and economic loss (or the Consequence of Failure) presents a significant risk and provides the main driver for the Project. The most effective way to address this risk is to install a bypass as further discussed in Section 4 of the Application.

FEI has engaged third party experts to conduct both a qualitative and quantitative risk assessment. The Huntington Station was ranked the highest in terms of business risk exposure as well as the highest in terms of the CoF factor. Both the qualitative and quantitative risk assessments conclude that a bypass constructed around the station could mitigate or reduce the risk, specifically the Consequence of Failure.

[6] Mihell, J.N. and Len, N. "Quantitative Risk Assessment of Huntingdon Control Station", Report submitted to FortisBC Energy Inc. by Dynamic Risk Assessment Systems, Inc., March 30, 2011, page 46.

4. OPTIONS ANALYSIS

This section will describe:

- the objectives and requirements that the Company intends to meet with the options considered;
- the options considered and evaluated by the Company; and
- the preferred option selected by the Company.

4.1 OBJECTIVES AND REQUIREMENTS

As discussed in Section 3, the key concern for the Huntingdon Station is that it constitutes a single point of failure. If it shuts down, gas supply service on both the CTS and FEVI system will be disrupted and the consequence from such disruption will be severe. The single point of failure is caused by lack of redundancy in the design of many critical components and sections of piping within the Station. If a failure occurs to one of these critical components, there is no redundancy to compensate for it. Thus, the objective of any option considered is to create necessary redundancy and to eliminate the risk posed by the Station as the single point of failure.

In addition, any option considered and selected will have to eliminate or reduce the reliability concern identified in Section 3.3 of the Application and the risks from the failure events identified in Section 3.4.1 of the Application. Further, the option needs to satisfy the current code, standards and operating requirements. More specifically,

- The option should have station segment isolation valves that are capable of remote operation from FEI's Gas Control Centre. This is a Company requirement for major stations which are not manned on a full time basis. Remote operation will allow for safe and timely response to a failure of a component within the Station or the Station, especially in instances where it would be unsafe for employees to enter the Station by shutting down the supply source, and will simplify emergency responses procedures. The capability of remote operation also accords with CSA Z662, Annex N.10.5[7], which recommends a reduction in consequence from failure through improved methods for control and shutdown of the supply sources, emergency response procedures, and improved pipeline system design.
- The piping configuration of an option considered shall meet the current FortisBC Station Design Engineering standards and FortisBC Seismic Design Requirements for Buried Pipelines. The Company's standards are in accordance with CSA Z662. As discussed in Section 3.4.1 above, the Huntington Station is located in an active seismic zone.

[7] CAN/CSA-Z662-11 *Oil and Gas Pipeline Systems,* Annex N Guidelines for Pipeline System Integrity Management Systems, section 10.5 Consequence Reduction, clauses b, e and g.

Although an option that meets the seismic standards cannot completely eliminate the seismic risk, it should allow the Company to maintain operating pressures at the Station, to continue the supply of natural gas to the CTS and FEVI system, and to reduce the threat to the public safety following a major seismic event in the immediate vicinity of the Station;

- The option should have piping configuration that is capable of supplying natural gas to both the NPS 30 and NPS 42 piping of the CTS, as the start of the CTS has piping of both sizes; and
- The option should also consider constructability, operations and safety factors, such as limiting interruption of flow of gas during construction, simplifying gas flow procedures and allowing sufficient space to work around existing piping and components. The Huntingdon Station is a congested and complex site, and any new piping or components added should not increase the congestion or complexity. In addition, if achievable, avoiding working in close proximity to live gas lines will simplify the work procedure and increase safety.

For each option discussed below, the Company considered the pros and cons of the option in light of these above objectives and requirements.

4.2 OPTIONS DESCRIPTION

To achieve the objectives and requirements outlined above, FEI has considered various potential feasible alternatives, and has eventually selected installing a bypass around the Huntingdon Station (Option 4) as the preferred alternative based on an evaluation of both financial and non-financial factors.

The following options were considered, and each will be discussed in further details below:

- Option 1 - Doing nothing or deferring the capital improvements;
- Option 2 – Making operations and maintenance changes at the Station to mitigate risk,
- Option 3 – Performing some internal station upgrades; and
- Option 4 - Installing a bypass pipeline near the Huntingdon Station.

Relevant project total costs are shown in each option description and are discussed further in Section 4.3.1 below.

4.2.1 Option 1 - Do Nothing/Deferral

This option will prolong the lack-of-redundancy and the single-point-of-failure situation explained above in Section 3; thus, the significant operational, economical and business risks identified above will remain. Moreover, as the equipment within the Huntingdon Station ages, the risk of potential failure of critical components and therefore the entire Station is increased due to the Company's inability to perform a complete inspection and maintenance of the equipment and the Station without shutting the Station down. As discussed in Section 3.4.2, even shutting down the Station for a relatively short period of time can result in rapid loss of natural gas supplies to 600,000 customers. Thus, FEI does not believe the "do nothing" approach or maintaining the status quo is prudent.

FEI has also considered deferring the Project to avoid immediate capital expenditures and allow for redeployment of internal resources on other projects. However, deferral is no longer a safe option. As discussed in the DRAS report (see Confidential Appendix C1, at page 46), deferring the Project will increase the overall operational risk in five years by 275 percent, from $3,275,000 to $9,116,200 per year of operation.

Additionally, deferring the Project means that complete maintenance of critical components and sections of piping will have to be further delayed. As discussed above, without the ability for the Company to perform complete, fulsome inspection and maintenance of critical components within the Station, the reliability of the Station is put at further risk.

4.2.2 Option 2 – Implementing Operations & Maintenance Changes

This option involves implementing changes to the operations and maintenance practices at the Huntingdon Station, which include:

- Manning the Station to monitor operations; and
- Inspecting existing pipe for flaws and defects and recoating to deter corrosion.

Each alternative is further explained below.

MANNING THE STATION

Currently, the Huntingdon Station does not have a full time personnel stationed there. By locating a technician full time (24 hours, 7 days a week) at the Huntingdon Station, it allows for more frequent monitoring of the visible assets. For instance, if a small leak is discovered on a valve, where the technician can safely enter the incident area, the technician can assess and complete the minor repair and prevent the complete failure of the valve. Additionally, in the event that an incident occurs at the Station that cannot be repaired by the technician easily, the response time to the incident could be decreased. The on-site technician may be able to quickly assess and communicate the incident details to the appropriate departments within FEI, and a response plan can be developed.

However, for events such as a major leak on a valve, having a technician at the Station may not be sufficient. The technician may not be able to quickly remedy the situation or stop the event from further progressing, and may not give any option to maintain gas flow. Moreover, manning the Station full time cannot prevent failures of non-visible facility pipelines caused by corrosion; nor can a technician help with a spontaneous failure of facility components. If such failures occur, the Station may have to be shut-down eventually.

INSPECTION AND RECOATING OF PIPING

A full evaluation and inspection of the existing facility piping could be conducted, with the limitation discussed below. For instance, the sub-surface piping at the Huntingdon Station could be exposed using vacuum excavation, and integrity evaluations could be conducted on the pipe and welds. And if required, the piping would be coated to current Company standards. This will also allow the Company to gather additional field information to establish new corrosion rates for sub-surface piping, which enables a further, more fulsome evaluation of the piping with modelling simulations.

However, there is a substantial risk by completing this activity on the non-redundant sections of the piping. If the inspection mentioned above discovers a piping defect, there are limited methods of maintaining gas supply without shutting down the entire Station. If repair or replacement is required, the Company may have to construct a temporary bypass to complete the work. Costs would be incurred to develop and execute contingency plans to build the temporary bypass.

OPERATION AND MAINTENANCE CHANGES OPTION EVALUATION

This option, though enabling the Company to conduct inspection of the piping or potentially preventing the complete failure of certain components in some instances, is limited.

First, the option does not provide a solution to the lack-of-redundancy concern with respect to the critical components or sections of piping within the Station or to the single-point-of-failure concern with respect to the Huntingdon Station.

Second, as discussed above, under this option, the Company may not be able to keep the Station operational and maintain gas flow if a more significant event occurs within the Station or a non-redundant section of the piping needs repair. As discussed in Section 3.4.2 of the Application, the consequence of inability to maintain gas flow to the customers is severe.

Third, the two alternatives discussed above mainly address the Probability of Failure factor of the risk calculation as they focus on preventing a potential failure within the Huntingdon Station. They do not address or reduce the Consequence of Failure factor, which is more directly related to the lack-of-redundancy and the single-point-of-failure concerns discussed in Section 3 above.

4.2.3 Option 3 - Internal Station Upgrades

Project Total: $6.3 million (2013$)

This option consists of completing upgrades and additions to the valving and piping configuration within the Huntingdon Station to eliminate the majority of single points of failure. Specifically, the potential upgrades include: (1) addition of four automated valves; (2) automation to four existing valves; and (3) addition of approximately 50m of piping. A schematic of the proposed changes are shown in Figure 4-1, which is filed confidentially.

Figure 4-1: Internal Station Upgrades CONFIDENTIAL

This Figure redacted and filed confidentially.

As illustrated in the confidential Figure 4-1, these upgrades would remove all the single points of failures except a section of piping and two isolation valves at the inlet of the Station.

Although a few non-redundant sections and components remain within the Station, the operational risk is reduced. For comparison purposes, FEI conducted an evaluation of the operational risk reduction using the segment and equipment risk values contained in the DRAS report “Quantitative Risk Assessment of Huntingdon Control Station" (See Appendix C-1, Table

8). The calculated operational risk with the internal upgrades in place would be $140,869 per year, or a reduction of 96% from the current condition (without the internal upgrades).

Additionally, under this option, all of the additional piping would be located within the fenced compound of the Huntingdon Station, without the need to procure new land or acquire new Right-of-Way (ROW) from surrounding landowners.

However, this option presents the following challenges:

- The Huntingdon Station remains a single-point-of-failure facility as a section of sub-surface piping and two isolation valves are still non-redundant. Their failure still has the potential to lead to the complete shutdown of the entire Station;
- The internal upgrades as outlined above do not reduce risks from natural hazards. As mentioned above, the Company's objective with respect to reducing risks from natural gas hazards is to maintain operating pressures at the Station, to continue the supply of natural gas to the CTS and FEVI system, and to reduce the threat to the public safety. By continuing to leverage the piping and components in the design, this option may not meet this objective;
- Due to the limited space within the Huntingdon Station and the fenced compound, the installation of the new piping and valves will make an already congested and complex site more challenging to maneuver in. In addition, construction would have to take place in close proximity to live gas lines and would require a more complicated process to complete the upgrades safely;
- From an operations perspective, because of the increased congestion within the Station, it requires more measures and time for the Company to safely access and effectively maintain the Huntingdon Station operational if an incident (such as a fire) occurs within the fenced compound; and
- Building redundancy to these many, different components within the Station may not be the most practical solution.

4.2.4 Option 4 – Installation of a Bypass Pipeline External to the Huntingdon Station

4.2.4.1 Bypass Route Immediately Around the Station

Project Total: $6.8 million (2013$)

This alternative consists of installing a bypass external to the Huntington Station to allow for the flow of natural gas from the Spectra pipeline to the CTS. More specifically, FEI will install a bypass that would connect from the Spectra pipeline feeding Huntingdon Station to the CTS downstream of the Huntingdon Station facility. The bypass will be located within a new Right-of-Way. A schematic of the proposed changes are shown in Figure 4-2, which is filed confidentially.

Figure 4-2: Bypass Pipeline Option CONFIDENTIAL

This Figure redacted and filed confidentially.

The bypass option will have the following advantages:

- It will create redundancy to the Station, thereby removing the Station as a single point of failure;
- The Company can perform complete inspection and maintenance of the non-redundant components and sections of the piping within the Station without the need to shut down the entire Station, thereby enhancing the reliability of the Station;
- The bypass to be constructed will meet the current FortisBC Station Design Engineering standards and FortisBC Seismic Design Requirements for Buried Pipelines, which will reduce risks from natural hazards. For instance, with automated valves, the release of gas within the Station due to natural hazard can be controlled (i.e. shut off), making the area in the vicinity of the Station safer to the public;
- The bypass can be built to feed both NPS 42 and 30 CTS pipelines;

- The construction of the bypass will be outside the Station, thereby avoiding construction within a congested Station, and having sufficient clearances from live gas lines; and
- To have a station bypass will meet FEI's current internal design standard and be consistent with the practice of other major gas utilities for instances where a station is a single point of failure and cannot easily be taken out of service.

From the operations perspective:

- With additional automated valves on the bypass, the bypass will allow for remote operation as well as safe and timely response to failure of a component or the Station from FEI's Gas Control Centre. This is in compliance with Company standards and in accordance with CSA Z662, Annex N.10.5 recommendation;
- The bypass will provide additional safety in the event of a station incident (i.e. fire, gas release) because the Station may be shut down using the bypass and may not require personnel to enter an unsafe situation; and
- Locating the bypass around the Station will simplify its operation with simple, clear separation of the bypass equipment from the existing Station piping and components.

Additionally, DRAS completed a quantitative risk analysis of Option 4 (see Appendix C-3, page 10 and 11), comparing the risk (in terms of operational risk) without a bypass in place (current situation) with the risk if an external bypass is constructed. The result of the analysis shows that the bypass option will result in a reduction in operational risk by 99%, comparing to the current situation.

4.2.4.2 Other Alternative Routes

In the early, preliminary stage of considering options to address the single-point-of-failure concern of the Huntingdon Station, FEI has also reviewed alternate bypass alignment routes than currently proposed. But these alternative routes were eventually dismissed due to a re-evaluation of the objectives and significantly higher construction costs with negligible incremental reduction in operational risk as compared to the proposed route. For instance, a larger, longer, more costly alignment which would involve a tie-in upstream of the Spectra facility was considered, but was rejected due to different construction requirements and high costs. Accordingly, FEI has not included these alternative routes in the following evaluation.

4.3 *OPTIONS EVALUATION*

The Company conducted a financial and non-financial evaluation of only Options 3 and 4 because both options satisfy the objective to a significant degree, whereas Options 1 and 2 do not. Thus, Options 1 and 2 are eliminated from further evaluation.

4.3.1 Financial Considerations

The financial evaluation consists of the following two components, and their impact on the levelized rates and incremental cost of service:

- Capital costs, estimated by an independent engineering firm; and
- Present value of operating costs.

The following table provides a summary of the financial evaluation conducted.

Table 4-1: Financial Comparison

	Option 3 – Internal Station Upgrades	**Option 4 – External Bypass Pipeline**
Estimate Accuracy	Class 4	Class 3[8]
Total Direct Capital Cost excl. AFUDC (2013$)	$6.3 million	$6.8 million
Gross O&M (2013$/ year)	$13 thousand	$14 thousand
Levelized Rate Impact $ / GJ – 25 Yr.	$0.004 / GJ	$0.005 / GJ
Levelized Rate Impact $ / GJ – 60 Yr.	$0.004 / GJ	$0.006 / GJ
PV Incremental Cost of Service - 25 Yr	$7.8 million	$9.6 million
PV Incremental Cost of Service – 60 Yr	$9.1 million	$12.1 million

As the differential in terms of Levelized Rate Impact between the two options is negligible, financial considerations in this instance have a less significant role when selecting a preferred option in the overall Project objective of eliminating the Huntingdon Station as a single-point-of-failure facility.

A calculation of the present value of operational risk was conducted on Option 3 and Option 4. This was then added to the present value of the cost of service to provide an overall present value comparison, summarized in Table 4-2 below. Operational risk is defined as the sum of the quantitative risk value of each piping section and component per year of operation, based on failure frequency per year and financial cost per event.

[8] The Class 3 and Class 4 estimates are considered comparable because the Class 3 estimate limits of +30%/-20% are within the acceptable ranges of a Class 4 estimate limits of +50%/-30%.

Table 4-2: Financial and Operational Risk Comparison

	Option 3 – Internal Station Upgrades	Option 4 – External Bypass Pipeline
Operational Risk Reduction (%)	96	99
Operational Risk (2013$ / year)	$141 thousand	$31 thousand
PV Operational Risk – 25 Yr	$2.1 million	$0.4 million
PV Incremental Cost of Service – 25 Yr	$7.8 million	$9.6 million
PV Operational Risk + PV Incremental Cost of Service – 25 Yr	$9.9 million	$10.0 million

As demonstrated in Table 4-2 above, the benefit of Option 4 in the operational risk differential for a 25 year period was calculated to be $1.7 million ($2.1 million less $0.4 million).

Referring to the first line in Table 4-2, the difference in operational risk reduction for Option 4 as compared to Option 3 is 3% (99% - 96% = 3%). Referring to the last line of Table 4-2, where the 25 year PV Incremental Cost of Service and PV Operational Risk are added, the two options differ by $0.1 million ($10.0 million - $9.9 million = $0.1 million). Option 4, by reducing all of the operational risk for a relatively small incremental cost, is more cost effective.

4.3.2 Non-Financial Considerations

The Company also considered the advantages and disadvantages of each option based on non-financial factors. The discussion in Section 4.2 above explains in more detail the pros and cons of each option. The following table summarizes the pros and cons of Option 3 and Option 4. The objectives and requirements discussed in Section 4.1 are used as the main criteria for the evaluation and for the summary as these criteria reflect the Company's objectives to build a project that will address concerns identified in Section 3 of the Application, such as removing single points of failure of critical components within the Station and the Station as a single-point-of-failure facility, reducing the reliability concern identified in Section 3.3 of the Application and the risks from the failure events identified in Section 3.4.1 of the Application, and satisfying current codes, standards and operating requirements.

Table 4-3: Non-Financial Comparison

Objective/Requirement	Option 3 - Internal Upgrades	Option 4 - External Bypass Pipeline
Removing Single Point Of Failure	Upgrades would remove all the single points of failures within the Station **except** a section of piping and two isolation valves at the inlet of the facility. The Station is still subject to the single-point-of-failure risk.	External bypass would eliminate all single points of failure within the Station and remove the Station as the single point of failure on the system.
Allowing For Remote Operation	Upgrades would allow for remote operation by adding four automated valves and automating four existing valves.	Bypass would allow for remote operations by having four automated valves added to the external bypass.
Meeting Codes, Standards And Operating Requirements	Internal upgrades will leave in place existing piping and components. These components do not meet current seismic standards for new construction and may not be able to maintain operating pressures immediately following the occurrence of a natural hazard.	The bypass will be engineered to meet the current design and seismic requirements to maintain operating pressures immediately following a natural hazard.
Supplying Gas To Both CTS Lines	Upgrades would be built to allow for supplying gas to both CTS lines.	The bypass would be built to allow for supplying gas to both CTS lines.
Addressing Constructability, Operation, Safety Concerns	Upgrades would add new piping and valves to make an already congested and complex site more challenging to construct and maneuver in. Upgrades would require more complicated measures for safety during construction. Increased congestion would also impact the ability to safely access and effectively maintain the Huntingdon Station operational during an incident (e.g. fire, gas release).	The external bypass would allow construction of the bypass with acceptable clearances from live gas lines. Clean, simple layout of the external bypass establishes clear separation from existing station piping and components. Bypass operating procedure will be consistent with other FortisBC assets which have a bypass.

4.4 *CONCLUSION – PREFERRED OPTION*

Through the financial and non-financial evaluation of various alternatives, the Company has determined that the bypass pipeline external to the Huntingdon Station was the preferred option. This option will remove the Station as the single point of failure on the system. It will provide the necessary redundancy to the Station, which, in turn, will reduce the risk of loss of gas supplies to approximately 600,000 customers in the event that one of the critical components within the Station fails that can be isolated and leads to the shut-down of the Station.

Additionally, by building the bypass, the Company will have the ability to maintain and repair (if necessary) of any of the non-redundant components or sections of piping within the Station without the need to shut down the entire Station. This will increase the reliability of the Station.

Further, building a bypass external to the Station will satisfy all the objectives and requirements outlined in Section 4.1 above.

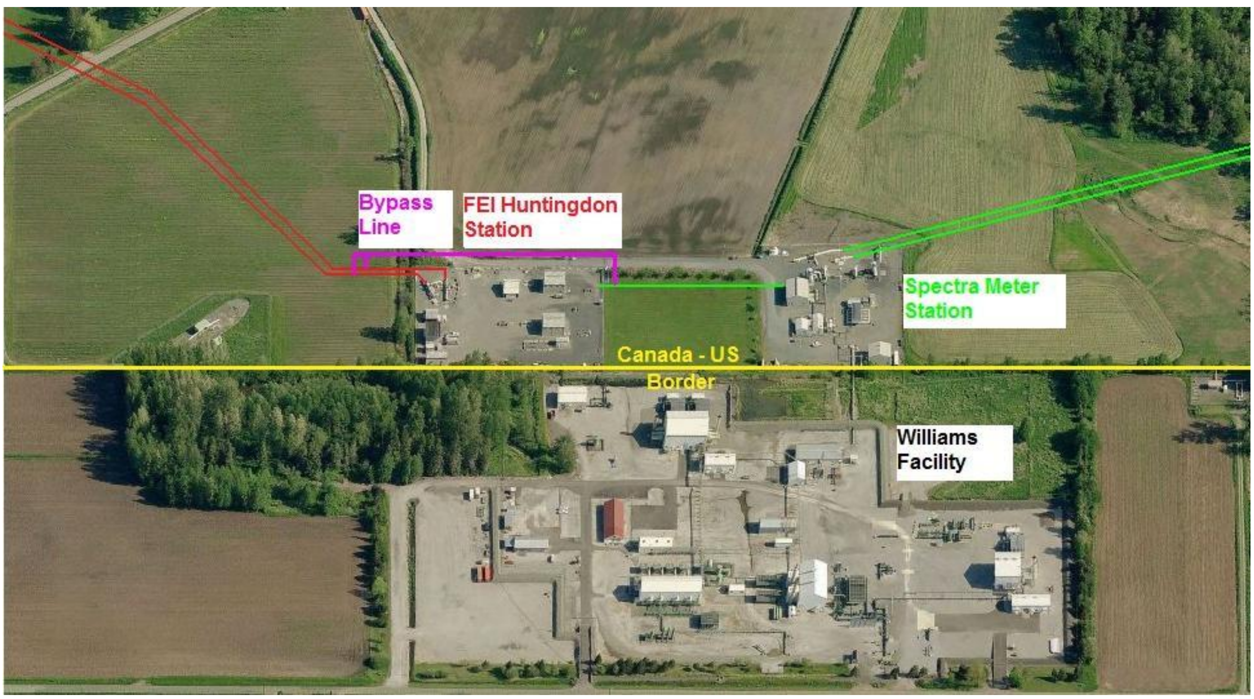
5. PROJECT DESCRIPTION

In this section, FEI will describe the proposed Project in more detail, including information on Project components, Project Schedule, Resources Requirement, and Project risks and management.

5.1 *INTRODUCTION*

The Project involves constructing 182m of NPS 36 pipeline connecting an existing Spectra pipeline (entering the Huntingdon Station from the east) to the existing transmission pipelines located west of the Huntingdon Station beneath an agricultural field. All construction will occur within a 100m radius of the Huntingdon Station, in the City of Abbotsford. The bypass will have a capacity of 1,635 mmcfd. The figure below illustrates the Project.

Figure 5-1: Proposed Bypass Pipeline



5.2 *PROJECT COMPONENTS*

The Project is comprised of the following two major components:

1. Construction of a new NPS 36 TP pipeline by conventional construction methods to tie into the existing Spectra pipeline adjacent to the Huntingdon Station on the upstream side and into the existing FEI NPS 30 and NPS 42 pipelines on the downstream side; and

2. Installation of inline pressure control and monitor valves and four isolation valves on the bypass to reduce the pressure from Spectra's maximum operating pressure to the FEI maximum operating pressure.

Each component is discussed in further detail below.

5.2.1 NPS 36 TP Pipeline

The Project will use conventional trenching methods to construct the new NPS 36 pipeline.

The bypass pipeline length will be approximately 182m. The pipeline route will start from the Spectra pipeline, immediately outside of the Huntingdon Station and head west. The eastern terminus of the bypass pipeline will tie into the existing Spectra pipeline. The western terminus of the bypass pipeline will tie into the existing FEI NPS 30 and 42 pipelines (refer to Figure 4-2 above). The entire route will be on private property, and a new Right-of-Way (ROW) will be required. The pipeline will cross a drainage ditch on the west side of the Huntingdon Station.

The technical requirements and other design and construction components and requirements of the pipeline construction are described in Section 5.3.

5.2.2 Pressure Control Valve and Isolation Valves

On the east or upstream (inlet) end of the bypass, FEI will install two isolation valves to direct gas flow from the main Spectra facility to the CTS through the existing station or through the bypass. Spectra operates their pipelines at a higher pressure than the FEI maximum operating pressure; therefore, a pressure control valve and a monitor valve for over pressure protection will be installed on the bypass line to regulate pressure to the CTS maximum operating pressure.

An odorant injection tap will also be installed on the bypass to facilitate the addition of odorant to the gas.

On the west or downstream (outlet) end of the bypass, FEI will install two isolation valves to direct flow of gas from the bypass into the existing NPS 30 and 42 pipelines.

5.3 *DESIGN AND CONSTRUCTION OF THE BYPASS*

This section describes the design and construction of the bypass. The new bypass will be built according to current FEI pipeline design standards.

5.3.1 Pipeline Method of Construction

Open trench is a common industry accepted method for constructing new pipelines across land. FEI has used this method of pipeline construction for over 50 years.

The basic method used in constructing steel, welded onshore gas pipelines in open cross-country areas is generally known as the spread technique. The spread technique utilizes the principles of the production line system, but in the case of a pipeline the product (the pipeline) is static and the individual work force (crews) move along the pipeline track (ROW). The implementation of the spread technique is conditional on the pipeline being welded above ground in maximum continuous lengths between obstructions/crossings. The welded pipeline lengths are then installed into unsupported/unobstructed trenches gradually in one continuous length utilizing multiple (three or more) mobile lifting side-booms in unison.

The final step involves "tie-ins" to the existing pipeline(s) upstream and downstream of the new pipeline.

5.3.2 Acquisition of Property

The Project will require acquisition of a new Right-of-Way. The approximate size of the ROW is 182m long by 18m wide. Discussions with stakeholders are progressing well. No issues have been raised, and FEI does not expect any issues associated with acquiring this ROW. FEI will complete the ROW acquisition process once the approval of this Application is received.

The Project does not require the acquisition of any Crown Land.

5.3.3 Other Utilities

The Project does cross below the BC Hydro overhead 25KV power line located near the northwest corner of the Huntingdon Station. The power line will not be impacted by the construction.

There are no other electrical, water or other third party utility services that will be impacted by the Project.

5.3.4 Roads, Highways and Railways

The Project does not cross any public roads, highways or railways. The Project does cross the Spectra facility access road located adjacent to the Huntingdon Station on the north property line.

Consultation with local residents has been initiated to ensure the increased traffic and activity associated with construction of the bypass does not adversely impact the residents of south Abbotsford. No significant impacts or disruptions to local businesses are expected. Some road construction on private property will be required to access the west end of the bypass.

5.3.5 Restoration

Restoration of the ROW and temporary work space on the bypass route will meet the requirements agreed to with the property owners affected and the permit requirements of the Agricultural Land Reserve.

5.3.6 Noise Control

The construction site is located close to residents in the southern area of Abbotsford. Noise monitoring and control will comply with local guidelines.

5.3.7 Safety and Security

Construction site safety and security will be maintained during the course of the installation including all working and non-working hours inclusive of weekends. A comprehensive safety plan will be developed by the pipeline contractor in compliance with FEI standards, WorkSafeBC regulations, and the requirements of other impacted stakeholders.

5.4 *PROJECT SCHEDULE*

Conceptual engineering has been substantially completed, and construction will be undertaken starting in 2015 and completing by the end of 2015. Specific activities and expected durations are as follows:

Table 5-1: Schedule Milestones

Activity	Duration
Concept Development	Completed.
CPCN Preparation	October 2012 – October 2013
CPCN Filing	October 2013
CPCN Review and Approval	October 2013 – March 2014
Finalize Detailed Engineering	November 2013 – February 2014
OGC Pipeline Application	January 2014 – June 2014
Tendering (Materials)	March 2014 – March 2015
Tendering (Pipeline & stations)	December 2014 – May 2015
Construction	May – September 2015
In Service	October 2015
Project ROW and Station Site Clean up	September - November 2015

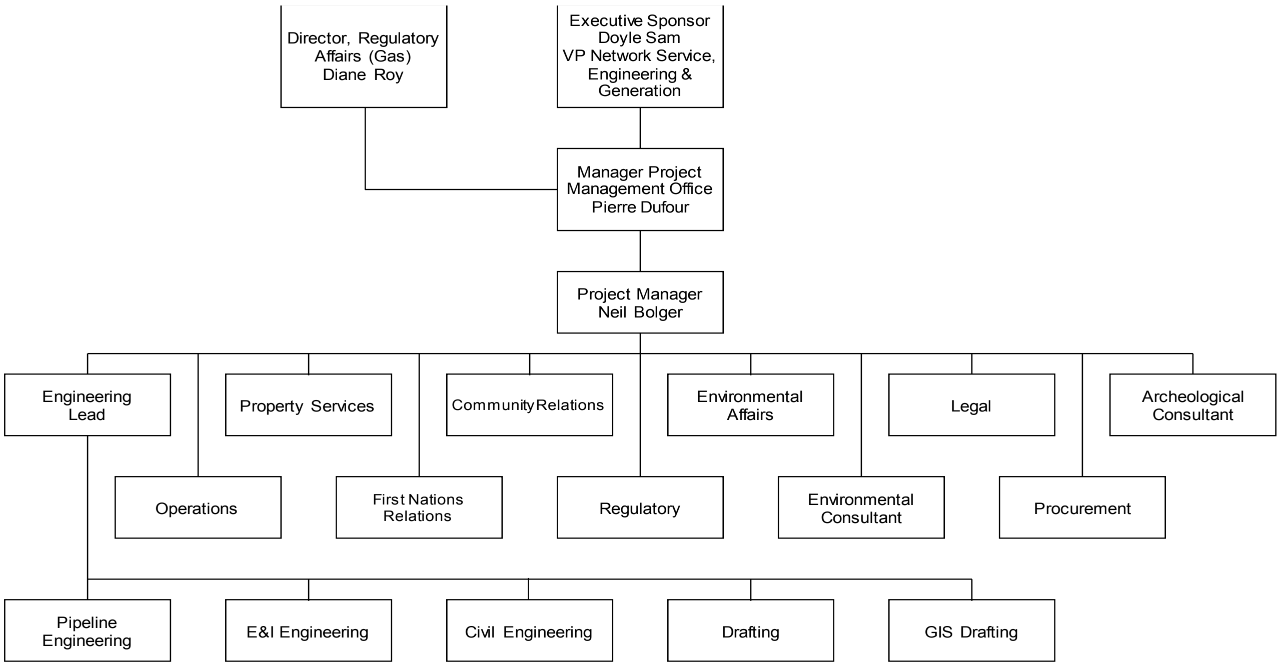
A more detailed schedule is attached as Appendix D.

5.5 *RESOURCE REQUIREMENTS*

5.5.1 Project Management

A FEI Project Manager will manage the Project and implement the execution plan for each phase of the Project. Figure 5-2 outlines the functional organization chart for management of this Project.

Figure 5-2: Project Functional Organization Chart



The Executive Sponsor for the execution of the Project is Doyle Sam, P.Eng., Executive Vice-President, Network Service, Engineering and Generation. The Project Manager is Neil Bolger, P.Eng.

5.5.2 Design and Quality Control

External engineering companies will be engaged for the design of all portions of the Project including the tie-ins. Any specialized services required for environmental management, geotechnical investigation and analysis, and construction inspection will be contracted to individuals and companies possessing the demonstrated skills and experience to complete the work. These individuals and companies will be expected to ensure that public and worker safety, quality workmanship and environmental compliance are maintained throughout the Project.

FEI operating personnel will ensure all facilities are efficiently placed into operation upon completion of construction and conform to FEI standards and industry practices.

5.5.3 Construction Services

Potential prime construction contractors will be pre-qualified prior to the release of the tender documents. The construction will be subject to a competitive tender for a lump sum form of contract and the bid that provides the best value will be selected by FEI at the close of the procurement process.

5.5.4 Materials

All owner-supplied materials will be purchased by FEI through the Company's standard procurement process. Owner supplied materials will be purchased through a competitive tender and awarded to the bidder that provides the best value.

5.6 OTHER APPLICATIONS AND APPROVALS

5.6.1 BC Oil and Gas Commission (OGC) Application

The construction and operation of the Project are governed by the *Oil and Gas Activities* Act and subject to the OGC regulation. The Project requires a Pipeline Application. FEI plans to file the Pipeline Application in January 2014. A Pipeline Application is a significant process with considerable technical scrutiny on the Project by the OGC. Public and First Nations Consultation, ROW acquisition, archaeological requirements, design reviews, environmental permits/approvals for work in and around fish bearing streams are all components of the Pipeline Application. Each component must receive OGC approval prior to the start of construction, a significant regulatory process in addition to the CPCN approval by the BCUC. A Pipeline Application can take up to one year for approval. However, since the proposed bypass is relatively simple and short, the current schedule assumes a six month approval period.

FEI will update the Commission when the OGC approves the Pipeline Application in its compliance filings if required.

5.6.2 Other Pending or Anticipated Applications/Conditions

A qualified environmental professional working in conjunction with the Company's Environmental Affairs group will assist the Project in identifying permits/approvals required and in the development of an Environmental Protection Plan including an Environmental Emergency Preparedness and Response Plan for the Project.

The Project is not expected to require an Environmental Assessment Certificate pursuant to the *British Columbia Environmental Assessment Act*. However, the Project may require a screening under the *Canadian Environmental Assessment Act* as a result of the Federal notifications/approvals that will be required to comply with provisions of the *Fisheries Act*.

Agency notifications, permits or approvals are anticipated under, but not limited to, the Fisheries Act, Species at Risk Act, Water Act, and Heritage Conservation Act. Notifications, permits or approvals may also be required from the Agricultural Land Commission and City of Abbotsford. The terms and conditions outlined in these permits and approvals will be adhered to during the construction of the Project.

As indicated above, the Project will involve the acquisition of new ROW from private property owners, but will not require any re-zoning.

5.7 *RISK ANALYSIS AND MANAGEMENT*

FEI conducted a risk analysis of the Project using internal resources, and has used the results of the analysis to calculate a contingency amount.

Based on FEI's analysis, the highest risks for the Project involve procurement of construction, materials and dewatering. FEI will manage and try to mitigate the procurement risk through careful tendering of materials and construction. The Company will manage the dewatering risk through early water contamination testing and addressing the risk in the construction tender documents.

A summary of the top five risks identified in the risk analysis are presented in Table 5-2.

Table 5-2: Project Execution – Risk Control Summary[9]

Key Risk	Probability	Consequence	Mitigation
Market Conditions (High Bids)	3	4	Communication with known contractors to ensure sufficient bidders are interested and available
Contaminated groundwater	2	5	Water sampling prior to bidding process
Late delivery of electrostop fittings	3	3	early order of material - have specification ready for immediate purchase on project approval or consider placing order prior to project approval
Late delivery of pipe	2	4	
Large amount of groundwater	2	4	water sampling, known issue addressed in contract

The risk analysis generated a contingency amount of $721,750. The detailed results of the risk analysis and contingency calculation are included in Appendix E.

[9] Relative probability and consequence for each key risk is evaluated in Appendix E.

6. PROJECT COST ESTIMATE

The Company prepared the Project cost estimate based on AACE Class 3 specifications, in accordance with the CPCN Guidelines.

This section discusses:

- the Project cost estimate;
- the deferred CPCN Application cost;
- the financial impacts; and
- the accounting treatment of the costs.

6.1 *COST ESTIMATE DETAILS*

The total capital cost of the Project, filed confidentially in Appendix F3, is estimated to be $8.0 million in as spent dollars. This cost estimate is based on preliminary Project definition and design, and the individual cost elements consist of historical costs, non-binding quotations and Projections. The estimate is also based on the expected in-service date for the Project of October, 2015. The expected accuracy of the cost estimate is +30 percent to -20 percent.

Cost estimates are based on the most recent studies and information currently available to FEI and an in-service date of October 2015. The estimate excludes GST but includes 7 percent PST on materials. FEI, as a GST registrant, is entitled to recover the GST it pays on its taxable purchases. As such, the tax does not represent a net cost to the Company. 2012 market prices have been used for the material supply and construction contracts. An escalation rate of 4.5 percent per annum is used based on the ten year average escalation rates from Statistics Canada for industrial construction and line pipe from 2002 to 2012. The cost estimates exclude First Nations Capacity Funding and Accommodation Costs as no such costs are anticipated at this time.

The estimated capital cost of $8.0 million will be the control budget, and cost reports will conform at a minimum to the level of detail as set out in Confidential Appendix F3. Prefeasibility costs will be tracked separately and will be reported on as well.

6.2 *FINANCIAL ANALYSIS*

The Company has also prepared the financial analysis for the final Project cost estimate, which includes the incremental cost of service, cash flow and incremental rate impacts over 25 and 60 year periods. Table 6-1 below presents a summary of the financial schedules included in Appendix F. The impact to customer rates in 2016 (when the asset is transferred to rate base) is approximately $0.006 per GJ and levelized over the analysis period is approximately $0.005

per GJ. For a typical FEI residential customer consuming an average 95 GJ per year in 2016, this would equate to approximately 67 cents per annum.

Table 6-1: Financial Analysis of the Huntingdon Station Bypass

	AACE Class 3
Total Direct Cost ($million) – As Spent $	7.6
AFUDC ($million)	0.3
2016 Rate Impact ($ / GJ)	0.007
Levelized Rate Impact 25 Years ($ / GJ)	0.005
Levelized Rate Impact 60 Years ($ / GJ)	0.006
Levelized Incremental Revenue Requirement ($million)	0.4
Incremental Revenue Requirement PV 25 Years ($million)	9.6
Incremental Revenue Requirement PV 60 Years ($million)	12.1
Net Cash Flow NPV 25 Years ($million)	0.1
Net Cash Flow NPV 60 Years ($million)	0.0
2016 Incremental Rate Base ($million)	8.3

6.3 *ACCOUNTING TREATMENT*

The capital costs of $8.0 million (including AFUDC), as shown on line 13 in Confidential Appendix F3 of this Application, will be held in work-in-progress until the beginning of the year after the asset is available for use. The Project is forecasted to be in service in October, 2015 and will be closed to gas plant in service on January 1, 2016. Depreciation and negative salvage provisions will commence on January 1, 2016. This treatment conforms to the treatment proposed in FEI's 2014-2018 PBR Application.

FEI requests Commission approval under sections 59-61 of the Act for deferral treatment of costs for preparing this Application and to amortize these costs over a three-year period. The Application costs include costs for legal review, expenses for consultant, Commission costs and Commission approved intervener costs. FEI is requesting a three year amortization period to commence in 2015 after the deferral charge has been incurred. FEI anticipates the application costs will all be incurred in 2013 and 2014 and amortization will commence in 2015. For the financial analyses in Appendix F, FEI is showing a three-year amortization period commencing in 2017 with the Application cost being shown in 2016. FEI is forecasting the Application costs to be about $100 thousand (after tax $74 thousand).

FEI is also seeking approval, under sections 59-61 of the Act from the Commission, to defer Prefeasibility Costs that cover the costs for Project Management, Engineering, and consultants' costs for assessing the potential design and alternatives and associated costs prior to Commission approval of the Project. The forecast cost is $573 thousand (Confidential Appendix F3, Line 5). FEI is seeking Commission approval to amortize these deferred Prefeasibility Costs over three years starting in 2016. The Prefeasibility would be recorded in a Non-Rate Base deferral account on a net-of-tax basis attracting AFUDC. At the beginning of 2016 the deferral account would be included in Rate Base, and no further AFUDC would be charged to the deferral account.

7. OVERVIEW OF ENVIRONMENTAL AND SOCIO-ECONOMIC ASSESSMENTS

FEI has assessed the environmental, archaeological and socio-economic impacts from the Project. Based on FEI's assessments, impacts to the environmental and archaeological resources from the Project are minimal and can be mitigated through the implementation of standard best management practices. There is also expected to be a limited positive socio-economic impact to the regional area resulting from the Project.

7.1 *ENVIRONMENTAL ASSESSMENT*

FEI retained Hemmera Envirochem (Hemmera)[10] to conduct a preliminary environmental assessment of the Project.

The assessment is based on a desk-top review of available information and an initial field study to determine the biophysical and fish habitat characteristics of the nearby drainage ditch. The assessment was undertaken to identify and describe the potential impacts to the biophysical environment from the Project and to provide a basis for the completion of a more detailed assessment to be completed once BCUC approval of this Application is received and prior to construction commencement.

Based on this preliminary assessment, the environmental risk is low and any potential environmental impacts from the Project can be mitigated through standard environmental protection and mitigation measures.

7.1.1 Preliminary Environmental Assessment

The results of the work undertaken by Hemmera are outlined in the Huntingdon Control Station Reinforcement Project Preliminary Environmental Assessment report, a copy of which is attached as Appendix G. The report summarizes (at page I) that:

- the Project will occur within a 100m radius of the Huntingdon Station;
- the land disturbance will occur on an existing gravel access road and the neighbouring land within the Agricultural Land Reserve (ALR);
- the environmental constraints can be avoided or mitigated by following applicable provincial and federal guidelines and through the application of standard best management practices and mitigation measures.

---

[10] Hemmera is a multi-discipline environmental consulting firm providing ecological, engineering, and planning and management services to the private and public services since 1994.

Table 7 in the assessment report (Appendix G) outlines proposed mitigation measures to avoid, minimize and reduce potential effects of the Project to ecological components. FEI will follow these measures where applicable during construction.

Based on the preliminary environmental assessment work completed by Hemmera, the Project will likely require provincial permitting/authorization under the Agricultural Land Commission Act, Water Act, Wildlife Act and potentially federal permitting/ authorization under the Fisheries Act. Upon BCUC approval of this Application, FEI, with the assistance of Hemmera, will undertake a detailed environmental assessment to confirm permitting requirements and apply for the required permits accordingly.

7.1.2 Further Plans

Environmental constraints and potential Project related environmental impacts will be documented during the Detailed Environmental Assessment, which will include vegetation, fish and wildlife and their habitat, surface/ground water resources and soils. Soil sampling will be undertaken to identify site reclamation requirements for ALR land.

Site specific mitigation strategies will be developed to offset any potential negative impacts associated with the Project. All environmental permits and approvals for the Project will be identified and applied for during the detailed engineering phase of the Project.

Detailed environmental specifications will be prepared as part of the Project tendering process to ensure the contractor(s) are aware of the Project's environmental requirements in addition to FEI's internal environmental standards. An Environmental Management Plan specific to the Project will be developed by the successful contractor(s) prior to commencement of the Project. Environmental monitoring will be undertaken during all sensitive aspects of the work program and the designated environmental monitor will have "stop work authority" in the event that works underway have the potential to impact the natural environment.

7.2 *ARCHAEOLOGY*

A preliminary Archaeological Overview Assessment (AOA) of the Project was undertaken by the Sto:lo Research and Resource Management Centre (SRRMC) to assess the potential for archaeological and/or cultural heritage resources within the Project area[11] and to determine the requirements for an Archaeological Impact Assessment (AIA) prior to ground disturbing activities.

In addition to providing information regarding archaeological sites protected by the *Heritage Conservation Act* (HCA), potential cultural sites of value to the Sto:lo Nation were also identified by reference to the *Sto:lo Heritage Policy* (2003). These sites have been included in the AOA. The AOA is based on a desk-top review of available information and a preliminary site

[11] On page 1 of Appendix H, this area is described as located at 176A Whatcom Road, Abbotsford.

reconnaissance via vehicle to view the general landscape and terrain. No attempt was made to directly access archaeological sites as they are located on private property. The preliminary AOA concludes that there is the potential for archaeological or other cultural heritage resources to be found within the Project area; therefore, a detailed AIA is required once BCUC approval of this Application is received and prior to construction of the Project.

7.2.1 Archaeological Overview Assessment

The results of the work undertaken by the SRRMC are outlined in the "Archaeological Overview Assessment of Proposed Upgrades to the Huntingdon Control Station in Abbotsford, BC" report, a copy of which is attached as Appendix H. This report summarizes (at pages 10-11) that:

- Three archaeological sites, as defined by the HCA, are located within the study area; two of which are within 500m of the Project.
- Two culturally important sites, as defined by the Sto:lo Heritage Policy, are also located within the study area; both within 500m of the Project (a trail and a gathering area).

Based on the preliminary AOA, a permit will be required under the Heritage Conservation Act in order to undertake a detailed AIA.

7.2.2 Further Plans

Potential archaeological and cultural impacts associated with the Project will be further assessed during the AIA, which will be undertaken once approval of this Application from the BCUC is obtained and prior to construction commencement. A surface survey and a subsurface testing program will be undertaken within the Project area, as part of the AIA, to identify sensitive areas. The AIA will provide a detailed assessment to allow for development of site specific mitigation strategies to offset any potential impacts associated with the Project. All archaeological permits will be obtained during the detailed engineering phase of the Project.

Detailed archaeological specifications will be prepared as part of the Project tendering process to ensure the contractor(s) are aware of the Project's archaeological requirements. As mentioned above, a Project specific Environmental Management Plan, including protection of archaeological and cultural resources, will be developed by the successful contractor(s) prior to commencement of the Project. If required, archaeological monitoring will be undertaken during all sensitive aspects of the work program and the designated archaeological monitor will have "stop work authority" in the event that works underway have the potential to impact archaeological or cultural resources.

7.3 *SOCIO-ECONOMIC ASSESSMENT*

The economic impact of the Project to the regional area where the Project is to be constructed is expected to be limited. The construction contract and the major materials will likely be procured from out-of-province sources since these resources are not readily available in B.C.

Most of the professional services, such as geotechnical engineering and environmental assessments have been or will be provided by personnel based in B.C., with some provided by personnel in the local area.

Expenditures by the small work force will be of some benefit to local businesses. The Project will have some minor impact on the operations of two farms and owners in the area. Preliminary discussions with property owners and lessees have included the use of temporary working space, noise control, vehicular access, ROW restoration, and compensation for business or crop losses.

The City of Abbotsford has been informed of the Project and will be consulted on pertinent issues as the Project proceeds.

7.4 CONCLUSION

Any potential environmental, archaeological, or socio-economic impacts associated with the Project are expected to be minimal and can be mitigated through the implementation of standard best management practices and mitigation measures. FEI will implement all applicable best management practices as determined appropriate by a Qualified Environmental Professional or a Professional Archaeologist.

8. PUBLIC CONSULTATION

Public consultation and communication are integral components of FEI's project development process. The details of the consultation plan and activities that have occurred to date with respect to the Project are provided in this section, which is organized as follows:

- An overview of the public consultation plan;
- A list of Project stakeholders;
- A summary of consultation activities to date and input received; and
- On-going consultation plans.

FEI has also engaged First Nations communities and leadership in the area. This is discussed separately in Section 9.

8.1 CONSULTATION PLAN

As discussed above, the Project is located in the south side of the City of Abbotsford and will be within the 100m radius of the existing Huntingdon Station. But the Project infrastructure will impact only the land directly west and north of the Station. The area impacted is rural, and most of the Station's neighbours are farmers.

The Company's comprehensive consultation plan identifies key stakeholders, including the local farming community and municipal authorities on a geographic basis. The focus of the Company's public consultation plan is to ensure that land owners and community stakeholders are informed about the Project, have access to Project information, and are encouraged to provide input that may be factored into the decision-making process. The Company's consultation responsibilities and coordination are shared between FEI's Community Relations and Lands departments.

8.2 PROJECT STAKEHOLDERS OTHER THAN FIRST NATIONS

FEI has identified, engaged and solicited feedback from community stakeholders and affected parties near the Project. They have also been provided updated information. They include:

- Two landowners (farmers) adjacent to the proposed bypass;
- City of Abbotsford senior staff (City Manager, Director of Engineering);
- Mayor of Abbotsford;
- Spectra;
- Williams;

- Kinder Morgan; and
- Neighbours adjacent to the Huntingdon Station.

8.3 SUMMARY OF CONSULTATIVE ACTIVITIES AND INPUT RECEIVED AND ADDRESSED

During the initial, preliminary stage of developing solutions to address the single-point-of-failure concern discussed in Section 3 of this Application, FEI's representatives from Community Relations and the Lands departments initially contacted a larger group of neighbouring farmers, as this group could have been affected by the external bypass route options initially considered by FEI. Subsequently, updated information on the Project was provided to this group of farmers, informing them that the Project as currently proposed in the Application would have lesser impact on their farming land.

FEI's representatives have contacted the two farmers who will be directly affected by the Project. Personal letters were mailed to the farmers on November 16, 2012, inviting them to contact us to set up a meeting.

One of the two farmers phoned FEI's Lands department when he received a letter about another FEI project in the area. He was informed that with respect to this Project, FEI would need to work with him to acquire some ROW on his property. He said he would look forward to it. FEI is planning to meet with the landowner later this year.

Letters were also mailed to the other neighbouring farmers on January 21, 2013, informing them of the Project scope, and inviting contact. One of the landowners contacted FEI to inquire about the Project, such as what the equipment would look like and where on the new ROW land it would be located. FEI representatives will provide further information about the exact location and appearance of the new infrastructure when it becomes available. No other feedback was received.

FEI also met and is working with Spectra, who have been cooperative. The Project scope, permit process and new ROW requirements were discussed. FEI also met and is working with Williams, who have also been cooperative. FEI specifically discussed the gas operations support required from Spectra and Williams during the bypass tie-in procedure.

Municipal stakeholders, specifically the Mayor of Abbotsford and the City of Abbotsford's City Manager and Director of Engineering, have also been informed and consulted.

To date, no major issues have been raised by the parties who have been contacted or have received information.

The following table provides a summary of the activities that have completed and will continue throughout the Project. FEI is committed to continuing the consultation with stakeholders if the Project is approved and will continue to work with stakeholders and affected parties to ensure that they are involved and engaged as the Project progresses.

Table 8-1: Summary of Public Consultation Activities

Activity	Completed By
Informational meetings regarding the Project held with key stakeholders	November 2012
Presentation made to the City of Abbotsford	November 2012
Key property owners and other stakeholders will receive regular Project updates and reports	As needed basis
FEI will continue to work directly with stakeholders	Throughout the Project

Copies of the above mentioned letters are included in Appendix I1. The consultation log is attached as Appendix I2.

8.4 CONCLUSION – SUFFICIENCY OF THE CONSULTATION PROCESS

FEI believes that the communication plan and the public consultation activities to the time of filing have been appropriate with respect to the Project given the limited geographical scope of the Project, and have met the expectations of landowners and interested stakeholders. In particular, initial communication with farmers who will be more directly affected by the Project and with the City of Abbotsford has been both useful and productive. FEI will continue to consult with property owners regarding access and accommodation issues, the Project schedule, temporary construction space, ROW, and public safety.

It is FEI's intent that good relationships with property owners and other stakeholders will be maintained through all phases of the Project. FEI will make every attempt to minimize Project impact, maintain the Project schedule and preserve our good relationships with stakeholders.

9. FIRST NATIONS CONSULTATION

9.1 INTRODUCTION

This section describes how First Nations have been engaged in the Project, especially in the early, preliminary stage of considering a solution to the single-point-of-failure concern discussed in Section 3. The Project, the Company's preferred option and currently proposed bypass route around the Huntingdon Station, will be completely on private farm land; thus, the potential impact of the Project on First Nations interests and title will be limited. The First Nations have been informed of the current scope of the Project. FEI is committed to maintaining communications with First Nations as the Project progresses and as necessary.

Below, FEI will first outline the Company's First Nation engagement approach and identification of potentially impacted First Nations, followed by a summary of its early activities of First Nation engagement during the earlier, preliminary stage of considering alternatives, information on engagement activities with respect to the proposed Project, and a discussion of the Company's plan going forward of First Nations engagement with respect to the Project. The evidence of First Nation engagement is current to August 30, 2013.

9.2 ENGAGEMENT APPROACH

The primary objectives of FEI's engagement efforts for the Project are to ensure that First Nations whose Aboriginal interests may be potentially affected by the Project are identified and are provided updated information on the nature and progress of the Project. FEI also tries to mitigate or avoid any potential adverse impact on First Nations' interests during the Project development and construction where appropriate.

As discussed above, the bypass alignment of the Project will be located within 100m of the existing Huntingdon Station and will be located in a new right-of-way. The Project will be completely developed on farmland in private ownership. Thus, FEI believes that this Project has limited potential impact on asserted Aboriginal rights and title.

First Nations with any potential interests in the general area of the Project have been identified, have been engaged since the early, preliminary stage when the Company was considering alternative bypass alignments, have been informed of the scope of the current proposed Project, and will continue to be engaged where appropriate during the Project construction.

9.3 IDENTIFICATION OF FIRST NATIONS WHICH MAY HAVE AN INTEREST

As outlined in the previous sections, the Project lies within the city limit of Abbotsford, British Columbia, located adjacent to the Canada/US border, approximately 3 km east of the Huntingdon/Sumas border crossing south of Abbotsford. More generally, the Project is located within the Fraser Valley region of BC, which is the area used to determine the potential impact of the Project upon asserted Aboriginal rights and title.

FEI reviewed maps of Statement of Intent areas submitted by First Nations in the British Columbia Treaty Commission process, as well as traditional territory maps made available by First Nations not presently participating in the Treaty process, attached as Map 1 in Appendix J5. FEI also relied on its past experience/knowledge gained in consulting with First Nations on other projects to identify First Nations who may potentially have an interest in the Project.

A review of this information indicated that the Project:

1. Is entirely located on developed farmland in private ownership;
2. Lies within the asserted traditional territory of the Sto:lo people (collectively);
3. Lies within an area in which member bands of the Sto:lo Nation Tribal Council, Sto:lo Tribal Council and other unaffiliated Sto:lo bands, namely the Kwikwetlem First Nation, may have interests; and
4. Does not cross or otherwise occupy any Indian Reserve lands.

The following subsections describe the identification of the First Nations who may have a potential interest in the Project area, grouped by their Council affiliation, as well as the unaffiliated Kwikwetlem First Nation.

9.3.1 Sto:lo Nation Tribal Council

The general area of the Project location is within the asserted traditional territory of the Sto:lo people, some of whom are represented by one of the two Sto:lo Tribal Councils, the Sto:lo Nation Tribal Council and the Sto:lo Tribal Council, although not all Sto:lo bands belong to either Council. The Sto:lo Nation Tribal Council represents the following eleven member Sto:lo First Nations: Aitchelitz, Leq'a:mel, Matsqui, Popkum, Shxwha:y Village, Skawahlook, Skowkale, Squiala, Sumas, Tzeachten, and Yakweakwioose. The closest Indian Reserve to the Project is that of a Sto:lo Nation Tribal Council member band, Sumas Indian Reserve No. 6 of the Sumas First Nation, located west of Sumas Lake at the base of Sumas Mountain, approximately 3.8km from the Project area. Please see Map 2 in Appendix J5, obtained from the City of Abbotsford's website.

Of the eleven Sto:lo First Nations represented by the Sto:lo Nation Tribal Council, seven have chosen to partake in the British Columbia Treaty Process, namely: Aitchelitz, Leq'a:mel, Popkum, Skawahlook, Skowkale, Tzeachten, and Yakweakwioose. The original Statement of Intent Map was submitted in 1995 with twenty-one Sto:lo First Nations, and has since been amended and accepted by the BC Treaty Commission in 2006 to account for the changes in the internal re-organization of the Sto:lo Nation forming the two separate Tribal Councils, as mentioned above. Please see Map 3 in Appendix J5 representing the present Statement of Intent Map on the BC Treaty Commission website. The general area of the Project potentially falls within the Statement of Intent Area of the Sto:lo Nation Tribal Council bands participating in the BC treaty process collectively.

9.3.2 Sto:lo Tribal Council

The following eight Sto:lo First Nations are represented by the Sto:lo Tribal Council: Seabird Island, Scowlitz, Soowahlie, Kwaw'kwaw'Apilt, Kwantlen, Shxw'ow'hamel, Chawathil, and Cheam. Neither the Sto:lo Tribal Council nor its eight member bands are participating in the BC treaty process at this time and as such there is no present Statement of Intent Map. However, the Sto:lo Tribal Council confirmed by phone call that the Sto:lo Nation Tribal Council's Statement of Intent Map presently available on the BC Treaty Commission website includes the asserted traditional territory of the Sto:lo Tribal Council member bands collectively, and may be used to identify the area of the Sto:lo Tribal Council's interest. The general area where the Project will be is thereby located within the collective boundary of the Sto:lo Tribal Council's asserted traditional territory.

9.3.3 Kwikwetlem First Nation

As the general area of the Project is located within the asserted traditional territory of the Sto:lo people collectively, the Kwikwetlem First Nation was identified as having potential interests in the Project area, being the closest unaffiliated Sto:lo First Nation. The Kwikwetlem First Nation is not participating in the Treaty process at this time and therefore no Statement of Intent Map is presently available. On March 31, 2011, Charles Littledale of Land Solutions Consultants Ltd. requested a map of the asserted traditional territory from the Kwikwetlem First Nation on behalf of FEI; however, the Kwikwetlem First Nation confirmed that this information is not yet public. A map of the Kwikwetlem First Nation's asserted traditional territory is therefore not available and not included in this Application.

FEI has consulted publications available on the internet, such as *The South Fraser Perimeter Road Profile of First Nations* prepared for the Ministry of Transportation in September 2006.[12] This publication describes the Kwikwetlem First Nation's asserted traditional territory as encompassing the mouth of the Coquitlam River and Port Coquitlam. This described area is not within the Project area, but FEI will continue to provide information to the Kwikwetlem First Nation should it have any interests or concerns regarding the Project.

9.4 ENGAGEMENT ACTIVITIES

The Company has engaged more extensively the First Nations that may be potentially impacted in the early, preliminary stage when the Company was considering various bypass alignments in the general area of the Huntingdon Station. When the proposed Project, with a route immediately around the Station and the construction to be completely on private developed farm land, is selected by the Company as the preferred option, the First Nations were accordingly informed. The following description offers a more detailed description of the Company's engagement with the First Nations identified above. Since the proposed Project will be on

[12] http://a100.gov.bc.ca/appsdata/epic/documents/p196/d22441/1160695849030_8472cae2a0154601bf12ab205e7b4d0f.pdf

private land, the following discussion is focused on engagement activities more pertinent to the proposed Project.

9.4.1 Sto:lo Nation Tribal Council

The Sto:lo Nation Tribal Council, as well as each of the eleven member First Nations individually, were first made aware of the potential bypass options by a formal introductory letter dated February 7, 2011. The letter describes the nature of the options, the rationale, permits and approvals required, and maps of the potential area. The letter also confirms that additional details will be forwarded once a final route is chosen. Copies of this letter sent to each of the eleven member First Nations - Aitchelitz, Leq'a:mel, Matsqui, Popkum, Shxwha:y Village, Skawahlook, Skowkale, Squiala, Sumas, Tzeachten, and Yakweakwioose - as well as the Sto:lo Nation Tribal Council, are included in Appendix J6.

Following a telephone conversation on January 13, 2011 with Jessica Morrison, Referrals Coordinator for the Sto:lo Nation Research and Resource Management Centre (SRRMC), FEI engaged the SRRMC to conduct the archaeological overview assessment field work. As of January 18, 2011, the SRRMC has been registered in FEI's Vendor Database as a potential supplier of future services to FEI. Although involving the SRRMC may not be solely for engagement purposes, FEI has retained SRRMC to ensure that archaeological findings of particular importance to the Sto:lo people are discovered, documented, and handled appropriately, thereby enabling the Sto:lo people to preserve artifacts and areas of special cultural meaning. The Sto:lo people, as represented by the Sto:lo Nation Tribal Council and Sto:lo Tribal Council, have agreed to the engagement of the SRRMC as representing their archaeological interests. The archaeological findings to date are discussed in Section 7. On-going archaeological monitoring will be conducted by the SRRMC as identified in Section 7.

On June 13, 2013, FEI provided an update to Sto: Lo Nation Tribal Council regarding the status of the proposed Project and explaining that FEI has chosen an option that will only have impact to the properties of two private land owners and no impact to the Sumas River (see Appendix J6).

9.4.2 Sto:lo Tribal Council

The Sto:lo Tribal Council, as well as each of the Sto:lo Tribal Council's eight member bands individually, were first made aware of the potential bypass options by a formal introductory letter dated February 7, 2011. The letter describes the nature of the options, the rationale, permits and approvals required, and maps of the potential area. The letter also provides contact information for FEI's Aboriginal Initiatives Manager and encourages contact should the Sto:lo Tribal Council or any of the eight member bands wish to bring any issues forward. The letter also confirms that additional details will be forwarded once a final route is chosen. Copies of this letter sent to each of the eight member First Nations - Seabird Island, Scowlitz, Soowahlie, Kwaw'kwaw'Apilt, Kwantlen, Shxw'ow'hamel, Chawathil, and Cheam - as well as the Sto:lo Tribal Council, are included in Appendix J6.

On February 22, 2011, FEI's Aboriginal Initiatives Manager met with Frank Andrew, Lands and Resource Management Coordinator for the Sto:lo Tribal Council, and Bill Andrew, Staff Member of the Sto:lo Tribal Council, to follow up regarding the February 7, 2011 letter and to establish whether there were any questions or concerns with respect to the options. Frank Andrew advised that there were no concerns at this time, but that the options will be reviewed in greater detail by the Sto:lo Tribal Council, and should any concerns arise, FEI's Aboriginal Initiatives Manager will be notified. Frank Andrew also confirmed that the Sto:lo Tribal Council had no concerns with FEI's use of the SRRMC to identify areas of Sto:lo archaeological interest in the area, and confirmed that the Sto:lo Tribal Council also relies on the expertise of the SRRMC in other projects.

Although the Project is located on private farmland, FEI has continued, and will continue, to make efforts to ensure that the Sto:lo Tribal Council's and Sumas First Nation's concerns are identified and addressed. On June 13, 2013, FEI provided an update to Sto: Lo Tribal Council regarding the status of the proposed Project and explaining that FEI has chosen an option that will only have impact to the properties of two private land owners and no impact to the Sumas River (see Appendix J6). As of August 30, 2013, no concerns have been raised by the Sumas First Nation or the Sto:lo Tribal Council regarding the Project.

9.4.3 Kwikwetlem First Nation

The Kwikwetlem First Nation was first made aware of a potential project by a formal introductory letter dated February 7, 2011. The letter describes the nature of the options, the rationale, permits and approvals required, and maps of the area. The letter also provides contact information for the FEI Aboriginal Initiatives Manager and encourages contact and states FEI's availability should the Kwikwetlem First Nation wish to bring any issues forward. The letter also confirms that additional details will be forwarded once a final route is chosen. A copy of this letter is included in Appendix J7. On June 13, 2013, FEI provided an update to the Kwikwetlem First Nation regarding the status of the proposed Project and explaining that FEI has chosen an option that will only have impact to the properties of two private land owners and no impact to the Sumas River (see Appendix J7). As of August 30, 2013, no response from the Kwikwetlem First Nation has been received.

9.5 *ONGOING AND FUTURE FIRST NATIONS CONSULTATION*

9.5.1 OGC Process Regarding First Nations Consultation

The OGC is the Crown agency responsible for First Nations consultation, and, if necessary, accommodation of First Nations' interests. The OGC's First Nations consultation process, as documented in its Pipeline Permit Application Manual, Pipeline Operations Manual, and Facilities Application and Operations Manual, is attached as Appendices J1, J2 and J3 respectively.

Under the OGC process, FEI as the Project proponent is responsible for conducting preliminary discussions with the identified First Nations, and for providing documentation such as Project descriptions, maps and drawings to First Nations to facilitate the OGC process. FEI's engagement activities that have taken place since the early, preliminary stage of Project consideration as detailed in Appendix J4 will be forwarded to the OGC for its consideration when FEI files its application with the OGC in January 2014.

FEI's continued consultation efforts will be in concert with the OGC's efforts as outlined in the OGC's manual. FEI will also continue to:

- Provide timely information and updates regarding the Project and the regulatory process where appropriate;
- Provide timely and comprehensive responses to any questions, concerns or requests for information regarding the Project;
- Engage in discussions to further identify any potential impacts of the Project on aboriginal interests, and seek to avoid, mitigate or accommodate any potential impacts if necessary; and
- Continue to encourage feedback from the Sto:lo Nation Tribal Council, Sto:lo Tribal Council and their member First Nations regarding FEI's plans for future consultation.

FEI will continue to work with the SRRMC to ensure that the Project's impact to the cultural values of the Sto:lo people are mitigated or avoided. FEI has developed positive working relationships with the Sto:lo Nation Tribal Council, Sto:lo Tribal Council and Kwikwetlem First Nation through past Projects, and intends to continue to enhance these relationships.

9.6 *SUFFICIENCY OF FEI'S ENGAGEMENT PROCESS WITH FIRST NATIONS TO DATE*

As the Project is confined to developed farmland in private ownership, it is unlikely that any Aboriginal rights and title will be impacted.

The potential of the Project to impact First Nations interests are confined to impacts on archaeological sites (if any) from construction activities associated with the bypass. FEI has engaged the SRRMC to conduct the archaeological assessments, and will work together with the SRRMC to mitigate and avoid to the extent possible all cultural heritage impacts identified, and as part of this mitigation, has agreed to have a qualified archaeologist monitor all ground disturbing activities. All ground disturbing activities during construction will be monitored by a qualified archaeologist. See Section 7 and Appendix H for the full Archaeological Overview Assessment Report and discussion.

The First Nations with any potential interests in the general area of the Project have been identified as above and have been provided, and will be continued to be provided, with information on the Project. No significant concerns, with the exception of the mitigation and avoidance of archaeological and heritage sites, have been raised as of August 30, 2013. Any further concerns will be addressed by the Company as necessary.

Accordingly, FEI believes that the level of First Nation engagement undertaken at this stage of the Project is appropriate. It is FEI's intention and regular practise to continue liaising with First Nations as the Project progresses. Additionally, FEI's continued consultation efforts will be in concert with the OGC's efforts as part of the OGC application process.

10. CONCLUSION

The Huntingdon Station is the sole gas supply source for 600,000 customers downstream of the Station, is a single-of-point-failure facility, and is a high risk facility largely because of the consequence its failure may cause. FEI has engaged a third party expert to evaluate the risk, and the expert confirms the high risk of the Station.

The Company has considered various options to reduce the risk, and is proposing the Project because it will provide the necessary redundancy to the Station and remove the Station as a single point of failure, which, in turn, will significantly reduce the risk of loss of gas supplies to approximately 600,000 customers in the event that one of the critical components within the Station fails that leads to the shut-down of the Station.

Additionally, by building the bypass, the Company will have the ability to maintain and repair (if necessary) of any of the non-redundant components or sections of piping within the Station without the need to shutting down the entire Station. This will increase the reliability of the Station.

The Company has engaged the public since the early, preliminary stage of finding solutions for the single-point-of-failure concern, and will continue to do so during various phases of the Project. The Project will be constructed on privately owned farm land, with limited impact to First Nations, but the Company has engaged, and will continue to engage where appropriate, the identified First Nations.

The Company believes that the Project is in the public interest and should be approved.

Appendix A

ESSO LONGFORD GAS PLANT IMPACTS

Appendix 1: The Case Studies

The Longford Gas Plant Accident

On Friday, September 25th, 1998, at about 12.26pm, a vessel ruptured at one of three gas plants operated by Esso at Longford, 20 kilometers from Sale, to process product flowing from wells in Bass Strait. The rupture led to the release of vapours and liquid. Several major explosions and fires followed. Two Esso employees, Peter Bubeck Wilson and John Francis Lowery, were killed. Eight others at the site were injured. Fires and leaks continued at the plant until the last fires were extinguished at 5.30pm on Sunday, September 27th (Royal Commission 1999; EMA 2004).

As a result of the fires and explosions, all three gas plants were shut down. This led to an immediate cessation of processing of natural gas, liquid petroleum gas and crude oil. Supplies to all domestic, commercial and industrial consumers in metropolitan Melbourne and in several country areas were rapidly curtailed. Within 36 hours, all Victorian gas consumers had been instructed to turn off gas supply lines to homes and commercial premises. Gas company and emergency service personnel were mobilized to ensure the shut down was implemented.

With the Longford facility supplying 98 per cent of the state's gas needs, most Victorian gas consumers were left without gas for 19 days. A restart of the gas supply was commenced on Friday, October 2nd using the two undamaged processing plants, with the first gas sales to industry commencing two days later. (Royal Commission 1999) Restrictions on the use of gas for domestic heating were finally lifted on Tuesday October 13th and by 14th October the interruption to gas supplies was effectively over. The damaged gas plant was brought back on line in mid-1999.

The Longford accident demonstrated the vulnerability of the state's power infrastructure to accident, let alone intentional disruption through causes such as terrorist attack. It also opened a political debate as to whether privatization of formerly state-run utilities had been the root cause of the failure of supply (Hopkins 2001).

A royal commission of inquiry, headed by retired High Court judge Sir Daryl Dawson, was charged with investigating the causes of the accident and the failure of the gas supply, but not the social or economic consequences of the event. The commission pointed to a lack of operator and supervisor knowledge of how to deal with the shutdowns that precipitated the failure of the plant as a key cause of the accident. This was due to inadequate training on the part of Esso. It found insufficient evidence of a reduction in maintenance or reduced supervision on the part of Esso to form a causal link (Royal Commission 1999; Nichol 2001).

The Royal Commission noted: "It is unfortunate after a successful restart of the Longford facilities, the full restoration of gas supplies to consumers, especially domestic consumers, took another five days" (Royal Commission 1999:159). However, correspondence between Esso and the supply companies noted that the producer was unable to guarantee that there would not be production problems once the processors were restarted.

Impacts

The Longford gas plant accident and subsequent loss of supply is considered to have been one of Victoria's worst disasters, especially in terms of economic impact. In the short-term, there were multiple consequences with potentially serious public health implications. The event was largely unanticipated and unplanned for as a wide area emergency.

Gas is the primary energy source for 80 per cent of Victorian households, 50 per cent of commercial enterprises and 25 per cent of industry (Hopkins 2001). It is estimated that 1.4 million households and 89,000 businesses were affected. In addition to directly affecting the daily lives of some 4 million Victorians for almost three weeks, the estimated cost of the accident to the Victorian economy was put at $1.3 billion (Royal Commission 1999, International Petroleum Encyclopedia 1999)

The gas shutdown coincided with the AFL Grand Final and extended over a period of cool to mild weather. It also coincided with the final week of the 1998 federal election campaign. These concurrences ironically helped to cast the event as more of an inconvenience to many people than an economic or social crisis.

Sectors particularly affected included the car industry, plastics production, food and drink manufacturers and the hospitality sector. Tens of thousands of workers were temporarily stood down (Campbell 1999). Within days, several manufacturing industries were forced to shut down. The brewing and chemical manufacturing industries were affected, along with vehicle makers (there were 7000 layoffs in the vehicle industry alone) and building supplies manufacturers.

The Commonwealth Budget papers reveal that the federal government lost some $300 million in resource taxes. (Yates 2003) The disaster spawned the largest class action in Australian legal history, with 10,000 litigants signed on. The Victorian Supreme Court later dismissed the action for purely economic loss, although in November 2004 it did allow for a $32 million compensation package for businesses that suffered material damage. Meanwhile BHP Billiton, a joint venture partner, commenced a damages action against Esso in December 2004 for damages arising from the accident.

Immediate impacts included temporarily curtailed production of some basic consumables including bread, milk and other dairy products. Supply lines of basic consumables were quickly established from interstate sources to overcome local shortfalls.

There were temporary suspensions of cremations and also of elective surgery at some hospitals. Many tourist facilities such as hotels were unable to provide hot water for patrons. Shortages of bottled LP gas occurred within days, with rationing on an odds-and-evens systems being implemented. Retail supplies of small domestic electrical cooking appliances were quickly exhausted (Age 28.9.1998).

Heavy fines were introduced for domestic and industrial users caught flouting the gas shutdown, with penalties of up to $10,000 for individuals and $1 million for companies. There were subsequently nine prosecutions by the Office of Gas Safety (OGS) for such infringements. (OGS 2004)

Public health implications

In general, impacts upon emergency medical care were minimal. Hospitals were exempt from the gas shutdown from the outset. Aged-care facilities, supported residential services and disability accommodation services were also exempted within a few days of the accident. Special provision was also made to support sufferers of incontinence.

Among the measures implemented immediately by the Department of Human Services (DHS) was the state’s Medical Displan, partly aimed at ensuring continued resourcing of emergency medical services. The Australian

Military Forces were mobilized to provide assistance with specialist medical equipment. The department also activated its Disaster Support and Recovery Plan. When the extent to which the gas shutdown would affect domestic and industry consumers became clear, the DHS Public Health Emergency Plan was also activated.

More broadly, the crisis posed dangers to the community from:

- explosions and burns through inappropriate connection LP gas to natural gas equipment
- increased risk of burns from the use of unfamiliar cooking equipment
- increased risk of fire from improper use of portable cooking equipment
- children at greater risk of being scalded or burned due to use of electric kettles for baths
- inadequate or inappropriate cooking methods rendering food unfit for consumption
- maintaining a healthy diet without normal cooking facilities
- personal hygiene issues related to lack of hot water for washing
- lack of hot water for washing dishes
- lack of clothes washing facilities (especially baby nappies)
- stress related to the gas emergency

At least one serious incident, involving minor injuries, was recorded when an explosion destroyed the front of a suburban restaurant. This accident was attributed to a leaking gas cylinder.

Communications

The extent of the emergency demanded a multi-agency, whole of government response. In practical terms, the immediate impacts of the explosion and fires were dealt with by the Country Fire Authority. Broader community impacts became the responsibility of the VENCorp (Victoria's gas transmission agency), the Department of Human Services and the OGS. The State Emergency Service, the CFA, the Metropolitan Fire Brigade and WorkCover also played a lesser role in issuing safety warnings and in the physical shutdown of the gas supply to consumers.

The key vehicles for the transmission of risk messages were:

- media (including television radio, print)
- telephone hotlines
- advertising
- Internet (web sites)
- press releases
- information sheets, brochures
- fax stream
- mailouts

Communications flowing from this event tended to be generic in nature, using broad distribution modes such as the media and advertising. Initial communications in relation to the safe shutting down of gas meters, improper use of LP gas equipment and issues such as fire safety were undertaken by VENCorp, the OGS and the fire brigades. This advice was distributed via the news media and through specific advertisements. In addition, an LPG Safety hotline was established by the fire services to deal with industry queries about the use of liquid petroleum gas. Service personnel involved in the shutdown were able to deliver informal warnings about the dangers of attempting to reconnect to the gas system once individual premises had been shut off. (Age 28.9.1998, 29.9.1998, 3.10.1998)

DHS established a 24-hour emergency operations centre to manage its own response and provide advice to government. A public information centre was also established to provide public health advice. The DHS established a 1800 (free call) “Home Health Support” telephone hotline within 36 hours to deal with public enquiries. The call centre was staffed by health professionals and administrative staff and provided advice on health and related matters, referrals to support agencies and approvals for exemptions from gas restrictions. VENCorp set up a recorded information line, along with separate hotlines, including multi-lingual and hearing impaired services, to deal with gas-related enquiries.

The Public Health and Development Division of DHS along, with the gas companies, was active in disseminating information through the electronic and print media. DHS also produced 23 fact sheets for distribution to the public dealing with a range of health-related issues, such as safe use of water heating appliances and food preparation. The Longford event also represented an early use of Internet technology for the dissemination of public health warnings.

Some of the DHS response was channeled through local government in accordance with emergency management procedures. Several local councils also undertook activities such as providing food vouchers, electric barbeques, showering facilities and visiting isolated elderly residents to ensure to their welfare.

Outcomes and discussion

General

The Longford gas accident and its aftermath are considered to have significantly affected planning for future broad-scale emergencies in Victoria, as well as providing salutary lessons for other jurisdictions. In particular, the need for greater inter-agency co-ordination and a whole-of-government approach were highlighted by the accident and the flow-on crisis.

One of the outcomes was an attempt by the Victorian Government in 2001 to amend the law to introduce tougher penalties for workplace deaths by introducing an offence of “corporate manslaughter” into the Victorian criminal code. Legislation to this end was blocked in the Legislative Council. A subsequent review of the Occupational Health and Safety Act 1985 did not address the issue of the crime of industrial manslaughter and it would appear that the Bracks Government has abandoned its introduction, despite now having control of both houses of parliament (Haines 2004).

In emergency management terms, Longford highlighted the need for closer co-ordination of response and particularly recovery issues including communication to the community. Information flow to the community, especially during the first 24-hours was largely uncoordinated and left to the media.

Communications

The Longford emergency led to a major DHS review of emergency management procedures. A key outcome of this process was the formulation of the DHS State Level plan for the management of emergencies and other critical events. As part of those arrangements, an Information and Communication Strategic Plan was developed.

Key elements of the communications plan include recognition of a central distribution point for information dissemination and a greater recognition of the cultural and linguistic diversity of the Victorian community (DHS 1999b). Risk communications developed during the gas crisis were adapted for future emergencies. The plan also provides for the establishment of community an industrial call centres.

The Information and Communication Strategic Plan notes that “the best possible information and communication system … is one that quickly alerts the key stakeholders and those in imminent danger prior to an event actually occurring”, while noting that this will in most cases not be possible.

Despite the extent of the risk communications involved in the aftermath of the Longford explosions, there has been remarkably little analysis of this aspect of the event. The focus of the Royal Commission and of most emergency service analyses of the event were on issues such as response, engineering and management failures. In the case of the Royal Commission, the terms of reference were so narrowly framed as to limit investigation of wider issues beyond the accident itself and the immediate failure of gas supply.

There has been, however, scope to test the procedures in the preparations for Y2K contingencies at the end of 1999 and also subsequent disaster events

References

The Age (various dates)

The Herald-Sun (various dates)

The Financial Review (various dates)

Campbell, R. (1999), ‘Controlling crisis chaos’, Australian Journal of Emergency Management, Vol.14 No.3, Spring, pp.51-54.

Department of Human Services (1999), Annual Report 1998-99, Victorian Government, Melbourne.

Department of Human Services (1999a) State Level Plan for the management of emergencies and critical events, Melbourne.

Department of Human Services (1999b) State Level Plan: Information and Communication Strategic Plan, Melbourne.

Emergency Management Australia (2004) EMA disasters database (http://www.ema.gov.au/ema/emaDisasters.nsf)

Haines, K. et al (2004), Workplace death and serious injury: a snapshot of legislative developments in Australia and overseas, Research Brief No.7 2004-05, Parliament of Australia, Canberra, 29 November 2004.

Hopkins, A. (2000), “Lessons from Longford: the Esso gas plant explosion, CCH, Sydney”.

International Petroleum Encyclopedia (1999) http://ogj.pennnet.com/

Nichol, J (2001) “Have Australia’s major hazard facilities learnt from the Longford disaster?” Institution of Engineers Australia, Canberra.

Office of Gas Safety (website: www.ogs.vic.gov.au)

Royal Commission (1999) The Esso Longford gas plant accident: Report of the Longford Royal Commission, Parliament of Victoria, Melbourne.

State Coroner Victoria (2002) Inquest into the deaths of Peter Brubeck Wilson and John Francis Lowery and the fire at Longford Gas Plant Number 1, Coroner's Case Number 2907/98, Melbourne.

Yates, A. (2003) Will industry’s investment in protecting its critical infrastructure be sufficient? SafeguardingAustralia.org.au, Institution of Engineers Australia, October.

Appendix B

GHD PHASE 1 RISK ASSESSMENT REPORT

FILED CONFIDENTIALLY

Appendix C1

DRAS QUANTITATIVE RISK ASSESSMENT MAR 30, 2011

FILED CONFIDENTIALLY

Appendix C2

DRAS CONSIDERATION OF IN-STATION BYPASS REPORT
JULY 15, 2011

FILED CONFIDENTIALLY

Appendix C3

DRAS CONSIDERATION OF IN-STATION BYPASS
REVISED REPORT JULY 18, 2013

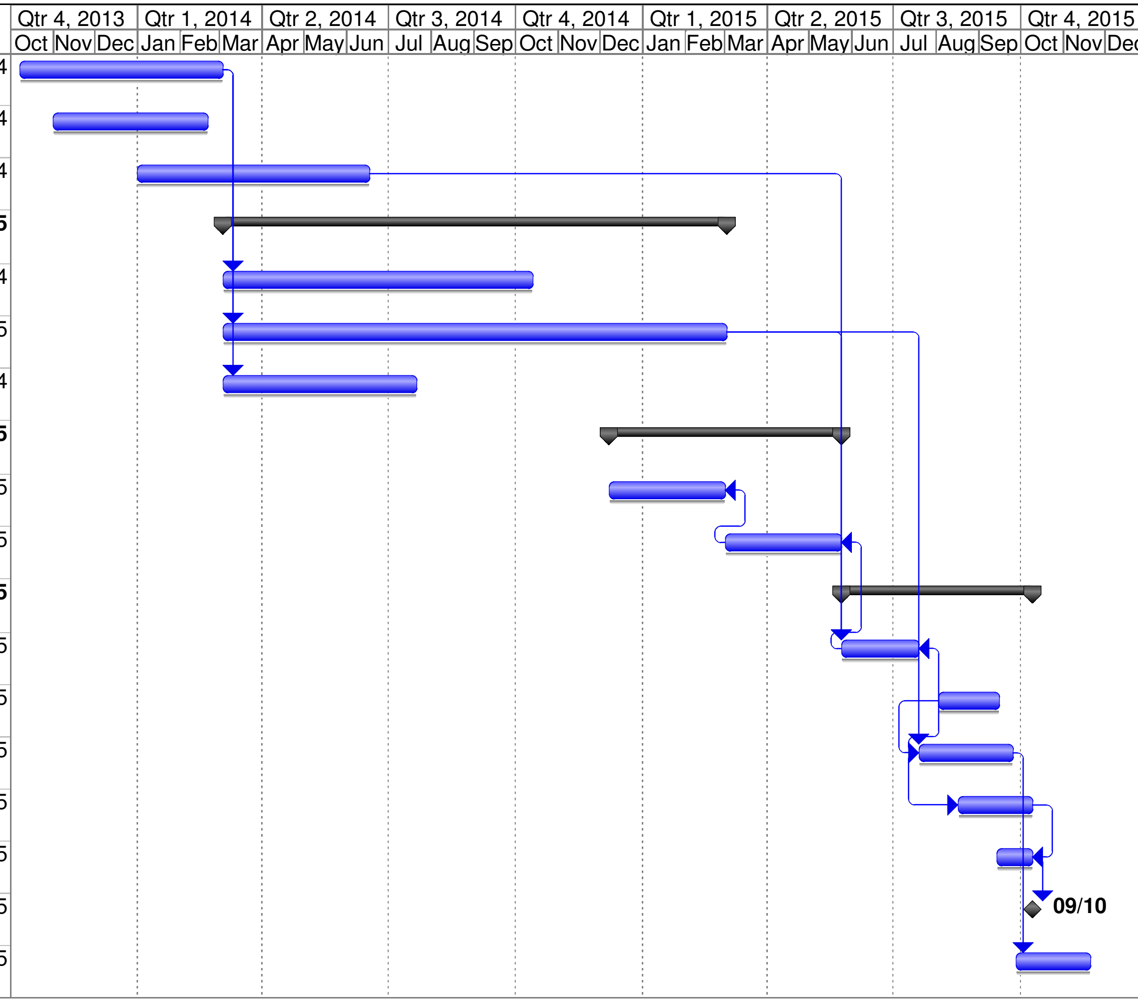
FILED CONFIDENTIALLY

Appendix D

DETAILED PROJECT SCHEDULE

FORTISBC ENERGY INC.
HUNTINGDON STATION BYPASS CPCN APPLICATION
PROJECT SCHEDULE

ID	Task Name	Duration	Start	Finish
1	BCUC Application	21 wks	Tue 08/10/13	Mon 03/03/14
2	Finalize Design	4 mons	Fri 01/11/13	Thu 20/02/14
3	OGC Application	6 mons	Wed 01/01/14	Tue 17/06/14
4	**Major Materials**	**260 days**	**Tue 04/03/14**	**Mon 02/03/15**
5	pipe	8 mons	Tue 04/03/14	Mon 13/10/14
6	valves	52 wks	Tue 04/03/14	Mon 02/03/15
7	other materials	5 mons	Tue 04/03/14	Mon 21/07/14
8	**Contracting**	**120 days**	**Mon 08/12/14**	**Mon 25/05/15**
9	prepare contracts	3 mons	Mon 08/12/14	Mon 02/03/15
10	bid process	3 mons	Mon 02/03/15	Mon 25/05/15
11	**Construction**	**100 days**	**Mon 25/05/15**	**Fri 09/10/15**
12	temporary bypass pipeline	2 mons	Mon 25/05/15	Mon 20/07/15
13	Fisheries window on ditch (	32 days	Mon 03/08/15	Tue 15/09/15
14	Bypass Installation	10 wks	Mon 20/07/15	Fri 25/09/15
15	E&I constuction	2 mons	Mon 17/08/15	Fri 09/10/15
16	Test and Commission	1 mon	Mon 14/09/15	Fri 09/10/15
17	In service	0 days	Fri 09/10/15	Fri 09/10/15
18	Restoration	2 mons	Mon 28/09/15	Fri 20/11/15



Revision 1
Date: Mon 30/09/13

Task		Milestone		External Tasks	
Split		Summary		External Milestone	
Progress		Project Summary		Deadline	

Appendix E

RISK ANALYSIS AND CONTINGENCY CALCULATION

Project: Huntingdon Station Bypass CPCN Application
Risk Analysis and Contingency Calculation
May 13, 2013

		Relative Risk						Expected Value		
		1 Low 5 High								
No.	Risk (description)	Probab	Conseq	Exposure	Mitigation	Impacts	Comment	Probability	Consequence	Contingency
1	Market conditions - high bids	3	4	12	Communication with known contractors to ensure sufficient bidders are interested and available	non commodity purchases - control valves and construction contract		50%	250,000	125,000
2	Contaminated groundwater	2	5	10	water sampling	construction contract, environmental monitoring	based on actual costs for Gateway projects	25%	250,000	62,500
3	Late delivery of electrostops	3	3	9	early order of material - have specification ready for immediate purchase on project approval or consider placing order prior to project approval	schedule delay may cost another year of escalation on construction contract, additional work for project team		50%	100,000	50,000
4	Late delivery of pipe	2	4	8				25%	100,000	25,000
5	Large amount of groundwater	2	4	8	water sampling, known issue addressed in contract	construction contract, environmental monitoring	based on actual costs for Gateway projects	25%	380,000	95,000
6	Delayed start due to OGC	2	4	8	Start application as early as possible	schedule delay may cost another year of escalation on construction contract		25%	100,000	25,000
7	Species at risk - increased permits and monitoring	2	3	6	environmental studies of area	delay during construction	species at risk noted in area	25%	150,000	37,500
8	Late delivery of valves - fisheries window	3	2	6	early order of material	construction contract, environmental monitoring		50%	150,000	75,000
9	Small amount of groundwater	5	1	5	water sampling	construction contract, environmental monitoring		80%	25,000	20,000
10	Significant chance find	1	5	5	Archaeoligical Impact Assesment	construction contract, environmental monitoring	Major archaeological field study, construction delay, redesign of project	10%	400,000	40,000
11	work in proximity to gas line	2	2	4	construction practices - hydrovac and inspection	delay during construction		25%	200,000	50,000
12	Right of way acquisition costs, potential expropriation, temporary workspace costs	2	2	4	Continued communication with property owners	property costs	link to ability to test for groundwater rates and contamination, AAIF	25%	87,000	21,750
13	archaeology - chance find,	2	2	4	Archaeological Impact Assesment	construction contract, environmental monitoring	minor delay during construction, small additional amount of archaeology, no redesign	25%	200,000	50,000
14	HR - Project team member leaves	3	1	3	Depth of resources at Fortis and design consultant	stakeholder management, design, construction contract	Proper project documentation by all team members required	50%	25,000	12,500
15	Contractor non performance	1	3	3	Careful wording in contract, bonding	construction contract		10%	150,000	15,000
16	Contaminated soils (asbestos…)	1	3	3	Soil testing	construction contract	materials may have to be sent off site for disposal	10%	150,000	15,000
17	work in proximity to power lines - damage	1	2	2	Proper construction methodology around power poles	construction contract		10%	25,000	2,500
18	US regulatory interference	1	2	2	Nearest neighbour has been communicated with	stakeholder management, design, construction contract				-
19	No bids for contract	1	2	2	Communication with known contractors to ensure sufficient bidders are interested and available	construction contract				-
20	Contractor insolvency	1	2	2	Prequalification of bidders, bonding	construction contract				-
21	Changes to Spectra station - gates	1	2	2	Ongoing communication with Spectra	stakeholder management, design, construction contract				-
22	AIA increases monitoring requirements	2	1	2						-
23	work in proximity to Kinder Morgan	1	1	1	Permit to be obtained from Kinder Morgan					-
24	Bird nesting window	1	1	1			No tree removal required			
									Total	**721,750**

Appendix F1

FINANCIAL SCHEDULES – COS 25 YEAR

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Cost of Service
Appendix F-1 - Schedule 1
($000's), unless otherwise stated

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	**Cost of Service**														
2	Cost of Energy Sold		-	-	-	-	-	-	-	-	-	-	-	-	-
3	Operation and Maintenance	Schedule 2, Line 19	13	13	13	14	14	14	15	15	15	15	16	16	16
4	Property Taxes	Schedule 2, Line 29	-	10	22	21	21	19	19	19	19	19	20	20	20
5	Depreciation Expense	Schedule 8, Line 49 + Line 102	179	179	179	179	179	179	179	179	179	179	179	179	179
6	Removal Cost Provision	Schedule 9, Line 47	6	12	12	12	12	12	12	12	12	12	12	12	12
7	Amortization Expense	Schedule 10, Line 55	191	216	216	25	-	-	-	-	-	-	-	-	-
8	Other Revenue	Schedule 2, Line 24	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Income Taxes	Schedule 3, Line 21	124	34	45	(11)	(8)	3	12	20	28	35	41	47	51
10	Earned Return	Schedule 5, Line 27	620	599	568	546	531	517	503	489	475	460	446	432	418
11															
12	**Annual Cost of Service**	Sum of Lines 2 through 10	**1,133**	**1,062**	**1,055**	**785**	**749**	**743**	**739**	**734**	**728**	**721**	**714**	**706**	**697**
13	**Cost of Service- Excluding Cost of Energy**	Sum of Lines 3 through 10	**1,133**	**1,062**	**1,055**	**785**	**749**	**743**	**739**	**734**	**728**	**721**	**714**	**706**	**697**
14	**Cost of Service Impact as a % of Delivery Margin**		0.19%	0.18%	0.18%	0.13%	0.13%	0.13%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Cost of Service
Appendix F-1 - Schedule 1
($000's), unless otherwise stated

Line	Particulars	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	**Cost of Service**												
2	Cost of Energy Sold	-	-	-	-	-	-	-	-	-	-	-	-
3	Operation and Maintenance	17	17	17	18	18	18	19	19	20	20	20	21
4	Property Taxes	20	20	21	21	21	21	21	22	22	22	22	22
5	Depreciation Expense	180	180	180	180	180	180	180	180	180	180	120	77
6	Removal Cost Provision	12	12	12	12	12	12	12	12	12	12	9	7
7	Amortization Expense	-	-	-	-	-	-	-	-	-	-	-	-
8	Other Revenue	-	-	-	-	-	-	-	-	-	-	-	-
9	Income Taxes	56	59	63	65	68	70	72	73	74	75	16	41
10	Earned Return	404	390	376	362	348	334	320	306	292	278	271	267
11													
12	**Annual Cost of Service**	**688**	**678**	**668**	**658**	**647**	**635**	**624**	**612**	**599**	**587**	**458**	**435**
13	**Cost of Service- Excluding Cost of Energy**	**688**	**678**	**668**	**658**	**647**	**635**	**624**	**612**	**599**	**587**	**458**	**435**
14	**Cost of Service Impact as a % of Delivery Margin**	0.12%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%	0.10%	0.10%	0.10%	0.08%	0.07%

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: O&M, Other Revenue and Property Tax
Appendix F-1 - Schedule 2
($000's), unless otherwise stated

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	**Gross O&M**														
2	Distribution Total		-	-	-	-	-	-	-	-	-	-	-	-	-
3															
4	Transmission Total		15	15	16	16	16	17	17	17	18	18	18	19	19
5	Storage Total		-	-	-	-	-	-	-	-	-	-	-	-	-
6	Measurement		-	-	-	-	-	-	-	-	-	-	-	-	-
7	General Operations Total		-	-	-	-	-	-	-	-	-	-	-	-	-
8	Marketing Total		-	-	-	-	-	-	-	-	-	-	-	-	-
9	Customer Care Total		-	-	-	-	-	-	-	-	-	-	-	-	-
10	Business & IT Services Total		-	-	-	-	-	-	-	-	-	-	-	-	-
11	Administration & General Total		-	-	-	-	-	-	-	-	-	-	-	-	-
12															
13			15	15	16	16	16	17	17	17	18	18	18	19	19
14															
15	Total Gross O&M Expenses		15	15	16	16	16	17	17	17	18	18	18	19	19
16															
17	(Less): Capitalized Overhead	Overhead rate of 14%	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)
18	Add (Less): Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-
19	Net O&M		13	13	13	14	14	14	15	15	15	15	16	16	16
20															
21	**Other Revenue**														
22	Environmental Credits		-	-	-	-	-	-	-	-	-	-	-	-	-
23	Miscellaneous		-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Other Revenue		-	-	-	-	-	-	-	-	-	-	-	-	-
25															
26	**Property Taxes**														
27	General, School and Other		-	10	10	11	11	11	11	12	12	12	12	13	13
28	1% in Lieu of General Municipal Tax[1]	Schedule , Line 6/1000 x 1%	-	-	11	11	11	8	7	7	7	7	7	7	7
29	Total Property Taxes		-	10	22	21	21	19	19	19	19	19	20	20	20
30															
31	1- Calculation is based on the second preceeding year; ex., 2018 is based on 2016 revenue														

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: O&M, Other Re
Appendix F-1 - Schedule 2
($000's), unless otherwise stated

Line	Particulars	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	**Gross O&M**												
2	Distribution Total	-	-	-	-	-	-	-	-	-	-	-	-
3													
4	Transmission Total	19	20	20	21	21	21	22	22	23	23	24	24
5	Storage Total	-	-	-	-	-	-	-	-	-	-	-	-
6	Measurement	-	-	-	-	-	-	-	-	-	-	-	-
7	General Operations Total	-	-	-	-	-	-	-	-	-	-	-	-
8	Marketing Total	-	-	-	-	-	-	-	-	-	-	-	-
9	Customer Care Total	-	-	-	-	-	-	-	-	-	-	-	-
10	Business & IT Services Total	-	-	-	-	-	-	-	-	-	-	-	-
11	Administration & General Total	-	-	-	-	-	-	-	-	-	-	-	-
12													
13		19	20	20	21	21	21	22	22	23	23	24	24
14													
15	Total Gross O&M Expenses	19	20	20	21	21	21	22	22	23	23	24	24
16													
17	(Less): Capitalized Overhead	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
18	Add (Less): Adjustment	-	-	-	-	-	-	-	-	-	-	-	-
19	Net O&M	17	17	17	18	18	18	19	19	20	20	20	21
20													
21	**Other Revenue**												
22	Environmental Credits	-	-	-	-	-	-	-	-	-	-	-	-
23	Miscellaneous	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Other Revenue	-	-	-	-	-	-	-	-	-	-	-	-
25													
26	**Property Taxes**												
27	General, School and Other	13	13	14	14	14	15	15	15	16	16	16	17
28	1% in Lieu of General Municipal Tax[1]	7	7	7	7	7	7	6	6	6	6	6	6
29	Total Property Taxes	20	20	21	21	21	21	21	22	22	22	22	22
30													
31	1- Calculation is based on the second preceeding ye												

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Income Tax Expense
Appendix F-1 - Schedule 3
($000's), unless otherwise stated

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	**Income Tax Expense**														
2															
3	Earned Return	Schedule 5, Line 27	619.8	598.6	568.5	545.5	530.6	516.6	502.6	488.5	474.5	460.5	446.5	432.4	418.4
4	Deduct: Interest on debt	Schedule 5, Line 26	(339.2)	(327.6)	(311.1)	(298.6)	(290.4)	(282.7)	(275.0)	(267.4)	(259.7)	(252.0)	(244.4)	(236.7)	(229.0)
5	Add (Deduct): Amortization Expense	Schedule 10, Line 55	191.0	215.7	215.7	24.7	-	-	-	-	-	-	-	-	-
6	Add: Depreciation Expense	Schedule 8, Line 49 + Line 102	179.3	178.9	178.9	179.0	179.0	179.1	179.1	179.2	179.3	179.3	179.4	179.4	179.5
7	Add: Removal Cost Provision	Schedule 9, Line 47	5.8	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
8	Add: Earnings Stabilization Account Other Revenue	Schedule 10, Line 30 /1000	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Deduct: Removal Costs Incurred	Schedule 9, Line 70	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Deduct: Overhead Capitalized Expensed for Tax Purposes	Schedule 2 , Line 17 x 6 / 14	(0.9)	(0.9)	(0.9)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)
11	Deduct: Capital Cost Allowance	Schedule 4, Line 130	(301.9)	(579.8)	(533.6)	(491.2)	(452.1)	(416.2)	(383.1)	(352.6)	(324.6)	(298.9)	(275.1)	(253.3)	(233.2)
12	Taxable Income After Tax	Sum of Lines 3 through 11	354.0	96.5	129.0	(29.9)	(22.2)	7.4	34.2	58.3	80.0	99.5	116.9	132.4	146.2
13															
14	Income Tax Rate		26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%
15	1 - Current Income Tax Rate	1 - Line 14	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%
16															
17	Taxable Income	Line 12 / Line 15	478.3	130.4	174.4	(40.4)	(30.0)	10.0	46.2	78.8	108.1	134.4	157.9	178.9	197.5
18															
19	Total Income Tax Expense	Line 17 x Line 14	124.4	33.9	45.3	(10.5)	(7.8)	2.6	12.0	20.5	28.1	34.9	41.1	46.5	51.4
20	Adjustments		-	-	-	-	-	-	-	-	-	-	-	-	-
21	Net Tax Expense	Line 19 + Line 20	124.4	33.9	45.3	(10.5)	(7.8)	2.6	12.0	20.5	28.1	34.9	41.1	46.5	51.4
22															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Income Tax Expense
Appendix F-1 - Schedule 3
($000's), unless otherwise stated

Line	Particulars	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	**Income Tax Expense**												
2													
3	Earned Return	404.4	390.4	376.3	362.3	348.3	334.3	320.2	306.2	292.2	278.1	270.7	267.1
4	Deduct: Interest on debt	(221.3)	(213.6)	(206.0)	(198.3)	(190.6)	(182.9)	(175.3)	(167.6)	(159.9)	(152.2)	(148.1)	(146.2)
5	Add (Deduct): Amortization Expense	-	-	-	-	-	-	-	-	-	-	-	-
6	Add: Depreciation Expense	179.6	179.6	179.7	179.8	179.8	179.9	180.0	180.0	180.1	180.2	119.9	76.9
7	Add: Removal Cost Provision	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	9.4	7.3
8	Add: Earnings Stabilization Account Other Revenue	-	-	-	-	-	-	-	-	-	-	-	-
9	Deduct: Removal Costs Incurred	-	-	-	-	-	-	-	-	-	-	(111.0)	-
10	Deduct: Overhead Capitalized Expensed for Tax Purposes	(1.2)	(1.2)	(1.2)	(1.2)	(1.3)	(1.3)	(1.3)	(1.3)	(1.4)	(1.4)	(1.4)	(1.4)
11	Deduct: Capital Cost Allowance	(214.8)	(197.8)	(182.1)	(167.7)	(154.5)	(142.3)	(131.1)	(120.8)	(111.3)	(102.6)	(94.6)	(87.2)
12	Taxable Income After Tax	158.3	169.0	178.3	186.4	193.4	199.2	204.1	208.1	211.3	213.7	44.9	116.4
13													
14	Income Tax Rate	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%
15	1 - Current Income Tax Rate	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%
16													
17	Taxable Income	213.9	228.4	241.0	251.9	261.3	269.2	275.8	281.3	285.6	288.8	60.7	157.4
18													
19	Total Income Tax Expense	55.6	59.4	62.7	65.5	67.9	70.0	71.7	73.1	74.2	75.1	15.8	40.9
20	Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
21	Net Tax Expense	55.6	59.4	62.7	65.5	67.9	70.0	71.7	73.1	74.2	75.1	15.8	40.9
22													

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Capital Cost Allowance
Appendix F-1 - Schedule 4
($000's), unless otherwise stated

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	Structures & Improvements- Class 1.3 @ 6%														
2	Opening Balance	Preceeding Year, Line 5	-	14	13	12	11	11	10	10	9	8	8	7	7
3	Additions	Schedule 7 , Line 28 - AFUDC	14	-	-	-	-	-	-	-	-	-	-	-	-
4	CCA	[Line 2 + (Line 3 x 1/2)] x CCA Rate	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	(0)
5	Closing Balance	Sum of Lines 2 through 4	14	13	12	11	11	10	10	9	8	8	7	7	7
6															
7	Pipeline - Transmission- Class 49 @ 8%														
8	Opening Balance	Preceeding Year, Line 11	-	4,747	4,368	4,018	3,697	3,401	3,129	2,879	2,648	2,436	2,242	2,062	1,897
9	Additions	Schedule 7 , Line 29 - AFUDC	4,945	-	-	-	-	-	-	-	-	-	-	-	-
10	CCA	[Line 8 + (Line 9 x 1/2)] x CCA Rate	(198)	(380)	(349)	(321)	(296)	(272)	(250)	(230)	(212)	(195)	(179)	(165)	(152)
11	Closing Balance	Sum of Lines 8 through 10	4,747	4,368	4,018	3,697	3,401	3,129	2,879	2,648	2,436	2,242	2,062	1,897	1,745
12															
13	Land Rights- Class CECA @ 7%														
14	Opening Balance	Preceeding Year, Line 17	-	184	171	159	148	138	128	119	111	103	96	89	83
15	Additions	Schedule 7 , Line 30 - AFUDC	191	-	-	-	-	-	-	-	-	-	-	-	-
16	CCA	[Line 14 + (Line 15 x 1/2)] x CCA Rate	(7)	(13)	(12)	(11)	(10)	(10)	(9)	(8)	(8)	(7)	(7)	(6)	(6)
17	Closing Balance	Sum of Lines 14 through 16	184	171	159	148	138	128	119	111	103	96	89	83	77
18															
19	Measuring & Regulating Equipment- Class 49 @ 8%														
20	Opening Balance	Preceeding Year, Line 23	-	2,225	2,047	1,883	1,733	1,594	1,467	1,349	1,241	1,142	1,051	967	889
21	Additions	Schedule 7 , Line 31 - AFUDC	2,318	-	-	-	-	-	-	-	-	-	-	-	-
22	CCA	[Line 20 + (Line 21 x 1/2)] x CCA Rate	(93)	(178)	(164)	(151)	(139)	(128)	(117)	(108)	(99)	(91)	(84)	(77)	(71)
23	Closing Balance	Sum of Lines 20 through 22	2,225	2,047	1,883	1,733	1,594	1,467	1,349	1,241	1,142	1,051	967	889	818
24															
25	Telemetry- Class 49 @ 8%														
26	Opening Balance	Preceeding Year, Line 29	-	101	93	86	79	73	67	62	57	52	48	44	41
27	Additions	Schedule 7 , Line 32 - AFUDC	106	-	-	-	-	-	-	-	-	-	-	-	-
28	CCA	[Line 26 + (Line 27 x 1/2)] x CCA Rate	(4)	(8)	(7)	(7)	(6)	(6)	(5)	(5)	(5)	(4)	(4)	(4)	(3)
29	Closing Balance	Sum of Lines 26 through 28	101	93	86	79	73	67	62	57	52	48	44	41	37
30															
121	Capitalized Overhead- Class average @ 7.6%														
122	Opening Balance	Preceeding Year, Line 125	-	1	2	3	4	5	6	7	8	8	9	10	11
123	Additions	Schedule 2 , Line 17 x 8 / 14	1	1	1	1	1	1	1	1	1	1	1	1	2
124	CCA	[Line 122 + (Line 123 x 1/2)] x CCA Rate	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
125	Closing Balance	Sum of Lines 122 through 124	1	2	3	4	5	6	7	8	8	9	10	11	11
126															
127	Total CCA														
128	Opening Balance	Preceeding Year, Line 131	-	7,273	6,695	6,162	5,672	5,221	4,807	4,425	4,074	3,750	3,453	3,179	2,928
129	Additions		7,575	1	1	1	1	1	1	1	1	1	1	1	2
130	CCA		(302)	(580)	(534)	(491)	(452)	(416)	(383)	(353)	(325)	(299)	(275)	(253)	(233)
131	Closing Balance	Sum of Lines 128 through 130	7,273	6,695	6,162	5,672	5,221	4,807	4,425	4,074	3,750	3,453	3,179	2,928	2,696
132															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Capital Cost A
Appendix F-1 - Schedule 4
($000's), unless otherwise stated

Line	Particulars	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	**Structures & Improvements- Class 1.3 @ 6%**												
2	Opening Balance	7	6	6	5	5	5	5	4	4	4	4	3
3	Additions	-	-	-	-	-	-	-	-	-	-	-	-
4	CCA	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
5	Closing Balance	6	6	5	5	5	5	4	4	4	4	3	3
6													
7	**Pipeline - Transmission- Class 49 @ 8%**												
8	Opening Balance	1,745	1,606	1,477	1,359	1,250	1,150	1,058	974	896	824	758	698
9	Additions	-	-	-	-	-	-	-	-	-	-	-	-
10	CCA	(140)	(128)	(118)	(109)	(100)	(92)	(85)	(78)	(72)	(66)	(61)	(56)
11	Closing Balance	1,606	1,477	1,359	1,250	1,150	1,058	974	896	824	758	698	642
12													
13	**Land Rights- Class CECA @ 7%**												
14	Opening Balance	77	72	67	62	58	54	50	46	43	40	37	35
15	Additions	-	-	-	-	-	-	-	-	-	-	-	-
16	CCA	(5)	(5)	(5)	(4)	(4)	(4)	(3)	(3)	(3)	(3)	(3)	(2)
17	Closing Balance	72	67	62	58	54	50	46	43	40	37	35	32
18													
19	**Measuring & Regulating Equipment- Class 4**												
20	Opening Balance	818	753	692	637	586	539	496	456	420	386	355	327
21	Additions	-	-	-	-	-	-	-	-	-	-	-	-
22	CCA	(65)	(60)	(55)	(51)	(47)	(43)	(40)	(37)	(34)	(31)	(28)	(26)
23	Closing Balance	753	692	637	586	539	496	456	420	386	355	327	301
24													
25	**Telemetry- Class 49 @ 8%**												
26	Opening Balance	37	34	32	29	27	25	23	21	19	18	16	15
27	Additions	-	-	-	-	-	-	-	-	-	-	-	-
28	CCA	(3)	(3)	(3)	(2)	(2)	(2)	(2)	(2)	(2)	(1)	(1)	(1)
29	Closing Balance	34	32	29	27	25	23	21	19	18	16	15	14
30													
121	**Capitalized Overhead- Class average @ 7.6%**												
122	Opening Balance	11	12	13	13	14	14	15	15	16	16	17	18
123	Additions	2	2	2	2	2	2	2	2	2	2	2	2
124	CCA	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
125	Closing Balance	12	13	13	14	14	15	15	16	16	17	18	18
126													
127	**Total CCA**												
128	Opening Balance	2,696	2,483	2,286	2,106	1,940	1,787	1,646	1,517	1,398	1,288	1,188	1,095
129	Additions	2	2	2	2	2	2	2	2	2	2	2	2
130	CCA	(215)	(198)	(182)	(168)	(155)	(142)	(131)	(121)	(111)	(103)	(95)	(87)
131	Closing Balance	2,483	2,286	2,106	1,940	1,787	1,646	1,517	1,398	1,288	1,188	1,095	1,010
132													

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Rate Base
Appendix F-1 - Schedule 5
($000's), unless otherwise stated

Line	Particulars	Reference		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	**Rate Base**															
2	Gross Plant In Service- Beginning	Schedule 7, Line 25		-	7,979	7,982	7,984	7,986	7,988	7,991	7,993	7,995	7,998	8,000	8,003	8,006
3	Gross Plant In Service- Ending	Schedule 7, Line 97		7,979	7,982	7,984	7,986	7,988	7,991	7,993	7,995	7,998	8,000	8,003	8,006	8,008
4																
5	Accumulated Depreciation- Beginning	Schedule 8, Line 25		-	(179)	(358)	(537)	(716)	(895)	(1,074)	(1,253)	(1,432)	(1,612)	(1,791)	(1,970)	(2,150)
6	Accumulated Depreciation- Ending	Schedule 8, Line 97		(179)	(358)	(537)	(716)	(895)	(1,074)	(1,253)	(1,432)	(1,612)	(1,791)	(1,970)	(2,150)	(2,329)
7																
8	Negative Salvage- Beginning	Schedule 9, Line 24		-	(6)	(17)	(29)	(41)	(52)	(64)	(76)	(87)	(99)	(110)	(122)	(134)
9	Negative Salvage- Ending	Schedule 9, Line 93		(6)	(17)	(29)	(41)	(52)	(64)	(76)	(87)	(99)	(110)	(122)	(134)	(145)
10																
11	Contributions in Aid of Construction- Beginning	Schedule 7, Line 101		-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
12	Contributions in Aid of Construction- Ending	Schedule 7, Line 104		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
13																
14	Accumulated Amortization- Beginning	Schedule 8, Line 101		-	-	-	-	-	-	-	-	-	-	-	-	-
15	Accumulated Amortization- Ending	Schedule 8, Line 104		-	-	-	-	-	-	-	-	-	-	-	-	-
16																
17	Net Plant in Service, Mid-Year	Sum (Lines 2 through 15)/2		3,897	7,700	7,512	7,323	7,135	6,947	6,758	6,570	6,381	6,193	6,005	5,816	5,628
18																
19	Adjustment to 13-month average		1	3,921	-	-	-	-	-	-	-	-	-	-	-	-
20	Unamortized Deferred Charges, Mid-Year	Schedule 10, Line 58		515	348	133	12	-	-	-	-	-	-	-	-	-
21	Cash Working Capital		2	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
22	**Total Rate Base**	**Sum of Lines 17 through 21**		**8,328**	**8,044**	**7,639**	**7,331**	**7,130**	**6,942**	**6,753**	**6,565**	**6,377**	**6,188**	**6,000**	**5,811**	**5,623**
23																
24	**Return on Rate Base**															
25	Equity Return	Line 22 x ROE x Equity %		281	271	257	247	240	234	228	221	215	208	202	196	189
26	Debt Component	Line 22 x (LTD Rate x LTD% + STD Rate x STD %)		339	328	311	299	290	283	275	267	260	252	244	237	229
27	Total Earned Return	Line 25 + Line 26		**620**	**599**	**568**	**546**	**531**	**517**	**503**	**489**	**475**	**460**	**446**	**432**	**418**
28	Return on AES Rate Base %	Line 27 / Line 22		7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%
29																
30	1- (Schedule 7, (Line 49 + Line 102) + Schedule 8, Line 49) x (Days In-service/365-1/2)															
31	2- Schedule 7, Line 97 x TGI CWC/Closing GPIS %															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Rate Base
Appendix F-1 - Schedule 5
($000's), unless otherwise stated

Line	Particulars	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	**Rate Base**												
2	Gross Plant In Service- Beginning	8,008	8,011	8,014	8,016	8,019	8,022	8,025	8,028	8,031	8,035	8,038	5,618
3	Gross Plant In Service- Ending	8,011	8,014	8,016	8,019	8,022	8,025	8,028	8,031	8,035	8,038	5,618	5,622
4													
5	Accumulated Depreciation- Beginning	(2,329)	(2,509)	(2,688)	(2,868)	(3,048)	(3,228)	(3,408)	(3,588)	(3,768)	(3,948)	(4,128)	(1,825)
6	Accumulated Depreciation- Ending	(2,509)	(2,688)	(2,868)	(3,048)	(3,228)	(3,408)	(3,588)	(3,768)	(3,948)	(4,128)	(1,825)	(1,902)
7													
8	Negative Salvage- Beginning	(145)	(157)	(169)	(180)	(192)	(203)	(215)	(227)	(238)	(250)	(262)	(160)
9	Negative Salvage- Ending	(157)	(169)	(180)	(192)	(203)	(215)	(227)	(238)	(250)	(262)	(160)	(167)
10													
11	Contributions in Aid of Construction- Beginning	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
12	Contributions in Aid of Construction- Ending	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
13													
14	Accumulated Amortization- Beginning	-	-	-	-	-	-	-	-	-	-	-	-
15	Accumulated Amortization- Ending	-	-	-	-	-	-	-	-	-	-	-	-
16													
17	Net Plant in Service, Mid-Year	5,439	5,251	5,062	4,874	4,685	4,497	4,308	4,120	3,931	3,743	3,641	3,593
18													
19	Adjustment to 13-month average	-	-	-	-	-	-	-	-	-	-	-	-
20	Unamortized Deferred Charges, Mid-Year	-	-	-	-	-	-	-	-	-	-	-	-
21	Cash Working Capital	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(3)	(3)
22	**Total Rate Base**	**5,434**	**5,246**	**5,057**	**4,869**	**4,680**	**4,492**	**4,303**	**4,115**	**3,926**	**3,738**	**3,637**	**3,589**
23													
24	**Return on Rate Base**												
25	Equity Return	183	177	170	164	158	151	145	139	132	126	123	121
26	Debt Component	221	214	206	198	191	183	175	168	160	152	148	146
27	Total Earned Return	**404**	**390**	**376**	**362**	**348**	**334**	**320**	**306**	**292**	**278**	**271**	**267**
28	Return on AES Rate Base %	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%
29													
30	1- (Schedule 7, (Line 49 + Line 102) + Schedule 8, Line 49) x												
31	2- Schedule 7, Line 97 x TGI CWC/Closing GPIS %												

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Capital Spending
Appendix F-1 - Schedule 6

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	Capital Spending Prior to 2016														
2	Structures & Improvements		14.2												
3	Pipeline - Transmission		4,945.2												
4	Land Rights		254.5												
5	Measuring & Regulating Equipment		2,317.9												
6	Telemetry		105.7												
22	Total Capital Spending Prior to 2016	Sum of Lines 2 through 21	7,637.5												
23															
24	AFUDC Prior to 2016														
25	Structures & Improvements		0.6												
26	Pipeline - Transmission		223.8												
27	Land Rights		5.8												
28	Measuring & Regulating Equipment		104.9												
29	Telemetry		4.8												
45	Total AFUDC Prior to 2016	Sum of Lines 25 through 44	339.9												
46															
47	Capital Spending 2016 Onwards														
48	Structures & Improvements		0.0	-	-	-	-	-	-	-	-	-	-	-	-
49	Pipeline - Transmission		-	-	-	-	-	-	-	-	-	-	-	-	-
50	Land Rights		-	-	-	-	-	-	-	-	-	-	-	-	-
51	Measuring & Regulating Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-
52	Telemetry		-	-	-	-	-	-	-	-	-	-	-	-	-
68	Total Capital Spending 2016 Onwards	Sum of Lines 48 through 67	0.0	-	-	-	-	-	-	-	-	-	-	-	-
69															
70	AFUDC 2016 Onwards														
71	Structures & Improvements		-	-	-	-	-	-	-	-	-	-	-	-	-
72	Pipeline - Transmission		-	-	-	-	-	-	-	-	-	-	-	-	-
73	Land Rights		-	-	-	-	-	-	-	-	-	-	-	-	-
74	Measuring & Regulating Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-
75	Telemetry		-	-	-	-	-	-	-	-	-	-	-	-	-
91	Total AFUDC 2016 Onwards	Sum of Lines 71 through 90	-	-	-	-	-	-	-	-	-	-	-	-	-
92															
93	Total Capital Spending[1]	Line 68	7,637.5	-	-	-	-	-	-	-	-	-	-	-	-
94	Total AFUDC	Line 91	339.9	-	-	-	-	-	-	-	-	-	-	-	-
95	Total Annual Capital Spending and AFUDC	Line 93 + Line 94	7,977.3	-	-	-	-	-	-	-	-	-	-	-	-
96															
97	Contributions in Aid of Construction		-	-	-	-	-	-	-	-	-	-	-	-	-
98	Removal Costs		-	-	-	-	-	-	-	-	-	-	-	-	-
99	Net Annual Project Costs- Capital	Line 95 + 97 + 98	7,977.3	-	-	-	-	-	-	-	-	-	-	-	-
100															
101	Total Project Costs- Capital Spending and AFUDC	Sum of Line 95	**7,977.3**												

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Capital Spending
Appendix F-1 - Schedule 6

Line	Particulars	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	Capital Spending Prior to 2016												
2	Structures & Improvements												
3	Pipeline - Transmission												
4	Land Rights												
5	Measuring & Regulating Equipment												
6	Telemetry												
22	Total Capital Spending Prior to 2016												
23													
24	AFUDC Prior to 2016												
25	Structures & Improvements												
26	Pipeline - Transmission												
27	Land Rights												
28	Measuring & Regulating Equipment												
29	Telemetry												
45	Total AFUDC Prior to 2016												
46													
47	Capital Spending 2016 Onwards												
48	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-
49	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-
50	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-
51	Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-	-	-	-
52	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-
68	Total Capital Spending 2016 Onwards	-	-	-	-	-	-	-	-	-	-	-	0.0
69													
70	AFUDC 2016 Onwards												
71	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-
72	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-
73	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-
74	Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-	-	-	-
75	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-
91	Total AFUDC 2016 Onwards	-	-	-	-	-	-	-	-	-	-	-	-
92													
93	Total Capital Spending[1]	-	-	-	-	-	-	-	-	-	-	-	0.0
94	Total AFUDC	-	-	-	-	-	-	-	-	-	-	-	-
95	Total Annual Capital Spending and AFUDC	-	-	-	-	-	-	-	-	-	-	-	0.0
96													
97	Contributions in Aid of Construction	-	-	-	-	-	-	-	-	-	-	-	-
98	Removal Costs	-	-	-	-	-	-	-	-	-	-	111.0	-
99	Net Annual Project Costs- Capital	-	-	-	-	-	-	-	-	-	-	111.0	0.0
100													
101	Total Project Costs- Capital Spending and AFUDC												

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Gross Plant in Service & Contributions in Aid of Construction
Appendix F-1 - Schedule 7
($000's), unless otherwise stated

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	**Gross Plant in Service**														
2															
3	Gross Plant in Service, Beginning														
4	Structures & Improvements	Preceeding Year, Line 76	-	15	15	15	15	15	15	15	15	15	15	15	15
5	Pipeline - Transmission	Preceeding Year, Line 77	-	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169
6	Land Rights	Preceeding Year, Line 78	-	260	260	260	260	260	260	260	260	260	260	260	260
7	Measuring & Regulating Equipment	Preceeding Year, Line 79	-	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423
8	Telemetry	Preceeding Year, Line 80	-	110	110	110	110	110	110	110	110	110	110	110	110
24	Capitalized Overhead	Preceeding Year, Line 96	-	2	4	6	9	11	13	16	18	20	23	26	28
25	Total Gross Plant in Service, Beginning	Sum of Lines 4 through 24	-	7,979	7,982	7,984	7,986	7,988	7,991	7,993	7,995	7,998	8,000	8,003	8,006
26															
27	Gross Plant in Service, Additions														
28	Structures & Improvements	Schedule 6, Lines 2 + 25 + 48 + 71	15	-	-	-	-	-	-	-	-	-	-	-	-
29	Pipeline - Transmission	Schedule 6, Lines 3 + 26 + 49 + 72	5,169	-	-	-	-	-	-	-	-	-	-	-	-
30	Land Rights	Schedule 6, Lines 4 + 27 + 50 + 73	260	-	-	-	-	-	-	-	-	-	-	-	-
31	Measuring & Regulating Equipment	Schedule 6, Lines 5 + 28 + 51 + 74	2,423	-	-	-	-	-	-	-	-	-	-	-	-
32	Telemetry	Schedule 6, Lines 6 + 29 + 52 + 75	110	-	-	-	-	-	-	-	-	-	-	-	-
48	Capitalized Overhead	Schedule 2, Line 17	2	2	2	2	2	2	2	2	2	3	3	3	3
49	Total Gross Plant in Service, Additions	Sum of Lines 28 through 48	7,979	2	2	2	2	2	2	2	2	3	3	3	3
50															
51	Gross Plant in Service, Retirements														
52	Structures & Improvements		-	-	-	-	-	-	-	-	-	-	-	-	-
53	Pipeline - Transmission		-	-	-	-	-	-	-	-	-	-	-	-	-
54	Land Rights		-	-	-	-	-	-	-	-	-	-	-	-	-
55	Measuring & Regulating Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-
56	Telemetry		-	-	-	-	-	-	-	-	-	-	-	-	-
72	Capitalized Overhead		-	-	-	-	-	-	-	-	-	-	-	-	-
73	Total Gross Plant in Service, Retirements	Sum of Lines 52 through 72	-	-	-	-	-	-	-	-	-	-	-	-	-
74															
75	Gross Plant in Service, Ending														
76	Structures & Improvements	Line 4 + Line 28 + Line 52	15	15	15	15	15	15	15	15	15	15	15	15	15
77	Pipeline - Transmission	Line 5 + Line 29 + Line 53	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169
78	Land Rights	Line 6 + Line 30 + Line 54	260	260	260	260	260	260	260	260	260	260	260	260	260
79	Measuring & Regulating Equipment	Line 7 + Line 31 + Line 55	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423
80	Telemetry	Line 8 + Line 32 + Line 56	110	110	110	110	110	110	110	110	110	110	110	110	110
96	Capitalized Overhead	Line 24 + Line 48 + Line 72	2	4	6	9	11	13	16	18	20	23	26	28	31
97	Total Gross Plant in Service, Ending	Sum of Lines 76 through 96	7,979	7,982	7,984	7,986	7,988	7,991	7,993	7,995	7,998	8,000	8,003	8,006	8,008
98															
99															
100	**Contributions in Aid of Construction (CIAC)**														
101	CIAC, Beginning		-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
102	Additions		-	-	-	-	-	-	-	-	-	-	-	-	-
103	Retirements		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
104	CIAC, Ending	Sum of Lines 101 through 103	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
105															
106															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Gross Plant in
Appendix F-1 - Schedule 7
($000's), unless otherwise stated

Line	Particulars	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	**Gross Plant in Service**												
2													
3	Gross Plant in Service, Beginning												
4	Structures & Improvements	15	15	15	15	15	15	15	15	15	15	15	15
5	Pipeline - Transmission	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169
6	Land Rights	260	260	260	260	260	260	260	260	260	260	260	260
7	Measuring & Regulating Equipment	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	-
8	Telemetry	110	110	110	110	110	110	110	110	110	110	110	110
24	Capitalized Overhead	31	34	36	39	42	45	48	51	54	57	61	64
25	Total Gross Plant in Service, Beginning	8,008	8,011	8,014	8,016	8,019	8,022	8,025	8,028	8,031	8,035	8,038	5,618
26													
27	Gross Plant in Service, Additions												
28	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-
29	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-
30	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-
31	Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-	-	-	-
32	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-
48	Capitalized Overhead	3	3	3	3	3	3	3	3	3	3	3	3
49	Total Gross Plant in Service, Additions	3	3	3	3	3	3	3	3	3	3	3	3
50													
51	Gross Plant in Service, Retirements												
52	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-
53	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-
54	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-
55	Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-	-	(2,423)	-
56	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-
72	Capitalized Overhead	-	-	-	-	-	-	-	-	-	-	-	-
73	Total Gross Plant in Service, Retirements	-	-	-	-	-	-	-	-	-	-	(2,423)	-
74													
75	Gross Plant in Service, Ending												
76	Structures & Improvements	15	15	15	15	15	15	15	15	15	15	15	15
77	Pipeline - Transmission	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169
78	Land Rights	260	260	260	260	260	260	260	260	260	260	260	260
79	Measuring & Regulating Equipment	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	-	-
80	Telemetry	110	110	110	110	110	110	110	110	110	110	110	110
96	Capitalized Overhead	34	36	39	42	45	48	51	54	57	61	64	67
97	Total Gross Plant in Service, Ending	8,011	8,014	8,016	8,019	8,022	8,025	8,028	8,031	8,035	8,038	5,618	5,622
98													
99													
100	**Contributions in Aid of Construction (CIAC)**												
101	CIAC, Beginning	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
102	Additions	-	-	-	-	-	-	-	-	-	-	-	-
103	Retirements	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
104	CIAC, Ending	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
105													
106													

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Accumulated Depreciation & Amortization
Appendix F-1 - Schedule 8
($000's), unless otherwise stated

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	**Accumulated Depreciation**														
2															
3	Accumulated Depreciation, Beginning														
4	Structures & Improvements	Preceeding Year, Line 76	-	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(6)	(6)	(7)
5	Pipeline - Transmission	Preceeding Year, Line 77	-	(75)	(149)	(224)	(298)	(372)	(447)	(521)	(596)	(670)	(745)	(819)	(893)
6	Land Rights	Preceeding Year, Line 78	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Measuring & Regulating Equipment	Preceeding Year, Line 79	-	(104)	(207)	(311)	(414)	(518)	(621)	(724)	(828)	(931)	(1,035)	(1,138)	(1,242)
8	Telemetry	Preceeding Year, Line 80	-	(0)	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(4)	(4)
24	Capitalized Overhead	Preceeding Year, Line 96	-	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(2)	(2)	(3)	(3)	(4)
25	Total Accumulated Depreciation, Beginning	Sum of Lines 4 through 24	-	(179)	(358)	(537)	(716)	(895)	(1,074)	(1,253)	(1,432)	(1,612)	(1,791)	(1,970)	(2,150)
26															
27	Accumulated Depreciation, Depreciation Expense														
28	Structures & Improvements@ 3.8%	Schedule 7, Line 4 & Line 28	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
29	Pipeline - Transmission@ 1.44%	Schedule 7, Line 5 & Line 29	(75)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)
30	Land Rights@ 0%	Schedule 7, Line 6 & Line 30	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Measuring & Regulating Equipment@ 4.27%	Schedule 7, Line 7 & Line 31	(104)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)
32	Telemetry@ 0.31%	Schedule 7, Line 8 & Line 32	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
48	Capitalized Overhead@ 2.35%	Schedule 7, Line 24 & Line 48	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)
49	Total Accumulated Depreciation, Depreciation Exp	Sum of Lines 28 through 48	(179)	(179)	(179)	(179)	(179)	(179)	(179)	(179)	(179)	(179)	(179)	(179)	(179)
50															
51	Accumulated Depreciation, Retirements														
52	Structures & Improvements	Schedule 7, Line 52	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Pipeline - Transmission	Schedule 7, Line 53	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Land Rights	Schedule 7, Line 54	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Measuring & Regulating Equipment	Schedule 7, Line 55	-	-	-	-	-	-	-	-	-	-	-	-	-
56	Telemetry	Schedule 7, Line 56	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Capitalized Overhead	Schedule 7, Line 72	-	-	-	-	-	-	-	-	-	-	-	-	-
73	Total Accumulated Depreciation, Retirements	Sum of Lines 52 through 72	-	-	-	-	-	-	-	-	-	-	-	-	-
74															
75	Accumulated Depreciation, Ending														
76	Structures & Improvements	Line 4 + Line 28 + Line 52	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(6)	(6)	(7)	(7)
77	Pipeline - Transmission	Line 5 + Line 29 + Line 53	(75)	(149)	(224)	(298)	(372)	(447)	(521)	(596)	(670)	(745)	(819)	(893)	(968)
78	Land Rights	Line 6 + Line 30 + Line 54	-	-	-	-	-	-	-	-	-	-	-	-	-
79	Measuring & Regulating Equipment	Line 7 + Line 31 + Line 55	(104)	(207)	(311)	(414)	(518)	(621)	(724)	(828)	(931)	(1,035)	(1,138)	(1,242)	(1,345)
80	Telemetry	Line 8 + Line 32 + Line 56	(0)	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(4)	(4)	(4)
96	Capitalized Overhead	Line 24 + Line 48 + Line 72	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(5)
97	Total Accumulated Depreciation, Ending	Sum of Lines 76 through 96	(179)	(358)	(537)	(716)	(895)	(1,074)	(1,253)	(1,432)	(1,612)	(1,791)	(1,970)	(2,150)	(2,329)
98															
99															
100	**Accumulated Amortization of Contributions in Aid of Construction (CIAC)**														
101	Accumulated Amortization CIAC, Beginning		-	-	-	-	-	-	-	-	-	-	-	-	-
102	Amortization	[1]	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
103	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
104	Accumulated Amortization CIAC, Ending	Sum of Lines 101 through 103	-	-	-	-	-	-	-	-	-	-	-	-	-
105															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Accumulated Depre
Appendix F-1 - Schedule 8
($000's), unless otherwise stated

Line	Particulars	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	**Accumulated Depreciation**												
2													
3	Accumulated Depreciation, Beginning												
4	Structures & Improvements	(7)	(8)	(8)	(9)	(10)	(10)	(11)	(11)	(12)	(12)	(13)	(13)
5	Pipeline - Transmission	(968)	(1,042)	(1,117)	(1,191)	(1,266)	(1,340)	(1,414)	(1,489)	(1,563)	(1,638)	(1,712)	(1,787)
6	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-
7	Measuring & Regulating Equipment	(1,345)	(1,449)	(1,552)	(1,656)	(1,759)	(1,862)	(1,966)	(2,069)	(2,173)	(2,276)	(2,380)	-
8	Telemetry	(4)	(5)	(5)	(5)	(6)	(6)	(7)	(7)	(7)	(8)	(8)	(8)
24	Capitalized Overhead	(5)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(14)	(15)	(17)
25	Total Accumulated Depreciation, Beginning	(2,329)	(2,509)	(2,688)	(2,868)	(3,048)	(3,228)	(3,408)	(3,588)	(3,768)	(3,948)	(4,128)	(1,825)
26													
27	Accumulated Depreciation, Depreciation Expense												
28	Structures & Improvements@ 3.8%	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
29	Pipeline - Transmission@ 1.44%	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)
30	Land Rights@ 0%	-	-	-	-	-	-	-	-	-	-	-	-
31	Measuring & Regulating Equipment@ 4.27%	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(43)	-
32	Telemetry@ 0.31%	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
48	Capitalized Overhead@ 2.35%	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)
49	Total Accumulated Depreciation, Depreciation Exp	(180)	(180)	(180)	(180)	(180)	(180)	(180)	(180)	(180)	(180)	(120)	(77)
50													
51	Accumulated Depreciation, Retirements												
52	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-
53	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-
54	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-
55	Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-	-	2,423	-
56	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-
72	Capitalized Overhead	-	-	-	-	-	-	-	-	-	-	-	-
73	Total Accumulated Depreciation, Retirements	-	-	-	-	-	-	-	-	-	-	2,423	-
74													
75	Accumulated Depreciation, Ending												
76	Structures & Improvements	(8)	(8)	(9)	(10)	(10)	(11)	(11)	(12)	(12)	(13)	(13)	(14)
77	Pipeline - Transmission	(1,042)	(1,117)	(1,191)	(1,266)	(1,340)	(1,414)	(1,489)	(1,563)	(1,638)	(1,712)	(1,787)	(1,861)
78	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-
79	Measuring & Regulating Equipment	(1,449)	(1,552)	(1,656)	(1,759)	(1,862)	(1,966)	(2,069)	(2,173)	(2,276)	(2,380)	-	-
80	Telemetry	(5)	(5)	(5)	(6)	(6)	(7)	(7)	(7)	(8)	(8)	(8)	(9)
96	Capitalized Overhead	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(14)	(15)	(17)	(18)
97	Total Accumulated Depreciation, Ending	(2,509)	(2,688)	(2,868)	(3,048)	(3,228)	(3,408)	(3,588)	(3,768)	(3,948)	(4,128)	(1,825)	(1,902)
98													
99													
100	**Accumulated Amortization of Contributions in Ai**												
101	Accumulated Amortization CIAC, Beginning	-	-	-	-	-	-	-	-	-	-	-	-
102	Amortization	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
103	Retirements	0	0	0	0	0	0	0	0	0	0	0	0
104	Accumulated Amortization CIAC, Ending	-	-	-	-	-	-	-	-	-	-	-	-
105													

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Negative Salvage Continuity
Appendix F-1 - Schedule 9
($000's), unless otherwise stated

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	**Negative Salvage**														
2															
3	Negative Salvage, Beginning														
4	Structures & Improvements	Preceeding Year, Line 73	-	0	0	0	0	0	0	0	0	0	0	0	0
5	Pipeline - Transmission	Preceeding Year, Line 74	-	4	11	18	25	33	40	47	54	62	69	76	83
6	Land Rights	Preceeding Year, Line 75	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Measuring & Regulating Equipment	Preceeding Year, Line 76	-	2	7	11	15	20	24	28	33	37	41	46	50
8	Telemetry	Preceeding Year, Line 77	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Negative Salvage, Beginning	Sum of Lines 4 through 23	-	6	17	29	41	52	64	76	87	99	110	122	134
25															
26	Removal Provision														
27	Structures & Improvements@ 0.18%		0	0	0	0	0	0	0	0	0	0	0	0	0
28	Pipeline - Transmission@ 0.14%		4	7	7	7	7	7	7	7	7	7	7	7	7
29	Land Rights@ 0%		-	-	-	-	-	-	-	-	-	-	-	-	-
30	Measuring & Regulating Equipment@ 0.18%		2	4	4	4	4	4	4	4	4	4	4	4	4
31	Telemetry@ 0%		-	-	-	-	-	-	-	-	-	-	-	-	-
47	Total Removal Provision	Sum of Lines 27 through 46	6	12	12	12	12	12	12	12	12	12	12	12	12
48															
49	Removal Costs														
50	Structures & Improvements		-	-	-	-	-	-	-	-	-	-	-	-	-
51	Pipeline - Transmission		-	-	-	-	-	-	-	-	-	-	-	-	-
52	Land Rights		-	-	-	-	-	-	-	-	-	-	-	-	-
53	Measuring & Regulating Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-
54	Telemetry		-	-	-	-	-	-	-	-	-	-	-	-	-
70	Total Removal Costs	Sum of Lines 50 through 69	-	-	-	-	-	-	-	-	-	-	-	-	-
71															
72	Negative Salvage, Ending														
73	Structures & Improvements	Line 4 + Line 27 + Line 50	0	0	0	0	0	0	0	0	0	0	0	0	0
74	Pipeline - Transmission	Line 5 + Line 28 + Line 51	4	11	18	25	33	40	47	54	62	69	76	83	90
75	Land Rights	Line 6 + Line 29 + Line 52	-	-	-	-	-	-	-	-	-	-	-	-	-
76	Measuring & Regulating Equipment	Line 7 + Line 30 + Line 53	2	7	11	15	20	24	28	33	37	41	46	50	55
77	Telemetry	Line 8 + Line 31 + Line 54	-	-	-	-	-	-	-	-	-	-	-	-	-
93	Total Negative Salvage, Ending	Sum of Lines 73 through 92	6	17	29	41	52	64	76	87	99	110	122	134	145

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Negative Salvage Co
Appendix F-1 - Schedule 9
($000's), unless otherwise stated

Line	Particulars	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	**Negative Salvage**												
2													
3	Negative Salvage, Beginning												
4	Structures & Improvements	0	0	0	0	0	0	0	1	1	1	1	1
5	Pipeline - Transmission	90	98	105	112	119	127	134	141	148	156	163	170
6	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-
7	Measuring & Regulating Equipment	55	59	63	68	72	76	81	85	89	94	98	(11)
8	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Negative Salvage, Beginning	145	157	169	180	192	203	215	227	238	250	262	160
25													
26	Removal Provision												
27	Structures & Improvements@ 0.18%	0	0	0	0	0	0	0	0	0	0	0	0
28	Pipeline - Transmission@ 0.14%	7	7	7	7	7	7	7	7	7	7	7	7
29	Land Rights@ 0%	-	-	-	-	-	-	-	-	-	-	-	-
30	Measuring & Regulating Equipment@ 0.18%	4	4	4	4	4	4	4	4	4	4	2	-
31	Telemetry@ 0%	-	-	-	-	-	-	-	-	-	-	-	-
47	Total Removal Provision	12	12	12	12	12	12	12	12	12	12	9	7
48													
49	Removal Costs												
50	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-
51	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-
52	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-
53	Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-	-	(111)	-
54	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-
70	Total Removal Costs	-	-	-	-	-	-	-	-	-	-	(111)	-
71													
72	Negative Salvage, Ending												
73	Structures & Improvements	0	0	0	0	0	0	1	1	1	1	1	1
74	Pipeline - Transmission	98	105	112	119	127	134	141	148	156	163	170	177
75	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-
76	Measuring & Regulating Equipment	59	63	68	72	76	81	85	89	94	98	(11)	(11)
77	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-
93	Total Negative Salvage, Ending	157	169	180	192	203	215	227	238	250	262	160	167

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Deferred Charges
Appendix F-1 - Schedule 10
($000's), unless otherwise stated

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	*Deferred Charge- O&M*														
2	Opening Balance	Previous Year, Line 8	-	74	49	25	-	-	-	-	-	-	-	-	-
3	Gross Additions		100	-	-	-	-	-	-	-	-	-	-	-	-
4	Tax	Line 3 x Tax Rate	(26)	-	-	-	-	-	-	-	-	-	-	-	-
5	AFUDC	(Lines 2 + 3 + 4) x Schedule 11, Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Net Additions	Sum of Lines 3 through 5	74	-	-	-	-	-	-	-	-	-	-	-	-
7	Amortization Expense @ 3 years		-	(25)	(25)	(25)	-	-	-	-	-	-	-	-	-
8	Closing Balance	Lines 2 + 6 + 7	74	49	25	-	-	-	-	-	-	-	-	-	-
9															
10	*Deferred Charge- Preliminary Investigation*														
11	Opening Balance	Previous Year, Line 17	573	382	191	-	-	-	-	-	-	-	-	-	-
12	Gross Additions		-	-	-	-	-	-	-	-	-	-	-	-	-
13	Tax	Line 12 x Tax Rate	-	-	-	-	-	-	-	-	-	-	-	-	-
14	AFUDC	(Lines 11 + 12 + 13) x Schedule 11, Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Net Additions	Sum of Lines 12 through 14	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Amortization Expense @ 3 years		(191)	(191)	(191)	-	-	-	-	-	-	-	-	-	-
17	Closing Balance	Lines 11 + 15 + 16	382	191	-	-	-	-	-	-	-	-	-	-	-
48															
49	**Deferred Charge- Rate Base**														
50	Opening Balance	Previous Year, Line 57	573	456	240	25	-	-	-	-	-	-	-	-	-
51	Opening Balance, Adjustment	- Line 41	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Gross Additions		100	-	-	-	-	-	-	-	-	-	-	-	-
53	Tax		(26)	-	-	-	-	-	-	-	-	-	-	-	-
54	Net Additions		74	-	-	-	-	-	-	-	-	-	-	-	-
55	Amortization Expense		(191)	(216)	(216)	(25)	-	-	-	-	-	-	-	-	-
56	Closing Balance	Lines 50 + 54 + 55	456	240	25	-	-	-	-	-	-	-	-	-	-
57															
58	Deferred Charge, Mid-Year	(Line 50+ Line 51 + Line 56) / 2	515	348	133	12	-	-	-	-	-	-	-	-	-
59															
60	1- (Line 29 + 32) x [Schedule 11 , (Lines 10 x 11+ Lines 12 x 13) x (1- Tax Rate)]														
61	2- Adjustment to net account to zero in final year; result of varying WACC rates throughout contract														

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Deferred Charges
Appendix F-1 - Schedule 10
($000's), unless otherwise stated

Line	Particulars	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	*Deferred Charge- O&M*												
2	Opening Balance	-	-	-	-	-	-	-	-	-	-	-	-
3	Gross Additions	-	-	-	-	-	-	-	-	-	-	-	-
4	Tax	-	-	-	-	-	-	-	-	-	-	-	-
5	AFUDC	-	-	-	-	-	-	-	-	-	-	-	-
6	Net Additions	-	-	-	-	-	-	-	-	-	-	-	-
7	Amortization Expense @ 3 years	-	-	-	-	-	-	-	-	-	-	-	-
8	Closing Balance	-	-	-	-	-	-	-	-	-	-	-	-
9													
10	*Deferred Charge- Preliminary Investigation*												
11	Opening Balance	-	-	-	-	-	-	-	-	-	-	-	-
12	Gross Additions	-	-	-	-	-	-	-	-	-	-	-	-
13	Tax	-	-	-	-	-	-	-	-	-	-	-	-
14	AFUDC	-	-	-	-	-	-	-	-	-	-	-	-
15	Net Additions	-	-	-	-	-	-	-	-	-	-	-	-
16	Amortization Expense @ 3 years	-	-	-	-	-	-	-	-	-	-	-	-
17	Closing Balance	-	-	-	-	-	-	-	-	-	-	-	-
48													
49	**Deferred Charge- Rate Base**												
50	Opening Balance	-	-	-	-	-	-	-	-	-	-	-	-
51	Opening Balance, Adjustment	-	-	-	-	-	-	-	-	-	-	-	-
52	Gross Additions	-	-	-	-	-	-	-	-	-	-	-	-
53	Tax	-	-	-	-	-	-	-	-	-	-	-	-
54	Net Additions	-	-	-	-	-	-	-	-	-	-	-	-
55	Amortization Expense	-	-	-	-	-	-	-	-	-	-	-	-
56	Closing Balance	-	-	-	-	-	-	-	-	-	-	-	-
57													
58	Deferred Charge, Mid-Year	-	-	-	-	-	-	-	-	-	-	-	-
59													
60	1- (Line 29 + 32) x [Schedule 11 , (Lines 10 x 11+ Lines 12 x 1												
61	2- Adjustment to net account to zero in final year; result of												

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Present Value & Average Levelized Cost of Service
Appendix F-1 - Schedule 11
($000's), unless otherwise stated

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1															
2	Annual Cost of Service (Excluding Cost of Energy)($000s)	Schedule 1, Line 13	1,133.2	1,062.1	1,055.3	785.3	748.9	743.1	738.7	733.7	727.9	721.2	713.9	705.9	697.3
4															
5	**Annual Discount Rate**														
6	Equity Component														
7	ROE %		8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%
8	Equity Portion		38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%
9	Debt Component														
10	Long Term Debt Rate		6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
11	Long Term Debt Portion		56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%
12	Short Term Debt Rate		3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
13	Short Term Debt Portion		4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%
14															
15	Tax Rate		26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%
16	Pre- Tax Weighted Average Cost of Capital (WACC)[1]		8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%
17	After- Tax Weighted Average Cost of Capital (WACC)[2]		6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%
18															
19	**Present Value of Cost of Service**														
20	PV of Annual Revenue Requirement	Line 2 / (1 + Line 17)^Yr	1,065.2	938.5	876.5	613.1	549.6	512.7	479.1	447.3	417.1	388.5	361.5	336.0	312.0
21	PV of Annual Revenue Requirement ($/Mnth)		89	78	73	51	46	43	40	37	35	32	30	28	26
22	Total PV of Revenue Requirement	Sum of Line 20	9,580.4												
23	Total PV of Revenue Requirement, $000s/Yr	Line 22 / Yrs	383.2												
24															
25	PV of Annual Customers	Line 3 / (1 + Line 17)^Yr	1	1	1	1	1	1	1	1	1	1	1	0	0
26	Total PV of Customers	Sum of Line 24	12												
27															
28	**Present Value of Cost of Energy**														
29	Cost of Energy		-	-	-	-	-	-	-	-	-	-	-	-	-
30	PV of Annual Cost of Energy	Line 29 / (1 + Line 17)^Yr	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Total PV of Cost of Energy	Sum of Line 30	-												
32															
33	Energy Produced (GJ)		-	-	-	-	-	-	-	-	-	-	-	-	-
34	PV of Energy Produced (GJ)		-	-	-	-	-	-	-	-	-	-	-	-	-
35	Total PV of Energy Produced (GJ)		-												
36															
37	Levelized Revenue Requirement/Energy Produced ($/GJ)		-												
38															
39	**Average Cost of Service Analysis**														
40	Annual Volume (TJ)		161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111
41															
44	Annual Volumetric Cost of Service $/GJ	Line 2 / Line 40	0.007	0.007	0.007	0.005	0.005	0.005	0.005	0.005	0.005	0.004	0.004	0.004	0.004
45															
46	**Levelized Cost of Service Analysis**														
47	PV of Annual Volume (TJ)	Line 40 / (1 + Line 17)^Yr	151,445	142,359	133,818	125,789	118,242	111,148	104,480	98,211	92,319	86,780	81,574	76,680	72,079
48	Total PV of Volume (TJ)	Sum of Line 47	1,986,749												
49															
52	Average Levelized Volumetric Cost of Service ($/GJ)	Line 22 / Line 48	**0.005**												
53															
54	1- (Line 7 x Line 8) / 1- Line 15 + (Line 10 x Line 11 + Line 12 x Line 13)														
55	2- Line 8 x Line 9 + [(Line 11 x Line 12 + Line 13 x Line 14) x 1- Line 16]														

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Present Value & Average Levelized Cost of
Appendix F-1 - Schedule 11
($000's), unless otherwise stated

Line	Particulars	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1													
2	Annual Cost of Service (Excluding Cost of Energy)($000s)	688.1	678.4	668.3	657.7	646.7	635.4	623.7	611.7	599.5	587.0	458.3	435.3
4													
5	**Annual Discount Rate**												
6	Equity Component												
7	ROE %	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%
8	Equity Portion	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%
9	Debt Component												
10	Long Term Debt Rate	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
11	Long Term Debt Portion	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%
12	Short Term Debt Rate	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
13	Short Term Debt Portion	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%
14													
15	Tax Rate	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%
16	Pre- Tax Weighted Average Cost of Capital (WACC)[1]	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%
17	After- Tax Weighted Average Cost of Capital (WACC)[2]	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%
18													
19	**Present Value of Cost of Service**												
20	PV of Annual Revenue Requirement	289.4	268.2	248.3	229.7	212.3	196.1	181.0	166.8	153.7	141.4	103.8	92.7
21	PV of Annual Revenue Requirement ($/Mnth)	24	22	21	19	18	16	15	14	13	12	9	8
22	Total PV of Revenue Requirement												
23	Total PV of Revenue Requirement, $000s/Yr												
24													
25	PV of Annual Customers	0	0	0	0	0	0	0	0	0	0	0	0
26	Total PV of Customers												
27													
28	**Present Value of Cost of Energy**												
29	Cost of Energy	-	-	-	-	-	-	-	-	-	-	-	-
30	PV of Annual Cost of Energy	-	-	-	-	-	-	-	-	-	-	-	-
31	Total PV of Cost of Energy												
32													
33	Energy Produced (GJ)	-	-	-	-	-	-	-	-	-	-	-	-
34	PV of Energy Produced (GJ)	-	-	-	-	-	-	-	-	-	-	-	-
35	Total PV of Energy Produced (GJ)												
36													
37	Levelized Revenue Requirement/Energy Produced ($/GJ)												
38													
39	**Average Cost of Service Analysis**												
40	Annual Volume (TJ)	161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111
41													
44	Annual Volumetric Cost of Service $/GJ	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.003	0.003
45													
46	**Levelized Cost of Service Analysis**												
47	PV of Annual Volume (TJ)	67,755	63,690	59,868	56,277	52,900	49,726	46,743	43,939	41,302	38,824	36,495	34,306
48	Total PV of Volume (TJ)												
49													
52	Average Levelized Volumetric Cost of Service ($/GJ)												
53													
54	1- (Line 7 x Line 8) / 1- Line 15 + (Line 10 x Line 11 + Line 12 x Line 13)												
55	2- Line 8 x Line 9 + [(Line 11 x Line 12 + Line 13 x Line 14) x 1- Line 16]												

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Discounted Cash Flow Analysis
Appendix F-1 - Schedule 12
($000's), unless otherwise stated

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	**Cash Flow**														
2	Add: Revenue	Schedule , Line 6	1,133.2	1,062.1	1,055.3	785.3	748.9	743.1	738.7	733.7	727.9	721.2	713.9	705.9	697.3
3	Less: O&M, Property Tax Expense & Cost of Energy	Schedule 1, - (Line 2 + Line 4) + Schedule 2, - Line 15	(15.0)	(25.6)	(37.4)	(37.2)	(37.7)	(35.6)	(35.8)	(36.3)	(36.8)	(37.4)	(37.9)	(38.5)	(39.0)
4	EBITDA[1]	Line 2 + Line 3	1,118.2	1,036.5	1,017.9	748.1	711.2	707.6	703.0	697.4	691.0	683.9	676.0	667.4	658.2
5	Capital Expenditures[2]	Schedule 6, Line 99	(7,977.3)	-	-	-	-	-	-	-	-	-	-	-	-
6	Deferred Charges, Net of Tax		(647.1)	-	-	-	-	-	-	-	-	-	-	-	-
7	Disposal Costs Incurred														
8	Pre-Tax Cash Flow		(6,859.1)	1,036.5	1,017.9	748.1	711.2	707.6	703.0	697.4	691.0	683.9	676.0	667.4	658.2
9	Income Tax on Operations	Line 4 * - Schedule 3, Line 14	(290.7)	(269.5)	(264.7)	(194.5)	(184.9)	(184.0)	(182.8)	(181.3)	(179.7)	(177.8)	(175.8)	(173.5)	(171.1)
10	Overhead Capitalized Tax Shield	Schedule 3, - Line 10 * Line14	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
11	CCA / Removal Cost Tax Shield	Schedule 3, - (Line 11 + Line 9) * Line 14	78.5	150.7	138.7	127.7	117.5	108.2	99.6	91.7	84.4	77.7	71.5	65.9	60.6
12	Terminal Value of CCA Tax Shield														
13	Terminal Value	Year 25, Line 15 / Line 17													
14															
15	Free Cash Flow	Line 8 + Line 9	(7,071.1)	918.0	892.2	681.5	644.1	632.1	620.1	608.1	596.0	584.0	572.0	560.0	548.0
16															
17	After Tax WACC %	Schedule 11, Line 17	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%
18	Present Value of Free Cash Flow [3]	Line 15 / (1 + Line 17)^Yr	(7,772.6)	811.2	741.1	532.1	472.7	436.0	402.1	370.7	341.5	314.6	289.6	266.5	245.2
19	Total Present Value of Free Cash Flow	Sum of Line 18	**142.4**												
20															
21	1- Earnings Before Interest, Taxes, Depreciation & Amortization (EBITDA)														
22	2- Net of CIAC and removal costs (if applicable) and excludes capitalized overhead														
23	3- 2016 present value calculates capital expenditure to occur at time zero														

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Discounted Cash Flow Analysis
Appendix F-1 - Schedule 12
($000's), unless otherwise stated

Line	Particulars	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	**Cash Flow**												
2	Add: Revenue	688.1	678.4	668.3	657.7	646.7	635.4	623.7	611.7	599.5	587.0	458.3	435.3
3	Less: O&M, Property Tax Expense & Cost of Energy	(39.6)	(40.2)	(40.8)	(41.4)	(42.0)	(42.6)	(43.2)	(43.9)	(44.5)	(45.2)	(45.8)	(46.5)
4	EBITDA[1]	648.5	638.2	627.5	616.3	604.7	592.8	580.5	567.9	555.0	541.8	412.5	388.8
5	Capital Expenditures[2]	-	-	-	-	-	-	-	-	-	-	(111.0)	(0.0)
6	Deferred Charges, Net of Tax	-	-	-	-	-	-	-	-	-	-	-	-
7	Disposal Costs Incurred												
8	Pre-Tax Cash Flow	648.5	638.2	627.5	616.3	604.7	592.8	580.5	567.9	555.0	541.8	301.5	388.8
9	Income Tax on Operations	(168.6)	(165.9)	(163.1)	(160.2)	(157.2)	(154.1)	(150.9)	(147.6)	(144.3)	(140.9)	(107.2)	(101.1)
10	Overhead Capitalized Tax Shield	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4
11	CCA / Removal Cost Tax Shield	55.8	51.4	47.4	43.6	40.2	37.0	34.1	31.4	28.9	26.7	53.4	22.7
12	Terminal Value of CCA Tax Shield												145.6
13	Terminal Value												4,507.7
14													
15	Free Cash Flow	536.0	524.0	512.0	500.0	488.0	476.0	464.0	452.0	440.0	428.0	248.0	4,964.1
16													
17	After Tax WACC %	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%
18	Present Value of Free Cash Flow [3]	225.4	207.2	190.3	174.7	160.2	146.9	134.6	123.3	112.8	103.1	56.2	1,057.0
19	Total Present Value of Free Cash Flow												
20													
21	1- Earnings Before Interest, Taxes, Depreciation & Amortization (EBITDA)												
22	2- Net of CIAC and removal costs (if applicable) and excludes capitalized ov												
23	3- 2016 present value calculates capital expenditure to occur at time zero												

Appendix F2

FINANCIAL SCHEDULES – COS 60 YEAR

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Cost of Service
Appendix F-2 - Schedule 1
($000's), unless otherwise stated

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	**Cost of Service**																
2	Cost of Energy Sold		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Operation and Maintenance	Schedule 2, Line 19	13	13	13	14	14	14	15	15	15	15	16	16	16	17	17
4	Property Taxes	Schedule 2, Line 29	-	10	22	21	21	19	19	19	19	19	20	20	20	20	20
5	Depreciation Expense	Schedule 8, Line 49 + Line 102	179	179	179	179	179	179	179	179	179	179	179	179	179	180	180
6	Removal Cost Provision	Schedule 9, Line 47	6	12	12	12	12	12	12	12	12	12	12	12	12	12	12
7	Amortization Expense	Schedule 10, Line 55	191	216	216	25	-	-	-	-	-	-	-	-	-	-	-
8	Other Revenue	Schedule 2, Line 24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Income Taxes	Schedule 3, Line 21	124	34	45	(11)	(8)	3	12	20	28	35	41	47	51	56	59
10	Earned Return	Schedule 5, Line 27	620	599	568	546	531	517	503	489	475	460	446	432	418	404	390
11																	
12	**Annual Cost of Service**	Sum of Lines 2 through 10	**1,133**	**1,062**	**1,055**	**785**	**749**	**743**	**739**	**734**	**728**	**721**	**714**	**706**	**697**	**688**	**678**
13	**Cost of Service- Excluding Cost of Energy**	Sum of Lines 3 through 10	**1,133**	**1,062**	**1,055**	**785**	**749**	**743**	**739**	**734**	**728**	**721**	**714**	**706**	**697**	**688**	**678**
14	**Cost of Service Impact as a % of Delivery Margin**		0.19%	0.18%	0.18%	0.13%	0.13%	0.13%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.11%

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Cost of Service
Appendix F-2 - Schedule 1
($000's), unless otherwise stated

Line	Particulars	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	**Cost of Service**															
2	Cost of Energy Sold	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Operation and Maintenance	17	18	18	18	19	19	20	20	20	21	21	22	22	22	23
4	Property Taxes	21	21	21	21	21	22	22	22	22	22	24	26	26	27	27
5	Depreciation Expense	180	180	180	180	180	180	180	180	201	240	240	240	240	241	241
6	Removal Cost Provision	12	12	12	12	12	12	12	12	13	14	14	14	14	14	14
7	Amortization Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Other Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Income Taxes	63	65	68	70	72	73	74	75	14	41	48	55	61	67	71
10	Earned Return	376	362	348	334	320	306	292	278	409	538	520	502	484	466	447
11																
12	**Annual Cost of Service**	**668**	**658**	**647**	**635**	**624**	**612**	**599**	**587**	**680**	**876**	**867**	**859**	**848**	**836**	**823**
13	**Cost of Service- Excluding Cost of Energy**	**668**	**658**	**647**	**635**	**624**	**612**	**599**	**587**	**680**	**876**	**867**	**859**	**848**	**836**	**823**
14	**Cost of Service Impact as a % of Delivery Margin**	0.11%	0.11%	0.11%	0.11%	0.11%	0.10%	0.10%	0.10%	0.12%	0.15%	0.15%	0.15%	0.14%	0.14%	0.14%

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Cost of Service
Appendix F-2 - Schedule 1
($000's), unless otherwise stated

Line	Particulars	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060
1	**Cost of Service**															
2	Cost of Energy Sold	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Operation and Maintenance	23	24	24	25	25	26	26	27	27	28	28	29	30	30	31
4	Property Taxes	27	27	28	28	28	28	29	29	29	30	30	30	30	31	31
5	Depreciation Expense	241	241	241	241	241	241	241	241	242	242	242	242	242	180	241
6	Removal Cost Provision	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
7	Amortization Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Other Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Income Taxes	75	79	82	84	86	88	89	90	91	91	92	91	91	69	90
10	Earned Return	428	409	391	372	353	335	316	297	279	260	241	223	204	187	171
11																
12	**Annual Cost of Service**	**809**	**795**	**780**	**764**	**749**	**732**	**716**	**699**	**682**	**665**	**647**	**629**	**611**	**511**	**578**
13	**Cost of Service- Excluding Cost of Energy**	**809**	**795**	**780**	**764**	**749**	**732**	**716**	**699**	**682**	**665**	**647**	**629**	**611**	**511**	**578**
14	**Cost of Service Impact as a % of Delivery Margin**	0.14%	0.13%	0.13%	0.13%	0.13%	0.12%	0.12%	0.12%	0.12%	0.11%	0.11%	0.11%	0.10%	0.09%	0.10%

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Cost of Service
Appendix F-2 - Schedule 1
($000's), unless otherwise stated

Line	Particulars	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075
1	**Cost of Service**															
2	Cost of Energy Sold	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Operation and Maintenance	31	32	33	33	34	35	35	36	37	38	38	39	40	41	42
4	Property Taxes	31	32	32	36	38	39	39	39	40	40	41	41	42	42	43
5	Depreciation Expense	241	362	346	346	346	347	347	347	347	347	347	348	348	348	348
6	Removal Cost Provision	14	16	19	19	19	19	19	19	19	19	19	19	19	19	19
7	Amortization Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Other Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Income Taxes	89	79	28	39	48	57	64	71	77	82	86	89	92	95	96
10	Earned Return	153	363	570	543	516	489	463	438	412	386	359	332	305	279	252
11																
12	**Annual Cost of Service**	**559**	**885**	**1,028**	**1,016**	**1,002**	**985**	**967**	**950**	**932**	**911**	**890**	**868**	**845**	**822**	**799**
13	**Cost of Service- Excluding Cost of Energy**	**559**	**885**	**1,028**	**1,016**	**1,002**	**985**	**967**	**950**	**932**	**911**	**890**	**868**	**845**	**822**	**799**
14	**Cost of Service Impact as a % of Delivery Margin**	0.09%	0.15%	0.17%	0.17%	0.17%	0.17%	0.16%	0.16%	0.16%	0.15%	0.15%	0.15%	0.14%	0.14%	0.14%

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: O&M, Other Revenue and Property Tax
Appendix F-2 - Schedule 2
($000's), unless otherwise stated

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	**Gross O&M**																
2	Distribution Total		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3																	
4	Transmission Total		15	15	16	16	16	17	17	17	18	18	18	19	19	19	20
5	Storage Total		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Measurement		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	General Operations Total		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Marketing Total		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Customer Care Total		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Business & IT Services Total		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Administration & General Total		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12																	
13			15	15	16	16	16	17	17	17	18	18	18	19	19	19	20
14																	
15	Total Gross O&M Expenses		15	15	16	16	16	17	17	17	18	18	18	19	19	19	20
16																	
17	(Less): Capitalized Overhead	Overhead rate of 14%	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(3)
18	Add (Less): Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Net O&M		13	13	13	14	14	14	15	15	15	15	16	16	16	17	17
20																	
21	**Other Revenue**																
22	Environmental Credits		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Miscellaneous		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Other Revenue		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																	
26	**Property Taxes**																
27	General, School and Other		-	10	10	11	11	11	11	12	12	12	12	13	13	13	13
28	1% in Lieu of General Municipal Tax[1]	Schedule , Line 6/1000 x 1%	-	-	11	11	11	8	7	7	7	7	7	7	7	7	7
29	Total Property Taxes		-	10	22	21	21	19	19	19	19	19	20	20	20	20	20
30																	
31	1- Calculation is based on the second preceeding year; ex., 2018 is based on 2016 revenue																

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: O&M, Other Re
Appendix F-2 - Schedule 2
($000's), unless otherwise stated

Line	Particulars	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	**Gross O&M**															
2	Distribution Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3																
4	Transmission Total	20	21	21	21	22	22	23	23	24	24	25	25	26	26	27
5	Storage Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Measurement	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	General Operations Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Marketing Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Customer Care Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Business & IT Services Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Administration & General Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12																
13		20	21	21	21	22	22	23	23	24	24	25	25	26	26	27
14																
15	Total Gross O&M Expenses	20	21	21	21	22	22	23	23	24	24	25	25	26	26	27
16																
17	(Less): Capitalized Overhead	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(4)	(4)	(4)	(4)
18	Add (Less): Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Net O&M	17	18	18	18	19	19	20	20	20	21	21	22	22	22	23
20																
21	**Other Revenue**															
22	Environmental Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Miscellaneous	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Other Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																
26	**Property Taxes**															
27	General, School and Other	14	14	14	15	15	15	16	16	16	17	17	17	18	18	18
28	1% in Lieu of General Municipal Tax[1]	7	7	7	7	6	6	6	6	6	6	7	9	9	9	8
29	Total Property Taxes	21	21	21	21	21	22	22	22	22	22	24	26	26	27	27
30																
31	1- Calculation is based on the second preceeding y															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: O&M, Other Re
Appendix F-2 - Schedule 2
($000's), unless otherwise stated

Line	Particulars	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060
1	**Gross O&M**															
2	Distribution Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3																
4	Transmission Total	27	28	28	29	29	30	31	31	32	32	33	34	34	35	36
5	Storage Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Measurement	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	General Operations Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Marketing Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Customer Care Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Business & IT Services Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Administration & General Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12																
13		27	28	28	29	29	30	31	31	32	32	33	34	34	35	36
14																
15	Total Gross O&M Expenses	27	28	28	29	29	30	31	31	32	32	33	34	34	35	36
16																
17	(Less): Capitalized Overhead	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(5)	(5)	(5)	(5)	(5)	(5)
18	Add (Less): Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Net O&M	23	24	24	25	25	26	26	27	27	28	28	29	30	30	31
20																
21	**Other Revenue**															
22	Environmental Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Miscellaneous	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Other Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																
26	**Property Taxes**															
27	General, School and Other	19	19	20	20	20	21	21	22	22	23	23	24	24	25	25
28	1% in Lieu of General Municipal Tax[1]	8	8	8	8	8	8	7	7	7	7	7	7	6	6	6
29	Total Property Taxes	27	27	28	28	28	28	29	29	29	30	30	30	30	31	31
30																
31	1- Calculation is based on the second preceeding y															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: O&M, Other Re
Appendix F-2 - Schedule 2
($000's), unless otherwise stated

Line	Particulars	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075
1	**Gross O&M**															
2	Distribution Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3																
4	Transmission Total	37	37	38	39	40	40	41	42	43	44	45	45	46	47	48
5	Storage Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Measurement	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	General Operations Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Marketing Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Customer Care Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Business & IT Services Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Administration & General Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12																
13		37	37	38	39	40	40	41	42	43	44	45	45	46	47	48
14																
15	Total Gross O&M Expenses	37	37	38	39	40	40	41	42	43	44	45	45	46	47	48
16																
17	(Less): Capitalized Overhead	(5)	(5)	(5)	(5)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(7)	(7)
18	Add (Less): Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Net O&M	31	32	33	33	34	35	35	36	37	38	38	39	40	41	42
20																
21	**Other Revenue**															
22	Environmental Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Miscellaneous	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Other Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25																
26	**Property Taxes**															
27	General, School and Other	26	26	27	27	28	28	29	30	30	31	31	32	33	33	34
28	1% in Lieu of General Municipal Tax[1]	5	6	6	9	10	10	10	10	10	10	9	9	9	9	8
29	Total Property Taxes	31	32	32	36	38	39	39	39	40	40	41	41	42	42	43
30																
31	1- Calculation is based on the second preceeding y															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Income Tax Expense
Appendix F-2 - Schedule 3
($000's), unless otherwise statea

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Income Tax Expense																
2																	
3	Earned Return	Schedule 5, Line 27	619.8	598.6	568.5	545.5	530.6	516.6	502.6	488.5	474.5	460.5	446.5	432.5	418.4	404.4	390.4
4	Deduct: Interest on debt	Schedule 5, Line 26	(339.2)	(327.6)	(311.1)	(298.6)	(290.4)	(282.7)	(275.1)	(267.4)	(259.7)	(252.0)	(244.4)	(236.7)	(229.0)	(221.3)	(213.7)
5	Add (Deduct): Amortization Expense	Schedule 10, Line 55	191.0	215.7	215.7	24.7	-	-	-	-	-	-	-	-	-	-	-
6	Add: Depreciation Expense	Schedule 8, Line 49 + Line 102	179.3	178.9	178.9	179.0	179.0	179.1	179.1	179.2	179.2	179.3	179.4	179.4	179.5	179.5	179.6
7	Add: Removal Cost Provision	Schedule 9, Line 47	5.8	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
8	Add: Earnings Stabilization Account Other Revenue	Schedule 10, Line 30 /1000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Deduct: Removal Costs Incurred	Schedule 9, Line 70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Deduct: Overhead Capitalized Expensed for Tax Purposes	Schedule 2 , Line 17 x 6 / 14	(0.9)	(0.9)	(0.9)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.2)	(1.2)
11	Deduct: Capital Cost Allowance	Schedule 4, Line 130	(301.9)	(579.8)	(533.7)	(491.2)	(452.1)	(416.2)	(383.1)	(352.7)	(324.6)	(298.9)	(275.2)	(253.3)	(233.3)	(214.8)	(197.8)
12	Taxable Income After Tax	Sum of Lines 3 through 11	353.9	96.5	129.0	(29.9)	(22.3)	7.4	34.2	58.3	80.0	99.4	116.9	132.4	146.1	158.3	169.0
13																	
14	Income Tax Rate		26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%
15	1 - Current Income Tax Rate	1 - Line 14	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%
16																	
17	Taxable Income	Line 12 / Line 15	478.3	130.3	174.3	(40.4)	(30.1)	10.0	46.2	78.8	108.1	134.4	157.9	178.9	197.5	213.9	228.4
18																	
19	Total Income Tax Expense	Line 17 x Line 14	124.4	33.9	45.3	(10.5)	(7.8)	2.6	12.0	20.5	28.1	34.9	41.1	46.5	51.3	55.6	59.4
20	Adjustments		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Net Tax Expense	Line 19 + Line 20	124.4	33.9	45.3	(10.5)	(7.8)	2.6	12.0	20.5	28.1	34.9	41.1	46.5	51.3	55.6	59.4
22																	

Huntingdon Station Bypass Project: Income Tax Expense
Appendix F-2 - Schedule 3
($000's), unless otherwise statea

Line	Particulars	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	**Income Tax Expense**															
2																
3	Earned Return	376.4	362.3	348.3	334.3	320.3	306.2	292.2	278.2	409.4	538.4	519.7	502.0	484.2	465.6	446.9
4	Deduct: Interest on debt	(206.0)	(198.3)	(190.6)	(183.0)	(175.3)	(167.6)	(159.9)	(152.2)	(224.1)	(294.6)	(284.4)	(274.7)	(265.0)	(254.8)	(244.6)
5	Add (Deduct): Amortization Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Add: Depreciation Expense	179.7	179.7	179.8	179.9	180.0	180.0	180.1	180.2	201.4	239.9	239.9	240.1	240.5	240.6	240.7
7	Add: Removal Cost Provision	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	12.9	14.1	14.1	14.1	14.2	14.2	14.2
8	Add: Earnings Stabilization Account Other Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Deduct: Removal Costs Incurred	-	-	-	-	-	-	-	-	(111.0)	-	-	-	-	-	-
10	Deduct: Overhead Capitalized Expensed for Tax Purposes	(1.2)	(1.2)	(1.3)	(1.3)	(1.3)	(1.3)	(1.4)	(1.4)	(1.4)	(1.4)	(1.5)	(1.5)	(1.5)	(1.6)	(1.6)
11	Deduct: Capital Cost Allowance	(182.1)	(167.8)	(154.5)	(142.3)	(131.1)	(120.8)	(111.3)	(102.6)	(247.3)	(380.3)	(350.1)	(323.0)	(298.1)	(274.5)	(252.7)
12	Taxable Income After Tax	178.3	186.4	193.3	199.2	204.1	208.1	211.3	213.7	39.9	115.9	137.8	157.0	174.2	189.4	202.8
13																
14	Income Tax Rate	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%
15	1 - Current Income Tax Rate	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%
16																
17	Taxable Income	241.0	251.9	261.3	269.2	275.8	281.2	285.5	288.8	53.9	156.7	186.2	212.1	235.4	256.0	274.0
18																
19	Total Income Tax Expense	62.7	65.5	67.9	70.0	71.7	73.1	74.2	75.1	14.0	40.7	48.4	55.2	61.2	66.6	71.2
20	Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Net Tax Expense	62.7	65.5	67.9	70.0	71.7	73.1	74.2	75.1	14.0	40.7	48.4	55.2	61.2	66.6	71.2
22																

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Income Tax Expense
Appendix F-2 - Schedule 3
($000's), unless otherwise stated

Line	Particulars	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060
1	**Income Tax Expense**															
2																
3	Earned Return	428.2	409.5	390.8	372.1	353.4	334.7	316.0	297.4	278.7	260.0	241.3	222.6	203.9	187.5	171.2
4	Deduct: Interest on debt	(234.3)	(224.1)	(213.9)	(203.7)	(193.4)	(183.2)	(173.0)	(162.7)	(152.5)	(142.3)	(132.0)	(121.8)	(111.6)	(102.6)	(93.7)
5	Add (Deduct): Amortization Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Add: Depreciation Expense	240.8	240.8	240.9	241.0	241.1	241.2	241.3	241.4	241.5	241.6	241.7	241.9	242.0	179.5	240.8
7	Add: Removal Cost Provision	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2
8	Add: Earnings Stabilization Account Other Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Deduct: Removal Costs Incurred	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Deduct: Overhead Capitalized Expensed for Tax Purposes	(1.6)	(1.7)	(1.7)	(1.7)	(1.8)	(1.8)	(1.8)	(1.9)	(1.9)	(1.9)	(2.0)	(2.0)	(2.1)	(2.1)	(2.2)
11	Deduct: Capital Cost Allowance	(232.7)	(214.3)	(197.4)	(181.8)	(167.5)	(154.3)	(142.2)	(131.0)	(120.8)	(111.4)	(102.7)	(94.7)	(87.4)	(80.6)	(74.4)
12	Taxable Income After Tax	214.4	224.4	232.9	240.1	246.0	250.8	254.5	257.3	259.1	260.2	260.4	260.0	259.0	195.9	255.9
13																
14	Income Tax Rate	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%
15	1 - Current Income Tax Rate	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%
16																
17	Taxable Income	289.7	303.2	314.7	324.4	332.4	338.9	343.9	347.7	350.2	351.6	352.0	351.4	350.0	264.7	345.9
18																
19	Total Income Tax Expense	75.3	78.8	81.8	84.4	86.4	88.1	89.4	90.4	91.0	91.4	91.5	91.4	91.0	68.8	89.9
20	Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Net Tax Expense	75.3	78.8	81.8	84.4	86.4	88.1	89.4	90.4	91.0	91.4	91.5	91.4	91.0	68.8	89.9
22																

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Income Tax Expense
Appendix F-2 - Schedule 3
($000's), unless otherwise stated

Line	Particulars	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075
1	**Income Tax Expense**															
2																
3	Earned Return	152.6	363.1	569.7	543.0	516.2	489.5	462.7	437.6	412.4	385.6	358.8	332.1	305.3	278.5	251.8
4	Deduct: Interest on debt	(83.5)	(198.7)	(311.8)	(297.2)	(282.5)	(267.9)	(253.2)	(239.5)	(225.7)	(211.1)	(196.4)	(181.7)	(167.1)	(152.4)	(137.8)
5	Add (Deduct): Amortization Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Add: Depreciation Expense	240.9	362.0	346.4	346.4	346.5	346.5	346.6	347.3	347.4	347.4	347.5	347.5	347.6	347.6	347.7
7	Add: Removal Cost Provision	14.2	16.4	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6
8	Add: Earnings Stabilization Account Other Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Deduct: Removal Costs Incurred	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Deduct: Overhead Capitalized Expensed for Tax Purposes	(2.2)	(2.2)	(2.3)	(2.3)	(2.4)	(2.4)	(2.5)	(2.5)	(2.6)	(2.6)	(2.7)	(2.7)	(2.8)	(2.8)	(2.9)
11	Deduct: Capital Cost Allowance	(68.7)	(314.9)	(541.3)	(498.3)	(458.7)	(422.3)	(388.7)	(359.2)	(332.1)	(305.9)	(281.7)	(259.5)	(239.1)	(220.3)	(203.1)
12	Taxable Income After Tax	253.2	225.6	79.3	110.2	137.7	162.0	183.4	202.2	218.0	232.1	244.1	254.2	262.5	269.2	274.4
13																
14	Income Tax Rate	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%
15	1 - Current Income Tax Rate	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%	74.00%
16																
17	Taxable Income	342.2	304.9	107.1	148.9	186.1	218.9	247.9	273.3	294.6	313.7	329.9	343.5	354.8	363.8	370.8
18																
19	Total Income Tax Expense	89.0	79.3	27.9	38.7	48.4	56.9	64.4	71.1	76.6	81.6	85.8	89.3	92.2	94.6	96.4
20	Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Net Tax Expense	89.0	79.3	27.9	38.7	48.4	56.9	64.4	71.1	76.6	81.6	85.8	89.3	92.2	94.6	96.4
22																

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Capital Cost Allowance
Appendix F-2 - Schedule 4
($000's), unless otherwise stated

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	**Structures & Improvements- Class 1.3 @ 6%**																
2	Opening Balance	Preceeding Year, Line 5	-	14	13	12	11	11	10	10	9	8	8	7	7	7	6
3	Additions	Schedule 7 , Line 28 - AFUDC	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	CCA	[Line 2 + (Line 3 x 1/2)] x CCA Rate	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)
5	Closing Balance	Sum of Lines 2 through 4	14	13	12	11	11	10	10	9	8	8	7	7	7	6	6
6																	
7	**Pipeline - Transmission- Class 49 @ 8%**																
8	Opening Balance	Preceeding Year, Line 11	-	4,747	4,368	4,018	3,697	3,401	3,129	2,879	2,648	2,436	2,242	2,062	1,897	1,745	1,606
9	Additions	Schedule 7 , Line 29 - AFUDC	4,945	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	CCA	[Line 8 + (Line 9 x 1/2)] x CCA Rate	(198)	(380)	(349)	(321)	(296)	(272)	(250)	(230)	(212)	(195)	(179)	(165)	(152)	(140)	(128)
11	Closing Balance	Sum of Lines 8 through 10	4,747	4,368	4,018	3,697	3,401	3,129	2,879	2,648	2,436	2,242	2,062	1,897	1,745	1,606	1,477
12																	
13	**Land Rights- Class CECA @ 7%**																
14	Opening Balance	Preceeding Year, Line 17	-	184	172	160	148	138	128	119	111	103	96	89	83	77	72
15	Additions	Schedule 7 , Line 30 - AFUDC	191	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	CCA	[Line 14 + (Line 15 x 1/2)] x CCA Rate	(7)	(13)	(12)	(11)	(10)	(10)	(9)	(8)	(8)	(7)	(7)	(6)	(6)	(5)	(5)
17	Closing Balance	Sum of Lines 14 through 16	184	172	160	148	138	128	119	111	103	96	89	83	77	72	67
18																	
19	**Measuring & Regulating Equipment- Class 49 @ 8%**																
20	Opening Balance	Preceeding Year, Line 23	-	2,225	2,047	1,883	1,733	1,594	1,467	1,349	1,241	1,142	1,051	967	889	818	753
21	Additions	Schedule 7 , Line 31 - AFUDC	2,318	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	CCA	[Line 20 + (Line 21 x 1/2)] x CCA Rate	(93)	(178)	(164)	(151)	(139)	(128)	(117)	(108)	(99)	(91)	(84)	(77)	(71)	(65)	(60)
23	Closing Balance	Sum of Lines 20 through 22	2,225	2,047	1,883	1,733	1,594	1,467	1,349	1,241	1,142	1,051	967	889	818	753	692
24																	
25	**Telemetry- Class 49 @ 8%**																
26	Opening Balance	Preceeding Year, Line 29	-	101	93	86	79	73	67	62	57	52	48	44	41	37	34
27	Additions	Schedule 7 , Line 32 - AFUDC	106	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	CCA	[Line 26 + (Line 27 x 1/2)] x CCA Rate	(4)	(8)	(7)	(7)	(6)	(6)	(5)	(5)	(5)	(4)	(4)	(4)	(3)	(3)	(3)
29	Closing Balance	Sum of Lines 26 through 28	101	93	86	79	73	67	62	57	52	48	44	41	37	34	32
30																	
121	**Capitalized Overhead- Class average @ 7.6%**																
122	Opening Balance	Preceeding Year, Line 125	-	1	2	3	4	5	6	7	8	8	9	10	11	11	12
123	Additions	Schedule 2 , Line 17 x 8 / 14	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2
124	CCA	[Line 122 + (Line 123 x 1/2)] x CCA Rate	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
125	Closing Balance	Sum of Lines 122 through 124	1	2	3	4	5	6	7	8	8	9	10	11	11	12	13
126																	
127	**Total CCA**																
128	Opening Balance	Preceeding Year, Line 131	-	7,273	6,695	6,162	5,673	5,222	4,807	4,425	4,074	3,751	3,453	3,179	2,928	2,696	2,483
129	Additions		7,575	1	1	1	1	1	1	1	1	1	1	1	2	2	2
130	CCA		(302)	(580)	(534)	(491)	(452)	(416)	(383)	(353)	(325)	(299)	(275)	(253)	(233)	(215)	(198)
131	Closing Balance	Sum of Lines 128 through 130	7,273	6,695	6,162	5,673	5,222	4,807	4,425	4,074	3,751	3,453	3,179	2,928	2,696	2,483	2,286
132																	

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Capital Cost All
Appendix F-2 - Schedule 4
($000's), unless otherwise stated

Line	Particulars	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	**Structures & Improvements- Class 1.3 @ 6%**															
2	Opening Balance	6	5	5	5	5	4	4	4	4	3	3	3	27	25	24
3	Additions	-	-	-	-	-	-	-	-	-	-	-	25	-	-	-
4	CCA	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(2)	(2)	(1)
5	Closing Balance	5	5	5	5	4	4	4	4	3	3	3	27	25	24	22
6																
7	**Pipeline - Transmission- Class 49 @ 8%**															
8	Opening Balance	1,477	1,359	1,250	1,150	1,058	974	896	824	758	698	642	590	543	500	460
9	Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	CCA	(118)	(109)	(100)	(92)	(85)	(78)	(72)	(66)	(61)	(56)	(51)	(47)	(43)	(40)	(37)
11	Closing Balance	1,359	1,250	1,150	1,058	974	896	824	758	698	642	590	543	500	460	423
12																
13	**Land Rights- Class CECA @ 7%**															
14	Opening Balance	67	62	58	54	50	46	43	40	37	35	32	30	28	26	24
15	Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	CCA	(5)	(4)	(4)	(4)	(3)	(3)	(3)	(3)	(3)	(2)	(2)	(2)	(2)	(2)	(2)
17	Closing Balance	62	58	54	50	46	43	40	37	35	32	30	28	26	24	22
18																
19	**Measuring & Regulating Equipment- Class 49**															
20	Opening Balance	692	637	586	539	496	456	420	386	355	3,991	3,672	3,378	3,108	2,859	2,630
21	Additions	-	-	-	-	-	-	-	-	3,817	-	-	-	-	-	-
22	CCA	(55)	(51)	(47)	(43)	(40)	(37)	(34)	(31)	(181)	(319)	(294)	(270)	(249)	(229)	(210)
23	Closing Balance	637	586	539	496	456	420	386	355	3,991	3,672	3,378	3,108	2,859	2,630	2,420
24																
25	**Telemetry- Class 49 @ 8%**															
26	Opening Balance	32	29	27	25	23	21	19	18	16	15	14	13	12	11	10
27	Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	CCA	(3)	(2)	(2)	(2)	(2)	(2)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
29	Closing Balance	29	27	25	23	21	19	18	16	15	14	13	12	11	10	9
30																
121	**Capitalized Overhead- Class average @ 7.6%**															
122	Opening Balance	13	13	14	14	15	15	16	16	17	18	18	19	19	20	20
123	Additions	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
124	CCA	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)
125	Closing Balance	13	14	14	15	15	16	16	17	18	18	19	19	20	20	21
126																
127	**Total CCA**															
128	Opening Balance	2,286	2,106	1,940	1,787	1,646	1,517	1,398	1,288	1,188	4,759	4,381	4,033	3,737	3,441	3,168
129	Additions	2	2	2	2	2	2	2	2	3,819	2	2	27	2	2	2
130	CCA	(182)	(168)	(155)	(142)	(131)	(121)	(111)	(103)	(247)	(380)	(350)	(323)	(298)	(274)	(253)
131	Closing Balance	2,106	1,940	1,787	1,646	1,517	1,398	1,288	1,188	4,759	4,381	4,033	3,737	3,441	3,168	2,918
132																

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Capital Cost All
Appendix F-2 - Schedule 4
($000's), unless otherwise stated

Line	Particulars	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060
1	**Structures & Improvements- Class 1.3 @ 6%**															
2	Opening Balance	22	21	20	19	17	16	15	15	14	13	12	11	11	10	9
3	Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	CCA	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
5	Closing Balance	21	20	19	17	16	15	15	14	13	12	11	11	10	9	9
6																
7	**Pipeline - Transmission- Class 49 @ 8%**															
8	Opening Balance	423	389	358	329	303	279	256	236	217	200	184	169	156	143	132
9	Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	CCA	(34)	(31)	(29)	(26)	(24)	(22)	(21)	(19)	(17)	(16)	(15)	(14)	(12)	(11)	(11)
11	Closing Balance	389	358	329	303	279	256	236	217	200	184	169	156	143	132	121
12																
13	**Land Rights- Class CECA @ 7%**															
14	Opening Balance	22	21	19	18	17	16	15	14	13	12	11	10	9	9	8
15	Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	CCA	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
17	Closing Balance	21	19	18	17	16	15	14	13	12	11	10	9	9	8	8
18																
19	**Measuring & Regulating Equipment- Class 49**															
20	Opening Balance	2,420	2,226	2,048	1,884	1,734	1,595	1,467	1,350	1,242	1,143	1,051	967	890	819	753
21	Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	CCA	(194)	(178)	(164)	(151)	(139)	(128)	(117)	(108)	(99)	(91)	(84)	(77)	(71)	(65)	(60)
23	Closing Balance	2,226	2,048	1,884	1,734	1,595	1,467	1,350	1,242	1,143	1,051	967	890	819	753	693
24																
25	**Telemetry- Class 49 @ 8%**															
26	Opening Balance	9	8	8	7	6	6	5	5	5	4	4	4	3	3	3
27	Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	CCA	(1)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
29	Closing Balance	8	8	7	6	6	5	5	5	4	4	4	3	3	3	3
30																
121	**Capitalized Overhead- Class average @ 7.6%**															
122	Opening Balance	21	21	22	22	23	23	24	24	25	25	26	27	27	28	28
123	Additions	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3
124	CCA	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
125	Closing Balance	21	22	22	23	23	24	24	25	25	26	27	27	28	28	29
126																
127	**Total CCA**															
128	Opening Balance	2,918	2,687	2,475	2,280	2,100	1,935	1,783	1,643	1,515	1,397	1,288	1,188	1,096	1,011	933
129	Additions	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3
130	CCA	(233)	(214)	(197)	(182)	(168)	(154)	(142)	(131)	(121)	(111)	(103)	(95)	(87)	(81)	(74)
131	Closing Balance	2,687	2,475	2,280	2,100	1,935	1,783	1,643	1,515	1,397	1,288	1,188	1,096	1,011	933	862
132																

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Capital Cost All
Appendix F-2 - Schedule 4
($000's), unless otherwise stated

Line	Particulars	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075
1	**Structures & Improvements- Class 1.3 @ 6%**															
2	Opening Balance	9	8	8	7	7	6	6	6	48	45	42	40	37	35	33
3	Additions	-	-	-	-	-	-	-	44	-	-	-	-	-	-	-
4	CCA	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(2)	(3)	(3)	(3)	(2)	(2)	(2)	(2)
5	Closing Balance	8	8	7	7	6	6	6	48	45	42	40	37	35	33	31
6																
7	**Pipeline - Transmission- Class 49 @ 8%**															
8	Opening Balance	121	111	102	94	87	80	73	68	62	57	53	48	45	41	38
9	Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	CCA	(10)	(9)	(8)	(8)	(7)	(6)	(6)	(5)	(5)	(5)	(4)	(4)	(4)	(3)	(3)
11	Closing Balance	111	102	94	87	80	73	68	62	57	53	48	45	41	38	35
12																
13	**Land Rights- Class CECA @ 7%**															
14	Opening Balance	8	7	7	6	-	-	-	-	-	-	-	-	-	-	-
15	Additions	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0
16	CCA	(1)	(0)	(0)	(0)	6	5	5	5	4	4	4	3	3	3	3
17	Closing Balance	7	7	6	6	-	-	-	-	-	-	-	-	-	-	-
18																
19	**Measuring & Regulating Equipment- Class 49**															
20	Opening Balance	693	637	6,620	6,091	-	-	-	-	-	-	-	-	-	-	-
21	Additions	-	6,285	-	-	-	-	-	-	-	-	-	-	-	-	-
22	CCA	(55)	(302)	(530)	(487)	-	-	-	-	-	-	-	-	-	-	-
23	Closing Balance	637	6,620	6,091	5,603	0	0	0	0	0	0	0	0	0	0	0
24																
25	**Telemetry- Class 49 @ 8%**															
26	Opening Balance	3	2	2	2	(448)	(412)	(379)	(349)	(321)	(295)	(272)	(250)	(230)	(212)	(195)
27	Additions	-	-	-	-	5,155	4,743	4,363	4,014	3,693	3,398	3,126	2,876	2,646	2,434	2,239
28	CCA	(0)	(0)	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-
29	Closing Balance	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-
30																
121	**Capitalized Overhead- Class average @ 7.6%**															
122	Opening Balance	29	30	30	31	31	32	33	33	34	35	36	36	37	38	39
123	Additions	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4
124	CCA	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
125	Closing Balance	30	30	31	31	32	33	33	34	35	36	36	37	38	39	39
126																
127	**Total CCA**															
128	Opening Balance	862	796	6,770	6,231	5,736	5,281	4,862	4,476	4,164	3,835	3,533	3,255	2,999	2,763	2,547
129	Additions	3	6,288	3	3	3	3	3	47	3	3	4	4	4	4	4
130	CCA	(69)	(315)	(541)	(498)	(459)	(422)	(389)	(359)	(332)	(306)	(282)	(260)	(239)	(220)	(203)
131	Closing Balance	796	6,770	6,231	5,736	5,281	4,862	4,476	4,164	3,835	3,533	3,255	2,999	2,763	2,547	2,348
132																

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Rate Base
Appendix F-2 - Schedule 5
($000's), unless otherwise stated

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	**Rate Base**																
2	Gross Plant In Service- Beginning	Schedule 7, Line 25	-	7,979	7,982	7,984	7,986	7,988	7,991	7,993	7,995	7,998	8,000	8,003	8,006	8,008	8,011
3	Gross Plant In Service- Ending	Schedule 7, Line 97	7,979	7,982	7,984	7,986	7,988	7,991	7,993	7,995	7,998	8,000	8,003	8,006	8,008	8,011	8,014
4																	
5	Accumulated Depreciation- Beginning	Schedule 8, Line 25	-	(179)	(358)	(537)	(716)	(895)	(1,074)	(1,253)	(1,432)	(1,612)	(1,791)	(1,970)	(2,150)	(2,329)	(2,509)
6	Accumulated Depreciation- Ending	Schedule 8, Line 97	(179)	(358)	(537)	(716)	(895)	(1,074)	(1,253)	(1,432)	(1,612)	(1,791)	(1,970)	(2,150)	(2,329)	(2,509)	(2,688)
7																	
8	Negative Salvage- Beginning	Schedule 9, Line 24	-	(6)	(17)	(29)	(41)	(52)	(64)	(76)	(87)	(99)	(110)	(122)	(134)	(145)	(157)
9	Negative Salvage- Ending	Schedule 9, Line 93	(6)	(17)	(29)	(41)	(52)	(64)	(76)	(87)	(99)	(110)	(122)	(134)	(145)	(157)	(169)
10																	
11	Contributions in Aid of Construction- Beginning	Schedule 7, Line 101	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Contributions in Aid of Construction- Ending	Schedule 7, Line 104	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13																	
14	Accumulated Amortization- Beginning	Schedule 8, Line 101	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Accumulated Amortization- Ending	Schedule 8, Line 104	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16																	
17	Net Plant in Service, Mid-Year	Sum (Lines 2 through 15)/2	3,897	7,700	7,512	7,323	7,135	6,947	6,758	6,570	6,381	6,193	6,005	5,816	5,628	5,439	5,251
18																	
19	Adjustment to 13-month average	[1]	3,921	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Unamortized Deferred Charges, Mid-Year	Schedule 10, Line 58	515	348	133	12	-	-	-	-	-	-	-	-	-	-	-
21	Cash Working Capital	[2]	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
22	**Total Rate Base**	**Sum of Lines 17 through 21**	**8,328**	**8,044**	**7,639**	**7,331**	**7,130**	**6,942**	**6,753**	**6,565**	**6,377**	**6,188**	**6,000**	**5,811**	**5,623**	**5,435**	**5,246**
23																	
24	**Return on Rate Base**																
25	Equity Return	Line 22 x ROE x Equity %	281	271	257	247	240	234	228	221	215	208	202	196	189	183	177
26	Debt Component	Line 22 x (LTD Rate x LTD% + STD Rate x STD %	339	328	311	299	290	283	275	267	260	252	244	237	229	221	214
27	Total Earned Return	Line 25 + Line 26	**620**	**599**	**568**	**546**	**531**	**517**	**503**	**489**	**475**	**460**	**446**	**432**	**418**	**404**	**390**
28	Return on AES Rate Base %	Line 27 / Line 22	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%
29																	
30	1- (Schedule 7, (Line 49 + Line 102) + Schedule 8, Line 49) x (Days In-service/365-1/2)																
31	2- Schedule 7, Line 97 x TGI CWC/Closing GPIS %																

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Rate Base
Appendix F-2 - Schedule 5
($000's), unless otherwise stated

Line	Particulars	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	**Rate Base**															
2	Gross Plant In Service- Beginning	8,014	8,016	8,019	8,022	8,025	8,028	8,031	8,035	8,038	9,435	9,439	9,442	9,456	9,459	9,463
3	Gross Plant In Service- Ending	8,016	8,019	8,022	8,025	8,028	8,031	8,035	8,038	9,435	9,439	9,442	9,456	9,459	9,463	9,467
4																
5	Accumulated Depreciation- Beginning	(2,688)	(2,868)	(3,048)	(3,228)	(3,408)	(3,588)	(3,768)	(3,948)	(4,128)	(1,906)	(2,146)	(2,386)	(2,612)	(2,852)	(3,093)
6	Accumulated Depreciation- Ending	(2,868)	(3,048)	(3,228)	(3,408)	(3,588)	(3,768)	(3,948)	(4,128)	(1,906)	(2,146)	(2,386)	(2,612)	(2,852)	(3,093)	(3,333)
7																
8	Negative Salvage- Beginning	(169)	(180)	(192)	(203)	(215)	(227)	(238)	(250)	(262)	(163)	(178)	(192)	(206)	(220)	(234)
9	Negative Salvage- Ending	(180)	(192)	(203)	(215)	(227)	(238)	(250)	(262)	(163)	(178)	(192)	(206)	(220)	(234)	(248)
10																
11	Contributions in Aid of Construction- Beginning	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Contributions in Aid of Construction- Ending	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13																
14	Accumulated Amortization- Beginning	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Accumulated Amortization- Ending	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16																
17	Net Plant in Service, Mid-Year	5,062	4,874	4,685	4,497	4,308	4,120	3,931	3,743	5,507	7,240	6,990	6,751	6,513	6,262	6,011
18																
19	Adjustment to 13-month average	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Unamortized Deferred Charges, Mid-Year	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Cash Working Capital	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
22	**Total Rate Base**	**5,058**	**4,869**	**4,681**	**4,492**	**4,304**	**4,115**	**3,927**	**3,738**	**5,501**	**7,234**	**6,984**	**6,746**	**6,507**	**6,256**	**6,005**
23																
24	**Return on Rate Base**															
25	Equity Return	170	164	158	151	145	139	132	126	185	244	235	227	219	211	202
26	Debt Component	206	198	191	183	175	168	160	152	224	295	284	275	265	255	245
27	Total Earned Return	**376**	**362**	**348**	**334**	**320**	**306**	**292**	**278**	**409**	**538**	**520**	**502**	**484**	**466**	**447**
28	Return on AES Rate Base %	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%
29																
30	1- (Schedule 7, (Line 49 + Line 102) + Schedule 8, Line 49) x (D															
31	2- Schedule 7, Line 97 x TGI CWC/Closing GPIS %															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Rate Base
Appendix F-2 - Schedule 5
($000's), unless otherwise stated

Line	Particulars	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060
1	**Rate Base**															
2	Gross Plant In Service- Beginning	9,467	9,471	9,474	9,478	9,482	9,487	9,491	9,495	9,499	9,504	9,508	9,513	9,518	9,523	9,525
3	Gross Plant In Service- Ending	9,471	9,474	9,478	9,482	9,487	9,491	9,495	9,499	9,504	9,508	9,513	9,518	9,523	9,525	9,528
4																
5	Accumulated Depreciation- Beginning	(3,333)	(3,574)	(3,815)	(4,056)	(4,297)	(4,538)	(4,779)	(5,021)	(5,262)	(5,503)	(5,745)	(5,987)	(6,229)	(6,471)	(6,648)
6	Accumulated Depreciation- Ending	(3,574)	(3,815)	(4,056)	(4,297)	(4,538)	(4,779)	(5,021)	(5,262)	(5,503)	(5,745)	(5,987)	(6,229)	(6,471)	(6,648)	(6,887)
7																
8	Negative Salvage- Beginning	(248)	(262)	(277)	(291)	(305)	(319)	(333)	(347)	(362)	(376)	(390)	(404)	(418)	(432)	(446)
9	Negative Salvage- Ending	(262)	(277)	(291)	(305)	(319)	(333)	(347)	(362)	(376)	(390)	(404)	(418)	(432)	(446)	(461)
10																
11	Contributions in Aid of Construction- Beginning	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Contributions in Aid of Construction- Ending	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13																
14	Accumulated Amortization- Beginning	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Accumulated Amortization- Ending	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16																
17	Net Plant in Service, Mid-Year	5,760	5,509	5,257	5,006	4,755	4,504	4,253	4,002	3,750	3,499	3,248	2,997	2,745	2,525	2,306
18																
19	Adjustment to 13-month average	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Unamortized Deferred Charges, Mid-Year	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Cash Working Capital	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
22	**Total Rate Base**	**5,754**	**5,503**	**5,252**	**5,001**	**4,749**	**4,498**	**4,247**	**3,996**	**3,745**	**3,493**	**3,242**	**2,991**	**2,740**	**2,520**	**2,300**
23																
24	**Return on Rate Base**															
25	Equity Return	194	185	177	168	160	152	143	135	126	118	109	101	92	85	77
26	Debt Component	234	224	214	204	193	183	173	163	153	142	132	122	112	103	94
27	Total Earned Return	**428**	**409**	**391**	**372**	**353**	**335**	**316**	**297**	**279**	**260**	**241**	**223**	**204**	**187**	**171**
28	Return on AES Rate Base %	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%
29																
30	1- (Schedule 7, (Line 49 + Line 102) + Schedule 8, Line 49) x (D															
31	2- Schedule 7, Line 97 x TGI CWC/Closing GPIS %															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Rate Base
Appendix F-2 - Schedule 5
($000's), unless otherwise stated

Line	Particulars	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075
1	**Rate Base**															
2	Gross Plant In Service- Beginning	9,528	9,531	12,003	12,006	12,009	12,012	12,015	12,019	12,041	12,044	12,048	12,051	12,055	12,059	12,062
3	Gross Plant In Service- Ending	9,531	12,003	12,006	12,009	12,012	12,015	12,019	12,041	12,044	12,048	12,051	12,055	12,059	12,062	12,066
4																
5	Accumulated Depreciation- Beginning	(6,887)	(7,125)	(3,668)	(4,012)	(4,357)	(4,701)	(5,045)	(5,389)	(5,709)	(6,054)	(6,398)	(6,743)	(7,088)	(7,433)	(7,778)
6	Accumulated Depreciation- Ending	(7,125)	(3,668)	(4,012)	(4,357)	(4,701)	(5,045)	(5,389)	(5,709)	(6,054)	(6,398)	(6,743)	(7,088)	(7,433)	(7,778)	(8,122)
7																
8	Negative Salvage- Beginning	(461)	(475)	(491)	(510)	(528)	(547)	(565)	(584)	(603)	(621)	(640)	(659)	(677)	(696)	(714)
9	Negative Salvage- Ending	(475)	(491)	(510)	(528)	(547)	(565)	(584)	(603)	(621)	(640)	(659)	(677)	(696)	(714)	(733)
10																
11	Contributions in Aid of Construction- Beginning	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Contributions in Aid of Construction- Ending	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13																
14	Accumulated Amortization- Beginning	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Accumulated Amortization- Ending	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16																
17	Net Plant in Service, Mid-Year	2,056	4,887	7,663	7,304	6,944	6,585	6,225	5,887	5,549	5,189	4,829	4,470	4,110	3,750	3,391
18																
19	Adjustment to 13-month average	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Unamortized Deferred Charges, Mid-Year	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Cash Working Capital	(6)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
22	**Total Rate Base**	**2,050**	**4,880**	**7,656**	**7,297**	**6,937**	**6,578**	**6,218**	**5,880**	**5,542**	**5,182**	**4,822**	**4,462**	**4,103**	**3,743**	**3,383**
23																
24	**Return on Rate Base**															
25	Equity Return	69	164	258	246	234	222	209	198	187	175	162	150	138	126	114
26	Debt Component	84	199	312	297	283	268	253	239	226	211	196	182	167	152	138
27	Total Earned Return	**153**	**363**	**570**	**543**	**516**	**489**	**463**	**438**	**412**	**386**	**359**	**332**	**305**	**279**	**252**
28	Return on AES Rate Base %	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%
29																
30	1- (Schedule 7, (Line 49 + Line 102) + Schedule 8, Line 49) x (D															
31	2- Schedule 7, Line 97 x TGI CWC/Closing GPIS %															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Capital Spending
Appendix F-2 - Schedule 6

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Capital Spending Prior to 2016																
2	Structures & Improvements		14.2														
3	Pipeline - Transmission		4,945.2														
4	Land Rights		254.5														
5	Measuring & Regulating Equipment		2,317.9														
6	Telemetry		105.7														
22	Total Capital Spending Prior to 2016	Sum of Lines 2 through 21	7,637.5														
23																	
24	AFUDC Prior to 2016																
25	Structures & Improvements		0.6														
26	Pipeline - Transmission		223.8														
27	Land Rights		5.8														
28	Measuring & Regulating Equipment		104.9														
29	Telemetry		4.8														
45	Total AFUDC Prior to 2016	Sum of Lines 25 through 44	339.9														
46																	
47	Capital Spending 2016 Onwards																
48	Structures & Improvements		0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Pipeline - Transmission		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Land Rights		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Measuring & Regulating Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Telemetry		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
68	Total Capital Spending 2016 Onwards	Sum of Lines 48 through 67	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
69																	
70	AFUDC 2016 Onwards																
71	Structures & Improvements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Pipeline - Transmission		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
73	Land Rights		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
74	Measuring & Regulating Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
75	Telemetry		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
91	Total AFUDC 2016 Onwards	Sum of Lines 71 through 90	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
92																	
93	Total Capital Spending[1]	Line 68	7,637.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
94	Total AFUDC	Line 91	339.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-
95	Total Annual Capital Spending and AFUDC	Line 93 + Line 94	7,977.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
96																	
97	Contributions in Aid of Construction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
98	Removal Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
99	Net Annual Project Costs- Capital	Line 95 + 97 + 98	7,977.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
100																	
101	Total Project Costs- Capital Spending and AFUDC	Sum of Line 95	**18,148.1**														

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Capital Spending
Appendix F-2 - Schedule 6

Line	Particulars	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	Capital Spending Prior to 2016															
2	Structures & Improvements															
3	Pipeline - Transmission															
4	Land Rights															
5	Measuring & Regulating Equipment															
6	Telemetry															
22	Total Capital Spending Prior to 2016															
23																
24	AFUDC Prior to 2016															
25	Structures & Improvements															
26	Pipeline - Transmission															
27	Land Rights															
28	Measuring & Regulating Equipment															
29	Telemetry															
45	Total AFUDC Prior to 2016															
46																
47	Capital Spending 2016 Onwards															
48	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	24.9	-	-	-
49	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	3,816.9	-	-	-	-	-	-
52	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
68	Total Capital Spending 2016 Onwards	-	-	-	-	-	-	-	-	3,816.9	0.0	-	24.9	-	-	-
69																
70	AFUDC 2016 Onwards															
71	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
73	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
74	Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
75	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
91	Total AFUDC 2016 Onwards	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
92																
93	Total Capital Spending[1]	-	-	-	-	-	-	-	-	3,816.9	0.0	-	24.9	-	-	-
94	Total AFUDC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
95	Total Annual Capital Spending and AFUDC	-	-	-	-	-	-	-	-	3,816.9	0.0	-	24.9	-	-	-
96																
97	Contributions in Aid of Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
98	Removal Costs	-	-	-	-	-	-	-	-	111.0	-	-	-	-	-	-
99	Net Annual Project Costs- Capital	-	-	-	-	-	-	-	-	3,927.9	0.0	-	24.9	-	-	-
100																
101	Total Project Costs- Capital Spending and AFUDC															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Capital Spending
Appendix F-2 - Schedule 6

Line	Particulars	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060
1	Capital Spending Prior to 2016															
2	Structures & Improvements															
3	Pipeline - Transmission															
4	Land Rights															
5	Measuring & Regulating Equipment															
6	Telemetry															
22	Total Capital Spending Prior to 2016															
23																
24	AFUDC Prior to 2016															
25	Structures & Improvements															
26	Pipeline - Transmission															
27	Land Rights															
28	Measuring & Regulating Equipment															
29	Telemetry															
45	Total AFUDC Prior to 2016															
46																
47	Capital Spending 2016 Onwards															
48	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
68	Total Capital Spending 2016 Onwards	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
69																
70	AFUDC 2016 Onwards															
71	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
73	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
74	Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
75	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
91	Total AFUDC 2016 Onwards	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
92																
93	Total Capital Spending[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
94	Total AFUDC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
95	Total Annual Capital Spending and AFUDC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
96																
97	Contributions in Aid of Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
98	Removal Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
99	Net Annual Project Costs- Capital	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
100																
101	Total Project Costs- Capital Spending and AFUDC															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Capital Spending
Appendix F-2 - Schedule 6

Line	Particulars	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075
1	Capital Spending Prior to 2016															
2	Structures & Improvements															
3	Pipeline - Transmission															
4	Land Rights															
5	Measuring & Regulating Equipment															
6	Telemetry															
22	Total Capital Spending Prior to 2016															
23																
24	AFUDC Prior to 2016															
25	Structures & Improvements															
26	Pipeline - Transmission															
27	Land Rights															
28	Measuring & Regulating Equipment															
29	Telemetry															
45	Total AFUDC Prior to 2016															
46																
47	Capital Spending 2016 Onwards															
48	Structures & Improvements	-	-	-	-	-	-	-	43.7	-	-	-	-	-	-	-
49	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Measuring & Regulating Equipment	-	6,285.3	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
68	Total Capital Spending 2016 Onwards	-	6,285.3	-	-	-	-	-	43.7	-	-	-	-	-	-	-
69																
70	AFUDC 2016 Onwards															
71	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
73	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
74	Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
75	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
91	Total AFUDC 2016 Onwards	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
92																
93	Total Capital Spending[1]	-	6,285.3	-	-	-	-	-	43.7	-	-	-	-	-	-	-
94	Total AFUDC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
95	Total Annual Capital Spending and AFUDC	-	6,285.3	-	-	-	-	-	43.7	-	-	-	-	-	-	-
96																
97	Contributions in Aid of Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
98	Removal Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
99	Net Annual Project Costs- Capital	-	6,285.3	-	-	-	-	-	43.7	-	-	-	-	-	-	-
100																
101	Total Project Costs- Capital Spending and AFUDC															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Gross Plant in Service & Contributions in Aid of Construction
Appendix F-2 - Schedule 7
($000's), unless otherwise stated

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	**Gross Plant in Service**																
2																	
3	Gross Plant in Service, Beginning																
4	Structures & Improvements	Preceeding Year, Line 76	-	15	15	15	15	15	15	15	15	15	15	15	15	15	15
5	Pipeline - Transmission	Preceeding Year, Line 77	-	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169
6	Land Rights	Preceeding Year, Line 78	-	260	260	260	260	260	260	260	260	260	260	260	260	260	260
7	Measuring & Regulating Equipment	Preceeding Year, Line 79	-	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423
8	Telemetry	Preceeding Year, Line 80	-	110	110	110	110	110	110	110	110	110	110	110	110	110	110
24	Capitalized Overhead	Preceeding Year, Line 96	-	2	4	6	9	11	13	16	18	20	23	26	28	31	34
25	Total Gross Plant in Service, Beginning	Sum of Lines 4 through 24	-	7,979	7,982	7,984	7,986	7,988	7,991	7,993	7,995	7,998	8,000	8,003	8,006	8,008	8,011
26																	
27	Gross Plant in Service, Additions																
28	Structures & Improvements	Schedule 6, Lines 2 + 25 + 48 + 71	15	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Pipeline - Transmission	Schedule 6, Lines 3 + 26 + 49 + 72	5,169	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Land Rights	Schedule 6, Lines 4 + 27 + 50 + 73	260	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Measuring & Regulating Equipment	Schedule 6, Lines 5 + 28 + 51 + 74	2,423	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Telemetry	Schedule 6, Lines 6 + 29 + 52 + 75	110	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Capitalized Overhead	Schedule 2, Line 17	2	2	2	2	2	2	2	2	2	3	3	3	3	3	3
49	Total Gross Plant in Service, Additions	Sum of Lines 28 through 48	7,979	2	2	2	2	2	2	2	2	3	3	3	3	3	3
50																	
51	Gross Plant in Service, Retirements																
52	Structures & Improvements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Pipeline - Transmission		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Land Rights		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Measuring & Regulating Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	Telemetry		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Capitalized Overhead		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
73	Total Gross Plant in Service, Retirements	Sum of Lines 52 through 72	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
74																	
75	Gross Plant in Service, Ending																
76	Structures & Improvements	Line 4 + Line 28 + Line 52	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
77	Pipeline - Transmission	Line 5 + Line 29 + Line 53	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169
78	Land Rights	Line 6 + Line 30 + Line 54	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
79	Measuring & Regulating Equipment	Line 7 + Line 31 + Line 55	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423
80	Telemetry	Line 8 + Line 32 + Line 56	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
96	Capitalized Overhead	Line 24 + Line 48 + Line 72	2	4	6	9	11	13	16	18	20	23	26	28	31	34	36
97	Total Gross Plant in Service, Ending	Sum of Lines 76 through 96	7,979	7,982	7,984	7,986	7,988	7,991	7,993	7,995	7,998	8,000	8,003	8,006	8,008	8,011	8,014
98																	
99																	
100	**Contributions in Aid of Construction (CIAC)**																
101	CIAC, Beginning		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
102	Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
103	Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
104	CIAC, Ending	Sum of Lines 101 through 103	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
105																	
106																	

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Gross Plant in
Appendix F-2 - Schedule 7
($000's), unless otherwise stated

Line	Particulars	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	**Gross Plant in Service**															
2																
3	Gross Plant in Service, Beginning															
4	Structures & Improvements	15	15	15	15	15	15	15	15	15	15	15	15	25	25	25
5	Pipeline - Transmission	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169
6	Land Rights	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
7	Measuring & Regulating Equipment	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	3,817	3,817	3,817	3,817	3,817	3,817
8	Telemetry	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
24	Capitalized Overhead	36	39	42	45	48	51	54	57	61	64	67	71	74	78	82
25	Total Gross Plant in Service, Beginning	8,014	8,016	8,019	8,022	8,025	8,028	8,031	8,035	8,038	9,435	9,439	9,442	9,456	9,459	9,463
26																
27	Gross Plant in Service, Additions															
28	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	25	-	-	-
29	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	3,817	-	-	-	-	-	-
32	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Capitalized Overhead	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4
49	Total Gross Plant in Service, Additions	3	3	3	3	3	3	3	3	3,820	3	3	28	4	4	4
50																
51	Gross Plant in Service, Retirements															
52	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	(15)	-	-	-
53	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	(2,423)	-	-	-	-	-	-
56	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Capitalized Overhead	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
73	Total Gross Plant in Service, Retirements	-	-	-	-	-	-	-	-	(2,423)	-	-	(15)	-	-	-
74																
75	Gross Plant in Service, Ending															
76	Structures & Improvements	15	15	15	15	15	15	15	15	15	15	15	25	25	25	25
77	Pipeline - Transmission	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169
78	Land Rights	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
79	Measuring & Regulating Equipment	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	3,817	3,817	3,817	3,817	3,817	3,817	3,817
80	Telemetry	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
96	Capitalized Overhead	39	42	45	48	51	54	57	61	64	67	71	74	78	82	85
97	Total Gross Plant in Service, Ending	8,016	8,019	8,022	8,025	8,028	8,031	8,035	8,038	9,435	9,439	9,442	9,456	9,459	9,463	9,467
98																
99																
100	**Contributions in Aid of Construction (CIAC)**															
101	CIAC, Beginning	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
102	Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
103	Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
104	CIAC, Ending	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
105																
106																

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Gross Plant in
Appendix F-2 - Schedule 7
($000's), unless otherwise stated

Line	Particulars	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060
1	**Gross Plant in Service**															
2																
3	Gross Plant in Service, Beginning															
4	Structures & Improvements	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
5	Pipeline - Transmission	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169
6	Land Rights	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
7	Measuring & Regulating Equipment	3,817	3,817	3,817	3,817	3,817	3,817	3,817	3,817	3,817	3,817	3,817	3,817	3,817	3,817	3,817
8	Telemetry	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
24	Capitalized Overhead	85	89	93	97	101	105	109	114	118	122	127	132	136	141	144
25	Total Gross Plant in Service, Beginning	9,467	9,471	9,474	9,478	9,482	9,487	9,491	9,495	9,499	9,504	9,508	9,513	9,518	9,523	9,525
26																
27	Gross Plant in Service, Additions															
28	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Capitalized Overhead	4	4	4	4	4	4	4	4	4	5	5	5	5	5	5
49	Total Gross Plant in Service, Additions	4	4	4	4	4	4	4	4	4	5	5	5	5	5	5
50																
51	Gross Plant in Service, Retirements															
52	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Capitalized Overhead	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	(2)
73	Total Gross Plant in Service, Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	(2)
74																
75	Gross Plant in Service, Ending															
76	Structures & Improvements	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
77	Pipeline - Transmission	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169
78	Land Rights	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
79	Measuring & Regulating Equipment	3,817	3,817	3,817	3,817	3,817	3,817	3,817	3,817	3,817	3,817	3,817	3,817	3,817	3,817	3,817
80	Telemetry	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
96	Capitalized Overhead	89	93	97	101	105	109	114	118	122	127	132	136	141	144	147
97	Total Gross Plant in Service, Ending	9,471	9,474	9,478	9,482	9,487	9,491	9,495	9,499	9,504	9,508	9,513	9,518	9,523	9,525	9,528
98																
99																
100	**Contributions in Aid of Construction (CIAC)**															
101	CIAC, Beginning	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
102	Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
103	Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
104	CIAC, Ending	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
105																
106																

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Gross Plant in
Appendix F-2 - Schedule 7
($000's), unless otherwise stated

Line	Particulars	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075
1	**Gross Plant in Service**															
2																
3	Gross Plant in Service, Beginning															
4	Structures & Improvements	25	25	25	25	25	25	25	25	44	44	44	44	44	44	44
5	Pipeline - Transmission	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169
6	Land Rights	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
7	Measuring & Regulating Equipment	3,817	3,817	6,285	6,285	6,285	6,285	6,285	6,285	6,285	6,285	6,285	6,285	6,285	6,285	6,285
8	Telemetry	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
24	Capitalized Overhead	147	150	153	156	159	162	165	169	172	175	179	183	186	190	194
25	Total Gross Plant in Service, Beginning	9,528	9,531	12,003	12,006	12,009	12,012	12,015	12,019	12,041	12,044	12,048	12,051	12,055	12,059	12,062
26																
27	Gross Plant in Service, Additions															
28	Structures & Improvements	-	-	-	-	-	-	-	44	-	-	-	-	-	-	-
29	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Measuring & Regulating Equipment	-	6,285	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Capitalized Overhead	5	5	5	5	6	6	6	6	6	6	6	6	6	7	7
49	Total Gross Plant in Service, Additions	5	6,290	5	5	6	6	6	50	6	6	6	6	6	7	7
50																
51	Gross Plant in Service, Retirements															
52	Structures & Improvements	-	-	-	-	-	-	-	(25)	-	-	-	-	-	-	-
53	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Measuring & Regulating Equipment	-	(3,817)	-	-	-	-	-	-	-	-	-	-	-	-	-
56	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Capitalized Overhead	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
73	Total Gross Plant in Service, Retirements	(2)	(3,819)	(2)	(2)	(2)	(2)	(2)	(27)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
74																
75	Gross Plant in Service, Ending															
76	Structures & Improvements	25	25	25	25	25	25	25	44	44	44	44	44	44	44	44
77	Pipeline - Transmission	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169
78	Land Rights	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
79	Measuring & Regulating Equipment	3,817	6,285	6,285	6,285	6,285	6,285	6,285	6,285	6,285	6,285	6,285	6,285	6,285	6,285	6,285
80	Telemetry	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
96	Capitalized Overhead	150	153	156	159	162	165	169	172	175	179	183	186	190	194	198
97	Total Gross Plant in Service, Ending	9,531	12,003	12,006	12,009	12,012	12,015	12,019	12,041	12,044	12,048	12,051	12,055	12,059	12,062	12,066
98																
99																
100	**Contributions in Aid of Construction (CIAC)**															
101	CIAC, Beginning	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
102	Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
103	Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
104	CIAC, Ending	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
105																
106																

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Accumulated Depreciation & Amortization
Appendix F-2 - Schedule 8
($000's), unless otherwise stated

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	**Accumulated Depreciation**																
2																	
3	Accumulated Depreciation, Beginning																
4	Structures & Improvements	Preceeding Year, Line 76	-	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(6)	(6)	(7)	(7)	(8)
5	Pipeline - Transmission	Preceeding Year, Line 77	-	(75)	(149)	(224)	(298)	(372)	(447)	(521)	(596)	(670)	(745)	(819)	(893)	(968)	(1,042)
6	Land Rights	Preceeding Year, Line 78	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Measuring & Regulating Equipment	Preceeding Year, Line 79	-	(104)	(207)	(311)	(414)	(518)	(621)	(724)	(828)	(931)	(1,035)	(1,138)	(1,242)	(1,345)	(1,449)
8	Telemetry	Preceeding Year, Line 80	-	(0)	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(4)	(4)	(4)	(5)
24	Capitalized Overhead	Preceeding Year, Line 96	-	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(5)	(5)
25	Total Accumulated Depreciation, Beginning	Sum of Lines 4 through 24	-	(179)	(358)	(537)	(716)	(895)	(1,074)	(1,253)	(1,432)	(1,612)	(1,791)	(1,970)	(2,150)	(2,329)	(2,509)
26																	
27	Accumulated Depreciation, Depreciation Expense																
28	Structures & Improvements@ 3.8%	Schedule 7, Line 4 & Line 28	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
29	Pipeline - Transmission@ 1.44%	Schedule 7, Line 5 & Line 29	(75)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)
30	Land Rights@ 0%	Schedule 7, Line 6 & Line 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Measuring & Regulating Equipment@ 4.27%	Schedule 7, Line 7 & Line 31	(104)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)
32	Telemetry@ 0.31%	Schedule 7, Line 8 & Line 32	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
48	Capitalized Overhead@ 2.35%	Schedule 7, Line 24 & Line 48	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)
49	Total Accumulated Depreciation, Depreciation Exp	Sum of Lines 28 through 48	(179)	(179)	(179)	(179)	(179)	(179)	(179)	(179)	(179)	(179)	(179)	(179)	(179)	(180)	(180)
50																	
51	Accumulated Depreciation, Retirements																
52	Structures & Improvements	Schedule 7, Line 52	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Pipeline - Transmission	Schedule 7, Line 53	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Land Rights	Schedule 7, Line 54	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Measuring & Regulating Equipment	Schedule 7, Line 55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	Telemetry	Schedule 7, Line 56	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Capitalized Overhead	Schedule 7, Line 72	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
73	Total Accumulated Depreciation, Retirements	Sum of Lines 52 through 72	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
74																	
75	Accumulated Depreciation, Ending																
76	Structures & Improvements	Line 4 + Line 28 + Line 52	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)	(5)	(6)	(6)	(7)	(7)	(8)	(8)
77	Pipeline - Transmission	Line 5 + Line 29 + Line 53	(75)	(149)	(224)	(298)	(372)	(447)	(521)	(596)	(670)	(745)	(819)	(893)	(968)	(1,042)	(1,117)
78	Land Rights	Line 6 + Line 30 + Line 54	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
79	Measuring & Regulating Equipment	Line 7 + Line 31 + Line 55	(104)	(207)	(311)	(414)	(518)	(621)	(724)	(828)	(931)	(1,035)	(1,138)	(1,242)	(1,345)	(1,449)	(1,552)
80	Telemetry	Line 8 + Line 32 + Line 56	(0)	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(4)	(4)	(4)	(5)	(5)
96	Capitalized Overhead	Line 24 + Line 48 + Line 72	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(5)	(5)	(6)
97	Total Accumulated Depreciation, Ending	Sum of Lines 76 through 96	(179)	(358)	(537)	(716)	(895)	(1,074)	(1,253)	(1,432)	(1,612)	(1,791)	(1,970)	(2,150)	(2,329)	(2,509)	(2,688)
98																	
99																	
100	**Accumulated Amortization of Contributions in Aid of Construction (CIAC)**																
101	Accumulated Amortization CIAC, Beginning		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
102	Amortization	[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
103	Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
104	Accumulated Amortization CIAC, Ending	Sum of Lines 101 through 103	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
105																	

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Accumulated Depre
Appendix F-2 - Schedule 8
($000's), unless otherwise stated

Line	Particulars	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	**Accumulated Depreciation**															
2																
3	Accumulated Depreciation, Beginning															
4	Structures & Improvements	(8)	(9)	(10)	(10)	(11)	(11)	(12)	(12)	(13)	(13)	(14)	(15)	(0)	(1)	(2)
5	Pipeline - Transmission	(1,117)	(1,191)	(1,266)	(1,340)	(1,414)	(1,489)	(1,563)	(1,638)	(1,712)	(1,787)	(1,861)	(1,935)	(2,010)	(2,084)	(2,159)
6	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Measuring & Regulating Equipment	(1,552)	(1,656)	(1,759)	(1,862)	(1,966)	(2,069)	(2,173)	(2,276)	(2,380)	(81)	(244)	(407)	(570)	(733)	(896)
8	Telemetry	(5)	(5)	(6)	(6)	(7)	(7)	(7)	(8)	(8)	(8)	(9)	(9)	(9)	(10)	(10)
24	Capitalized Overhead	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(14)	(15)	(17)	(18)	(20)	(21)	(23)	(25)
25	Total Accumulated Depreciation, Beginning	(2,688)	(2,868)	(3,048)	(3,228)	(3,408)	(3,588)	(3,768)	(3,948)	(4,128)	(1,906)	(2,146)	(2,386)	(2,612)	(2,852)	(3,093)
26																
27	Accumulated Depreciation, Depreciation Expense															
28	Structures & Improvements@ 3.8%	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
29	Pipeline - Transmission@ 1.44%	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)
30	Land Rights@ 0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Measuring & Regulating Equipment@ 4.27%	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(125)	(163)	(163)	(163)	(163)	(163)	(163)
32	Telemetry@ 0.31%	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
48	Capitalized Overhead@ 2.35%	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(2)	(2)
49	Total Accumulated Depreciation, Depreciation Exp	(180)	(180)	(180)	(180)	(180)	(180)	(180)	(180)	(201)	(240)	(240)	(240)	(240)	(241)	(241)
50																
51	Accumulated Depreciation, Retirements															
52	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-
53	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	2,423	-	-	-	-	-	-
56	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Capitalized Overhead	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
73	Total Accumulated Depreciation, Retirements	-	-	-	-	-	-	-	-	2,423	-	-	15	-	-	-
74																
75	Accumulated Depreciation, Ending															
76	Structures & Improvements	(9)	(10)	(10)	(11)	(11)	(12)	(12)	(13)	(13)	(14)	(15)	(0)	(1)	(2)	(3)
77	Pipeline - Transmission	(1,191)	(1,266)	(1,340)	(1,414)	(1,489)	(1,563)	(1,638)	(1,712)	(1,787)	(1,861)	(1,935)	(2,010)	(2,084)	(2,159)	(2,233)
78	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
79	Measuring & Regulating Equipment	(1,656)	(1,759)	(1,862)	(1,966)	(2,069)	(2,173)	(2,276)	(2,380)	(81)	(244)	(407)	(570)	(733)	(896)	(1,059)
80	Telemetry	(5)	(6)	(6)	(7)	(7)	(7)	(8)	(8)	(8)	(9)	(9)	(9)	(10)	(10)	(10)
96	Capitalized Overhead	(7)	(8)	(9)	(10)	(11)	(12)	(14)	(15)	(17)	(18)	(20)	(21)	(23)	(25)	(27)
97	Total Accumulated Depreciation, Ending	(2,868)	(3,048)	(3,228)	(3,408)	(3,588)	(3,768)	(3,948)	(4,128)	(1,906)	(2,146)	(2,386)	(2,612)	(2,852)	(3,093)	(3,333)
98																
99																
100	**Accumulated Amortization of Contributions in Aid**															
101	Accumulated Amortization CIAC, Beginning	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
102	Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
103	Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
104	Accumulated Amortization CIAC, Ending	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
105																

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Accumulated Depre
Appendix F-2 - Schedule 8
($000's), unless otherwise stated

Line	Particulars	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060
1	**Accumulated Depreciation**															
2																
3	Accumulated Depreciation, Beginning															
4	Structures & Improvements	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
5	Pipeline - Transmission	(2,233)	(2,308)	(2,382)	(2,457)	(2,531)	(2,605)	(2,680)	(2,754)	(2,829)	(2,903)	(2,978)	(3,052)	(3,126)	(3,201)	(3,275)
6	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Measuring & Regulating Equipment	(1,059)	(1,222)	(1,385)	(1,548)	(1,711)	(1,874)	(2,037)	(2,200)	(2,363)	(2,526)	(2,689)	(2,852)	(3,015)	(3,178)	(3,341)
8	Telemetry	(10)	(11)	(11)	(11)	(12)	(12)	(12)	(13)	(13)	(13)	(14)	(14)	(14)	(15)	(15)
24	Capitalized Overhead	(27)	(29)	(31)	(34)	(36)	(38)	(41)	(43)	(46)	(49)	(52)	(55)	(58)	(61)	(0)
25	Total Accumulated Depreciation, Beginning	(3,333)	(3,574)	(3,815)	(4,056)	(4,297)	(4,538)	(4,779)	(5,021)	(5,262)	(5,503)	(5,745)	(5,987)	(6,229)	(6,471)	(6,648)
26																
27	Accumulated Depreciation, Depreciation Expense															
28	Structures & Improvements@ 3.8%	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
29	Pipeline - Transmission@ 1.44%	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)
30	Land Rights@ 0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Measuring & Regulating Equipment@ 4.27%	(163)	(163)	(163)	(163)	(163)	(163)	(163)	(163)	(163)	(163)	(163)	(163)	(163)	(163)	(163)
32	Telemetry@ 0.31%	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
48	Capitalized Overhead@ 2.35%	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	59	(2)
49	Total Accumulated Depreciation, Depreciation Exp	(241)	(241)	(241)	(241)	(241)	(241)	(241)	(241)	(242)	(242)	(242)	(242)	(242)	(180)	(241)
50																
51	Accumulated Depreciation, Retirements															
52	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Capitalized Overhead	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
73	Total Accumulated Depreciation, Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
74																
75	Accumulated Depreciation, Ending															
76	Structures & Improvements	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
77	Pipeline - Transmission	(2,308)	(2,382)	(2,457)	(2,531)	(2,605)	(2,680)	(2,754)	(2,829)	(2,903)	(2,978)	(3,052)	(3,126)	(3,201)	(3,275)	(3,350)
78	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
79	Measuring & Regulating Equipment	(1,222)	(1,385)	(1,548)	(1,711)	(1,874)	(2,037)	(2,200)	(2,363)	(2,526)	(2,689)	(2,852)	(3,015)	(3,178)	(3,341)	(3,504)
80	Telemetry	(11)	(11)	(11)	(12)	(12)	(12)	(13)	(13)	(13)	(14)	(14)	(14)	(15)	(15)	(15)
96	Capitalized Overhead	(29)	(31)	(34)	(36)	(38)	(41)	(43)	(46)	(49)	(52)	(55)	(58)	(61)	(0)	(0)
97	Total Accumulated Depreciation, Ending	(3,574)	(3,815)	(4,056)	(4,297)	(4,538)	(4,779)	(5,021)	(5,262)	(5,503)	(5,745)	(5,987)	(6,229)	(6,471)	(6,648)	(6,887)
98																
99																
100	**Accumulated Amortization of Contributions in Ai**															
101	Accumulated Amortization CIAC, Beginning	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
102	Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
103	Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
104	Accumulated Amortization CIAC, Ending	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
105																

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Accumulated Depre
Appendix F-2 - Schedule 8
($000's), unless otherwise stated

Line	Particulars	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075
1	**Accumulated Depreciation**															
2																
3	Accumulated Depreciation, Beginning															
4	Structures & Improvements	(18)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(1)	(2)	(4)	(6)	(7)	(9)	(11)
5	Pipeline - Transmission	(3,350)	(3,424)	(3,499)	(3,573)	(3,647)	(3,722)	(3,796)	(3,871)	(3,945)	(4,020)	(4,094)	(4,168)	(4,243)	(4,317)	(4,392)
6	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Measuring & Regulating Equipment	(3,504)	(3,667)	(134)	(403)	(671)	(939)	(1,208)	(1,476)	(1,744)	(2,013)	(2,281)	(2,550)	(2,818)	(3,086)	(3,355)
8	Telemetry	(15)	(16)	(16)	(16)	(17)	(17)	(17)	(18)	(18)	(18)	(19)	(19)	(20)	(20)	(20)
24	Capitalized Overhead	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
25	Total Accumulated Depreciation, Beginning	(6,887)	(7,125)	(3,668)	(4,012)	(4,357)	(4,701)	(5,045)	(5,389)	(5,709)	(6,054)	(6,398)	(6,743)	(7,088)	(7,433)	(7,778)
26																
27	Accumulated Depreciation, Depreciation Expense															
28	Structures & Improvements@ 3.8%	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
29	Pipeline - Transmission@ 1.44%	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)	(74)
30	Land Rights@ 0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Measuring & Regulating Equipment@ 4.27%	(163)	(284)	(268)	(268)	(268)	(268)	(268)	(268)	(268)	(268)	(268)	(268)	(268)	(268)	(268)
32	Telemetry@ 0.31%	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
48	Capitalized Overhead@ 2.35%	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
49	Total Accumulated Depreciation, Depreciation Exp	(241)	(362)	(346)	(346)	(346)	(347)	(347)	(347)	(347)	(347)	(347)	(348)	(348)	(348)	(348)
50																
51	Accumulated Depreciation, Retirements															
52	Structures & Improvements	-	-	-	-	-	-	-	25	-	-	-	-	-	-	-
53	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Measuring & Regulating Equipment	-	3,817	-	-	-	-	-	-	-	-	-	-	-	-	-
56	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Capitalized Overhead	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3
73	Total Accumulated Depreciation, Retirements	2	3,819	2	2	2	2	2	27	3	3	3	3	3	3	3
74																
75	Accumulated Depreciation, Ending															
76	Structures & Improvements	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(1)	(2)	(4)	(6)	(7)	(9)	(11)	(12)
77	Pipeline - Transmission	(3,424)	(3,499)	(3,573)	(3,647)	(3,722)	(3,796)	(3,871)	(3,945)	(4,020)	(4,094)	(4,168)	(4,243)	(4,317)	(4,392)	(4,466)
78	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
79	Measuring & Regulating Equipment	(3,667)	(134)	(403)	(671)	(939)	(1,208)	(1,476)	(1,744)	(2,013)	(2,281)	(2,550)	(2,818)	(3,086)	(3,355)	(3,623)
80	Telemetry	(16)	(16)	(16)	(17)	(17)	(17)	(18)	(18)	(18)	(19)	(19)	(20)	(20)	(20)	(21)
96	Capitalized Overhead	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
97	Total Accumulated Depreciation, Ending	(7,125)	(3,668)	(4,012)	(4,357)	(4,701)	(5,045)	(5,389)	(5,709)	(6,054)	(6,398)	(6,743)	(7,088)	(7,433)	(7,778)	(8,122)
98																
99																
100	**Accumulated Amortization of Contributions in Ai**															
101	Accumulated Amortization CIAC, Beginning	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
102	Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
103	Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
104	Accumulated Amortization CIAC, Ending	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
105																

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Negative Salvage Continuity
Appendix F-2 - Schedule 9
($000's), unless otherwise stated

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	**Negative Salvage**																
2																	
3	Negative Salvage, Beginning																
4	Structures & Improvements	Preceeding Year, Line 73	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Pipeline - Transmission	Preceeding Year, Line 74	-	4	11	18	25	33	40	47	54	62	69	76	83	90	98
6	Land Rights	Preceeding Year, Line 75	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Measuring & Regulating Equipment	Preceeding Year, Line 76	-	2	7	11	15	20	24	28	33	37	41	46	50	55	59
8	Telemetry	Preceeding Year, Line 77	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Negative Salvage, Beginning	Sum of Lines 4 through 23	-	6	17	29	41	52	64	76	87	99	110	122	134	145	157
25																	
26	Removal Provision																
27	Structures & Improvements@ 0.18%		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Pipeline - Transmission@ 0.14%		4	7	7	7	7	7	7	7	7	7	7	7	7	7	7
29	Land Rights@ 0%		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Measuring & Regulating Equipment@ 0.18%		2	4	4	4	4	4	4	4	4	4	4	4	4	4	4
31	Telemetry@ 0%		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Total Removal Provision	Sum of Lines 27 through 46	6	12	12	12	12	12	12	12	12	12	12	12	12	12	12
48																	
49	Removal Costs																
50	Structures & Improvements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Pipeline - Transmission		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Land Rights		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Measuring & Regulating Equipment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Telemetry		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
70	Total Removal Costs	Sum of Lines 50 through 69	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
71																	
72	Negative Salvage, Ending																
73	Structures & Improvements	Line 4 + Line 27 + Line 50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
74	Pipeline - Transmission	Line 5 + Line 28 + Line 51	4	11	18	25	33	40	47	54	62	69	76	83	90	98	105
75	Land Rights	Line 6 + Line 29 + Line 52	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
76	Measuring & Regulating Equipment	Line 7 + Line 30 + Line 53	2	7	11	15	20	24	28	33	37	41	46	50	55	59	63
77	Telemetry	Line 8 + Line 31 + Line 54	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
93	Total Negative Salvage, Ending	Sum of Lines 73 through 92	6	17	29	41	52	64	76	87	99	110	122	134	145	157	169

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Negative Salvage Co
Appendix F-2 - Schedule 9
($000's), unless otherwise stated

Line	Particulars	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	**Negative Salvage**															
2																
3	Negative Salvage, Beginning															
4	Structures & Improvements	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1
5	Pipeline - Transmission	105	112	119	127	134	141	148	156	163	170	177	185	192	199	206
6	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Measuring & Regulating Equipment	63	68	72	76	81	85	89	94	98	(7)	(0)	6	13	20	27
8	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Negative Salvage, Beginning	169	180	192	203	215	227	238	250	262	163	178	192	206	220	234
25																
26	Removal Provision															
27	Structures & Improvements@ 0.18%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Pipeline - Transmission@ 0.14%	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
29	Land Rights@ 0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Measuring & Regulating Equipment@ 0.18%	4	4	4	4	4	4	4	4	6	7	7	7	7	7	7
31	Telemetry@ 0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Total Removal Provision	12	12	12	12	12	12	12	12	13	14	14	14	14	14	14
48																
49	Removal Costs															
50	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	(111)	-	-	-	-	-	-
54	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
70	Total Removal Costs	-	-	-	-	-	-	-	-	(111)	-	-	-	-	-	-
71																
72	Negative Salvage, Ending															
73	Structures & Improvements	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1
74	Pipeline - Transmission	112	119	127	134	141	148	156	163	170	177	185	192	199	206	213
75	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
76	Measuring & Regulating Equipment	68	72	76	81	85	89	94	98	(7)	(0)	6	13	20	27	34
77	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
93	Total Negative Salvage, Ending	180	192	203	215	227	238	250	262	163	178	192	206	220	234	248

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Negative Salvage Co
Appendix F-2 - Schedule 9
($000's), unless otherwise stated

Line	Particulars	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060
1	**Negative Salvage**															
2																
3	Negative Salvage, Beginning															
4	Structures & Improvements	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
5	Pipeline - Transmission	213	221	228	235	242	250	257	264	271	279	286	293	300	308	315
6	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Measuring & Regulating Equipment	34	41	48	55	61	68	75	82	89	96	103	110	116	123	130
8	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Negative Salvage, Beginning	248	262	277	291	305	319	333	347	362	376	390	404	418	432	446
25																
26	Removal Provision															
27	Structures & Improvements@ 0.18%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Pipeline - Transmission@ 0.14%	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
29	Land Rights@ 0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Measuring & Regulating Equipment@ 0.18%	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
31	Telemetry@ 0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Total Removal Provision	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
48																
49	Removal Costs															
50	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
70	Total Removal Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
71																
72	Negative Salvage, Ending															
73	Structures & Improvements	1	1	1	1	1	1	1	1	1	1	1	1	1	1	2
74	Pipeline - Transmission	221	228	235	242	250	257	264	271	279	286	293	300	308	315	322
75	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
76	Measuring & Regulating Equipment	41	48	55	61	68	75	82	89	96	103	110	116	123	130	137
77	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
93	Total Negative Salvage, Ending	262	277	291	305	319	333	347	362	376	390	404	418	432	446	461

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Negative Salvage Co
Appendix F-2 - Schedule 9
($000's), unless otherwise stated

Line	Particulars	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075
1	**Negative Salvage**															
2																
3	Negative Salvage, Beginning															
4	Structures & Improvements	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
5	Pipeline - Transmission	322	329	337	344	351	358	365	373	380	387	394	402	409	416	423
6	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Measuring & Regulating Equipment	137	144	153	164	176	187	198	210	221	232	243	255	266	277	289
8	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Negative Salvage, Beginning	461	475	491	510	528	547	565	584	603	621	640	659	677	696	714
25																
26	Removal Provision															
27	Structures & Improvements@ 0.18%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Pipeline - Transmission@ 0.14%	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
29	Land Rights@ 0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Measuring & Regulating Equipment@ 0.18%	7	9	11	11	11	11	11	11	11	11	11	11	11	11	11
31	Telemetry@ 0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Total Removal Provision	14	16	19	19	19	19	19	19	19	19	19	19	19	19	19
48																
49	Removal Costs															
50	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Pipeline - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
70	Total Removal Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
71																
72	Negative Salvage, Ending															
73	Structures & Improvements	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
74	Pipeline - Transmission	329	337	344	351	358	365	373	380	387	394	402	409	416	423	431
75	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
76	Measuring & Regulating Equipment	144	153	164	176	187	198	210	221	232	243	255	266	277	289	300
77	Telemetry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
93	Total Negative Salvage, Ending	475	491	510	528	547	565	584	603	621	640	659	677	696	714	733

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Deferred Charges
Appendix F-2 - Schedule 10
($000's), unless otherwise stated

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	*Deferred Charge- O&M*																
2	Opening Balance	Previous Year, Line 8	-	74	49	25	-	-	-	-	-	-	-	-	-	-	-
3	Gross Additions		100	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Tax	Line 3 x Tax Rate	(26)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	AFUDC	(Lines 2 + 3 + 4) x Schedule 11, Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Net Additions	Sum of Lines 3 through 5	74	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Amortization Expense @ 3 years		-	(25)	(25)	(25)	-	-	-	-	-	-	-	-	-	-	-
8	Closing Balance	Lines 2 + 6 + 7	74	49	25	-	-	-	-	-	-	-	-	-	-	-	-
9																	
10	*Deferred Charge- Preliminary Investigation*																
11	Opening Balance	Previous Year, Line 17	573	382	191	-	-	-	-	-	-	-	-	-	-	-	-
12	Gross Additions		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Tax	Line 12 x Tax Rate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	AFUDC	(Lines 11 + 12 + 13) x Schedule 11, Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Net Additions	Sum of Lines 12 through 14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Amortization Expense @ 3 years		(191)	(191)	(191)	-	-	-	-	-	-	-	-	-	-	-	-
17	Closing Balance	Lines 11 + 15 + 16	382	191	-	-	-	-	-	-	-	-	-	-	-	-	-
18																	
49	**Deferred Charge- Rate Base**																
50	Opening Balance	Previous Year, Line 57	573	456	240	25	-	-	-	-	-	-	-	-	-	-	-
51	Opening Balance, Adjustment	- Line 41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Gross Additions		100	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Tax		(26)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Net Additions		74	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Amortization Expense		(191)	(216)	(216)	(25)	-	-	-	-	-	-	-	-	-	-	-
56	Closing Balance	Lines 50 + 54 + 55	456	240	25	-	-	-	-	-	-	-	-	-	-	-	-
57																	
58	Deferred Charge, Mid-Year	(Line 50+ Line 51 + Line 56) / 2	515	348	133	12	-	-	-	-	-	-	-	-	-	-	-
59																	
60	1- (Line 29 + 32) x [Schedule 11 , (Lines 10 x 11+ Lines 12 x 13) x (1- Tax Rate)]																
61	2- Adjustment to net account to zero in final year; result of varying WACC rates throughout contract																

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Deferred Charges
Appendix F-2 - Schedule 10
($000's), unless otherwise stated

Line	Particulars	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	*Deferred Charge- O&M*															
2	Opening Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Gross Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	AFUDC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Net Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Amortization Expense @ 3 years	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Closing Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9																
10	*Deferred Charge- Preliminary Investigation*															
11	Opening Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Gross Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	AFUDC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Net Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Amortization Expense @ 3 years	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Closing Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18																
49	**Deferred Charge- Rate Base**															
50	Opening Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Opening Balance, Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Gross Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Net Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Amortization Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	Closing Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57																
58	Deferred Charge, Mid-Year	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59																
60	1- (Line 29 + 32) x [Schedule 11 , (Lines 10 x 11+ Lines 12 x 1															
61	2- Adjustment to net account to zero in final year; result of															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Deferred Charges
Appendix F-2 - Schedule 10
($000's), unless otherwise stated

Line	Particulars	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060
1	*Deferred Charge- O&M*															
2	Opening Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Gross Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	AFUDC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Net Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Amortization Expense @ 3 years	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Closing Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9																
10	*Deferred Charge- Preliminary Investigation*															
11	Opening Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Gross Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	AFUDC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Net Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Amortization Expense @ 3 years	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Closing Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18																
49	**Deferred Charge- Rate Base**															
50	Opening Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Opening Balance, Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Gross Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Net Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Amortization Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	Closing Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57																
58	Deferred Charge, Mid-Year	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59																
60	1- (Line 29 + 32) x [Schedule 11 , (Lines 10 x 11+ Lines 12 x 1															
61	2- Adjustment to net account to zero in final year; result of															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Deferred Charges
Appendix F-2 - Schedule 10
($000's), unless otherwise stated

Line	Particulars	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075
1	*Deferred Charge- O&M*															
2	Opening Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Gross Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	AFUDC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Net Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Amortization Expense @ 3 years	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Closing Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9																
10	*Deferred Charge- Preliminary Investigation*															
11	Opening Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Gross Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	AFUDC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Net Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Amortization Expense @ 3 years	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Closing Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18																
49	**Deferred Charge- Rate Base**															
50	Opening Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Opening Balance, Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Gross Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Net Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Amortization Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	Closing Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57																
58	Deferred Charge, Mid-Year	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59																
60	1- (Line 29 + 32) x [Schedule 11 , (Lines 10 x 11+ Lines 12 x 1															
61	2- Adjustment to net account to zero in final year; result of															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Present Value & Average Levelized Cost of Service
Appendix F-2 - Schedule 11
($000's), unless otherwise stated

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1																	
2	Annual Cost of Service (Excluding Cost of Energy)($000s)	Schedule 1, Line 13	1,133.2	1,062.1	1,055.3	785.3	748.8	743.1	738.7	733.7	727.8	721.2	713.9	705.9	697.3	688.1	678.4
4																	
5	**Annual Discount Rate**																
6	Equity Component																
7	ROE %		8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%
8	Equity Portion		38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%
9	Debt Component																
10	Long Term Debt Rate		6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
11	Long Term Debt Portion		56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%
12	Short Term Debt Rate		3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
13	Short Term Debt Portion		4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%
14																	
15	Tax Rate		26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%
16	Pre- Tax Weighted Average Cost of Capital (WACC)[1]		8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%
17	After- Tax Weighted Average Cost of Capital (WACC)[2]		6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%
18																	
19	**Present Value of Cost of Service**																
20	PV of Annual Revenue Requirement	Line 2 / (1 + Line 17)^Yr	1,065.2	938.4	876.5	613.1	549.6	512.7	479.0	447.2	417.1	388.5	361.5	336.0	311.9	289.4	268.2
21	PV of Annual Revenue Requirement ($/Mnth)		89	78	73	51	46	43	40	37	35	32	30	28	26	24	22
22	Total PV of Revenue Requirement	Sum of Line 20	12,056.3														
23	Total PV of Revenue Requirement, $000s/Yr	Line 22 / Yrs	200.9														
24																	
25	PV of Annual Customers	Line 3 / (1 + Line 17)^Yr	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0
26	Total PV of Customers	Sum of Line 24	15														
27																	
28	**Present Value of Cost of Energy**																
29	Cost of Energy		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	PV of Annual Cost of Energy	Line 29 / (1 + Line 17)^Yr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Total PV of Cost of Energy	Sum of Line 30	-														
32																	
39	**Average Cost of Service Analysis**																
40	Annual Volume (TJ)		161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111
41																	
44	Annual Volumetric Cost of Service $/GJ	Line 2 / Line 40	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
45																	
46	**Levelized Cost of Service Analysis**																
47	PV of Annual Volume (TJ)	Line 40 / (1 + Line 17)^Yr	151,445	142,359	133,818	125,789	118,242	111,148	104,480	98,211	92,319	86,780	81,574	76,680	72,079	67,755	63,690
48	Total PV of Volume (TJ)	Sum of Line 47	1,986,749														
49																	
52	Average Levelized Volumetric Cost of Service ($/GJ)	Line 22 / Line 48	**0.006**														
53																	
54	1- (Line 7 x Line 8) / 1- Line 15 + (Line 10 x Line 11 + Line 12 x Line 13)																
55	2- Line 8 x Line 9 + [(Line 11 x Line 12 + Line 13 x Line 14) x 1- Line 16]																

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Present Value & Average Levelized Cost
Appendix F-2 - Schedule 11
($000's), unless otherwise statea

Line	Particulars	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1																
2	Annual Cost of Service (Excluding Cost of Energy)($000s)	668.3	657.7	646.7	635.4	623.7	611.7	599.5	587.0	680.2	876.2	867.0	859.0	848.4	835.8	822.7
4																
5	**Annual Discount Rate**															
6	Equity Component															
7	ROE %	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%
8	Equity Portion	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%
9	Debt Component															
10	Long Term Debt Rate	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
11	Long Term Debt Portion	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%
12	Short Term Debt Rate	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
13	Short Term Debt Portion	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%
14																
15	Tax Rate	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%
16	Pre- Tax Weighted Average Cost of Capital (WACC)[1]	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%
17	After- Tax Weighted Average Cost of Capital (WACC)[2]	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%
18																
19	**Present Value of Cost of Service**															
20	PV of Annual Revenue Requirement	248.3	229.7	212.3	196.1	181.0	166.8	153.7	141.4	154.1	186.6	173.5	161.6	150.0	139.0	128.6
21	PV of Annual Revenue Requirement ($/Mnth)	21	19	18	16	15	14	13	12	13	16	14	13	13	12	11
22	Total PV of Revenue Requirement															
23	Total PV of Revenue Requirement, $000s/Yr															
24																
25	PV of Annual Customers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	Total PV of Customers															
27																
28	**Present Value of Cost of Energy**															
29	Cost of Energy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	PV of Annual Cost of Energy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Total PV of Cost of Energy															
32																
39	**Average Cost of Service Analysis**															
40	Annual Volume (TJ)	161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111	161,111	-	-	-	-	-
41																
44	Annual Volumetric Cost of Service $/GJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	-	-	-	-	-
45																
46	**Levelized Cost of Service Analysis**															
47	PV of Annual Volume (TJ)	59,868	56,277	52,900	49,726	46,743	43,939	41,302	38,824	36,495	34,306	-	-	-	-	-
48	Total PV of Volume (TJ)															
49																
52	Average Levelized Volumetric Cost of Service ($/GJ)															
53																
54	1- (Line 7 x Line 8) / 1- Line 15 + (Line 10 x Line 11 + Line 12 x Line 13)															
55	2- Line 8 x Line 9 + [(Line 11 x Line 12 + Line 13 x Line 14) x 1- Line 16]															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Present Value & Average Levelized Cost
Appendix F-2 - Schedule 11
($000's), unless otherwise statea

Line	Particulars	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060
1																
2	Annual Cost of Service (Excluding Cost of Energy)($000s)	808.9	794.5	779.6	764.3	748.6	732.4	716.0	699.1	682.0	664.7	647.0	629.2	611.1	511.1	578.1
4																
5	**Annual Discount Rate**															
6	Equity Component															
7	ROE %	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%
8	Equity Portion	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%
9	Debt Component															
10	Long Term Debt Rate	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
11	Long Term Debt Portion	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%
12	Short Term Debt Rate	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
13	Short Term Debt Portion	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%
14																
15	Tax Rate	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%
16	Pre- Tax Weighted Average Cost of Capital (WACC)[1]	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%
17	After- Tax Weighted Average Cost of Capital (WACC)[2]	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%
18																
19	**Present Value of Cost of Service**															
20	PV of Annual Revenue Requirement	118.8	109.7	101.2	93.3	85.9	79.0	72.6	66.6	61.1	55.9	51.2	46.8	42.7	33.6	35.7
21	PV of Annual Revenue Requirement ($/Mnth)	10	9	8	8	7	7	6	6	5	5	4	4	4	3	3
22	Total PV of Revenue Requirement															
23	Total PV of Revenue Requirement, $000s/Yr															
24																
25	PV of Annual Customers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	Total PV of Customers															
27																
28	**Present Value of Cost of Energy**															
29	Cost of Energy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	PV of Annual Cost of Energy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Total PV of Cost of Energy															
32																
39	**Average Cost of Service Analysis**															
40	Annual Volume (TJ)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41																
44	Annual Volumetric Cost of Service $/GJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45																
46	**Levelized Cost of Service Analysis**															
47	PV of Annual Volume (TJ)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Total PV of Volume (TJ)															
49																
52	Average Levelized Volumetric Cost of Service ($/GJ)															
53																
54	1- (Line 7 x Line 8) / 1- Line 15 + (Line 10 x Line 11 + Line 12 x Line 13)															
55	2- Line 8 x Line 9 + [(Line 11 x Line 12 + Line 13 x Line 14) x 1- Line 16]															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Present Value & Average Levelized Cost
Appendix F-2 - Schedule 11
($000's), unless otherwise stated

Line	Particulars	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075
1																
2	Annual Cost of Service (Excluding Cost of Energy)($000s)	558.7	884.7	1,027.5	1,016.2	1,001.8	984.8	966.7	950.1	931.7	911.2	889.9	867.9	845.4	822.3	798.7
4																
5	**Annual Discount Rate**															
6	Equity Component															
7	ROE %	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%
8	Equity Portion	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%
9	Debt Component															
10	Long Term Debt Rate	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
11	Long Term Debt Portion	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%	56.98%
12	Short Term Debt Rate	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
13	Short Term Debt Portion	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%
14																
15	Tax Rate	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%
16	Pre- Tax Weighted Average Cost of Capital (WACC)[1]	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%
17	After- Tax Weighted Average Cost of Capital (WACC)[2]	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%
18																
19	**Present Value of Cost of Service**															
20	PV of Annual Revenue Requirement	32.4	48.3	52.7	49.0	45.4	42.0	38.7	35.8	33.0	30.3	27.8	25.5	23.4	21.4	19.5
21	PV of Annual Revenue Requirement ($/Mnth)	3	4	4	4	4	3	3	3	3	3	2	2	2	2	2
22	Total PV of Revenue Requirement															
23	Total PV of Revenue Requirement, $000s/Yr															
24																
25	PV of Annual Customers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	Total PV of Customers															
27																
28	**Present Value of Cost of Energy**															
29	Cost of Energy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	PV of Annual Cost of Energy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Total PV of Cost of Energy															
32																
39	**Average Cost of Service Analysis**															
40	Annual Volume (TJ)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41																
44	Annual Volumetric Cost of Service $/GJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45																
46	**Levelized Cost of Service Analysis**															
47	PV of Annual Volume (TJ)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Total PV of Volume (TJ)															
49																
52	Average Levelized Volumetric Cost of Service ($/GJ)															
53																
54	1- (Line 7 x Line 8) / 1- Line 15 + (Line 10 x Line 11 + Line 12 x Line 13)															
55	2- Line 8 x Line 9 + [(Line 11 x Line 12 + Line 13 x Line 14) x 1- Line 16]															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Discounted Cash Flow Analysis
Appendix F-2 - Schedule 12
($000's), unless otherwise stated

Line	Particulars	Reference	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	**Cash Flow**																
2	Add: Revenue	Schedule , Line 6	1,133.2	1,062.1	1,055.3	785.3	748.8	743.1	738.7	733.7	727.8	721.2	713.9	705.9	697.3	688.1	678.4
3	Less: O&M, Property Tax Expense & Cost of Energy	Schedule 1, - (Line 2 + Line 4) + Schedule 2, - Line 15	(15.0)	(25.6)	(37.4)	(37.2)	(37.7)	(35.6)	(35.8)	(36.3)	(36.8)	(37.4)	(37.9)	(38.5)	(39.0)	(39.6)	(40.2)
4	EBITDA[1]	Line 2 + Line 3	1,118.2	1,036.5	1,017.9	748.0	711.1	707.6	702.9	697.4	691.0	683.9	676.0	667.4	658.2	648.5	638.2
5	Capital Expenditures[2]	Schedule 6, Line 99	(7,977.3)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Deferred Charges, Net of Tax		(647.1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Disposal Costs Incurred																
8	Pre-Tax Cash Flow		(6,859.1)	1,036.5	1,017.9	748.0	711.1	707.6	702.9	697.4	691.0	683.9	676.0	667.4	658.2	648.5	638.2
9	Income Tax on Operations	Line 4 * - Schedule 3, Line 14	(290.7)	(269.5)	(264.6)	(194.5)	(184.9)	(184.0)	(182.8)	(181.3)	(179.7)	(177.8)	(175.7)	(173.5)	(171.1)	(168.6)	(165.9)
10	Overhead Capitalized Tax Shield	Schedule 3, - Line 10 * Line14	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
11	CCA / Removal Cost Tax Shield	Schedule 3, - (Line 11 + Line 9) * Line 14	78.5	150.7	138.7	127.7	117.6	108.2	99.6	91.7	84.4	77.7	71.5	65.9	60.6	55.8	51.4
12	Terminal Value of CCA Tax Shield																
13	Terminal Value	Year 60, Line 15 / Line 17															
14																	
15	Free Cash Flow	Line 8 + Line 9	(7,071.1)	918.0	892.2	681.5	644.1	632.1	620.0	608.0	596.0	584.0	572.0	560.0	548.0	536.0	524.0
16																	
17	After Tax WACC %	Schedule 11, Line 17	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%
18	Present Value of Free Cash Flow[3]	Line 15 / (1 + Line 17)^Yr	(7,772.6)	811.1	741.1	532.1	472.7	436.0	402.1	370.7	341.5	314.6	289.6	266.5	245.2	225.4	207.2
19	Total Present Value of Free Cash Flow	Sum of Line 18	**44.1**														
20																	
21	1- Earnings Before Interest, Taxes, Depreciation & Amortization (EBITDA)																
22	2- Net of CIAC and removal costs (if applicable) and excludes capitalized overhead																
23	3- 2016 present value calculates capital expenditure to occur at time zero																

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Discounted Cash Flow Analysis
Appendix F-2 - Schedule 12
($000's), unless otherwise stated

Line	Particulars	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	**Cash Flow**															
2	Add: Revenue	668.3	657.7	646.7	635.4	623.7	611.7	599.5	587.0	680.2	876.2	867.0	859.0	848.4	835.8	822.7
3	Less: O&M, Property Tax Expense & Cost of Energy	(40.8)	(41.4)	(42.0)	(42.6)	(43.2)	(43.9)	(44.5)	(45.2)	(45.8)	(46.5)	(48.3)	(51.1)	(51.9)	(52.7)	(53.5)
4	EBITDA[1]	627.5	616.3	604.7	592.8	580.5	567.9	555.0	541.8	634.3	829.7	818.7	807.9	796.5	783.2	769.2
5	Capital Expenditures[2]	-	-	-	-	-	-	-	-	(3,927.9)	(0.0)	-	(24.9)	-	-	-
6	Deferred Charges, Net of Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Disposal Costs Incurred															
8	Pre-Tax Cash Flow	627.5	616.3	604.7	592.8	580.5	567.9	555.0	541.8	(3,293.5)	829.7	818.7	782.9	796.5	783.2	769.2
9	Income Tax on Operations	(163.1)	(160.2)	(157.2)	(154.1)	(150.9)	(147.6)	(144.3)	(140.9)	(164.9)	(215.7)	(212.9)	(210.0)	(207.1)	(203.6)	(200.0)
10	Overhead Capitalized Tax Shield	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
11	CCA / Removal Cost Tax Shield	47.4	43.6	40.2	37.0	34.1	31.4	28.9	26.7	93.1	98.9	91.0	84.0	77.5	71.4	65.7
12	Terminal Value of CCA Tax Shield										-	-	-	-	-	-
13	Terminal Value										-	-	-	-	-	-
14												697.3	657.3	667.3	651.3	635.3
15	Free Cash Flow	512.0	500.0	488.0	476.0	464.0	452.0	440.0	428.0	(3,364.9)	713.2	697.3	657.3	667.3	651.3	635.3
16																
17	After Tax WACC %	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%
18	Present Value of Free Cash Flow[3]	190.3	174.7	160.2	146.9	134.6	123.3	112.8	103.1	(762.2)	151.9	139.6	123.7	118.0	108.3	99.3
19	Total Present Value of Free Cash Flow															
20																
21	1- Earnings Before Interest, Taxes, Depreciation & Amortization (EBITDA)															
22	2- Net of CIAC and removal costs (if applicable) and excludes capitalized ov															
23	3- 2016 present value calculates capital expenditure to occur at time zero															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Discounted Cash Flow Analysis
Appendix F-2 - Schedule 12
($000's), unless otherwise stated

Line	Particulars	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060
1	**Cash Flow**															
2	Add: Revenue	808.9	794.5	779.6	764.3	748.6	732.4	716.0	699.1	682.0	664.7	647.0	629.2	611.1	511.1	578.1
3	Less: O&M, Property Tax Expense & Cost of Energy	(54.3)	(55.1)	(55.9)	(56.7)	(57.6)	(58.4)	(59.3)	(60.2)	(61.1)	(62.0)	(63.0)	(64.0)	(65.0)	(66.0)	(67.0)
4	EBITDA[1]	754.6	739.4	723.8	707.6	691.0	674.0	656.7	638.9	620.9	602.6	584.0	565.2	546.2	445.1	511.1
5	Capital Expenditures[2]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Deferred Charges, Net of Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Disposal Costs Incurred															
8	Pre-Tax Cash Flow	754.6	739.4	723.8	707.6	691.0	674.0	656.7	638.9	620.9	602.6	584.0	565.2	546.2	445.1	511.1
9	Income Tax on Operations	(196.2)	(192.3)	(188.2)	(184.0)	(179.7)	(175.2)	(170.7)	(166.1)	(161.4)	(156.7)	(151.8)	(147.0)	(142.0)	(115.7)	(132.9)
10	Overhead Capitalized Tax Shield	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6
11	CCA / Removal Cost Tax Shield	60.5	55.7	51.3	47.3	43.6	40.1	37.0	34.1	31.4	29.0	26.7	24.6	22.7	21.0	19.3
12	Terminal Value of CCA Tax Shield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Terminal Value	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14		619.3	603.3	587.4	571.4	555.4	539.4	523.4	507.4	491.4	475.4	459.4	443.4	427.4	350.9	398.1
15	Free Cash Flow	619.3	603.3	587.4	571.4	555.4	539.4	523.4	507.4	491.4	475.4	459.4	443.4	427.4	350.9	398.1
16																
17	After Tax WACC %	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%
18	Present Value of Free Cash Flow[3]	91.0	83.3	76.2	69.7	63.7	58.2	53.0	48.3	44.0	40.0	36.3	33.0	29.9	23.1	24.6
19	Total Present Value of Free Cash Flow															
20																
21	1- Earnings Before Interest, Taxes, Depreciation & Amortization (EBITDA)															
22	2- Net of CIAC and removal costs (if applicable) and excludes capitalized ov															
23	3- 2016 present value calculates capital expenditure to occur at time zero															

FortisBC Energy Inc.
Huntingdon Station Bypass Project
September, 2013

Huntingdon Station Bypass Project: Discounted Cash Flow Analysis
Appendix F-2 - Schedule 12
($000's), unless otherwise stated

Line	Particulars	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075
1	**Cash Flow**															
2	Add: Revenue	558.7	884.7	1,027.5	1,016.2	1,001.8	984.8	966.7	950.1	931.7	911.2	889.9	867.9	845.4	822.3	798.7
3	Less: O&M, Property Tax Expense & Cost of Energy	(67.3)	(69.2)	(70.3)	(74.9)	(77.7)	(78.9)	(80.2)	(81.4)	(82.7)	(84.0)	(85.4)	(86.7)	(88.1)	(89.5)	(90.9)
4	EBITDA[1]	491.5	815.5	957.2	941.3	924.1	905.9	886.6	868.6	849.0	827.1	804.5	781.2	757.3	732.8	707.7
5	Capital Expenditures[2]	-	(6,285.3)	-	-	-	-	-	(43.7)	-	-	-	-	-	-	-
6	Deferred Charges, Net of Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Disposal Costs Incurred															
8	Pre-Tax Cash Flow	491.5	(5,469.7)	957.2	941.3	924.1	905.9	886.6	824.9	849.0	827.1	804.5	781.2	757.3	732.8	707.7
9	Income Tax on Operations	(127.8)	(212.0)	(248.9)	(244.7)	(240.3)	(235.5)	(230.5)	(225.8)	(220.7)	(215.1)	(209.2)	(203.1)	(196.9)	(190.5)	(184.0)
10	Overhead Capitalized Tax Shield	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8
11	CCA / Removal Cost Tax Shield	17.9	81.9	140.7	129.6	119.3	109.8	101.1	93.4	86.3	79.5	73.3	67.5	62.2	57.3	52.8
12	Terminal Value of CCA Tax Shield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14.5
13	Terminal Value	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,205.6
14		382.1	(5,599.3)	849.7	826.7	803.7	780.7	757.8	693.1	715.3	692.3	669.3	646.3	623.3	600.3	8,797.4
15	Free Cash Flow	382.1	(5,599.3)	849.7	826.7	803.7	780.7	757.8	693.1	715.3	692.3	669.3	646.3	623.3	600.3	8,797.4
16																
17	After Tax WACC %	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%
18	Present Value of Free Cash Flow[3]	22.2	(305.6)	43.6	39.9	36.4	33.3	30.4	26.1	25.3	23.0	20.9	19.0	17.2	15.6	214.8
19	Total Present Value of Free Cash Flow															
20																
21	1- Earnings Before Interest, Taxes, Depreciation & Amortization (EBITDA)															
22	2- Net of CIAC and removal costs (if applicable) and excludes capitalized ov															
23	3- 2016 present value calculates capital expenditure to occur at time zero															

Appendix F3

CAPITAL COST

FILED CONFIDENTIALLY

Appendix G

PRELIMINARY ENVIROMENTAL ASSESSMENT

Huntingdon Control Station Reinforcement Project Preliminary Environmental Assessment

Prepared for:
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8

Prepared by:
Hemmera
250 – 1380 Burrard Street
Vancouver, BC V6Z 2H3

File: 855-023.04
May 2013

HEMMERA

EXECUTIVE SUMMARY

FortisBC Energy Inc (FEI) is proposing to construct 200 m of 36” natural gas pipeline connecting an existing pipeline from Spectra Energy (entering Huntingdon Control Station from the east) to existing transmission pipelines located west of Huntingdon Control Station beneath an agricultural field. This “Project” is being constructed to allow FEI to continue to provide natural gas to customers in the Lower Mainland, Sunshine Coast, Vancouver Island and Sea to Sky corridor in the event of a shut down at the Huntington Control Station. All construction will occur within 100 m of Huntingdon Control Station.

This preliminary environmental assessment is based on a desktop review and site visit to identify and describe the potential effects of the Project on the biophysical environment, recommend mitigation measures to avoid, reduce, or minimize these potential effects and outline potential environmental permitting requirements. The submission of this assessment is required as part of FEI’s application for a Certificate of Public Convenience and Necessity (CPCN) from the BC Utilities Commission (BCUC).

The potential effects to ecological components identified in this report are focused on proposed Project construction activities, such as vegetation clearing, excavation, soil stockpiling and grading, and working within or in proximity to a fish-bearing agricultural ditch. Notable environmental considerations associated with the proposed pipeline include:

- Impacts to fish and fish habitat, including fish salvage, and permitting/authorization requirements under the *Water Act, Wildlife Act* and the *Fisheries Act* associated with instream works required for pipeline installation beneath a salmonid-bearing unnamed agricultural ditch.
- Impacts to agricultural land use, based on the Project’s proposed alignment within the provincially designated Agricultural Land Reserve.
- No federal or provincial species at risk are known to occur within the study area; however, depending on detailed design, specific surveys should be conducted for:
    - Townsend’s mole (look for mole hills in adjacent agricultural field).
    - Raptor and heron nest presence and / or activity. Surveys should be conducted in spring (March) to determine nest status. Currently there is a bald eagle nest approximately 400 m away (complies with 100 m buffer recommended by MOE) and a potential red-tailed hawk approximately 150 m away (inside the 200 m buffer recommended by MOE).

While there is potential for environmental effects to occur during construction of this Project, these effects can be mitigated by following provincial and federal guidelines and best management practices. Discussion with relevant agencies: Fisheries and Oceans (DFO), Ministry of Forests, Land, and Natural Resource Operations (MFLNRO), and the Agricultural Land Commission (ALC) will be required to determine conditions of permits and/or approvals required for this Project. Communication with the City of Abbotsford is also recommended to ensure compliance with municipal legislation.

TABLE OF CONTENTS

List of Tables

List of Figures

List of Appendices

1.0 INTRODUCTION

FortisBC Energy Inc (FEI) is proposing to install 200 m of 36” nominal pipe size (NPS) natural gas pipeline and five buried valves around the FEI Huntingdon Control Station (the “Project”), located at the Canada/United States border in Abbotsford, BC to improve the reliability and availability of this control station (**Figure 1**). Huntingdon Control Station has provided reliable gas service for more than 50 years serving more than 600,000 customers between the Lower Mainland, Squamish, Whistler, the Sunshine Coast, and Vancouver Island and is the sole source of gas supply for many of the residents, businesses, schools, and hospitals in these areas. The implications of a shutdown would be significant; therefore, these improvements are considered necessary to maintain and improve the reliability and accessibility of this station.

To proceed with this Project, an application for a Certificate of Public Convenience and Necessity (CPCN) from the BC Utilities Commission (BCUC) is required. In order to support the Project’s planning process and the submission of an application for a CPCN, FEI requires an assessment of the potential environmental effects associated with the Project.

The purpose of this preliminary environmental assessment is to identify and describe the potential effects of the Project on the biophysical environmental and recommend potential mitigation measures to avoid, minimize, or reduce these potential effects. For the sake of this assessment, the study area is defined as a 250 m radius extending from Huntingdon Control Station excluding south of the Canada/United States border (see Figure 1), Potential municipal, provincial, and federal environmental permitting requirements are also identified for further consideration.

2.0 PROJECT DESCRIPTION AND SCOPE

2.1 PROJECT DESCRIPTION

The proposed Project involves the installation of 200 m of NPS 36" natural gas pipeline and five buried valves connecting to existing pipelines. The pipeline will be installed via an open cut utility trench and all work will occur within 100 m radius of Huntingdon Control Station. As indicated in **Figure 1**, the pipeline will exit the northeast part of Huntingdon Control Station (where it will connect to an incoming Spectra Energy natural gas supply line), head north briefly, then turn 90 degrees west beneath the Huntingdon Control Station access road and cross an unnamed, fish-bearing agricultural ditch before terminating beneath an agricultural field where it will connect to existing pipelines along an existing right-of-way. Construction activity is expected to occur during the summer of 2015, with an expected in-service date of October, 2015.

2.2 SCOPE OF PRELIMINARY ASSESSMENT

The scope of this assessment includes identification of potential effects to the biophysical environment associated with Project construction and operation, followed by identification of mitigation measures to avoid, minimize, or reduce these potential effects. Potential environmental permitting requirements are also identified. To determine the potential effects a desktop review was completed, followed by a site visit (January 10, 2013) to ground-truth results of the desktop review and gather additional information regarding:

- Environmental site conditions including soils, surface water, fish, vegetation and wildlife (including species at risk).
- Potential effects to ecological components and preliminary description of potential mitigation measures associated with the Project.
- Potential environmental permits and approvals that may be required from municipal, provincial, and federal regulatory agencies, including the identification of any potential environmental least-risk windows that may apply.

For the purposes of this preliminary assessment, the study area extends from the Huntingdon Control Station in a 250 m radius, excluding all land south of the Canada / United States border as shown on **Figure 1**. It is understood that general Project activities will involve clearing of vegetation, pipe stringing, bending, welding, excavation of a utility trench to place pipe, backfilling and restoration, and crossing of a fish-bearing ditch requiring instream work (work area isolation and bypass).

3.0 DESCRIPTION OF THE ENVIRONMENT

A desktop database / literature review was conducted to identify existing environmental conditions within the Project area including potential occurrences of at-risk plants, plant communities, and terrestrial and aquatic wildlife. Where actual occurrences of species at risk were not documented, habitat requirements were used to evaluate the likelihood of the species occurring within the study area. The following sources were referenced during the review process:

- On-line Aerial photographs.
- BC Conservation Data Centre (CDC; http://www.env.gov.bc.ca/atrisk/ims.htm) and BC Species and Ecosystem Explorer (http://www.env.gov.bc.ca/atrisk/toolintro.html).
- BC Natural Resource Information Centre habitat sensitivity maps: Abbotsford Watershed atlas (http://cmnbc.ca/atlas_gallery/abbotsford-watershed-atlas).
- Canadian Wildlife Service (CWS) / Environment Canada.
- Species at Risk Public Registry (http://www.sararegistry.gc.ca/default_e.cfm).
- Fisheries and Oceans Canada's (DFO) online MAPSTER.
- DFO and BC Ministry of Environment's (MoE), Fisheries Information Summary System (FISS) and Habitat Wizard.

3.1 SOILS AND SURFICIAL GEOLOGY

The Project Site is located within the Agricultural Land Reserve (ALR) (ALC 2011), which is designated by the province in areas where agriculture is recognized as the priority land use. In this zone, farming is encouraged and non-agricultural activities are controlled (ALC 2010). The agricultural field in the western section of the proposed pipeline (**Figure 1**) is seasonally flooded and planted in young blueberries (**Photo 1**). The rest of the pipeline will be installed beneath an existing gravel access road paralleling an agricultural field to the north that appears to be planted with grass or grains (possibly wheat, barley, rye, or similar) as indicated in **Photo 2**.

Surficial geology at the Project Site consists of post-glacial, lacustrine deposits. Specifically, silt, clayey silt, and silty clay up to 50 feet or more thick, but normally less than 10 feet thick and overlying sand (GSC 1961). Based on the January 10, 2013 site visit, the soils appear to be poorly drained and experience a high seasonal water table and flooding from the agricultural ditch crossed by the proposed pipeline (**Figure 1**).

3.2 SURFACE WATER

A review of the City of Abbotsford online mapping database indicates the study area is relatively flat and within a floodplain. The study area is located within the historic Sumas Lake, upstream of flood control structures on the lower Sumas River designed to control rising floodwaters from the Fraser River.

Floodwaters have historically backed up from the Whatcom Road interchange of Highway 1 and ponded in the western portion of the West Sumas Prairie, with some floodwater ponding in the Lower Sumas River, Saar Creek, and Arnold Slough.

Searches of the provincial Habitat Wizard database and the City of Abbotsford web mapping tool identified no watercourses within the study area. The Sumas River flows approximately 350 m north west of Huntingdon Control Station and a tributary of Saar Creek flows approximately 450 north east of Huntingdon Control Station. An agricultural ditch was identified crossing the proposed pipeline between Huntingdon Control Station and the agricultural field to the west. This unnamed agricultural ditch runs north-south along the Huntingdon Control Station access road joining the Sumas River via a 0.6 m diameter, 120 m long culvert beneath Whatcom Road (Hemmera 2012b). It appears that this agricultural ditch (channel width 3.1 m) creates flooding conditions at the Huntingdon Control Station, along the access road to the facility, and in the agricultural field west of the facility at the western terminus of the proposed pipeline. Watercourse locations are provided on **Figure 1**. During the January 10, 2013 site visit, water levels in the western agricultural field were such that several small flocks of mallard ducks (*Anas platyrhyncos*) were swimming among the blueberry bushes (**Photo 1**).

A water intake, presumably for agricultural purposes, is located in a shipping container / storage shed approximately 200 m north of the proposed pipeline alignment (**Figure 1**).

3.3 FISH AND FISH HABITAT

The unnamed ditch (**Figure 1**) was sampled for fish presence in late June 2012 using ten gee-type minnow traps set between the Canada / US border and the Whatcom Road culvert (Hemmera 2012b). Fish species captured included:

- Redside Shiner *(Richardsonius balteatus).*
- Pumpkinseed *(Lepomis gibbosus).*
- Brassy Minnow *(Hybognathus hankinsoni).*
- Threespine Stickleback *(Gasterosteus aculeatus).*
- Coho Salmon *(Oncorhynchus kisutch).*

Threespine Stickleback were the most frequently captured species (n=64), followed by Coho (n=12), Redside Shiner (n=2), Pumpkinseed (n=1), and Brassy Minnow (n=1). Mean Coho length was 53 mm, indicating that they were likely 0^+ fry hatched in the Sumas River or other Fraser River tributary and rearing in the agricultural ditch (Hemmera 2012).

Riparian vegetation along the agricultural ditch consists primarily of grasses and shrubs such as salmonberry (*Rubus spectabilis*) and rose (*Rosa* sp.) with occasional deciduous trees including black cottonwood (*Populus balsamifera* ssp. *trichocarpa*). The January 10, 2013 site visit noted four young to mature cottonwood trees, one of which has been stumped / pollarded but is producing new shoots from the cut limbs. This tree was recently assessed for stability and was considered to be a hazard tree that had potential to fall onto the adjacent fence (Leslie Kristoff, pers. comm, 2013). It is unclear whether the remaining trees will require removal for pipeline installation. Hawthorn (*Crataegus* sp.) and snowberry (*Symphoricarpos albus*) were also noted and there is a single clump of paper birch (*Betula papyrifera*) along the ditch closer to the Canada / US border. At the proposed watercourse crossing there is a considerable amount of Himalayan blackberry (*Rubus armeniacus*) that is currently mowed as well as salmonberry, rose, and reed canary grass (*Phalaris arundinacea*). Riparian habitat is managed along the existing fence line of Huntingdon Control Station to the Canada / US borders (**Photo 3**), to ensure visibility and address potential security issues. While there is some riparian habitat present that functions to provide shade, detritus, insects, and stability to the ditch, it is limited as seen in **Photo 4**.

The watercourse evaluation report (Hemmera 2012) identified an upstream and downstream section of the agricultural ditch, with the proposed pipeline alignment within the upstream section near the approximate boundary of the two sections (**Figure 1**). Both sections contain slough-like mesohabitat with the upstream section providing moderate salmonid rearing values due to presence of in-stream cover and more pool and riffle habitat than the downstream section. Salmonid habitat values in the downstream section were considered poor (Hemmera 2012). Neither section of the ditch provides salmonid spawning habitat and it is likely that the juvenile coho enter the ditch from the Sumas River during periods of moderate to high water levels. The suitability of this rearing habitat likely decreases during summer months with lower water levels, higher temperatures, and lower dissolved oxygen levels. Channel substrates were primarily fines with some small patches of gravel in the upstream section. Channel width of the ditch averaged 3.1 m, though clearly there is seasonal flooding into the agricultural field, the Huntingdon Control Station access road, and into Huntingdon Control Station itself as evidenced from the January 10, 2013 site visit.

A FISS database search indicated the following species present in the Sumas River (**Table 1**). Some of these fish species may also be found in the unnamed watercourse at certain times of the year, pending the availability of access into the ditch and availability of suitable habitat characteristics.

Table 1 Fish species occurring in the Sumas River (FISS Database 2012).

Common Name	Scientific Name	Likelihood of Occurrence
Black Crappie	*Promoxis nigromaculatus*	Possible
Brown catfish	*Ameiurus nebulosus*	Possible
Carp	*Cyprinus carpio*	Possible
Chinook salmon	*Oncorhynchus tshawytscha*	Unlikely
Chub (General)	*Mylocheilus sp.*	Possible
Chum salmon	*Oncorhynchus keta*	Unlikely
Coho salmon	*Oncorhynchus kisutch*	Confirmed
Cutthroat trout	*Oncorhynchus clarkii clarkii*	Possible
Dace (General)	*Rhinichthys sp.*	Unlikely
Dolly Varden	*Salvelinus malma*	No
Kokanee	*Oncorhynchus nerka*	No
Lamprey (General)	*Lampetra spp.*	Possible
Mountain whitefish	*Prosopium williamsoni*	Unlikely
Northern pikeminnow	*Ptychocheilus oregonensis*	Possible
Pink salmon	*Oncorhynchus gorbuscha*	Unlikely
Rainbow trout	*Oncorhynchus mykiss*	Unlikely
Redside shiner	*Notropis lutrenis*	Confirmed
Sculpin (General)	*Cottus sp.*	Possible
Sockeye salmon	*Oncorhynchus nerka*	No
Steelhead	*Oncorhynchus mykiss*	Unlikely
Stickleback (General)	*Gasterosteus sp.*	Confirmed
Sturgeon (General)	*Acipenser spp.*	No
Sucker (General)	*Catostomus sp.*	Possible
Whitefish (General)	*Prosopium spp.*	Unlikely

Table 2 indicates fish species at risk potentially occurring in the municipality of Abbotsford (BC CDC 2013). None of these species are known to occur in the agricultural ditch, based on sampling conducted in June 2012 (Hemmera 2012b). Furthermore, the habitat values within this water feature would be unlikely to support the majority of these species, perhaps with the exception of Cutthroat Trout.

Table 2 Fish species at risk potentially occurring in Abbotsford (BC CDC 2013).

English Name	Scientific Name	BC List	COSEWIC	SARA
Green Sturgeon	*Acipenser medirostris*	Red	SC (May 1987)	1-SC (Aug 2006)
White Sturgeon (Lower Fraser River population)	*Acipenser transmontanus* pop. 4	Red	T (Nov 2012)	
Mountain Sucker	*Catostomus platyrhynchus*	Blue	SC (Nov 2010)	
Salish Sucker	*Catostomus* sp. 4	Red	T (Nov 2012)	1-E (Jan 2005)
Cutthroat Trout, *clarkii* subspecies	*Oncorhynchus clarkii clarkii*	Blue		
Nooksack Dace	*Rhinichthys cataractae - Chehalis lineage*	Red	E (Apr 2007)	1-E (Jun 2003)
Bull Trout	*Salvelinus confluentus*	Blue	SC (Nov 2012)	
Eulachon	*Thaleichthys pacificus*	Blue	E (May 2011)	

Notes: T – Threatened: a wildlife species likely to become endangered if limiting factors are not reversed
SC – Special Concern: a wildlife species that may become a threatened or an endangered species because of a combination of biological characteristics and identified threats
E – Endangered: a species facing imminent extirpation or extinction)
Red – Species that are extirpated, endangered, or threatened
Blue – Species of special concern

3.4 VEGETATION

The study area is located in the Coastal Western Hemlock (CWH) biogeoclimatic (BGC) zone and very dry maritime variant (CWHxm1) within the Sumas River watershed. Forest cover typical of this BGC variant is not present within the agricultural and industrial (existing Fortis facilities and counterparts south of the border) dominated study area. Sparse tree cover (black cottonwood, birch, hawthorn) and more frequent shrub cover (Himalayan blackberry and rose) occur along the relatively narrow riparian corridor adjacent to the agricultural ditch (**Photo 5**). Invasive species present along the riparian corridor include Himalayan blackberry and reed canary grass. No plant communities at risk have the potential to develop or persist within the anthropogenically altered landscape of the study area. The agricultural field to the west of the Huntingdon Control Station is planted in blueberries with bare ground between shrub rows. The field north of the facility appears to be planted in grass or a winter cover crop, possibly barley, rye, or wheat. There is a row of ornamental trees of the genus *Prunus* in the small grass-covered field between Fortis facilities (**Figure 1** and **Photo 6**).

A search of the BC Conservation Data Centre (BC CDC 2012) indicates potential for six plant species at-risk to occur in agricultural, riparian, or urban habitats in the CWH biogeoclimatic zone (**Table 3**). A CDC database search limited to the municipality of Abbotsford yielded no results; and a slightly expanded search of plant species at risk occurring in the FVRD indicated potential for only blue vervain (*Verbena hastata* var. *scabra*) based on known occurrences and habitat characteristics.

Table 3 Plant species at risk potentially occurring in agricultural, riparian, or urban habitats within the CWH Biogeoclimatic Zone (BC CDC 2012).

English Name	Scientific Name	BC List	COSEWIC	SARA
Field dodder	*Cuscuta campestris*	Blue	-	-
Awned cyperus	*Cyperus squarrosus*	Blue	-	-
False-pimpernel	*Lindernia dubia* var. *anagallidea*	Blue	-	-
Slender woolly-heads	*Psilocarphus tenellus*	Blue	NAR	-
Blue vervain	*Verbena hastata* var. *scabra*	Blue	-	-
Yellow montane violet	*Viola praemorsa* ssp. *praemorsa*	Red	E	E

Notes: T – Threatened: a wildlife species likely to become endangered if limiting factors are not reversed
SC - Special Concern: a wildlife species that may become a threatened or an endangered species because of a combination of biological characteristics and identified threats
E – Endangered: a species facing imminent extirpation or extinction)
Red - Species that are extirpated, endangered, or threatened
Blue - Species of special concern

There are no documented occurrences of these species in the study area (iMap BC 2012). The closest known occurrence (false-pimpernel) is approximately 20 km distant (E-Flora BC 2012). Based on habitat requirements, there is low potential for false-pimpernel, a low annual herb with small blue-violet to whitish narrowly bell-shaped flowers, to occur along the riparian habitat associated with the unnamed ditch. It is occasionally found along wet, sandy or muddy banks. Field dodder could occur in association with legumes if present in and along the agricultural fields; however, this does not appear likely based on the current uses of nearby fields. Blue vervain has been recorded in Port Coquitlam and Chilliwack. It occurs on disturbed ground, wet fields, roadsides, ditches; however, based on the current uses of the study area for agricultural purposes, and regular maintenance along the agricultural ditch (mowing Himalayan blackberry) and grass beneath and around the ornamental *Prunus* trees, occurrence of this blue-listed species is very unlikely. The other species are not known to occur in the FVRD and their presence in the study area is very unlikely based on site conditions, known occurrences, and habitat information (E-Flora BC 2013 and BC CDC 2013). Yellow montane violet, the only federally listed species identified, is only known from Garry oak woodlands and grass dominated meadows on Vancouver Island and Salt Spring Island.

3.5 WILDLIFE

A search of the BC Conservation Database (BC CDC 2013) yielded 26 terrestrial and aquatic wildlife species at risk that could occur within the FVRD in agricultural, riparian, or urban areas based on known distributions. However, there are no documented occurrences of species at risk in the study area (iMap BC 2012) and based on the limited habitat available and known habitat requirements of the species identified in **Table 4,** it is unlikely that any of these species rely on or use the study area extensively.

While there are no known occurrences of species at risk within the study area, iMap BC (2012) confirms the presence of Townsend's mole (*Scapanus townsendii*), a provincially red-listed and federally endangered species, approximately two kilometres west of the study area. Moles occur in pastures, farmland, and lawns with a rich humus layer overlying silt loam soil (COSEWIC 2003). Territories are identified by a cluster of mole hills or mounds created by castings from tunnel excavations. Though formerly considered a pest under the BC *Wildlife Act*, Townsend's mole are now protected by both the provincial *Wildlife Act* and the federal *Species at Risk Act* (SARA); however, a recovery plan identifying critical habitat (which would have legislated protection under SARA) has not been completed. In the interim, conservation and best management recommendations have been identified in the COSEWIC (2003) status report. A small portion of the agricultural field north of the proposed alignment was searched for mole hills during the January 10, 2013 site visit. None were detected. The blueberry field to the west was completely flooded and there is no cover between shrub rows, likely precluding moles from this field.

A bald eagle nest was detected approximately 400 m east of the Project footprint (**Figure 1** and **Photo 7**). Two adult bald eagles were present, and while this observation did not occur during the breeding season (eggs may be present in early February with young present until the end of August), it is indicative of territorial behaviour suggesting that this may be an active nest site during the breeding season. An unknown nest, potentially constructed by a red-tailed hawk was detected across the Canada / US border south of a small fenced in section of the gas plant located in the blueberry field west of the study area (**Figure 1** and **Photo 8**). This nest is approximately 150 m south east of the Project footprint. Its activity status is unclear.

Table 4 Wildlife and vegetation species at risk potentially occurring in the FVRD in agricultural, riparian, and urban habitats (BC CDC 2013).

English Name	Scientific Name	COSEWIC	BC List	Identified Wildlife	SARA
Northwestern Salamander	*Ambystoma gracile*	NAR (May 1999)	Yellow		
Western Toad	*Anaxyrus boreas*	SC (Nov 2012)	Blue		1-SC (Jan 2005)
Northern Red-legged Frog	*Rana aurora*	SC (Nov 2004)	Blue	Y (May 2004)	1-SC (Jan 2005)
Columbia Spotted Frog	*Rana luteiventris*	NAR (May 2000)	Yellow		
Oregon Spotted Frog	*Rana pretiosa*	E (May 2011)	Red		1-E (Jun 2003)
Barn Swallow	*Hirundo rustica*	T (May 2011)	Blue		
Barn Owl	*Tyto alba*	T (Nov 2010)	Blue		1-SC (Jun 2003)

English Name	Scientific Name	COSEWIC	BC List	Identified Wildlife	SARA
Band-tailed Pigeon	*Patagioenas fasciata*	SC (Nov 2008)	Blue		1-SC (Feb 2011)
Common Nighthawk	*Chordeiles minor*	T (Apr 2007)	Yellow		1-T (Feb 2010)
Great Blue Heron, *fannini* subspecies	*Ardea herodias fannini*	SC (Mar 2008)	Blue	Y (May 2004)	1-SC (Feb 2010)
Green Heron	*Butorides virescens*		Blue		
Northern Harrier	*Circus cyaneus*	NAR (May 1993)	Yellow		
Peregrine Falcon	*Falco peregrinus*	SC (Apr 2007)	No Status		
Purple Martin	*Progne subis*		Blue		
Rough-legged Hawk	*Buteo lagopus*	NAR (May 1995)	Blue		
Short-eared Owl	*Asio flammeus*	SC (Mar 2008)	Blue	Y (May 2004)	1-SC (Jul 2012)
Western Screech-Owl, *kennicottii* subspecies	*Megascops kennicottii kennicottii*	T (May 2012)	Blue		1-SC (Jan 2005)
Yellow-breasted Chat	*Icteria virens*	E (Nov 2011)	Red	Y (May 2004)	1-E (Jun 2003)
Monarch	*Danaus plexippus*	SC (Apr 2010)	Blue		1-SC (Jun 2003)
Dun Skipper	*Euphyes vestris*	T (Nov 2000)	Blue		1-T (Jun 2003)
Townsend's Big-eared Bat	*Corynorhinus townsendii*		Blue		
Snowshoe Hare, *washingtonii* subspecies	*Lepus americanus washingtonii*		Red		
Long-tailed weasel, *altifrontalis* subspecies	*Mustela frenata altifrontalis*		Red		
Townsend's Mole	*Scapanus townsendii*	E (May 2003)	Red		1-E (Jan 2005)
Pacific Water Shrew	*Sorex bendirii*	E (Apr 2006)	Red	Y (May 2004)	1-E (Jun 2003)
Painted Turtle - Pacific Coast Population	*Chrysemys picta pop. 1*	E (Apr 2006)	Red		1-E (Dec 2007)

Notes: T – Threatened: a wildlife species likely to become endangered if limiting factors are not reversed
SC - Special Concern: a wildlife species that may become a threatened or an endangered species because of a combination of biological characteristics and identified threats
E – Endangered: a species facing imminent extirpation or extinction)
Red - Species that are extirpated, endangered, or threatened
Blue - Species of special concern
Yellow - all species not found on the Red or Blue Lists

Potential effects of the Project on watercourses, vegetation, and wildlife are summarized below in **Section 4.**

4.0 POTENTIAL ENVIRONMENTAL EFFECTS

Construction activities will involve vegetation clearing, pipe stringing, bending, welding, excavation of a utility trench to place pipe, backfilling and restoration, and a watercourse crossing via instream work (block and bypass, excavate and install pipeline below the drainage ditch). Potential effects from these project activities on ecological components are expected to be limited to the construction phase of the Project and include:

- Sensory disturbance such as loud percussive noises that could disturb or displace wildlife.
- Habitat loss and alteration.
- Water quality effects.
- Direct mortality.

Table 5 identifies and evaluates potential effects from Project activities on each ecological component using discrete categories that reflect a “high”, “moderate”, “low” and “negligible” impact potential (prior to incorporation of mitigation measures) defined as:

- High – “at risk” species and ecosystems; watercourses with salmonids and functioning native riparian habitat; and other species potentially affected by the project. Non-standard mitigation measures, in addition to Standard Operating Procedures (SOPs) and Best Management Practices (BMPs) may be required to address effects; or
- Moderate – “at risk” species and vegetation; watercourses with non-salmonids and functioning riparian habitat (including non-native) potentially affected by the project. Non-standard mitigation measures, in addition to SOPs and BMPs may be required to address impacts.; or
- Low - ecosystems and species not “at risk”, channelized roadside ditches with non-functioning riparian habitat are potentially affected by the project. Residual impacts not likely. SOPs and BMPs are sufficient to address impacts; or
- Negligible – no (or negligible) impacts are associated with the project.

Table 5 Evaluation of potential effects to ecological components from project construction and operation.

Project Activities and Physical Works	Ecological Component										
	Agricultural Land	Surface Water	Fish and Fish Habitat	Rare Plants and Ecological Communities	Songbirds	Waterfowl / Waterbirds	Raptors	Small Mammals	Large Mammals	Amphibians	Invertebrates
Construction and Commissioning											
Site preparation and vegetation clearing	L	L	L	N	L	N	L	L	N	L	N
Materials and equipment transportation	L	N	N	N	L	N	L	L	N	L	N
Temporary bypass installation NPS 16”	L	N	N	N	L	N	L	L	N	L	N
Preparation, use and clean-up of ancillary construction areas such as lay-down areas and storage activities	L	L	L	N	L	N	L	L	N	L	N
Pipeline trench excavation	L	**H**	**H**	N	L	N	L	L	N	L	N
Pipeline installation	L	**H**	**H**	N	L	N	L	L	N	L	N
Backfilling trench	L	**H**	**H**	N	L	N	L	L	N	L	N
Operation and Maintenance											
Pipeline operation	N	L	L	N	N	N	N	N	N	N	N
Pipeline maintenance	N	L	L	N	N	N	N	N	N	N	N
Decommissioning											
To be considered closer to time of Project decommissioning	-	-	-	-	-	-	-	-	-	-	-

Note: N = Negligible, L = Low magnitude, M = Moderate magnitude, H = High magnitude

5.0 POTENTIAL REGULATORY REQUIREMENTS

The following potential consultation and regulatory requirements related to the environment should be considered.

5.1 MUNICIPAL

Relevant City of Abbotsford permitting and bylaws associated with the Project include:

- Consolidated Soil Removal and Deposit bylaw (#1228-2003) regulates the removal and deposit of soil.
- Erosion and Sediment Control Bylaw (#1989-2010) protects municipal watercourses from pollution, obstructions and sediment laden water.
- Streamside Protection Bylaw (#1465-2005) provides requirements for development along streams. Personal communication (January 2013) with Tanya Bettles, City of Abbotsford, indicates that a riparian areas assessment is not required; however, submission of Project description materials used in MFLNRO (*Water Act*) and DFO (*Fisheries Act*) Permits or Notifications [see Provincial and Federal requirements below] to the City of Abbotsford is recommended to assure compliance with this bylaw.
- Waterways Protection Bylaw (#269-96) regulates watercourse fouling or obstructions.

As the study area is within the Agricultural Land Reserve (ALR), the municipal Tree Cutting Bylaw (#1831-2009) does not appear to be required for tree removal during the Project's site preparation and clearing works provided any tree clearing is within FEI's Project right-of-way.

5.2 PROVINCIAL

Due to the location of the pipeline within the ALR, appropriate permits will be required through the Agricultural Land Commission to expand the existing right-of-way for pipeline installation. A plan to reclaim disturbed agricultural land should be determined through consultation with the ALC.

Given the proposed construction approach for the pipeline crossing the unnamed watercourse (i.e., open-cut trenching), it is apparent that application under Section 9 of the *Water Act* will apply. An application under the *Water Act* will need to be submitted to Oil and Gas Commission BC. Wildlife permits through the *Wildlife Act* (Ministry of Environment) will need to be obtained if fish or wildlife salvage activities are required during Project construction. Instream work should be completed as per fish timing windows identified by the Ministry of Environment and Fisheries and Oceans Canada (mid-July to mid-September for salmon) to minimize potential impacts to fish.

Where feasible, tree removal should occur outside the critical bird breeding period (approximately March 15 to July 31), or a nest survey should be conducted by a qualified professional to determine presence / absence prior to clearing. The nests of several raptor species, including bald eagles, are afforded year-round protection by the *Wildlife Act* regardless of activity status, and if present in the study area, buffers such as those described in the Best Management Practices for Raptor Conservation During Urban and Rural Land Development (BC MOE 2005) should be followed where possible. Bald eagles, especially those living in populated areas of the Lower Mainland are fairly tolerant of human activities and disturbance buffers of 100 m are recommended. The distance between the Project footprint and the existing eagle nest (approximately 400 m) fulfills this recommended buffer.

While not protected year round (as is a bald eagle nest), red-tailed hawk nests are protected under the *Wildlife Act* when active (potentially late February to August) and suitable buffers should be applied to avoid or minimize potential effects that would violate section 34 of the *Wildlife Act*. The recommended disturbance buffer for an active red-tailed hawk nest is 200 m (BC MOE 2005). As the Project footprint is within this recommended buffer, re-assessment to determine nest status is recommended prior to construction. If the nest is that of an active red-tailed hawk and the recommended 200 m buffer cannot be adhered to, proceeding with the western portion of the pipeline installation (west of the agricultural ditch) once chicks have fledged (generally after early August) would avoid potential effects. Alternatively, the suggested disturbance buffer could be reduced, if considered appropriate by a qualified environmental professional (QEP) and discussed with the BC MOE. Existing site conditions and activity (active gas plant already within recommended buffer) as well as retention of existing trees around the nest may factor into a QEP decision. In this case, effects monitoring and temporary work stoppages may be required to avoid nest abandonment, especially early in the nesting period.

5.3 FEDERAL

5.3.1 Fisheries Act

Given the confirmed presence of Coho Salmon within the unnamed agricultural ditch, it is apparent that this watercourse has fish habitat values afforded protection by the federal *Fisheries Act*. Although the *Fisheries Act* was amended in late June of 2012 in order to further clarify fisheries protection provisions, anticipated changes relating to habitat protection have not yet come into effect. It is expected that these changes will involve the development of new policy and regulations, including clarification about the need for Authorizations for any projects or works which will result in unavoidable impacts to fish habitat. In advance of these changes being finalized, it is understood that existing guidance and policies continue to apply.

The proposed works are on a channelized watercourse (ditch), characterized by low gradient and relatively poor riparian habitat conditions. Salmonid values, which are a key management concern under existing (and obviously future) DFO policy/guidelines, appear to be limited to rearing habitats. Furthermore, it is anticipated that these rearing habitat values might be seasonally constrained by water quality (e.g., warmer summer months - lower flows, higher water temperatures, and lower dissolved oxygen levels). Any potential construction-related impacts are expected to affect a relatively short ditch section and can likely be effectively mitigated through the application of a timing window, isolation of flow, work in-the-dry, and fish salvage. Through the implementation of mitigation during construction and follow-up restoration, including re-establishment and/or improvement of the channel and riparian vegetation, it appears that any impacts on fish habitat will be relatively minor (i.e., minor habitat affects, with a low spatial extent within a short temporal scale).

The Pipeline Associated Watercourse Crossings (3rd Edition, October 2005), which is endorsed by DFO, outlines the present regulatory framework which applies to pipeline watercourse crossings in Canada. These guidelines provide recommended practices for the design, construction, operation and maintenance of pipeline watercourses. With consideration towards the existing fish habitat values and anticipated construction approach, these proposed works appear to qualify as a “low risk crossing”. As a result, there are no anticipated requirements for a Fisheries and Oceans Canada (DFO) *Fisheries Act* Authorization. Instead, application of appropriate mitigation measures and a DFO notification are expected to apply. In the event that the proposed construction approach is modified to avoid instream work (i.e., directional drilling or a punch and bore watercourse crossing method), then the relevant DFO Operational Statement will apply.

Although new *Fisheries Act* policy and regulations are not in place yet, it appears that any pending changes will not alter this anticipated lack of need for a formal approval in support of these works.

The confirmed presence of Coho Salmon, along with the currently proposed construction approach (i.e., instream work, with a fish salvage), will require a fish sampling/collection permit from Fisheries and Oceans Canada (DFO) in addition to the previously noted provincial permit.

5.3.2 Navigable Waters Protection Act

No changes to navigable watercourses are expected as a result of this Project (single crossing of an agricultural ditch); therefore, the *Navigable Waters Protection Act* is not applicable to this Project.

In summary, the following provincial and federal permitting requirements (**Table 6**) are expected to apply to this development based on the identified watercourse crossing method proposed for this pipeline installation.

Table 6 Anticipated permitting requirements based on crossing the fish-bearing agricultural ditch via instream isolation and bypass.

Act/Regulation	Agency	Anticipated Permitting Requirements
Water Act	OGC	Approval under the Water Act for "changes in and about a stream".
Agricultural Land Commission Act	ALC	Extension of existing pipeline ROW. Sampling to guide reclamation.
Wildlife Act	MFLNRO	Fish salvage permit.
Fisheries Act	DFO	Anadromous fish salvage permit
Fisheries Act	DFO	Submission of "Request for Project Review" to DFO (note: it is anticipated that a formal Authorization will not be required for this work)

6.0 POTENTIAL MITIGATION MEASURES

Many of the potential effects identified in **Table 5** can be mitigated through adherence to timing windows and best management practices (or DFO operational statements, contingent upon changes to planned construction methodology), some of which were identified in **Section 5.0**. Several published guidelines may be directly applicable towards this project including:

- Develop with Care: Environmental Guidelines for Urban and Rural Land Development in British Columbia Guidelines by Ministry of Environment.
- Land Development Guidelines for the Protection of Aquatic Habitat, DFO and BC MOE (ILMB).
- Standards and Best Practices for Instream Works, BC WLAP Best Management Practices Series.
- Best Management Practices for Amphibians and Reptiles in Urban and Rural Environments in British Columbia Guidelines by Ministry of Environment.
- Best Management Practices for Raptor Conservation during Urban and Rural Land Development in British Columbia Guidelines by Ministry of Environment.
- Fisheries and Oceans Canada Operational Statements for Directional Drilling or Punch and Bore Crossings (currently not selected as preferred crossing methods).

These guidelines can aid in the development of an Environmental Management Plan (EMP) for construction purposes. An EMP would describe relevant mitigation measures and any environmental monitoring recommended during Project construction to ensure that the recommended mitigation measures are implemented and to monitor their effectiveness.

Table 7 summarizes potential environmental effects to ecological components identified in this report and describes general mitigation measures to avoid, minimize, or reduce the magnitude of the potential impacts associated with this Project.

Table 7 Proposed mitigation measures to avoid, minimize, and reduce potential effects of the project to ecological components.

Environmental Component	Potential Impact	Proposed Mitigation Measures
Agricultural Activities and Soil	• Loss of agricultural land from pipeline construction. • Farming activities temporarily disrupted by construction traffic. • Loss of top soil through erosion and excess storm water runoff from stockpiled soil. • Soil compaction from construction equipment and vehicles. • Contamination caused by accidental spills of deleterious material (i.e., oils, lubricants, or fuel).	• A minimum of two soil samples must be collected to assess agricultural soils and guide post construction reclamation. • Ensure machinery is in good condition prior to construction and that contractors do not utilize excessively noisy equipment. Consult with landowners and provide scheduling notice to minimize impacts and provide access to agricultural properties during construction works. • Minimize disturbance of soil by staging in a designated area and staying on established routes. • Strip topsoil to a minimum depth of 30 cm (exact depth to be determined through soil sampling) using non-toothed buckets and stockpile along berm strips. Place a layer of geotextile or other separator on the ground prior to stockpiling. Cover. • Following construction re-spread topsoil and de-compact to a minimum of 30 cm. • Re-establish crop (if within farm land) or low growing native vegetation. • Erosion, run-off, and sediment control measures should be implemented as required, including limiting the size of area that is exposed at any one time. • Where appropriate, disturbed areas should be re-vegetated with a native seed mix or appropriate crop / ground cover as soon as possible.

Environmental Component	Potential Impact	Proposed Mitigation Measures
Watercourses	• Impacts to surface water quality from fuel or oil leakage from construction equipment and vehicles or temporary storage areas. • Impacts to channel including disturbance of ditch banks and substrates and potential for turbidity. • Sediment laden runoff from excavation and other construction activities (i.e., soil stockpiles, channel bypass, clearing, grading, and staging areas near watercourses). • Water disposal following hydrostatic testing of pipes	• Minimize exposed soil and soil erosion, and implement sediment control measures, including limiting the size of area that is exposed at any one time. • Employ a dugout/settling basin or other sediment control measures to discharge sediment-laden water. • Maintain natural drainage patterns wherever possible. • Place excavated materials as far as possible from watercourse channels and cover soil stockpiles. • Minimize the length and steepness of any slopes to reduce the risk of erosion and sediment loss. • Keep fuelling activity at a distance greater than 30 m from a watercourse. • All generated waste should be appropriately contained, collected and recycled/disposed of at appropriate locations. • Stabilize and promptly re-vegetate disturbed riparian areas with suitable native species. • Restore channel substrates to original or improved specifications to re-establish fish habitat values. • Ensure hydrostatic testing water does not directly enter watercourses. • Employ a qualified environmental professional to monitor sensitive Project activities and document contractor compliance with the construction EMP.
Fish and Fish Habitat	• Temporary loss or disturbance of instream habitat and riparian vegetation. • Temporary disturbance to fish from construction noise / vibrations. • Injury and/or mortality of fish during instream works.	• Refer to sediment and erosion control measures in “Watercourses” above to mitigate potential water quality impacts. • Incorporate Standards and Best Management Practices identified in **Section 6.0**. • Minimize impacts to riparian vegetation. • Stabilize and re-vegetate any disturbed riparian areas promptly with appropriate native species. • Schedule any proposed instream works to comply with appropriate least-risk timing windows, whenever feasible (typically July 15 to September 15 for salmonids) or follow specific mitigation to be determined, based on site conditions and work proposed. • Conduct any instream works “in the dry” and with fish salvages. • Employ a qualified environmental professional to monitor sensitive Project activities and document contractor compliance with the construction EMP.

Environmental Component	Potential Impact	Proposed Mitigation Measures
Vegetation	• Direct loss or disturbance of vegetation. • Introduction of invasive species.	• Minimize disturbance of vegetation. • Conduct pre-construction surveys for sensitive and at-risk vegetation and avoid, if possible. • Conduct sensitive plant relocations for any species at risk encountered, if appropriate. • Stabilize and re-vegetate disturbed native vegetation areas with suitable native species as soon as operationally possible following construction. • Ensure vehicles and equipment on-site are clean (i.e., equipment should be pressure washed or steam cleaned).
Wildlife	• Sensory disturbance resulting from noise generated during construction. • Habitat loss or alteration. • Direct mortality from vegetation removal, vehicular traffic.	• Conduct pre-construction surveys for sensitive and at-risk wildlife / wildlife use (nests, etc). • Where possible, clear vegetation outside of the general bird breeding season (March 15 to July 31). If clearing is required within the breeding season, nest searches must be completed prior to work. • Conduct pre-construction surveys for raptor nests / activity. Disturbance buffers will be required around all active nests and nests of bird species named in Section 34b of the *Wildlife Act* whether active or not. (There are no current implications with the distance of the existing bald eagle nest to the Project (approximately 400 m). Status of the potential red-tailed hawk nest should be confirmed prior to construction to determine the applicability of a disturbance buffer. MOE suggests a 200 m disturbance buffer.) • Follow guidance found in Best Management Practices identified in **Section 6.0**.
Air Quality	• Particulate matter from soil disturbed by equipment and from soil tracked on roads by construction equipment. • Wind erosion on stockpiles or exposed soils. • Emissions from construction vehicles and combustion engines, and idling vehicles.	• Application of water or another environmentally acceptable dust suppressant to minimize the incidence of fugitive dust during clearing activities or other construction activities that create dust conditions, as required by weather and work conditions. • Cover soil stockpiles and use water or another environmentally acceptable dust suppressant on the soil stockpiles when the soil is dry. • Use covers on trucks, where possible, while transporting material to and from the site. • Implement equipment tire wash stations before accessing paved roads and sweep roadway surfaces, if applicable, to reduce the potential for airborne particulate matter. • Minimize exposed areas and re-vegetate exposed soils as soon as possible. • Construction vehicles and equipment should be well maintained, and shut off when not in use to minimize exhaust fumes from idling.

Environmental Component	Potential Impact	Proposed Mitigation Measures
Noise	• Increased noise levels above ambient conditions as a result of construction activities may impact local residents and livestock in proximity to the construction area.	• Shut-down equipment when not in use. • Ensure machinery is in good condition prior to construction and that contractors do not utilize excessively noisy equipment. • Adhere to appropriate timing windows (construction will occur between 7:00 AM and 7:00 PM, Monday through Friday and 9:00 AM to 5:00 PM on Saturdays -City of Abbotsford bylaw 1811-2008). • Provide advanced notice to local residents of scheduling and scheduling changes for construction activities.

7.0 CONCLUSIONS

This preliminary environmental assessment identifies environmental effects to ecological components potentially resulting from Project construction and operation, and recommends mitigations to avoid, minimize, or reduce these potential effects. As final construction methodologies and footprints have not been determined, this preliminary assessment can be used to develop a detailed design and Environmental Management Plan that will help the Project proceed in an environmentally responsible manner such that no significant adverse impacts to ecological components are anticipated. Primary environmental considerations associated with the Project include:

- Impacts to fish and fish habitat, salvage activities, and permitting and/or notification requirements under the *Water Act, Wildlife Act,* and *Fisheries Act*. Directional drilling or punch and bore crossing in adherence to DFO Operational Statements will avoid any requirements for DFO project review. If either of these options is selected, it is apparent that work can proceed with a federal *Fisheries Act* notification and no specific requirements for DFO review/input. If the currently supported option for instream works applies, then a “Request for Project Review” application will need to be submitted to DFO. Although it appears very unlikely that an Authorization will be required, this will be subject to agreement by DFO. Supporting documents supplied with these applications should be provided to the City of Abbotsford to comply with and fulfill the spirit of the municipal *Streamside Protection Act*.
- Temporary impacts to land in the ALR will require soil sampling to guide reclamation following construction as well as permitting to extend the existing pipeline right-of-way.
- No federal or provincial species at risk are known within the study area; however, depending on expected Project footprint, the following surveys are recommended:
  - Townsend’s mole presence (look for mole hills in adjacent agricultural field).
  - Raptor and heron nest presence and / or activity. Surveys should be conducted in spring (March) to determine status. Currently there is a bald eagle nest approximately 400 m away (complies with buffers recommended by MOE) and a potential red-tailed hawk approximately 150 m away (inside the recommended 200 m buffer).

The results of these recommended follow-up surveys will allow a more thorough assessment of actual impacts; however, with the application of mitigation measures outlined in **Table 7**, no significant adverse impacts to ecological components are expected.

Report prepared by:
Hemmera

Brian Paterson, EIT, R.P.Bio.
Field Technician / Biologist
604-669-0424 (158)
bpaterson@hemmera.com

Jim Roberts, R.P.Bio.
Senior Fisheries Biologist
604.669.0424 (229)
jroberts@hemmera.com

Wayne Sakamoto, RPF
Project Manager
604.669.0424 (107)
wsakamoto@hemmera.com

8.0 REFERENCES

Agricultural Land Commission (ALC). 2010. Agricultural Land Reserve within the Fraser Valley Regional District. Geographic Information Systems Department, Agricultural Land Commission. February, 2010.

ALC. 2011. About the Agricultural Land Reserve. Web site: http://www.lrc.gov.bc.ca/alr/alr_main.htm.

BC Conservation Data Centre (CDC). 2013. BC Species and Ecosystems Explorer. B.C. Minist. of Environ. Victoria, B.C. Available: http://a100.gov.bc.ca/pub/eswp/. Accessed January 2013.

BC Conservation Data Centre (CDC). 2012. BC Species and Ecosystems Explorer. B.C. Minist. of Environ. Victoria, B.C. Available: http://a100.gov.bc.ca/pub/eswp/. Accessed December 2012.

BC Ministry of Water, Land, and Air Protection (BC MWLAP). 2004. Best management practices for amphibians and reptiles in urban and rural environments in British Columbia.

BC Ministry of Environment (MOE). 2005. Best management practices for raptor conservation during urban and rural land development in British Columbia.

City of Abbotsford. 2013. City of Abbotsford WebMap. http://webmap.abbotsford.ca/WebMap/main.asp.

BC Ministry of Environment (MOE). 2012a. Develop With Care 2012: Environmental guidelines for urban and rural land development in British Columbia Available: http://www.env.gov.bc.ca/wld/documents/bmp/devwithcare2012/index.html.

BC Ministry of Environment (MOE). 2012b. Habitat Wizard. Available: http://www.env.gov.bc.ca/habwiz/. Accessed December 2012.

BC Ministry of Enviroenment (MOE). 2012c. Fisheries Information Summary System. Available: http://www.env.gov.bc.ca/fish/fiss/index.html. Accessed: December 2012.

BC Ministry of Water, Land and Air Protection (MWLAP). 2004. Standards and best practices for instream works.

BC Natural Resource Information Centre habitat sensitivity maps: Abbotsford Watershed atlas. Available: http://cmnbc.ca/atlas_gallery/abbotsford-watershed-atlas. Accessed: January 2013.

COSEWIC 2003. COSEWIC assessment and update status report on Townsend's mole Scapanus townsendi in Canada. Committee on the Status of Endangered Wildlife in Canada. Ottawa. vi + 24 pp.

Department of Fisheries and Oceans (DFO). 1992. Land development guidelines for the protection of aquatic habitat.

GSC (Geological Survey of Canada). 1961. Map 39-1960 Surficial Geology. Chilliwack, Sumas, and Kent Municipalities. New Westminster and Yale Districts, British Columbia. Geological Survey of Canada,Ottawa.

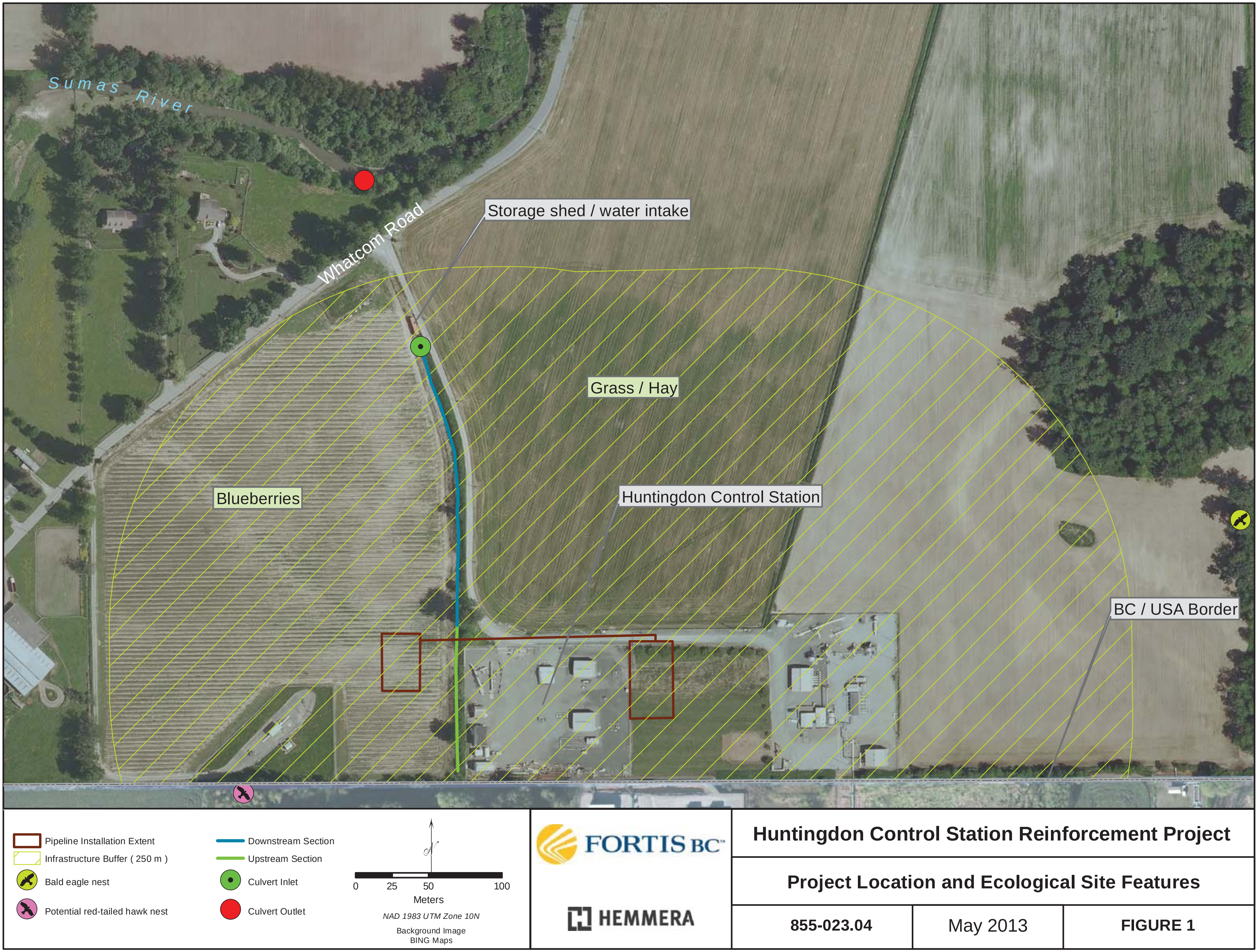
Hemmera. 2011. Huntingdon control station bypass project preliminary environmental assessment. Prepared for Fortis Energy Inc.

Hemmera. 2012. Fortis BC Huntingdon Facility Watercourse Evaluation. Letter report prepared for Fortis Energy Inc.

Pacific Water Shrew Recovery Team. 2009. Recovery Strategy for the Pacific Water Shrew (Sorex bendirii) in British Columbia. Prepared for the B.C. Ministry of Environment, Victoria, BC. 27 pp.

Species at Risk Public Registry (SARA). 2012. Available: http://www.sararegistry.gc.ca/default_e.cfm. Accessed December 2012.

FIGURES



Huntingdon Control Station Reinforcement Project

Project Location and Ecological Site Features

855-023.04	May 2013	**FIGURE 1**

APPENDIX A

Photos

Photo1. Flooded blueberry field west of proposed pipeline.

Photo2. Looking east along proposed pipeline route. Pipeline will follow existing access road south of agricultural field.

Photo 3. Western boundary of Huntingdon facility showing riparian vegetation near along proposed alignment.

Photo 4. Riparian vegetation just north of proposed alignment.

Photo 5. Riparian vegetation along ditch looking north.

Photo 6. Excavation for pipeline installation will likely require removal of several of these trees of the *Prunus* genus.

Photo 7. Bald eagle nest observed located approximately 400 m west of the proposed pipeline.

Photo 8. Possible red-tailed hawk nest located approximately 200 south west of the proposed pipeline near the Canada / US border.

Appendix H

SRRMC ARCHAEOLOGICAL OVERVIEW ASSESSMENT REPORT

Stó:lō Research and Resource Management Centre

10-7201 Vedder Road
Chilliwack, BC V2R 4G5
phone 604.824.2420
fax 604.824.0278
www.srrmcentre.com

ARCHAEOLOGICAL OVERVIEW ASSESSMENT OF PROPOSED UPGRADES TO THE HUNTINGDON CONTROL STATION IN ABBOTSFORD, BC

SHIP 2013-006

Prepared for:
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC
V4N 0E8

February 2013

GRANT OF LICENSE

I, David Schaepe, Director of the Stó:lō Research and Resource Management Centre (SRRMC) confirm that the SRRMC, in accordance with its' copyright policy and acting to maintain copyright in trust on behalf of the collective use of the Stó:lō community, is the copyright owner of this permit report, and for good and valuable consideration irrevocably grant a non-exclusive license to the Province of British Columbia, for a term equal to the life of the copyright commencing on the date of execution below, to make copies of the reports, including all appendices and photos, and to provide such copies to anyone, at the discretion of the Province, either at no charge or at the cost incurred by the Province of British Columbia in making and distributing the copies. All parties, except the party for whom the report was prepared, acknowledge that any use or interpretation of this report is at the sole risk and liability of the subsequent user(s).

Executed on the 1st of February 2013, by

____

Signature, on behalf of the Copyright Owner

CREDITS

Permit Holder.. ......Cara Brendzy, B.A., B.App.GIS

Project Director... ......Cara Brendzy

Report Author .... Lisa Dojack, M.A.

Field Supervisor.. Lisa Dojack

Field Director.. Cara Brendzy

GIS/Graphics .... Lisa Dojack

Research... Lisa Dojack

RESULTS AND MANAGEMENT SUMMARY

This report presents the results of an archaeological overview assessment of proposed upgrades to the Huntingdon Control Station at 176A Whatcom Road in Abbotsford, BC (*S'olh Téméxw*). The assessment was directed by Stó:lō Research and Resource Management Centre project archaeologist Cara Brendzy, and was carried out under Stó:lō Heritage Investigation Permit #2013-06, held by Cara Brendzy.

Assessment methods were comprised of two main components: (1) background research; and (2) preliminary field reconnaissance. Background research included a documentary and transcript review of information pertinent to the Study Area. The data gathered during background research was used to guide in-field decisions of archaeological potential during the preliminary field reconnaissance.

Background research found a number of cultural heritage resources within the 1.5 km context zone, including three previously recorded archaeological sites, one documented travel route, and one traditional use area, one of which (a traditional use gathering area) is geographically juxtaposed with the Study Area.

The preliminary field reconnaissance was carried out on January 24, 2013, and the results suggest that there is archaeological potential for the Study Area. Prior to ground disturbing activities for the proposed development in the Study Area, it is recommended that additional work be undertaken in the form of an **Archaeological Impact Assessment (AIA)** under a *Heritage Conservation Act* Section 14 Heritage Investigation Permit. It is recommended that the AIA be conducted in accordance with (1) the *British Columbia Archaeological Impact Assessment Guidelines* (1998) and (2) the Stó:lō Heritage Policy (2003). See Management Recommendations (Section 5.1) for details.

TABLE OF CONTENTS

1.0 INTRODUCTION

This report presents the results of an archaeological overview assessment (AOA) of proposed upgrades to the Huntingdon Control Station on Whatcom Road in Abbotsford, BC (*S'olh Téméxw*; Figure 1). The assessment was directed by Stó:lō Research and Resource Management Centre (SRRMC) project archaeologist Cara Brendzy, and was carried out under Stó:lō Heritage Investigation Permit (SHIP) #2013-006, held by Cara Brendzy. The preliminary field reconnaissance was completed on January 24, 2013 by Cara Brendzy and Lisa Dojack.

This assessment was carried out in accordance with the following guidelines: (1) the *British Columbia Archaeological Impact Assessment Guidelines* (1998), developed by the Archaeology Branch; and (2) the Stó:lō Heritage Policy (2003), developed by the Stó:lō Nation and administered by the Stó:lō Research and Resource Management Centre.

1.1 Proposed Development

The proposed development consists of upgrades to the Huntingdon Control Station. The approximate 0.25 ha Study Area is located at 176A Whatcom Road on the Fraser River floodplain in Abbotsford, BC (Figures 1 & 3). The Study Area is 14 km south of the Fraser River, 5.5 km west of Vedder Mountain, and 300 m south and east of the Sumas Canal. Proposed development activities which could potentially impact surface or subsurface archaeological sites in the Study Area include, but are not limited to:

- installation and construction of 200 m of NPS 36 pipeline and five buried valves;
- construction of temporary access driveway and equipment staging area; and
- installation of fencing surrounding the facility.

All ground-disturbing activities will be located at the existing Huntingdon Control Station, and within 100 m of the station yard. Construction is planned to take place during the summer of 2015.

1.2 Project Objectives

In accordance with the provincial *Archaeological Impact Assessment Guidelines* (Apland and Kenny 1998) and the Stó:lō Heritage Policy Manual (2003), the objectives of this AOA were to:

- evaluate the potential for archaeological and other cultural heritage resources within the Study Area; and
- recommend future archaeological or other cultural heritage studies, as necessary.

The *Heritage Conservation Act (HCA)* provides legal protection against the disturbance of archaeological sites, defined as places that demonstrate past human activity predating 1846, all burial and pictograph sites, and shipwrecks more than two years old. The Archaeology Branch is the provincial regulatory body responsible for implementing the *HCA*. Common types of archaeological sites located in *S'ólh Téméxw* (Stó:lō Traditional Territory) include, but are not limited to:

- lithic scatters (i.e., stone tools and flakes)
- cultural depressions (e.g., pit houses, cache pits)
- culturally modified trees (e.g., bark-stripped trees, aboriginally-logged trees)
- rock art (i.e., pictographs and petroglyphs)
- cultural earthworks (e.g., burial mounds, rock cairns, defensive sites)
- karst features (e.g., caves, rock shelters)

In addition to archaeological sites, a number of cultural site types not recognized under the *HCA* were also included for consideration in this AOA, as defined and protected by the Stó:lō Heritage Policy Manual (2003). These include:

- *Iyoqthet* (Transformation) Sites – sites created as a result of the transformation of people or animals by *Xexá:ls* (The Transformers), *Tel Swayel* (The Sky-Borne People), or any other agent of *Chichel Siya:m* (The Creator)

- *Halq'eméylem* Place Names – sites indicating the significance of a place, due to their inherent characteristics, activities or events that took place there, or the oral histories tied to or coming from such places
- *Sx̱wôx̱wiyám* / Cultural Landscape Features – places in the landscape with broad cultural significance
- Traditional Land and Resource Use Areas – areas used for activities such as hunting, fishing, and gathering
- Spiritual/Ceremonial Regalia Sites – places on the landscape where spiritual or ceremonial items have been placed and will *remain*
- *X̱á:X̱a* (sacred or taboo places) Sites – sites often associated with spiritually potent 'taboo' places in the landscape (e.g., *stl'áleqem* sites) or ceremonial activities
- *Sx̱wó:yx̱wey* – places in the landscape related to the origin of the *Sx̱wó:yx̱wey* mask, considered among the most sacred of Stó:lō traditions

1.3 Report Organization

This report is presented in four key sections. Section 2 describes the setting and context of the Study Area. Section 3 is a review of the methods employed during the research and preliminary field reconnaissance components of the assessment. Section 4 summarizes the results, and Section 5 provides conclusions and offers management recommendations.

2.0 STUDY AREA SETTING

2.1 Lower Fraser Basin Environment

The Study Area is located in the Lower Fraser Basin, in southwestern BC. Extending from the mouth of the Fraser River east to the Fraser Canyon, the Lower Fraser Basin Watershed embodies the large coastal delta, river lowlands, and forested montane slopes bordering the Coast and Cascade Mountain Ranges and the Strait of Georgia (Dorcey 1991). Fraser Basin topography is characterized by glacially modified landforms of Quaternary age, resultant from the Fraser Glaciation that occurred 26,000-10,000 years ago (Armstrong 1981).

2.2 Study Area

The approximate 0.25 ha Study Area is located on agricultural fields on the Fraser River floodplain at 176A Whatcom Road in Abbotsford, BC (Figures 1 & 3). The Study Area is 14 km south of the Fraser River, 5.5 km west of Vedder Mountain, and 300 m south and east of the Sumas Canal. Other unnamed creeks and sloughs are in close proximity to the Study Area, some of which are well contained and others are meandering. Air photos show abandoned channels in the fields adjacent the Study Area.

The Study Area is situated on Section 6, Township 19, East of the Coast Meridian, New Westminster District, on the following lots:

- 126 Lot A Whatcom Road (PID 026-604-507)
- 176 Lot C Whatcom Road (PID 011-040-238)
- 176 Lot 12 Whatcom Road (PID 007-340-699)

For the purposes of this report, the Study Area has been divided into four distinct sections (Figure 3):

- Section 1: gravel access road north of the control station
- Section 2: field east of the control station
- Section 3: field north of the gravel access road
- Section 4: field west of the control station

2.3 Cultural Overview – The Stó:lō

The Stó:lō, or '*People of the River*', traditionally speak the *Halq'eméylem* language, a dialect of the Central Coast Salish language family. The traditional territory of the Stó:lō, referred to in *Halq'eméylem* as *S'ólh Téméxw,* "our land" or "our world", encompasses the entire Lower Fraser Basin Watershed, from the Fraser Delta at the west to the Coquihalla River at the east, and the headwaters of the Harrison and Pitt lakes at the north to the Nooksack and Chilliwack river drainages at the south. *S'ólh Téméxw* incorporates a broad sphere of cultural interaction among Halkomelem speakers from the Fraser Canyon to southeastern Vancouver Island (Suttles 1990). Stó:lō oral tradition establishes the aboriginal occupation of this area since 'the beginning of the world' or 'time immemorial'. Archaeological evidence presently documents human occupation extending back at least 10,000 years in the region, which constitutes some of the earliest evidence of human existence in northwestern North America (Borden 1975; McLaren and Storey 2010; Mitchell and Pokotylo 1996). There is strong archaeological, linguistic, historical, and oral historic evidence indicating long term, continuous occupation of this area by the ancestors of the contemporary Stó:lō (Burley and Beattie 1989; Carlson et al. 2001; Mitchell 1971; Schaepe 2009; Suttles and Elmendorf 1962).

At the time of European contact, the Stó:lō practiced a semi-permanent lifestyle, living in two types of habitations: pithouses and plankhouses. The Stó:lō remained sedentary in villages comprised of circular semi-subterranean pithouses, insulated from the cold, during the principal ceremonial season in the winter months, while plankhouse villages were occupied during the summer months. A portion of the population moved into the uplands throughout the territory during the spring, summer, and fall, while others inhabited villages year round. Temporary lodges, often made of woven reed mats, were constructed and used as seasonal hunting and fishing camps.

Fishing, hunting, and gathering formed the basis of Stó:lō subsistence. Fishing was practiced year-round and was deeply connected with the migratory patterns of abundant, locally available spawning anadromous fish, particularly Pacific salmon, eulachon, and sturgeon. The Stó:lō historically have a very strong connection to salmon, both spiritually and economically. Salmon and trout of all kinds were and continue to be caught and utilized in many ways by the Stó:lō. Deer, mountain goat, and bear meat, and various roots (e.g. camas, bracken fern, and tiger lily) and berries (e.g. huckleberries, strawberries, salmon berries, salal berries, blueberries, cranberries, and Saskatoon berries) also comprised significant plant resources which were collected, processed, and stored for the winter. Hunting and collecting activities were practiced throughout all areas of the landscape, from the valley bottom to the high elevation parkland and alpine environments (Schaepe et al. 1998).

Forest resources, particularly western red cedar, figured prominently into Stó:lō technology. Capable woodworkers, the Stó:lō fashioned nearly all parts of the cedar tree, including roots, bark, and trunk, into a vast number of usable items, such as basketry, mats, nets, clothing, cordage, bowls, spoons, storage boxes, canoes, house planks, house posts, fishing and hunting equipment, and ceremonial items (e.g., masks, poles). Other tree species, stone, bone, and antler materials were also used as tools and implements. The Stó:lō actively manipulated the productivity of the landscape through practices such as managed burning.

Trade with neighboring groups was facilitated by a network of mountaintop and riverside travel routes. Numerous travel routes provided access to the Nooksack and Skagit river valleys, to the south and east, and the up and downriver sections of the Fraser River (SFU 1994). Aboriginal trails are recorded throughout the Chilliwack River watershed (Wells 1987; Carlson et al. 2001).

Socially, Stó:lō society was stratified into upper and lower social classes. Bilaterally reckoned kinship and marriage provided the foundation of Stó:lō community, determining familial, community, and economic ties, as well as social standing. As early as 1780, traditional Stó:lō social structure and cultural practices were severely impacted by the smallpox epidemics and general economic upheaval associated with the arrival of the Europeans in and around *S'ólh Téméxw*. Smallpox epidemics, which occurred repeatedly throughout the late 1800's, devastated the Stó:lō population, effectively annihilating some Stó:lō groups, such as the Hatzic (Hatzic Lake vicinity) and *Sxayaks* (Stave Lake vicinity). Although disrupted, numerous aspects of traditional Stó:lō culture continue to persist and be practiced today. A discussion of the effects of European influence and the development of contemporary Stó:lō lifeways is presented by Carlson (1997). Detailed ethnographic accounts are available in anthropological literature (Barnett 1955; Boas 1894; Carlson 2001; Duff 1952; Hill-Tout 1903; 1978; Jenness 1955; Smith 1947; Suttles 1955; Wells 1987).

It is important to note that not all aspects of traditional First Nations' cultures are recorded in the anthropological and ethnohistoric literature. Additional knowledge of traditional culture and lifeways still exists in many contemporary First Nations communities. Furthermore, aboriginal societies underwent significant changes as a result of their contact with Europeans, and some cultural aspects reported in the literature may not accurately reflect that culture prior to contact.

2.4 Archaeological Overview

The Gulf of Georgia Region has a long history of archaeological research on the Northwest Coast (Ames and Maschner 1999; Matson and Coupland 1995). The vast majority of regional archaeological research, however, has focused upon the coastal and riverine lowlands, to the exclusion of the surrounding upland areas and tributary drainages. Comparatively, the Upper Fraser Valley – between Mission and Yale - has experienced limited archaeological attention. The relationship between the Upper Fraser Valley and the rest of *S'ólh Téméxw*, remains to be clearly understood from a cultural historic perspective (Barnett 1955; Matson 1994; Schaepe 1998; von Krogh 1976). Archaeological work in the Upper Fraser Valley area has been conducted since the 1960's, but until the 1990's, archaeological investigations of the Maurer site (LeClair 1973, 1976) and Flood-Hope sites (von Krogh 1976) contributed the majority of information pertaining to the Upper Fraser Valley. Recent research at the Scowlitz site (Bernick 1992; Blake 1992; Blake et al. 1994; Lepofsky et al. 2000; Matson 1994), the X̲á:ytem site (Mason 1994; Ormerod and Matson 2000), and the Maurer site (LeClair 1976, Schaepe 1998) have provided significant insights into the last 5,000 years of cultural occupation on the Upper Fraser Valley. Occupation of the region extends back even farther, as data from a ca. 9,000 year old occupation has been recovered from the Milliken site (Borden 1975) near Yale, BC. Schaepe (2009) offers an examination of housepit settlements and community organization in the Fraser Valley from 2,550 – 100 BP. General overviews of archaeological research in the Upper Fraser Valley and Gulf of Georgia Region are presented by Ames and Maschner (1999) and Matson and Coupland (1995).

3.0 METHODOLOGY

The AOA was conducted in accordance with *British Columbia Archaeological Impact Assessment Guidelines* (Archaeology Branch 1998) and referenced the guidelines and terminology of the Stó:lō Heritage Policy Manual (2003). Methods were comprised of two main components: (1) background research; and (2) preliminary field reconnaissance.

3.1 Background Research

Prior to field inspection, background research was conducted on the Study Area and its immediate vicinity. Information was gathered from the following sources, as appropriate:

(i) documentary review: a review of readily available published and unpublished documents that provide information about (1) historical and current aboriginal land and resource use in relevant proximity to the Study Area; (2) the traditions of Stó:lō First Nations in relevant proximity to the Study Area; (3) non-aboriginal land and resource use in relevant proximity to the Study Area; and (4) bio-geo-physical data pertinent to the Study Area; and

(ii) transcript review: of documented interviews from Stó:lō community members who are knowledgeable about historic and current land use and sites in relevant proximity to the Study Area, and of persons who are knowledgeable about Stó:lō traditions.

Information gathering involved a review of previously recorded site location maps, topographic maps, aerial maps or photos, development plans, and literature generally applicable to the Study Area and immediate vicinity. Sources for this information include local museums and archives, including those housed at the SRRMC. The Stó:lō Archives includes interviews with Stó:lō elders and others knowledgeable of the history and traditional use of the concerned Study Area. The Study Area was also assessed within the framework of the Stó:lō Heritage Management Plan spatial databases (GIS), housed at the SRRMC.

The following sources of existing cultural heritage resource-related information were used in addressing the objectives of this AOA. These data sets comprise the Stó:lō Heritage Management Plan (SRRMC 2007), and include:

- Documented archaeological sites (B.C. Archaeology and Registry Services Branch 2010)
- Documented Settlements ca. 1800-1880 – Historic Map Inventory (Schaepe 2001)
- Documented and Projected aboriginal trail/travel routes (Schaepe 1999)

- Existing information on Stó:lō Traditional Uses of *S'olh Téméxw* collected by previous traditional use studies (Albers 2000; Angelbeck and Schaepe 2004; Rafter 2001:106-07; Soto 2001; Stó:lō Nation 1998)
- Documented Transformation Sites/ Stó:lō *Sx̱wô̱xwiyám*/Cultural Landscape Features, Spiritual Sites, and *Halq'eméylem* Place Names (McHalsie 2001)

Results of background research were used as a primary guide for inductively determining where archaeological sites are most likely to occur within the Study Area. Thus, the factors listed below were used as guiding variables applied to making in-field site potential determinations. These factors included:

- presence/ proximity to known ethnographic use sites (e.g., trails)
- known aboriginal land use
- known non-aboriginal land use (i.e., disturbances)
- presence/ proximity to known (both recorded and unrecorded) archaeological sites
- slope
- distance to water (extant or extinct)
- landform
- forest cover
- contemporary resource availability
- 'landscape' (i.e., environmental and geomorphologic) changes through time and extant paleo-landforms

3.2 Preliminary Field Reconnaissance

An examination of the microtopographic setting of the Study Area was conducted by way of vehicle survey of the accessible portion of the Study Area (Section 1). The preliminary field reconnaissance focused on identifying high potential areas for subsurface archaeological materials.

4.0 RESULTS

4.1 Background Research

Several previously recorded cultural heritage sites/areas are located within the 1.5 km context zone of the Study Area, including three previously recorded archaeological sites, one documented travel route, and one traditional use area (Figure 2), one of which (a traditional use gathering area) is geographically juxtaposed with the Study Area.

Previously Recorded Archaeological Sites

The provincial Remote Access to Archaeological Data (RAAD) database displays three previously recorded archaeological sites within the 1.5 km context zone of the Study Area (Figure 2; Table 1); however, none are geographically juxtaposed with the Study Area.

TABLE 1 – Previously Recorded Archaeological Sites in Context Zone

Site Number	Site Type	Proximity
DgRn-1	precontact surface lithics	300 m W
DgRn-5	precontact surface lithics	400 m NW
DgRn-6	precontact habitation feature	1,250 m NE

DgRn-1 is located along the eastern and western banks of the Sumas Canal north of the Canada-US border, on the Fraser River floodplain in Abbotsford, BC. The site was recorded by the Archaeological Sites Advisory Board (ASAB) in 1974 as a precontact surface lithics site. Artifacts present were not specified.

DgRn-5 is located on the west bank of the Sumas Canal on the Fraser River floodplain in Abbotsford, BC. The site was recorded by UBC in 1953 as a precontact surface lithics site. Artifacts collected include several decorated stone bowls.

DgRn-6 is located 100 m east of the Sumas Canal on the Fraser River floodplain in Abbotsford, BC. The site was recorded by UBC in 1953 as a precontact habitation feature consisting of a group of plank houses.

Documented Travel Routes

One documented Travel Route (DOC_ID:104) is located 300 m north and west of the Study Area following the Sumas Canal (Figure 2). Documented Travel Routes are considered insightful indicators of past land and resource use and, as such, recognition of these places is an important component in the context of aboriginal rights and title. Travel routes in this category have either been ground-truthed or verified to have been used.

Aboriginal Trails and travel routes were used by the Stó:lō for travel and trade, to access seasonally abundant plant and wildlife resources, and for spiritual purposes. The majority of physical evidence of these trails no longer exists due to urbanization; however, a large percentage of contemporary transportation routes in *S'ólh Téméwx* coincide with these original pathways (Myles 1995). In cases where physical evidence of historic trails is still present, the trail itself may be subject to protection under the Stó:lō Heritage Policy (2003) and the provincial Heritage Conservation Act.

Traditional Use Areas

One traditional use gathering area (GSE-53, an unmaintained plant source and collection area) is geographically juxtaposed with the Study Area (Figure 2). Stó:lō use of the area surrounding the Study Area for fishing, hunting, and spiritual use has been documented by a variety of sources including traditional use studies, oral history, and ethnography.

Additional Documentary Background Research

In addition to cultural heritage resource sites mentioned in Section 4.1, Appendix III summarizes supplementary background research used in determining archaeological potential of the Study Area. Archaeological potential of the Study Area is indicated by its being situated on the Fraser River floodplain and proximity to previously recorded archaeological sites. The entire Fraser River floodplain has high GIS-modeled archaeological potential.

4.2 Preliminary Field Reconnaissance Results

The approximate 0.25 ha Study Area is located on the Fraser River floodplain at 176A Whatcom Road in Abbotsford, BC (Figures 1 & 3). The Study Area is 14 km south of the Fraser River, 5.5 km west of Vedder Mountain, and 300 m south and east of the Sumas Canal. The Study Area is divided into four sections. Sections 3 and 4 are located on private property not owned by Fortis BC Energy Inc, and Section 2 is fenced and was not accessible by foot at the time of the preliminary field reconnaissance. As such, an examination of the microtopographic setting of the Study Area was conducted by way of vehicle survey of Section 1 of the Study Area. The preliminary field reconnaissance focused on identifying high potential areas for subsurface archaeological materials.

The Study Area is located on flat unforested agricultural land on the Fraser River floodplain and is accessible by a private gravel road from Whatcom Road. Section 1 consists of a gravel road bordering the control station on the north (Photos 1-2). The gravel road is raised approximately 0.20 m over the surrounding land, and has archaeological potential below the ground capped road layer. Section 2 consists of a grass field east of the control station that is lined with decorative trees at the northern boundary adjacent the gravel access road (Photo 1). Section 3 consists of a hay field north of the gravel road (Photo 2). Section 4 consists of a berry field located on private property west of the control station (Photo 3). Sections 2, 3, and 4 have been disturbed by farming activities in the upper meter, but archaeological materials could be present in a disturbed context. Sections 2, 3, and 4 also have potential for undisturbed deeply buried deposits containing archaeological materials.

The Study Area has potential for archaeological materials because it is located on the Fraser River floodplain, and it is in close proximity to the Sumas Canal and previously recorded archaeological sites.

5.0 CONCLUSIONS AND RECOMMENDATIONS

5.1 Management Recommendations

The Study Area has potential for both surface and subsurface archaeological materials, including deeply buried cultural deposits. Prior to future ground disturbing activities for the proposed development in the Study Area, it is recommended that additional work be undertaken in the form of an Archaeological Impact Assessment (AIA). It is recommended that the AIA be conducted in accordance with (1) the *British Columbia Archaeological Impact Assessment Guidelines* (1998) and (2) the Stó:lō Heritage Policy (2003).

The objective of the AIA is to:

- identify and evaluate archaeological resources within the Study Area;
- identify and assess all impacts on archaeological resources which might result from the proposed development; and
- recommend viable alternatives for managing unavoidable adverse impacts to archaeological sites including a preliminary program for:
    - implementing and scheduling impact management actions and, where necessary,
    - conducting surveillance and/ or monitoring

The AIA should include a surface survey and subsurface testing to identify buried cultural materials. Because deeply buried deposits on the Fraser River floodplain are known to contain archaeological materials, the AIA may require mechanical trenching if ground disturbing activities are planned below the effective depth of a shovel test (approximately 1.2 m depth).

It is recommended that the proponent retain the services of a professional archaeologist to apply for and obtain an HCA Section 14 Heritage Investigation Permit to conduct an AIA prior to ground disturbing activities in the Study Area for the proposed development. The provincial Archaeology Branch is currently processing permits in 8 to 10 weeks following methodological review and a First Nations comment period.

5.2 Study Limitations and Unanticipated Materials

FortisBC Energy Inc. is advised that if any unanticipated cultural materials or features protected by the *Heritage Conservation Act* and the Stó:lō Heritage Policy (2003) including, but not limited to, rock art, culturally modified trees, archaeological materials, or human remains, are encountered prior to or during development or related activities, all land-altering work in the immediate area should cease, and the Archaeology Branch and the Stó:lō Research and Resource Management Centre should be contacted immediately so that an archaeological management plan can be developed and implemented. The results of this AOA address project-specific developments only.

5.3 Land Use Decisions

Stó:lō connections and uses of the land represent aspects of their aboriginal rights and title. What the Stó:lō community currently does in the areas to which they have access, has been limited by encroachment, alienation of lands, and land use decisions in which they had no participation. However, Stó:lō culture is undergoing a revival, and as such, impacts associated with developments must be taken into consideration in the framework of cumulative effects - adding to those of previous developments which have impacted the environment of that area - as potentially affecting the exercise of aspects of Stó:lō aboriginal rights and title. It is suggested the relationship between future developments and issues of Stó:lō rights and title be dealt with by the affected Stó:lō communities.

Please be advised that Stó:lō Research and Resource Management Centre’s participation in this Project does not constitute consultation with the the Stó:lō Nation, or any other Stó:lō First Nation. Nothing in this report is intended to affect the exercise or scope of, or justify any infringement of any Aboriginal rights, nor shall anything in this report be interpreted as affecting the legal relationship between parties.

This report, and negotiations leading up to it, and information shared as a result of it, are without prejudice to any legal positions that have been taken or may be taken by either of the parties in any court proceedings, process or otherwise or any treaty or other negotiations, and shall not be construed as an admission of fact or liability in any such proceedings, process or negotiations.

The proponent can use the information in this report to inform management decisions and can exhibit this report in a court of law in any case that challenges their decisions.

The sharing of information in this report shall not be construed as concurrence with provincial policies.

Report Author:

Lisa Dojack

Lisa Dojack, M.A.

Archaeologist

SRRMC

6.0 WORKS CITED

Albers, Karen
2000 Resource Sites in S'olh Téméxw: Traditional Concepts of Ownership. Unpublished report on file in the Stó:lō Archives, Chilliwack, BC.

Ames, K. and Maschner, H.D.G.
1999 *Peoples of the Northwest Coast: Their Archaeology and Prehistory*. Thames & Hudson, London.

Angelbeck, Bill and David Schaepe
2004 Heritage Resource Management Study of Cattermole Timber FL A19202 Amendment 24/24a and Selected BCTS Forestry Cutblocks within Major Amendment 192, Chilliwack River Valley: PART III - Traditional and Contemporary Uses of the Mid-Chilliwack River Valley. Unpublished report on file in the Stó:lō Archives, Chilliwack.

Archaeology Branch
1998 British Columbia Archaeological Inventory Guidelines. Archaeology Branch, Ministry of Small Business, Tourism and Culture, Victoria, BC.

Armstrong, J.E
1981 *Post-Vashon Wisconsin Glaciation, Fraser Lowland, British Columbia*. Geological Survey of Canada Bulletin No. 322. Energy, Mines and Resources Canada, Vancouver, B.C.

Barnett, Homer
1955 The Coast Salish of British Columbia. University of Oregon Press: Eugene, Oregon.7-9.

Bernick, Katheryn
1992 Preliminary Report of Archaeological Waterlogged Deposits at the Scowlitz Site. Report on file, Culture Department Library, Ministry of Small Business Tourism and Culture, Victoria, B.C.

Blake, Michael
1992 Interim Report on the 1992 Excavations at the Scowlitz Site (DhRl 16). Report on file, Culture Department Library, Ministry of Small Business Tourism and Culture, Victoria, B.C.

Blake, Michael, Gary Coupland and Brian Thom
1994 Dating the Scowlitz Site. The Midden 25(1):7-9.

Boas, Franz
1894 Indian Tribes of the Lower Fraser River. In *64th Report of the British Association for the Advancement of Science for 1890*. Pp. 454-463. London.

Borden, Charles
1975 Origins and Development of Early Northwest Coast Culture to about 3000 B.C. National Museum of Man Mercury Series, Archaeological Survey of Canada Paper No. 45, National Museum of Canada, Ottawa, Ontario.

Burley, David V. and Owen B. Beattie
1989 Coast Salish Origins: Ethnicity and Time Depth in Northwest Coast Prehistory. In *Ethnicity and Culture*, pp. 199 - 207. University of Calgary: Calgary.

Carlson, Keith (editor)
1997 You Are Asked to Witness: The Stó:lō in Canada's Pacific Coast History. Stó:lō Heritage Trust, Chilliwack, B.C.
2001 A Stó:lō – Coast Salish Historical Atlas. Douglas & McIntyre, Vancouver and Toronto.

Dorcey, Anthony, ed.
1991 Perspectives on Sustainable Development in Water Management: Towards Agreement in the Fraser Basin. Westwater Research Centre, University of British Columbia: Vancouver.

Duff, Wilson
1952 *The Upper Stalo Indians of the Fraser Valley*. Anthropology in British Columbia Memoir No. 1. British Columbia Provincial Museum: Victoria, BC.

Hill-Tout, Charles
1903 *The Salish Tribes of the Coast and Lower Fraser Delta*. Ontario Provincial Museum Annual Archaeological Report 12:225-235.
1978 The Salish People, Volume III: The Mainland Halkomelem, edited by Ralph Maud. Talonbooks: Vancouver, B.C.

Jenness, D.
1955 The Faith of a Coast Salish Indian. *Anthropology in British Columbia. Memoirs 3.* Edited by W. Duff. British Columbia Provincial Museum, Dept. of Education, Victoria.

LeClair, Ronald
1973 *Investigations at the Maurer Site, an early pithouse manifestation in the Upper Fraser Valley: Preliminary report.* Unpublished report on file in the Stó:lō Archives, Chilliwack, BC.
1976 Investigations at the Maurer Site near Agassiz. In *Current Research Reports*, edited by Roy Carlson. Department of Archaeology, Simon Fraser University Publication No. 3. Pp.33-42. Burnaby, B.C.

Lepofsky, Dana et al.
2000 Report on the 1999 Excavations at the Scowlitz Site (DhRl 16), Fraser Valley, B.C. Report on file, Culture Department Library, Ministry of Small Business, Tourism and Culture, Victoria, B.C.

Mason, Andrew
1994 The Hatzic Rock Site: A Charles Culture Settlement. Unpublished M.A. Thesis, Department of Anthropology and Sociology, University of British Columbia, Vancouver, B.C.

Matson, R.G
1994 Report on the 1993 Excavations at Scowlitz: Excavations at Scowlitz, Stage II. Report on file, Culture Development Library, Ministry of Small Business, Tourism and Culture, Victoria, B.C.

Matson, R.G. and G. Coupland
1995 *The Prehistory of the Northwest Coast*. Academic Press, New York.

McHalsie, Albert
2001 Halq'eméylem Place Names in Stó:lō Territory. In *A Stó:lō-Coast Salish Historical Atlas*, edited by Keith Carlson et al. Vancouver: Douglas McIntyre, University of Washington and Stó:lō Heritage Trust, 134-153.

McLaren, Duncan and Jenny Storey
2010 Report for Archaeological Site Management for Stave and Hayward Reservoir 2008-2009. Report on file, Culture Department Library, Ministry of Small Business, Tourism and Culture, Victoria, B.C.

Mitchell, Donald
1971 Archaeology of the Gulf of Georgia Area: A Natural Region and its Culture Types. *Syesis* Vol.4 Supplement 1.

Mitchell, Donald and David Pokotylo
1996 Early Period Components at the Milliken Site. In Early Human Occupation in British Columbia, edited by Roy Carlson and Luke Dalla Bona, Pp. 65-82. UBC Press: Vancouver, B.C.

Myles, Heather
1995 *Chilliwack River Watershed Heritage Overview Study.* Unpublished report on file in the Stó:lō Archives, Chilliwack, BC.

Ormerod, Patricia and R.G. Matson
2000 Excavations at DgRn 23 in 1997 and 1999 – Permit Report. Report on file, Culture Department Library, Ministry of Small Business, Tourism and Culture, Victoria, B.C.

Rafter, Tina
2001 Contested Spaces: The Chilliwack River Diversion. In *A Stó:lō-Coast Salish Historical Atlas*, edited by Keith Carlson et al, pp. 106-107. Vancouver: Douglas McIntyre, University of Washington, and Stó:lō Heritage Trust.

Schaepe, David M.
1998 *From Plain to Peak: Results of the Chilliwack River Watershed Archaeological Inventory Study*. Stó:lō Nation Archives, Chilliwack.
1999 Tracking the Ancestors: A Pilot Inventory of Aboriginal Trails Within Stó:lō Traditional Territory and the Chilliwack Forest District. Unpublished document on file in the Stó:lō Archives, Chilliwack, BC.
2001 Stó:lō Communication and Transportation Routes, c. 1850. In *A Stó:lō-Coast Salish* Historical *Atlas*, edited by Keith Carlson et al, pp. 60-61. Vancouver: Douglas McIntyre, University of Washington, and Stó:lō Heritage Trust.
2009 Pre-colonial Sto:lo-Coast Salish Community Organization : An Archaeological Study. Doctoral Thesis. UBC, Vancouver, BC.

Schaepe, David M., Marianne Berkey, Jonathon Stamp and Tia Halstad
1998 *From Plain to Peak: Results of the Chilliwack River Watershed Archaeological Inventory Study*. Stolo Nation Archives, Chilliwack.

SFU
1994 Land and Resource Use Inventory.

Smith, Marian
1947 The Nooksack, the Chilliwack, and the Middle Fraser. *American Antiquity* 12(4):255-267.

Soto, Cristina
2001 Jones Watershed: A study of Stó:lō contemporary and traditional use. Stó:lō Nation, Chilliwack BC.

Stó:lō Nation
1998 Stó:lō Nation Traditional Use Study – Final Report. Unpublished document on file in the Stó:lō Archives, Chilliwack, BC.
2003 Stó:lō Heritage Policy. Unpublished report on file, Stó:lō Nation Archives, Chilliwack, B.C.

Stó:lō Research and Resource Management Centre
2007 Stó:lō Heritage Management Plan. GIS database and unpublished document on file in the Stó:lō Research and Resource Management Centre, Stó:lō Nation. Chilliwack.

Suttles, Wayne
1955 Katzie Ethnographic Notes. *Anthropology in British Columbia, Memoirs Nos. 2&3.* British Columbia Provincial Museum.
1990 Central Coast Salish. In Handbook of North American Indians Volume 7: Northwest Coast, edited by Wayne Suttles, Pp. 453-475. Smithsonian Institution Press: Washington, B.C.

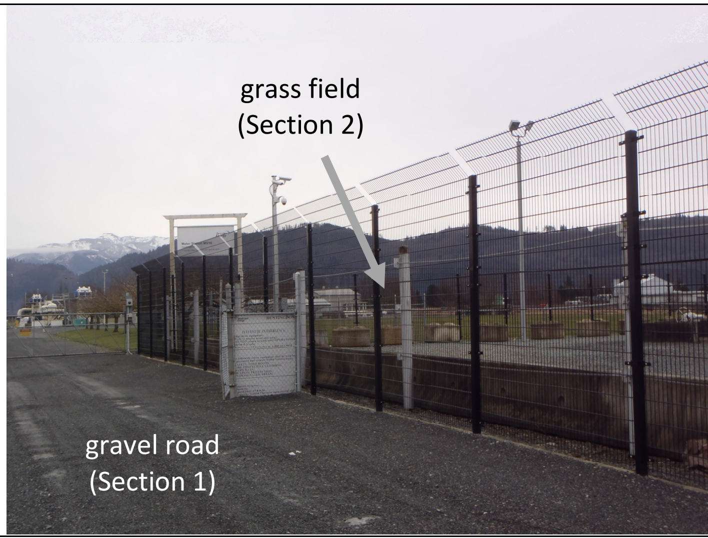
Suttles, Wayne and W. Elmendorf
1962 Linguistic Evidence for Salish Prehistory. Symposium on Language and Culture. Proceedings of the 1962 Spring Meeting, American Ethnological Society, Seattle pp. 40-52.

Von Krogh, G.H.
1976 Archaeological Investigations at the Flood and Pipeline sites near Hope, British Columbia. Unpublished M.A. Thesis, Department of Archaeology, Simon Fraser University, Burnaby.

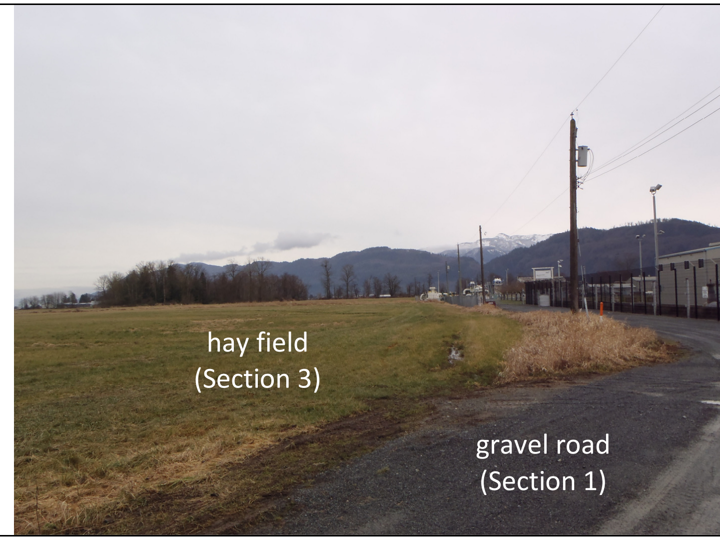
Wells, Oliver N.
1987 *The Chilliwacks and Their Neighbors*. Edited by Ralf Maud, Brent Galloway and Marie Weeden, Talonbooks, Vancouver.

APPENDIX I – PHOTOS

Photograph 1: grass field in Section 2 east of control station (view SE)

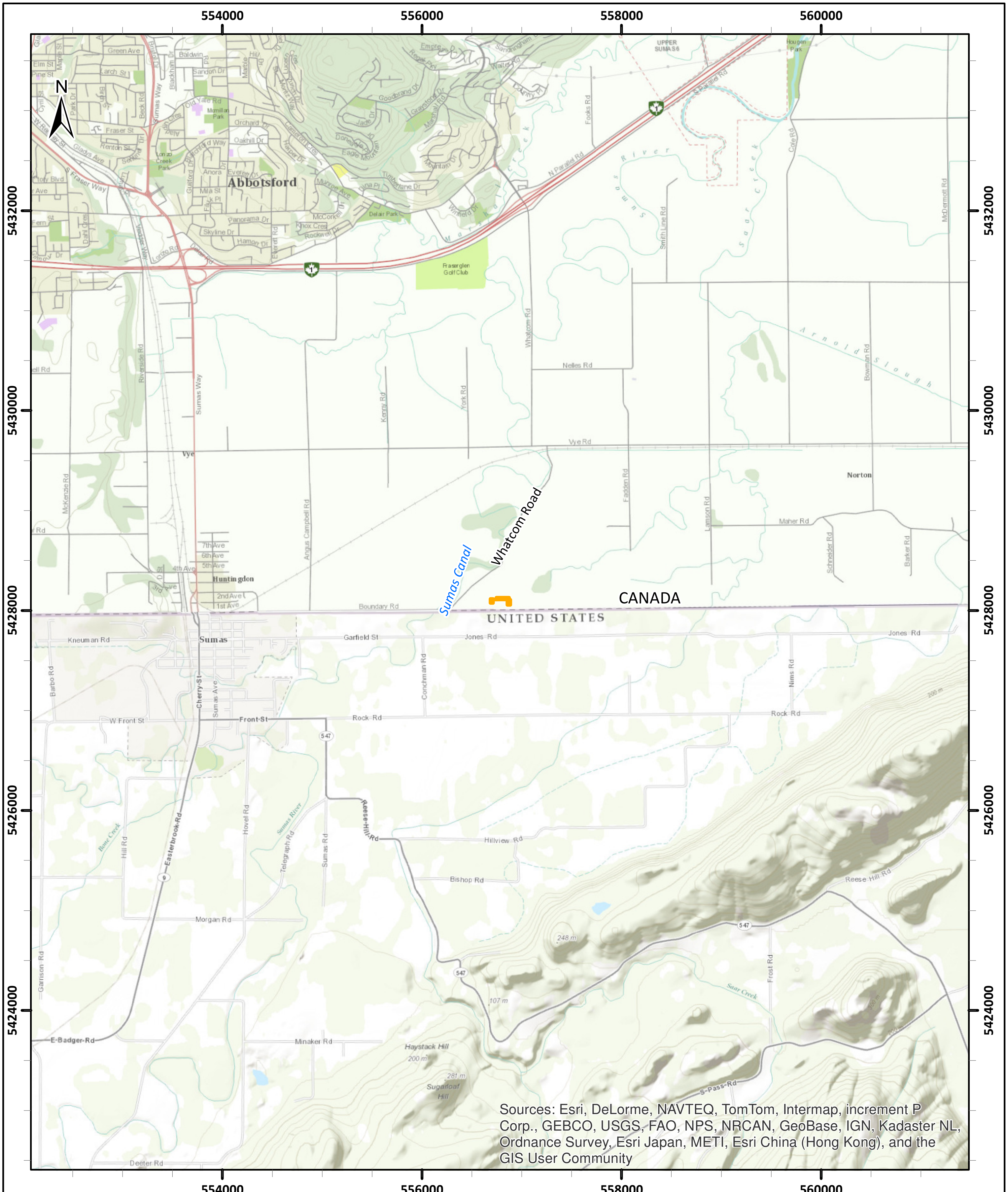


Photograph 2: hay field in Section 3 north of control station (view E)



Photograph 3: berry field in Section 4 west of control station (view SW)

APPENDIX II – FIGURES



Stó:lō Research and Resource Management Centre

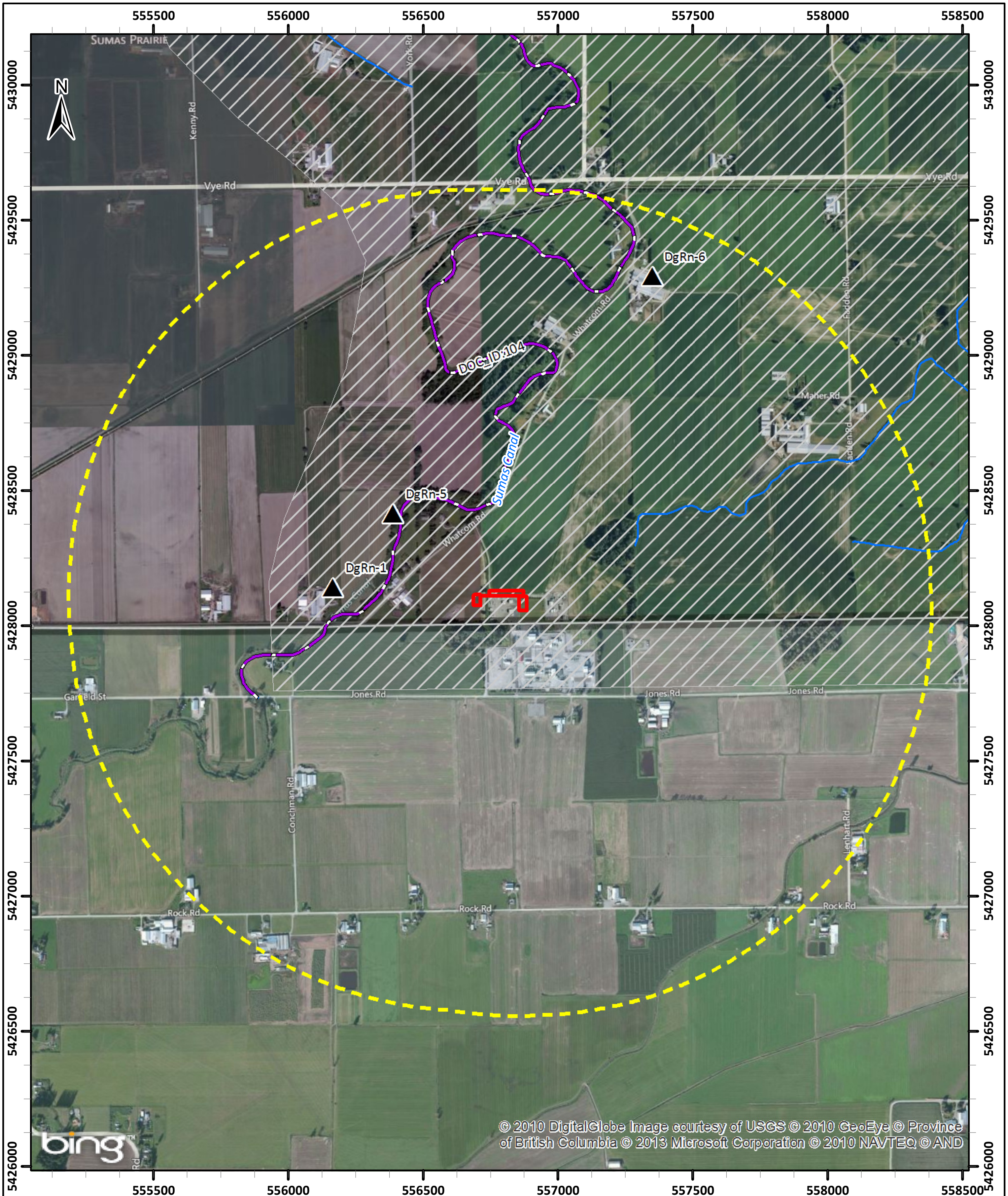
0 500 1,000 1,500 m

Projection/Datum: UTM Zone 10 NAD 83

Study Area

TITLE:	Overview of Study Area		
PROJECT:	P2013-02 Huntingdon AOA		
Figure 1	GIS	LMD	Jan. 25, 2013
	QAQC	CAB	Feb. 1, 2013
	SCALE	1:50,000	

D:\Projects\2013\P2013-02\reporting\Figure1.mxd



Stó:lō Research and Resource Management Centre

0 200 400 600 m

Projection/Datum: UTM Zone 10 NAD 83

Study Area

1.5 km Context Zone

Previously Recorded Archaeological Site

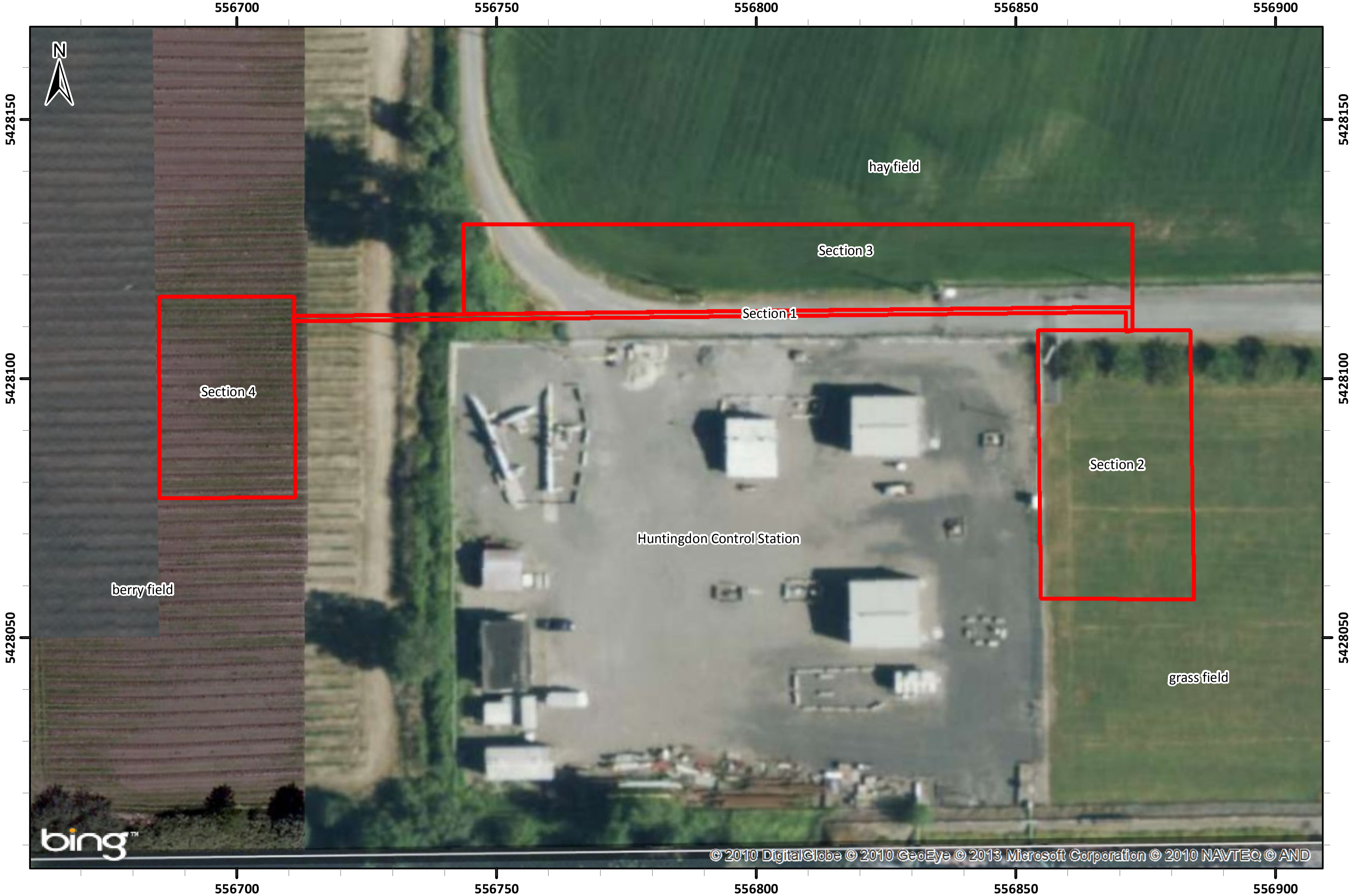
Stream

Traditional Use Gathering Area

Documented Travel Route

TITLE:	Cultural Heritage Overview		
PROJECT:	P2013-02 Huntingdon AOA		
Figure 2	GIS	LMD	Feb. 1, 2013
	QAQC	CAB	Feb. 1, 2013
	SCALE	1:18,500	

D:\Projects\2013\P2013-02\reporting\Figure2.mxd



Stó:lō Research and Resource Management Centre

0 10 20 30 m

Projection/Datum: UTM Zone 10 NAD 83

Study Area

TITLE:	Study Area Detail		
PROJECT:	P2013-02 Huntingdon AOA		
Figure 3	GIS	LMD	Jan. 25, 2013
	QAQC	CAB	Feb. 1, 2013
	SCALE	1:1,000	

D:\Projects\2013\P2013-02\reporting\Figure3.mdx

APPENDIX III – BACKGROUND RESEARCH: STUDY AREA SETTING RESULTS

Background Research: Study Area Setting Results

Research	Detail
proximity to known but unrecorded archaeological sites (i.e., site leads)	• none in close proximity
vegetation and terrain mapping	• terrain flat
distance to water	• Sumas Canal 300 m north and west • Fraser River 14 km north
modeled slope less than 20%	• 100 % of Study Area
known disturbances	• previous logging/vegetation clearing • agricultural use • road construction • Huntingdon Control Station construction • construction of Spectra facility
ecological / biogeoclimatic literature	• Coastal Western Hemlock biogeoclimatic zone
geologic and geomorphologic literature	• Devonian to Permian undivided sedimentary rocks • topography defined by glacial modified landforms
paleoenvironmental literature	• 15,000 BP Study Area covered by glacial ice, by 11,000 BP region more or less ice-free • between 11,000 BP - 5,000 BP temperature warmer and drier and between 5,000 BP and present, temperature and precipitation reached modern trends
GIS archaeological potential model	• 100 % of Study Area

Appendix I1

LANDOWNER LETTERS

November 16, 2012

[redacted]

I'd like to take this opportunity to give you the latest update regarding the project FortisBC (formerly Terasen Gas) has been considering in your area.

You may remember that last year we consulted landowners in the area, looking for a possible route for our reinforcement pipeline. We have now chosen an option that will minimize the impact to the land of private owners and the Sumas River, yet still increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

Huntingdon Station provides reliable gas service in your neighbourhood while serving more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project next Spring. With approval to proceed, the expected in-service date of the station reinforcement piping is 2015.

We would appreciate the opportunity to meet with you to discuss project details in person and to receive your input into our planning process. Please contact us at one of the numbers below to arrange a meeting at your earliest convenience.

Sincerely,

Amy Hennessy
Community Relations Manager
604-576-7363
Amy.hennessy@fortisbc.com

Colleen Bohun
Lands Representative
604-576-7121
Colleen.bohun@fortisbc.com

November 16, 2012

[redacted]

I'd like to take this opportunity to give you the latest update regarding the project FortisBC (formerly Terasen Gas) has been considering near your property at 126 Whatcom Road in Surrey.

You may remember that last year we consulted landowners in the area, looking for a possible route for our reinforcement pipeline. We have now chosen an option that will minimize the impact to the land of private owners and the Sumas River, yet still increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

Huntingdon Station provides reliable gas service in your neighbourhood while serving more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project next Spring. With approval to proceed, the expected in-service date of the station reinforcement piping is 2014.

We would appreciate the opportunity to meet with you to discuss project details in person and to receive your input into our planning process. Please contact us at one of the numbers below to arrange a meeting at your earliest convenience.

Sincerely,

Amy Hennessy
Community Relations Manager
604-576-7363
Amy.hennessy@fortisbc.com

Colleen Bohun
Lands Representative
604-576-7121
Colleen.bohun@fortisbc.com

Appendix I2

CONSULTATION LOG

Stakeholder	Communication Type	Purpose of the Communication	Date
City of Abbotsford - Mayor Banman	conversation	Inform Mayor Banman of "new" reinforcement project	20-Nov-12
City of Abbotsford - Mayor Banman	letter	Sent Mayor Banman a letter as a follow up	12-Dec-12
City of Abbotsford/Jim Gordon	conversation	Inform Jim of "new" reinforcement project	20-Nov-12
City of Abbotsford/Jim Gordon	letter	Sent Jim Gordon a letter as a follow up	12-Dec-12
Landowner	letter	Letter explaining new project and requesting meeting	16-Nov-12
Landowner	letter	Letter explaining new project and requesting meeting	16-Nov-12
Spectra Energy - M. Manning, B. Ogden. L. Olsen	meeting	Design review meeting	12-Jul-12
Landowner	letter	Inform of new reinforcement project and invite contact/feedback	21-Jan-13
Landowner	letter	Inform of new reinforcement project and invite contact/feedback	21-Jan-13
Landowner	letter	Inform of new reinforcement project and invite contact/feedback	21-Jan-13
Landowner	letter	Inform of new reinforcement project and invite contact/feedback	21-Jan-13
Landowner	letter	Inform of new reinforcement project and invite contact/feedback	21-Jan-13
Landowner	letter	Inform of new reinforcement project and invite contact/feedback	21-Jan-13
Landowner	letter	Inform of new reinforcement project and invite contact/feedback	21-Jan-13
Landowner	phone call	Questioning what newly proposed infrastructure would look like, and how close it would be to his property line.	27-Jan-13
Spectra Energy - L. Olsen	email	Permitting process	28-Jan-13
Kinder Morgan Canada - Lexa Hobenshield	phone call	Inform of new reinforcement project	28-Jun-13
Kinder Morgan Canada - Lexa Hobenshield	letter	Inform of new reinforcement project	16-Jul-13
Landowner	phone call	Phoned to get email to send him photo and map of valves to be put in near our station.	
Williams Pipeline	phone call	Positive discussion regarding gas flow arrangements for Huntingdon project.	31-May-13
Spectra Energy - Mac Manning, Doug Methot	meeting	Positive discussion regarding new reinforcement project	28-Aug-13
City of Abbotsford - Phil Blaker	conversation	Informed Phil Blaker about progress of "new" reinforcement project progress	10-Oct-13

Appendix J1

OGC PIPELINE PERMIT APPLICATION MANUAL

PIPELINE PERMIT APPLICATION MANUAL

April | 2011

Version 1.5

CONTENTS

Manual Revisions

Summary of Revisions

The Pipeline Application Manual has been updated. Changes by section in the updated manual are highlighted below

Applications received on or after the effective date are required to meet the revised application standards.

Effective Date	Section	Description/Rationale
4-Nov-2010	6 – Consultation Tab	To help meet the requirements of the Consultation and Notification Regulation, a consultation tab has been built into KERMIT to track landowner information. Instructions on using this tab have been added to the manual.
	6 – First Nations Tab	Clarified that First Nations Packages require both a 1:50,000 program map and a 1:250,000 access map.
5-Nov-2010	4 – Preparation & Planning	Replaced the first item on the numbered list with updated authority and additional information on submitting product chemical analysis when hydrogen sulphide is present. Added chemical analysis to attachments list.
1-Dec-2010	6 – Attachments Tab	Revised mapping requirements. The 1:250,000 is now submitted as a stand-alone map; not as an insert on the 1:50,000 map.
1-Feb-2011	6- Engineering Tab	Added clarification.
	6 - Attachments Tab	Added Attachment definitions for Appurtenance Design, Proposed Pressure Test Design, Valve Location Design and Pig Barrel Design.
	6 – Consultation Tab	Added email address where Written Submissions may be sent.
	1	Changed OGC.Documentation to OGC.Systems
	General	Updated hyperlinks
1-March-11		Post Construction Plans
	6 – Engineering Tab	Included IMP information.
	Appendix B	Revised pipeline Construction Plan requirements.
1-April-2011	Section 3	Removed reference to C&N Manual relating to expropriation, under Permit Determination
	Section 4	Revised Additional Information – Engaging First Nations.
	6 – First Nations Tab	Revised First Nations Consultation/Aboriginal Community Notice Package.
1-May-2011	2 – Additional Information	Added Fixing the Site of a Proposed Pipeline, Pipeline Preliminary Plan Requirements, Pipeline Preliminary Plan Submission, Security Calculation and Submission, Notification Required Before Entry, Return of Security, Dispute Resolution, Recommended Best Practices and Landowners.

1 Preface

Purpose

This manual has been created to guide users through Commission processes and procedures. It also serves to highlight changes in process, procedure, requirements and terminology resulting from the Oil and Gas Activities Act (OGAA).

For users already familiar with the Commission application process, this manual provides a quick reference highlighting the steps required to complete specific tasks. For users less familiar, this manual presents a complete overview of Commission requirements and provides links to more detailed material.

This manual is not intended to take the place of the applicable legislation. The user is encouraged to read the full text of legislation and each applicable regulation and seek direction from Commission staff, if and when necessary for clarification.

Scope

This manual focuses exclusively on requirements and processes associated with the Commission's legislative authorities, and does not provide information on legal responsibilities that the Commission does not regulate. It is the responsibility of the applicant or permit holder to know and uphold its other legal responsibilities.

How to Use This Manual

This manual is divided into sections which are organized chronologically, and match the order of the steps which applicants and permit holders will follow when engaging in oil and gas activities.

Beginning with pre-application, the manual takes the user through the steps of application preparation and submission; and permit revision and amendment. Each section begins with a brief overview describing the content which follows.

Section 2 **Pre-Application** outlines what companies new to British Columbia need to have in place before applying for oil and gas permits.

Section 3 **Permit Application Review Process** provides an overview of Commission's review and determination process to provide the applicant with an understanding of Commission procedures, and what to expect during the permitting process.

Section 4 **Preparing a Pipeline Permit Application** explains what is required to prepare all of the required components of the permit application.

Section 5 **KERMIT Overview** shows the basic components that are general to all KERMIT submission types.

Section 6 **Pipeline Permit Application** provides clear procedural direction on how to complete and submit pipeline permit applications and reporting requirements in the Commission's KERMIT database.

Section 7 **Permit Revision & Amendment** details the procedures required to make revisions or amendments to an application or permitted activity.

Additional Guidance

Guidance for constructing and operating pipeline projects within the jurisdiction of the Commission is located in the Pipeline Operations Manual.

Guidance for land tenures is found in the Commission's Corporate Land Management Manual.

The glossary page on the Commission website provides a comprehensive list of terms.

The appendices contain documents to be used as reference when compiling information required by the Commission.

Other navigational and illustrative elements used in the manual include:

Hyperlinks: Hyperlinked items appear as blue, underlined text. Clicking on a hyperlink takes the user directly to a document or location on a webpage.

Sidebars: Sidebars highlight important information such as a change from the old procedure, new information, or reminders and tips.

Figures: Figures illustrate a function or process to give the user a visual representation of a large or complex item.

Tables: Tables organize information into columns and rows for quick comparison.

Frequently Asked Questions

A Frequently Asked Questions (FAQ) link is available on the Commission OGAA page. The information provided is categorized into topics which reflect the manuals for easy reference. Please consult the FAQ page before contacting the Commission to help keep response times short.

Feedback

The Commission is committed to continuous improvement by collecting information on the effectiveness of guidelines and manuals. Clients and stakeholders wishing to comment on Commission guidelines and manuals may send constructive comments to OGC.Systems@gov.bc.ca.

2 Pre-Application Requirements

Companies applying to engage in oil and gas activities in BC for the first time must ensure all pre-application requirements have been met. These include the New Permit Holder Application Form, and a Master Licence to Cut Application (MLTC), and ePASS submission.

In addition to these pre-application requirements, the Commission may require a company to provide a security to ensure the performance of an obligation under the Oil and Gas Activities Act (OGAA) prior to, during, or after the permit application process, in accordance with Section 30 of OGAA.

New Permit Holder Application Form

The new permit holder application form captures general administrative and corporate registry information.

Completed new permit holder application forms and required attachments are to be submitted to the Commission's Corporate Land Management Unit. New permit holder application forms must be processed by the Commission prior to the submission of any oil and gas activity permits to the Commission.

For more information on the new permit holder application form, please refer to the Commission's Corporate Land Management Manual (currently in development).

Master Licence to Cut

A Master Licence to Cut (MLTC) on Crown land is required where the removal of timber is necessary to conduct an oil and gas activity. A separate agreement is required for each forest district.

An MLTC must be completed and submitted before an application for oil and gas activity is made, as the MLTC will govern the cutting permit that authorizes the removal of timber on Crown land.

ePASS

ePASS stands for electronic petroleum applications spatial submission. All companies new to the Commission must create an ePASS account.

Section 2 of the ePASS Submission Standards describes all attribute data components that must be submitted using ePASS for permit applications.

All ePASS submissions must conform to the shapefile spatial data format. These spatial standards are outlined in the Environmental Systems Research Institute White Paper, ESRI Shapefile Technical Description.

Spatial data associated with post construction plans will appear on the Commission's FTP site (outgoing data) for download by the public.

Fixing the Site of a Proposed Pipeline

Under Section 23 of OGAA, before entering on to land for the purpose of making surveys, examinations or other arrangements for the purpose of fixing the site of a proposed pipeline, a person must first submit a Pipeline Preliminary Plan showing the proposed pipeline route and either:

- Provide the prescribed security to the Commission to compensate the land owner or the Crown for any damage or disturbance that may be caused while fixing the site, and provide prescribed notices, or
- Enter into an agreement with the landowner for entry on to the land

Because requirements are met prior to making application for a permit, someone fixing the site of a proposed pipeline is referred to simply as "a person."

Pipeline Preliminary Plan Requirements

Persons following the preliminary plan process are required to submit the prescribed security (where required), and a Pipeline Preliminary Plan mapping the proposed pipeline route.

Proposed Route

The proposed route shown on the Pipeline Preliminary Plan must be represented at an appropriate scale and include:

- Base data
- Tenure holders
- Land parcels (legal land title)
- Portions of private land under agreement
- Portions of private land without an agreement
- Portion of land on which activities will be completed

Pipeline Preliminary Plan Submission

Pipeline Preliminary Plans are submitted electronically through the Commission data system, KERMIT. When an application is initiated in KERMIT, the user must upload a Pipeline Preliminary Plan in the attachments tab. Any accompanying documents are uploaded as “miscellaneous documents”. The related Commission file number used for tracking purposes, and should be referenced on the security submission.

Security Calculation and Submission

Under the Fee, Levy and Security Regulation (Section 8(2)) states that the amount of security required under Section 23(2)(b)(i) of OGAA, is $50,000.^{00} per kilometre of proposed pipeline.

For the purpose of security calculation, round distances up to the nearest whole kilometre and include all portions of the pipeline route where an entry agreement does not exist. If there are multiple landowners without an agreement, security may be submitted as a combined payment and must be accompanied by a detailed summary allocating the applicable amount to each portion of the proposed route.

Submit the security as an Irrevocable Letter of Credit made to the BC Oil and Gas Commission in person or by mail to:

BC Oil and Gas Commission

#100 10003 110th Avenue

Fort St John, BC V1J 6M7

Notification Required Before Entry

When planning to enter on to land to fix the site of a proposed pipeline, notification must be provided to the land owner by a person who does not hold an agreement to enter. The requirement to provide notice before entry, specific to fixing the site of a pipeline, is established in Section 23 (3) of OGAA. The notification content requirements and timelines are established under Section 15 of the Consultation and Notification Regulation.

Under the regulation a person without an entry agreement is required to notify the land owner of their intent to enter onto the landowner’s property, two clear days prior to entering.

This notification precedes the consultation and notification associated with the pipeline permit application.

Notice Requirements

Under Section 15 of the Consultation and Notification Regulation, notice must include:

- The name of the person intending to enter on to the land
- The name, phone number, fax number and email mail address (if available), of the contact person for the person, company or agent providing notification
- A copy of the Pipeline Preliminary Plan submitted to the Commission under Section 23 (1) of OGAA
- A description of the specific portion of the land to be surveyed or examined, and the activities to be undertaken for the purpose of fixing the site of the pipeline
- A description of the approximate order that the activities specified under subparagraph (iv) will be carried out and
- A statement advising the landowner that if the person intends to submit an application to the Commission for a pipeline permit on the their land, and that the company or their agent will notify and consult with the owner in accordance with Section 22 of OGAA and this regulation

Return of Security

To initiate the return of a security held under Section 23 of OGAA, a person must submit a Security Return Request along with any supporting documentation. This is to demonstrate that all obligations (under Section 8(4)(a) of the Fee, Levy and Security Regulation) have been met. The Commission returns the security to the person who provided the security where it is demonstrated that these obligations have been met.

Supporting Documentation

Supporting documentation should include:

- One copy of any post-entry agreements made with landowners for compensation for any damage or disturbance to the land
- An evaluation demonstrating that any land accessed under Section 23 of OGAA has been restored to the condition it was in before it was entered
- The evaluation should be based on a methodology which provides for an effective evaluation of the presence of damage or disturbance

Security Return Requests must be sent on the official letterhead of the requesting company to the Area Director, Project Assessment.

Dispute Resolution

It is up to parties of an agreement to uphold the agreement's terms. In the case where the person and the landowner are unable to come to an agreement, but desire mediation to resolve the matter, they should hire an independent mediator. The Commission will not act as a mediator in relation to any issues arising from activities carried out under Section 23 of OGAA.

Recommended Best Practices

Offered below are best management practices that should be consider in addition to the regulatory requirements.

Persons following the preliminary plan process should:

- Immediately advise the landowner of any situation that may require the landowner's attention
- Immediately notify the landowner of any changes made in respect of the obligations in Section 15 of the Consultation & Notification Regulation
- Consult the landowner with respect to their method of access over the lands, and use motorized vehicles only with the permission of the landowner
- Ensure surveyors minimize the number of survey stakes used
- Ensure surveyors only cut trees or branches in areas where growth is too dense for sight lines
- Ensure any trees or branches cut down will be disposed of in a manner acceptable to the landowner
- Ensure assessments are coordinated (for example, soil assessment with archaeology assessment) to avoid secondary intrusions
- Provide the landowner with any soil assessment reports

Landowners

Landowners should advise the person of any concerns with respect to the activity of the person and/or its contractors, and of any damage incurred as a result of the entry.

3 Application Review Process

Permit Review & Approval

The following process flowchart shows the major steps in the Commission's application review and determination processes.

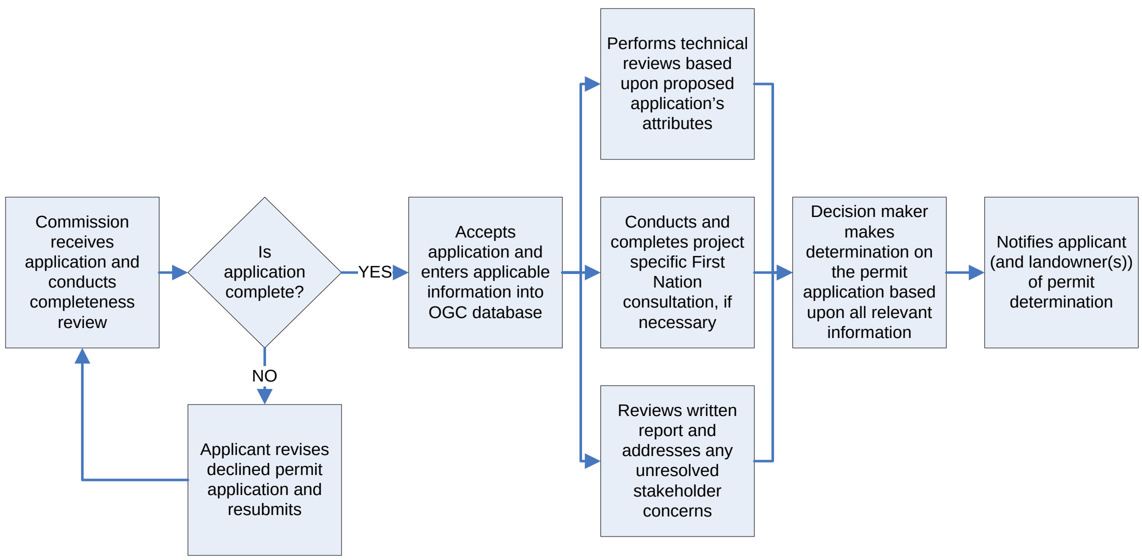


Figure 3.2. An overview of the Commission's role in the permit application review and determination processes.

Permit Review & Determination

Once an application has been submitted the company is referred to as the applicant.

Once the application has been approved, the Commission refers to the applicant as the permit holder.

Permit Review
Once an application has been received by the Commission it will be reviewed for completeness.

Declined Applications
Applications containing incomplete information are declined and returned to the applicant. A rationale explaining why the application was declined is sent to the applicant by email.

Revision and Resubmission
Revised applications must be resubmitted following the same procedure, and are then subject to full review. Revised applications may also be subject to additional notification requirements, in accordance with Section 5 of the Consultation and Notification Regulation.

Once any deficiencies have been addressed, the application can be resubmitted. Applications that have previously been declined are reviewed in order based on the resubmission date; not from the date of original submission.

Permit Determination
When all requirements have been met, the application is classified as complete. It is then accepted and enters the processing phase.

To make a determination on the application, the Commission will consult with First Nations (where applicable), review the applicant's consultation and notification record, and perform technical reviews on areas such as archaeology and land and habitat.

Once all application actions have been completed, the Commission may issue a permit specifying the conditions attached to the permit and what activities the permit holder may carry out, including related authorizations under the Forest Act and Water Act.

For permits issued on Crown land, the Commission will authorize the occupation of Crown land pursuant to the Land Act.

Permits issued over private land are subject to a landowner agreement. If agreement cannot be reached, an application may be made to the Surface Rights Board under Part 17 of the Petroleum and Natural Gas Act.

With respect to a pipeline (other than a flowline), in the case of a failed agreement with the landowner, the applicant may acquire the land or the necessary interests in accordance with the Expropriation Act.

Sections 70 and 72 of OGAA establish an applicant or permit holder’s right to a review and/or appeal of a determination. Guidance on the review process is found within the Commission’s Determination Review Guideline. Instructions regarding appeals may be obtained from the Oil and Gas Appeals Tribunal.

Post Approval

Landowner Notification Process

Following a permit approval, the Commission provides notice to the landowner(s) that an oil and gas permit has been issued over their land. The notice cites specific details about the location of the approved activity, and the landowner(s) right to appeal.

The permit holder must wait 15 days from the day the permit is issued before commencing any oil and gas activity, unless the landowner has consented to the permit holder in writing that the oil and gas activity may commence.

Written consent from a landowner does not have to be provided to the Commission as part of the application, however the permit holder must retain it for their records and for auditing purposes.

Instruction regarding appeals may be obtained from the Oil and Gas Appeals Tribunal.

Term of Permit
The term is the length of time the permit is valid, and is defined by regulation.

To extend a permit term, the permit holder should consult the Commission's Permit Expiry and Extension Guideline.

If activities have not begun by the end of the permit term, the permit will expire and the Commission will proceed with the cancellation process.

Permit Transfers
A permit holder may apply to the Commission to transfer a permit in accordance with Section 29 of OGAA.

For more information on the permit transfer process and transfer application requirements, please refer to the Corporate Land Management Manual.

4 Preparing Permit Applications

To undertake any proposed pipeline activity, whether within an existing right-of-way or over new Crown land or private land, companies must first submit a completed pipeline permit application through the Commission's KERMIT database. Refer to Section 5 for an overview of KERMIT features.

A pipeline permit application provides the Commission with the information necessary to conduct a review of the proposed project. Upon completion of the review, the Commission may issue a permit.

Prior to submitting the application, certain preparation and planning activities may be required. Following the directions provided in this section will help to ensure that the application is complete and correct, which may minimize Commission review timelines.

Construction plans, and if required, First Nations packages must be submitted in person or via mail to the BC Oil and Gas Commission in Fort St John.

BC Oil and Gas Commission
100, 10003 100th Avenue
Fort St John, BC V1J 6M7

Preparation & Planning

In accordance with section 7(1) of the Pipeline Regulation, an IMP that complies with CSA Z662 must be prepared before the permit holder operates the pipeline.

When preparing a permit application, certain activities must be carried out to ensure that a complete and correct application is submitted.

The following sections show the steps applicants must take when planning and preparing an application.

Every applicant must:

1) Prepare Construction Plan(s) in accordance with OGAA s. 24(1)(b) and Pipeline and Liquefied Natural Gas Facility Regulation s.2 and 3(1). If a fluid containing hydrogen sulphide gas is to be transported in the pipeline, the chemical analysis of the gas or fluid to be transported and the expected release volume (expressed at standard conditions of 15 degrees C and 101.3 kPa), of hydrogen sulphide from the pipeline must be submitted with the application as a separate attachment.
2) Develop Integrity Management Program (IMP) as outlined in the Pipelines Operations Manual and develop a Damage Prevention Program as outlined in the British Columbia Common Ground Alliance's Recommended Practice for Damage Prevention Programs by October 4, 2011.
3) Contract an archaeologist to complete an archaeological assessment in accordance with the Heritage Conservation Act and the Commission's Archaeology Guidelines
4) Enter surface agreement with landowner if activity is located on private land, or if an agreement cannot be reached pursue guidance through the Surface Rights Board or the *Expropriation Act.*
5) Undertake the prescribed consultations and/or notifications by:
    I. Identifying the landowner(s) as defined by OGAA, and affected persons as defined in the Consultation and Notification Regulation within the notification and consultation area;
    II. Providing the landowner(s) and affected persons with the requirements of a notification package and/or consultation invitation, as defined by the Consultation and Notification Manual and provide any required responses to landowners or affected parties.
    III. Prepare a written report in accordance with the Commission's Consultation and Notification Manual

6) Conduct a site assessment if the program is located within the Agricultural Land Reserve (ALR).
7) Prepare Emergency Planning Zone in accordance with Pipeline and Liquefied Natural Gas Facility Regulation s.8, if necessary.
8) If the pipeline is to be constructed across, along, over or under another pipeline and the applicant has not obtained agreement of the owner of the other pipeline with respect to the construction, a detailed description of the construction in relation to the other pipeline and a report of efforts made to obtain the agreement must be submitted to the Commission at the time of application.

Additional Considerations

Engaging First Nations

Prior to submitting an application to the Commission, companies are encouraged to initiate and build relationships with First Nations communities directly by discussing their intended development plans.

It is recommended that an Engagement Log be used to record be kept of this and all subsequent meetings and conversations that are held. A sample format for the Engagement Log is located in Appendix G.

An Engagement Log can greatly benefit the flow of the process where the First Nation has been advised that the applicant's engagement activities will be shared with the Commission. The engagement log may be considered in the decision making process

First Nations Consultation Boundaries maps are available for review at the Commission office. These maps along with advice from Commission First Nation Liaison Officers provide companies a starting point for their engagement responsibilities.

Details regarding engagement and consultation requirements are located in Section 5 First Nations/Aboriginal Communities Consultation and Notice.

Forms

Form used in conjunction with First Nation Consultation (including First Nation Cover Letters) are found on the Commission website.

Spatial Data

Provincial spatial data is stored within the BC Geographic Warehouse, a central, consolidated repository of land and resource information from across the province. It includes many types of data including cadastral information (tenures, ownership, boundaries); resource information (vegetation, fisheries, wildlife), provincial atlas (rivers, roads, buildings, topography, surveys), and planning and analysis information (land and resource management plans, sustainable resource management plans).

Spatial data from the BC Geographic Warehouse is available to view through iMapBC, discover through the Discovery Service, and download from the Distribution Service. All services can be accessed through the GeoBC Gateway.

5 KERMIT Overview

KERMIT is the Commission’s Knowledge, Enterprise, Resource, Management, Information and Technology data system.

KERMIT enables electronic submission of applications, performance/compliance data submission, and electronic workflow management.

For additional information, the applicant should refer to the KERMIT application page on the Commission’s website. This page provides links to frequently asked questions about KERMIT, an external overview document which illustrates how to navigate within KERMIT, and a company administration document which illustrates how to manage KERMIT accounts.

KERMIT Functions

Fields
Most mandatory fields display a shaded background. Some fields that are conditional may become mandatory, and do not appear with the shaded background and instead appear under finalize tab as an outstanding issue.

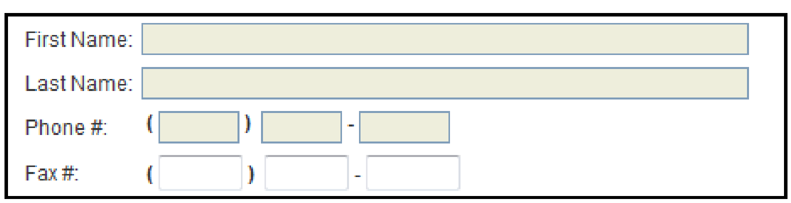


Fig. 5.1. Shaded mandatory fields in KERMIT

Date

All editable date fields have a calendar button which opens up a calendar. Select a date, or enter it manually in the MMM/DD/YYYY format.

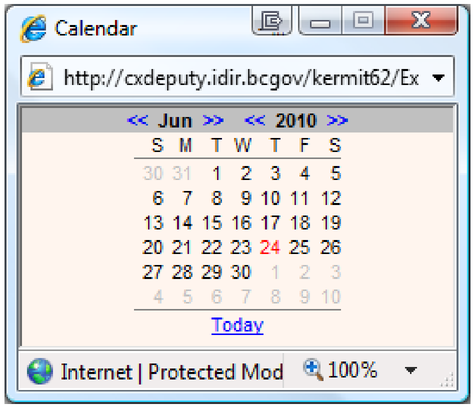


Fig. 5.2. Calendar window.

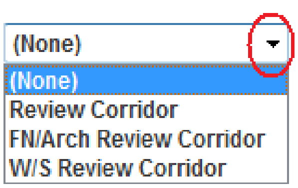
Buttons and Menus

The save button 

updates the application. This is convenient because it allows the user to enter in information, save it and come back at a different time to edit or complete it.

The find button 

opens a pop-up window the user can use to search for a detail.



Dropdown menus contain a list of pre-set values that the user can choose from. Click on the down arrow to see the list, and select.

Search

The search function in KERMIT provides a way to link an application, notice or activity to an existing site or project.

For applications and notices of intent, step one of the search is the same. Applicants may search for a specific site or project by entering information in any of the open search fields. The more specific the information used to search with is the more specific the search result will be. The OGC file number is the preferred search method.

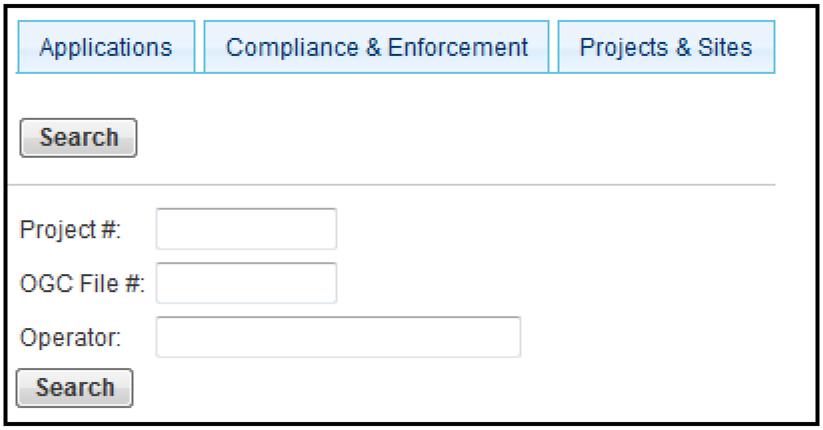


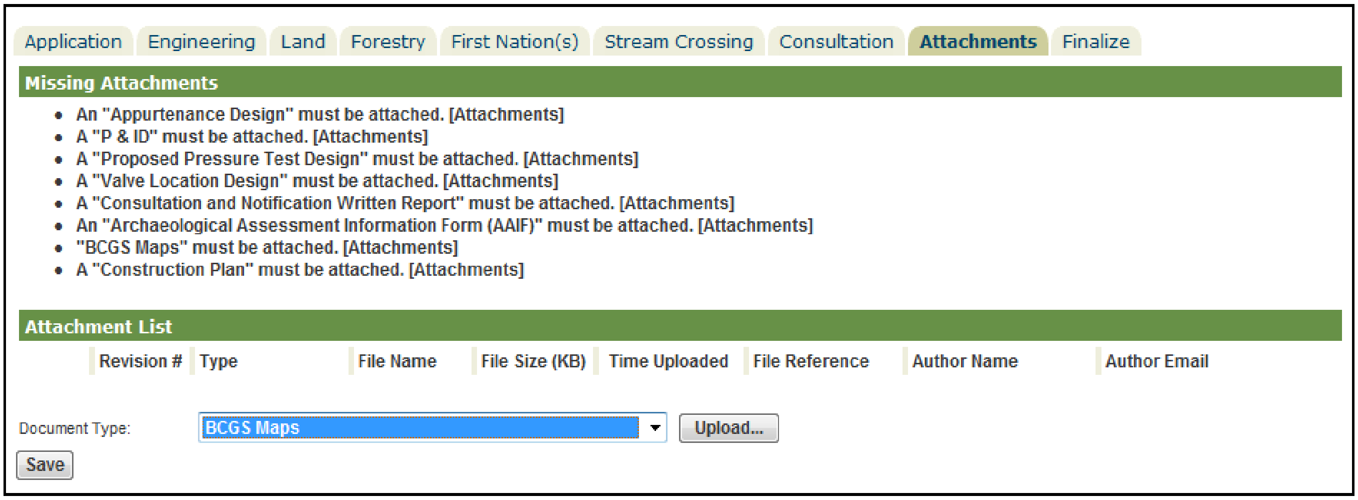
Fig. 5.3. KERMIT search fields.

Attachments Tab

The attachments tab allows a user to upload documents and relate then to the job. To attach a document:

1) Choose the document type from the dropdown menu.
2) Click the upload button.
3) Type the name and extension of the file, or click the browse button to open a search window to search for a document.
4) Click the upload button again to upload the document.
5) Fill in the file reference, author name and author's email address
6) Click the save button to finalize the attachment.

Fig. 5.4. Pipeline attachments page



Finalize Tab

KERMIT will indicate if there are outstanding issues with the Application. Once the outstanding Issues are corrected, the application can be finalized.

Finalize the application and submit to the Commission.

If First Nations packages are required, the Commission will not review the application in KERMIT until the hard copy packages are submitted and applicable fees are received by the Commission.

KERMIT Application Header

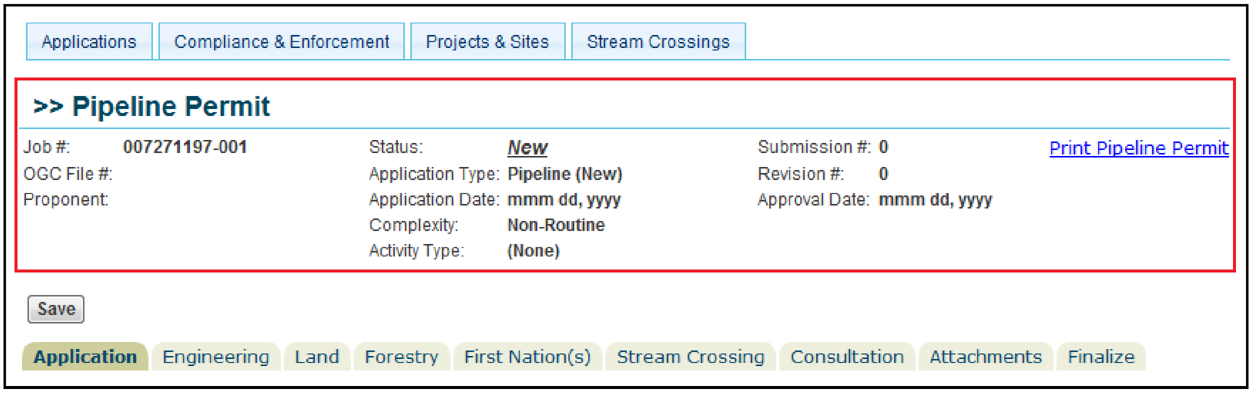


Fig. 5.5. KERMIT application header on pipeline application page.

At the top of the pipeline application is the header. The header displays:

Job # Used to identify a specific pipeline or facility. The user can click on the link to navigate to that job.

OGC File # Used to identify related surface rights applications.

Proponent Name of the related organization.

Status Displays what stage the job is in.

Application Type Type of the pipeline or facility application.

Application Date The date on which the application was submitted or the hardcopy was received

Complexity Identifies the application as either Routine or Non-Routine.

Submission # The number of times the application has been submitted.

Revision # The number of times the application has been resubmitted after screening.

Approval Date The date on which the application was approved.

Print Pipeline Application View and print a hard copy of the application. Used when a hard copy needs to be submitted with other application deliverables (e.g. First Nation(s) package).

6 Pipeline Permit Applications

The applicant that will hold the surface tenure is accountable for the accuracy of the application content entered into KERMIT. If the applicant chooses to use outside agents or consultants, the applicant remains accountable for the accuracy of the application.

Applicants seeking approval for a pipeline must complete all required KERMIT application components and ensure the required attachments are uploaded.

Applications are to be submitted through KERMIT when new Crown or private land is to be acquired, or when the right to occupy the land has already been acquired.

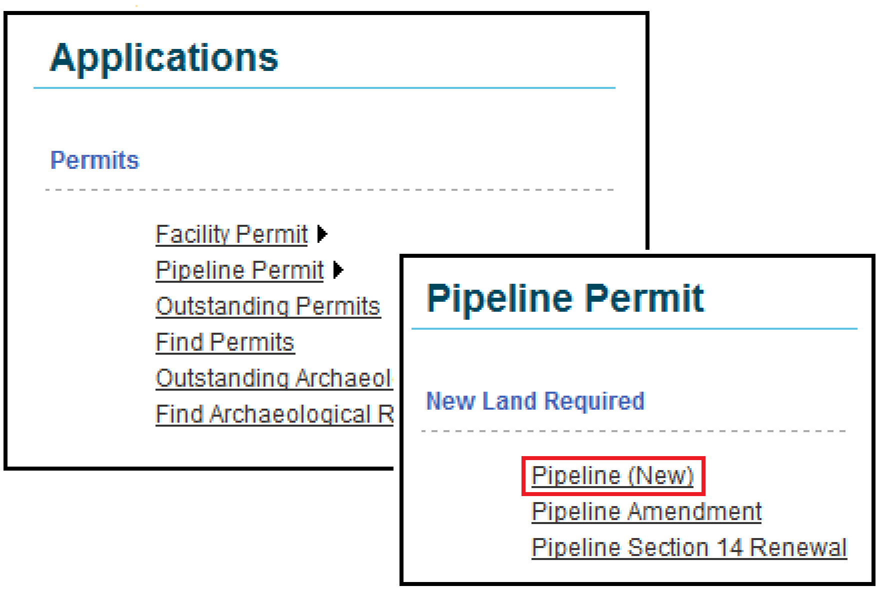
If an additional pipeline is required in an existing tenured right of way, a new application is required.

The following sections provide guidance for completing each component (or tab), of a pipeline application through KERMIT.

Where necessary, the applicant is directed to a link or specific document which will provide expanded information or explanation.

New Pipeline Permit Application

1) Select new application
2) Select pipeline (new) to open the new pipeline application page.



Pipeline Application Page

The new pipeline application page opens and a job number and OGC file number are generated. The pipeline application contains categorized tabs where information is to be entered. The tab categories are application, engineering, land, forestry, First Nation(s), stream crossing and attachments and finalize which are covered in the KERMIT overview section of the manual.

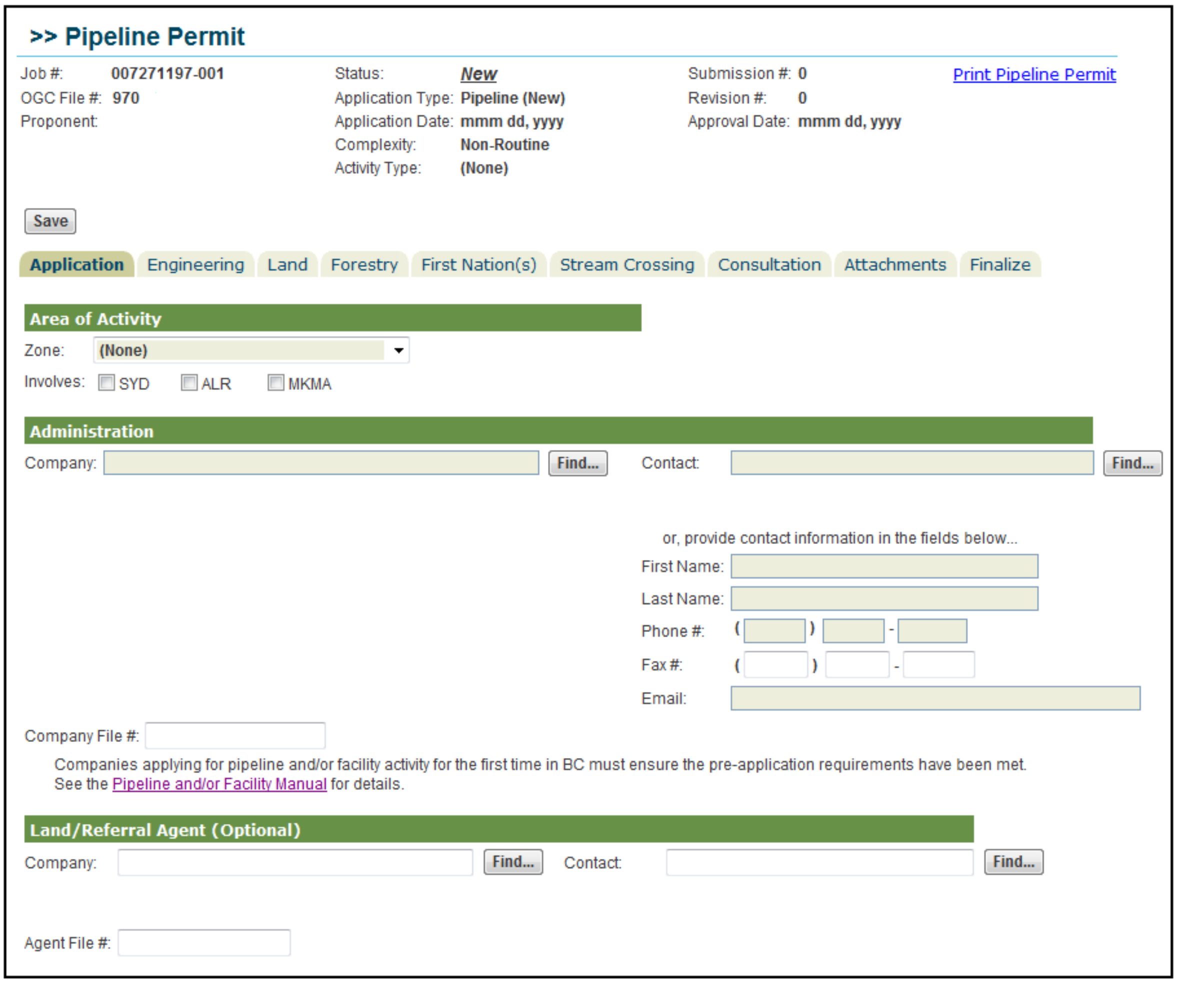


Fig. 6.1. Pipeline application page.

Application Tab

The application tab establishes the area of activity within British Columbia and identifies key applicant and land/referral agent information.

Area of Activity

Select the appropriate from the dropdown menu.

In addition to the regional zone, the applicant must indicate other geographic characteristics. Descriptions of these characteristics are provided below. Select the appropriate check boxes for the applicable geographic characteristics.

SYD
Indicate if the activity is located within the Sierra-Yoyo-Desan Assessable Area, which comprises parts of the NTS grid 094J, 094I, 0940 and all of 094P. Further details are available on Ledcor Group's webpage.

ALR
Indicate if the activity (or any portion) is located within the Agricultural Land Reserve. For further details see Agricultural Land Reserve and Agricultural Land Reserve Mapping. The OGC-ALC Delegation Agreement between the Commission and the Agricultural Land Commission must be adhered to.

MKMA
Indicate if the activity occurs within the designated area called Muskwa-Kechika Management Area (MKMA). This triggers additional application information, and further details are discussed in the additional information section of the manual.

Administration

This section captures key applicant information.

Enter Company Information
To enter company information, click the find button and choose the applicable company. If the company name does not appear, or the address is incorrect, the applicant must contact the Commission's Corporate Land Management Unit to update the information prior to application submission.

Enter Contact Information
If the contact does not appear or is not already entered in the Commission database, the applicant's company administrator for KERMIT must enter the individual in prior to proceeding.

Land Referral Agent

Only an employee or agent of the applicant, who has the designated authority to sign legal agreements, can sign on behalf of the applicant.

If an agent is signing on behalf of the applicant, a letter of authorization from the applicant must be on file at the Commission prior to submitting the application. For applicants utilizing a land/referral agent, all information fields must be entered.

To find a land/referral agent, click the find button and choose the applicable company. If the company name does not appear, or the address is incorrect, the applicant must contact the Commission's Corporate Land Management Unit to update the information prior to application submission.

For reference, enter the agent's internal file number.

New Company Contact
To enter the land/referral agent, select the find button and add contact. If the contact is not entered in the Commission database, the applicant company's KERMIT administrator must enter the individual in prior to proceeding.

Engineering Tab

The engineering tab contains pipeline specifications, engineering firm details and spatial information.

It contains all of the known design specifications for the pipeline, and the start and end points of the pipeline. The start and end points are not just from lease to lease, but the exact start and end point of the pipeline. For example; from a riser on a starting site to another riser on the end site.

See Appendix F for specific information on identifying known and unknown pipeline segments.

Pipeline Specifications

Pipeline specification allows applicants to identify each segment of pipe, including new pipe that will be built in existing right-of-ways. The pipe length to be reported is the actual pipeline length, not the surface land length. Pipelines will be specifically denoted by using the Project and Segment numbers.

Information to assist answering the following questions is below.

1) Indicate if any lines fall within a review corridor and select the review corridor type from the dropdown list. Enter the OGC file number and well authorization number, if applicable.
2) Indicate whether any of the lines start or terminate at a cross-border pipeline or connect to a cross-border gathering system.
3) Indicate whether the lines enable well production to flow to two or more separate reporting facilities. If so attach a Schedule 1. For further information with respect to reporting requirements, refer to the Pipeline Operations Manual.
4) Indicate if an emergency response plan or addendum is required or if the Emergency Response Plan will be submitted prior to leave to open.

Applicants need to resolve potential stakeholder concerns, complete archaeology work and resolve other resource issues over the entire review corridor area prior to submitting the pipeline application. The Commission will consult on the entire review corridor applied for.

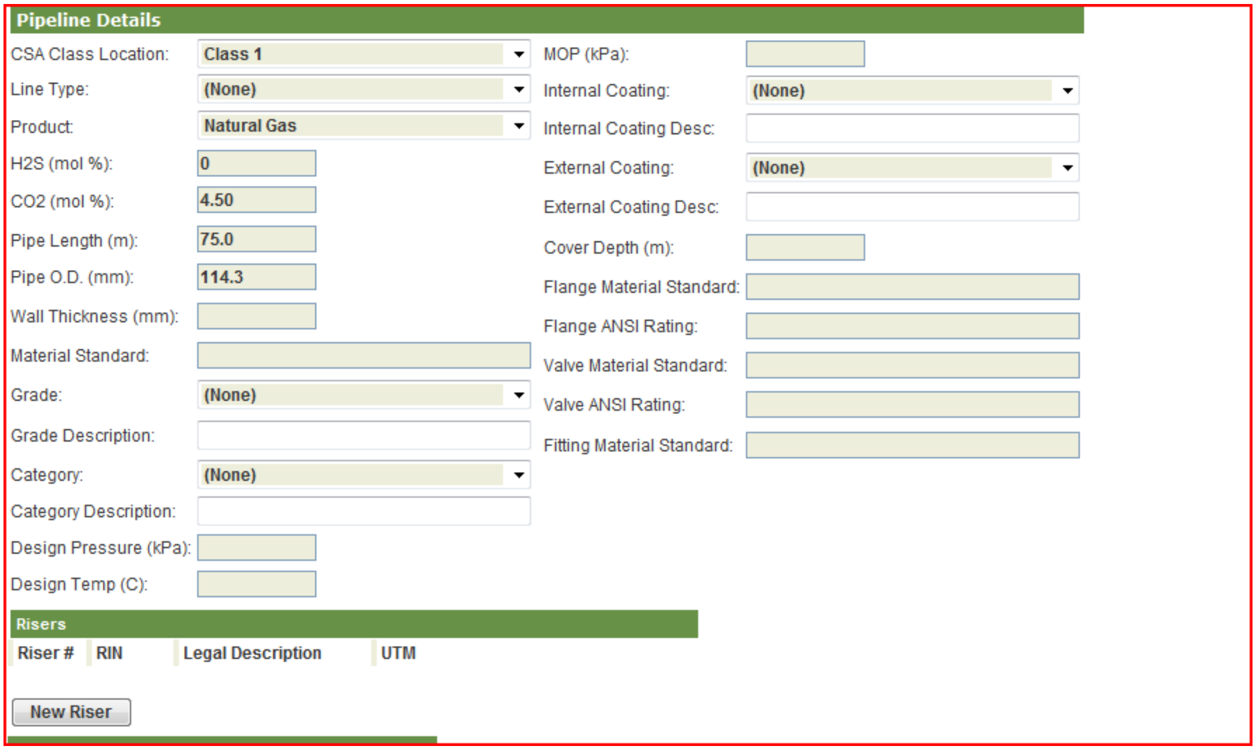
The following information must be entered for each segment:

- Location; actual start and end point location; not tenured area start and end points
- Pipeline product
- CSA class location
- Line type
- Pipe length in meters (actual pipe length, not surface land length)
- Pipe outer diameter in millimetres (O.D.)
- Wall thickness in millimetres (wt)
- Maximum designed H_2S percentage
- Maximum designed CO_2 percentage
- Material standard
- Material grade
- Material category
- Design temperature (°C)
- Design pressure (kPa)
- Maximum operating pressure (MOP)
- Depth of Cover

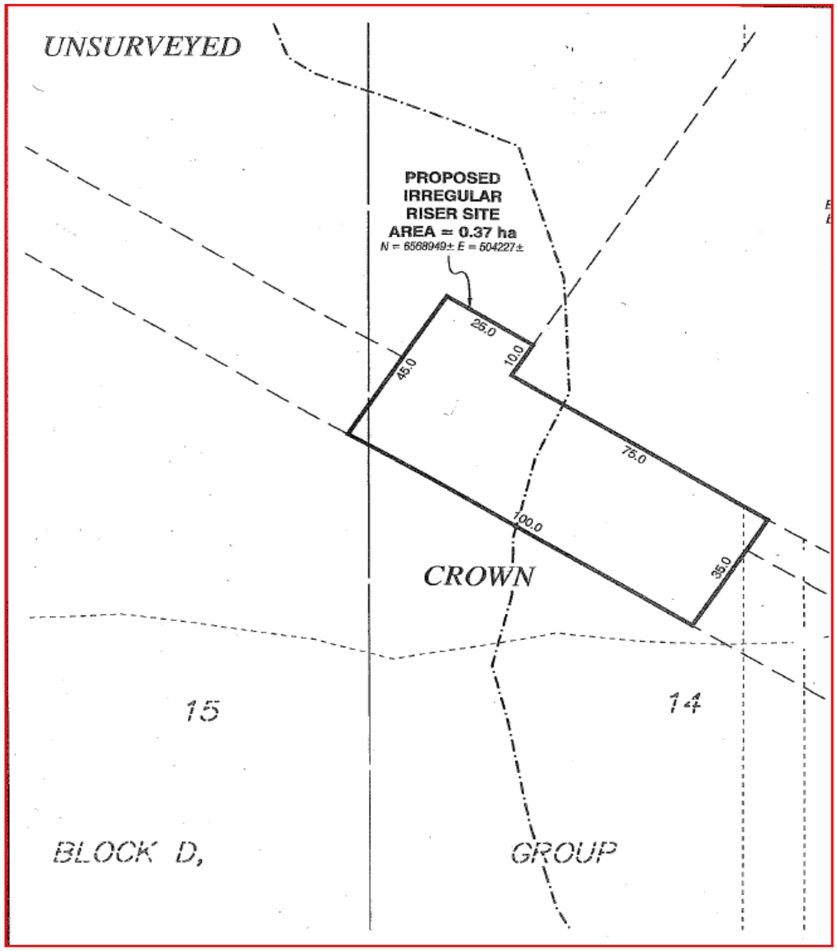
For example, a significant bore and drag section may be a different wall thickness and be considered as a separate segment. A simple road crossing, which may have differing wall thickness would not be a separate segment. Nor would an s-bend coming up into a riser, with a transitions piece and higher wall thickness.

Indicate if there has been an Integrity Management Plan (IMP) developed for this line, or if the IMP has been updated to include the line.

Riser Locations
If there are risers associated with the pipeline, these riser locations need to be entered by NTS or DLS co-ordinates for location confirmation. These locations must be filled out and indicated on the design schematics as well as in the segment specification tab as shown below.


Pipeline Details
CSA Class Location:
Class 1
MOP (kPa):
Line Type:
(None)
Internal Coating:
(None)
Product:
Natural Gas
Internal Coating Desc:
H2S (mol %):
0
External Coating:
(None)
CO2 (mol %):
4.50
External Coating Desc:
Pipe Length (m):
75.0
Cover Depth (m):
Pipe O.D. (mm):
114.3
Flange Material Standard:
Wall Thickness (mm):
Flange ANSI Rating:
Material Standard:
Valve Material Standard:
Grade:
(None)
Valve ANSI Rating:
Grade Description:
Fitting Material Standard:
Category:
(None)
Category Description:
Design Pressure (kPa):
Design Temp (C):
Risers
Riser #
RIN
Legal Description
UTM
New Riser

If there is a riser at the either endpoint of the pipeline, then it is applied for as part of the pipeline or is an amendment to the pipeline, even if it exceeds the width of the existing ROW. On applications this area should be included in the pipeline application, if it is an amendment, then it would be an amendment with new land required. Please see the example on the next page for illustration.


UNSURVEYED
PROPOSED
IRREGULAR
RISER SITE
AREA = 0.37 ha
N = 6568949± E = 504227±
25.0
10.0
45.0
75.0
100.0
35.0
CROWN
15
14
BLOCK D,
GROUP

Equipment
Pipeline systems may include equipment and above ground piping. Equipment allowed to be considered part of the pipeline systems is equipment reviewed by the Facility Engineering Group:

- Pig Barrel
- Emergency Shutdown/Safety Device Valves
- Block Valves
- Regulators
- Chemical (non-production) tanks
- Odorizing equipment

Any equipment that is not included on the list above will require a Facility Permit. Full instructions are located in the Facility Application and Operations Manual.

Engineering Attachments
The attachments required to be submitted with a Pipeline Permit Application for engineering review are:

- Project description
- Design schematics
- Isolation valve locations and design schematics
- Riser locations and design schematics
- Pig barrel locations and design schematics
- Crossing designs (rivers, roads, bore profiles
- Area flow schematic
- Pressure testing procedure description (if air is the intended medium)

Wellsite review corridors were previously identified with a well application.

Wellsite Review Corridors
An applicant may use a previously identified review corridor used on a wellsite construction plan. The well authorization number and the Commission file number must appear on the pipeline construction plan and should be identified as a "wellsite review corridor".

Pipeline Review Corridors

Review corridors have been established to allow flexibility during construction for pipeline placement, as well as ancillary disturbances.

The total corridor width for routine applications is reviewed by First Nations and Archaeology; additionally by Land and Habitat and Forestry for non-routine applications.

Cross-border Information

This information will be used by the Commission's Production Audit Technician to ensure compliance with cross-border measurement and is provided to the Commission for the Engineering division to make determinations for compliance.

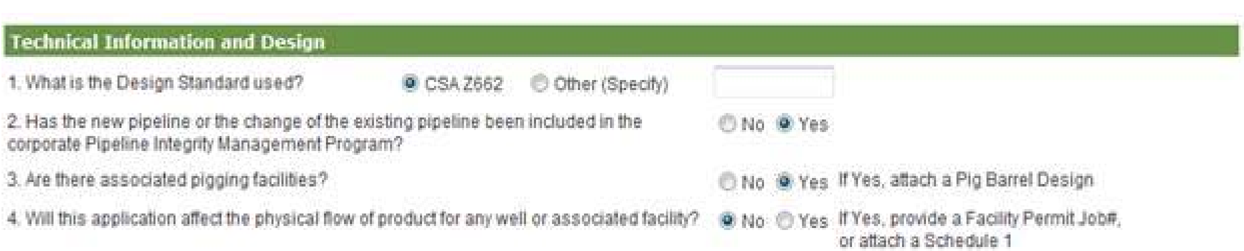
Emergency Response Plan

If submitting an update to an existing ERP, state which plan the update is to be inserted into.

An Emergency Response Plan (ERP), or an update to an existing plan, must be submitted to the Commission's Emergency Response Technician prior to commissioning the pipeline (Leave To Open), when the product in the pipeline has an H_2S concentration of ten moles per kilomole, in accordance with Section 8 of the Pipeline and Liquefied Natural Gas Facility Regulation.

IMP

Permit holders are required to answer the IMP-related question in all new pipeline permit application and pipeline amendments. An explanation and a plan for the inclusion of the new pipeline or amendment should be given in the application, if the new pipeline or the change to the existing pipeline is not included in the permit holder's pipeline IMP during the permit application. Otherwise, application approvals may be delayed.



Technical Information and Design

1. What is the Design Standard used?	CSA Z662 / Other (Specify)	
2. Has the new pipeline or the change of the existing pipeline been included in the corporate Pipeline Integrity Management Program?	No / Yes	
3. Are there associated pigging facilities?	No / Yes	If Yes, attach a Pig Barrel Design
4. Will this application affect the physical flow of product for any well or associated facility?	No / Yes	If Yes, provide a Facility Permit Job#, or attach a Schedule 1

KERMIT Details Tab

The new pipeline segment button opens the details window where information regarding pipeline details, location and wells is entered.

The pipeline details section of KERMIT is undergoing an enhancement for OGAA. Therefore, the content of this section of the manual will be augmented once IT development is finalized.

Pipeline Details

The following information must be entered for each segment:

- Pipeline product. See Appendix D for a table of product codes.
- CSA Class Location of the application area.
- Proposed pipe length in meters (the actual pipeline length, not the surface land length).
- Proposed pipe outside diameter in millimetres.
- Choose the Line Type for the selected segment from the dropdown box.
- Indicate anticipated H_2S content by mole %
- Indicate anticipated CO^2 content by mole %
- Indicate the Wall Thickness in millimetres.
- Indicate the Material Standard.
- Choose the Grade from the dropdown box.
- Choose the Category from the dropdown box.
- Indicate the Design Pressure in kilopascals.
- Indicate the Design Temperature in Celsius.
- Indicate the Maximum Operating Pressure in kilopascals.
- Choose the Internal Coating from the dropdown box.
- Choose the External Coating from the dropdown box.
- Indicate the Cover Depth in meters.
- Indicate the Flange Material Standard.
- Indicate the Flange ANSI Rating.
- Indicate the Valve Material Standard.

- Indicate the Valve ANSI Rating.
- Indicate the Fitting Material Standard.

Location

1) Enter the segment number
2) Enter the *from* and *to* location, with complete NTS or DLS descriptions for the selected segment.
3) Enter the UTM (NAD83 CSRS) Location for both the *from* and *to* location of the selected segment.

NAD 83 CSRS
The North American Datum of 1983 (NAD83) is the adopted reference coordinate system in both Canada (NAD83 (CSRS)) and the United States (NAD83 (NSRS)). It is a 3-dimensional representation of the NAD83 horizontal datum adopted in 1986. To comply with a resolution of the International Association of Geodesy (IAG), the North American plate fixed NAD83 (CSRS) is rigorously related to the current International Terrestrial Reference Frame via a 6 parameter transformation (three translations and three rotations).

Wells Being Produced

1) Indicate the well authority number (WA No.) for all wells that are being produced at the *from* location.
2) Click the find button.
3) Search for the well by entering WA #, site #, project # or surface owner.
4) Click the search button.
5) The well name should match the NTS or DLS location in the from location details.

Location Notes

Remember to save the information before closing the window.

Location notes provide space to add more information about the location at the discretion of the applicant.

Engineer's Details

To enter the engineer firm, click the find button and choose the applicable name. If the engineer firm does not appear, or the address is incorrect, the applicant must contact the Commission's Corporate Land Management Unit to update the information prior to application submission.

To enter the engineer contact, select the find button and add contact. If the contact is not entered in the Commission database, the company's KERMIT administrator must enter the individual in prior to proceeding

For reference, enter the engineer project or file name in the appropriate field.

The engineer project or file name is provided so the engineering firm will be able to search the Commission website by their file or name.

Spatial Data & Construction Plan Details

Construction Plan requirements are located in Appendix C.

Enter the ePASS number and choose the survey company name from the dropdown box. Enter the job number as recorded on the construction plan.

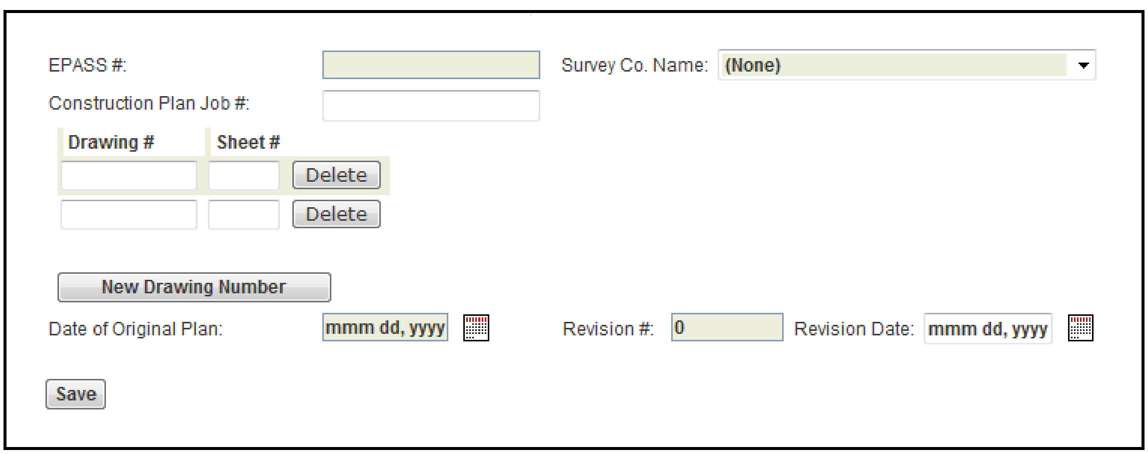


Fig. 6.2. Information fields for spatial data and construction plan details.

New Drawing Number
Click the new drawing number button and enter the drawing and sheet numbers. Enter the drawing number from the construction plan.

The date of the original plan refers to the date the original plan was drawn. The revision number refers to the revision number of the plan being submitted with the application, and the corresponding revision date.

Land Tab

Information on land status and land use planning allows the Commission to determine how the proposed pipeline activity impacts or affects various facets of the land base.

It is the responsibility of the applicant to determine the location and status of all tenure holders. Information sources include the ILRR, MapView, and current tenure holder operational plans.

A Practical Guide to Effective Coordination of Resource Tenures indicates the various types of tenures and rights conveyed.

Land Status & Land Use Planning

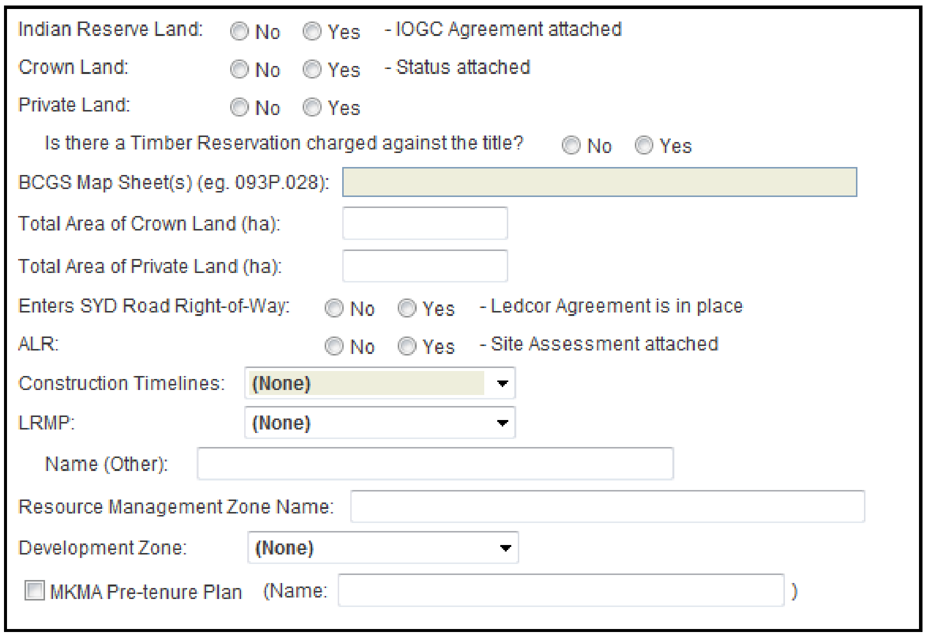

Indian Reserve Land: ○ No ○ Yes - IOGC Agreement attached
Crown Land: ○ No ○ Yes - Status attached
Private Land: ○ No ○ Yes
Is there a Timber Reservation charged against the title? ○ No ○ Yes
BCGS Map Sheet(s) (eg. 093P.028):
Total Area of Crown Land (ha):
Total Area of Private Land (ha):
Enters SYD Road Right-of-Way: ○ No ○ Yes - Ledcor Agreement is in place
ALR: ○ No ○ Yes - Site Assessment attached
Construction Timelines: (None)
LRMP: (None)
Name (Other):
Resource Management Zone Name:
Development Zone: (None)
☐ MKMA Pre-tenure Plan (Name:)

Fig. 6.3. Information fields in land status and land use planning; land tab.

Indian Reserve Land

If the proposed activity occurs within Indian Reserve lands, a copy of the Indian Oil and Gas Canada (IOGC) Agreement must form part of the pipeline permit application and be uploaded as an attachment.

A Crown land status sheet example is located in Appendix C.

Crown Land
If the proposed activity occurs exclusively or partially within Crown land, a complete status sheet indicating all interests and tenure holders (crossing or adjoining) must form part of the pipeline permit application and be uploaded as an attachment.

Private Land
If the activity is exclusively or partially within private land, applicants must identify if a timber reservation exists against the title of the parcel.

If a timber reservation does exist, the applicant must ensure the Ministry of Forests and Range has issued a licence to cut to the landowner prior to removal of timber. Indicate yes or no to the timber reservation question.

BCGS Map sheet(s)
Indicate all BC Geographic Series map sheets (BCGS) affected by the application area. The map sheet numbers should also be indicated on the 1:20,000 BCGS Sketch Map uploaded as an attachment.

Total Area of Crown Land
Indicate the total hectares of what is shown on the construction plan, including the right-of-way and any temporary workspaces, pushouts, decking sites, etc.

Total Area of Private Land
Indicate the total hectares of what is shown on the construction plan, including the right-of-way and any temporary workspaces, pushouts, decking sites, etc.

Enters SYD Road Right of Way
If any new construction is proposed within the right-of-way of the SYD Road, or crossings of the SYD road are proposed, an agreement with Ledcor Group (holder of the SYD Road), must be in place prior to application submission: SYD Protocols Link.

A copy of the agreement is not required to be submitted with the application, but must be retained on file and provided to the Commission during an audit.

Agricultural Land Reserve (ALR)
Indicate whether any portion of the application area is within the ALR. For project activities within the ALR, a Schedule A site assessment must be uploaded as an attachment with the application and a Schedule B reclamation assessment must be completed within 24 months of pipeline installation. Details related to ALR requirements can be found in the OGC-ALC Delegation Agreement between the Commission and the Agricultural Land Commission (ALC).

Construction Timelines

Choose the ground conditions the intended works are to be conducted from the dropdown box.

LRMP

For Crown land applications, choose the Land and Resource Management Plan or the BC Land or Coastal Marine Plan within which the project falls from the dropdown box. If the required LRMP is not listed, enter LRMP name in field below dropdown box. If there is no LRMP for the specified area, select *none* and enter in the plan name in the space provided for *other*.

Resource Management Zone

For Crown land applications, enter the applicable resource management zones name. If the zone is general, enhanced, agriculture/settlement, special or protected, choose it from the dropdown box. Applications within special management zones or protected zones require additional application information, as outlined within the additional information requirements section of the manual.

Muskwa Kechika Management Area (MKMA)

Specify the pre-tenure plan name if the application lies within the MKMA.

Additional Information Requirements

Additional Information replaces the application categorization process.

The additional information requirements section directs the applicant to provide further details about the proposed program, and replaces the Commission's application categorization process.

Additional information requirements in the form of application attachments are required when oil and gas activities are located in areas of environmental sensitivity, or require deviations from Commission guidance.

If the proposed program does not fall within any of the identified areas, or doesn't deviate from recommended practices, the N/A (not applicable) box must be checked.

Applications that do not require any additional application information will be subject to the standard application review process by Commission staff.

For applications that do require additional application information for at least one reason, ,in addition to the standard application review, Commission staff will review the provided justification or mitigation strategy to ensure it meets the objectives for the identified area or guidance document.

Prior to completing this portion of the application, applicants are encouraged to review the procedures and practices established for each of the categories in this section, to determine whether proposed activities meet the established criteria.

A written justification must specify what standard is not being met, provide a rationale, and outline the steps that will be taken instead of the recommended practice.

Refer to the Environmental Protection and Management Guidebook for guidelines outlining the Commission's expectations in regard to mitigation strategies and when they may be deemed appropriate.

Spatial or Identified Areas

Special management or protected development zones, as per a BC Land or Coastal Marine Plan

All land and marine planning documents are available at the Integrated Land Management Bureau website.

BC Land or Coastal Marine Plans provide increased certainty and form the foundation for balanced solutions that meet economic, environmental, social and cultural needs throughout the province. They inform both government decision makers and those seeking natural resource development opportunities. Proposed oil and gas activities should be reviewed prior to application in the context of any applicable Land or Coastal Marine Plans. Projects should conform to the objectives set out for the plan management zone in which the project is proposed.

Where projects fall within special management zones or the equivalent, applicants are expected to provide a summary detailing why the activity must occur within the special management zone or equivalent; what planning and/or operational measures have and/or will been taken to mitigate or minimize impacts to the values identified for the zone, and how the zone objectives will be achieved or maintained.

Any issuance, approval, permit or authorization, by a Minister, Ministry or Agent of the Crown, of an oil and gas exploration or development plan, allocation, tenure, disposition, licence or any other instrument or document of oil and gas development or exploration allocation or management must be consistent with any pre-tenure plan which includes the subject area of the instrument or document of allocation or management.

Parks, protected areas and ecological reserves are viewable through the GeoBC gateway.

Park, protected area or Ecological Reserve

Oil and gas activities are not generally allowed within parks, protected areas or ecological reserves. However, there are extenuating circumstances where the Commission may consider applications for activities proposed within these areas.

Before submitting an application for oil and gas activity within a park, protected area or ecological reserve, contact the Commission's Operations Manager for the zone in which the activity is being contemplated to determine whether or not the Commission will consider the application.

In the event that the Commission will consider the application, it must be accompanied by a justification detailing why it is necessary to operate within the park, protected area or ecological reserve. In addition a mitigation strategy, outlining what measures will be taken to minimize or mitigate impacts to Crown values within the area, must accompany the application.

For a detailed outline of the Commission's expectations with respect to mitigation strategies, refer to the Environmental Protection and Management Regulation Guidebook.

Areas established under order under the EPMR will be viewable through the GeoBC gateway.

Areas Established by Order under the Oil and Gas Activities Act

In accordance with OGAA s.104, the Environmental Protection and Management Regulation may establish areas of interest, and may establish measures associated with these areas.

Applications for oil and gas activities in areas established by order under the Environmental Protection and Management Regulation must include a detailed mitigation strategy, illustrating how the application conforms to the order objectives established for the identified area. For a detailed outline of the Commission's expectations with respect to mitigation strategies, refer to the Environmental Protection and Management Regulation Guidebook.

Currently, the Commission has not identified any streams or waterbodies that require enhanced management.

Streams and Waterbodies Identified by the Commission

The Commission has identified waterbodies that may require enhanced management for various reasons. Waterbodies and areas requiring enhanced management for the purposes of *Water Act* authorizations are available via LRDW.

All crossings proposed within these areas require a mitigation strategy. Refer to the Environmental Protection and Management Regulation Guidebook for guidelines outlining the Commission's expectations in regard to mitigation strategies.

Guidance Requirements

Deviation from the Environmental Protection and Management Regulation Guidebook

Where operational or other constraints preclude the applicant from following the guidelines set out in the Environmental Protection and Management Regulation Guidebook, then applicants must explain the rationale for their deviation from the Commission standards.

The deviation must be allowable under legislation, regulations or guidelines and is to accompany the application and must include an explanation of why the guidelines can or will not be followed, what measures will be taken to ensure impacts to the value identified will be mitigated or minimized, and if appropriate a mitigation strategy.

Refer to the Environmental Protection and Management Guidebook for guidelines outlining the Commission's expectations in regard to conforming to the regulation and detailed information regarding mitigation strategies.

Regulatory Exemption Requests

Environmental Protection and Management Regulation Exemption

The Commission may exempt a person from one or more of the requirements of Part 3 of the Environmental Protection and Management Regulation, if complying with that requirement is not reasonably practicable(in accordance with Section 21 of the Environmental Protection and Management Regulation).

The exemption request may accompany the application and must include an explanation of why the regulation cannot be followed, what measures will be taken to ensure impacts to the value identified will be mitigated or minimized, and if appropriate a mitigation strategy.

Refer to the Environmental Protection and Management Regulation Guidebook for guidelines outlining the Commission's expectations in regard to conforming to the regulation and detailed information regarding mitigation strategies.

Pipeline and Liquefied Natural Gas Facility Regulation Exemption

A Commission official may exempt a permit holder from one or more of the provisions of the regulation if compliance with the provision is not reasonably practicable, or the exemption is in the public interest (in accordance with Section 14 of the Pipeline and Liquefied Natural Gas Facility Regulation).

The exemption request may accompany the application and must include an explanation of why the regulation cannot be followed.

Forestry Tab

The forestry tab provides administrative information on proposed timber activities and road use for activities on Crown land.

Fibre Utilization

Permit holders are encouraged to utilize merchantable timber, as outlined in Information Letter OGC 08-21 and must upload a fibre utilization plan as an attachment when there is new cut on crown land.

Stumpage

In accordance with the *Forest Act,* stumpage is payable for harvesting activity conducted under the Master License To Cut. The Ministry of Forests and Range bills the applicant according to the data submitted on the pipeline, application, or the data submitted on the pipeline as-cleared form which is required 60 days after construction completion.

The Ministry of Forests and Range Interior Appraisal Manual outlines the parameters related to stumpage.

Timber Marking

Timber marking must be carried out in accordance with the Timber Marking and Transportation Regulation.

Applicants are encouraged to incorporate forest and range tenure digital information into their plans.

Woodlot Tenures

The Applicant must ensure woodlot tenures affected by the project have been identified, and agreement has been reached with the licensee(s).

The woodlot holder must obtain cutting authority for oil and gas related harvesting from the Ministry of Forests and Range.

The following page describes the requirements to fill out the forestry tab in KERMIT.

Clicking on the new forestry entry button opens the application information window where new forestry details are entered.

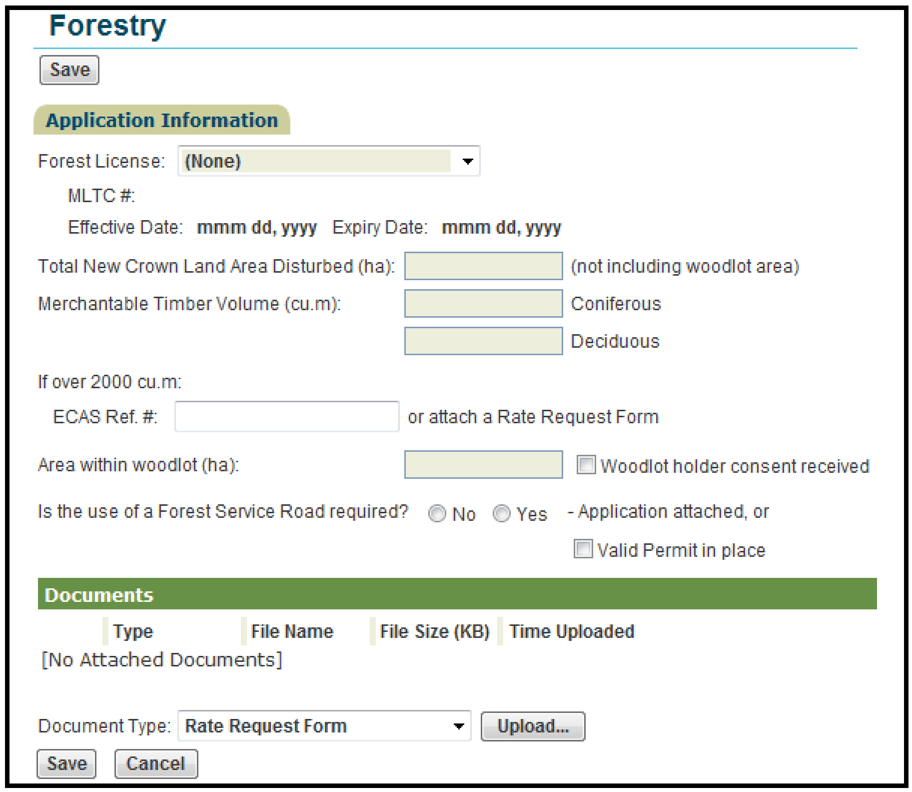


Fig. 6.4. Application information detail window on the forestry tab.

Application Information

Forest District

Select the applicable forest district that encompasses the project based upon the Provincial Forest District maps. The master licence to cut (MLTC) no., effective date, and expiry date will auto-generate.

MLTC No.

If the project is located on Crown land, indicate the forest district specific master license to cut tenure number assigned to the applicant by the Commission in the form M######.

New Crown Land Area Disturbance (proposed)
The area in hectares to be included in this section will be:

- The total area of Crown land, minus
- Any woodlot areas included in the project area and/or,
- Minus any previously cleared areas (where stumpage has already been collected)

This area must be clearly identified in the construction plan, and subsequently labeled as “new Crown land area disturbed” on the pipeline as-cleared submission form.

Merchantable Timber Volume
Estimate the volume of coniferous and deciduous timber in cubic metres.

If the merchantable volume exceeds 2000m^3 an appraisal is required. Refer to the Ministry of Forests and Range Interior Appraisal Manual. Appraisal data submissions are made directly to the Electronic Commerce Appraisal System (ECAS).

State the ECAS reference number if applicable or indicate if a rate request form is being submitted with the application as an attachment.

Woodlot Exclusions
The Commission cannot issue authorization to harvest within a woodlot tenure area. Authority to harvest within a woodlot tenure area must be obtained through the woodlot holder. Indicate the woodlot tenure area to be excluded from the cutting authority.

The area within a woodlot is *not* included as area of new Crown disturbance. This area must also be clearly marked on the construction plan.

Forest Service Road
Indicate whether or not the use of a forest service road is required, and if a valid permit is in place, or if an forest service road application is attached.

Where construction is proposed within a forest service road right of way, the applicant must obtain a works permit from the Ministry of Forests and Range.

Before connecting a road to a forest service road the applicant must obtain the consent of the Ministry of Forests and Range District Manager.

Road Use Permit

If a forest service road is required, a road use permit (RUP) must be submitted to the Commission as part of the pipeline application. The road use permit must indicate what sections of the forest service road the applicant requires authorization for.

When using forestry permitted roads (other than a forest service road), the applicant is required to notify the road permit holder of their intended activities. A road use agreement must be in place between the parties. A road use permit from the Commission is not required.

Documents

If required, upload a rate request form or a road use permit application.

First Nation(s) Consultation/ Aboriginal Community Notice Package

The Province of British Columbia has the duty to consult and where required accommodate First Nations whenever it proposes a decision or activity that could have potential impact to treaty rights or aboriginal rights recognized and affirmed by Section 35(1) of the Constitution Act, 1982. As an agent of the Crown, the Commission fulfills any provincial obligation to consult with First Nations prior to the authorization of activities under the Oil and Gas Activities Act, and related specified enactments.

Consultation

Consultation with Treaty 8 First Nations about any potential impact of their treaty rights by oil and gas activities are guided by agreements between the Commission and First Nations. First Nations agreements with the Commission can be found on the Commission First Nations Web Page.

For Treaty 8 First Nation Communities without agreements with the Commission or First Nation Communities who are not members of Treaty 8, the British Columbia Interim Consultation Process applies.

The Commission may consider engagement which has occurred between First Nations and the applicant as part of its decision making process

Consultation Timelines

The Commission consults with First Nations through the process and timelines established in the Consultation Agreements. The consultation process begins once the First Nation community receives the completed package. Commission internal reviews occur simultaneously with reviews conducted by First Nations.

If concerns are identified in First Nations responses, the Commission will, where appropriate, facilitate meetings with the Nation (involving the applicant as necessary) to discuss their concerns and proposed accommodation measures.

Where no agreement is in place, there is no defined timeline. The Commission strives to facilitate an efficient and effective consultation process.

Administrative Boundaries

Administration boundaries established through the agreements guide consultation for each First Nation. Where there is no agreement in place, the boundaries are guided by the Provincial Consultation Boundaries.

Notice packages are different from, and must not be confused with, Notification as defined within the consultation agreements with First Nations.

Notice Only Communities

There are four Aboriginal communities that the Commission provides information to regarding surrounding oil and gas activities in the form of a notice.

Notice Only Communities	
Abbreviation	**Aboriginal Community Names**
KLCN	Kelly Lake Cree Nation
KLFN	Kelly Lake First Nation
KLMSS	Kelly Lake Métis Settlement Society
FLFN	Fort Liard First Nation

First Nation(s) Tab

First Nation(s) Consultations/Notifications

An applicant must first determine which First Nations require consultation. Each First Nation requiring consultation must be entered in KERMIT.

To enter the appropriate First Nations information into KERMIT, click the new consultation/notification button, which opens the details window.

Select the affected First Nation from the dropdown menu.

If the First Nation required is not in the list provided, manually enter it into the text box labeled *other*.

If there is more than one First Nation, add another selection using the new consultation/notification button.

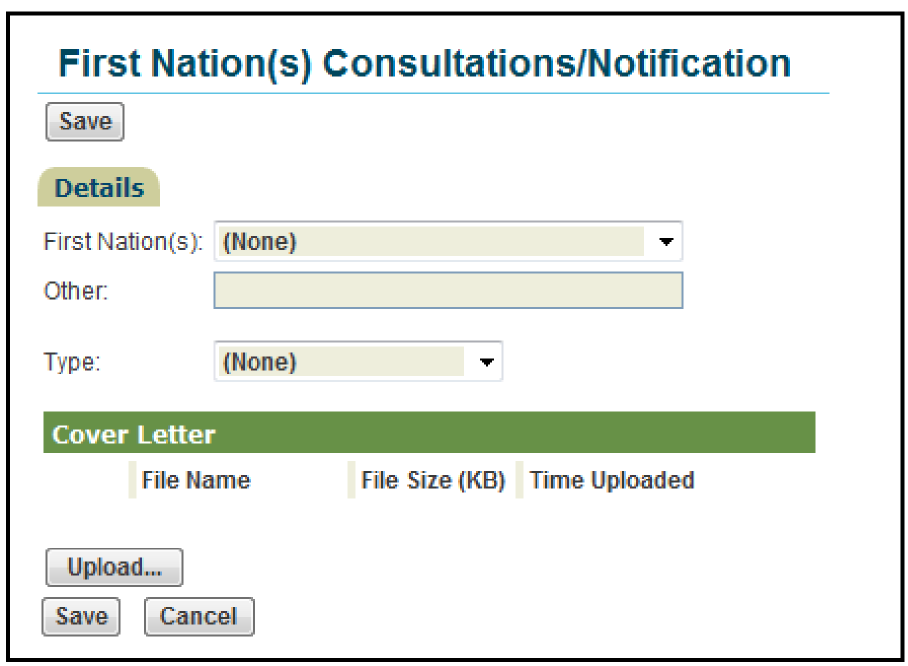
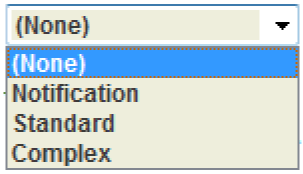


Fig. 6.5. Required information fields in First Nation consultation and notification detail window.



Select the application type from the dropdown list. If an application is a pre-assessment, choose notification.

For First Nations, other than Notice only Nations, that do not have agreements with the Commission, the application type should be entered as complex.

Cover Letter

Upload the First Nation package cover letter to KERMIT. Cover letters are found on the First Nation Forms section of the Commission's website.

First Nations Packages

Print Pipeline Application

Package Requirements
Each package must contain two cover letters for each community, a copy of the KERMIT application printout, and a copy of the following, if required with the application:

- Cover letter
- Construction plan, as described in Appendix C.
- Maps, 1:20,000 BCGS sketch; 1:50,000 program map and 1:250,000 access map.
- Archaeological assessment information form
- Archaeological reports (if available)
- Fibre utilization plan
- Other information included with the application as part of the additional information requirements

Once an application has been submitted electronically, the appropriate number of hard copy packages and maps will have to be submitted to the Commission with a clear cross reference to the electronic submission number provided with the initial electronic application.

These packages are required to be submitted to the Commission prior to the application being reviewed in KERMIT.

Each package must contain two cover letters for *each* consultation and notification area affected, a copy of the Application, and a copy of each attachment uploaded into KERMIT.

Stream Crossings Tab

The stream crossings section indicates whether approval to construct stream crossings is required and what level of information is required by the Commission to process the application.

Stream crossings required

All stream and waterbody crossings needed in order to carry out the oil and gas activity contemplated in the application must have Commission issued authorization under Section 9 of the *Water Act*. All stream crossings must be identified on the construction plan.

Stream crossing guidelines

Stream crossing guidelines are detailed within the EPMR Guidebook. Stream crossings consistent with the EPMR Guidebook are categorized as routine stream crossings.

Crossings not constructed to the standards outlined in the EPMR Guidebook are considered non-routine. A non-routine stream crossing deviates from the best management practices outlined within the EPMR Guidebook and requires a mitigation strategy or justification to be submitted as part of the additional application requirements. This mitigation strategy should articulate how the government's environmental objectives in regard to riparian values are being met.

For more details regarding the information required in this section, refer to the *Water Act* Application Manual (currently in development).

Routine Stream Crossings

Stream crossings that follow the Environmental Protection and Management Regulation Guidebook (and are therefore routine), are to be identified within this section.

Click on the new routine crossing button for each new stream crossing entry.

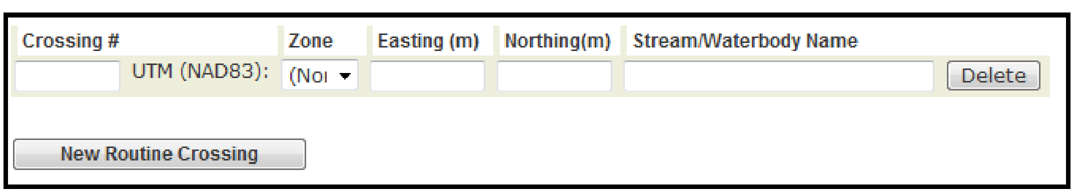


Fig. 6.6. Routine stream crossing information fields.

The crossing number must match that crossing identified in the construction plan. UTM Coordinates (NAD 83 CSRS) must be identified as well as the name of the stream or waterbody.

Non-Routine Stream Crossings

Stream crossings that do not follow the Environmental Protection and Management Regulation Guidebook, (and are therefore non-routine) are to be identified within this section.

The crossing number must match that crossing identified in the construction plan. UTM Coordinates (NAD 83 CSRS) must be identified as well as the name of the stream or waterbody. Select the crossing type from the dropdown menu which lists permanent, temporary, pipeline and other as options.

Select the riparian class, as defined within the Environmental Protection and Management Regulation Guidebook , from the dropdown menu beside stream details. Include the width in metres and the gradient as a percentage.

Select the access methods from the frozen/non-frozen access dropdown menu and indicate the type of pipeline. Follow the same steps for non-frozen access.

Click on the new routine crossing button for each new stream crossing entry.

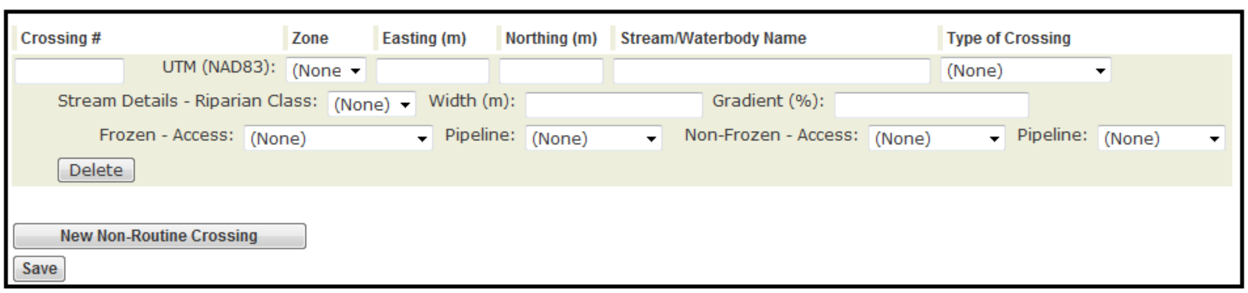


Fig. 6.7. Routine stream crossing information fields.

Consultation Tab

The consultation tab is where applicants must identify all landowners of the land on which the applicant intends to carry out the oil and gas activity. Landowners of land on which the applicant does not intend to carry out the oil and gas activity and were consulted or notified by the applicant; do not have to be included in this section of KERMIT.

Owner/Occupant

An owner/occupant entry must be created for each landowner of the land on which the applicant intends to carry out the oil and gas activity. Contact information, including the mailing address and the landowner's preferred contact method must be included.

This preferred contact method allows the Commission to notify landowners of permit determinations in a timely manner.

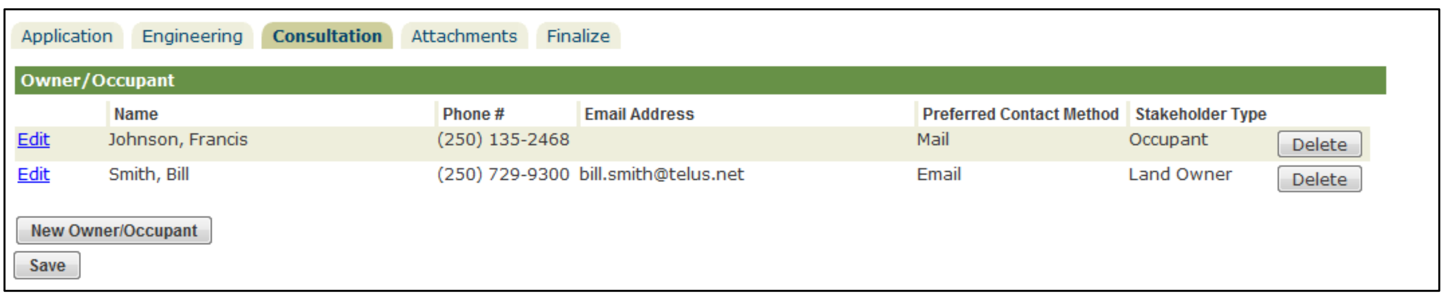


Figure 6.8. Landowner information fields.

Selecting the "New Owner / Occupant" button will bring up a popup window to allow the entry of the landowner's name, mailing address, email address, and preferred contact method.

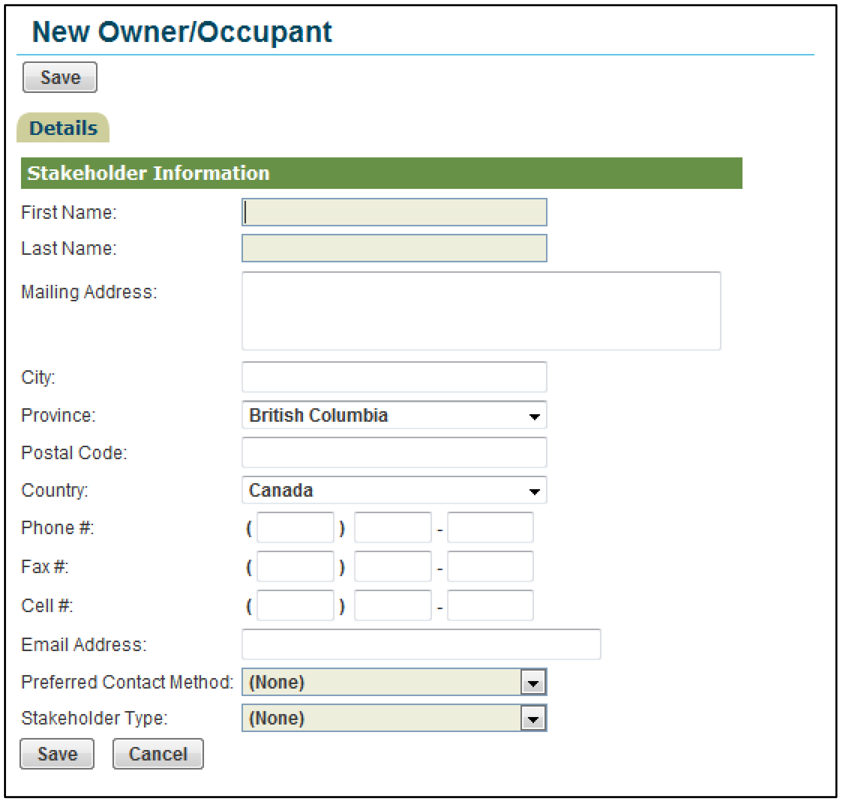


Figure 6.9. New Owner / Occupant screen.

Written Submissions

Written Submissions sent to the Commission and directed to the applicant prior to the application can be incorporated and uploaded into the KERMIT application, in person, or by email to OGC.WrittenSubmissions@gov.bc.ca.

Attachments Tab

The attachments tab is where applicants can upload any required documentation.

Missing Attachments

The missing attachments section indicates any outstanding documents that have not yet been uploaded to KERMIT. The documents listed must be attached in order to finalize the application.

Attachment List

The attachment list shows what documents have been successfully uploaded to KERMIT, and allows for the attachment of any outstanding items.

Archaeology
The archaeological assessment information form (AAIF), is completed by a permitted archaeologist and will indicate all recommendations for the program, and must be uploaded into KERMIT as an attachment.

Any archaeological assessments (such as the archaeological impact assessments (AIA)), that have been completed at the time of application should also be uploaded.

Assessment reports produced after the application has been made must be submitted promptly after the archaeologists have completed their assessment. For more information, refer to the Commission Archaeology Guidelines.

Consultation and Notification Written Report
The Commission requires applicants to involve the affected public in their operational planning. OGAA section 24(1)(c) states each permit application must contain a written report to summarize the results of the consultations carried out and/or the notifications provided to stakeholders.

The consultation and notification report is a written report, summarizing consultation and notification activities associated with the application and which must be submitted with the permit application. The written report consists of the written report cover sheet, line list, map and affected party responses and applicant replies. Specific information on the content and form of the written report is found in the Consultation and Notification Manual.

Each component of the written report (the written report cover sheet, the line list, the replies and responses, and the written report map) must be uploaded into KERMIT as an attachment.

A Permit holder must maintain the prescribed records and plans, and be able to produce records or plans at the request of the Commission.

Required Attachments
The following must be attached to all pipeline applications prior to submission to the Commission.

- Archaeological assessment information form
- Construction plan
- 1:20,000 sketch maps
- 1:50,000 BCGS map
- 1:250,000 access map
- Consultation and notification written report

Mapping Criteria
All maps should clearly indicate:

- Map date
- NTS and BCGS map sheet numbers indicated on legend and on the maps
- North arrow
- Version number (e.g., Revision #1, Amendment #1)

Application Specific Attachments
The following must be attached prior to submission to the Commission if required for the specific application, as outlined in this manual.

- ALC Schedule A Site Assessment
- Archaeological assessment report
- Chemical Analysis Sheet
- Crown land status sheet

- Emergency response plan document
- Fibre Utilization Plan
- First Nation notification form
- Flow schematic
- IOGC agreement
- Miscellaneous document
- Non-routine details
- P & ID
- Plot plan
- Stream crossing variance request

Attachment Definitions

Appurtenance Design

AN appurtenance is an item that belongs to the pipeline, such as a riser, pig sender, pig receiver or pump stations. The appurtenance design may be shown as a table or schematic that includes all specifications, codes and or standards and appurtenance location.

Proposed Pressure Test Design

This must indicate the pressure test medium and the calculations for the pressure test (in accordance with the pipeline design) If the proposed test design is gaseous, then a procedure and reasoning must be also be included.

Valve Location Design

Maps or schematics (plot plans) that indicate where the valves protecting the pipeline are. Not all pipelines will have Emergency Shutdown/Safety Devices (ESD), but where the ESD protecting the pipeline is situated on-site, plot plans are required.

Indicate set points to document that the pipeline is protected Block valves (manual, pneumatic) should also be included in the schematics, (i.e. indicated at river crossings) if they are present.

Pig Barrel Design

The design (typically in isometrics), of the pig barrel. Indicate the barrel slopes, the end of the trap, pile spacing for support, valves and kicker lines (to indicate whether it is a sender or a receiver).

ALC Schedule A Site Assessment

Under article 7 of the OGC-ALC Delegation Agreement, a Schedule A Site Assessment of soils must be documented prior to construction so that the reclamation of the land can be planned effectively and reclamation requirements can be achieved.

Archaeological Assessment Report

As described in KERMIT Attachments Tab

BCGS Maps
Every pipeline application must be accompanied by the complete set of maps and plans illustrating in detail the location and extent of planned activities at an appropriate scale.

Chemical Analysis Sheet
If a fluid containing hydrogen sulphide gas is to be transported in the pipeline, the chemical analysis of the gas or fluid to be transported and the expected release volume, expressed at standard conditions of 15 degrees C and 101.3 kPa, of hydrogen sulphide from the pipeline must be submitted with the application as a separate attachment.

Crown Land Status Sheet
As described in KERMIT land tab and Appendix C.

ERP Document
As described in the engineering tab.

Fibre Utilization Plan
A Fibre Utilization Plan or exemption request must be included with every application on Crown land requiring new cut.

First Nation Notification Form
This refers to the First Nations cover letter, as described in the First Nation(s) section.

Flow Schematic
Shows all the directions of the flow.

IOGC Agreement
This document is required if an agreement is required from Indian Oil and Gas Canada for the project.

Miscellaneous Document
Any document that is required that is not listed in this table. A Fibre Utilization Plan is a miscellaneous document.

P&ID
Process and instrumentation diagram.

Plot Plan
Shows where the riser/pipeline starts and ends on a site and how it leaves the site going into the right-of-way.

Stream Crossing Variance
As described in KERMIT stream crossing tab.

Finalize Tab

KERMIT will indicate if there are outstanding issues with the Application. Once the outstanding Issues are corrected, the application can be finalized.

Finalize the application and submit to the Commission.

If First Nations packages are required, the Commission will not review the application in KERMIT until the hard copy packages are submitted and applicable fees are received by the Commission.

7 Permit Revision and Amendment

When changes to a permit application are required, they can be made through the revision process. Changes to an existing permit must be made through the amendment process.

Applicants submitting revisions, or permit holders submitting amendments to the Commission must do so in accordance with the requirements and processes prescribed in the Consultation and Notification Regulation, and summarized in the Commission's Consultation and Notification Manual.

Both amendments and revisions require the submission of a new application form.

Application Revision

A revision is a change to a permit application *prior* to the Commission making a determination.

A revision requires the initial application to be negated when a new revised application is submitted. In order to revise an application, the applicant must request that the application be placed on 'pending' by the Commission. Once the application is pending, the Applicant can make the desired changes, following the same procedures as a new application.

Attach a letter of explanation as to what the revision is and why it is being requested.

Permit Amendment

An amendment is a change required *after* the permit has been approved by the Commission.

Amendments are submitted through KERMIT, and follow the same process (selecting Pipeline Amendment in the New Application list), as described in section 6 of this manual, along with the required fee.

Any change to an permit prior to or post approval resulting in the addition of total length of pipeline and/or pipeline segment(s) or an increase to the diameter class of a pipeline and/or pipeline segment(s) which covers a total distance of 2 kilometres or greater shall require the submission of a new permit application for the area of the change.

Consultation and Notification for Amendments

Major Amendment
Both OGAA and the Consultation and Notification Regulation outline consultation and notification requirements for permit amendments. If a pipeline permit amendment application meets the criteria of a major amendment, as outlined within Section 1 of the Consultation and Notification Regulation, the consultation and notification process must follow the process outlined within the regulation.

Amendment fee calculation worksheet in Appendix A.

Non-Major Amendment
If an amendment application does not meet the criteria of a major amendment, the amendment process outlined within Section 31 of OGAA must be followed. Before submitting an application for a minor permit amendment, the permit holder must provide notice to the landowner. This notice must:

- Provide a description of the proposed amendment
- Advise the landowner that he or she may make a submission to the Commission regarding the proposed amendment within 15 days of receiving the notice

After providing notice to the landowner, a permit holder may submit an amendment application to the Commission.

Amendments that do not meet the criteria of a major amendment, the Commission may require the permit holder to carry out additional consultation and/or notification with respect to the proposed amendment as per OGAA section 31. Any additional notification will be determined once the amendment application has been submitted to the Commission.

Consultation & Notification Written Report

If additional consultation and/or notification is required, a written report detailing steps taken must be submitted to the Commission at the conclusion of consultation and/or notification activities.

If a land owner makes a submission to the Commission in regards to a proposed amendment, the Commission will send a copy of the submission to the permit holder.

Effective Date

An amendment is effective on, and after the day it is made unless the landowner makes a submission to the Commission; in which case the amendment is effective on and after the 15th day after it is made.

Amendment Procedures

For amendments to surface disturbance or to cancel a pipeline, follow the procedures below. For all other amendment types, refer to the Pipeline Operations Manual.

Amendments to Surface Disturbance

Consultation and Notification may be required for amendments to surface disturbance in accordance with the Consultation and Notification Regulation.

1) Select *New Application* from the applications menu
2) Select Pipeline Amendment
3) Search application by desired method
4) Select the application to amend
5) *Modify Application* following the same procedures as a new application
6) Attach a letter of explanation as to why the amendment is being requested

Amendments to cancel a pipeline or a segment
Information for this section is currently in development.

Appendix A – Pipeline Permit Application Fee Worksheet

BC Oil & Gas COMMISSION

Pipeline Application Fee Calculation Worksheet – New Applications

Applicant: ______________________________ OGC File #: __________

Section 2(d) of the Fee, Levy, and Security Regulation establishes pipeline permit application fees. This pipeline permit application fee is dependent on both the outside diameter and length of the pipeline. This worksheet has been established to assist with the calculation of required pipeline application fees.

Determine the outside diameter of the pipeline contained in the pipeline application.

If the pipeline application has multiple outside diameters, choose the maximum outside diameter contained in the pipeline application. This value will be used to determine the fixed cost portion of the application fee. Check the appropriate box below to determine the fixed cost of the pipeline application, and enter the appropriate value in Field 1.

☐ < 152 mm (Enter $900 in Field 1)

☐ ≥ 152 mm (Enter $1200 in Field 1)

1 $__________

Determine the length of the pipeline contained in the pipeline application.

- If the pipeline application only contains pipe with an outside diameter <152 mm, complete part A
- If the pipeline application only contains pipe with an outside diameter ≥152 mm, complete part B
- If the pipeline application contains pipe with an outside diameter greater and less than 152 mm, complete part A and B

A). For pipelines with an outside diameter < 152 mm, enter the total length (to the nearest kilometre – with a minimum of 1 km) in Field 2. Multiply this value by $200, and enter the total in Field 3.

2 __________ km x $200/km 3 $__________

B). For pipelines with an outside diameter ≥ 152 mm, enter the total length (to the nearest kilometre – with a minimum of 1 km) in Field 4. Multiply this value by $400, and enter the total in Field 5.

4 __________ km x $400/km 5 $__________

Calculate the total pipeline application fee by summing together Fields 1, 3, and 5. Enter this total pipeline application fee in Field 6.

6 $__________

Please make cheque payable to the Ministry of Finance. The cheque is required to be submitted at the time of application.

THIS IS AN AUDITABLE DOCUMENT

Appendix B – Construction Plans

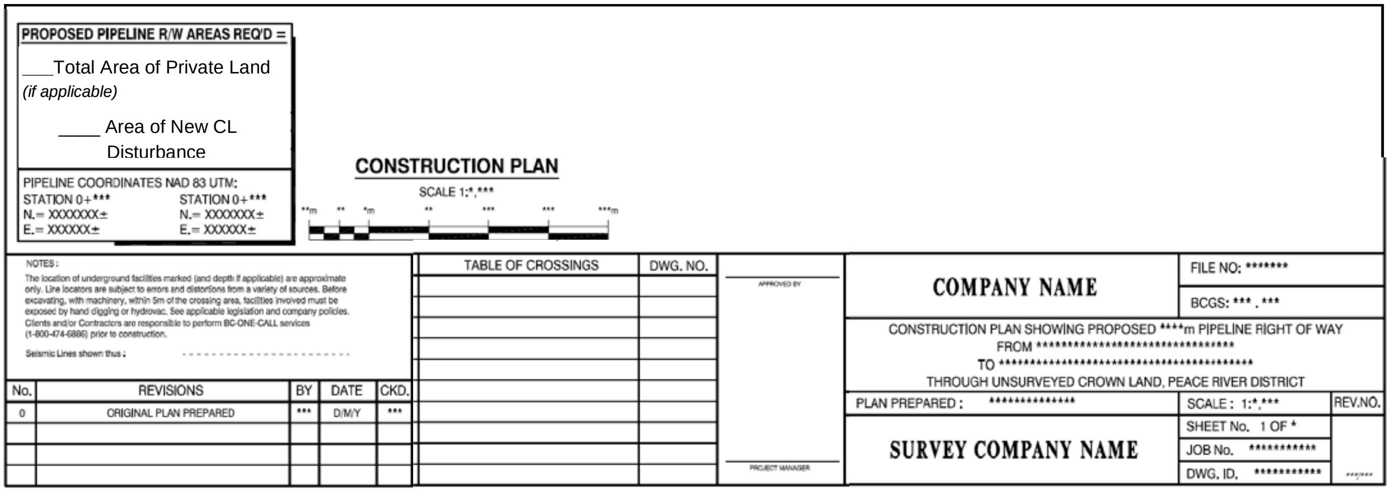


Figure B.1. Sample construction plan.

Construction Plan Requirements
Pipeline construction plans must reflect the total area required (including ancillary sites – e.g.: workspaces & decking sites)

in a bold outline. Within the plans (and ePASS), each polygon is to be shown in a bold outline.

The basic requirements for a pipeline construction plan must include the following information:

Title Block

- Applicant Company Name
- Applicant File No.
- BCGS Mapsheet
- Legal Description of Project
- Date Plan Prepared (YYYY/MM/DD)
- Scale Used
- Revision #
- Survey Company Name, Address & Phone Number
- Sheet # (i.e. 1 of 2)
- Survey Company Job Number

- Survey Company Drawing Number
- Table of Crossings
- Crossing Number
- Drawing Number
- (Approved By)
- (Project Manager)
- Notes
- Legend
- Revision Information
    - Revision Number
    - Revision Done By
    - Date of Revision
    - Checked By

Scale Bar
A scale bar should be placed just above the title block where it can be placed without interference of the drafted areas. (See Figure B.1)

Area Table (proposed pipeline R/W areas)

Summarize the following in the legend:

- The total area of private land (if applicable) equals the total area proposed.
- The area of new crown land disturbance (proposed) equals the total area of crown land plus the area of existing crown land disturbed.
- Indicate pipeline coordinates in NAD 83 UTM CSRS
    - Station 0 + 000 Northing & Easting
    - Station 1 + 123 Northing & Easting
    - Lateral from Station 0 + 035Northing & Easting
    - Lateral to Station 0 + 456 Northing & Easting

Plan Diagram
Indicate the following on the plan diagram:

- Dimensions and area of ancillary sites (decking sites, temporary workspaces, etc.)
- Dimensions and area of segments
- Location of Agricultural Land Reserve (ALR) if applicable
- Surveyed Crown land (district lots, sections etc. that are posted but not titled) and unsurveyed Crown land (mainly NTS) should be indicated
- Private land should indicate the owner name, parcel identifier number (PID#), title number and the areas of disturbance broken down into pipeline area, temporary workspace area, etc. within each parcel
- Cut blocks, range tenures, guide outfitter areas, Indian reserves, coal tenures and all other areas of special interest should be indicated

Labeling of Plan
The labeling of the plan should include:

- The NTS coordinates (units, block, group)
- Chainages
- Deflections
- Any crossing numbers (to correspond to the table of crossings), vegetation changes (brush/tree types)
- A north arrow

Review Corridor
Within the corridor, the pipeline, decking sites, workspaces, brush pushouts, or any other ancillary requirements must be indicated on the construction plan and listed in the plan legend.

To indicate the review corridor on the construction plan, use dashed lines and mark “Review Corridor”. The specific pipeline route may be altered within the review corridor but the width of the pipeline may not be altered to a width greater than that identified in the plan.

Chemical Analysis Attachment
If a fluid containing hydrogen sulphide gas is to be transported in the pipeline, the chemical analysis of the gas or fluid to be transported and the expected release volume (expressed at

standard conditions of 15 degrees C and 101.3 kPa), of hydrogen sulphide from the pipeline must be submitted with the application as a separate attachment.

Appendix C – Crown Land Status Sheet

The following represents an example of a Crown land status sheet, required as a pipeline permit application attachment.

Code and Name	Explanation
DL 2444: Vacant Crown Land	The District Lot is surveyed, however there are no tenures associated with this location and the land is held by the Crown
9612345: R/W, EnCana Corporation, pipeline Expires 2030	EnCana Corporation holds a Statutory Right of Way on File Number 9612345, expires in 2030
9601111: LOC, EnCana Corporation, well site Expires 2010	EnCana Corporation holds a Licence of Occupation for a wellsite on File Number 9601111, expires in 2010
8002475: PDR #100 – Petro Canada	Petro Canada has Petroleum Development Road #100 on File 8002475
0234547: Map Reserve, EMPR, Quarry	The Ministry of Energy, Mines and Petroleum Resources has established the exclusive right to an area for quarry purposes on File Number 0234547
615-300: Canfor Cutblock	Canfor has a cutblock under Ministry of Forests reference number 615-300
RAN073357: Grazing Licence, Joe Farmer	Joe Farmer has a Grazing Licence (issued by Ministry of Forests) under Number RAN073357
A65327: Small Business TSL	The Ministry of Forests, Small Business Unit, has designed area A65327 set aside for Timber Sales
410284: Patrick Sunshine, Coal Licence Expires 2009	Patrick Sunshine holds a Coal Licence from Ministry of Energy, Mines and Petroleum Resources under Licence Number 410284, expires in 2009

Figure C.1. Example Crown Land Status Sheet

Appendix D – Product Code Table

Table D.1. Pipeline product codes

Code	Product
AG	Acid Gas
CG	Coal bed Gas (Methane)
CO	Crude Oil
FW	Fresh Water
FG	Fuel Gas
HVP	High Vapour Pressure
JF	Jet Fuel
LVP	Low Vapour Pressure
ME	Methanol
MG	Miscellaneous Gases (air, ammonia, carbon dioxide, ethane, helium, hydrogen, HyS, nitrogen, steam)
ML	Miscellaneous Liquids (produced water, sulphur slurry)
MP	Multiphase
NG	Natural Gas (less than 1 mole % of H2S content)
OE	Oilwell Effluent
OTH	Other – identify the product type
PW	Produced Water
SC	Sour Crude Oil
SE	Sour Oilwell Effluent
SG	Sour Natural Gas (1 mole % or more of H2S content)
SHC	Sweet Hydrocarbon Condensate
ST	Sweet Gas

Appendix E- Review Corridor Examples

Environmental upgrades and field changes will no longer be accepted by the Commission.

Review Corridors
Review Corridors present an opportunity for applicants to achieve the greatest range of flexibility post approval. Utilizing this approach effectively can greatly reduce the need for permit amendments.

A review corridor allows a permit holder the freedom to manage the location and size of the oil and gas activity through effective preliminary planning.

Within the review corridor, applicants will be required to satisfy all pre-application requirements such as environmental and archaeological evaluations. Consultation & Notification requirements, as per the Consultation and Notification Requirement, are of particular importance as any potential modifications to an approved activity must be consistent with those aspects of the application contemplated during the consultation and notification process. Therefore, it must be stated that applications will only be approved to the extent contemplated during the consultation and notification process.

Mapping Review Corridors
Review Corridors are to be mapped using a dashed line indicating “review corridor” on the construction plan. (See sample map in Appendix).

The application must clearly identify the proposed activity or activities, their proposed location(s), and the total proposed area of each activity within a defined review corridor. E.g., decking sites - 0.48 ha.

A review corridor shown on a construction plan should include the proposed location of future activities where applicable. E.g. The location of a future pipeline within the wellsite review corridor area.

Sample Map - Wellsite Review Corridor

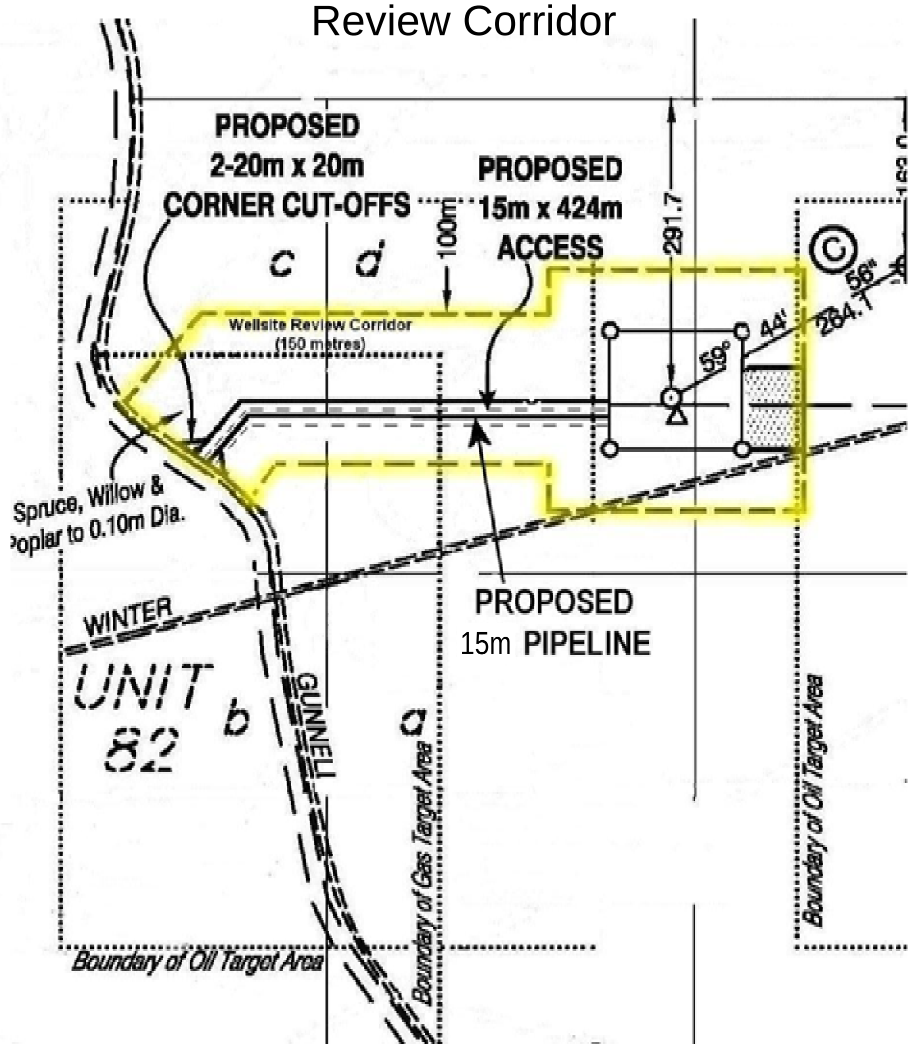


Figure E.1. Wellsite Review Corridor Map

Sample Map – Ancillary Works and New Crown Land Review Corridors

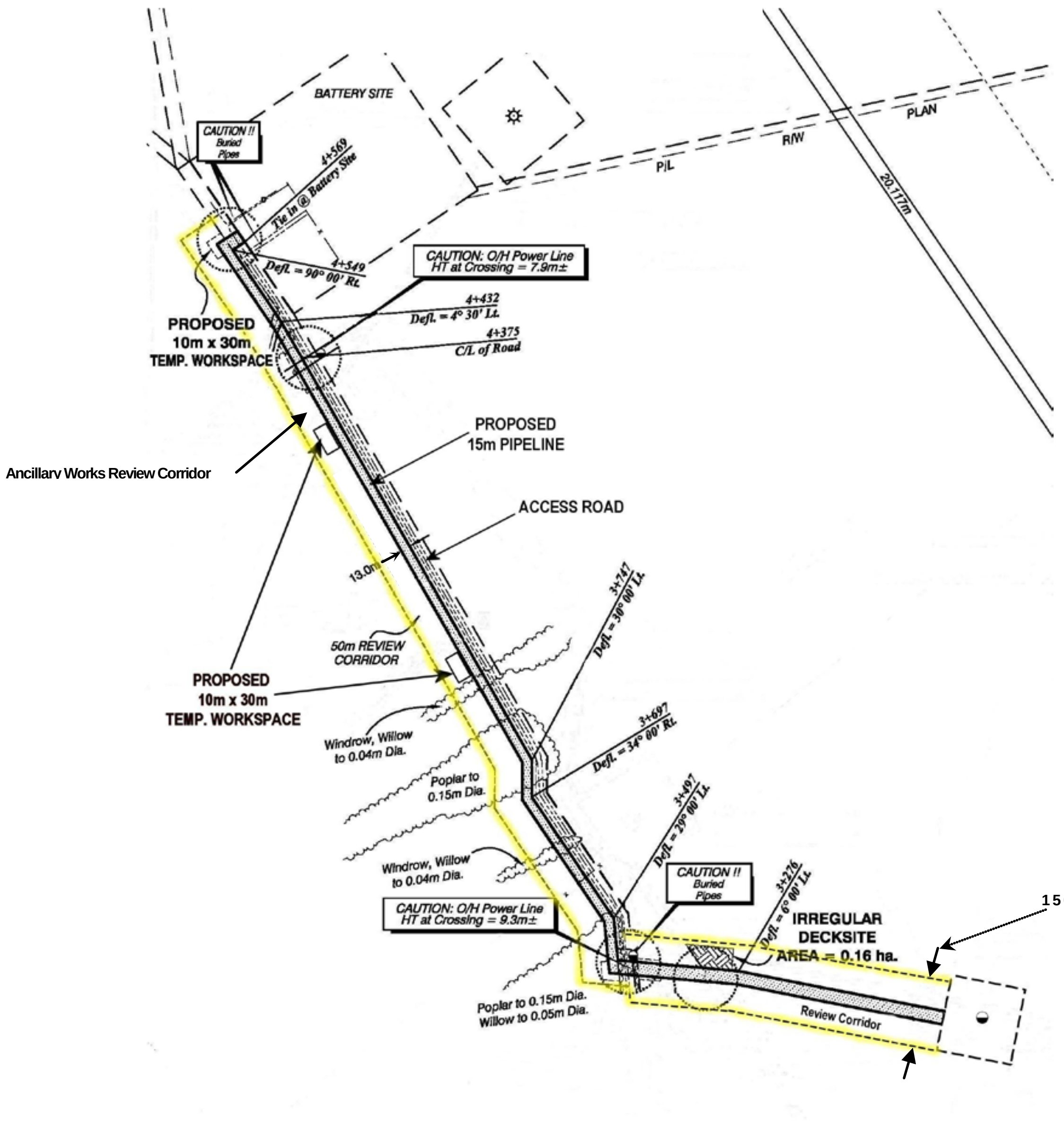


Figure E.2. Ancillary Works and New Crown Land Review Corridors Map

Appendix F- Identifying Pipeline Segments

If an Applicant requires more than five segments for a single application they must contact the Operations Manager for the specified area for written permission.

Identifying Known Pipeline Segments
This section allows companies to identify each segment of pipe, including new pipe that will be built in existing rights of way. Pipelines will be specifically denoted by the project number and segment number.

The applicant must refer to the Pipeline Operations Manual for complete engineering and segment information.

The diagram below provides an example of how segments are identified. Segment 1 runs from the left hand well A to the facility D. Segments 2 and 3 run from wells B and C into segment 1.

Identify no more than 5 segments in each application, including fuel gas lines.

Note: pipe length is actual pipe, not surface land length.

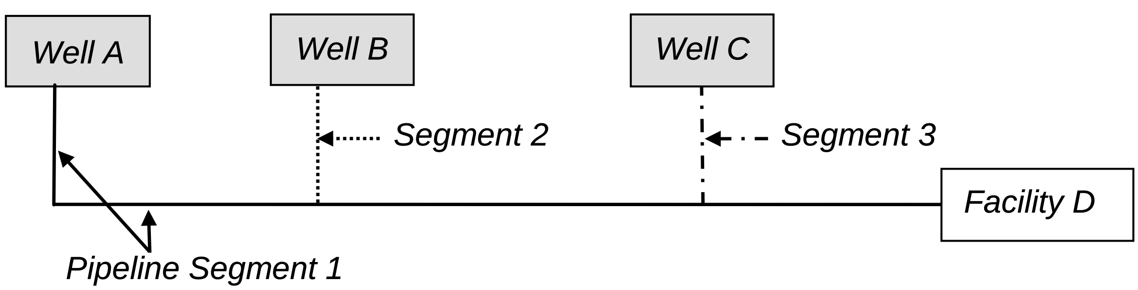


Figure F.1. How to identify known pipeline segments.

Identifying Unknown Pipeline Segments
The purpose of this section is for companies to identify each segment of pipe, including new pipe that will be built in existing rights of way. Pipelines will be specifically denoted by the Project Number and Segment Number.

The diagram below provides an example of how segments are identified. Segment 1 runs from the left hand well A to the facility D. Segments 2 and 3 run from wells B and C into segment 1. Identify no more than 5 segments in each application, including fuel gas lines.

If an applicant requires more than 5 segments for an application they must contact the Operations Manager for the specified area for written permission.

Note: pipe length is actual pipe, not surface land length.

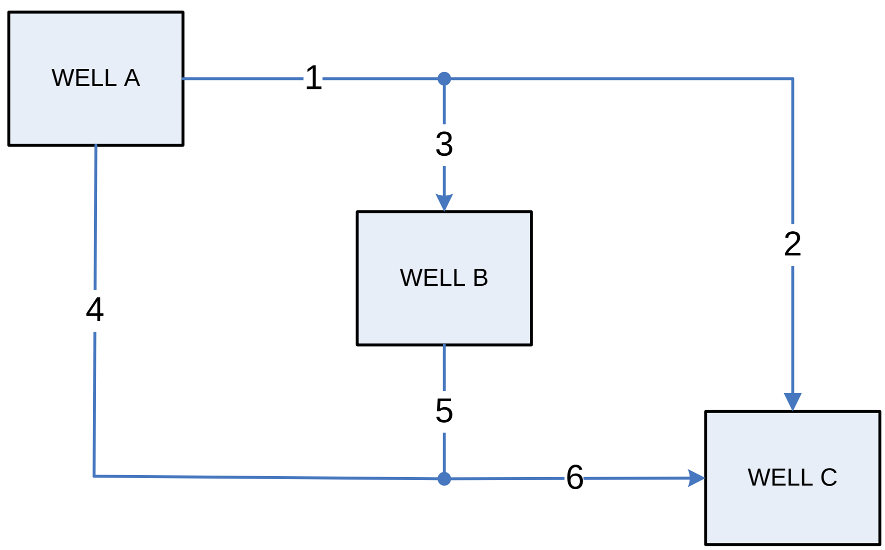


Figure F.2. How to identify potential pipeline routes/segments (example).

Example: In the above situation tying in wells A, B and/or C together could occur in a number of ways. In order to provide the applicant with maximum flexibility, each route between points is identified as a segment. This enables an applicant to tie in the wells required.

See Appendix D for a table of product codes.

Appendix G - Engagement Log Example

First Nation Engagement Log

The Commission recommends keeping a log of all engagement and attempts to engage. An engagement log can greatly benefit the process flow when the First Nation has been advised that the applicant's engagement activities will be shared with the Commission. The engagement log may be considered in the decision making process.

Below is a description of the potential information fields in an Engagement Log and example format that may be used.

Communities	List which communities require engagement.
Attempts to Engage	Provide a description of what efforts to engage were made and whether or not engagement occurred.
Date	List the corresponding dates of attempted and actual engagement.
Meeting Successfully Held	Indicate if meetings resulted from attempts to engage.
Meeting Topics	Provide a description of what topics of discussion arose during the meeting.
Attendees/ Parties to Meeting	List all of the people attended, or were involved in the meeting. This should include parties on both sides of the discussion.
Meeting Location	Indicate where the meeting took place; for example, at a specific location or via teleconference.
Issues Raised	List any potential adverse impacts identified during discussion.
Commitments Made	List any mitigative measures, or other commitments offered.

First Nation Engagement Log									
Communities	Attempts to Engage	Date	Meeting Successfully Held?		Meeting Topics	Attendees/ Parties to Meeting	Meeting Location	Issues Raised	Commitments Made
			Y	N					

Appendix J2

OGC PIPELINE OPERATIONS MANUAL

PIPELINE OPERATIONS MANUAL
March | 2011

OGAA Version 1.3

Contents

Manual Revisions

Summary of Revisions

The Pipeline Operations Manual has been revised based upon feedback to provide clarity in terms of requirements and process. Structural changes by section are highlighted below.

Applications received on or after the effective date will be required to meet the revised application standards.

Effective Date	Section	Description/Rationale
15-Oct-2010	4	Added sidebar explaining why the Commission no longer requires Major Licensee Comment Sheet.
15-Oct-2010	3	Clarified distances for more than one facility and for 9 or more wells (Table 1).
15-Oct-2010	4	Clarified distances for more than one facility and for 9 or more wells (Table 2).
1-Dec-2010	Pg. 65	Amendment restriction for risers sites removed.
1-January-2011	11	Replaced the IMP information in Section 11 with updated information to correspond with Commission Directive 2011-01.
1-March-2011		
	8	Revised Post-Construction. Removed Certificate of Operations, revised the information under Post-Construction Plan Submission
	5	Added Riser Location information and example figure.
	10	Amendment to Install a Mid-Point Riser: removed “This riser installation must fall wholly within the pipeline right-of-way. If this riser does not fall within the right-of-way a facility permit will be required for the riser site.”
		Facility Schedule A updated to Facility Schedule 1.
	10	Amendment – Mid-Point Riser: removed This riser installation must fall wholly within the pipeline right-of-way. If this riser does not fall within the right-of-way a facility permit will be required for the riser site.
	11	Updated IMP information.

1 Preface

Purpose

This manual has been created to guide users through Commission processes and procedures. It also serves to highlight changes in process, procedure, requirements and terminology resulting from the Oil and Gas Activities Act (OGAA).

For users already familiar with the Commission application process, this manual provides a quick reference highlighting the steps required to complete specific tasks. For users less familiar, this manual presents a complete overview of Commission requirements and provides links to more detailed material.

This manual is not intended to take the place of the applicable legislation. The user is encouraged to read the full text of legislation and each applicable regulation and seek direction from Commission staff, if and when necessary for clarification.

Scope

This manual focuses exclusively on requirements and processes associated with the Commission's legislative authorities, and do not provide information on legal responsibilities that the Commission does not regulate. It is the responsibility of the applicant or permit holder to know and uphold its other legal responsibilities.

How to Use This Manual

This manual is divided into sections which are organized chronologically, and match the order of the steps which applicants and permit holders will follow when engaging in oil and gas activities.

Beginning with pre-application, the manual takes the user through the steps of application preparation and submission; and permit revision and amendment. This manual describes what permit holders must take into consideration while planning pipeline construction, operational, and maintenance activities. Each section begins with a brief overview describing the content which follows.

Section 2 **Pre-Application Requirements** outlines what companies new to British Columbia need to have in place before applying for oil and gas permits.

Section 3 **Pipeline Construction and Operation Process** illustrates and explains the key steps in the construction and operation of a pipeline.

Section 4 **KERMIT Overview** shows the basic components that are general to all KERMIT submission types.

Section 5 **Pre Construction** details regulatory planning and notification requirements that must be completed before a permit holder commences pipeline construction.

Section 6 **During Construction** details the two types of pressure tests submitted for pipeline operation, shop test and pressure test.

Section 7 **Commencing Operations** details what the permit holder must submit prior to the operation of a pipeline through the Leave to Open process.

Section 8 **Post Construction** Shows how to complete the As-Cleared Plan Form, and details requirements for issuance of Licence of Occupation, Issuance of Certificate of Operations, and As-Built submission.

Section 9 **Notice of Intent** Shows how and when to submit the various notices required when proposing operational changes, modifications and repairs.

Section 10 **Pipeline Permit Engineering Amendments** details how to submit changes that require a pipeline permit amendment in KERMIT.

Section 11 **Integrity Management and Damage Prevention Programs** describes what is required of permit holders when implementing these programs.

Section 12 **Incident Reporting** explains the process for reporting incidents and spillage.

Section 13 **In-Line Testing** details the requirements for on-lease and off-lease testing.

Additional Guidance

Guidance for submitting applications for pipeline projects within the jurisdiction of the Commission is located in the Commission's Pipeline Permit Application Manual.

Guidance for pipeline tenures is found in the Commission's Corporate Land Management Manual.

The glossary page on the Commission website provides a comprehensive list of terms.
The appendices contain documents to be used as reference when compiling information required by the Commission.

Other navigational and illustrative elements used in the manual include:

Hyperlinks: Hyperlinked items appear as blue, underlined text. Clicking on a hyperlink takes the user directly to a document or location on a webpage.

Sidebars: Sidebars highlight important information such as a change from an old procedure, new information, or reminders and tips.

Figures: Figures illustrate a function or process to give the user a visual representation of a large or complex item.

Tables: Tables organize information into columns and rows for quick comparison.

Frequently Asked Questions
A Frequently Asked Questions (FAQ) link is available on the Commission OGAA page. The information provided is categorized into topics which reflect the manuals for easy reference. Please consult the FAQ page before contacting the Commission to help keep response times short.

Feedback
The Commission is committed to continuous improvement by collecting information on the effectiveness of guidelines and manuals. Clients and stakeholders wishing to comment on Commission guidelines and manuals may send constructive comments to OGC.Systems@gov.bc.ca

2 Pre-Application Requirements

Because the Master Licence to Cut Application and the ePASS submission processes are generally not applicable to the pipeline operations processes, information on these subjects is only found within the Pipeline Permit Application Manual.

Companies applying to engage in oil and gas activities in British Columbia (B.C.) for the first time must ensure all pre-application requirements have been met. These include the New Permit Holder Application Form, and a Master Licence to Cut Application (MLTC), and ePASS submission.

In addition to these pre-application requirements, the Commission may require a company to provide a security to ensure the performance of an obligation under the Oil and Gas Activities Act (OGAA) prior to, during, or after the permit application process, in accordance with Section 30 of OGAA.

Engineering firms new to B.C. must also complete the applicable portions of the new permit holder application form before they can submit engineering details on behalf of an oil and gas applicant or permit holder. Once completed, engineering firms will be eligible to access the Commission's KERMIT database.

New Permit Holder Application Form

The new permit holder application form captures general administrative and corporate registry information.

Completed New Permit Holder Application Forms and required attachments are to be submitted to the Commission's Corporate Land Management Unit. New Permit Holder Application Forms have to be processed by the Commission before any permitting documentation is submitted to the Commission.

For more information on the New Permit Holder Application Form, please refer to the Commission's Corporate Land Management Manual (currently in development).

BC One Call

Section 7 of the Pipeline Regulation states that a permit holder must not operate a pipeline approved by a permit unless the permit holder is a member of BC One Call.

For more information on BC One Call, visit the BC One Call website.

3 Pipeline Constructions and Operation Process

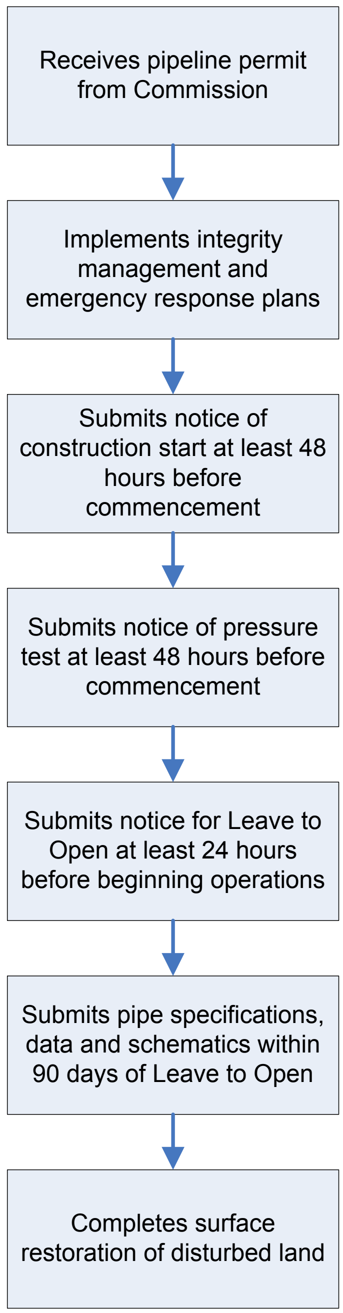


Figure 3.1. An overview of the pipeline permit pre-construction; construction and operation activities. Beginning with notifying the Commission of construction commencement through to decommissioning a pipeline.

4 KERMIT Overview

KERMIT is the Commission's Knowledge, Enterprise, Resource, Management, Information and Technology data system.

KERMIT enables electronic submission of applications, performance and compliance data submission, and electronic workflow management.

For additional information, the applicant or permit holder should refer to the [Kermit Application page] on the Commission website. This page provides links to frequently asked questions about KERMIT, an external overview document which illustrates how to navigate within KERMIT, and a company administration document which illustrates how to manage KERMIT accounts.

KERMIT Functions

The information requested in Conditional fields are not required in every instance, but must be answered if the conditions of the project indicate it.

Fields

Most mandatory fields display a shaded background. As project specific information is entered, some fields that are conditional may become mandatory and appear under finalize tab as an outstanding issue.

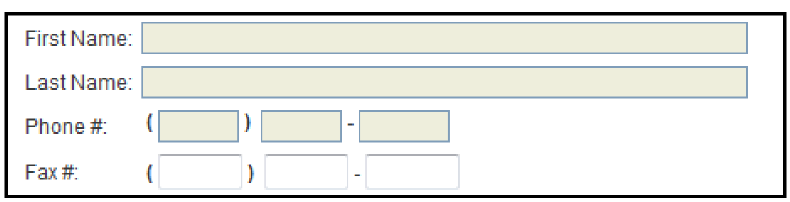


Fig. 4.1. Shaded mandatory fields in KERMIT

Date

All editable date fields have a calendar button which opens an active calendar. Select a date, or enter it manually in the MMM/DD/YYYY format.

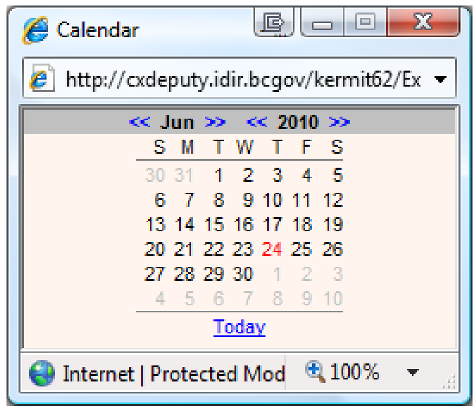


Fig. 4.2. Calendar window

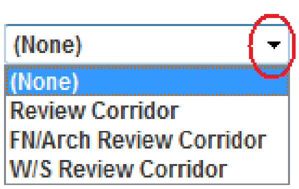
Buttons and Menus

The save button 

updates the application. This allows the user to enter information, save it and return later to edit or complete the application.

The find button 

opens a pop-up window used to search for a detail.



Dropdown menus contain a list of pre-set values that the user can choose from. Click on the down arrow to see the list, and select.

Search

The search function in KERMIT provides a way to link an application, notice or activity to an existing site or project.

Step one of the search function is the same for applications and Notices of Intent. Applicants or permit holders may search for a specific project by entering information in any of the open search fields. The more specific the information used to search with is the more specific the search result will be.

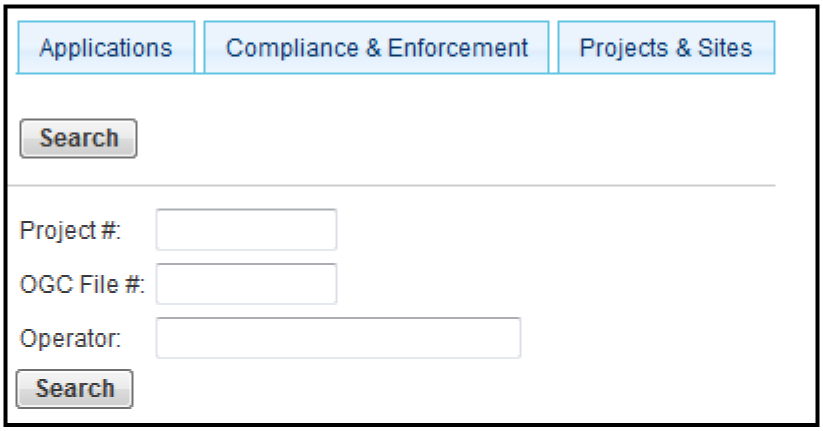


Fig. 4.3. KERMIT search fields.

Attachments Tab

The attachments tab allows users to upload documents and relate them to the job. To attach a document:

1) Choose the document type from the dropdown menu.
2) Click the upload button.
3) Type the name and extension of the file, or click the browse button to open a search window to search for a document.
4) Click the upload button again to upload the document.
5) Fill in the file reference, author name and author's email address
6) Click the save button to finalize the attachment.

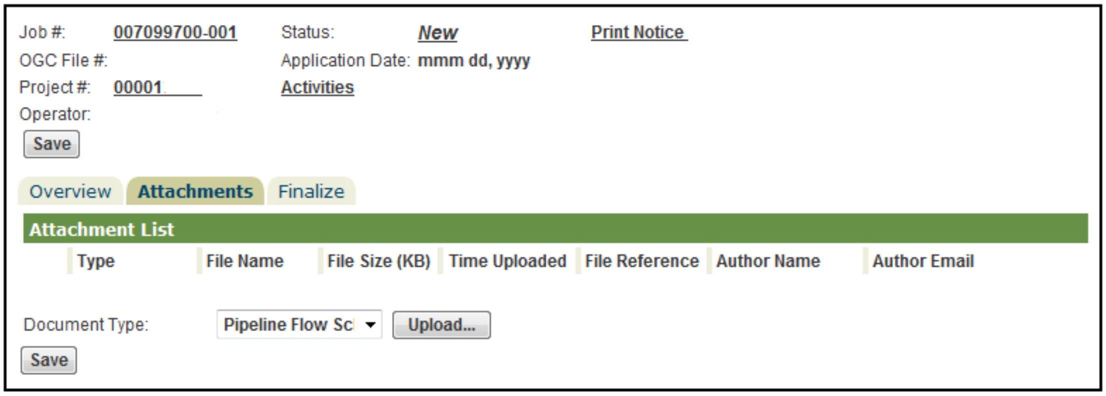


Fig. 4.4. Pipeline attachments page

Once the document is uploaded, KERMIT will show the file type, name, reference and size. It will also indicate the time the file was uploaded, and the author's name and email.

Finalize Tab

KERMIT identifies any outstanding issues associated with the application. Once all outstanding issues are corrected, the application can be finalized.

If First Nations packages are required as part of the submission, the Commission will not review the application in KERMIT until the hard copy First Nation packages are submitted and applicable fees are received by the Commission.

KERMIT Header

At the top of pipeline operation submissions in KERMIT is the header. The header displays:

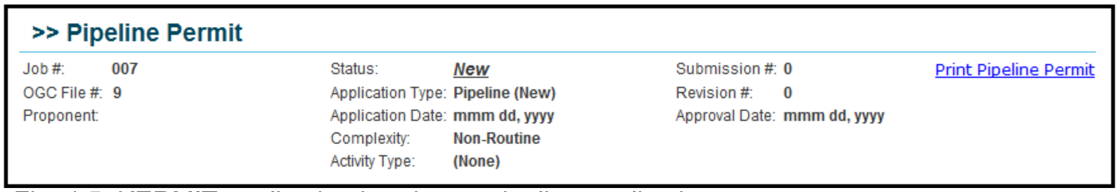


Fig. 4.5. KERMIT application header on pipeline application page.

Job # The job number is used to identify a specific pipeline or facility. A unique job number will be created for each submission associated with the project. The user can click on the link to navigate to that job.

OGC File # The OGC file number is a seven digit number used to identify related surface rights applications. For example, 9700000.

Proponent The proponent is the company that holds or is applying for a pipeline permit.

Status Status displays what stage the job is in.

Application Type Application type displays what type of permit is being applied for.

Application Date Application date displays the date the application is officially submitted.

Complexity Complexity displays whether the application is classified as Routine or Non-Routine.

Activity Type Activity type displays

Submission # Submission number displays

Revision # Revision number shows how many revisions have been made to the permit application.

Print Pipeline Permit Print Pipeline Permit is a hyperlink that allows the applicant to view and print a hard copy of the application submission.

5 Pre-Construction

For information on the requirements for integrity management and damage prevention programs, see Section 10.

The pre-construction section of this manual outlines requirements that must be met prior to the commencement of pipeline construction. This includes, Emergency Response Plans and the Notice of Construction Start and approval from other jurisdictions.

To help distinguish between upstream and downstream activities to follow, a brief definition is provided.

Defining Upstream and Downstream Activities

The Commission’s operational requirements differ depending on pipeline categorization; upstream or downstream. This section provides definitions to distinguish between the two categories.

Upstream Activity
The majority of Commission regulated pipelines are categorized as upstream activities. Upstream activities involve the recovery, production and gathering of petroleum and natural gas. Upstream activities require metering to track production for royalty purposes.

Downstream Activity
Downstream activities refer to selling and distribution of natural gas and the refining of petroleum. Downstream activities do not require metering for royalty purpose, as metering occurred as part of the product gathering process.

Piping used to transmit natural gas at less than 700 kPa to consumers by a gas utility is not regulated by the Commission. Please contact BC Utilities Commission for more information on registration of the gas utility pipelines.

Approval from other Jurisdictions

The Commission may authorize a permit holder to construct a pipeline across, along, over or under any highway, road, public place, railway, underground communication or powerline, or another pipeline.

Despite this permission, the permit holder still may require authorization for the use or occupation of land from the affected jurisdiction. Applicable legislation should be consulted.

Implement Emergency Response Plan

An Emergency Response Plan (ERP) must be prepared and implemented before any pipeline is open for service.

Pipelines with a hydrogen sulphide concentration of 10 moles per kilomole or greater (≥1%), require a sour service Emergency Response Plan respecting the Emergency Planning Zone to be submitted to the Commission before operation begins (in accordance with Section 8 of the Pipeline Regulation).

Pipelines with a hydrogen sulphide concentration of less than 10 moles per kilomole (<1%) will require at a minimum, a corporate ERP.

The ERP must also be revised for any applicable pipeline permit amendments (e.g. Change of Service).

For more information on Emergency Response Plans and Emergency Planning Zones, refer to the Commission's Emergency Response Plan Requirements document.

Notice of Construction Start

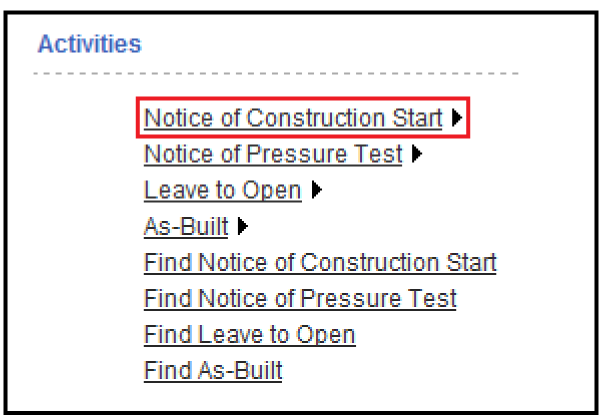
Every Notice of Construction Start (NCS) must:

- Be submitted prior to commencement of clearing land and/or the set-up of equipment on location, and *cannot* be used for multiple projects
- Be submitted 48 hours prior to the construction start of the project/segment(s) for both downstream and upstream activity per Section 4(1)(a) of the Pipeline Regulation
- Quote a project number and include all segments being constructed

A Notice of Construction Start is submitted through the Commission's KERMIT database. The instructions which follow detail how to complete and submit this notice.

Go to Notice of Construction Start

1) From the Applications page, go to the Activities group
2) Select Notice of Construction Start
3) Select NCS (Upstream or Downstream) for project
4) Search for the project, OGC file number or operator
5) Select new NCS for the associated project or OGC file number to open the Notice of Construction Start page



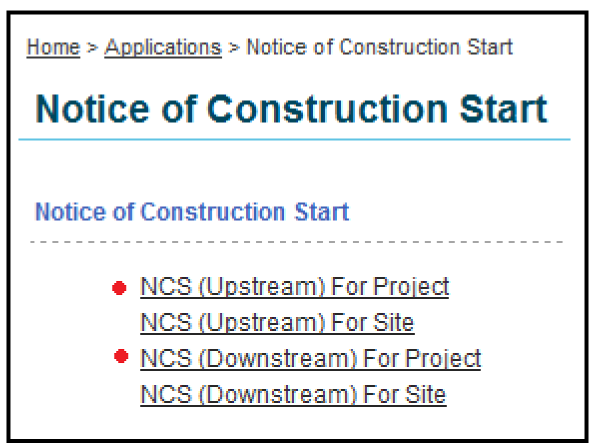
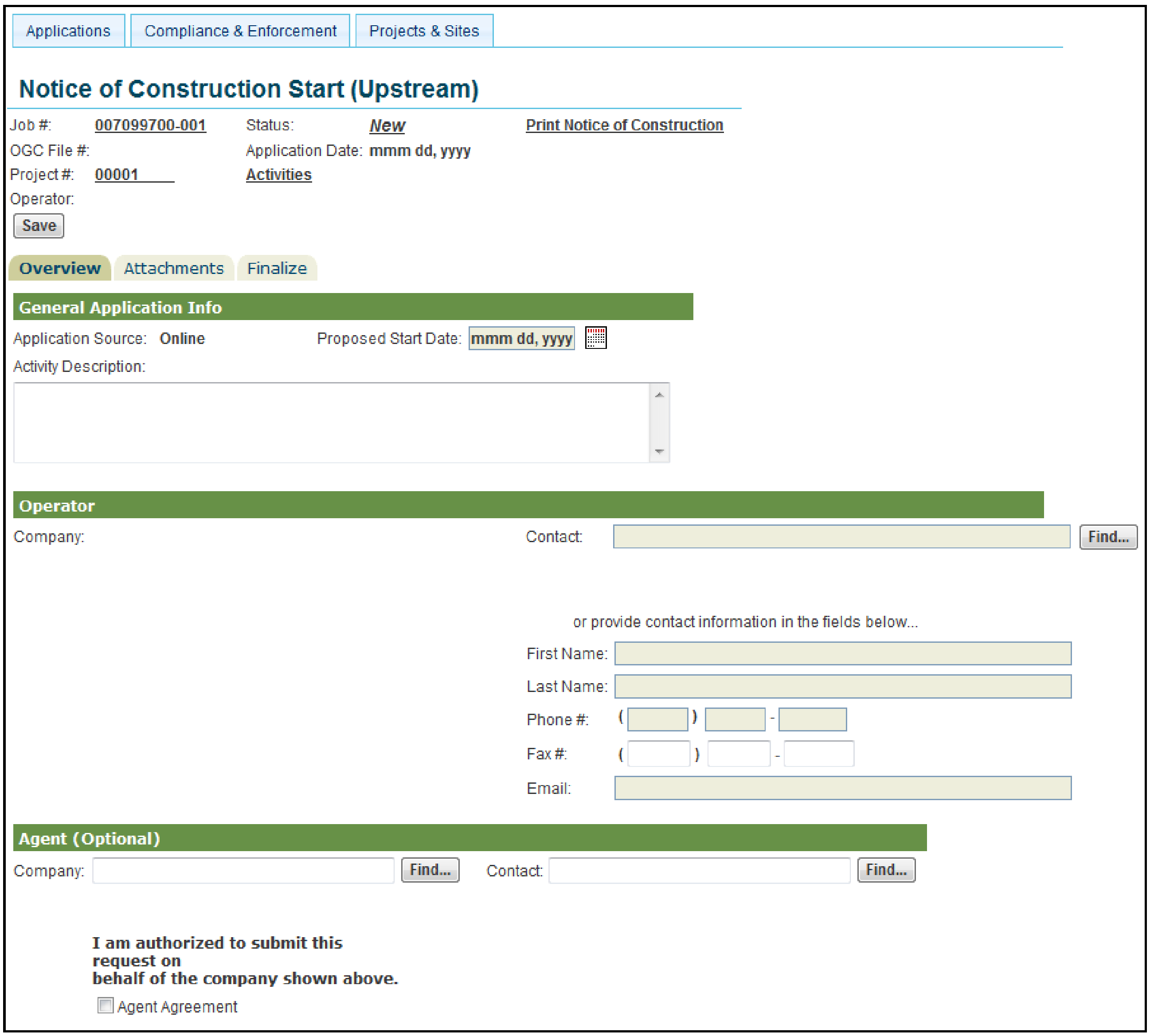


Fig. 5.1. Open a Notice of Construction Start

Notice of Construction Start (NCS) Page

The Notice of Construction Start for the project has been opened, and a job number has been generated. The page contains categorized tabs where information is to be entered. The tab categories are overview, attachments and finalize.

In this section the overview tab is covered in detail. The attachments and finalize tabs which are general to all pipeline operation submissions are covered in the KERMIT overview section of this manual.



Overview Tab

The overview tab identifies permit holder and land/referral agent information, as well as project specific details. For most pipeline operation submissions, the information fields are the same from general application info to field representative. The pipeline activity section houses information fields that are specific to the submission.

General Application Info

This section shows the source of the application. Enter the proposed construction start date and in the Activity Description box enter a summary of the activity which includes the location of where the pipeline construction will commence.

Operator

The Operator section captures permit holder information.

Company name and information should appear automatically. If the company name does not appear, or the address is incorrect, the permit holder must contact the Commission's Corporate Land Management Unit to update the information prior to application/notice submission.

If a company contact has previously been entered into the Commission database, use the find button to search for the contact. If no contact is found, enter the information manually.

> The permit holder that holds the surface tenure is accountable for the accuracy of the application content entered into KERMIT. If the permit holder chooses to use outside agents or consultants, the permit holder remains accountable for the accuracy of the application.

Agent (Optional)

If an agent submits on behalf of the permit holder, a letter of authorization from the permit holder must be on file at the Commission prior to application submission.

Company name and information should appear automatically. If the company name does not appear, or the address is incorrect, the permit holder must contact the Commission's Corporate Land Management Unit to update the information prior to application/notice submission.

If a company contact has previously been entered into the Commission database, use the find button to search for the contact. If no contact is found, enter the information manually.

Indicate in the check box if there is an agent agreement in place.

Field Representative

Enter the full name and phone number of the Field Representative for the project.

Pipeline Activity

Click the segment number to open the project detail window. Here information in the details, activity, location, wells, and farm taps tabs can be viewed.

Indicate if the pipeline is surface or buried in the dropdown menu.

For each affected pipeline segment, check the include checkbox to ensure that the associated information will be included in the application. KERMIT will not accept the submission if the details are not included.

If the activity requires a change; click on the segment number to open the pipeline detail window and include the updated information. The system will automatically check the include checkbox to include the new details.

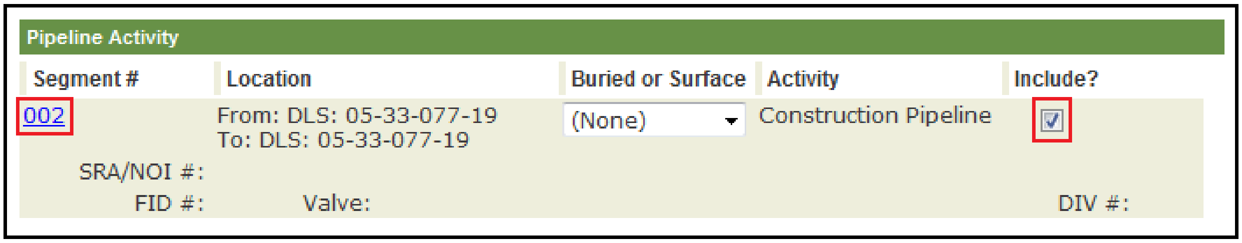


Fig. 5.3

Riser Locations

If there are risers associated with the pipeline, these riser locations need to be entered by NTS or DLS co-ordinates for location confirmation. These locations must be filled out and indicated on the design schematics as well as in the segment specification tab as shown below.

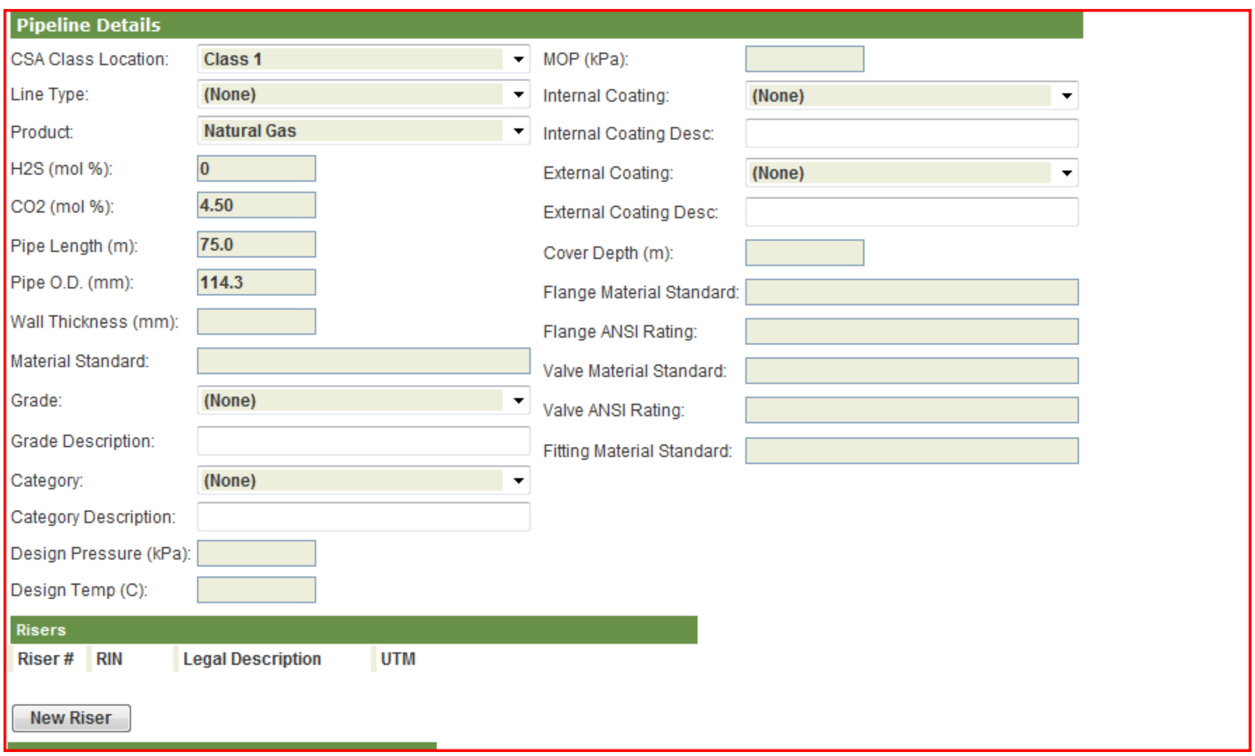


Fig. 5.4

If there is a riser at the either endpoint of the pipeline, then it is applied for as part of the pipeline or is an amendment to the pipeline, even if it exceeds the width of the existing ROW. On applications this area should be included in the pipeline application, if it is an amendment, then it would be an amendment with new land required. Please see the example on the below.

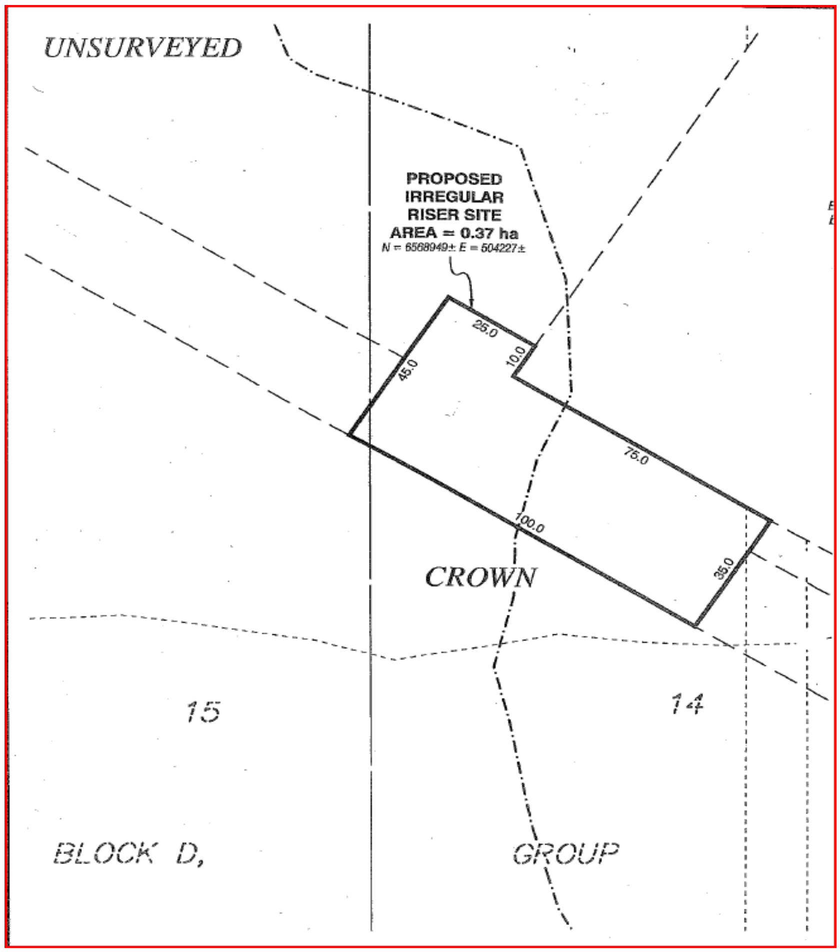


Fig. 5.5

6 During Construction

Notice of Pressure Test

The Notice of Pressure Test provides notification to the Commission 48 hours prior to the start of a pressure test in accordance with Section 4(1)(b) of the Pipeline Regulation. The permit holder must notify the Commission of the start date, to allow a Commission inspector to oversee pipeline pressure testing, if required.

There are two types of Notice of Pressure Test: Shop Test and Field Test. Both Shop Tests and Field Tests must be entered in to KERMIT.

The steps for entering a Shop Test and a Field Test in KERMIT are identical.

1) A **Shop Test** is used during repairs or modifications where short segments of pipe are pre-tested and placed in line with final welds undergoing proper Notice of Pressure Test.
2) A **Field Test** is used upon initial construction testing when replacing long portions of pipe which will require a full line pressure test.

Go to Pressure Test
The steps for entering a shop test or a field test in KERMIT are identical. To illustrate the steps, Shop Test (upstream) for project has been selected as an example.

1) Select Notice of Pressure Test
2) Select NPT shop test for project
3) Search the project or OGC file number
4) Select New Shop Pressure Test for the associated project to open the pressure test page

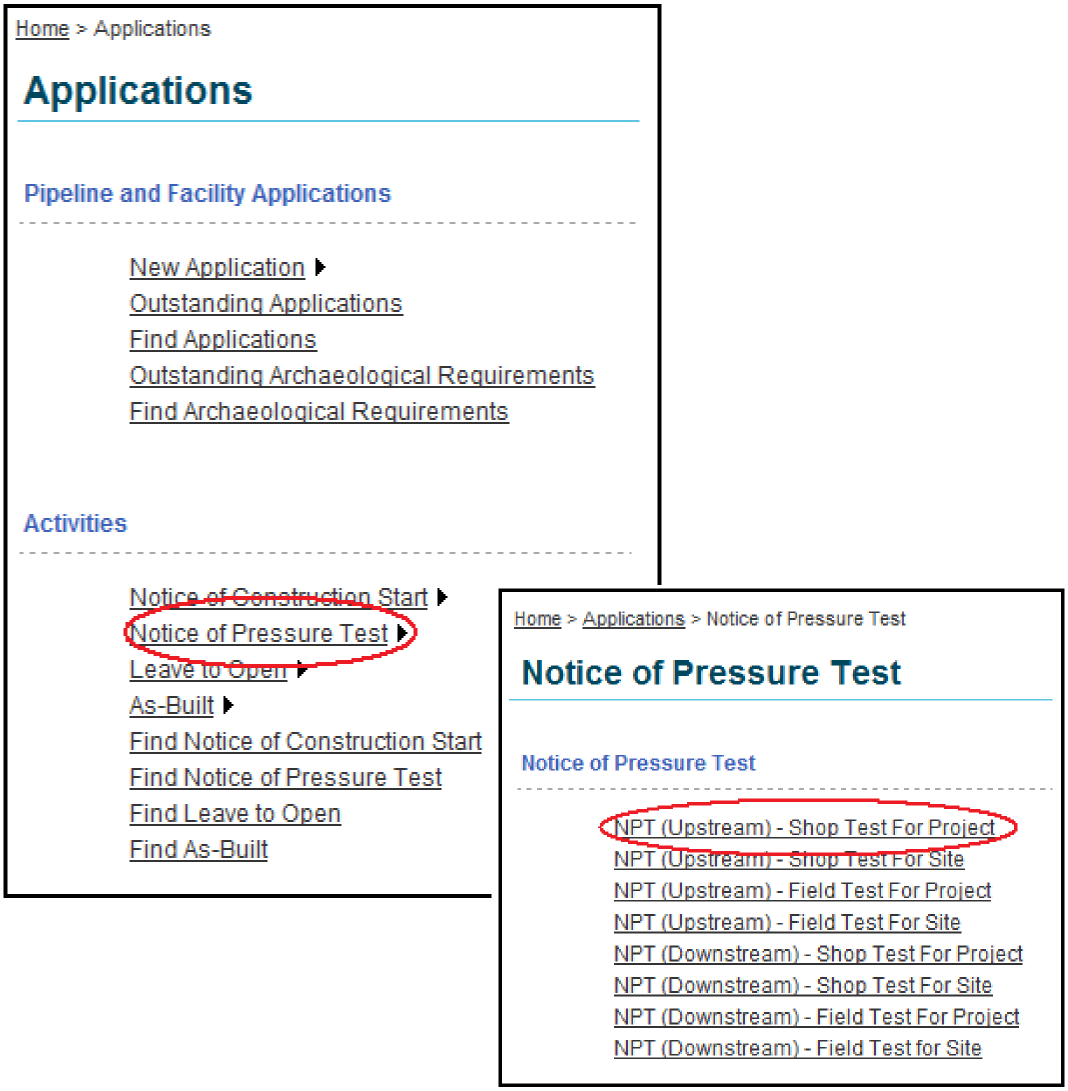


Fig. 6.1. Open a Notice of Pressure Test

Notice of Pressure Test (Upstream) – Shop Test Page

Once the new Notice of Pressure Test for the project has been opened, a job number is generated. Here, information specific to the notice appears, including the project number.

Below the project information are categorized tabs where the permit holder adds information related to the notice. The tab categories are overview, attachments and finalize.

The attachments and finalize tabs which are general to all pipeline operation submissions are covered in the KERMIT overview section of this manual.

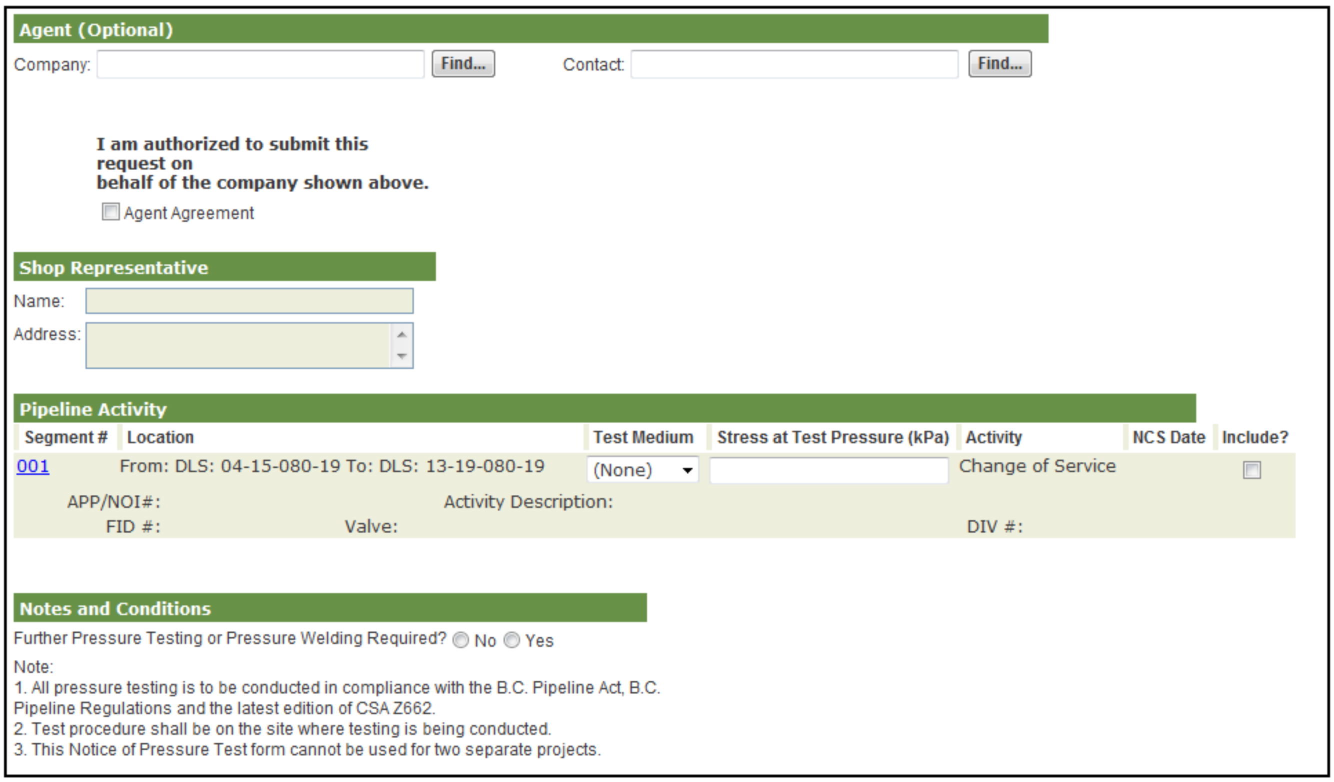


Fig. 6.2. NPT page

Overview Tab
The Notice of Pressure Test overview tab, general application info, operator and agent sections are all c the same way as a Notice of Construction Start. Particular to the Notice of Pressure Test are the shop representative, pipeline activity and notes and conditions sections.

Shop Representative

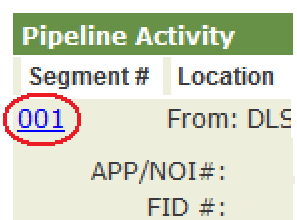
Enter the full name and contact information of the shop representative project.

> The permit holder that holds the surface tenure is accountable for the accuracy of the application content entered into KERMIT. If the permit holder chooses to use outside agents or consultants, the permit holder remains accountable for the accuracy of the application.

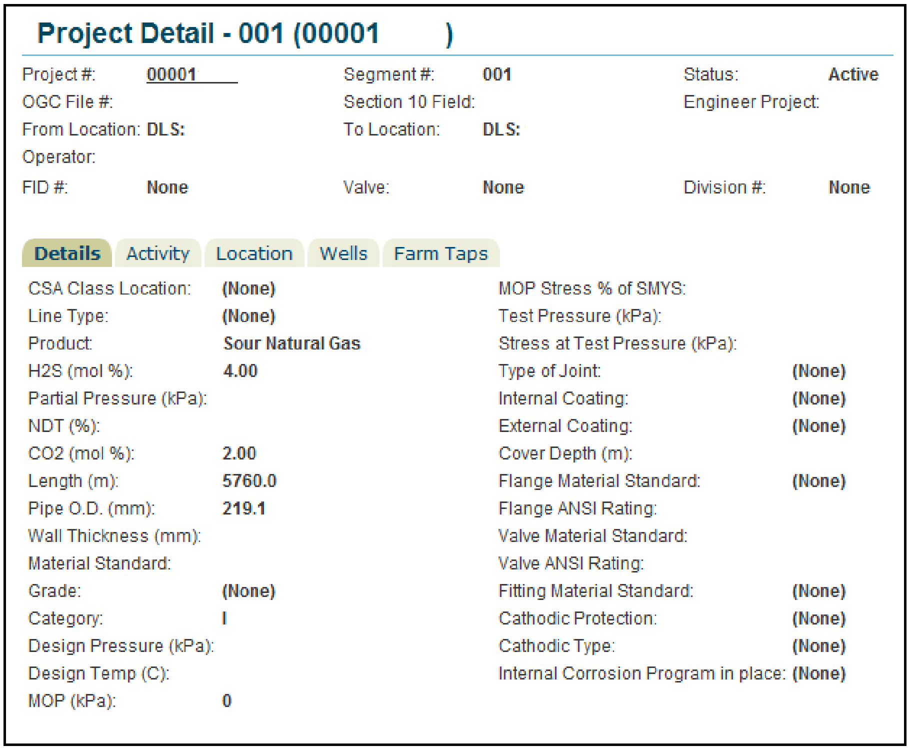
Pipeline Activity

Under pipeline activity, the permit holder is required to enter the following information for each section:

- Test medium. From the drop-down menu select either liquid (hydro) or gaseous (non-hydrocarbon gases)
- Stress at Test Pressure (kPa)
- Include; the box must be checked in order to finalize the submission



Click the segment number to open the project detail window. Here information in the details, activity, location, wells, and farm taps tabs can be viewed.



Project Detail - 001 (00001)

Project #:	00001	Segment #:	001	Status:	Active
OGC File #:		Section 10 Field:		Engineer Project:	
From Location:	DLS:	To Location:	DLS:		
Operator:					
FID #:	None	Valve:	None	Division #:	None

Details | Activity | Location | Wells | Farm Taps

CSA Class Location:	(None)	MOP Stress % of SMYS:	
Line Type:	(None)	Test Pressure (kPa):	
Product:	Sour Natural Gas	Stress at Test Pressure (kPa):	
H2S (mol %):	4.00	Type of Joint:	(None)
Partial Pressure (kPa):		Internal Coating:	(None)
NDT (%):		External Coating:	(None)
CO2 (mol %):	2.00	Cover Depth (m):	
Length (m):	5760.0	Flange Material Standard:	(None)
Pipe O.D. (mm):	219.1	Flange ANSI Rating:	
Wall Thickness (mm):		Valve Material Standard:	
Material Standard:		Valve ANSI Rating:	
Grade:	(None)	Fitting Material Standard:	(None)
Category:	I	Cathodic Protection:	(None)
Design Pressure (kPa):		Cathodic Type:	(None)
Design Temp (C):		Internal Corrosion Program in place:	(None)
MOP (kPa):	0		

Fig. 6.3. Project detail window showing tabs

Notes and Conditions

The permit holder must indicate Yes or No, if further pressure testing or pressure welding is required?

A Leave to Open must be submitted after final pressure testing has been completed, whether or not pressure testing is required.

(See Section 7 for details on submitting a Leave to Open in KERMIT).

If pneumatic testing was done, an e-mail explaining why, along with calculations and the pneumatic test procedure must be sent to the Commission's Pipeline Engineer prior to a Notice of Pressure Test.

Attachments Tab
The attachments tab allows permit holders to upload the required documentation.

Finalize Tab
The finalize tab shows a list of any outstanding Issues related to the application. KERMIT will not finalize an application that has outstanding actions to be completed.

7 Commencing Operations

To avoid delays at the leave to open stage, As-Built plans are not required until 90 days after the LTO.

A pipeline permit holder must notify the Commission of its intention before beginning operation of a pipeline, in accordance with Section 4(1)(c) of the Pipeline Regulation. This is done by submitting a notice of Leave to Open (LTO). Notice of Leave to Open must be submitted 24 hours prior to commissioning any pipeline project or segment.

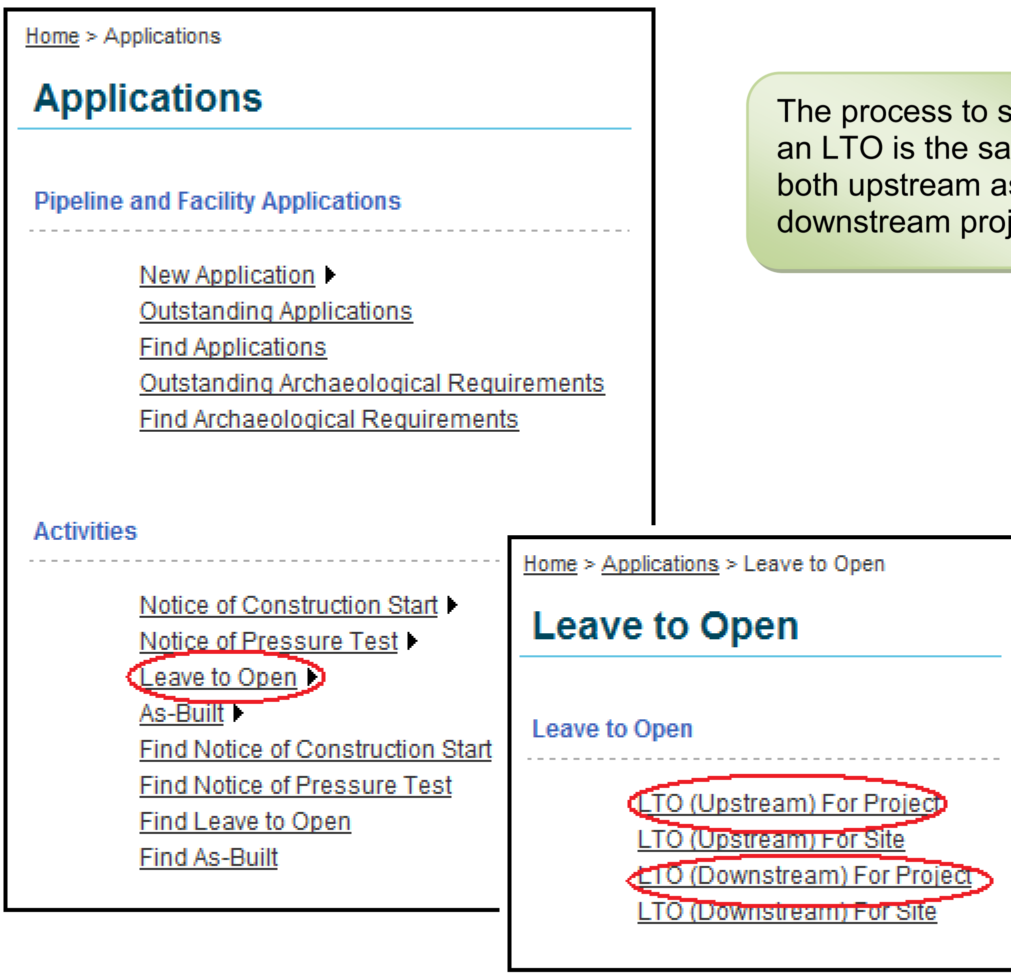
By submitting a notice of Leave to Open, the permit holder affirms that the pipeline has been constructed to CSA standards and that all technical information contained in the notice is accurate and complete.

Leave to Open must be electronically designated by the Professional Engineer (P. Eng.), responsible for the construction of the pipeline and who is a member in good standing of the Association of Professional Engineers of the Province of British Columbia.

Notice of Leave to Open

Go to Notice of Leave to Open

1) Select Leave to Open for project
2) Select LTO (upstream/downstream) for project
3) Search for the project or OGC file number
4) Select new LTO for the associated project or OGC file number to open the leave to open page



The process to submit an LTO is the same for both upstream as downstream projects.

Fig. 7.1. Open a Leave to Open page

Leave to Open Page

Once the new notice of Leave to Open for the project has been opened, a job number will be generated and information specific to the notice also appears, including the project number.

Below the project information header are categorized tabs where the permit holder adds information related to the notice. The tab categories are overview, attachments and finalize tabs are available.

Overview Tab

The overview tab identifies permit holder and land/referral agent information, as well as project specific details.

In the Leave to Open section the overview tab, general application info and operator sections are all filled in the same way as for a Notice of Construction Start.

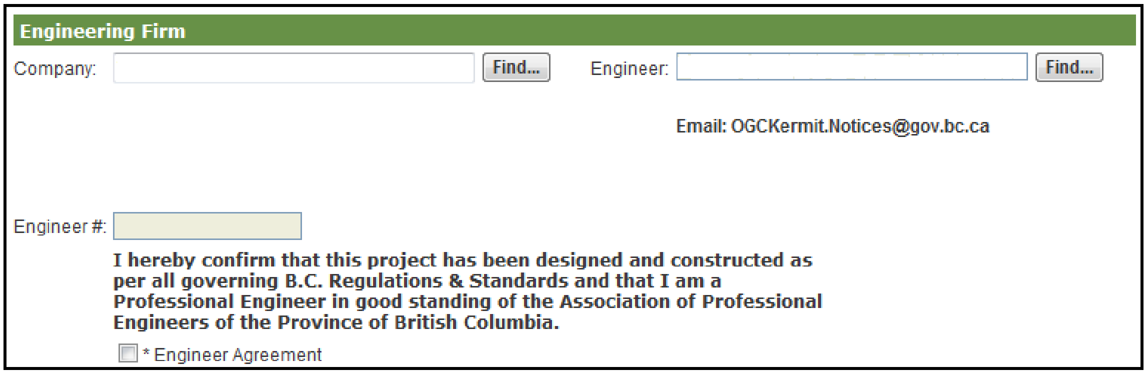
Particular to the Leave to Open are the engineering firm, pipeline activity and information and conditions sections.

The permit holder of the surface tenure is accountable for the accuracy of the application content entered into KERMIT. If the permit holder chooses to use outside agents or consultants, the permit holder remains accountable for the accuracy of the application.

Engineering Firm

Company and engineer information are entered by selecting the find button to the right of both fields.

Enter the Engineer number, and after reading the declaration, the Engineer checks the agreement box to indicate that they agree to the information stated.


Engineering Firm

Company: Find... Engineer: Find...

Email: OGCKermit.Notices@gov.bc.ca

Engineer #:

I hereby confirm that this project has been designed and constructed as per all governing B.C. Regulations & Standards and that I am a Professional Engineer in good standing of the Association of Professional Engineers of the Province of British Columbia.

☐ * Engineer Agreement

Fig. 7.1. Engineering information fields

Pipeline Activity

Clicking the blue segment number opens the segment detail page. As the information for each segment is saved, the check box under pipeline activity will show that it has been accepted, and marked as included.

Pipeline Activity

Segment #	Location	Pipe Length (m)	Product	Activity	NCS Date	NPT Date	Include?
001	From: DLS: 03- - - To: DLS: 04- - -	7172.0	Natural Gas	Construction Pipeline	Mar 12, 2010	Apr 28, 2010	☐
	APP/NOI #:		Activity Description:				
	FID #:	Valve:			DIV #:		
003	From: DLS: To: DLS:	7172.0	Salt Water	Construction Pipeline	Mar 12, 2010	Apr 28, 2010	☐
	APP/NOI #:		Activity Description:				
	FID #:	Valve:			DIV #:		

Fig. 7.2. Pipeline activity fields

Information and Conditions

An ERP must be submitted prior to Leave to Open.

Answer all of the questions and ensure the Emergency Response Plan (ERP) has been submitted or updated.

All As-Built drawings, specs, & data must be submitted within 90 days in accordance with Section 4(2) of the Pipeline Regulation.

Information and Conditions

Cathodic Protection will be in service for above projects: (None)

Internal corrosion program will be in effect: (None) WITHIN DAYS OF COMMISSIONING

Have required safety valves been operationally tested and proven serviceable? ○ Yes ◉ No

If product is ">="1% H2S, new or revised ERP has been submitted to the OGC? ○ Yes ◉ No ○ N/A(<1% H2S)

Has the BC 21 linkage been approved? (required prior to commissioning pipelines) ○ Yes ◉ No ○ N//A

All As-Built drawings, specifications, and data will be submitted within 90 days of opening for service.

Fig. 7.3. Information and Conditions – Conditional questions

Conditional Questions

Cathodic Protection will be in service for above projects:

Cathodic protection controls pipeline corrosion, and is required within one year of commissioning the pipeline in accordance with CSA Z622, 9.5.1.

Internal corrosion program will be in effect:

- Immediately after the commission of a pipeline, or
- Not applicable

An internal corrosion program is not required when composite pipe, instrumentation air or fuel gas is used. Where this is the case, choose N/A.

Have required safety valves been operationally tested and proven serviceable?

All safety devices must be proven to be operable prior to opening the pipeline for service.

If product is greater than or equal to 1% H_2S, new or revised ERP has been submitted to the Commission?

In accordance with Section 8 of the Pipeline Regulation, pipelines with a hydrogen sulphide concentration of 10 moles per kilomole or greater (≥1%), require a sour service Emergency Response Plan respecting the Emergency Planning Zone to be submitted to the Commission before beginning operation.

Has the Schedule 1 linkage been approved? (Required prior to commissioning pipelines.)

A Schedule 1 (previously BC-21), must be approved by the Commission before operations are linked.

Pressure test charts are required at the LTO stage, and must be included as an attachment.

Attachments Tab

The attachments tab allows permit holders to upload the required documentation.

Finalize Tab

The finalize tab shows a list of any outstanding Issues related to the application. KERMIT will not finalize an application that has outstanding actions to be completed.

8 Post-Construction

This section covers Commission requirements during the post-construction phase of a project. This includes:

- Post-Construction Plan
- Pipeline As-Cleared Plan Form
- Issuance of Licence of Occupation
- Renewed Cutting Permit
- As-Built requirements

Post-Construction Plan Submission

To ensure the Commission has the most current digital and spatial information of actual area cleared for oil and gas activity, Post-Construction Plans must be submitted within 60 days of completed construction. This applies equally to projects located on Crown and private land.

Requirements
The submission must include upload of a new ePASS shape file, and one hard copy of a Post-Construction Map. Both must indicate exactly where construction has occurred should be accurate to +/- 2 meters.

Post-Construction Plan submission does not replace the requirements to submit As-Cleared maps, or As-Built submissions.

Post-Construction Map
Permanent disturbances must be distinguished from temporary disturbances.

If constructed locations have not changed from the original application, and no temporary ancillary features were included with the application, the ePASS number from the most recent application may be indicated on the post-construction map.

ePASS
For Pipeline and Facility applications in Kermit, the ePASS number must be entered with the Activity Type of "Post-Construction."

Any temporary ancillary features must be indicated as clearings. Examples of temporary clearings include:

- Camp sites and decking sites
- Visibility clearings
- Road flare-outs
- Brush storage areas
- Corner cut-offs (which are often part of a pipeline project or road construction project)

The permitted value in ePASS for a clearing is CLEAR as indicated in the ePASS submission Standards document.

As-Cleared Plan Form

As-Cleared refers to the forestry area that was cleared to construct the works.

As-Built refers to specific piping (engineering) details.

An As-Cleared Plan Form is required ONLY where a Cutting Permit was issued for an activity, and reflects the actual area used in the construction of the pipeline (including ancillary disturbances). This includes all amendments that result in a change to the total area used.

As a condition of the permit holder's MLTC, pipeline permit holders are required within 60 days of clearing to submit an As-Cleared plan to the address stated on the form. The information will then be forwarded to the Ministry of Forests and Range for stumpage billing purposes.

The following information shows what is required on the As-Cleared plan form.

Block A – Administration

Commission File No.	Commission surface file number generated by KERMIT. E.g. 9700000.
Permit Holder Name	Enter the company name as registered with the BC Corporate Registry and holds the permit.
Contact Information	Enter the contact information of the representative. If the form is completed by a referral agent, referral company information is also required.

Block B – Forestry Information

Disturbance Type	Indicate the type of activity associated with the disturbance.
Forest District	British Columbia is divided by regions into forest districts. Indicate which district(s) the project is in.
Permit Approval Date	Indicate the date the permit was approved by the Commission.
Construction Completion Date	Indicate the date that clearing was completed. Use YYYY/MMM/DD format.
MLTC No.	Master Licence to Cut number.
Proposed New Crown Land	The total of proposed new Crown land area disturbance (in hectares excluding woodlot areas, as indicated as part of the permit application process. The total area of Crown land is the area shown on the construction plan including the pipeline area, any temporary workspaces, decking sites etc.; whether or not the area was previously cleared or within an existing right-of-way.
As-Cleared New Crown Land	The total As-Cleared new Crown land area disturbance (in hectares), is the total area of Crown land utilized minus any woodlot areas and any previously cleared areas where stumpage has been collected.

If the total As-Cleared area is the same as what was proposed, map attachments are not required. Hand sketches are not acceptable as map attachments.

Block C – Form Deliverables

As-Cleared Form

Include two completed copies of the As-Cleared Form. The Commission will distribute the duplicate to the Ministry of Forests and Range for billing purposes.

As-Cleared Sketch Plan

In accordance Section 9.01 of the permit holder's MLTC, the permit holder must submit a map showing all disturbances that have occurred pursuant to the cutting permit, at a scale of 1:20,000 or 1:50,000.

If the total As-Cleared area is the same as what was proposed within the application, map attachments are not required. Hand sketches are not acceptable for the sketch plan.

License of Occupation

The Commission will issue a licence of occupation in accordance with Section 39 of the Land Act after either:

- All Leave to Ppen notices have been submitted for the pipeline project; OR
- If the term of the pipeline permit expires andLeave to Open notices have been received for some segments

A Licence of Occupation conveys non-exclusive use for the purpose described and is not a registerable interest in the land. Government may authorize overlapping and layering of tenures.

The Commission will prepare a Licence of Occupation for the right-of-way identified in the Construction Plan originally submitted with the permit application or in a subsequent Construction Plan received. The licence will be sent to the permit holder's surface land administrator in order to authorize occupation of the land. Any pipeline segments not constructed at this stage will be cancelled.

Permit holders have 60 days from the issuance of the Licence of Occupation to return one signed copy of the licence and the pipeline consideration fees. The duplicate licence of occupation is to be retained by the permit holder for their records.

Consideration Fees

A pipeline consideration is charged for the term of the licence based on the zonal rates for linear development (pipelines) outlined in the Ministry of Agriculture and Lands Crown Land Use Operational Policy: Utility Policy for Linear Development (pipelines).

For the purposes of section 24 of the OGAA General Regulation, a pipeline is considered complete once the LTO has been submitted.

Term

The Licence of Occupation is intended as an interim tenure that is valid for three years, pending completion of legal survey requirements. The permit holder must complete the surveying and posting of the pipeline right-of-way in accordance with the rules made under Section 75 of the Land Surveyor's Act within 16 months of completing a pipeline (in accordance with Section 24 of the OGAA General Regulation).

Applications for surveying period extension can be made to the BC Surveyor General.

Statutory Right-of-Way

If survey requirements are met, a Statutory right-of-way tenure document will be issued to replace the Licence of Occupation tenure.

A fee for the replacement of a disposition is payable for the issuance of the Statutory right-of-way tenure as outlined in the Land Act Fees Regulations. Statutory right-of-way tenures are issued for a nominal $1.00 consideration when the legal survey requirements are met.

More information on the Statutory right-of-way process is found within the Commission's Corporate Land Management Manual (currently in development).

Renewing an Expired Cutting Permit

If timber removal on Crown land is required to construct a pipeline, a cutting permit will be issued as part of the pipeline permit. The pipeline permit will state the term of the cutting permit to remove Crown timber.

To renew an expired cutting permit, a completed Cutting Permit Renewal Form must be submitted to the Commission.

As-Built Requirements

As-Built specifications, data and drawings provide the Commission with information about the technical aspects of the constructed facility.

This section outlines the procedures for completing As-Built requirements in KERMIT.

If there is required information that cannot be entered into KERMIT, it must be noted in the cover letter and indicate the reason.

Transfer
Permit holders may not transfer a project unless As-Built documentation, or a suitable alternative, in the form of a Historical Pipeline Data Submission is in place.

Refer to information letter #OGC 07-20 for information on historical pipeline data submission requirements.

Submissions
A pipeline permit holder must submit specifications, data and drawings of the pipeline to the Commission within 90 days of pipeline construction completion, in accordance with Section 4(2) of the Pipeline Regulation.

As-Built specifications, data and drawings provide the Commission with information about the technical aspects of the constructed pipeline.

All As-Builts require original Process and Instrumentation Diagrams, Plot Plans and Flow Schematics and must be signed and sealed by the Professional Engineer and submitted with the As-Built form. “Typical” drawings are not acceptable.

As-Builts should include the following attachments:

- Cover letter
- Index (optional)
  - In situations where many pages of drawings exist and have an index or cover sheet identifying each drawing within, Professional Engineers need only sign and seal that index or cover sheet. If an index or cover sheet is not provided, each drawing must be signed and sealed.
- Legend (may be included within the P&ID package)
- P&ID (see example)
  - Include schematics of all mid-point risers, with the exact location of the riser listed on the schematic
  - Include the start and end points of each segment, properly labeled
- Plot plan (see example)
- Flow schematic (see example)
- Tie-in Schematics of ESD valves
- System map showing isolation valve locations

These submissions are reviewed for completeness and may be declined for the following reasons:

- Line specification details not complete
- Engineer seal and signature missing
- No legend indicating the symbols used
- Missing attachments
- Not all endpoints/apurtenances shown
- Not all location shown
- Labels incomplete or incorrect
- Lines being As-Built are not clearly indicated and not apparent which lines are the ones to review
- Clarification required (e.g. sour pig barrel that does not show release going to flare, but appears to go to atmosphere)

As-Built

1) Select As-Built from the activities menu
2) Select As-Built for project
3) Search the project or OGC file number
4) Select new As-uilt for the associated project to open the As-Built page

The submission process in KERMIT is the same for both upstream and downstream projects.

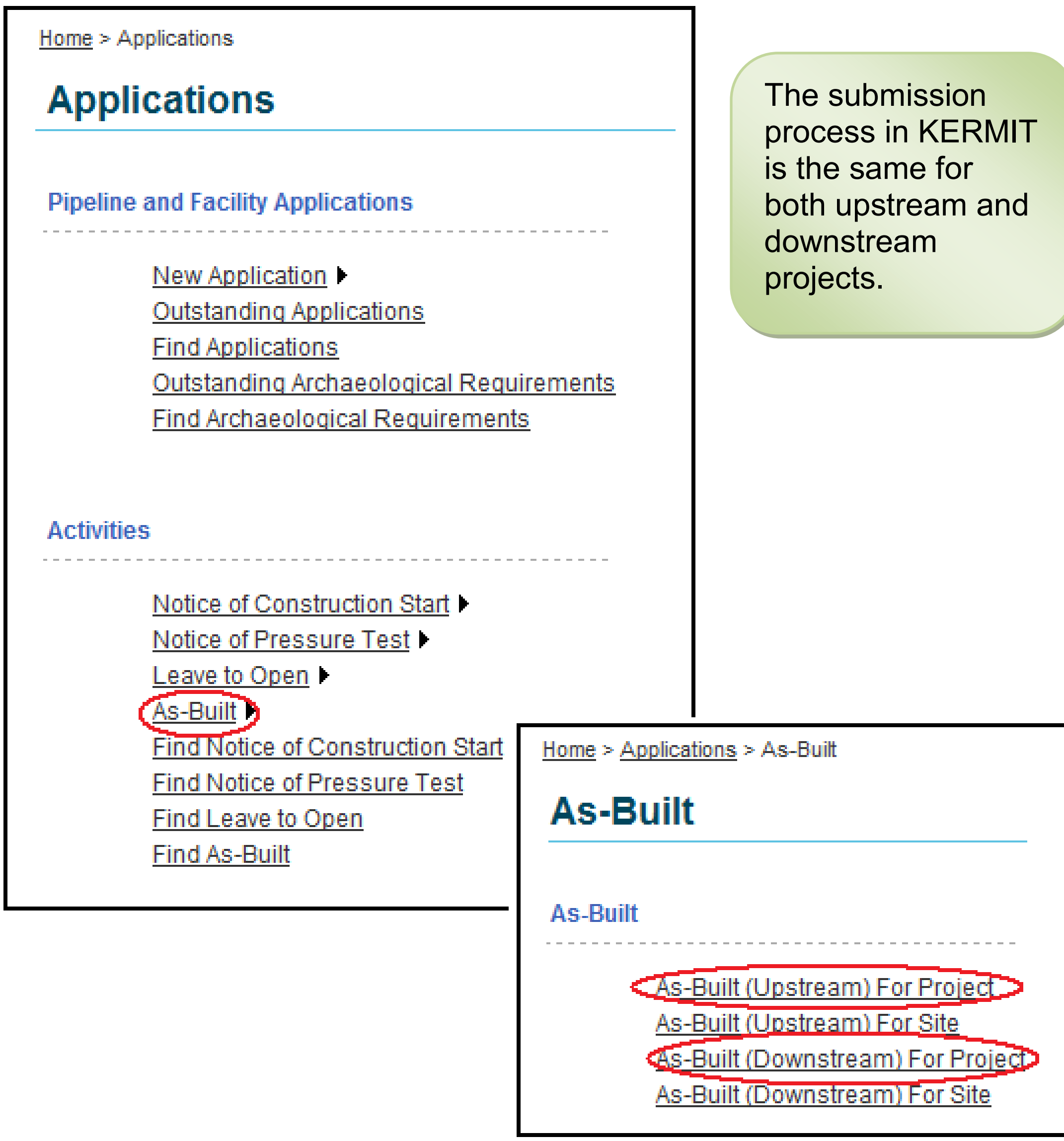


Fig. 8.1. Open an As-Built

As-Built Page

Once the As-Built for the project has been opened, a job number is generated. Here, information specific to the As-Built also appears, including the project number.

Below the project information are categorized tabs where the applicant must add information related to the As-Built. The tab categories are overview, attachments and finalize.

The attachments and finalize tabs which are general to all pipeline operation submissions are covered in the KERMIT overview section of this manual.

The surface tenure holder is accountable for the accuracy of the application content entered into KERMIT. If the permit holder chooses to use outside agents or consultants, the permit holder remains accountable for the accuracy of the application.

Overview Tab
The As-Built overview tab, general application info and operator sections are all filled in the same way as for a Notice of Construction Start. Particular to the As-Built is the pipeline activity section.

Engineering Firm

Company and engineer information can be entered by selecting the find button to the right of both fields.

Enter the Engineer number. After reading the declaration, the Engineer uses the check box to indicate agreement with the information stated.

Engineering Firm

Company: [ ] Find... Engineer: [ ] Find...

Email: OGCKermit.Notices@gov.bc.ca

Engineer #: [ ]

I hereby confirm that this project has been designed and constructed as per all governing B.C. Regulations & Standards and that I am a Professional Engineer in good standing of the Association of Professional Engineers of the Province of British Columbia.

* Engineer Agreement

Fig. 8.2. Engineering information fields

Pipeline Activity

Information must be provided for each segment number that appears pipeline activity. Click on the blue segment number which appears for each segment of pipe included in the As-Built. This opens the As-Built Project Detail window.

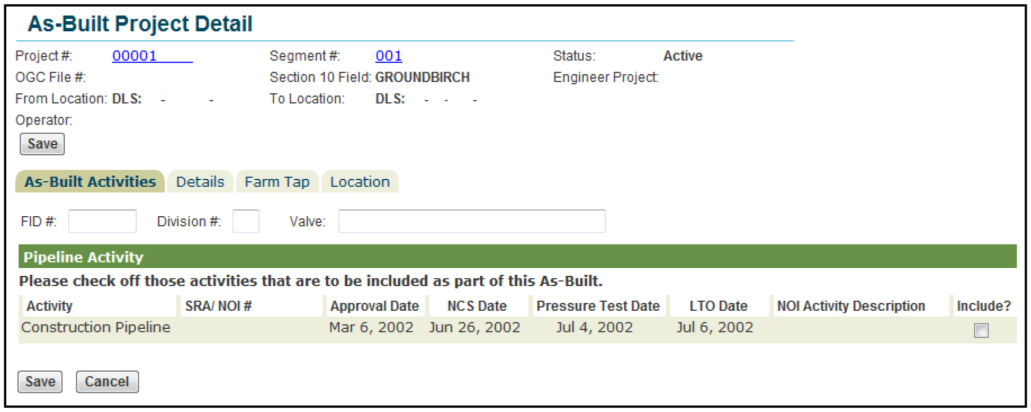


Fig. 8.3. As-Built project detail window

All As-Builts require line specification information to be entered under the Details tab, shown in figure 8.4.

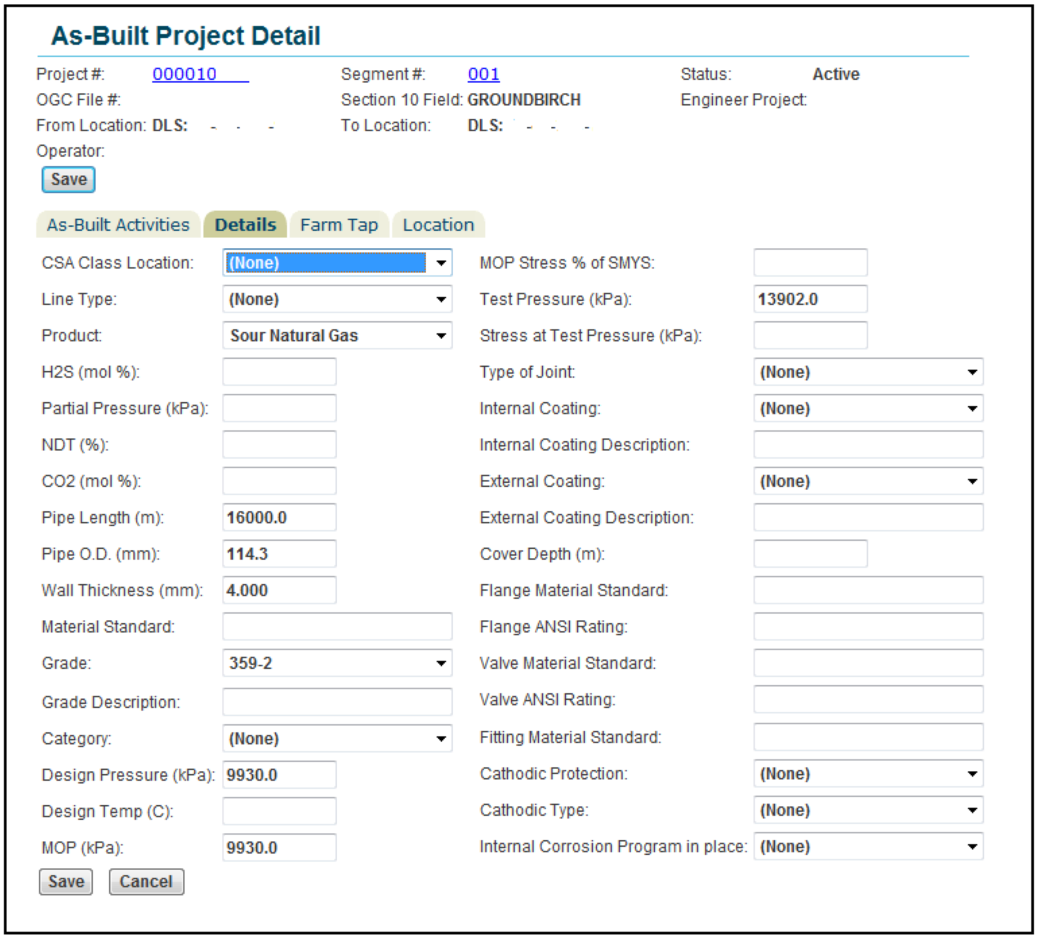


Fig. 8.4. As-Built detail window

As information for each segment is saved, the check box under Pipeline Activity shows that it has been accepted, and marked as included.

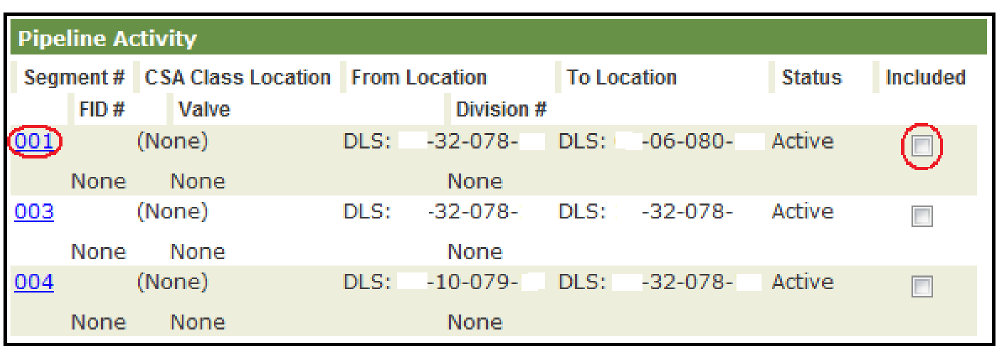


Fig. 8.5. Pipeline Activity fields

Attachments Tab
The attachments tab allows applicants to upload the required documentation.

Finalize Tab
The finalize tab shows a list of any outstanding Issues related to the application. KERMIT will not finalize an application that has outstanding actions to be completed.

9 Notice of Intent

The Notice of Intent (NOI) section details what information is required when submitting the notice in KERMT. The Notices of Intent types are:

- Decrease Maximum Operating Pressure (upstream)
- Decrease Maximum Operating Pressure (downstream)
- Repair or Replace pipeline (in-kind)
- Deactivate pipeline
- Modify data
- Install farm tap (downstream)

Under OGAA, a number of former NOI's have been re-categorized as amendments.

Information on these operational amendments is located in Section 10.

The notice of intent allows for the reporting of operational changes and modifications or repairs to existing pipelines requiring no new acquisition of land, or additional surface tenures.

Companies must submit a Pipeline Permit Application for construction of any new pipelines; this includes lines within an existing right-of-way.

There are four different Notices of Intent that may be applied for against upstream pipelines, and five that can be applied for against downstream pipelines. Definitions of upstream and downstream pipeline activities are provided in Section 5.

Notices of Intent are reviewed by the Commission's Engineering division and the applicant will be notified by email if the notice is accepted or declined.

Declined Notice of Intent
A notice may be declined if more information is required. A declined notice will include an explanation from the Commission.

Once all deficiencies have been addressed, the notice can be re-submitted. A new application is not required unless specifically requested in the decline notice.

A pipeline Notice of Intent matrix is located in Appendix C, and shows all pipeline activities which are submitted through the Notice of Intent process. It also indicates all other required submissions through to completion of the activity.

Notice of Intent

Go to Notice of Intent

1) Select NOI (upstream/downstream) for project
2) Select the activity from the NOI pipeline project menu
3) Search for the related project
4) Select the new NOI related to the project

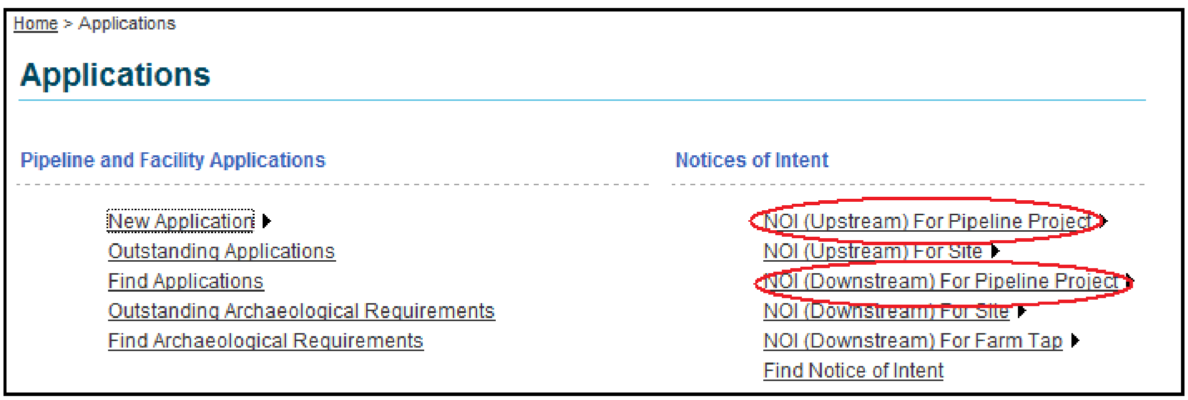


Fig. 9.1. Shaded mandatory fields in KERMIT

Find Notice of Intent
"Find Notice of Intent" is used to search for a previously created NOI; either to complete it, or determine its current status.

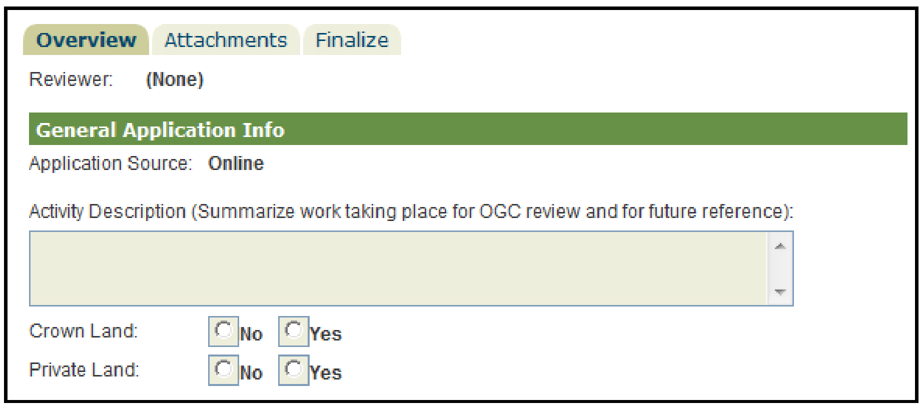
Find Notice of Intent can also be used when an applicant wants to create a new NOI but cannot find the correct segment. Where this is the case; select find notice of intent and search the project number to see if one has been created and just needs to be completed.

NOI (Upstream/Downstream) Page

Once the new Notice of Intent for the project has been opened, a job number is generated. Below this information are tabs where the applicant enters project specific information.

General Application Info

General application info shows the application source and provides a field for activity description. The activity description should include the date of the planned construction start and location of construction.


Overview | Attachments | Finalize

Reviewer: (None)

General Application Info

Application Source: Online

Activity Description (Summarize work taking place for OGC review and for future reference):

Crown Land: No Yes

Private Land: No Yes

Fig. 9.2. General Application Info fields

If the description is more detailed than space will allow, a scope of work description attachment should be included to clarify. If there are two notices of intent that need to be submitted together, reference the other job number in the activity description.

The permit surface tenure holder is accountable for the accuracy of the application content entered into KERMIT. If the permit holder chooses to use outside agents or consultants, the permit holder remains accountable for the accuracy of the application.

Operator

The operator section captures key applicant information. Company name and information should appear automatically. If the company name does not appear, or the address is incorrect, the applicant must contact the Commission's Corporate Land Management Unit to update the information prior to application submission.

If a company contact has previously been entered into the Commission database, use the find button to search for the contact. If no contact is found, enter the information manually.

Engineering Firm

Company and engineer information can be entered by selecting the find button to the right of both fields.

Include the Engineer number, and after reading the declaration, the Engineer uses the check box to indicate that they agree to the information stated.

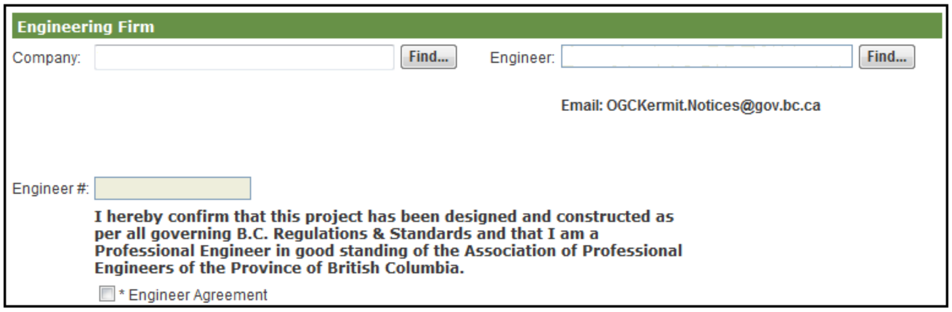
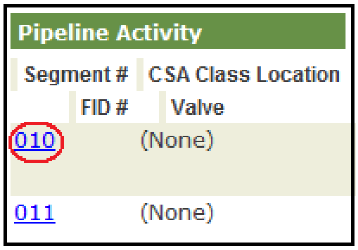


Fig. 9.3. Engineering information fields

Field Contact

Enter the full name and phone number of the field contact for the project.

Pipeline Activity



Information must be provided for each segment showing under pipeline activity.

Open the segment by clicking on the segment number to the left of the line list details. The line list details appear for each segment of pipe.

The notice of intent project detail window opens, and the permit holder must fill in the required information and answer the conditional questions.

Attachment Tab
The attachments tab allows applicants to upload documents and relate them to the job.

Include documents that will clarify and properly explain the scope of work.

Finalize Tab
The finalize tab shows a list of any outstanding Issues related to the application. KERMIT will not finalize an application that has outstanding actions to be completed.

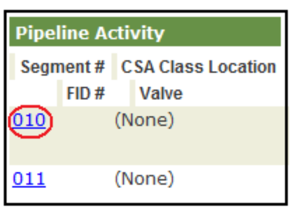
Decrease MOP (Upstream)

Decreasing the maximum operating pressure (MOP) will not change the design pressure, but will reduce the maximum operating pressure of the line. It is used when a) the current maximum operating pressure can no longer be safely sustained or b) field pressures have changed and the permit holder wants to decrease the maximum operating pressure to field match the pressures.

1) Select NOI (Upstream) for pipeline project
2) Select decrease MOP
3) Search for project
4) Select new NOI for the related project number
5) Enter required information in the general application info, operator, engineering firm and field contact sections.

If a permit holder wants to raise the MOP on lines after a decrease, a pipeline permit engineering amendment will be required (see Section 10).

Pipeline Activity



Click on the pipeline segment(s) to open the NOI project detail window, and enter the new MOP (kPa) and new MOP Stress % of Specified Minimum Yield Stress (SMYS).

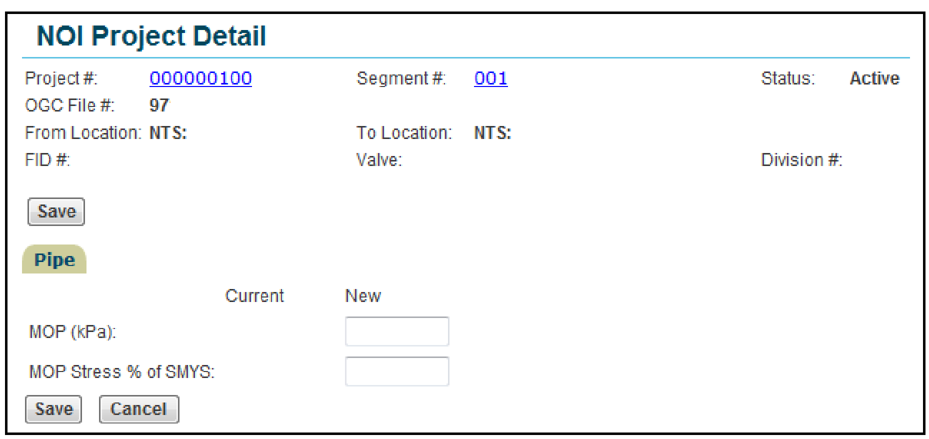


Fig. 9.4. Notice of Intent detail window

Answer the conditional questions:

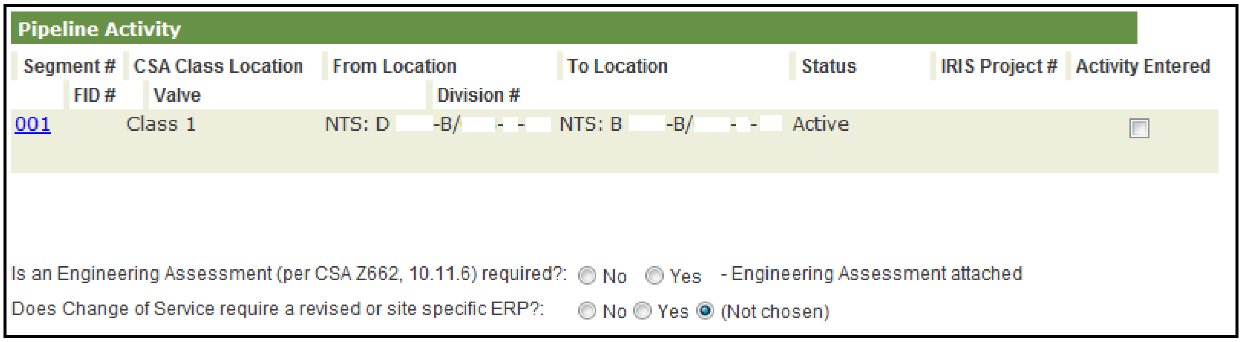


Fig. 9.5. Pipeline Activity - Conditional questions

In the attachments tab, upload documentation of the reasons for the maximum operating pressure decrease, and then finalize the notice.

Decrease MOP (Downstream)

If a permit holder wants to raise the MOP on lines after a decrease, a pipeline permit engineering amendment and a full engineering assessment will be required see Section 10).

Decreasing the maximum operating pressure will not change the design pressure but will reduce the maximum operating pressure of the line. It is used when the pipeline is being taken to pressures that are below the Commission's jurisdictional pressure of 700kPa.

1) Select NOI (Downstream) for pipeline project
2) Select decrease MOP
3) Search for project
4) Select new NOI for the related project number
5) Enter required information in the general application info, operator, engineering firm and field contact sections.

Pipeline Activity

Click on the pipeline segment (s) to open the NOI project detail window, and enter the new MOP (kPa) and new MOP Stress % of Specified Minimum Yield Stress.

Answer the conditional questions:

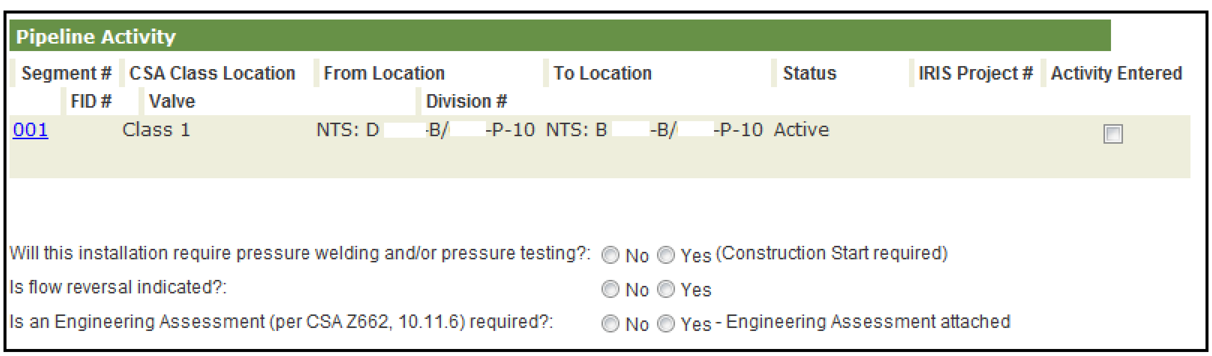


Fig.9.6. Pipeline Activity – Conditional questions

In the attachments tab, upload documentation of the reasons for the maximum operating pressure decrease, and then finalize the notice.

Repair or Replace Pipeline (In-Kind)

A repair to, or replacement of, a pipeline (segment) is a procedure which maintains integrity, and does not change design.

A Notice of Construction Start, Notice of Pressure Test and a Leave to Open are also required if pressure welding and/or pressure testing is conducted.

1) Select NOI (Upstream) for pipeline project
2) Select Repair/Replace pipeline NOI
3) Search for project
4) Select New NOI for the related project number
5) Enter required information in the general application info, operator, engineering firm and field contact sections.

Pipeline Activity

Click on the pipeline segment (s) to open the NOI project detail window, and enter the repair date and comments.

Comment Box
In the comment box indicate whether this is a repair due to maintenance or an incident.

If it is due to an incident, include the DGIR number (Provincial Emergency Program tracking number) given when the incident was reported or the application will be declined.

Include a schematic showing where along the segment the work will be taking place, or include the preventive maintenance results indicating the need for repair or replacement.

Comments must include the work locations addresses (UTM NAD 83 CSRS), a description of all work including descriptions of modifications and/or repairs.

Answer the conditional questions:

Is an Engineering Assessment (per CSA Z662, 10.11.6) required?: No Yes - Engineering Assessment attached
Does Change of Service require a revised or site specific ERP?: No Yes (Not chosen)

In the attachments tab, upload documentation providing a detailed scope of work. Attach any other documentation that may better clarify the application and then finalize the notice.

Deactivate a Pipeline

Permit holders may want to contact the BC Assessment Authority regarding a tax reduction as a result of deactivation.

A permit holder wishing to deactivate a pipeline or segment(s) must follow the requirements of the latest edition of CSA Z662. No documentation is returned to the permit holder for this NOI type.

1) Select NOI (upstream/downstream) for pipeline project
2) Select Deactivate Pipeline
3) Search for project
4) Select new NOI for the related project number
5) Enter required information in the general application info, operator, engineering firm and field contact sections.

General Application Info

In the activity description box, indicate in detail what will be done to deactivate the line. Indicate whether the activity is located on Crown or Private land.

Pipeline Activity

Click on the pipeline segment (s) to open the NOI project detail window, and enter the deactivation date.

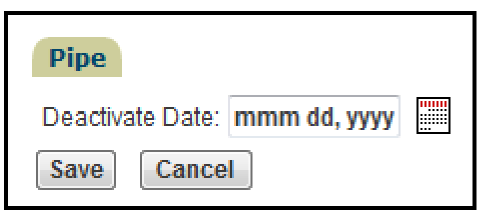
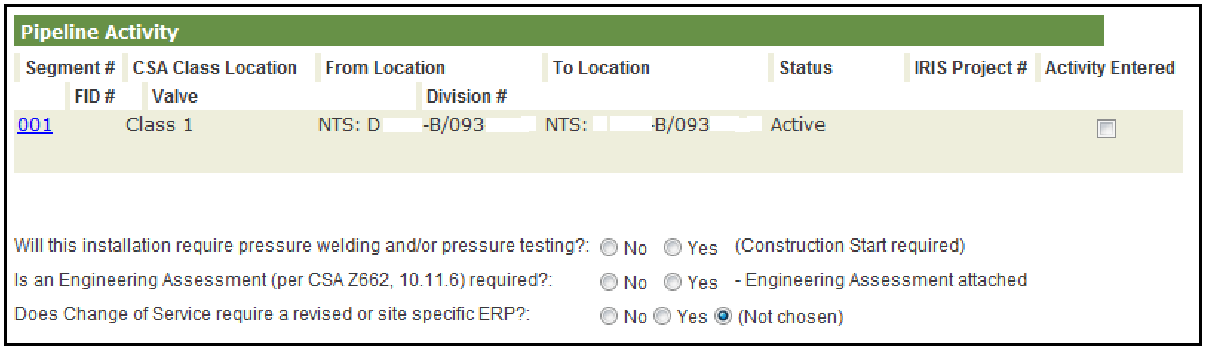


Fig. 9.6. Deactivation date field

Answer the conditional questions:



Pipeline Activity

Segment # / FID #	CSA Class Location / Valve	From Location	To Location / Division #	Status	IRIS Project #	Activity Entered
001	Class 1	NTS: D -B/093	NTS: B/093	Active		☐

Will this installation require pressure welding and/or pressure testing?: ○ No ○ Yes (Construction Start required)

Is an Engineering Assessment (per CSA Z662, 10.11.6) required?: ○ No ○ Yes - Engineering Assessment attached

Does Change of Service require a revised or site specific ERP?: ○ No ○ Yes ◉ (Not chosen)

Fig. 9.7. Pipeline Activity – Conditional questions

Background on the deactivation requirements for is located in IL 08-09.

Attachments Tab

In the attachments tab upload:

- Documentation providing a detailed scope of work
- Maintenance schedule list
- Letter of Explanation from the land owner (if applicable), regarding removal of easement
- Completed Field Survey
- Any other documentation that may better clarify the application and then finalize the notice

Letter of Explanation

A Letter of Explanation should include:

- Reasoning for deactivation of the pipeline
- Method of isolation
- Pressure left on the pipeline
- The medium used to fill the pipeline and the effects of the medium on the integrity of the pipeline
- Method being used for internal and external corrosion monitoring and mitigation
- Planned length of deactivation and,
- Planned maintenance activities on the pipeline during the deactivation time frame

Field Survey

The Field Survey should list the wells and pipelines in the area and which are active, suspended/deactivated and abandoned. This will provides the Commission with an overview of the field and helps determine the potential future of the pipe.

Modify or Update Existing Data

Any discrepancies in pipeline specifications or details in KERMIT can be corrected or completed through the Modify Data Notice of Intent.

Such discrepancies may include:

- Incorrect product
- Incorrect pressures
- Identified pipelines size

These discrepancies refer to the mistake in data entry. This does not apply to any data change that affects the application or amendment fees before permit approval, or any data change that should be addressed with an amendment (e.g. Change of Service amendment).

1) Select NOI (upstream/downstream) for pipeline project
2) Select Modify data
3) Search for project
4) Select new NOI for the related project number
5) Enter required information in the general application info, operator, engineering firm and field contact sections.

General Application Info

Enter information about the modification in the activity description box and indicate if the activity is located on Crown or private land.

In the attachments tab, upload include all relevant data and documentation (e.g. old notice of construction start, pressure test charts), and then finalize the notice.

Pipeline Activity

Click on the pipeline segment (s) to open the NOI project detail window. In the comments box, enter any data that needs to be corrected or updated.

Specific information about data to be modified must be entered for each detail (segment).

Install Farm Taps

Farm Taps are given site numbers (FID#) associated with projects (not project numbers).

All work done against a Farm Tap will be registered under the site number issued upon Notice of Intent submission.

Farm tap is a natural gas line with a nominal diameter of 25 mm or less, which feeds from a pipeline to an individual end user, or to a tap off of an Intermediate Pressure (IP) line that will send gas below 100 psi to a distribution system.

The addition, repair, replacement, or removal of a Farm Tap are all downstream Notices of Intent.

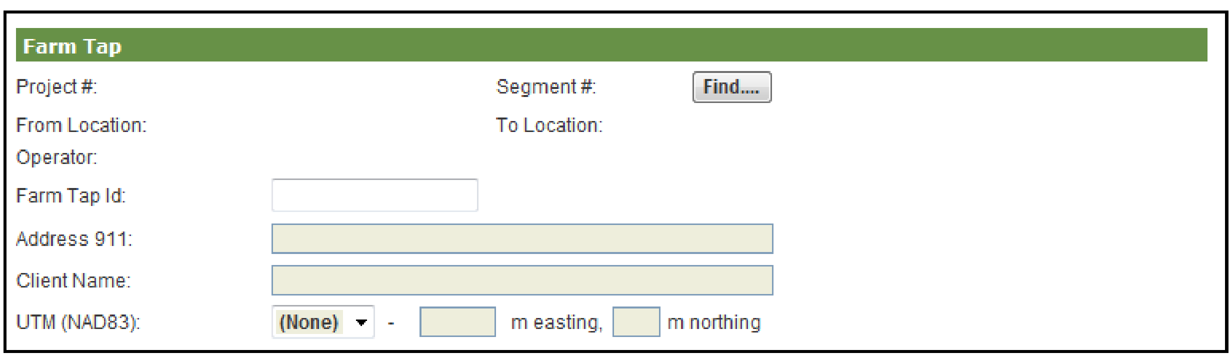
Schematics must be submitted as attachments.

1) Select NOI (Downstream) for Farm Tap
2) Select Add, Repair/Replace, or Remove Farm Tap
3) Enter required information in the general application info, operator, engineering firm and field contact sections.

Farm Tap

Use the Find button to search for the associated project. Under Farm tap information enter the correct project number and segment number of the pipeline being tapped into. Enter the Farm Tap I.D. (FID #) if applicable

Ensure the 911 Address is complete and the client name and the UTM co-ordinates are entered.



Farm Tap

Project #: Segment #: Find....

From Location: To Location:

Operator:

Farm Tap Id:

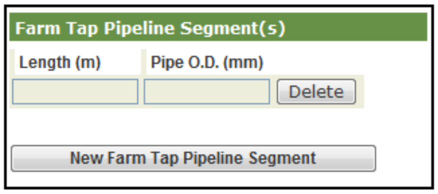
Address 911:

Client Name:

UTM (NAD83): (None) - m easting, m northing

Fig. 9.8. Farm Tap information fields

Farm Tap Pipeline Segment



The farm tap pipeline segment button activates information fields where the length of the pipeline segment (m) and the outside diameter are to be added. Enter the required information for each pipeline segment.

In the attachments tab, upload all relevant schematics and a map with the location of the Farm Tap; then finalize the notice.

10 Pipeline Permit Engineering Amendment

KERMIT enhancements associated with pipeline engineering amendments are still in development at this time. The Commission plans an external testing opportunity during the summer of 2010. Once enhancements are finalized, this manual will be updated to reflect those business processes.

Pipeline Permit Engineering Amendment Applications are requests to change the operating parameters of the original permit; therefore, the Commission is required to make a determination on the amendment application. All pipeline permit amendments are submitted through the KERMIT database.

Section 3 of the Consultation and Notification Regulation identifies classes of persons that are prescribed for the purposes of Section 22 of OGAA.

Pipeline permit engineering amendments that are included in these prescribed classes are subject to the Consultation and Notification Regulation and Section 31 of OGAA. Pipeline permit engineering amendments that are not included in the prescribed classes are only subject to Section 31 of OGAA.

For more information on the prescribed classes and on the consultation and notification process, refer to the commission's Consultation and Notification Guidelines.

Pipeline permit engineering amendments cannot be submitted alone for changes to surface land, but may need to be included in conjunction with any amendment submitted for changes to surface land.

Changes that require a pipeline permit engineering amendment are:

- Change to CSA class location
- Increase in Maximum Operating Pressure
- Cancel pipeline
- Modify sub-surface pipe
- Repair/ replace (not in-kind)
- Installation of a mid-point riser
- Change of service
- Pipeline flow reversal
- Abandon pipeline
- Reactivate pipeline
- Splitting segments

All permit amendments should be as complete as possible, including all proposed changes to the pipeline permit being considered.

More than one change to the permit may be included within the same amendment. E.g. splitting a line and installing a mid-point riser at the split junction.

If any activity applied for requires more surface land than what has been approved, please refer to the Pipeline Permit Application Manual.

KERMIT Procedures Currently in Development

Amendment to Increase CSA Z662 Class Location

An amendment is required when a pipeline originally designed for a specific CSA class location experiences dwelling encroachments and/or development that will reclassify the pipeline and result in non-compliance. For definitions and explanations of class locations refer to CSA Z662.

This amendment will require:

- Consultation / notification written report in accordance with Section 31(6) of OGAA.
- An engineering assessment

This amendment may require:

- Modifications to the existing pipe
- Engineering design specifications
- Engineering hazard controls
- Notice of Construction Start
- Notice of Pressure Test
- Notice of Leave to Open
- As-Built

All changes, modifications, and controls must address the safety of the public, environment, workers and the pipeline. A revised ERP is needed for this type of an amendment.

Amendment to Increase MOP

Permit holders may find that after subsequent wells are drilled in a given area there is a need to increase the operating pressure of any given line. This requires the permit holder to submit an amendment to increase the maximum operating pressure of the given pipeline.

This amendment requires:

- Consultation / Notification Written Report in accordance with Section 31(6) of OGAA.
- Engineering Assessment

This amendment may require:

- Modifications to the existing pipe
- Engineering design specifications
- Notice of Construction Start
- Notice of Pressure Test
- Notice of Leave to Open
- As-Built

If there are any changes that occur to accommodate the increase, the amendment may require a Notice of Construction Start, a Notice of Pressure Test, a Notice for Leave to Open and an updated ERP.

Amendment to Modify Pipeline

If a pipeline requires modification, an amendment to the original permit is needed. Examples of modifications to existing sub-surface pipeline include:

- Installing a liner within an existing pipeline
- Installing a riser tee
- Altering the diameter of the pipe.

Please refer to fee schedules to see if they are required for this application.

This amendment requires:

- New Construction Plan
- Consultation / Notification Written Report in accordance with Section 31(6) of OGAA.
- Engineering design specifications
- Notice of Construction Start
- Notice of Pressure Test
- Notice of Leave to Open
- As-Built

This amendment may require a revised As-Constructed drawing.

Upon approval and as a condition of Leave-to-Open, this amendment may require an updated ERP.

Amendment to Repair/Replace (not in-kind)

If all piping is the same as the original, it is a Notice of Intent for Repair/Replacement (in- kind).

To repair or replace existing pipe with a different spec of pipe, an amendment to the original permit is required.

The Repair/Replacement (not in-kind) may require a segment of a pipeline to be split to accommodate the repairs. This is done when the pipe needs to be upgraded and the existing pipe is no longer manufactured.

This amendment requires:

- New Construction Plan
- Consultation / Notification Written Report in accordance with Section 31(6) of OGAA.
- Engineering design specifications
- Notice of Construction Start
- Notice of Pressure Test
- Notice of Leave to Open
- As-Built

This amendment may require:

New land (see Pipeline Permit Application Manual)

- New As-Constructed drawing

Upon approval and as a condition of leave to open, the amendment may require an updated ERP.

Amendment to Install a Mid-Point Riser

An amendment is required when mid-point risers are to be installed where a new well is being brought onto a pipeline.

For any installation of a riser on a pipeline midway section (i.e.: – not at either end points), the original project number of the pipeline must be identified and the riser must be identified as to which pipeline segment the riser is to be attached and must also indicate the NTS or DLS location of the riser.

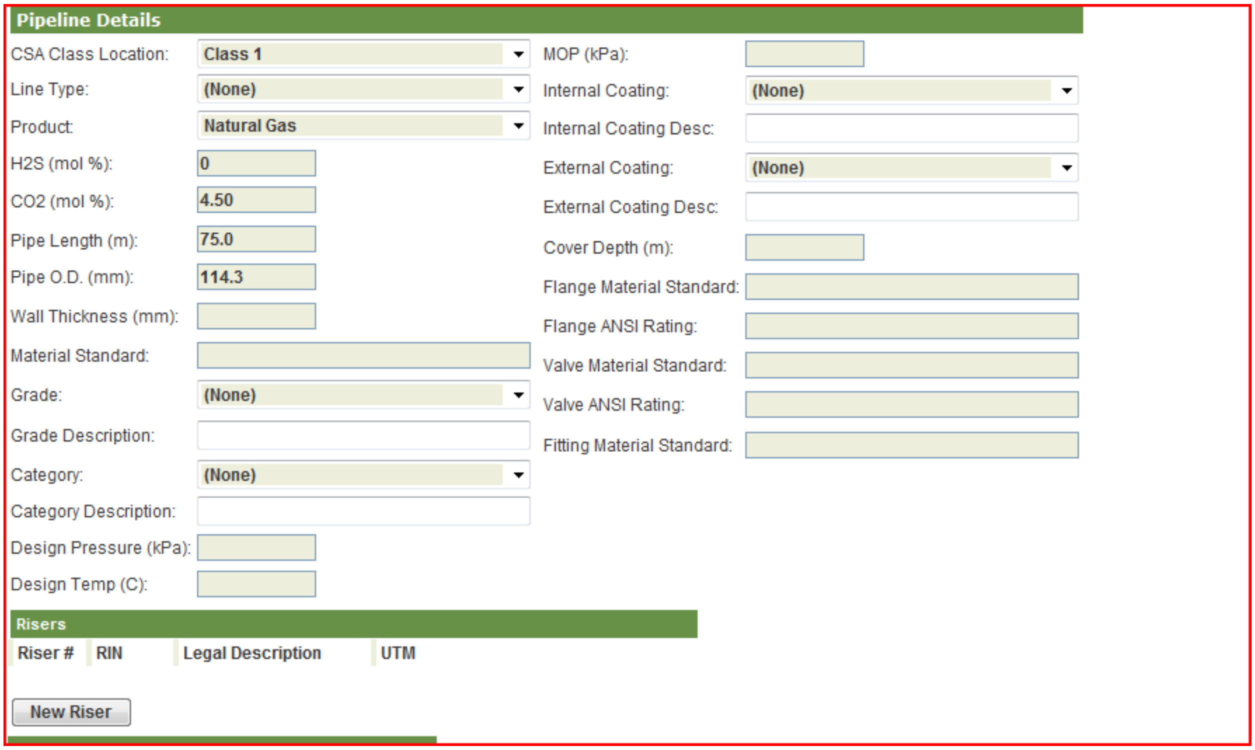
This amendment will require:

- Consultation / Notification Written Report in accordance with Section 31(6) of OGAA.
- Engineering design specifications
- Notice of Construction Start
- Notice of Pressure Test
- Notice of Leave to Open
- As-Built

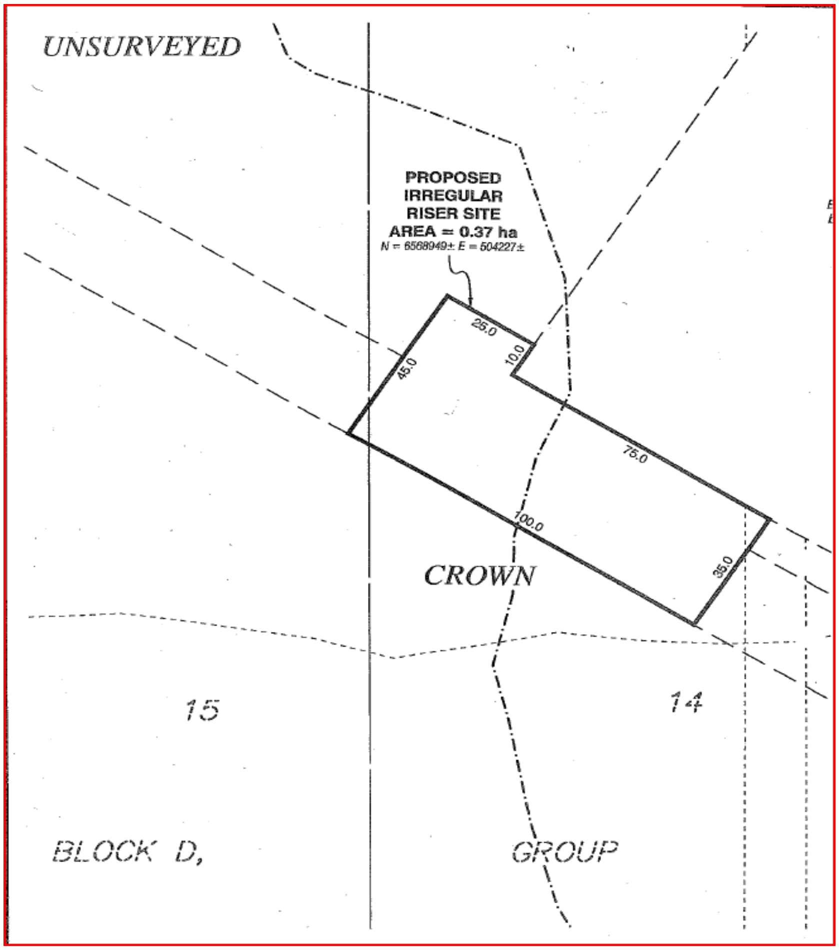
Upon approval and as a condition of leave to open, this may require an updated ERP.

Riser Locations

If there are risers associated with the pipeline, these riser locations need to be entered by NTS or DLS co-ordinates for location confirmation. These locations must be filled out and indicated on the design schematics as well as in the segment specification tab as shown below.



If there is a riser at the either endpoint of the pipeline, then it is applied for as part of the pipeline or is an amendment to the pipeline, even if it exceeds the width of the existing ROW. On applications this area should be included in the pipeline application, if it is an amendment, then it would be an amendment with new land required. Please see an example below for further clarification.


UNSURVEYED
PROPOSED
IRREGULAR
RISER SITE
AREA = 0.37 ha
N = 6568949± E = 504227±
25.0
10.0
45.0
75.0
100.0
35.0
CROWN
15
14
BLOCK D,
GROUP

Amendment to Change of Service

It is critical that changes in service from sweet to sour less than 1% H_2S to 1% or greater, and less than 5% to 5% or greater, are submitted to the Commission in before any changes occur, or upon the next differing gas analysis.

A Facility Permit Amendment must also be submitted if the pipeline change of service will create a change of service to the facility. E.g. if a pipeline becomes the largest H_2S concentration of the lines going into or out of the facility, and it therefore increases the licensed H_2S concentration of the facility; a facility permit amendment must be created.

The Facility Permit Amendment job number must be noted in the Pipeline Permit Amendment to have both applications will be reviewed simultaneously.

Refer to the Facilities Manual (currently in development) for more information on facility amendments.

Engineering Assessment
If a sour product is introduced into a pipeline that was not originally designed for sour, an engineering assessment (in accordance with the CSA Z662), must be completed and submitted to the Commission with the change of service.

Emergency Response Plan
The emergency response plan is to be evaluated and updated (if required), and must be on file with the Commission before the sour product is introduced into the pipeline.

If H_2S is increased from less than 1% to 1% or greater, there, there must be a site-specific ERP submitted to the Commission prior to commissioning or coming on-stream.

A facility Schedule 1 may also be attached depending on the nature of the change, as it may also affect the facility linkage codes.

If pressure welding and/or pipe pressure testing are to be conducted during the change in service a Notice of Construction Start and Notice of Pressure Test and Leave to Open are required.

This amendment will require:

- Consultation / Notification Written Report in accordance Section 31(6) of OGAA.
- Engineering Assessment
- Facility Permit Amendment

This amendment may require:

- Facility Achedule A (formerly BC21)

Amendment to Reverse Flow

An amendment is required to reverse the flow of a specific pipeline. This does not apply to a change of service to the line; only a flow direction-change. This may also create modifications to the pipe of to an adjoining facility.

Concurrent Facility Applications
If modifications to the facility are required, refer to the Facility Manual (currently in development) to determine which application is required. If a Facility Application or Notice of Intent is required, the job number associated with those must be included on the pipeline amendment application.

If the flow reversal will cause a facility linkage change, a Facility Schedule 1 must be attached.

If there are facility applications that are required for the flow reversal all submissions will be accepted and reviewed simultaneously.

This amendment will require:

- Consultation / Notification written report in accordance with Section 31(6) of OGAA.
- Engineering assessment
- Facility Permit Amendment
- Facility Schedule 1 (formerly BC21)
- New flow schematic

This amendment may require:

- Modifications to the existing pipe
- Engineering design specifications
- Notice of Construction Start
- Notice of Pressure Test
- Notice of Leave to Open
- As-Built

If modifications on the pipeline are required, it must be noted in the amendment in the description box.

Upon approval and prior to leave to open this may require an updated ERP.

Amendment to Abandon

Pipelines may be abandoned in place if they are properly de-activated in accordance with CSA Z662; are cut and capped below grade; and include identification markers.

For pipelines that have not been removed in their entirety and the land restored, submit a Notice of Intent to deactivate a pipeline and follow directions regarding deactivation.

The permit holder must also contact the BC Assessment Branch in reference to removal from the tax roll.

This amendment requires Consultation/Notification. During Consultation/Notification, the permit holder must allow the land owner the opportunity to request removal of easement of the title.

The abandoned line must remain registered with BC One Call and the company remains liable for the environmental impacts of the pipeline remaining in the ground.

Amendment to Re-Activate

To reactivate a project, pipeline or segment(s) from a deactivated state, a permit holder must follow the requirements of the latest edition of CSA Z662.

This amendment will require:

- Consultation / Notification Written Report in accordance with Section 31(6) of OGAA.
- Engineering assessment
- Pressure Test
- Leave to Open

This amendment may require:

- Modifications to the existing pipe
- Engineering design specifications
- Notice of Construction Start
- Notice of Pressure Test
- Notice of Leave to Open
- As-Built
- Facility Schedule 1 (formerly BC21)
- Facility Permit Amendment

Amendment to Split Existing Segments

An amendment is required to split existing segments to accommodate further tie-ins to an existing line or repair work, or to deactivate/abandon portions of lines. This is an amendment does not require consultation or notification unless it is in conjunction with a modification.

This amendment will require:

- A revised As-Constructed drawing
- A revised As-Built

This amendment may require:

- Modifications to the existing pipe
- Engineering design specifications
- Notice of Construction Start
- Notice of Pressure Test
- Notice of Leave to Open
- As-Built

11 Integrity Management and Damage Prevention Programs

To ensure the safe, reliable, and environmentally sound operation of pipelines in B.C., the Commission requires pipeline companies to comprehensively assess, identify, and address the integrity of their pipeline systems by implementing and maintaining a pipeline integrity management program (IMP) in accordance with Section 7 of the Pipeline Regulation.

An IMP is a system used to identify and assess activities that prevent or reduce the likelihood of incidents, as well as activities that mitigate consequences of incidents, should they occur.

A permit holder must develop and implement an IMP fulfilling the requirements of the Self Assessment Protocol - Integrity Management Programs for Pipeline Systems (Self Assessment Protocol) which was framed based on Annex N of CSA Z662-07 - Oil and Gas Pipeline Systems.

The Self Assessment Protocol is intended as a self assessment tool of the pipeline permit holder's IMP, in which the permit holder should conduct a baseline integrity assessment of all their pipelines, address any safety issues, reassess the integrity of their pipelines at specified intervals, and establish performance measures to evaluate the effectiveness of their IMP.

A selected number of pipeline permit holders will be notified in January each year to file the Self Assessment Protocol with the Commission by March 31 of the same year. The Commission will review all the submission and assess the conformance of each submission using the Commission Assessment Report for the Evaluation of Integrity Management Programs for Pipeline Systems (Assessment Report). The permit holder will then meet with the Commission to discuss the assessment findings in the Assessment Review Meeting. The details of the IMP regulatory process and some frequently answered questions can be found in Directive 2011-01 *Integrity Management Programs Self Assessment Protocols and Regulatory Process*.

All pipeline permit holders must update and re-submit the Self Assessment Protocol every five years. The findings of the Assessment Reports will be presented and published in the Pipeline Performance Report each calendar year.

Damage Prevention Program Procedure

All pipeline permit holders must implement a damage prevention program and present the program for review at the Commission's request. A similar Self Assessment Protocol to the pipeline Integrity Management Program is currently under development for Damage Prevention Program.

12 Incident Reporting

Any pipeline incidents with potential to or resulting in damage to the integrity of a pipeline must be reported to the Commission; even if there is no spillage of product or substances from the pipeline.

The incident reporting criteria is applicable regardless of the status of the pipeline and the type of product released. That is, hits on a deactivated or abandoned pipeline, leaks of fresh water from a pipeline, or spills of any substances within the right-of-way of the pipeline during the construction or operational processes must be reported.

Causes of pipeline incidents include but not limit to:

Causes	Incident Examples
Corrosion	• Internal corrosion • External corrosion
External interference	• Damage by permit holder excavation • Damage by third party excavation • Vandalism
Material manufacturing or construction	• Defective weld • Defective pipe body • Wrinkle or buckle
Weather-related or geotechnical failure	• Slope movement • Wash-out erosion • Freeze-thaw • Lightning • Fire
Overpressure	• Overpressure failure
Non-operational damage	• Damage during construction • Pressure test failure

Incident Reporting Procedure

Report pipeline-related spills to the Provincial Emergency Program (PEP) at 1-800-663-3456, and the commission at (250)261-5700.

There are two options for filing a repair or replacement after an incident:

1) Submit an NOI of Repair/Replace Pipeline (in-kind) for repairing and replacing a pipeline with the same material specification; or
2) Submit a Pipeline Amendment for Repair/Replace pipeline with different material specification (not in-kind).

Submit the Form D Licensee Post Incident Report (currently in development) along with any failure analysis results to the Commission within 60 days from the pipeline incident to OGCPipelines.Facilities@gov.bc.ca.

The report should reflect the analysis of what changes are needed to prevent the occurrence of similar incidents.

Should an extension of the 60 day time frame be required, the permit holder must notify the Pipeline Engineer.

13 In-Line Testing

An example of the form required to report inline testing is located in Appendix E.

On-Lease

If the riser is situated on-lease and all associated piping required for the in-line test is on site, an In-Line Testing Form, along with a Facility Schedule 1 must be submitted.

The form requires the pipeline project and segment numbers that the in- line test is being conducted into. The pipeline must:

- Be registered and capable of flowing the product in question
- Be licensed to handle to the product in question
- Be licensed to handle the pressure of the test
- Be fit for flow

If the pipeline does not meet the pressure product licence (in accordance with 10.11.6 CSA Z622), an engineering assessment or fit for purpose study must be submitted with the In-Line Testing Form as proof that the pipeline is capable of handling the test.

Off-Lease

If the riser is situated off lease, a temporary surface line must be applied for. Information on how to apply for and license a temporary surface line is found in the Pipeline Applications Manual.

Once a temporary line is licensed, an In-Line Testing Form must be submitted and must meet the same criteria as for the on-lease pipeline.

Appendix A – Product Code Table

Code	Product
AG	Acid Gas
CG	Coal bed Gas (Methane)
CO	Crude Oil
FW	Fresh Water
FG	Fuel Gas
HVP	High Vapour Pressure
JF	Jet Fuel
LVP	Low Vapour Pressure
ME	Methanol
MG	Miscellaneous Gases (air, ammonia, carbon dioxide, ethane, helium, hydrogen, HyS, nitrogen, steam)
ML	Miscellaneous Liquids (produced water, sulphur slurry)
MP	Multiphase
NG	Natural Gas (less than 1 mole % of H_2S content)
OE	Oilwell Effluent
OTH	Other – identify the product type
PW	Produced Water
SC	Sour Crude Oil
SE	Sour Oilwell Effluent
SG	Sour Natural Gas (1 mole % or more of H_2S content)
SHC	Sweet Hydrocarbon Condensate
ST	Sweet Gas

Appendix B – Engineering Attachments Table

Engineering Attachments for KERMIT Application

						Pre-Construction	Post Construction
	Project Description	**Design Schematics***	**Appurtenance Location Map**	**Crossing Designs**	**Pressure Test Design**	**Notice of Pressure Test**	**Notice of Pressure Test**
Crown Land Non-Routine	Y	Y	Y	M	Y	Y	Y
Crown Land Routine	Y	Y	Y	M	Y	Y	Y
Private Land Non-Routine	Y	Y	Y	M	Y	Y	Y
Private Land Routine	Y	Y	Y	M	Y	Y	Y

Y = Required submission

M = May be required if it is present in the project

* = Multiple design schematics may be required.

Appendix C – Notice of Intent Matrix

Notice of Intent Matrix

		Pre-Construction	During Construction		Post Construction
	Notice of Intent	**Notice of Construction Start**	**Notice of Pressure Test**	**Leave to Open**	**As-Built**
Decrease MOP (upstream)	Y	N	N	Y	N
Decrease MOP (downstream)	Y	N	N	Y	N
Modify Data	Y	N	N	N	Y*
Repair/Replace (in-kind)	Y	Y	M	Y	N
Install Farm Tap	Y	Y	Y	Y	Y

Y = Required submission
Y* = if not previously submitted
N = Not required
M = May be required if any work was done to allow for task

Appendix D – Amendment Matrix

Amendment Matrix

		Pre-Construction	During Construction				Post Construction
	Amendment	**Notice of Construction Start**	**Facility Amendment**	**Facility Schedule 1**	**Notice of Pressure Test**	**Leave to Open**	**As-Built**
Change in CSA Class Location	Y	N	N	N	N	Y	M
Increase MOP	Y	N	N	N	Y	Y	M
Cancel Pipeline	Y	N	N	N	N	N	N
Modify Sub-Surface Pipe	Y	Y	N	N	Y	Y	Y
Repair/Replace (not in-kind)	Y	Y	N	N	Y	Y	Y
Installation of Mid Point Riser	Y	Y	N	N	Y	Y	Y
Change of Service	Y	N	Y	Y	M	Y	Y
Pipeline Flow Reversal	Y	N	N	Y	N	Y	Y
Abandon Pipeline	Y	N	N	N	N	N	M
Splitting Segments	Y	N	N	N	N	N	Y

Y = Required submission

N = Not required

M = May be required if not previously submitted.

If more than one amendment is being applied for (For example, increase MOP and modify sub-surface pipe), the documentation requirements for each must be met.

Appendix E – Inline Testing Form Sample

BC Oil & Gas COMMISSION

INLINE TESTING NOTIFICATION
OGC, 100 10003 110 AVE
Fort St. John, B.C. V1J 6M7
Phone: (250) 794-5200
Fax: (250) 794-5380
Email: OGCPipelines.Facilities@gov.bc.ca

Date Received

THIS IS AN AUDITABLE DOCUMENT

COMMISSION USE ONLY			**A**
Commission File No.:			
ADMINISTRATION			**B**
Company Name:			
Address:			
City, Province, Postal Code:			
Contact Name:	Email:		
Phone:	Fax:		
Site Supervisor:	Phone:		
Well Permit No./ Facility No.:	Well Name/Facility Name:		
Well Location (in decimal degrees using NAD83): Latitude:	Longitude:		
GEOLOGICAL INFORMATION			**C**
Start Date (MM/DD/YYYY):	End Date (MM/DD/YYYY):		
Geological Formation:	Expected H_2S (%):		
Geological Formation:	Expected H_2S (%):		
Geological Formation:	Expected H_2S (%):		
TIE IN INFORMATION			**D**
Pipeline being tied into:			
Project No.:	Segment No.:	H_2S %:	
☐ New ☐ Existing (Attach Engineering Assessment)			
Has it been deactivated or not producing over the last 12 months? ☐ Yes (Attach Engineering Assessment) ☐ No			
Is gas composition changing? ☐ Yes ☐ No (Attach Engineering Assessment)			
Is temporary surface line being used? ☐ Yes ☐ No			
Does test line go off lease? ☐ Yes ☐ No			
Is there a Schedule 1 - Application for Well or Facility Linkage approval? ☐ Yes ☐ No (Attached)			
APPLICATION DELIVERABLES			**E**
☐ Engineering Assessment			
☐ Pipe Specifications			
☐ Schedule 1			
CONDITIONS			**F**
For gas well tests, the Well Deliverability Test Report, supporting fluid analyses, gas and liquid production rates and a schematic of the downhole equipment must be submitted to the Commission's Resource Conservation division within 60 days of the end of the test. The appropriate ERP must be in effect for all testing operations. All of the requirements as outlined in the Drilling and Production Regulation apply.			
COMMISSION USE ONLY			**L**
Accepted for Filing by:	Date:		
Pipeline Operations Review; Employee Signature & Date	Facility Operations Review; Employee Signature & Date		

Appendix J3

OGC FACILITY APPLICATION AND OPERATIONS MANUAL

BC Oil & Gas COMMISSION

FACILITY APPLICATION AND OPERATIONS MANUAL

April | 2011

Version 1.5

Contents

Manual Revisions

Summary of Revisions

The Facility Application and Operations Manual has been revised based upon feedback to provide clarity in terms of requirements and process. Structural changes by section are highlighted below.

Applications received on or after the effective date will be required to meet the revised application standards.

Effective Date	Section	Description/Rationale
1-Feb-2011	6	Added information on added KERMIT security features.
	6	Added information regarding Gas Processing Plant Applications, now in KERMIT. There is no longer a Schedule 2 to upload.
	6	Added details for new compressor facility requirements.
	6	Added a requirement for oil condensate capacity with description of design capacity.
	6	Added required attachments to the attachments tab.
	7	Added detail to the P&ID requirements.
	8	Well or Facility to Facility Linkage change is no longer an Amendment.
	9	Added information regarding linkage changes.
	14	Removed Isolation valve location maps, and tie-in schematics of ESD valves from required attachments.
	14	Added definition of Design Standard and Gathering System Schematic.
	9	Added contact information for Facility Application Coordinators.
	Appendix F	Removed Summary of Rationale from Gathering Block Diagram.
	8 & 9	Added examples of when an NOI is required.
	1	OGC.Documentation to OGC.Systems
	General	Updated all links
1-March-2011	14	Revised Post-Construction Plan information
	6	Consultation Tab – replaced all reference from multiple stakeholders to multiple owner/occupants.
	Appendix F	Under Flare/incinerator: revised the guideline name to the new title, “Flaring and Venting Reduction Guideline.”
		Added reference to Drilling & Production Regulation, Section 42(1)(2)(5) on flaring limits, and Section 43(1)(2)(3).
1-April-2011	6	Engineering Tab - Facility Specification Question. Moved the answer “If yes; attach a Schedule 3” from question 7 to question 6, “Does the facility require a registration to discharge waste under Section 6 of the Oil and Gas Waste Regulation?”
	Appendix F	Under Flare/incinerator: added ”Describe the flare metering configuration that is proposed in order to measure both the purge gas within the meter range and accuracy lower limit…”,
	Forms	Made formatting changes to facility forms, including updating phone number.

1-April-2011	4	Revised Additional Information – Engaging First Nations.
	7	Revised First Nations Consultation/Aboriginal Community Notice Package.
	Appendix I	Added Appendix J – Engagement Log Example.
1-May-2011	5 Engineering Tab – Gas Processing Plant	Revised Total Recovered Products &Technical information to read, Total Recovered Products & Technical Information at Design Capacity
	9	Added that piping and equipment for a new well tie-in cannot be submitted with a NOI. A facility permit, or permit amendment is required.

1 Preface

Purpose

This manual has been created to guide users through Commission processes and procedures. It also serves to highlight changes in process, procedure, requirements and terminology resulting from the Oil and Gas Activities Act (OGAA).

For users already familiar with the Commission application process, this manual provides a quick reference highlighting the steps required to complete specific tasks. For users less familiar, this manual presents a complete overview of Commission requirements and provides links to more detailed material.

This manual is not intended to take the place of the applicable legislation. The user is encouraged to read the full text of legislation and each applicable regulation and seek direction from Commission staff, if and when necessary for clarification.

Scope

This manual focuses exclusively on requirements and processes associated with the Commission's legislative authorities, and do not provide information on legal responsibilities that the Commission does not regulate. It is the responsibility of the applicant or permit holder to know and uphold its other legal responsibilities. Examples of legal responsibilities outside of this manual include obligations under the Federal Fisheries Act, the Transportation Act, the Highway Act, the Workers Compensation Act, and the Wildlife Act.

How to Use This Manual

The applicant must determine in advance of application whether or not new land is required for the proposed activity.

This manual is divided into sections which are organized chronologically, and match the order of the steps which applicants and permit holders will follow when engaging in oil and gas activities.

Beginning with pre-application, the manual takes the user through the steps of permit application preparation, submission, review and amendment; construction and operation; and operational reporting.

In the facility manual, applicants must be aware of whether or not new land is required for the activities they propose. Applications and amendments requiring new land differ from those using existing land, and are housed in separate sections of the manual to ensure the correct procedures are followed.

For the applications, amendments and notices of intent that must be submitted electronically through the Commission's KERMIT database, step-by-step instructions are provided.

Section 2	**Pre-Application Requirements** outlines what companies new to British Columbia need to have in place before applying for oil and gas permits.
Section 3	**Application & Review Process** explains and illustrates the application, review and determination process to provide the applicant with an understanding of Commission procedures, and what to expect during the permitting process.
Section 4	**Preparing Facility Permit Applications** shows what considerations should be taken into account when preparing facility permit applications prior to submission.
Section 5	**KERMIT Overview** explains and illustrates the features that are common to all KERMIT submissions.
Section 6	**Facility Permit Application (no new land) Application** provides clear procedural direction on how to complete and submit facility permit applications and reporting requirements in the Commission's KERMIT database where no new land is required.
Section 7	**Facility (New) Permit Application Application** provides clear procedural direction on how to complete and submit facility permit applications and reporting requirements in the Commission's KERMIT database where new land is required.

Section 8 **Facility Permit Amendments** details the procedures to make amendments to a permitted facility where no new land is required.

Section 9 **Notice of Intent** describes what is required to Cancel a Facility, Repair/Modify Equipment, and Add/Delete Equipment. It also provides step-by-step instruction on how to submit the notices in KERMIT.

Section 10 **Pre-Construction** details what is required for, and how to submit a Notice of Construction Start.

Section 11 **During Construction** details what is required for and how to submit a Notice of Pressure Test; Shop Test and Field Test.

Section 12 **Commencing Operations** details the requirements for, and how to submit a Leave-to-Open.

Section 13 **Tenuring** outlines right-of-way requirements.

Section 14 **Post-Construction** details what is required for and how to submit As-Built, As-Cleared and Post-Construction Plans.

Section 15 **Historical Facility Entry** outlines what is required when dealing with previously permitted facilities that do not appear in the KERMIT database.

Section 16 **Gas Processing Plants** describes the process for applying for a new gas processing plant.

Additional Guidance

Guidance for land tenures is found in the Corporate Land Management Manual.

The glossary page on the Commission website provides a comprehensive list of terms.
The appendices contain documents to be used as reference when compiling information required by the Commission.

Other navigational and illustrative elements used in the manual include:

Hyperlinks: Hyperlinked items appear as blue, underlined text. Clicking on a hyperlink takes the user directly to a document or location on a webpage.

Sidebars: Sidebars highlight important information such as a change from an old procedure, new information, or reminders and tips.

Figures: Figures illustrate a function or process to give the user a visual representation of a large or complex item.

Tables: Tables organize information into columns and rows for quick comparison.

Frequently Asked Questions
A Frequently Asked Questions (FAQ) link is available on the Commission OGAA page. The information provided is categorized into topics which reflect the manuals for easy reference. Please consult the FAQ page before contacting the Commission to help keep response times short.

Feedback
The Commission is committed to continuous improvement by collecting information on the effectiveness of guidelines and manuals. Clients and stakeholders wishing to comment on Commission guidelines and manuals may send constructive comments to OGC.Systems@gov.bc.ca.

2 Pre-Application Requirements

Companies applying to engage in oil and gas activities in BC the must ensure all pre-application requirements have been met. These include the New Permit Holder Application Form, and a Master Licence to Cut Application (MLTC), and ePASS submission.

In addition to these pre-application requirements, the Commission may require a company to provide a security to ensure the performance of an obligation under the Oil and Gas Activities Act (OGAA) prior to, during, or after the permit application process, in accordance with Section 30 of the OGAA.

New Permit Holder Application Form

The New Permit Holder Application Form captures general administrative and corporate registry information.

Completed New Permit Holder Application Forms and required attachments are to be submitted to the Commission's Corporate Land Management Unit.

Refer to the Commission's Corporate Land Management Manual for additional information.

Master Licence to Cut

A Master Licence to Cut (MLTC) on Crown land is required where the removal of timber is necessary to conduct an oil and gas activity. A separate agreement is required for each forest district.

An MLTC must be completed and submitted before an application for oil and gas activity is made, as the MLTC will govern the cutting permit that authorizes the removal of timber on Crown land.

ePASS

ePASS stands for electronic Petroleum Applications Spatial Submission. All companies new to the Commission must create an ePASS account.

Section 2 of the ePASS Submission Standards describes all attribute data components that must be submitted using ePASS for pipeline permit applications.

All ePASS submissions must conform to the shapefile spatial data format. These spatial standards are outlined in the Environmental Systems Research Institute White Paper, ESRI Shapefile Technical Description.

Spatial data associated with facility post-construction plans will appear on the Commission's FTP site (Outgoing Data) for download by the public.

3 Application & Review Process

Permit Review & Approval

The following process flowcharts show the major steps in the application preparation process, and the Commission's application review and determination processes.

Once all pre-application requirements have been met, the applicant must determine if the proposed activity will require new land, or no new land.

If new land is required, the applicant will follow the facility application instructions in Section 7 of this manual. Direction for applications that require no new land is in Section 6.

Figure 3.1 below outlines the basic steps when submit either type of facility application.

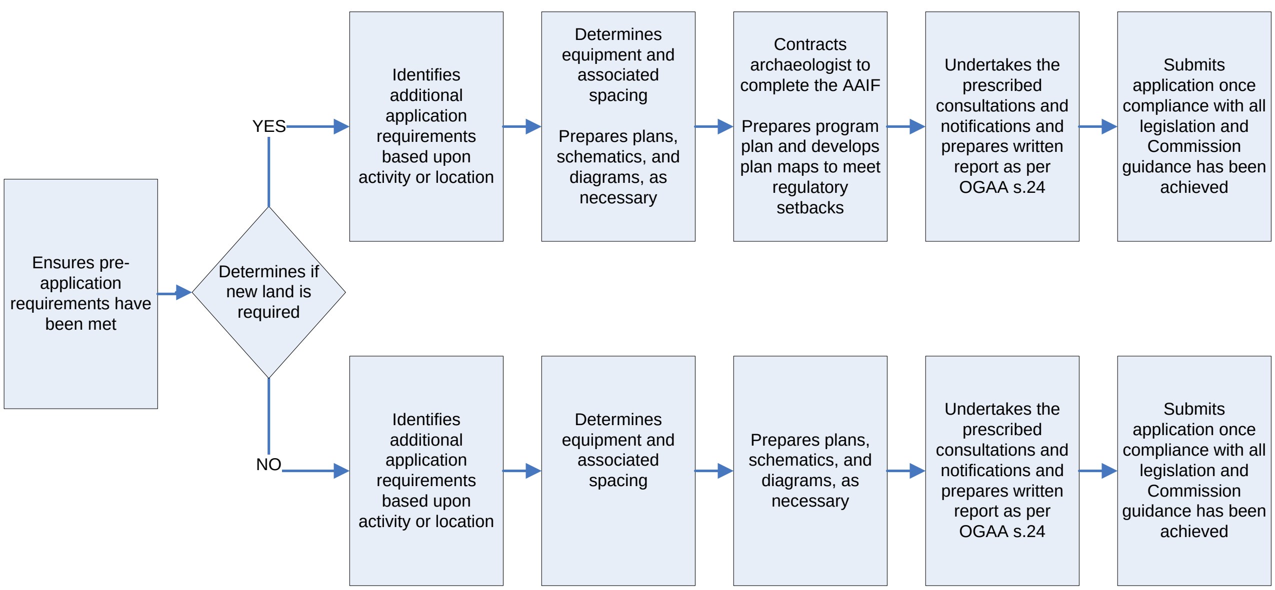


Figure 3.1. An overview of the applicant's role in the application preparation process.

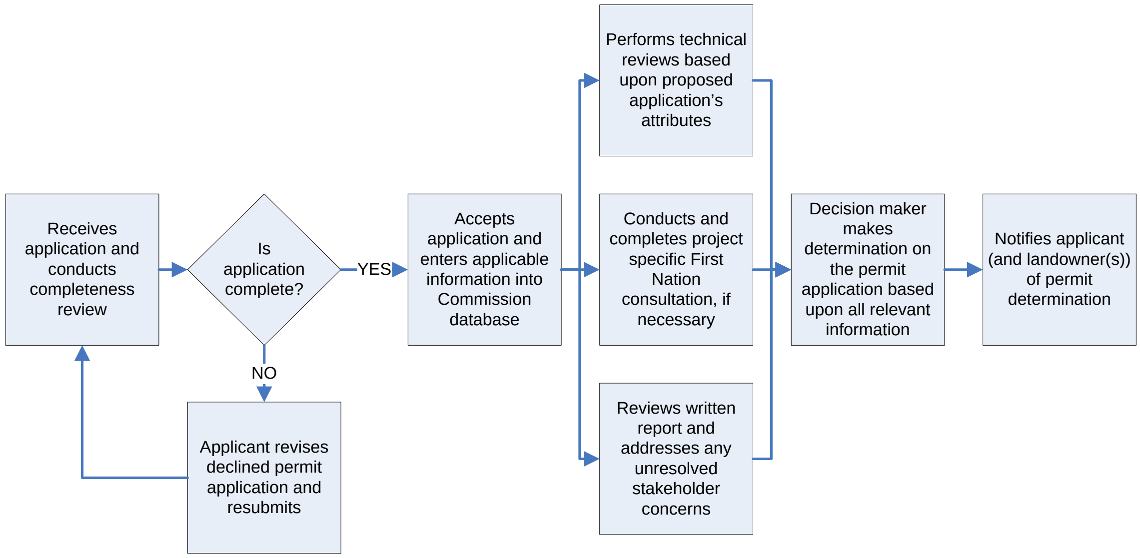


Figure 3.2. An overview of the Commission's role in the permit application review and determination processes.

Permit Review & Determination

Permit Review

Once an application has been received by the Commission it is reviewed for completeness.

Declined Applications

Applications containing incomplete information are declined and returned to the applicant. A rationale explaining why the application was declined is sent to the applicant by email.

Revision and Resubmission

Once any deficiencies have been addressed, the application can be resubmitted. Applications that have previously been declined are reviewed in order based on the resubmission date; not from the date of original submission.

Permit Determination

When all requirements have been met, the application is classified as complete. It is then accepted and enters the processing phase.

To make a determination on the application, the Commission will consult with First Nations (where applicable), review the applicant's consultation and notification record and perform technical reviews on areas such as archaeology, land and habitat, and engineering design of any equipment being added in regard to safety and emissions management.

Section 26 (1) of OGAA indicates the Commission may: refuse to issue a permit, suspend a permit or a permission specified in a permit, cancel a permit or a permission specified in a permit or amend a permit.

Once all application requirements have been met, the Commission may issue a permit specifying the conditions attached to the permit, and what activities the permit holder may carry out, including related authorizations under the Forest Act, Water Act.

For permits issued on Crown land, the Commission will authorize the occupation of Crown land pursuant to the Land Act.

Permits issued over private land are subject to a landowner agreement. If agreement cannot be reached, an application may be made to the Surface Rights Board In accordance with Part 16 of the Petroleum and Natural Gas Act. For more information see the Consultation and Notification Manual.

Sections 70 and 72 of OGAA establish an applicant or permit holder's right to a review and/or appeal of a determination. Guidance on the review and appeals process is found within the Determination Review Guideline.

Approved permit applications requiring no new land will be sent to the Operator and uploaded to the project in KERMIT. Approved permit applications requiring new land will be delivered as hard copy permit.

Post Approval

Landowner Notification Process

Following a permit approval, the Commission provides notice to the landowner(s) that an oil and gas permit has been issued over their land. The notice cites specific details about the location of the approved activity, and the landowner(s) right to appeal.

The permit holder must wait 15 days from the day the permit is issued before commencing the oil and gas activity, unless the landowner has consented to the permit holder in writing that the oil and gas activity may commence.

Written consent from a landowner does not have to be provided to the Commission as part of the application; however the permit holder must retain it for their records and for auditing purposes.

Instruction regarding appeals may be obtained from the Oil and Gas Appeals Tribunal.

Term of Permit
The term is the length of time the permit is valid, and is defined by regulation.

To extend a permit term, the permit holder should consult the Commission's Permit Expiry and Extension Guideline.

If activities have not begun by the end of the permit term (for permits on new land), the permit will expire and the Commission will proceed with the cancellation process.

Permits which require no new land have no internal cancellation process. Permit holders must submit a Cancel Facility Notice of Intent to cancel an existing permit.

Permit Transfers
A permit holder may apply to the Commission to transfer a permit in accordance with Section 29 of OGAA.

For more information on the permit transfer process and transfer application requirements, please refer to the Corporate Land Management Manual.

4 Preparing Permit Applications

To undertake any proposed facility activity, whether within an existing right-of-way or over new Crown land or private land, companies must first submit a completed facility permit application through the Commission's KERMIT database. Refer to Section 5 for an overview of KERMIT features.

A permit application provides the Commission with the necessary information to conduct a review of the proposed project. Upon completion of the review the Commission may issue a permit.

Prior to submitting the application, certain preparation and planning activities may be required. Following the directions provided in this section will help to ensure that the application is complete and correct, which may minimize Commission review timelines.

Construction plans, and if required, First Nations packages must be submitted in person or via mail to the BC Oil and Gas Commission in Fort St John.

BC Oil and Gas Commission
100, 10003 100th Avenue
Fort St John, BC V1J 6M7

Preparation & Planning

When preparing a permit application, certain activities must be carried out to ensure that a complete and correct application is submitted. Applicants must first determine whether or not new land will be required.

No New Land Required
If no new land is required every applicant must:

1) Determine what equipment is to be on-site
2) Plan equipment spacing and design in accordance with the Drilling and Production Regulation.
3) Undertake the prescribed consultation & notification by:
   a) Identifying the landowner(s), as defined by OGAA, in the area of intended activity
   b) Providing the landowner(s) with the requirements of a notification package, as defined by the Consultation and Notification Guideline
   c) Preparing a written report in accordance with the Commission's Consultation and Notification Guideline
4) Complete Agricultural Land Reserve obligations per the Agricultural Land Commission Delegation Agreement if program is located within the Agricultural Land Reserve.
5) Prepare plot plan, process flow diagram, piping and instrumentation diagrams (P&ID).
6) If necessary, prepare metering block and gathering block diagrams for measurement review for processing facilities. See Appendix F for requirements.
7) If necessary, prepare production accounting model for processing facilities.
8) Receive and consider written submissions forwarded from Commission in accordance with OGAA s.22(6).
9) Prepare and map Emergency Planning Zone (EPZ). See Appendix D.
10) Compile and submit application to the Commission.

New Land Required

If new land is required every applicant must:

1) Determine what equipment is to be on-site, and whether or not new land will be required.
2) Plan equipment spacing and design in accordance with the Drilling and Production Regulation.
3) Prepare construction plan(s) in accordance with OGAA s.24(1)(b). Construction plan requirements are located in Appendix A.
4) Contract an archaeologist to complete an archaeological assessment per the Heritage Conservation Act and the Commission's Archaeology Guidelines (if new land is required).
5) Undertake the prescribed consultation & notification by:
    a) Identifying the landowner(s), as defined by OGAA, in the area of intended activity
    b) Providing the landowner(s) with the requirements of a notification package, as defined by the Consultation and Notification Guideline
    c) Preparing a written report in accordance with the Commission's Consultation and Notification Guideline
6) Enter a surface agreement with landowner, if activity is located on new private land in accordance with OGAA s.34.
7) Complete Agricultural Land Reserve obligations per the Agricultural Land Commission Delegation Agreement if program is located within the Agricultural Land Reserve.
8) Prepare plot plan, process flow diagram, piping and instrumentation diagrams (P&ID).
9) If necessary, prepare metering block and gathering block diagrams for measurement review for processing facilities. See Appendix F for requirements.
10) If necessary, prepare production accounting model for processing facilities.
11) Receive and consider written submissions forwarded from Commission in accordance with OGAA s.22(6).
12) Prepare and map Emergency Planning Zone (EPZ) See Appendix E.
13) Compile and submit application to the Commission.

Information on Block Diagrams and Production Accounting Models is found within the Measurement Requirements for Upstream Oil and Gas Operations Manual.

Additional Considerations

Engaging First Nations

Prior to submitting an application to the Commission, companies are encouraged to initiate and build relationships with First Nations communities directly by discussing their intended development plans.

It is recommended that an Engagement Log be used to record be kept of this and all subsequent meetings and conversations that are held. A sample format for the Engagement Log is located in Appendix I.

An Engagement Log can greatly benefit the flow of the process where the First Nation has been advised that the applicant's engagement activities will be shared with the Commission. The engagement log may be considered in the decision making process

First Nations Consultation Boundaries maps are available for review at the Commission office. These maps along with advice from Commission First Nation Liaison Officers provide companies a starting point for their engagement responsibilities.

Details regarding engagement and consultation requirements are located in Section 5 First Nations/Aboriginal Communities Consultation and Notice.

Forms

Form used in conjunction with First Nation Consultation (including First Nation Cover Letters) are found on the Commission website.

Spatial Data

Provincial spatial data is stored within the BC Geographic Warehouse, a central, consolidated repository of land and resource information from across the province. It includes many types of data including cadastral information (tenures, ownership, boundaries); resource information (vegetation, fisheries, wildlife), provincial atlas (rivers, roads, buildings, topography, surveys), and planning and analysis information (land and resource management plans, sustainable resource management plans).

Spatial data from the BC Geographic Warehouse is available to view through iMapBC, discover through the Discovery Service, and download from the Distribution Service.

All services can be accessed through the GeoBC Gateway.

5 KERMIT Overview

KERMIT is the Commission's Knowledge, Enterprise, Resource, Management, Information and Technology data system.

KERMIT enables electronic submission of applications, performance/compliance data submission, and electronic workflow management.

For additional information, the applicant should refer to the KERMIT application page on the Commission's website. This page provides links to frequently asked questions about KERMIT, an external overview document which illustrates how to navigate within KERMIT, and a company administration document which illustrates how to manage KERMIT accounts.

Application Header

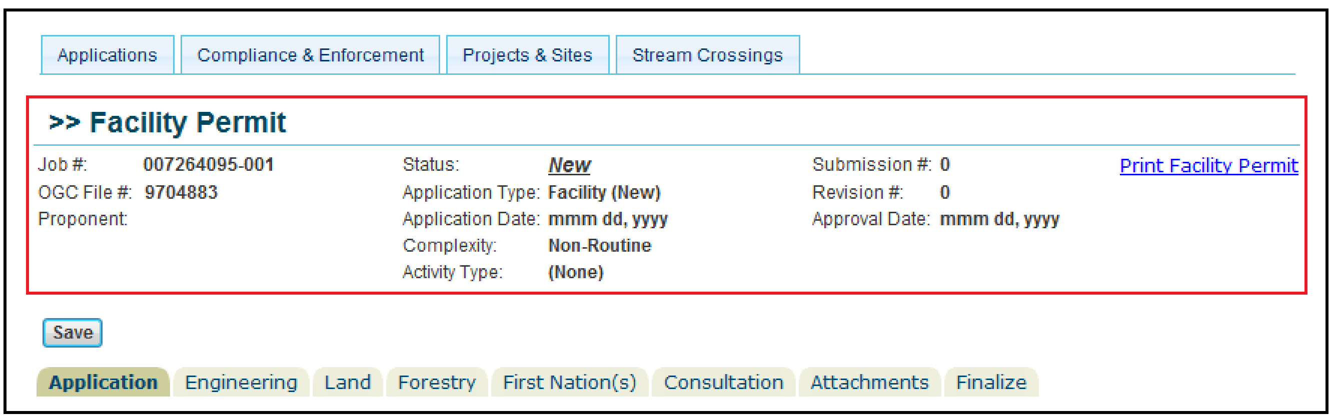


Fig. 5.1. KERMIT example application header on facility (new land) application page.

At the top of the facility application is the header. The header displays:

Job #	Used to identify a specific project. The user can click on the link to navigate to that job.
OGC File #	Used to identify related surface rights applications.
Proponent	Name of the related organization.
Status	Displays what stage the job is in.
Application Type	New Land: • Facility (New) • Facility Amendment • Facility Permit Extension No New Land: • Facility (New) • Facility Amendment – Add/Delete Equipment • Facility Amendment – Repair/Modify Equipment
Application Date	The date on which the application was submitted or the hardcopy was received
Complexity	Identifies the application as either routine or non-routine.
Submission #	The number of times the application has been submitted.
Revision #	The number of times the application has been resubmitted after screening.
Approval Date	The date on which the application was approved.
Print Facility Application	View and print a hard copy of the application. Used when a hard copy needs to be submitted with other application deliverables (For example, First Nation(s) package).

KERMIT Functions

Fields

Most mandatory fields display a shaded background. Some fields that are conditional may become mandatory, and do not appear with the shaded background and instead appear under finalize tab as an outstanding issue.

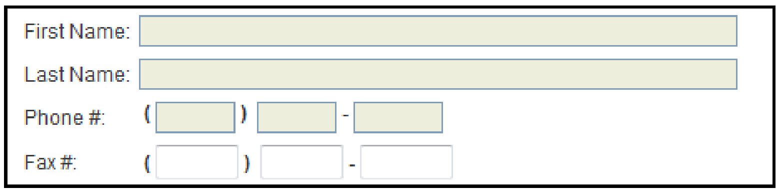


Fig. 5.2. Shaded mandatory fields in KERMIT

Search

The search function in KERMIT provides a way to link an application, notice or activity to an existing site or project.

Applicants can search for a specific site by entering the site number. The more specific the information used to search with is the more specific the search result will be.

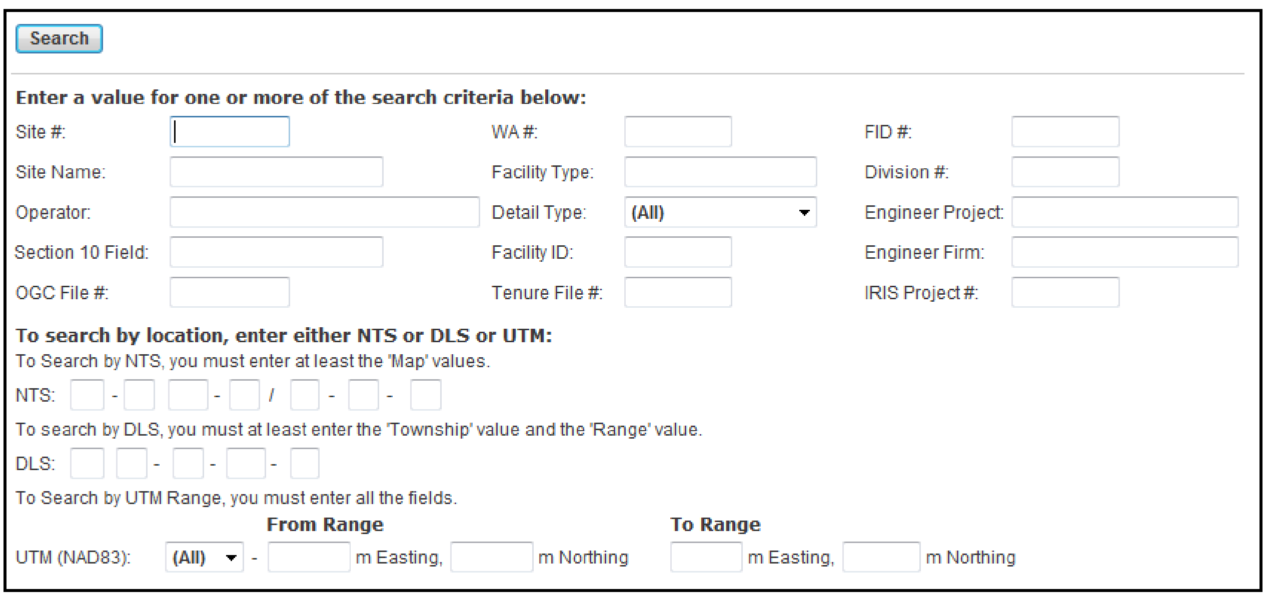


Fig. 5.3. KERMIT Search – No New Land.

Depending on which search method is used, one site or a choice of sites will be displayed. Choose the related site and click on New Permit to open the Facility Permit Application page.

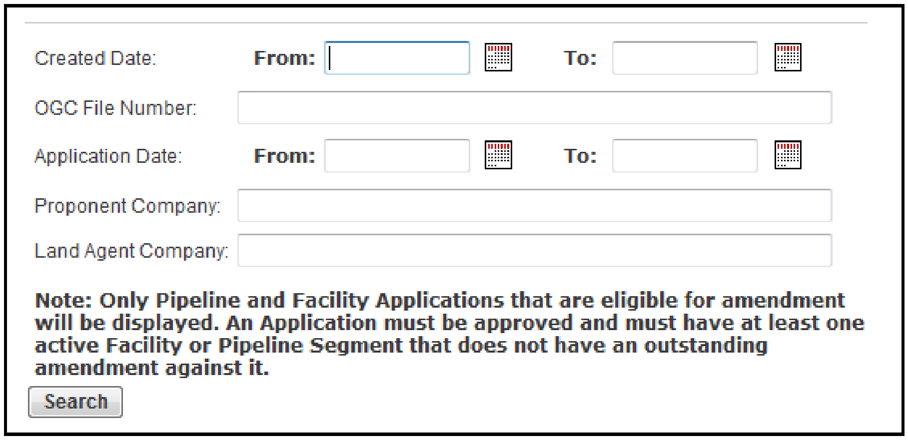


Fig. 5.4. KERMIT Search – New Land.

Date
All editable date fields have a calendar button which opens up a calendar. Select a date, or enter it manually in the MM/DD/YYYY format.

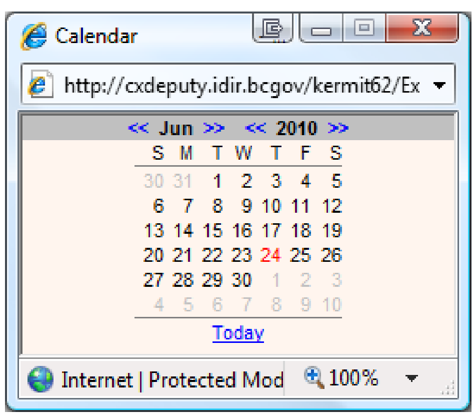


Fig. 5.5. Calendar window.

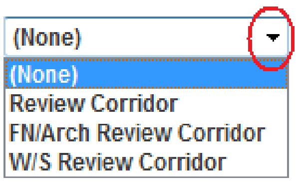
Buttons and Menus

The save button 

updates the application. This is convenient because it allows the user to enter in information, save it and come back at a different time to edit or complete it.

The find button 

opens a pop-up window the user can use to search for a detail.



Dropdown menus contain a list of pre-set values that the user can choose from. Click on the down arrow to see the list, and select.

Attachments Tab

The attachments tab allows a user to upload documents and relate them to the job. To attach a document:

1) Choose the document type from the dropdown menu.
2) Click the upload button.
3) Type the name and extension of the file, or click the browse button to open a search window to search for a document.
4) Click the upload button again to upload the document.
5) Fill in the file reference, author name and author's email address
6) Click the save button to finalize the attachment.

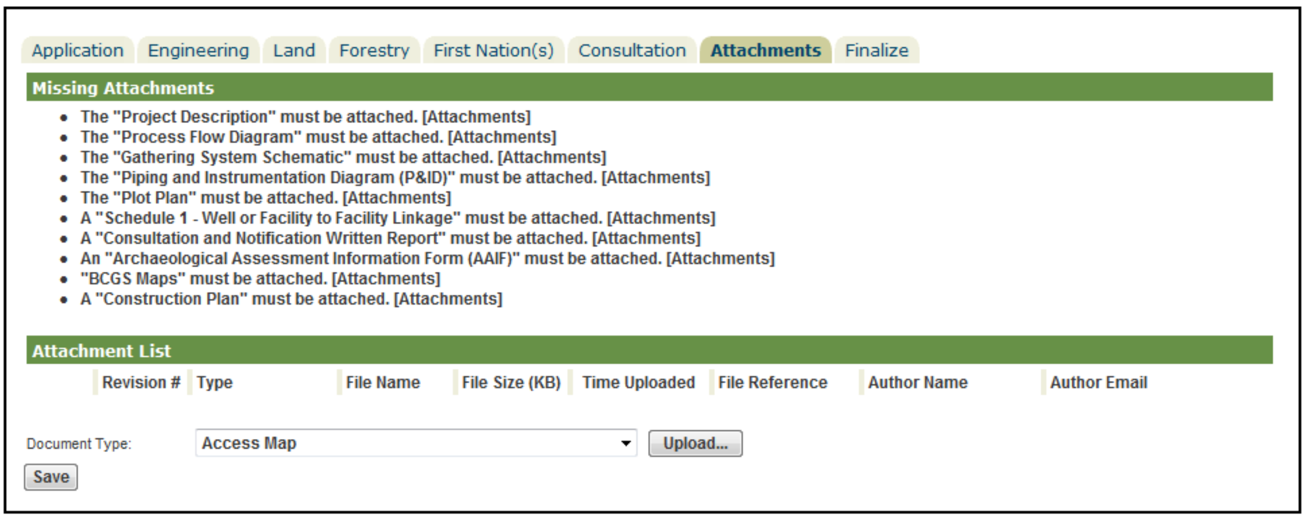


Fig. 5.6. Facility attachments page

Finalize Tab

KERMIT will indicate if there are outstanding issues with the Application. Once the outstanding Issues are corrected, the application can be finalized.

Finalize the application and submit it to the Commission.

If First Nations packages are required, the Commission will not review the application in KERMIT until the hard copy packages are submitted and applicable fees are received by the Commission.

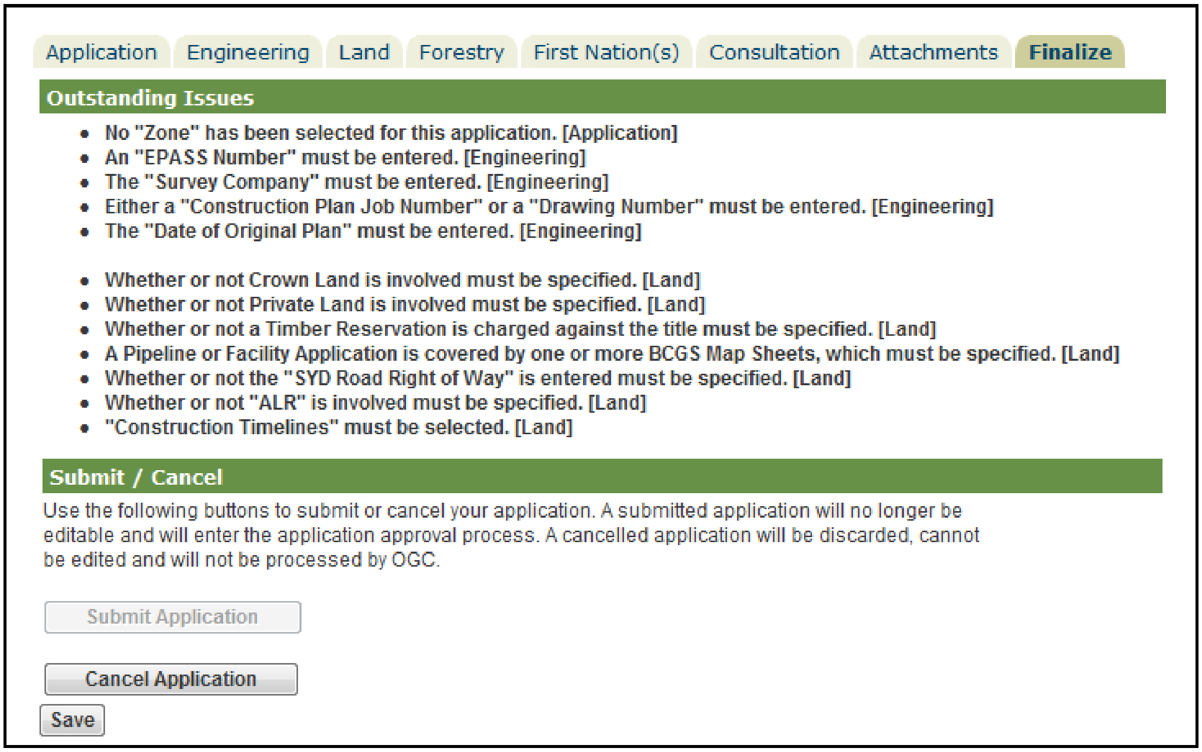


Fig. 5.7. Facility attachments page

Structure and Function of the Facility Information in KERMIT

In KERMIT, facility information is housed in three main divisions, site, detail and activity.

Site
A site number is assigned to each legal location that will contain equipment. A site number is automatically assigned in KERMIT upon approval of a Facility (New) application where new land is required, or upon approval the initial Well Permit Application.

Applications for wells which have different legal locations, but occupy the same surface lease will be submitted under their respective site numbers.

Detail
A detail number is assigned per company, per detail type, per location.

Detail types are facility piping, equipment and compressor. All equipment, with the exception of compressors, is listed under the equipment detail. Each compressor is assigned its own detail number, and if there is more than one lease at the same legal location (i.e. a riser site and a separate wellsite), separate detail numbers will be used. Detail numbers are listed under the Details tab.

For Example, c-014-H, c-A014-H, c-B014-H will get their own detail numbers as they are for separate wells, each compressor will get its own detail number, and shared well equipment would be listed under the c-014-H detail.

Activity
Each permit or notice that is submitted creates a new activity that subsequent notices (construction start, pressure test, etc.) may be applied to.

Activities are listed under the Activity Status tab, and posted under the detail number used in the application.

Job Number
When initiating an application, a job number will be generated. A job number is application specific, and should be used for future application referencing.

6 Facility Permit Applications No New Land Required

A Facility Permit Application (No New Land) is submitted when an Operator applying for the initial installation of their equipment or piping onto a site where no new land is required.

Permit approval is required prior to any construction or installation of equipment and flow of product. The permit must be on-site for the duration of construction.

New Permit Application – No New Land

To open a new permit application where no new land is required:

1) Select Facility (New) from the facility permit menu
2) Search using the site or location
3) Select the associated site or file and click on New Permit
4) Select the Operator from the drop down list (only the Operators that the user has permissions for will appear).

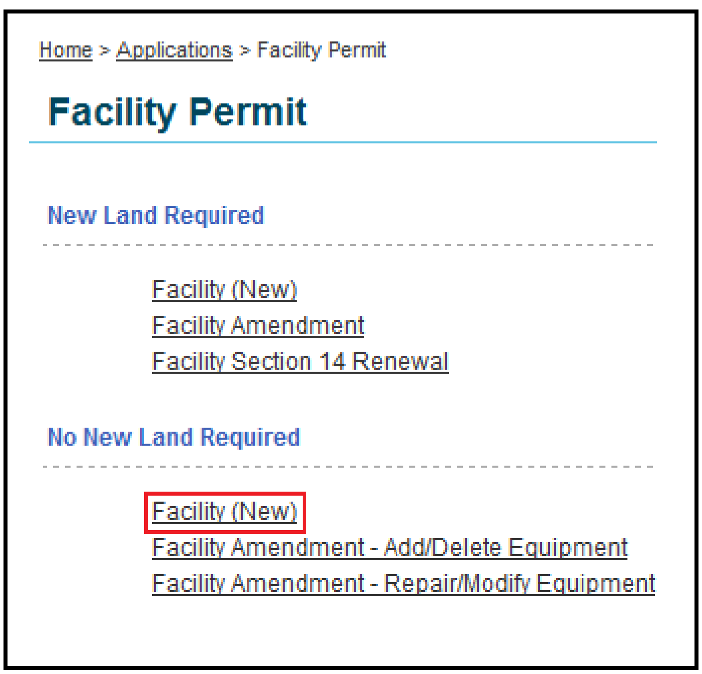


Fig. 6.1. KERMIT Application Page.

Facility Permit Application Page

Permit amendments are entered the same way as permit applications.

The new Facility Permit Application page for the site is open and a job number has been generated. The page contains categorized tabs where information is to be entered. The tab categories are Application, Engineering, Consultation, Attachments and Finalize.

In this section the Application tab is covered in detail. The Attachments and Finalize tabs which are general to all facility submissions are covered in the KERMIT overview section of this manual.

Application Tab

The Application tab identifies applicant information and engineer's details.

Begin by indicating if the site is on Crown land, private land or both.

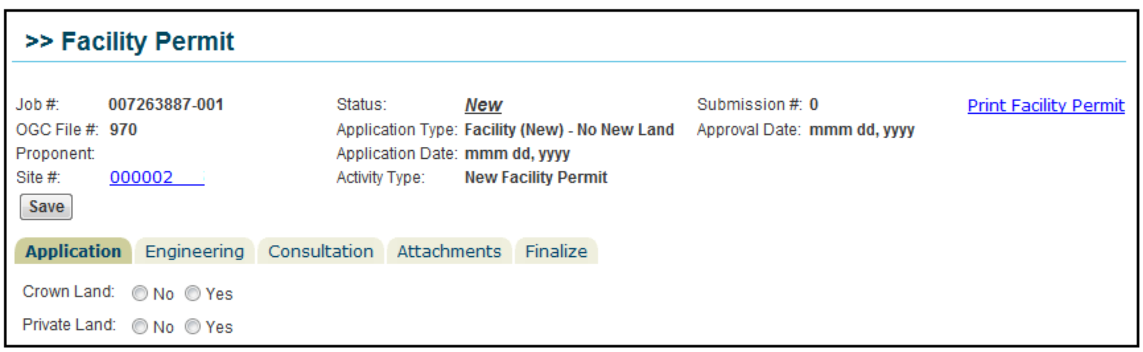


Fig. 6.2 KERMIT New Facility Permit Application header and tabs.

Administration

Company name and information should appear automatically. If the company name does not appear, or the address is incorrect, the applicant must contact the Commission's Corporate Land Management Unit to update the information prior to application submission.

Use the Find button to search for a company contact that has previously been entered into the Commission database. If no contact is found, enter the information manually.

Enter the company file number to relate the KERMIT application to internal filing.

> The facility permit holder is accountable for the accuracy of the application content entered into KERMIT, even where outside agents or consultants are used.

Engineer's Details

Engineer's information is entered by selecting the find button to the right of the information fields.

Enter the engineer project or file name for reference.

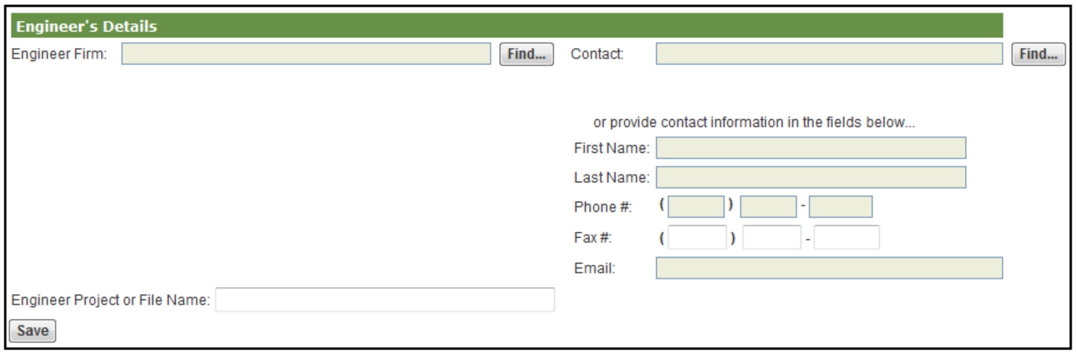


Fig.6.3. Engineer's Details fields.

Engineering Tab

Application Information

Application information indicates what type of application is being submitted for review, and enables the Commission to link the information provided to other existing projects.

Check any of the following boxes if they apply to the subject application.

Temporary Facility/Equipment

When a portion of, or all of the equipment added at a well, facility, or pipeline right-of-way is to be in place for a period of six months or less, and may include pressure vessels, gas fired equipment, flare stacks/incinerators, tanks, compressors, or other equipment as specified by the Commission. This includes equipment for an extended gas well test, or oil well flow test. This does **not** include instances where temporary equipment is set up at a well location for an in-line test or well clean-up operation where:

- Temporary equipment is portable and directly associated with the completions operations
- The equipment is supervised 24 hours per day
- The equipment is not permanent in nature (for example, placed on piling) and is in place for three weeks or less

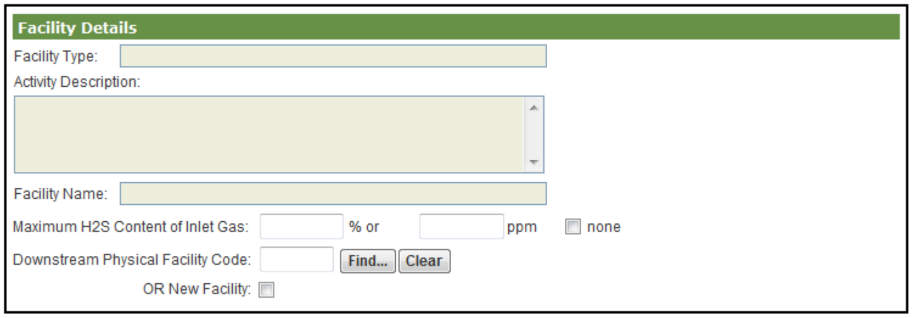
Gas Processing Plant

If a Gas Processing Plant Application is being made, additional questions will appear under the Engineering tab. More information on Gas Processing Plants is located in Section 16 and Appendix F of this manual.

Facility Details

Facility Types
Examples of facility types include:

- Compressor site
- Riser Site
- Gas Plant



Activity Description
Include a brief description of the project and any comments relevant to the facility.

Facility Name
The facility name includes the applicant company name, field name, and legal location of facility site. If this is a wellsite facility, the field name should reflect the designated field the facility is in, or the one assigned to the well when the well permit is issued.

For example, O & G Canada Ltd. Graham a-100-L/094-B-09 or Gas USA Ltd. Cache 10-22-088-22 W6M

Maximum H_2S Content of Inlet Gas
Enter the appropriate figure:

- if 1% or greater, use %
- If less than 1%, use ppm
- if there is no H_2S content, select “none”

Downstream Physical Facility Code
Physical Facility Code is the numerical code of the first downstream facility that product from a well, facility or gathering system is linked to. This can be a reporting or non-reporting facility.

Use the Find button to open the PIMS Facility Search window, or enter the code and click find if the code is known. If there is no existing facility code to link to, check the “New Facility” box below and enter the name and location of the facility.

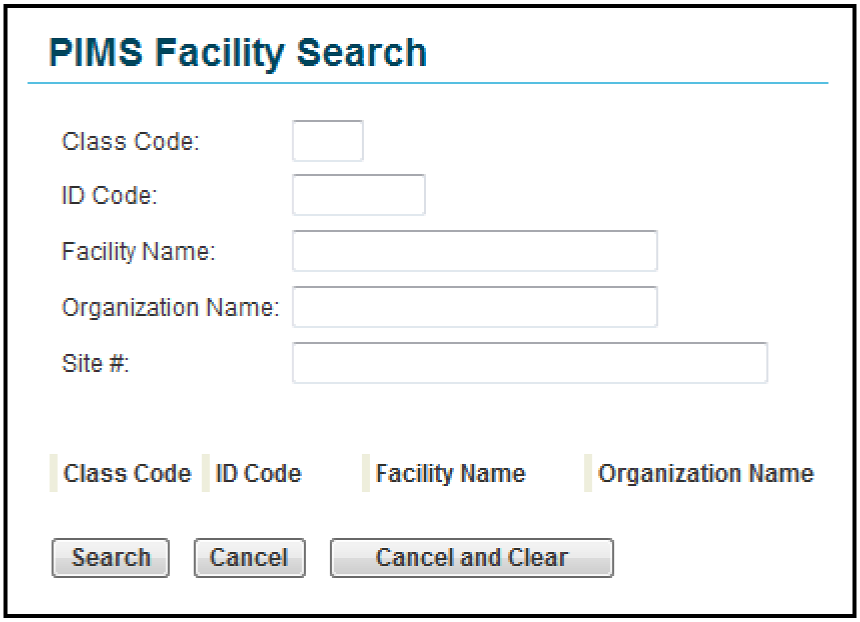


Fig. 6.4 PIMS Facility Search window

Entering information in the Facility Name, Organization Name or Site Number, opens a window containing a line list of each facility associated with the organization. The list shows the Class Code and the ID Code for each facility. Clicking on the line of the applicable facility saves the information to the facility code information field.

The ID Code is an eight digit numeric code (i.e.: 00001234) related to the Petroleum Information Management System (PIMS) database and is assigned by the Oil and Gas Commission.

The Facility Name is the name of the facility, including the legal surface location.

Clicking on the line of the applicable facility saves the information to the facility code information field.

The Class Code is a two letter code related to the Petroleum Information Management System (PIMS) database. See list below:

FACILITY CLASS

BA	BATTERY
BC	BATTERY, COMPRESSOR
BG	BATTERY, COMPRESSOR, CENTRAL DEHYDRATOR, GAS INJECTION STATION
BI	BATTERY, COMPRESSOR, CENTRAL DEHYDRATOR, WATER INJECTION STATION
BP	BATTERY, COMPRESSOR, WASTE DISPOSAL STATION
BS	BATTERY, COMPRESSOR, WATER INJECTION STATION
BT	BATTERY, COMPRESSOR, CENTRAL DEHYDRATOR
BW	BATTERY, WATER INJECTION STATION
CD	CENTRAL GAS DEHYDRATOR
CH	COMPRESSOR, CENTRAL DEHYDRATOR
CI	COMPRESSOR, CENTRAL DEHYDRATOR, SATELLITE, GAS INJECTION STATION
CJ	BATTERY, COMPRESSOR, DEHYDRATOR, GAS INJECTION & WATER INJECTION STATION
CP	BATTERY, COMPRESSOR, PIPELINE TERMINAL
CS	COMPRESSOR STATION
CW	COMPRESSOR, CENTRAL DEHYDRATOR, WASTE DISPOSAL STATION
DW	CENTRAL DEHYDRATOR, WASTE DISPOSAL STATION
GI	GAS INJECTION STATION
GP	GATHERING POINT
OM	OIL SALES METER
PL	GAS PLANT
PT	PIPELINE TERMINAL
SB	SATELLITE BATTERY
SM	SALES METER – GAS
TF	TEST FACILITY
WD	WATER DISPOSAL STATION
WI	WATER INJECTION STATION

Facility Specifications

The Facility Specifications section requires the applicant to enter information for new facility equipment, compressor(s) and facility piping to be installed at the site.

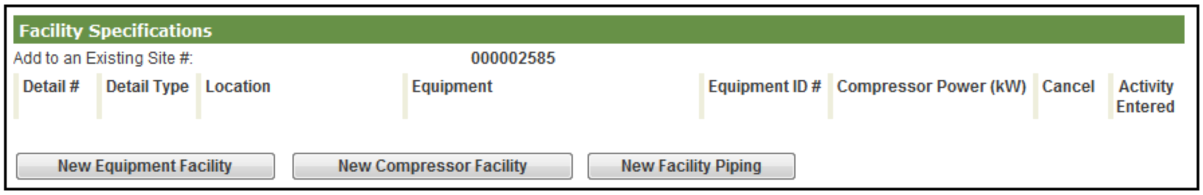


Fig. 6.5 Facility Specification fields

New Equipment Facility

Enter the location using NTS, DLS or UTM (NAD83) coordinates, and provide any additional location information in the Location Notes text box.

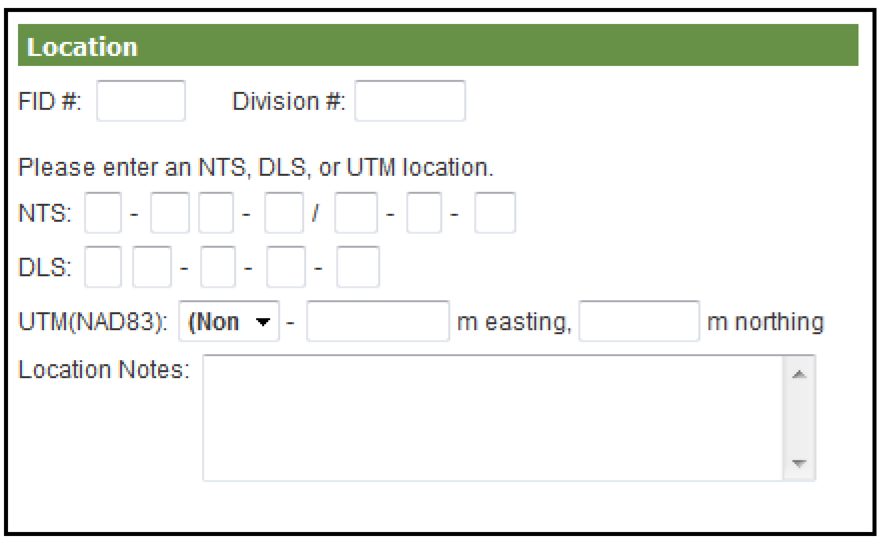


Fig. 6.6 Facility location

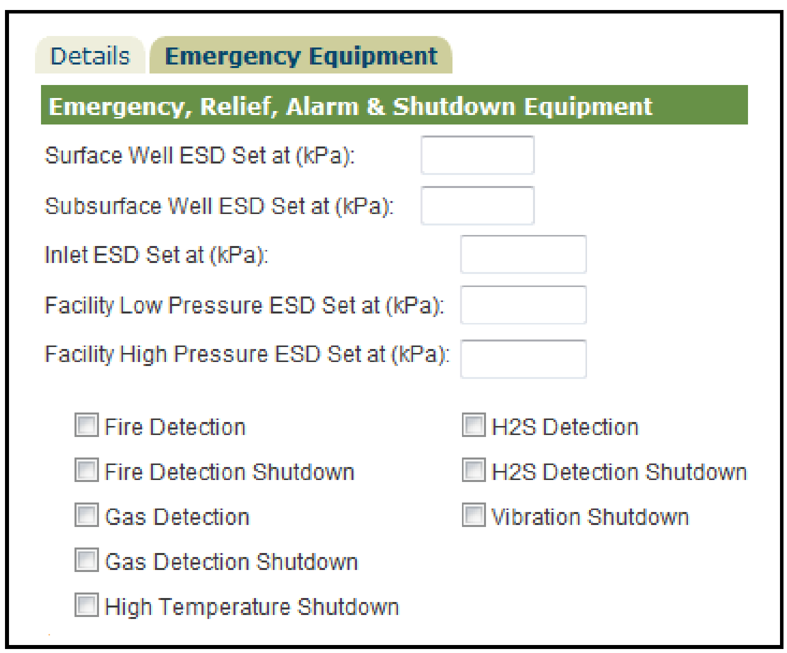
Add Equipment

Click the Add Equipment button to activate the Equipment Description dropdown menu. Select the equipment to be added and indicate the planned quantity. Repeat this step for additional equipment.

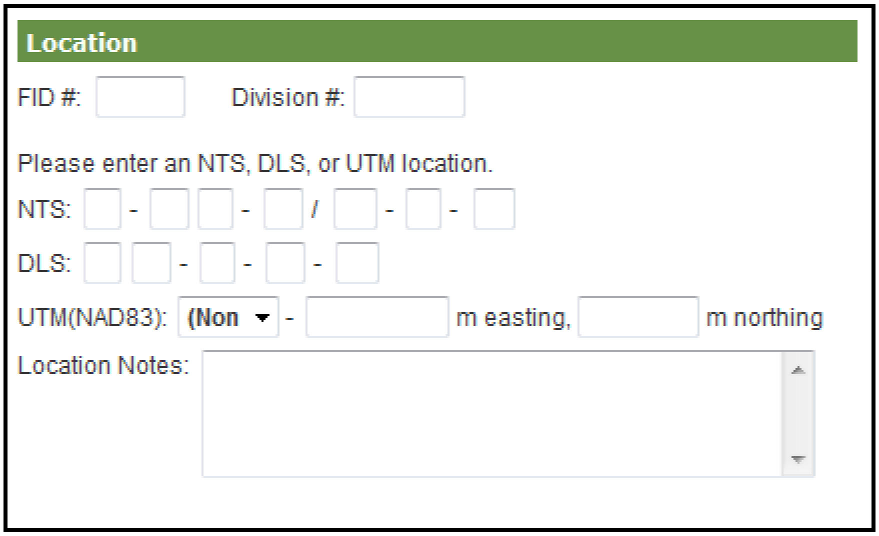
If any equipment to be added is not listed on the dropdown menu, select “Other” from the dropdown list and include the quantity and equipment description. Use the selection buttons to indicate whether the related Facility Piping is sour or sweet (not designed for sour service).

Emergency Equipment Tab

Entering information on emergency equipment at this stage is optional.



New Compressor Facility
Enter the location using NTS, DLS or UTM (NAD83) coordinates, and provide any additional location information in the Location Notes text box.


Location
FID #: Division #:
Please enter an NTS, DLS, or UTM location.
NTS: - - / - -
DLS: - - -
UTM(NAD83): (Non - m easting, m northing
Location Notes:

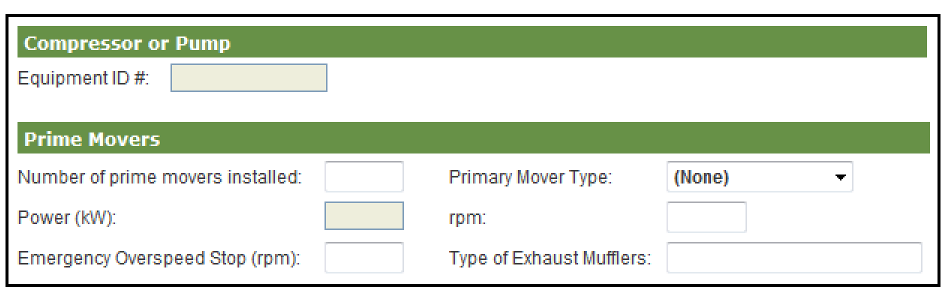
Enter the equipment identification number, and under the Prime Movers section, enter the Power (kW) of the compressor or pump.

If the cumulative facility compressor(s) prime mover kilowatt rating is between 600 and 3000, a Schedule 3 Waste Registration Report must be included in the Attachments tab.

Similarly, if the cumulative facility pump(s) or generator(s) prime mover kilowatt rating is between 600 and 3000, a Schedule 3 Waste Registration Report must be included in the Attachments tab.

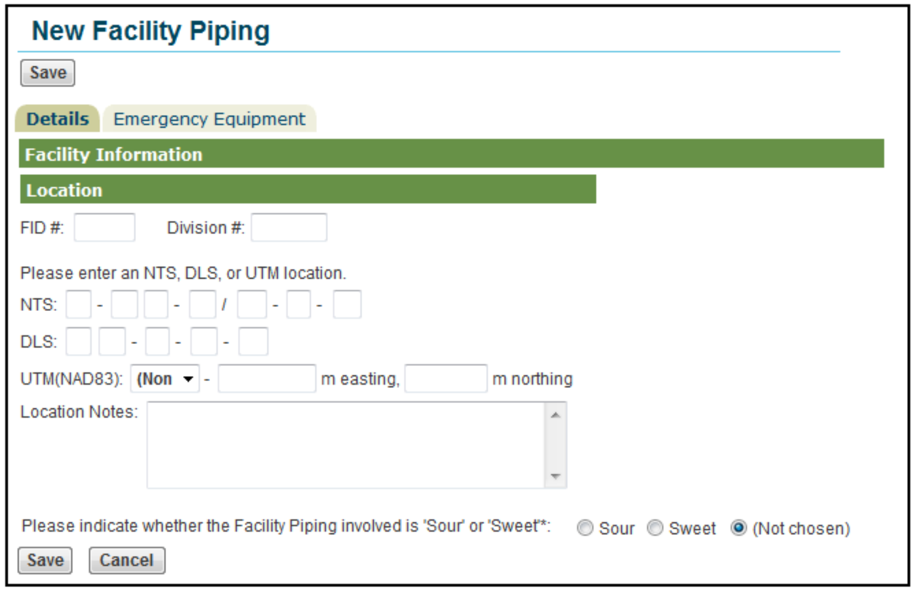
Under Compressor, Pump and Product, use the selection buttons to indicate whether the related Facility Piping is for sour or sweet service.

The other information fields shown in the Details and Emergency Equipment tabs are optional at this point in the application process.


Compressor or Pump
Equipment ID #:
Prime Movers
Number of prime movers installed: Primary Mover Type: (None)
Power (kW): rpm:
Emergency Overspeed Stop (rpm): Type of Exhaust Mufflers:

New Facility Piping
Under Location, enter the. Enter the location using NTS, DLS or UTM (NAD83) coordinates, and provide any additional location information in the text box.

Indicate whether the facility piping is for sweet or sour product.



When filing the required notices for the equipment detail, they must be filed for the corresponding Facility Piping activity as well.

Facility Specification Questions

Answer the following questions as they pertain to the application.

If the proposed new installation or amendment is not within the Agricultural Land Reserve (ALR), skip questions two to five.

Regulations and Requirements

1. Is the proposed new installation or amendment within the Agricultural Land Reserve (ALR)?
2. Does placement of equipment at this location constitute a “Change in Use” per Appendix 1 Item 4a of the ALC/OGC Delegation Agreement or is this a “New Installation” per Appendix 1 Item 5, where the area of buildings and structures is less than 450 m2?

   If yes; attach ALC Act Non-Farm Use Application with the facility application.
3. Does placement of equipment at this location constitute a "Change in Use" per Appendix 1 Item 4b of the ALC/OGC Delegation Agreement or is this a new installation per Item 5 where the area of buildings and structures is greater than 450 m2 or per Item 9 of Appendix 1 where the total oil and gas activity exceeds seven hectares per quarter section?

   If yes; submit an ALC Act Non-Farm Use Application to the Agricultural Land Commission through local government (for example, Peace River Regional District, Northern Rockies Regional Municipality).
4. Cumulative square meters of building and structures on the quarter section or equivalent area.
5. Cumulative hectares of oil and gas activity on the quarter section or equivalent area.
6. Does the facility require a registration to discharge waste under Section 6 of the Oil and Gas Waste Regulation?

   If the cumulative facility compressor(s) prime mover kilowatt rating is between 600 and 3000, Section 6 applies.

   If yes; attach a Schedule 3.
7. Is the facility authorized to discharge waste under Section 4 of the Oil and Gas Waste Regulation?

8. Is the facility described by Section 2(1) of the Oil and Gas Waste Regulation and therefore not subject to the regulation?

    For facilities to which the regulation does apply; all requirements with respect to the facility (For example, NOx standards, registration of operations between 600 and 3000kW driver power, fees,) must be met.

    If the facility exceeds one of the thresholds in Section 2 of the Oil and Gas Waste Regulation, a Waste Discharge Permit under the Environmental Management Act is required prior to start up of facility operation. The Commission's Director of Waste Management and Reclamation may be contacted for further information regarding application requirements

9. Does the facility meet the BC Noise Control Guideline requirements?

10. Does the facility meet the Commission Secondary Containment requirements?

    If no, attach authorized exemption document (email) from the Commission, or note the exemption request in this application.

11. What is the distance to the nearest populated area (as per the Drilling and Production Regulation)?

Technical Information and Design

12. Will this installation require pressure welding and/or pressure testing?

    If yes, a Construction Start is required.

13. Will this application affect the physical flow of product for any well/associated facility?

    If yes, attach a Schedule 1.

14. Does this facility deliver water or acid gas to an injection/disposal facility?

    If yes, enter Facility Code.

15. Does this application include the installation of new or used glycol dehydration equipment, modification to existing dehydration equipment, or changes to the facility that may affect the existing dehydrations process?

    If yes, a Dehydrator Engineering and Operations Sheet (DEOS) within the June 2006 CAPP Benzene Control BMP must be attached.

16. Does this application include a molecular sieve dehydration process?

    If yes, a DEOS (Dehydrator Engineering and Operations Sheet) is not required.

17. Does commingling occur at this facility?

18. Does this facility have a Commission approval for commingled production?

    If commingling, and the facility is not within an area based commingled production approval, a separate approval must be attached.

19. What is the design capacity of the facility?

    This refers to gas rates for a gas facility, and solution gas rates for an oil facility. Please include the oil condensate capacities in the project description.

20. What are the total sulphur emissions of the facility?

21. What is the Design Standard used?

22. Was a sand fracture completed at the well(s)?

    If yes; a Sand Management Plan must be or must have been submitted.

23. What is proposed for leak detection and control?

24. What measures are proposed for facility security?

    There may be other means of providing security and access control that can be explained in the application project description. Refer to Section 39(3) of the Drilling & Production Regulation for regulatory requirements.

Flaring and Venting

25. Will there be any flaring activity?

    If yes; will the flaring be continuous or non-continuous.

26. Is flare measurement proposed?

    Provide estimated flare rates for high and low pressures.

27. Will there be any venting activity?

    If yes; specify the source(s) and rate.

28. Will a method to recover low pressure vapours be implemented?

    If yes; specify method: vapour recovery unit; utilize as fuel.

29. What is being used to power instruments and provide motive force to pumps?

30. If there is a compressor, is its start gas discharge connected to the flare system?

    N/A (air start or electric drive)

Cross Border

31. Does the facility deliver/receive production volumes into or out of the Province of British Columbia?

    If yes; chapter 7 of the Measurement Requirements for Upstream Oil & Gas Operations Manual must be complied with.

Gas Processing Plant

Total Recovered Products & Technical Information at Design Capacity

These questions become active only if the Gas Processing Plant (under Application Information) is checked off.

Gas Processing Plant - Total Recovered Products

Sales Gas: [ ] $10^3m^3/d$

LPG Mix: [ ] m^3/d H2S: [ ] %

Sulphur: [ ] t/d

C2: [ ] m^3/d [ ] %

C3: [ ] m^3/d [ ] %

C4: [ ] m^3/d [ ] %

C5+: [ ] m^3/d [ ] %

CO2: [ ] m^3/d [ ] %

Gas Processing Plant - Technical Information

32. A gas processing plant proliferation review has been completed and included in the submission? ◯ Yes ◯ No

33. How will the proposed gas processing plant manage the acid gas stream H2S component?

◯ Recover and well injection ◯ Recover and re-inject to: [ ]
◯ Sulphur recovery process ◯ N/A
◯ Recover and incinerate

34. How will the proposed gas processing plant manage the acid gas stream CO2 component?

◯ Recover and well injection ◯ Recover and re-inject to: [ ]
◯ Recover and vent ◯ N/A

35. Plant supervision level:

◯ 24 hour On-Site Personnel ◯ Shift Coverage

32. A gas processing plant proliferation review has been completed and included in the submission?

    A gas processing plant proliferation review must include the rationale for constructing the newly proposed plant after consideration of existing active plants and pipeline infrastructure feeding into active plants within a 50 km radius. This is required as an attachment with the application for new plants and amendments that increase the throughput of the plant. Other plant amendments do not require a proliferation review.

33. How will the proposed gas processing plant manage the acid gas stream H_2S component?

34. How will the proposed gas processing plant manage the acid gas stream CO_2 component?

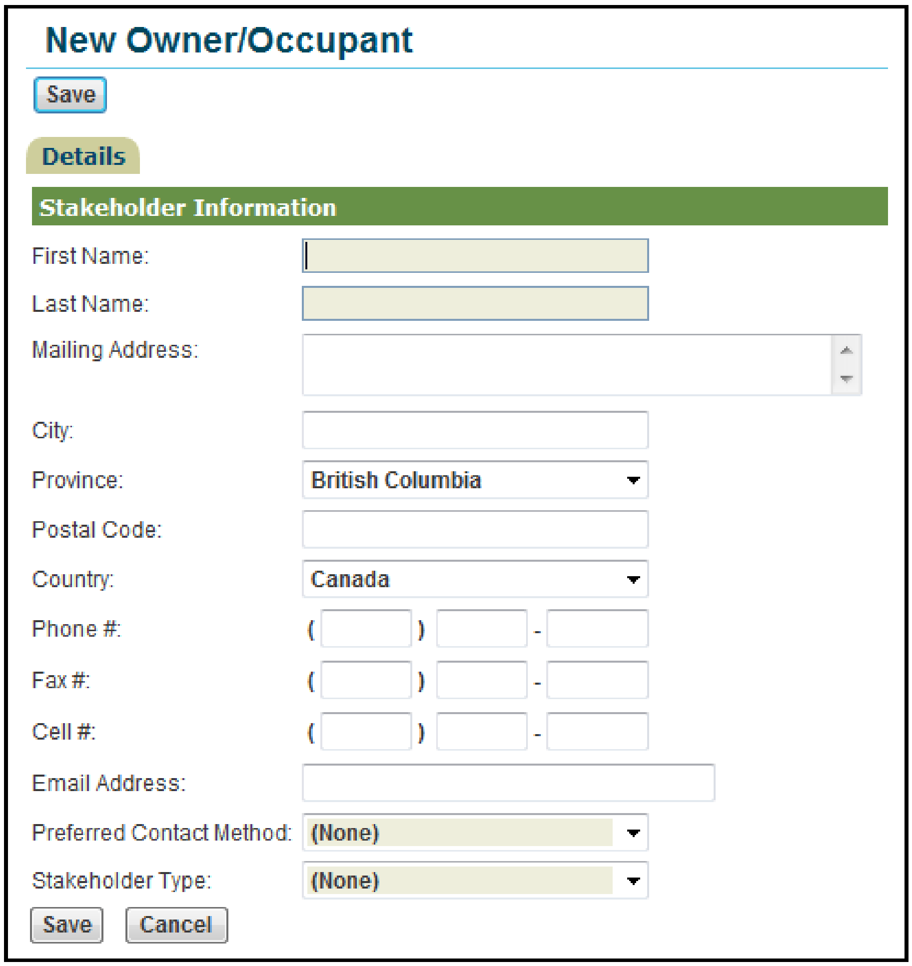
Consultation Tab

Enter New Owner/Occupant information as required in the Detail Window. Multiple owners or occupants may be entered if necessary.

Once the information has been saved, it is possible to return to the consultation tab to edit or delete owner or occupant information.

The Consultation & Notification Written Report is required as an attachment.

The Consultation & Notification Written Report must be uploaded under the Attachments Tab.



Attachments Tab

This application may require:

- ALC Act Non Farm Use Application
- ALC Schedule A Site Assessment
- ALC Approval
- Comingled Production Approval
- Construction Plan
- Consultation and Notification Written Report
- Dehydrator Engineering and Operations Sheet (DEOS)
- Engineering Assessment
- ERP Document
- Flow Schematic
- Gathering System Schematic
- Piping and Instrumentation Diagram (P&ID)
- Plot Plan
- Process Flow Diagram (PFD)
- Project Description
- Sand Management Plan
- Schedule 1 – Well or Facility to Facility Linkage
- Schedule 3 – Waste Registration Report
- Miscellaneous Document
- Engineering Technical Review Package
- BCGS Maps
- Production Accounting Model

7 Facility Permit Application

New Land Required

Applicants seeking approval for a Facility Permit Application where new Crown or private land is to be acquired, must complete all required KERMIT application components and ensure the required attachments are uploaded.

The following sections provide guidance for completing each component (or tab), of a facility application through KERMIT.

Where necessary, the applicant is directed to a link or specific document which will provide expanded information or explanation.

New Facility Permit Application

This section first shows how to fill out the portions of the application that are general to all new facility applications where new land is required. The subsequent sections provide details that are specific to each activity type.

1) Select Facility Application
2) Select Facility (New)

Facility Application Page - New Land Required
The new facility application page opens and a job number and OGC file number are generated. The application contains categorized tabs where information is to be entered.

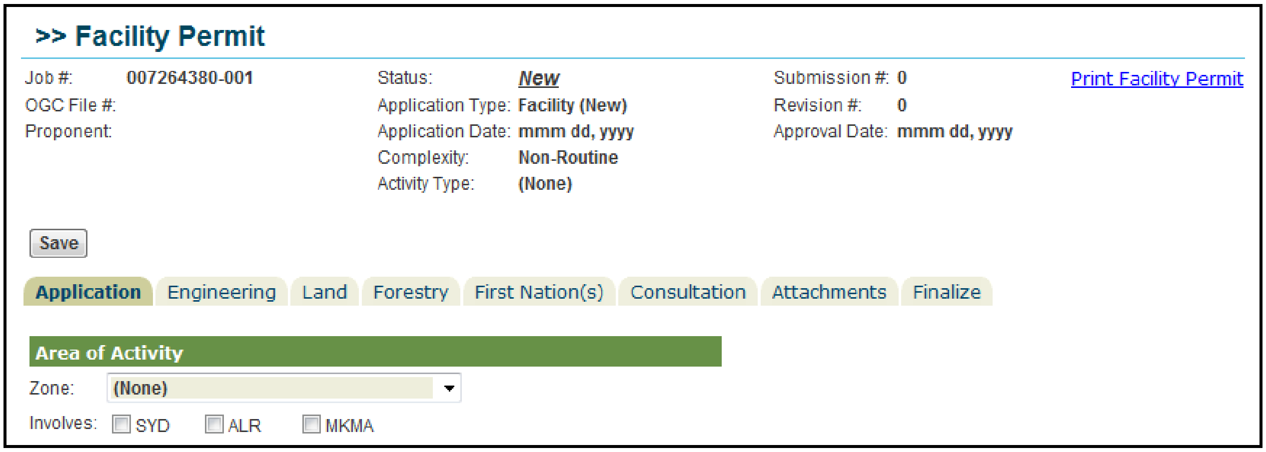


Fig.7.1. Facility Permit Application Page – New Land Required.

The tab categories are Application, Engineering, Land, Forestry, First Nation(s), Consultation and Attachments and Finalize, (which are covered in the KERMIT Overview section of the manual).

Application Tab

Information provided under the application tab establishes the area of activity within British Columbia, and identifies key applicant and land/referral agent information. With the exception of the Area of Activity fields, the Application tab for new land is filled out the same way as in the no new land application.

Area of Activity

Select the appropriate Regional Zone from the dropdown menu.

In addition to the regional zone, the applicant must indicate other geographic characteristics. Descriptions of these characteristics are provided below. Select the appropriate check boxes for the applicable geographic characteristics.

SYD

Indicate if the activity is located within the Sierra-Yoyo-Desan Assessable Area, which comprises parts of the NTS grid 094J, 094I, 0940 and all of 094P. Further details are available on Ledcor Group's webpage.

ALR

Indicate if the activity (or any portion) is located within the Agricultural Land Reserve. For further details see Agricultural Land Reserve and Agricultural Land Reserve Mapping. The Delegation Agreement between the Commission and the Agricultural Land Commission must be adhered to.

MKMA

Indicate if the activity occurs within the designated area called Muskwa-Kechika Management Area (MKMA). This is a non-routine trigger and further details are discussed under the additional information section of this manual.

Administration

Company name and information should appear automatically. If the company name does not appear, or the address is incorrect, the applicant must contact the Commission's Corporate Land Management Unit to update the information prior to application submission.

Use the Find button to search for a company contact that has previously been entered into the Commission database. If no contact is found, enter the information manually.

Enter the company file number to relate the KERMIT application to internal filing.

The facility permit holder is accountable for the accuracy of the application content entered into KERMIT, even where outside agents or consultants are used.

Land/Referral Agent (Optional)

Here the applicant may choose to enter the Land/Referral Agent's information for reference.

Engineer's Details

Engineer's information is entered by selecting the find button to the right of the information fields.

Enter the engineer project or file name for reference.

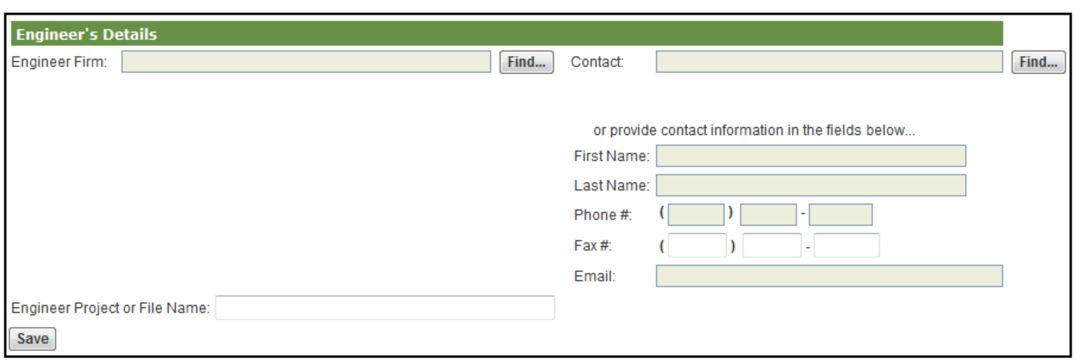


Fig.6.3. Engineer's Details fields.

Engineering Tab

With the exception of Spatial Data and Construction Plan Details, the Engineering tab for new land is filled out the same way as in the No New Land Application.

Details on Construction Plan requirements are located in Appendix A.

Spatial Data & Construction Plan Details

In the space provided, enter the construction plan job no., and select the survey company from the dropdown menu.

For this application, enter the ePASS number, select the activity type from the dropdown menu and enter the submission date.

Clicking the New Drawing Number button opens fields to enter the new drawing and sheet numbers.

Enter the date of the original plan by typing in the date, or by clicking on the calendar and selecting the date. Enter the revision number and the revision date.

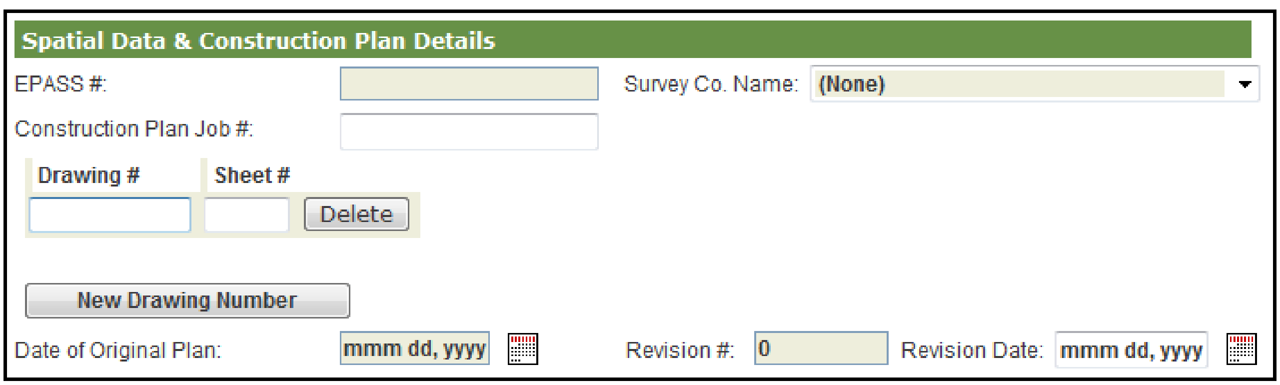


Fig. 7.2. Active information Fields for Spatial Data and Construction Plan Details.

Land Tab

Information on land status and land use planning allows the Commission to determine how the proposed oil and gas activity affects various facets of the land base.

It is the responsibility of the applicant to determine the location and status of all tenure holders. Information sources include but are not limited to the ILRR, MapView, imap and current tenure holder operational plans.

The Corporate Land Management Manual covers the various types of tenures and rights conveyed.

Land Status & Land Use Planning

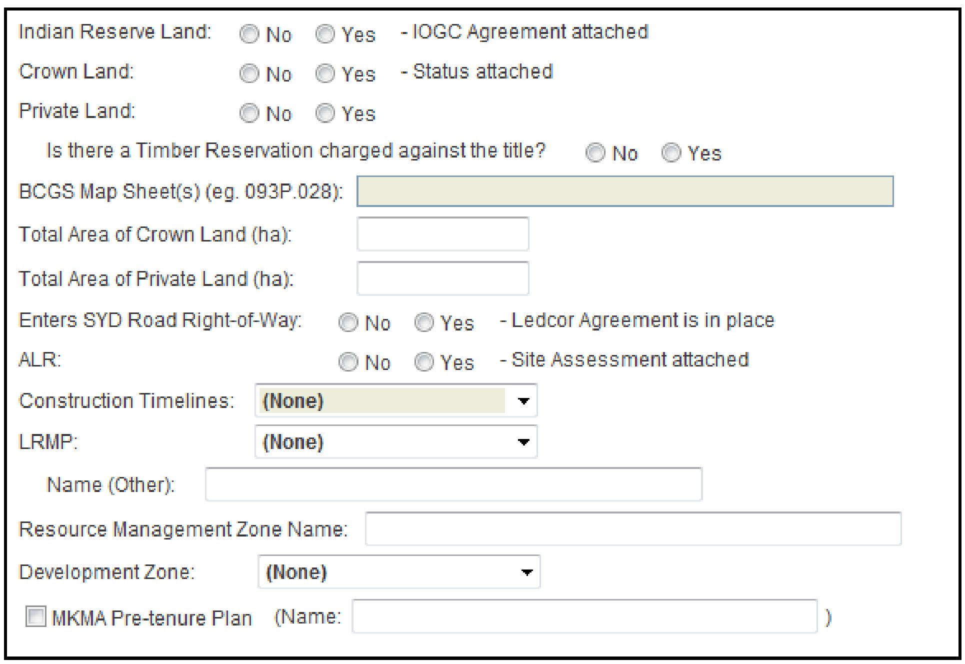

Indian Reserve Land: No Yes - IOGC Agreement attached
Crown Land: No Yes - Status attached
Private Land: No Yes
Is there a Timber Reservation charged against the title? No Yes
BCGS Map Sheet(s) (eg. 093P.028):
Total Area of Crown Land (ha):
Total Area of Private Land (ha):
Enters SYD Road Right-of-Way: No Yes - Ledcor Agreement is in place
ALR: No Yes - Site Assessment attached
Construction Timelines: (None)
LRMP: (None)
Name (Other):
Resource Management Zone Name:
Development Zone: (None)
MKMA Pre-tenure Plan (Name:)

Fig. 7.3 Information fields in Land Status and Land Use Planning; Land Tab.

Indian Reserve Land

If the proposed activity occurs within Indian Reserve lands, a copy of the Indian Oil and Gas Canada (IOGC) Agreement must be uploaded as an attachment.

Crown Land

If the proposed activity occurs exclusively or partially within Crown land, a complete status sheet indicating all interests and

A Crown Land Status Sheet example is located in Appendix E.

tenure holders (crossing or adjoining) must be uploaded as an attachment.

Private Land
If the activity is exclusively or partially on private land, applicants must identify if a timber reservation exists against the title of the parcel.

If a timber reservation exists against the title, the applicant must ensure the Ministry of Forests and Range has issued a licence to cut to the landowner prior to removal of timber. Indicate yes or no to the timber reservation question.

BCGS Map sheet(s)
Indicate all BC Geographic Series map sheets (BCGS) affected by the application area. The map sheet numbers should also be indicated on the 1:20,000 BCGS Sketch Map uploaded as an attachment.

Total Area of Crown Land
Indicate the total hectares of what is shown on the construction plan, including the facility site and any temporary workspaces, decking sites, etc.

Total Area of Private Land
Indicate the total hectares of what is shown on the construction plan, including the right-of-way and any temporary workspaces, decking sites, etc.

Enters SYD Road Right-of-Way
If any new construction is proposed within the right-of-way of the SYD Road, an agreement with Ledcor Group (holder of the SYD Road), must be in place prior to application submission: SYD Protocols Link.

A copy of the agreement is not required to be submitted with the application, but must be retained on file and provided to the Commission during an audit.

Agricultural Land Reserve (ALR)
Indicate whether any portion of the application area is within the ALR. For project activities within the ALR, a Schedule A Site Assessment must be uploaded as an attachment with the application. Details related to ALR requirements can be found in the Delegation Agreement between the Commission and the Agricultural Land Commission (ALC).

Construction Timelines
Indicate when the intended works are to be conducted from the KERMIT dropdown box.

LRMP

For Crown land applications, choose the Land and Resource Management Plan or the BC Land or Coastal Marine Plan within which the project falls from the dropdown box. If the required LRMP is not listed, enter LRMP name in field below dropdown box. If there is no LRMP for the specified area, select *none* and enter in the plan name in the space provided for *other*.

Resource Management Zone

For Crown land applications, enter the applicable resource management zones name. If the zone is general, enhanced, agriculture/settlement, special or protected, choose it from the dropdown box. Applications within special management zones or protected zones require additional application information, as outlined within the additional information requirements section of the manual.

Development Zone

Muskwa- Kechika Management Area (MKMA)

Specify the pre-tenure plan name if the application lies within the MKMA.

Additional Information Requirements

Additional Information replaces the Application Categorization Process.

The additional information requirements section directs the applicant to provide further details about the proposed program, and replaces the Commission's application categorization process.

Additional information requirements in the form of application attachments are required when activity is located in areas of environmental sensitivity, or require an exemption from Commission guidance.

If the proposed facility does not fall within any of the Identified Areas, the N/A (not applicable) box must be checked.

Routine Applications
Applications that do not require any additional application information will be categorized as routine and will be subject to the standard application review process by Commission staff.

Non - Routine Applications
Applications that do require additional application information for at least one reason will be categorized as non-routine. In addition to the standard application review, Commission staff will review the provided justification or mitigation strategy to ensure it meets the objectives for the identified area or guidance document.

Prior to completing this portion of the permit application form, applicants are encouraged to review the procedures and practices established for each of the categories in this section, to determine whether proposed activities meet the established criteria.

Justification Requirements
A written justification must:

- Specify what standard is not being met
- Explain why it cannot be met, and
- Explain what steps will be taken

Mitigation Specification Requirements
Refer to the Environmental Protection and Management Guidebook for guidelines outlining the Commission's expectations in regard to mitigation strategies and when they may be deemed appropriate.

All land and marine planning documents are available at the Integrated Land Management Bureau [website.](#)

Spatial or Identified Areas

Special management or protected development zones, as per a BC Land or Coastal Marine Plan

BC Land or Coastal Marine Plans provide increased certainty and form the foundation for balanced solutions that meet economic, environmental, social and cultural needs throughout the province. They inform both government decision makers and those seeking natural resource development opportunities. Proposed oil and gas activities should be reviewed prior to application in the context of any applicable Land or Coastal Marine Plans. Projects should conform to the objectives set out for the plan management zone in which the project is proposed.

Where projects fall within special management zones or the equivalent, applicants are expected to provide a summary detailing why the activity must occur within the special management zone or equivalent; what planning and/or operational measures have and/or will been taken to mitigate or minimize impacts to the values identified for the zone, and how the zone objectives will be achieved or maintained.

Applications in the M-KMA must be submitted with a detailed explanation illustrating how the permit application is consistent with the pre-tenure plan, and the Muskwa-Kechika Management Plan Regulation.

Any issuance, approval, permit or authorization, by a Minister, Ministry or Agent of the Crown, of an oil and gas exploration or development plan, allocation, tenure, disposition, licence or any other instrument or document of oil and gas development or exploration allocation or management must be consistent with any pre-tenure plan which includes the subject area of the instrument or document of allocation or management.

Regional Plans

Regional districts are empowered under Part 26 of the Local Government Act to adopt and implement plans stating objectives and policies to guide decisions on planning and land use management, within the plan area, respecting the purposes of local government.

Applications submitted for activities that fall within a regional plan area must be accompanied by a detailed explanation outlining how the objectives and values identified in the plan will be achieved or maintained in light of the activity.

Activities outside of these two regional districts will require non-farm use approval directly from the Agricultural Land Commission.

Agricultural Land Reserve

The Commission has been issued limited delegated authority by the Agricultural Land Commission (ALC), to authorize non-farm use of agricultural lands for oil and gas activities within the Northern Rockies and Peace River Regional Districts. Appendix I of the ALC-OGC Delegation Agreement establishes the responsibilities of each Agency.

As detailed in Appendix I, exempt ALC Act applications, may be permitted directly by the Commission, and must be accompanied a Schedule A Pre-Site Assessment as detailed in the ALC-OGC Delegation Agreement.

In accordance with article 7.3 of the Delegation Agreement, proposed applications requiring ALC Act applications to the Commission (Column 2), maybe submitted directly to the Commission though must be accompanied by two complete ALC Act applications. The Commission will forward one copy to the Regional District and the other to the Ministry of Agriculture and Lands (MAL).

The Commission will review the application, consider any comments or concerns that have been received from the Regional District, MAL, or other affected parties, and will then determine to proceed to decision or to refer the application to the ALC for any of the reasons stipulated in article 7.3 of the Delegation Agreement.

If the Commission proceeds to decision, the applicant will be informed of the approval or refusal of the non-farm use application by letter. If the application is forwarded to the ALC for decision, the Commission will inform the applicant of this by letter.

Applications requiring non-farm use authorization directly from the ALC must be submitted to the ALC. Applicants awaiting review by the ALC, may submit their facility application accompanied by a copy of the ALC application, to the Commission. However, facility permit approval is dependent on an ALC authorization for non-farm use.

Parks, protected areas and ecological reserves are viewable through the [GeoBC gateway].

Park, protected area or Ecological Reserve

Oil and gas activities are not generally allowed within parks, protected areas or ecological reserves. However, there are extenuating circumstances where the Commission may consider applications for activities proposed within these areas.

Before submitting an application within a park, protected area or ecological reserve, contact the Commission's Operations Manager for the zone in which the activity is being contemplated to determine whether or not the Commission will consider the application.

In the event that the Commission will consider the application, it must be accompanied by a justification detailing why it is necessary to operate within the park, protected area or ecological reserve, and a mitigation strategy, outlining what measures will be taken to minimize impact to Crown values within the area, must accompany the application.

For a detailed outline of the Commission's expectations with respect to mitigation strategies, refer to the Environmental Protection and Management Guidebook.

Areas Established by Order under the Oil and Gas Activities Act

In accordance with OGAA s.104, the Environmental Protection and Management Regulation may establish areas of interest, and measures associated with these areas.

Applications to conduct activity in areas established by order under the Environmental Protection and Management Regulation must include a detailed mitigation strategy, illustrating how the application conforms to the measures established for the identified area.

Areas established under order under the EPMR will be viewable through the GeoBC gateway.

For details of the Commission's expectations with respect to mitigation strategies, refer to the Environmental Protection and Management Regulation Guidebook.

Streams and Waterbodies Identified by the Commission

The Commission has identified waterbodies that may require enhanced management for various reasons. Waterbodies and areas requiring enhanced management for the purposes of Water Act authorizations are available via LRDW.

All crossings proposed within these areas require a mitigation strategy. Refer to the Environmental Protection and Management Regulation Guidebook for guidelines outlining the Commission's expectations in regard to mitigation strategies.

Areas established by the Commission

Applications in the Horn River Basin (HRB) must submit a justification to explain any deviation from the Commission's requirements.

Guidance Requirements

Deviation from the Environmental Protection and Management Regulation Guidebook

Where operational or other constraints preclude the applicant from following the guidelines set out in the Environmental Protection and Management Regulation Guidebook, then applicants must provide a mitigation strategy..

Refer to the Environmental Protection and Management Guidebook for guidelines outlining the Commission's expectations in regard to conforming to the regulation and detailed information regarding mitigation strategies.

Regulatory Exemption Requests

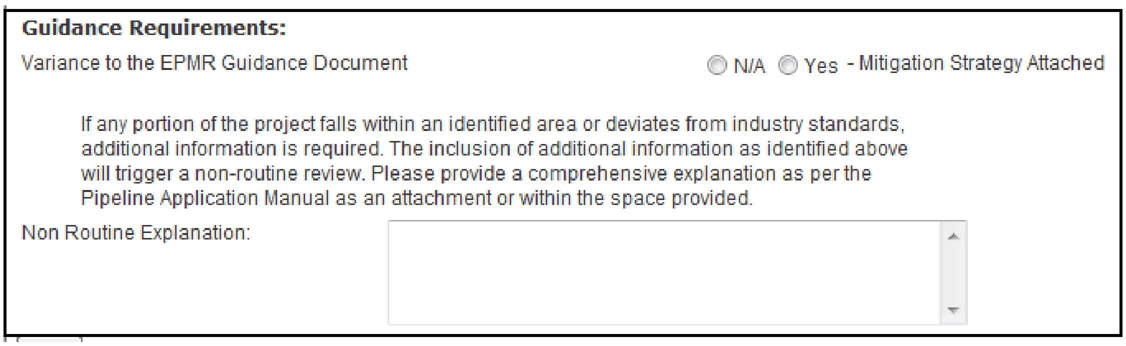
Environmental Protection and Management Regulation Exemption

In accordance with Section 21 of the Environmental Protection and Management Regulation, the Commission may exempt a person from one or more of the requirements of Part 3 of the Environmental Protection and Management Regulation, if complying with that requirement is not reasonably practicable.

The exemption request must accompany the application and must include an explanation of why the regulation cannot be followed, what measures will be taken to ensure impacts to the value identified will be mitigated or minimized, and if appropriate a mitigation strategy. Refer to the Environmental Protection and Management Regulation Guidebook for guidelines outlining the Commission's expectations in regard to conforming to the regulation and detailed information regarding mitigation strategies.

Exemption from the Drilling and Production Regulation

The Commission may exempt particular sites and installations from specified provisions of the regulation in accordance with Section 2 of the Drilling and Production Regulation. If a specific exemption is desired for an application, a justification must be provided as part of the permit application.


Guidance Requirements:

Variance to the EPMR Guidance Document ◯ N/A ◯ Yes - Mitigation Strategy Attached

If any portion of the project falls within an identified area or deviates from industry standards, additional information is required. The inclusion of additional information as identified above will trigger a non-routine review. Please provide a comprehensive explanation as per the Pipeline Application Manual as an attachment or within the space provided.

Non Routine Explanation:

Forestry Tab

The forestry tab provides administrative information on proposed timber activities and road use for activities on Crown land.

Fibre Utilization
Permit holders are encouraged to utilize merchantable timber, as outlined in Information Letter OGC 08-21 and must upload a fibre utilization plan as an attachment when there is new cut on crown land.

Stumpage
In accordance with the Forest Act, stumpage is payable for harvesting activity conducted under the Master License to Cut. The Ministry of Forests and Range bills the applicant according to the data submitted on the pipeline, application, or the data submitted on the pipeline as-cleared form which is required 60 days after construction completion.

The Ministry of Forests and Range Interior Appraisal Manual outlines the parameters related to stumpage.

Timber Marking
Timber marking must be carried out in accordance with the Timber Marking and Transportation Regulation.

Applicants are encouraged to incorporate forest and range tenure digital information into their plans.

Woodlot Tenures
The Applicant must ensure woodlot tenures affected by the project have been identified, and agreement has been reached with the licensee(s).

The woodlot holder must obtain cutting authority for oil and gas related harvesting from the Ministry of Forests and Range.

The following page describes the requirements to fill out the forestry tab in KERMIT.

Clicking on the new forestry entry button opens the application information window where new forestry details are entered.

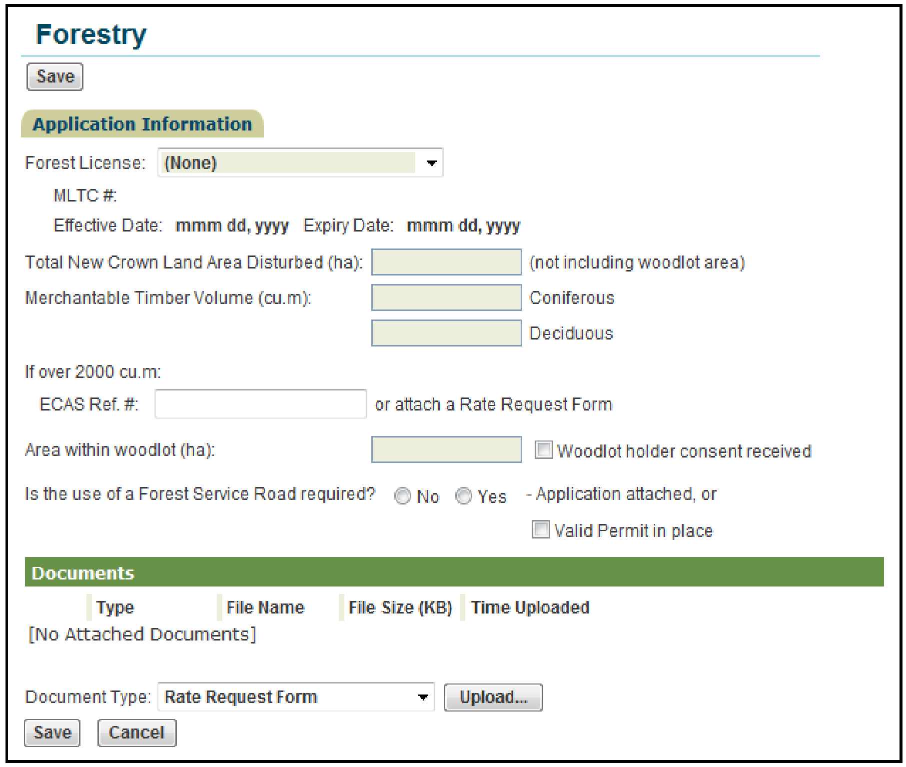


Fig. 7.4. Application Information detail window on the Forestry Tab.

Forest Licence

Select the applicable forest district that encompasses the project based upon the Provincial Forest District maps. The master licence to cut (MLTC) no., effective date, and expiry date will auto-generate.

MLTC No.

If the project is located on Crown land indicate the forest district specific master license to cut tenure number assigned to the applicant by the Commission in the form M######.

Total New Crown Land Area Disturbance (proposed)

The area in hectares to be included in this section will be:

- The total area of Crown land, minus
- Any woodlot areas included in the project area and/or,
- Minus any previously cleared areas (where stumpage has already been collected)

This area must be clearly identified in the construction plan, and subsequently labelled as “new Crown land area disturbed” on the Facility As-Cleared Submission Form.

Merchantable Timber Volume

Estimate the volume of coniferous and deciduous timber in cubic metres.

If the merchantable volume exceeds 2000m^3 an appraisal is required. Refer to the Ministry of Forests and Range Interior Appraisal Manual. Appraisal data submissions are made directly to the Electronic Commerce Appraisal System (ECAS).

State the ECAS reference number if applicable or indicate if a rate request form is being submitted with the application as an attachment.

Woodlot Exclusions

The Commission cannot issue authorization to harvest within a woodlot tenure area. Authority to harvest within a woodlot tenure area must be obtained through the woodlot holder. Indicate the woodlot tenure area to be excluded from the cutting authority.

The area within a woodlot is *not* included as area of new Crown disturbance. This area must also be clearly marked on the construction plan.

Forest Service Road

Indicate whether or not the use of a forest service road is required, and if a valid permit is in place, or if an forest service road application is attached.

Where construction is proposed within a forest service road right-of-way, the applicant must obtain a works permit from the Ministry of Forests and Range.

Before connecting a road to a forest service road the applicant must obtain the consent of the Ministry of Forests and Range District Manager.

Road Use Permit

If a forest service road is required, a road use permit must be submitted to the Commission as part of the pipeline application. The road use permit must indicate what sections of the forest service road the applicant requires authorization for.

When using forestry permitted roads (other than a forest service road), the applicant is required to notify the road permit holder of their intended activities. A road use agreement must be in place between the parties. A road use permit from the Commission is not required.

Documents

If required, upload a road use permit application and/or a rate request form

First Nation(s) Tab

First Nations/Aboriginal Communities

The Province of British Columbia has the duty to consult and where required accommodate First Nations whenever it proposes a decision or activity that could have potential impact to treaty rights or aboriginal rights recognized and affirmed by Section 35(1) of the Constitution Act, 1982. As an agent of the Crown, the Commission fulfills any provincial obligation to consult with First Nations prior to the authorization of activities under the Oil and Gas Activities Act, and related specified enactments.

Consultation

Consultation with Treaty 8 First Nations about any potential impact of their treaty rights by oil and gas activities are guided by agreements between the Commission and First Nations.

First Nations agreements with the Commission can be found on the Commission First Nations Web Page.

For Treaty 8 First Nation Communities without agreements with the Commission or First Nation Communities who are not members of Treaty 8, the British Columbia Interim Consultation Process applies.

The Commission may consider engagement which has occurred between First Nations and the applicant as part of its decision making process

Consultation Timelines

The Commission consults with First Nations through the process and timelines established in the Consultation Agreements. The consultation process begins once the First Nation community receives the completed package. Commission internal reviews occur simultaneously with reviews conducted by First Nations.

If concerns are identified in First Nations responses, the Commission will, where appropriate, facilitate meetings with the Nation (involving the applicant as necessary) to discuss their concerns and proposed accommodation measures.

Where no agreement is in place, there is no defined timeline. The Commission strives to facilitate an efficient and effective consultation process.

Administrative Boundaries
Administration boundaries established through the agreements guide consultation for each First Nation. Where there is no agreement in place, the boundaries are guided by the Provincial Consultation Boundaries.

Notice Only Communities
There are four Aboriginal communities that the Commission provides information to regarding surrounding oil and gas activities in the form of a notice.

Notice packages are different from, and must not be confused with, Notification as defined within the consultation agreements with First Nations.

Notice Only Communities	
Abbreviation	**Aboriginal Community Names**
KLCN	Kelly Lake Cree Nation
KLFN	Kelly Lake First Nation
KLMSS	Kelly Lake Métis Settlement Society
FLFN	Fort Liard First Nation

First Nation(s) Consultation/Notification

An applicant must first determine which First Nations require consultation. Each First Nation requiring consultation must be entered in KERMIT.
To enter the appropriate First Nations information into KERMIT, click the new consultation/notification button, which opens the details window.

Select the affected First Nation from the dropdown menu.

If the First Nation required is not in the list provided, manually enter it into the text box labelled *other*.

If there is more than one First Nation, continue adding using the New Consultation/Notification button.

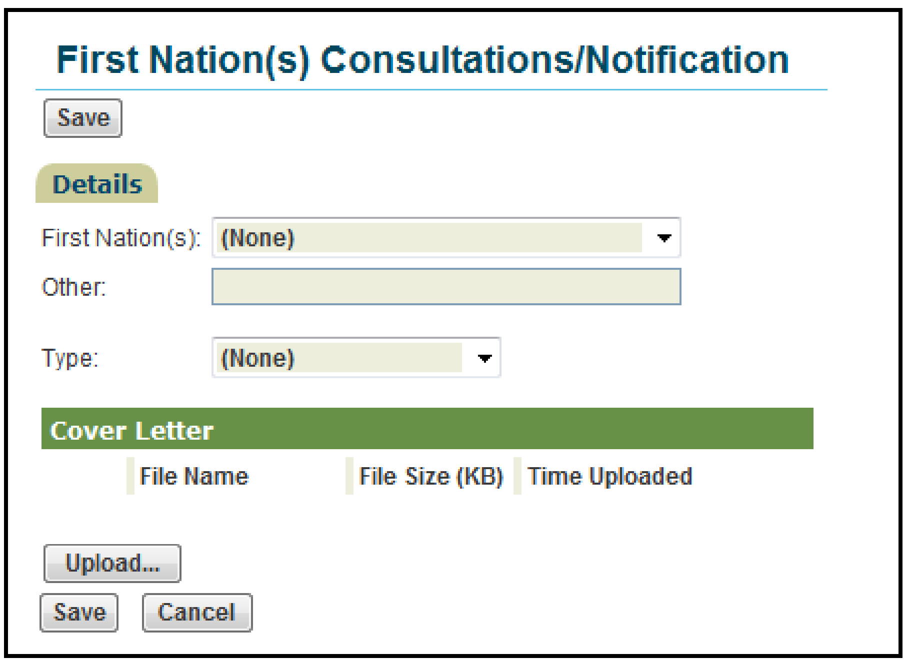
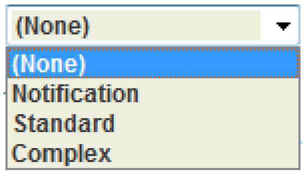


Fig. 7.5. Required information fields in First Nation Consultation and Notification detail window.



Select the application type from the dropdown list. If an application is a pre-assessment, choose notification.

For First Nations, other than Notice only Nations, that do not have agreements with the Commission, the application type should be entered as complex.

Cover Letter

Upload the First Nation package cover letter to KERMIT. Cover letters are found on the First Nation Forms section of the Commission's website.

First Nations Packages

Package Requirements
Each package must contain two cover letters for each community, a copy of the KERMIT application printout, and a copy of the following, if required with the application:

- Cover letter
- Construction plan, as described in Appendix C.
- Maps, 1:20,000 BCGS sketch; 1:50,000 & 1:250,000
- Archaeological assessment information form
- Archaeological reports (if available)
- Fibre utilization plan (if required)
- Other information included with the application as part of the Additional Information Requirements

Once an application has been submitted electronically, the appropriate number of hard copy packages and maps will have to be submitted to the Commission with a clear cross reference to the electronic submission number provided with the initial electronic application.

These packages are required to be submitted to the Commission prior to the application being reviewed in KERMIT.

Each package must contain two cover letters for *each* consultation and notification area affected, a copy of the Application, and a copy of each attachment uploaded into KERMIT

Consultation Tab

Enter New Owner/Occupant information as required in the Detail Window. Multiple owners or occupants may be entered if necessary.

Once the information has been saved, it is possible to return to the consultation tab to edit or delete owner or occupant information.

The Consultation & Notification Written Report must be uploaded under the Attachments Tab.

Enter New Owner/Occupant information as required in the pop up window. Multiple owners or occupants may be entered if necessary.

Question 1 & 2 must be answered in accordance with the Commission's Consultation and Notification Manual.

In many cases the consultation for the installation of equipment is included with the initial consultation associated with the new Well Authorization Application. In this scenario the concerns would have been addressed early in the process, and any specific conditions in the Well Permit Approval relating to facilities must be adhered to in the Application for a Facility. When early consultation did not take place, the applicant is required to engage affected public and tenure holders where there is a potential impact to their rights. This may or may not involve further consultation or notification.

Attachments Tab

The Attachments tab is where applicants can upload any required documentation.

Missing Attachments

The missing attachments section indicates any outstanding documents that have not yet been uploaded to KERMIT. The documents listed must be attached in order to finalize the application.

Attachment List

The attachment list shows what documents have been successfully uploaded to KERMIT, and allows for the attachment of any outstanding items.

Archaeology

The Archaeological Assessment Information Form (AAIF), is completed by a permitted archaeologist and will indicate all recommendations for the program, and must be uploaded into KERMIT as an attachment.

Any archaeological assessments (such as the Archaeological Impact Assessment (AIA), that have been completed at the time of application should also be uploaded.

Assessment reports produced after the application has been made must be submitted promptly, once the archaeologists have completed their assessment. These reports must be submitted digitally through KERMIT

For assistance or more information, refer to the Commission Archaeology Guidelines.

A Permit holder must maintain the prescribed records and plans, and be able to produce records or plans at the request of the Commission.

Consultation and Notification Report

The Commission requires applicants to involve the affected public in their operational planning. OGAA Section 24(1)(c) states each permit application must contain a written report to summarize the results of the consultations carried out and/or the notifications provided to recipients.

Details and criteria of the written report can be found within the Commission's Consultation and Notification Guideline.

A copy of the applicant's written report must be uploaded as an attachment, and will form part of the facility permit application.

Attachment Definitions

ALC Schedule A Site Assessment
In accordance with article 7 of the ALC-OGC Delegation Agreement, a Schedule A Site Assessment of soils must be documented prior to construction so that the reclamation of the land can be planned effectively and reclamation requirements can be achieved.

Archaeological Assessment Report
As described in KERMIT attachments tab.

BCGS Maps
Every pipeline application must be accompanied by the complete set of maps and plans illustrating in detail the location and extent of planned activities at an appropriate scale.

ERP Document
As described in the engineering tab.

Fibre Utilization Form
A fibre utilization form, or exemption request must be included with every application on Crown land requiring new cut.

First Nation Notification Form
This refers to the First Nations cover letter, as described in the First Nation(s) section.

Flow Schematic
A diagram showing all major equipment, vessels, meters, and interconnecting piping (process, fuel, flare and vent at a minimum) at the facility, or within an identified skid or building.

IOGC Agreement
This document is required if an agreement is required from Indian Oil and Gas Canada for the project.

Miscellaneous Document
Any document that is required that is not listed in this table. A Fibre Utilization Plan is a miscellaneous document.

P&ID
A detailed diagram for each facility or skid/building identifying all instrumentation symbols, valves & connections, piping and vessels, line numbering, fuel gas, flare and vent streams. This drawing must include all safety systems such as H_2S detection,

flammable gas detection, and fire detection inside and outside of buildings. The P&ID must also include the initial high and low setpoints of all pressure switches proposed at the facility.

Plot Plan
A diagram identifying the surface area required for the facility and the proposed equipment, including but not limited to, the lease area, the access road point of entry including proposed fencing and/or access control measures, and how the access continues past the facility site if applicable, the equipment layout with distances shown in meters, (for example all storage tanks, buildings, compressors, flare stacks, flare knock out drums, line heaters, pump jacks, etc), all wellhead positions (clearly labelled by location), where the riser/pipeline starts and ends on a site and how it leaves the site going into the right-of-way. Fencing and/or gates must also be shown on the plot plan.

Crown Land Status Sheet
As described in KERMIT Land tab and Appendix C.

Finalize Tab

KERMIT will indicate if there are outstanding issues related to the application. KERMIT will not finalize an application that has outstanding issues. Once the outstanding issues have been addressed, the application can be finalized.

Finalize and submit the application. If First Nations packages are required, the Commission will not review the application in KERMIT until the hard copy packages are submitted and applicable fees are received.

8 Facility Permit Amendments

A permit amendment is a change required *after* the permit has been approved by the Commission. An amendment may be used for modifications to, addition or removal of equipment or piping. This type of amendment also includes the addition of new wells.

Amendments are submitted through KERMIT, and follow the same process (selecting Facility Amendment in the New Application list) as described in Section 7 of this manual.

Consultation and Notification for Amendments

Under OGAA, Well or Facility-to-Facility linkage changes must be submitted through KERMIT.

Permit holders submitting amendments to the Commission must do so in accordance with the requirements and processes prescribed in the Consultation and Notification Regulation, and summarized in the Commission Consultation and Notification Guidelines.

Major Amendment
Both OGAA and the Consultation and Notification Regulation outline consultation and notification requirements for permit amendments. If a facility permit amendment application meets the criteria of a major amendment, as outlined within Consultation and Notification Regulation, the consultation and notification process must follow the process outlined within the regulation.

Other
If an amendment application does not meet the criteria of a major amendment, the amendment process outlined within Section 31 of OGAA must be followed. Before submitting an application for a permit amendment, the permit holder must provide notice to the landowner. This notice must:

- Provide a description of the proposed amendment.
- Advise the landowner that he or she may make a submission to the Commission regarding the proposed amendment within 15 days of receiving the notice.

After providing notice to the landowner, a permit holder may submit an amendment application to the Commission.

For amendments that do not meet the criteria of a major amendment, the Commission may require the permit holder to carry out additional consultation and/or notification with respect to the proposed amendment in accordance with OGAA Section 31. Any additional notification will be determined once the amendment application has been submitted to the Commission.

Consultation & Notification Written Report

If additional consultation and/or notification is required, a written report detailing steps taken must be submitted to the Commission at the conclusion of consultation and/or notification activities.

If a land owner makes a submission to the Commission in regards to a proposed amendment, the Commission will send a copy of the submission to the permit holder.

All drawings and project description must reflect the proposed changes.

Effective Date

An amendment is effective on, and after the day it is made unless the landowner makes a submission; in which case the amendment is effective on and after the 15th day after it is made.

If an amendment changes the effect of the permit on the land of the landowner, the Commission will provide notice to the landowner of the changes.

Facility Amendment - No New Land Required

When applying to make changes to an existing facility where no new land is required, permit holders must determine if an amendment or a Notice of Intent is required.

An amendment is required for activities where work initiates or impacts measurement, noise/air emissions, or production accounting.

Piping and equipment for a new well tie-in cannot be submitted with a NOI. A facility permit, or permit amendment is required.

Examples of Where a Permit Amendment is Required:

- Modifications that initiate or impact measurement.
- Addition of temporary or permanent water or hydrocarbon production tanks if not included in the previously approved permit or subsequent permit amendment for the facility
- Replacing inlet or test separator with a different sized unit
- Adding or removing equipment such as compressor, dehydrator, separator, slug catcher, reboiler (amine or glycol), wet gas meter skid, deethanizer, condensate stabilizer, debutanizer, plunger lift, vapour recovery unit, H_2S scrubber, generator, oil battery (test or permanent), waste disposal/processing facility, water injection/disposal station, pumping station, gas injection station
- The addition of plunger lift on a gas well where the well is located on private land only - minor amendment

An NOI is required for activities where work does not impact measurement, noise/air emissions or production accounting, but does impact existing well/facility linkages.

If pressure welding is associated with any of the below listed works; a Notice of Intent can still be submitted, and additional notices (Construction Start, Pressure Test, Leave to Open, and As-Builts) are not required.

Amendment Activity Types

For facility amendments where no new land is required, there are two amendment types; Add or Delete Equipment and Repair or Modify Equipment.

Amendments are submitted through KERMIT and are completed in the same way as Facility Permit Applications - No New Land Required (Section 6), unless otherwise indicated in this section.

Add or Delete Equipment
This amendment type is submitted for the addition and/or removal of equipment/piping, including temporary equipment. Examples include:

- Add equipment to tie in an additional well on an existing pad
- Production tank additions
- Sales meter run changes
- Permanent or temporary compressor installation/removal
- Add a dehydrator

Repair or Modify Equipment
This amendment type is to be submitted when equipment and/or piping is in need of repair due to an incident or deterioration, or when any modifications are required.

Examples include:

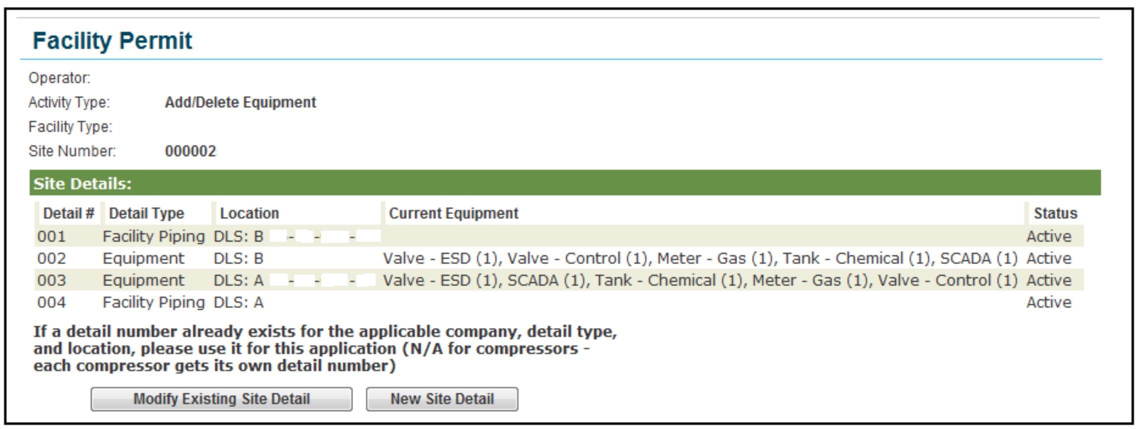
- Repairs from damages/deterioration
- Change of Service

Add or Delete Equipment

Under the Add or Delete Equipment Amendment type, permit holders can choose to modify an existing site detail, or add a new site detail .

That is, if equipment is being added to an existing site detail, and a new site detail is to be added (e.g. installing a new compressor and adding equipment to an existing detail), two applications must be submitted, as this requires adding a new detail and modifying an existing one. Each should cross-reference the other, and the same attachments must be uploaded for both.

1) Select Facility Amendment – Add/Delete Equipment
2) Search the site by location
3) Select the associated site or file and click on New Permit Amendment to open the modification window, where a new site detail may be added or an existing site detail may be modified.



Facility Permit

Operator:
Activity Type: **Add/Delete Equipment**
Facility Type:
Site Number: **000002**

Site Details:

Detail #	Detail Type	Location	Current Equipment	Status
001	Facility Piping	DLS: B - - -		Active
002	Equipment	DLS: B	Valve - ESD (1), Valve - Control (1), Meter - Gas (1), Tank - Chemical (1), SCADA (1)	Active
003	Equipment	DLS: A - - -	Valve - ESD (1), SCADA (1), Tank - Chemical (1), Meter - Gas (1), Valve - Control (1)	Active
004	Facility Piping	DLS: A		Active

If a detail number already exists for the applicable company, detail type, and location, please use it for this application (N/A for compressors - each compressor gets its own detail number)

Modify Existing Site Detail | New Site Detail

Either Modify Existing Site Detail or New Site Detail must be selected.

New Site Detail:
Clicking on the New Site Detail Button opens the permit page where information regarding the new equipment, compressor(s) or facility piping must be entered.

All fields are entered in the same manner as described in the Modify Existing Site Detail section of Section 6. This includes the information under the Application, Engineering, Consultation, Attachments and Finalize tabs.

Modify Existing Site Detail
Clicking on the Modify Existing Site Detail opens the permit page where information regarding the changes must be entered under categorized tabs. The tab categories are Application, Engineering, Consultation, Attachments and Finalize.

Application Tab

General Application Info

General application information is provided here.

Indicate whether the amendment is on Crown land, private land or both.

Administration and Engineer's Details fields are completed the same way as with a facility permit application.

Engineering Tab

Application Information

Check these items if any apply to this application

Temporary Facility/Equipment
When a portion of, or all of the equipment added at a well, facility, or pipeline right-of-way is to be in place for a period of six months or less, and may include pressure vessels, gas fired equipment, flare stacks/incinerators, tanks, compressors, or other equipment as specified by the Commission. This includes equipment for an extended gas well test, or oil well flow test.

A Permit Amendment/Notice of Intent is not required when:

- Temporary equipment is set up at a well location for an in-line test or well clean-up operation only; and:
    - the temporary equipment is portable and directly associated with the completions operations

- o the equipment is supervised 24 hours per day
- o the equipment is not permanent in nature (e.g. placed on piling) and is in place for three weeks or less.

Gas Processing Plant
If the amendment is related to a Gas Processing Plant, additional questions will appear under the Engineering tab. This includes expansions and/or modifications. More information on Gas Processing Plants is location in Section 16 and Appendix F of this manual.

Converting Temporary Facility/Equipment to Permanent
Check this box if there is existing temporary equipment that will become permanent.

Major Permit Amendment
Check this box if the application is a Major permit amendment in accordance with the Consultation and Notification Regulation.

Existing Facility Code
The Commission may have assigned a Facility Code for the following installations to link the flow of produced and processed product.

- Compressor
- Dehydrator
- Gathering point
- Oil battery/gas battery/satellite
- Gas/water injection or disposal
- Test / reporting facility
- Sales meter (oil/gas)
- Gas plant
- Pipeline terminal

Enter the facility code if one has previously been assigned to the subject facility.

Facility Details

Facility Details fields are completed the same way as with a facility permit application, as described in Section 6.

Facility Specifications

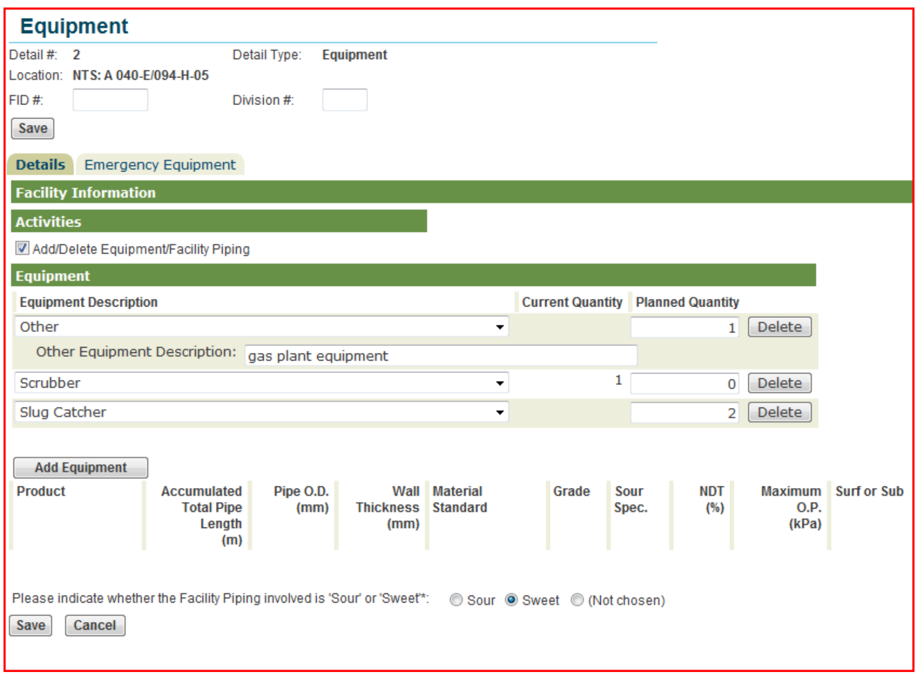
Click on the detail number to open the detail window for facility piping which displays the Details, and Emergency Equipment tabs.

Details Tab

Check the Add/Delete Equipment/Facility Piping box to activate the Activities section of the form.

Enter a Removal Date only if **all** equipment is being removed; otherwise leave the field blank. After the application has been accepted the detail status will show as “removed”.

Select additional equipment and planned quantity to add, or change the planned quantity of existing equipment to remove.



Emergency Equipment
Information that may be entered in this tab is optional.

Engineering Questions
Answer the engineering questions under Regulations and Requirements, Technical Information and Design, Flaring and Venting and Cross Border Requirements.

Consultation Tab
The consultation tab allows the applicant to enter recipient information.

Attachments Tab
Upload all required information in the attachments tab.

All drawings and project description must reflect the proposed changes.

- Project Description
- Process Flow Diagram
- Gathering System Schematic
- Piping and Instrumentation Diagram (P&ID)
- Plot Plan
- Schedule 1 (if applicable)

Finalize Tab
If any outstanding issues appear in the finalize tab, they must be addressed before the application can be completed.

Repair/Modify Equipment

Under the Repair/Modify Equipment amendment activity type, permit holders modify an existing site detail.

1) Select Facility Amendment – Repair/Modify Equipment
2) Search the site by location
3) Select the associated site or file and click on New Permit Amendment to open the modification window, where a new site detail may be added or an existing site detail may be modified.

Application Information

Check these items if any apply to this application

Temporary Facility/Equipment

When a portion of, or all of the equipment added at a well, facility, or pipeline right-of-way is to be in place for a period of six months or less, and may include pressure vessels, gas fired equipment, flare stacks/incinerators, tanks, compressors, or other equipment as specified by the Commission. This includes equipment for an extended gas well test, or oil well flow test.

This does **not** include the following:

- Temporary equipment set up at a well location for an in-line test or well clean-up operation where:
- the temporary equipment is portable and directly associated with the completions operations
- the equipment is supervised 24 hours per day
- the equipment is not permanent in nature (e.g. placed on piling) and is in place for three weeks or less.

Check this box if some or all equipment to be installed is temporary.

Converting Temporary Facility/Equipment to Permanent

Check this box if there is existing temporary equipment that will become permanent.

Gas Processing Plant

If the amendment is related to a Gas Processing Plant, additional questions will be prompted. This includes expansions and/or modifications.

Suspend Facility
Check this box if the faculty is to be temporarily suspended, and indicate the length of time.

Reactivate Facility
Check this box if the facility is to be reactivated.

Major Permit Amendment
Check this box if this application is a major permit amendment in accordance with the Consultation and Notification Regulation.

Existing Facility Code
The Commission may have assigned a Facility Code for the following installations to link the flow of produced and processed product.

- Compressor
- Dehydrator
- Gathering point
- Oil battery/gas battery/satellite
- Gas/water injection or disposal
- Test / reporting facility
- Sales meter (oil/gas)
- Gas plant
- Pipeline terminal

Enter the facility code if one has previously been assigned to the subject facility.

Facility Specifications

Select an existing site detail number from the list to open the NOI site detail page.

Equipment, Facility Piping, or Compressor Details
Enter the repair/modify date, and include a summary of work, including a description of modifications and/or repairs of facility piping, work locations address / UTM (NAD83) and any other relevant comments or notes.

For equipment details, select the equipment description and indicate in the checkbox if a repair was made.

The repair/modify amendment also includes change of service (product), and a well to facility or facility-to-facility linkage changes.

Drawings must include clouded areas to show repairs/modifications.

Change of Service:

Usually a change of service applies to a facility and a pipeline – this requires two Amendments; one for the facility and one for the pipeline. If the change of service includes a pipeline, the job number for the Pipeline Amendment must be entered in the Amendment Explanation areas. See the Pipeline Operations Manual for information and application procedure regarding the pipeline.

It is critical that changes in service at a facility from sweet to sour (in accordance with the latest edition of CSA Z662), or from 100 ppm H_2S or less, increasing to greater than 100 ppm , and 5% or less increasing to over 5% (*Drilling Production Regulation S.39)* are submitted to the Oil and Gas Commission in a timely manner.

If a product is introduced into a facility or pipeline that was not originally designed for sour service, an Engineering Assessment, in accordance with the latest edition of CSA Z662 must be completed and submitted to the Commission.

The Emergency Response Plan is to be evaluated and updated (if required) and must be on file with the Commission before the sour product is introduced into the facility or pipeline.

Attachments Required:

- Project description
- Schedule 1 (if applicable)

9 Notice of Intent

A Notice of Intent (NOI) is an electronic notice submitted through KERMIT that captures the scope and location of a project, and allows for reporting of operational changes and modifications or repairs to existing facilities requiring no new acquisition of land. The information collected is used by the Commission to track and manage changes. Facility Notices of Intent are:

Construction Start, Pressure Test, Leave to Open and As-Built are not required for Notices of Intent.

- Cancel Facility
- Add/Delete equipment
- Repair/Modify equipment
- Linkage change

A Notice of Intent is used when adding equipment/piping to or modifying an existing site, and allows companies to report on installations, removals, modifications or repairs to locations where no new land is required.

A Cancel Facility, Add/Delete, or Repair/Modify Equipment NOI is required for activities where work does not impact measurement, noise/air emissions, production accounting, or existing well/facility linkages.

Submitting a Notice of Intent

The following section details what information is required when submitting a Notice of Intent, and how to submit the notice in KERMIT. Follow the same process for both upstream and downstream Notices of Intent.

Piping and equipment for a new well tie-in cannot be submitted with a NOI. A facility permit, or permit amendment is required

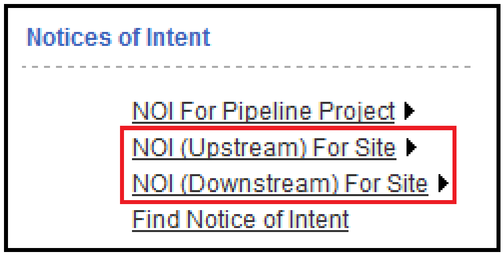
Examples of where Notice of Intent is Required:

- Piping modifications not impacting the process flow. such as adding isolation valves, strainers, etc.
- Replacing meter run, production tank, separator, or similar equipment that is unchanged in capacity and design. (“replacement in-kind”)
- For adding or removing equipment such as a propane tank, line heater, blowcase, sand filter/separator, filter pot, pump jack (electric), instrument air unit, field header, pigging equipment, gas coalescer, gas cooler, recycle pump, condensate pump, chemical/methanol pump, regulator, riser, fresh water meter, fresh water storage tank, fuel storage tank, chemical/methanol storage tanks, LPG storage bullet, thermal electric generator
- Removing temporary equipment such as produced water tanks.
- Facility piping spool replacement over 4 meters in length and 4 inch diameter not impacting process or measurement
- Adding ESD valves
- The addition of plunger lift on a gas well where the well is located on crown land only. The addition of plunger lift on a gas well located on private land is a facility amendment – minor

Notice of Intent Page

This section first shows how to fill out the portions of the application that are general to all Notice of Intent submissions. The subsequent sections provide details that are specific to each notice of intent type.

1) Select the Notice of Intent application type
2) Search using the site number or location
3) Select the Associated file and click on New NOI



Except where noted, the tabs are filled out the same way as in described in previous sections.

Overview Tab

The new Notice of Intent for the site has been opened, and a job number has been generated. Displayed with the job number is other information related to the notice such as the current status, activity type and site number.

The information required on the Overview tab is the same for Cancel Facility, Add/Delete Equipment, and Repair/Modify Equipment NOI; with the exception of the Facility Activity sections.

General Application Info

General application information shows the application source and provides a field for activity description.

Indicate if the activity is located on Crown land or private land or both.

Operator

This section captures key applicant information.

The applicant/company name and information will appear automatically. If the company name does not appear, or the address is incorrect, the Applicant must contact the Commission's Corporate Land Management Unit to update the information prior to application submission.

Use the Find button to search for a company contact that has previously been entered into the Commission database. If no contact is found, enter the information manually.

The facility permit holder is accountable for the accuracy of the application content entered into KERMIT, even where outside agents or consultants are used.

Engineering Firm

Company and Engineer information can be entered by selecting the find button to the right of both fields.

Field Contact

Field contact must include the full name and phone number for the field representative for the project.

Facility Details

Facility name and H_2S content must be provided as previously described in Section 6..

Facility Details

Facility Name:

Maximum H2S Content of Inlet Gas: % or ppm ☐ none

Facility Specifications

Details for what is required for each notice type, is covered in the following sections. No attachments are required.

Facility Activity

Detail # / FID #	Detail Type / Division #	Location	Current Equipment	Status	IRIS Project #	OGC File #	Activity Entered
003	Facility Piping	DLS: 10-04-078-19		New			☐
004	Equipment	DLS: 10-04-078-19		New			☐

Agreement

This agreement must be satisfied before submitting the Notice.

Cancel Facility

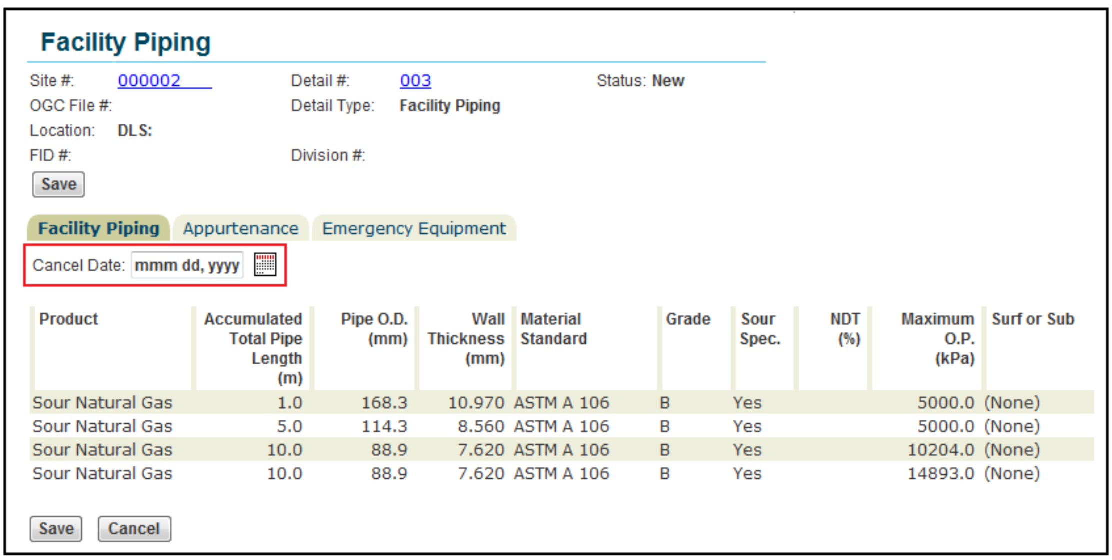
A Cancel Facility Notice of Intent must be submitted when a project will no longer be constructed, and site details should be cancelled.

All previously approved equipment to be cancelled must never have been installed on site. If any equipment has been installed, a Facility Amendment - Add/Delete Equipment must be submitted, rather than a Cancel Facility Notice.

Facility Specifications

To open the Facility Piping and/or Equipment detail window, click on the detail number enter a cancel date and save.

This triggers the status of the details to be updated to “cancelled” once the notice of intent is accepted.


Facility Piping

Site #: 000002 Detail #: 003 Status: New

OGC File #: Detail Type: Facility Piping

Location: DLS:

FID #: Division #:

Save

Facility Piping | Appurtenance | Emergency Equipment

Cancel Date: mmm dd, yyyy

Product	Accumulated Total Pipe Length (m)	Pipe O.D. (mm)	Wall Thickness (mm)	Material Standard	Grade	Sour Spec.	NDT (%)	Maximum O.P. (kPa)	Surf or Sub
Sour Natural Gas	1.0	168.3	10.970	ASTM A 106	B	Yes		5000.0	(None)
Sour Natural Gas	5.0	114.3	8.560	ASTM A 106	B	Yes		5000.0	(None)
Sour Natural Gas	10.0	88.9	7.620	ASTM A 106	B	Yes		10204.0	(None)
Sour Natural Gas	10.0	88.9	7.620	ASTM A 106	B	Yes		14893.0	(None)

Save Cancel

Fig. 9.1. Facility Piping detail window.

Add/Delete Equipment or Piping

This notice of intent must be submitted when equipment or piping is added to, or removed from a site. The equipment list will be limited to certain types for notices.

Piping and equipment for a new well tie-in cannot be submitted with a NOI. A facility permit, or permit amendment is required.

Facility Activity

To open the Facility Piping or Equipment detail window, click on the detail number.

Indicate changes, quantity of equipment, and record any applicable changes under the Emergency Equipment tabs.

Indicate whether the Facility Piping will be sour or sweet.

A single Notice of Intent can be used to add and delete selected equipment. No attachments are required for Notices of Intent.

Specifics for the facility piping changes will be required on the As-Built submission.

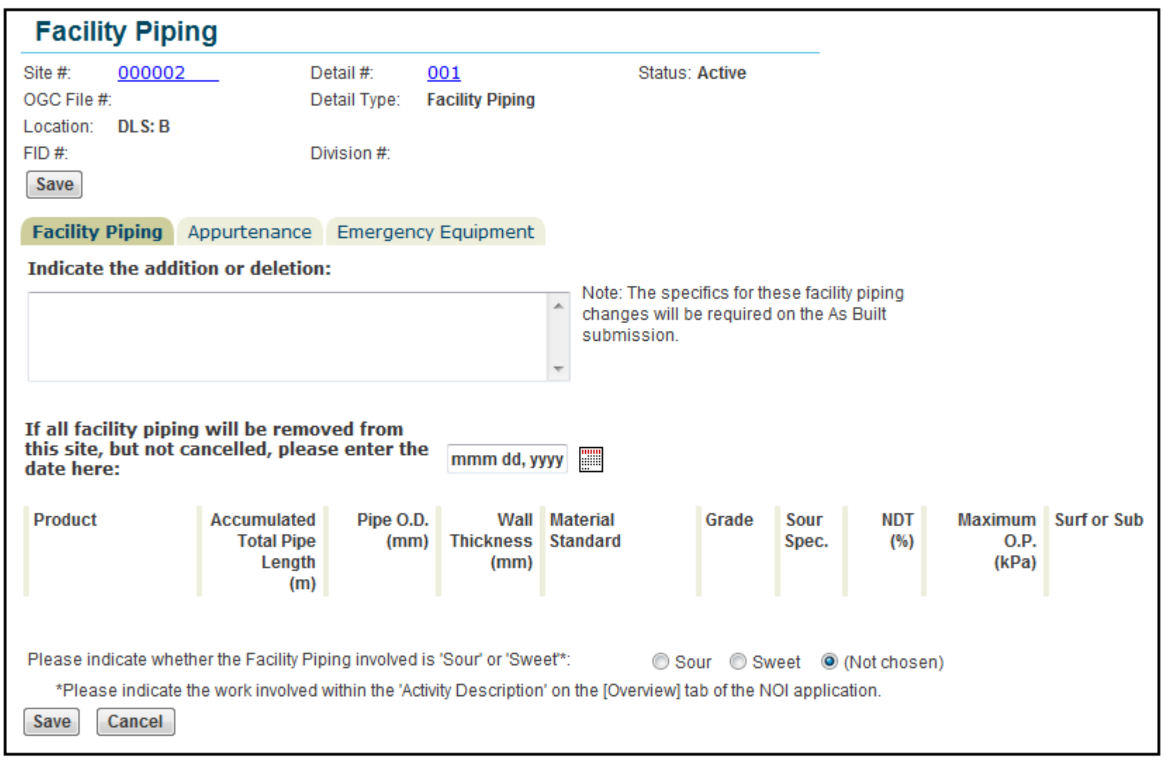


Fig. 9.2. Add/Delete Notice of Intent page

Repair/Modify Equipment or Piping

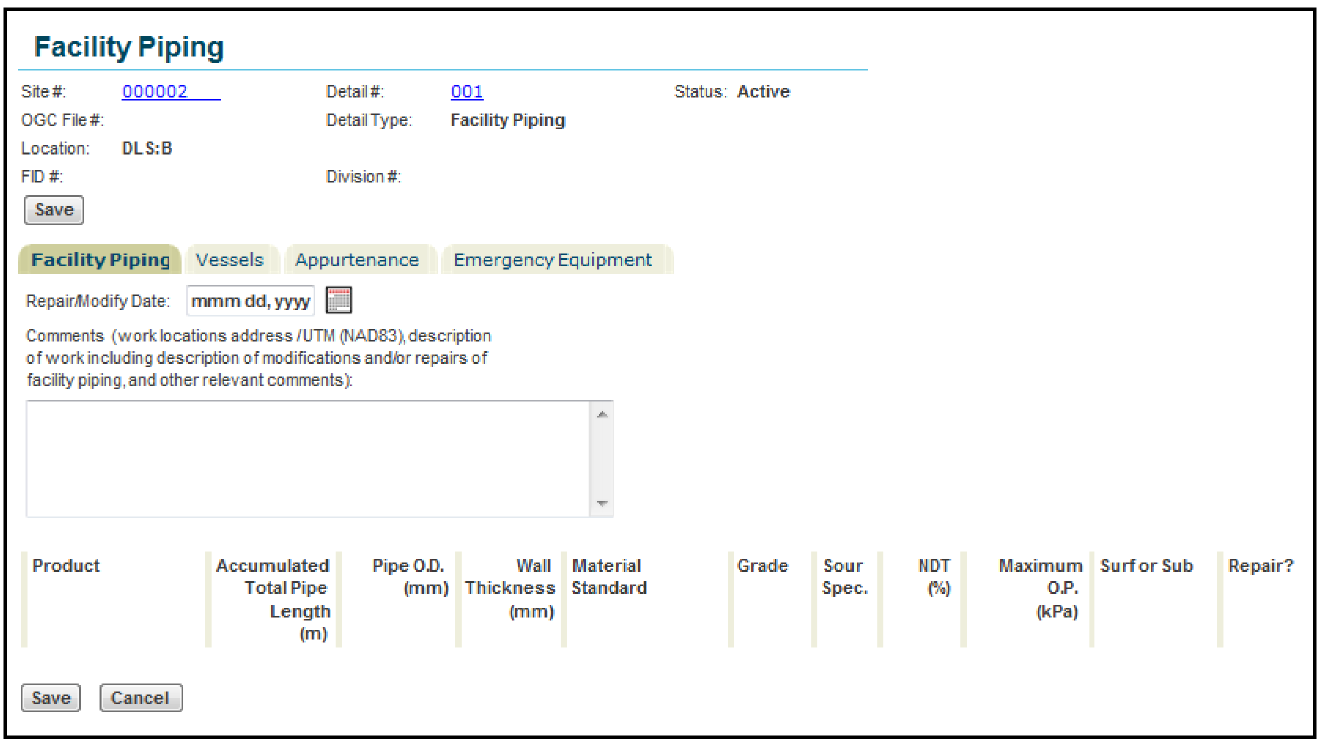
This Notice of Intent must be submitted for repairs/modifications to equipment and/or piping. In the Notice of Intent Page for Repair/Modify Equipment or Piping, (with the exception of the fields under Facility Activity) the Overview, Attachments and Finalize tabs are completed as described in previous sections.

Repair/Modify Equipment or Piping does not apply to the replacement of equipment.

Facility Specifications

Clicking on the Facility Detail number opens the Facility Piping Detail window, where existing details and information can be viewed.

Enter the Repair/Modify date, and in the Comments box include the work location, and a description of the repairs or modifications. Enter any applicable changes under the Emergency Equipment tabs.



Facility Piping

Site #: 000002 Detail #: 001 Status: Active

OGC File #: Detail Type: Facility Piping

Location: DLS:B

FID #: Division #:

Save

Facility Piping | Vessels | Appurtenance | Emergency Equipment

Repair/Modify Date: mmm dd, yyyy

Comments (work locations address / UTM (NAD83), description of work including description of modifications and/or repairs of facility piping, and other relevant comments):

Product	Accumulated Total Pipe Length (m)	Pipe O.D. (mm)	Wall Thickness (mm)	Material Standard	Grade	Sour Spec.	NDT (%)	Maximum O.P. (kPa)	Surf or Sub	Repair?

Save Cancel

Fig. 9.3. Add/Delete Notice of Intent page

Linkage Change

The selection of Crown or Private land is in reference to the new facility product will be going to.

A Schedule 1, Well or Facility-to-Facility Linkage must be submitted to change the existing linkage between a well and a facility or a facility and a facility.

Linkage changes affect both Engineering and Production Accounting.

Examples of these amendments include

- Wells will be redirected from an existing facility upon approval of a new facility.
- Product will be temporarily redirected, as a result of a shutdown.
- A facility is being decommissioned; therefore, product is to be redirected.

An example of a Schedule 1 form is located in Appendix B, along with instructions on how to complete the form. The active Schedule 1 form is available on the Commission website.

Fill in all the required information under the General Application Information, Operator, Engineering Firm and Field Contact categories.

Attachments Required:

- Project Description
- Gathering System Schematic
- Schedule 1

In-Line Testing
When planning to carry out an in-line test at a gas well, please refer to section 13 of the Pipeline Operations Manual for specific requirements. Currently, the Schedule 1 and Inline Testing Notification form must be submitted via email to The Facility Application Coordinators:

Carling.Goertzen@gov.bc.ca

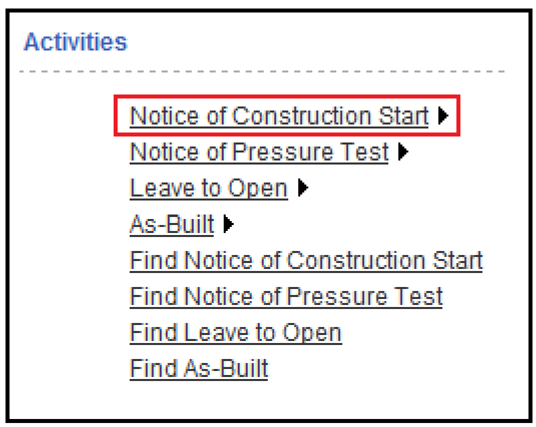
Julianne.Sprathoff@gov.bc.ca.

10 Pre-Construction

Notice of Construction Start

A Notice of Construction Start is to be submitted **prior to** installation of equipment and/or Facility Pipe.

Once the permit application or amendment is approved, a Construction Start can be entered. A minimum of 48 hours notice is required prior to starting construction (in accordance with Section 76(a) of the Drilling and Production Regulation); therefore, the start date entered in KERMIT must be a minimum of two days after the application date.



1) Select Notice of Construction Start from the Activities menu
2) Search for the site using the site or OGC number
3) Select the related site and click on New NCS

Notice of Construction Start Page

The process for submitting upstream and downstream applications in KERMIT is the same.

Except where indicated below, the Overview, Attachments and Finalize tables are completed as shown in previous sections.

General Application Info

Enter the proposed start date which must be at least 48 hours ahead of the application.

Facility Activity

Clicking on the detail number opens Site Detail window where the applicant can view information associated with the project.

For each affected detail, check the Include checkbox to ensure that the associated information will be included in the application. KERMIT will not accept the submission if the details are not included.

Attachment List

The attachments required for a Notice of Construction Start are:

- P& ID
- Plot Plan
- Miscellaneous

11 During Construction

Notice of Pressure Test

The steps for entering a Shop Test and a Field Test in KERMIT are identical.

A Notice of Pressure Test must be submitted 48 hours prior to the test occurring.

There are two types of Notice of Pressure Test: Shop Test and Field Test.

- A Shop Test is required if testing is done in a shop prior to field testing. Kermit will allow multiple shop tests to be entered if needed, prior to a field test.
- A Field Test is required for testing done in the field.

Both Shop Tests and Field Tests are entered into KERMIT. The steps to enter the information are identical for both tests, as well as for upstream and downstream activities. To illustrate the steps, Shop Test (Upstream) for Site has been selected.

Notice of Pressure Test Page

From the notice of pressure test menu, select NPT (Upstream) – Shop Test for Site, find the site operator and select a site. This opens the notice of pressure test page.

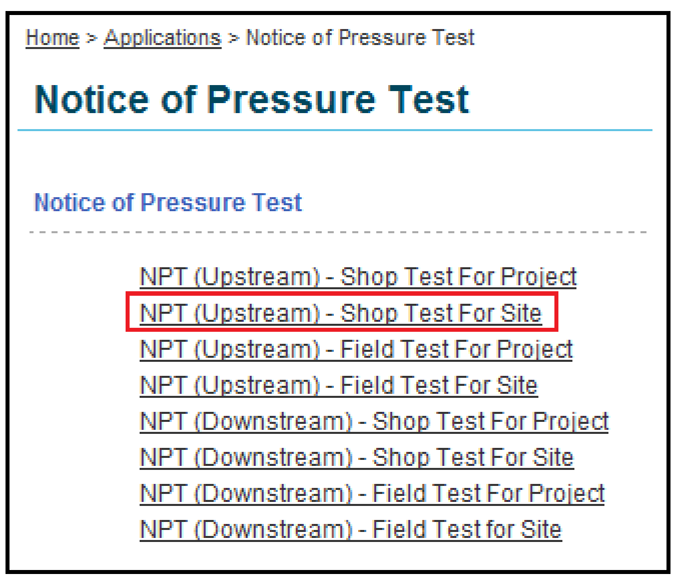


Fig. 11.1. Notice of Pressure Test menu.

1) Select NPT (Upstream) for Site from Notice of Pressure Test menu.
2) Search for the site using the site or OGC number
3) Select the relates site and click on New Shop Pressure Test

Except where indicated below, the Overview, Attachments and Finalize tables are completed as shown in previous sections.

General Application Info

Enter the Proposed Start Date, which must be at least 48 hours after the Notice of Pressure Test is submitted in KERMIT.

Shop Representative

Enter the full name and contact information of the Shop Representative for the project/site.

> The permit holder that holds the surface tenure is accountable for the accuracy of the application content entered into KERMIT. If the permit holder chooses to use outside agents or consultants, the permit holder remains accountable for the accuracy of the application.

Facility Activity

Clicking on Detail number opens The Site Detail Window where the applicant can view the information associated with that detail.

For each affected detail, check the Include checkbox to ensure that the associated information will be included in the application. KERMIT will not accept the submission if the details are not included.

Notes and Conditions

The applicant must indicate yes or no, if further Pressure Testing or Pressure Welding is required.

12 Commencing Operations

Leave to Open

Once the Notice of Pressure Test has been submitted, Leave to Open may be entered in KERMIT. Notice of Leave to Open must be submitted 24 hours before commissioning.

Leave to Open must be electronically designated by the Professional Engineer (P. Eng.) responsible for the construction of the facility and a member in good standing of the Association of Professional Engineers of the Province of British Columbia.

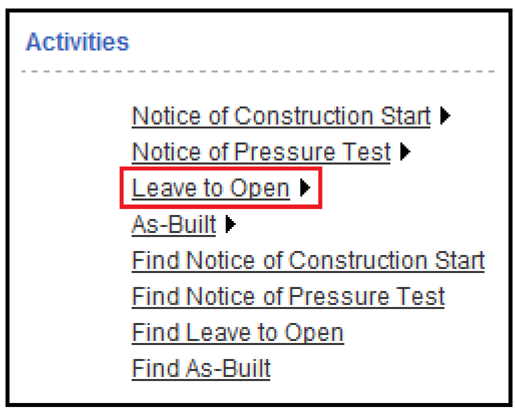


Fig. 12.1. Leave to Open link on Activity menu

The process for submitting upstream and downstream Leave to Open applications is the same.

1) Select LTO (Upstream) for Site from the Leave to Open menu
2) Search for the site using the site or OGC number
3) Select the related site and click on New LTO

Leave to Open Page

Except where explained below, the Overview, Attachments and Finalize tables are completed as shown in previous sections.

General Application Info

Enter the proposed Date of Commissioning, which must be at least 24 hours after the Leave to Open application is submitted in KERMIT.

Facility Activity

Clicking on the detail number opens Site Detail window where the applicant can view information associated with the project.

For each affected detail, check the Include checkbox to ensure that the associated information will be included in the application. KERMIT will not accept the submission if the details are not included.

Information and Conditions

All As-Built drawings, specs, & data must be submitted within 90 days.

Attachment List

The attachments required for a Leave to Open are:

- As-cleared Surface Construction Plan
- Pressure test charts
- Miscellaneous

13 Tenuring

Legal Statutory Right-of-Way Survey Requirements
During the term of the licence, companies must engage a British Columbia land surveyor (BCLS) to submit to the Commission plans of survey through Crown land for approval

A Statutory Right-of-Way survey is required to define the Crown tenured area. A Statutory Right-of-Way Survey Plan must be submitted to the BC Land Title and Survey Authority where a plan number will be given.

The plan number is required to issue Statutory Right-of-Way tenure which replaces the Licence of Occupation tenure. The Statutory Right-of-Way tenure is registered in the Land Title Office.

Survey Requirements for Statutory Right-of-Way
During the term of the Licence, companies must instruct a British Columbia Legal Surveyor (BCLS) to request legal survey instructions.

Preliminary Plans
The preliminary survey plan must be submitted to the Commission for pre-approval and will be forwarded to the Surveyor General.

Statutory Right-of-Way Survey Plan
A registered survey plan of a pipeline right-of-way is required within two years of submitting the leave to open.

If survey requirements are not met during the term of the licence of occupation, replacement licence of occupation tenure with a request for additional fees will be issued. A fee for the replacement of a disposition is payable as indicated in the Land Act Fees Regulations.

Tenure replacement means a new tenure document is issued to the tenure holder for the same purpose and area. Replacement tenures are issued at Commission's discretion and the terms and conditions of replacement tenure may be required to be altered.

Statutory Right-of-Way Document

Upon receipt of the registered Plan, a 30 year Statutory Right-of-Way tenure will be issued to the company by the Land Titles Office.

Companies have 60 days from the issuance of the documents to return both copies signed, and with the required fees. Authorized signatories within the Commission must execute and witness the Land Title Act Form C of both documents, and will return one fully executed copy to the company.

It is the responsibility of the company to register the Statutory Right-of-Way under the Land Title Act. This document is a transferable tenure but does not grant exclusive rights to the land.

Facility Statutory Right-of-Way Fees

Facilities within the Peace River Block and Peace River District are charged annual rent based on the Industrial Pricing for the Peace Subregion map, found in the Commission's Application Resource Handbook.

For the remainder of BC (outside the Peace River Block & Peace River District) annual rental is based on the Ministry of Agriculture and Lands, Crown Land Use Operational Policy: Oil and Gas. The minimum annual rental is $500. The fee for the replacement of a disposition is payable for the issuance of the tenure as outlined in the Land Act Fees Regulations.

Requirements for Facility Lease Tenures (Marketing/Refining Facilities)

Survey requirements will be outlined in the Land Act Tenure Offer letter which will be issued with the Licence of Occupation.

During the term of the Licence, companies must instruct a British Columbia Land Surveyor to request legal survey instructions for a District Lot Designation Number to complete survey requirements.

The preliminary survey plan is to be submitted to the Commission for pre-approval and will be forwarded to the Surveyor General.

Lease Documents
The accepted survey plan must be deposited at the Land Title Office in order to enable the issuance of 30 year Lease tenure. The Lease can be registered at the Land Title Office and grants exclusive use of the site for the purpose intended.

Fees
Marketing/Refining facilities are charged annual rental based on the appraised actual land value as outlined in the Crown Land Use Operational Policy: Oil and Gas. The minimum annual rent for prepaid tenure terms is $500. A fee for the replacement of a disposition is payable for the issuance of the Lease tenure as outlined in the Land Act Fees Regulation.

Companies have 60 days from the issuance of the Lease to return both signed documents and required fees. Commission will fully execute both documents and return one copy to the client for their records and registration in the Land Title Office. The tenure holder then has the right to modify the land and/or construct improvements as specified in the tenure contract.

14 Post-Construction

As-Builts

As-Built specifications, data and drawings provide the Commission with information about the technical aspects of the constructed facility.

As-Builts must be submitted to the Commission within 90 calendar days of submitting Leave to Open in accordance with the Drilling and Production Regulation, section 78(4):

A facility permit holder must submit to the Commission all As-Built drawings, Piping and Instrumentation Diagrams, Metering Schematics and Plot Plans, signed and sealed by a professional engineer (licensed or registered under the Engineers and Geoscientists Act), within 90 days of beginning of production or completing permitted modifications, as applicable.

As-Built Page

The process for submitting upstream and downstream applications in KERMIT is the same.

From the As-Built menu, select *As-Built for Site*, find the site operator and select a site. This will open the As-Built page.

KERMIT Overview Tab
The new As-Built for the project has been opened, and a job number has been generated. Along with the new job number, the site number and status of the application are displayed.

General Application Info

General Application Info shows the application source and provides a field for Activity Description.

Operator

This section captures key applicant information.

The Company name and information should appear automatically. If the company name does not appear, or the address is incorrect, the Applicant must contact the Commission's Corporate Land Management Unit to update the information prior to Application submission.

To enter a Company Contact, select the Find button and add contact. If the Contact is not entered in the Commission database, provide the information in the provided fields.

For reference, enter the company file number in the appropriate field.

The applicant that will hold the surface tenure is accountable for the accuracy of the application content entered into KERMIT. If the applicant chooses to use outside agents or consultants, the applicant remains accountable for the accuracy of the application.

Engineering Firm

Company and Engineer information can be entered by selecting the Find button to the right of both fields.

Include the Engineer number, and after reading the declaration, the Engineer uses the check box to indicate that they agree to the information stated.

Facility Activity

Information must be provided for each detail showing under facility activity. Open the detail by clicking on the detail number to the left of the line list details.

Complete all required fields in for the selected site detail. Clicking on the site detail number opens the detail window.

KERMIT Attachment Tab

The attachments tab allows permit holders to upload the various required documentation.

Select the Document Type from the dropdown menu, and then click the Upload button to locate and attach the document. Once the document is uploaded, KERMIT will show the file type, name, reference and size. It will also indicate the time the file was uploaded, and the author's name and email.

As-Builts

All As-Builts must meet the following criteria:

All As-Builts require original process and instrumentation diagrams, metering schematics, process flow diagrams, and plot plans. For historical submissions and single-well facilities, P&ID drawings will be acceptable in place of metering schematics; however, the P&ID's need to include metering information.

Gathering schematics are required for all compressor sites, dehydration sites, and gas plants. Typical drawings (one P&ID for multiple well sites, non-engineering drawings, etc.) are not acceptable.

The equipment list in KERMIT should be reflected in the P&ID attached. In cases where As-Built has only been done to a section or sections of a large facility site, only applicable drawings need to be stamped and sealed by a Professional Engineer. However, the full P&ID must still be submitted to capture the equipment list in its entirety.

In situations where many pages of drawings exist and an index sheet identifying each drawing is included, the Professional Engineer need only sign and seal the index sheet indicating signing and sealing for all subsequent drawings. If an index sheet is not provided, each drawing must be signed and sealed in accordance with the Engineers and Geoscientists Act, section 20(9):

Referenced manufacturer As-Builts must be submitted for all engineering equipment supplied by a vendor (metering skid, compressor, etc.) with a verification letter signed and sealed by a Professional Engineer in British Columbia in accordance with equipment safety.

If an As-Built includes facility piping, piping specifications must be entered.

Note: For more information on As-Built disclaimer, please refer to Information Bulletin IB 2010-14.

Design Standard
The P & ID and PFD (flow schematic) drawings must identify the design standard (code) used whether CSA Z662 or ASME B31.3, and include all code break points. These design codes must also be identified in the field where it is practical to do so.

Flow schematic/As-Built plan
A diagram showing all major equipment, vessels, meters, and interconnecting piping (process, fuel, flare and vent at a minimum) at the facility, or within an identified skid or building.

Gathering system schematic (Gathering block diagram)
A diagram indicating the flow path of oil and/or gas (including liquids) in pipelines between wells (well site facilities) and central facilities they are physically linked to (connected by pipelines). Identify the route of the primary product from the well to the reporting facility, and include the Well Authorization numbers and Facility Codes that are a part of the new linkage.

P&ID
A detailed diagram for each facility or skid/building identifying all instrumentation symbols, valves & connections, piping and vessels, line numbering, fuel gas, flare and vent streams. This drawing must include all safety systems such as H_2S detection, flammable gas detection, and fire detection inside and outside of buildings. The P&ID must also include the initial high and low setpoints of all pressure switches proposed at the facility.

Plot plan
A diagram identifying the surface area required for the facility and the proposed equipment, including but not limited to, the lease area, the access road point of entry including proposed fencing and/or access control measures, and how the access continues past the facility site if applicable, the equipment layout with distances shown in meters, (for example all storage tanks, buildings, compressors, flare stacks, flare knock out drums, line heaters, pump jacks, etc), all wellhead positions (clearly labelled by location), where the riser/pipeline starts and ends on a site and how it leaves the site going into the right-of-way. Fencing and/or gates must also be shown on the plot plan.

Miscellaneous document
Any additional relevant documentation that is not a required documentation item.

Finalize Tab

KERMIT will inform the Applicant if there are Outstanding Issues with the Application. KERMIT will not finalize an application that has outstanding actions. Once the Outstanding Issues are corrected, the application can be finalized.

When all of the mandatory fields have been filled in, the Submit Application button will become active.

Select Submit to complete or Cancel Application to discard.

Post-Construction Plan Submission

To ensure the Commission has the most current digital and spatial information of actual area cleared for oil and gas activity, Post-Construction Plans must be submitted within 60 days of completed construction. This applies equally to projects located on Crown and private land.

The submission must include upload of a ePASS shape file, and one hard copy of a Post-Construction Map. Both must indicate exactly where construction has occurred should be accurate to +/- 2 meters.

Post-Construction Map
Permanent disturbances must be distinguished from temporary disturbances.

If constructed locations have not changed from the original application, and no temporary ancillary features were included with the application, the ePASS number from the most recent application may be indicated on the post-construction map.

ePASS
For Pipeline and Facility applications in Kermit, the ePASS number must be entered with the Activity Type of "Post-Construction."

Post-Construction Plan submission does not replace the requirements to submit As-Cleared maps, or As-Built submissions.

Any temporary ancillary features must be indicated as clearings. Examples of temporary clearings include:

- Camp sites and decking sites
- Visibility clearings
- Road flare-outs
- Brush storage areas
- Corner cut-offs (which are often part of a pipeline project or road construction project)

The permitted value in ePASS for a clearing is CLEAR as indicated in the ePASS submission Standards document.

As-Cleared Plan Form

As-Cleared refers to the forestry area that was cleared to construct the works.

As-Built refers to specific piping (engineering) details.

An As-Cleared Plan Form is required ONLY where a Cutting Permit was issued for an activity, and reflects the actual area used in the construction of the facility. This includes all amendments that result in a change to the total area used.

As a condition of the permit holder's MLTC, facility permit holders are required within 60 days of clearing to submit an As-Cleared plan to the address stated on the form. The information will then be forwarded to the Ministry of Forests and Range for stumpage billing purposes.

The following information shows what is required on the As-Cleared plan form.

Block A – Administration

Commission File No.	Commission surface file number generated by KERMIT. E.g. 9700000.
Permit Holder Name	Enter the company name as registered with the BC Corporate Registry and holds the permit.
Contact Information	Enter the contact information of the representative. If the form is completed by a referral agent, referral company information is also required.

Block B – Forestry Information

Disturbance Type	Indicate the type of activity associated with the disturbance.
Forest District	British Columbia is divided by regions into forest districts. Indicate which district(s) the project is in.
Permit Approval Date	Indicate the date the permit was approved by the Commission.
Construction Completion Date	Indicate the date that clearing was completed. Use YYYY/MMM/DD format.

MLTC No.	Master Licence to Cut number.
Proposed New Crown Land	The total of proposed new Crown land area disturbance (in hectares excluding woodlot areas, as indicated as part of the permit application process. The total area of Crown land is the area shown on the construction plan including the pipeline area, any temporary workspaces, decking sites etc.; whether or not the area was previously cleared or within an existing right-of-way.
As-Cleared New Crown Land	The total As-Cleared new Crown land area disturbance (in hectares), is the total area of Crown land utilized minus any woodlot areas and any previously cleared areas where stumpage has been collected. If the total As-Cleared area is the same as what was proposed, map attachments are not required. Hand sketches are not acceptable as map attachments.

Block C – Application Deliverables

As-Cleared Form	Include two completed copies of the As-Cleared Form. The Commission will distribute the duplicate to the Ministry of Forests and Range for billing purposes.
As-Cleared Sketch Plan	In accordance Section 9.01 of the permit holder's MLTC, the permit holder must submit a map showing all disturbances that have occurred pursuant to the cutting permit, at a scale of 1:20,000 or 1:50,000. If the total As-Cleared area is the same as what was proposed within the application, map attachments are not required. Hand sketches are not acceptable for the sketch plan.

Post-Construction Plan Submission

To ensure the Commission has the most current digital and spatial information of actual area cleared for oil and gas activity, Post-Construction Plans must be submitted within 60 days of completed construction. This applies equally to projects located on Crown and private land.

Requirements

The required submission must include the upload of an updated ePASS shape file be, as well as one copy of a Post-Construction Map. Both must indicate exactly where construction has occurred should be accurate to +/- 2 meters.

Post-Construction Map

Permanent disturbances must be distinguished from temporary disturbances.

If constructed locations have not changed from the original application, and no temporary ancillary features were included with the application, the ePASS number from the most recent application may be indicated on the post-construction map.

The updated ePASS submission is the same as any ePASS submission. In the case where the constructed activity and locations have not changed from the original application, the ePASS number from the most recent application/amendment may be indicated on the post-construction map.

More information on the Commission’s post construction plan process, refer to the Post Construction Plan Directive (currently in development).

15 Historical Facility Entry

The Historical Facility Entry is not required by the Commission, but is provided for companies who would like to integrate data (for existing, previously approved facilities) that is not currently represented by KERMIT.

The application is located at the main KERMIT applications menu under Data Integrity.

Equipment
All existing, previously approved equipment is to be included in the equipment list.

Attachments
- Copy of original approval
- Plot plan
- P&IDs
- Gathering System Schematic

Project Description
Include the construction start, pressure test, and leave to open dates. Once accepted, the detail will be updated with these notice dates, and will be available for As-Built.

As-Built must be submitted separately.

16 Gas Processing Plants

The information that will be housed in this section is currently in development.

The new plant application process will be explained here.

Application Process

The Commission has defined a process where a minimum of three face-to-face meetings are required before a plant approval is issued. These meetings include:

- A pre-application submission meeting;
- A mid-process meeting to discuss Commission application reviewed feedback and,
- A final approval meeting when a plant is approved.
-

Note: In some cases the mid-process meeting is not required.

Required Attachments

- Project Description
- Process Flow Diagrams
- Piping and Instrumentation Diagrams (P&ID's)
- Plot Plan
- Gathering System Schematic
- Notice of Construction Start
- Notice of Pressure Test
- Notice of Leave to Open
- As-Built
- Schedule 1, Schedule 2, and other documents as indicated in the Guideline For Gas Processing Plant Applications (in Appendix F).

If pressure testing and/or welding are to be conducted, notices and As-Built are required.

The timeline for processing a plant application depends on the application complexity, geographic location, and the applicant's effort to engage with the public and the Commission.

Pre-Application Meeting

At least one week prior to the pre-application meeting, the Commission requires the applicant to submit a brief written description of the project scope, including sketches of the proposed tentative gathering/processing system and sales tie-in points.

This will allow a meeting with more meaningful feedback to assist in the preparation of the application.

The Commission has determined that in order for the application process to be effective, the applicant must engage representatives from its Engineering, Operations, Public and Community Relations, Surface Land, and Production Accounting divisions.

Suspend a Gas Plant

A Permit Amendment must be submitted and granted PRIOR to the commencement of the suspension period.

If the plant operation will be suspended for 60 consecutive days or longer, a Repair/Modify Equipment amendment is required (see Section 8 for instructions).

Suspending a gas plant requires the upload of specific attachments it KERMIT.

KERMIT Attachments

- Plan
- Updated Schematics
- Schedule 1, if applicable
- Project Description

Plan

Submit a plan for the safety and security of the Plant. The plan must be submitted to the Commission at least 48 hours prior to the commencement of the 60 day period. The plan must show that provisions have been made to:

- Store, handle and dispose of toxic material
- De-pressure the plant
- Dispose of corrosive, combustible or explosive fluids
- Minimize or prevent degradation of the plant equipment, vessels and piping
- Secure the plant against unauthorized entry and vandalism
- Periodically have the plant and site inspected by qualified persons
- Address any other concerns the Commission has identified.

Updated Schematics

Updated gathering system schematic showing where the wells (if any are effective), and facilities will be redirected to, as well as pipelines coming in or out of the facility.

Schedule 1

A Schedule 1 is used to define the physical flow process, and well or facility to facility linkages.

Project Description

The project description must include a list of wells from the schematic, a rationale for shut-in, plan and duration of shut-in.

Additional Information Sources

Below are key documents to review and reference when planning to submit a gas processing plant application, and to construct a plant in British Columbia.

The list helps applicants prepare for the engineering and surface land components of the application, and does not include all of the detailed regulatory requirements.

- The acceptable design standard for gas processing plants includes the latest version of ASME B31.3
- For the registration of all unfired pressure vessels, contact the BC Safety Authority (BCSA).
- Guideline for Gas Processing Plant Applications – Appendix F
- Gas Processing Plant & Cross Border Production Facility Application Requirement Clarification (Production Accounting Model). Information Letter, OGC 08-05.
- Measurement Requirements for Upstream Oil and Gas Operations Manual - January 2008
- Flaring, Incinerating and Venting Reduction Guideline for British Columbia
- OGC-ALC Delegation Agreement
- Secondary Containment for Non-Production Tanks
- Existing Gas Plant Capacities
- Memorandum of Understanding between the Commission and BCSA

Appendix A – Construction Plan Requirements

Construction Plan Requirements
The basic requirements for a construction plan must include the following information:

Title Block

- Applicant Company Name
- Applicant File No.
- BCGS Mapsheet
- Legal Description of Project
- Date Plan Prepared (YYYY/MM/DD)
- Scale Used
- Revision #
- Survey Company Name, Address & Phone Number
- Sheet # (i.e. 1 of 2)
- Survey Company Job Number
- Survey Company Drawing Number
- Table of Crossings
- Crossing Number
- Drawing Number
- Notes
- Legend
- Revision Information
- Revision Number
- Revision Done By
- Date of Revision
- Checked By

Scale Bar
A **Scale Bar** should be placed just above the title block where it can be placed without interference of the drafted areas.

Area Block (proposed R/W areas)
Summarize the following in the legend:

Total Area Proposed – equals the: Total Area of Private Land (if applicable)

Total Area of Crown Land – equals the: Area of New Crown Land Disturbance (Proposed) and Area of Existing Crown Land Disturbed

Labelling of Plan
Indicate the following on the plan diagram:

- Dimensions and area of ancillary sites (decking sites, temporary workspaces, etc.)
- Location of Agricultural Land Reserve (ALR) if applicable

The labelling of the plan should include the NTS coordinates (Units, Block, and Group), chainages, deflections, any crossing numbers (to correspond to the table of crossings), vegetation changes (brush/tree types) and a north arrow.

Surveyed Crown land (district lots, sections etc. that are posted but not titled) and unsurveyed Crown land (mainly NTS) should be indicated on the plan.

Private land should indicate the owner name, parcel identifier number (PID#), title number and the areas of disturbance, temporary workspace area, etc. within each parcel.

Cut Blocks, Range tenures, Guide Outfitter areas, Indian Reserves, Coal tenures and all other areas of special interest should be indicated.

Appendix B – Schedule 1 Well or Facility to Facility Linkage

Information provided on a Schedule 1 is used to define the physical flow process, and well or facility to facility linkages. The form is designed to ensure that the Oil and Gas Commission has the necessary information to identify and confirm the physical flow process from production to disposition.

A Schedule 1 must be submitted as an attachment in KERMIT when a new well will be flowing product, there is a well to facility or facility-to-facility linkage change, or there is a change of reporting facilities for a well.

BC Oil & Gas COMMISSION

SCHEDULE 1

WELL OR FACILITY TO FACILITY LINKAGE
OGC, 100 10003 110 AVE
Fort St. John, B.C. V1J 6M7
Phone: (250) 261-5700

FOR ASSISTANCE IN COMPLETING THIS FORM REFER TO THE "INSTRUCTIONS FOR COMPLETING A SCHEDULE 1 - WELL OR FACIILTY TO FACILITY LINKAGE" ON THE COMMISSION WEB SITE. THIS IS AN AUDITABLE DOCUMENT.

COMMISSION USE ONLY		**A**
Entered by:	Date:	
ADMINISTRATION		**B**
Facility Operator Name:	Operator Code:	
Contact:	Position:	
Phone:	Email:	
Address:		
City, Province, Postal Code:		
WELL OR FACILITY INFORMATION		**C**

Link from this Well or Facility: **To this Facility** Page X of Y

Well/Facility Name and Location	Well Permit No./Facility Code	Unique Well Identifier/ Facility Location	Pool code	Add or Del.	Prod Type	Link Type	Facility Name and Location	Facility Code	Effective Change Date YY/MM	Reporting Facility Code

Schedule 1 Well/Facility to Facility Linkage

Last Updated October 2010

Block B Administration

Facility Operator	The name of the operator of the wells and facilities identified on this form.
Operator Code	The four-digit code assigned to the operator by the Commission.
Contact	Include the name and position of the primary contact for the facility operator, along with their phone number and email address. Include the full mailing address.

Block C Well or Facility Information

Page	Enter this page number and the total number of pages of the application.
Well/ Facility Name & Location	Identify and provide the location of the upstream facility being linked to a downstream facility. If a well is being linked, enter the well name and location from the approved Well Permit.
Well Permit No./Facility Code	Enter the five-digit Drilling Authorization Approval Number for wells, or the four-digit code assigned to the facility.
Unique Well Identifier	The unique well identifier is the standard 16-character code which defines the bottom-hole location and each significant drilling or completion event in the well.
Pool Code	The Pool Code identifies the formation from which this unique Well identifier produces. The four-digit code and alphabetic suffix is only required if a well is being linked.
Add or Delete	Enter "A" if the linkage is being added; enter "D" if it is being deleted. If a linkage is being changed, use one line to delete the old linkage, and a second to add the new linkage.
Product Type	Insert the product type code from the list provided at the end of this document
Link Type	Enter "T" if the product is trucked; enter "P" if it flows through a pipeline.

Facility Name & Location Enter the name and location of the facility that the well or facility is being linked to.

Facility Code Enter the 4-digit code assigned to the facility. If this is a new facility this facility code may not be known, leave this section blank to be filled out by the Commission.

Effective Date Enter the applicable change effective date (year/month) (e.g., January 1st - 10/01) for amendments only.

Reporting Facility Enter the reporting facility where production will report to. It may be the same as the physical facility, or downstream of it.

Product Types

There are no product codes for Well, or Wet Gas.

02	Gas	54	Butanes
03	Oil	55	Ethane
06	Water	56	Ethane Plus
08	Waste Plus	57	Pentanes
13	Carbon Dioxide	58	Diesel Oil
16	LPG Effluent		Well
	(code to be assigned)		Wet Gas
18	Condensate	62	Oil/Water
	(code to be assigned)		
53	Propane Emulsion		

Appendix C– Example Crown Land Status Sheet

The following is an example of a Crown Land Status Sheet, required as a permit application attachment.

DL 2444: Vacant Crown Land	The District Lot is surveyed, however there are no tenures associated with this location and the land is held by the Crown
9612345: R/W, EnCana Corporation, pipeline Expires 2030	EnCana Corporation holds a Statutory Right-of-Way on File Number 9612345, expires in 2030
9601111: LOC, EnCana Corporation, well site Expires 2010	EnCana Corporation holds a Licence of Occupation for a wellsite on File Number 9601111, expires in 2010
8002475: PDR #100 – Petro Canada	Petro Canada has Petroleum Development Road #100 on File 8002475
0234547: Map Reserve, EMPR, Quarry	The Ministry of Energy, Mines and Petroleum Resources has established the exclusive right to an area for quarry purposes on File Number 0234547
615-300: Canfor Cutblock	Canfor has a cutblock under Ministry of Forests reference number 615-300
RAN073357: Grazing Licence, Joe Farmer	Joe Farmer has a Grazing Licence (issued by Ministry of Forests) under Number RAN073357
A65327: Small Business TSL	The Ministry of Forests, Small Business Unit, has designed area A65327 set aside for Timber Sales
410284: Patrick Sunshine, Coal Licence Expires 2009	Patrick Sunshine holds a Coal Licence from Ministry of Energy, Mines and Petroleum Resources under Licence Number 410284, expires in 2009

Figure C.1. Example Crown Land Status Sheet

Appendix D– Sour Production Facility Emergency Planning Zone

(From Section 2.1.2 of the BC Oil and Gas Commission Emergency Response Plan Requirements**)**

The emergency planning zone (EPZ) for a sour production facility is calculated by using the largest H_2S release volume from any pipeline entering or leaving the facility.

If the facility has an acid gas disposal well on site, the emergency planning zone for the well may determine the size of the EPZ for the sour production facility.

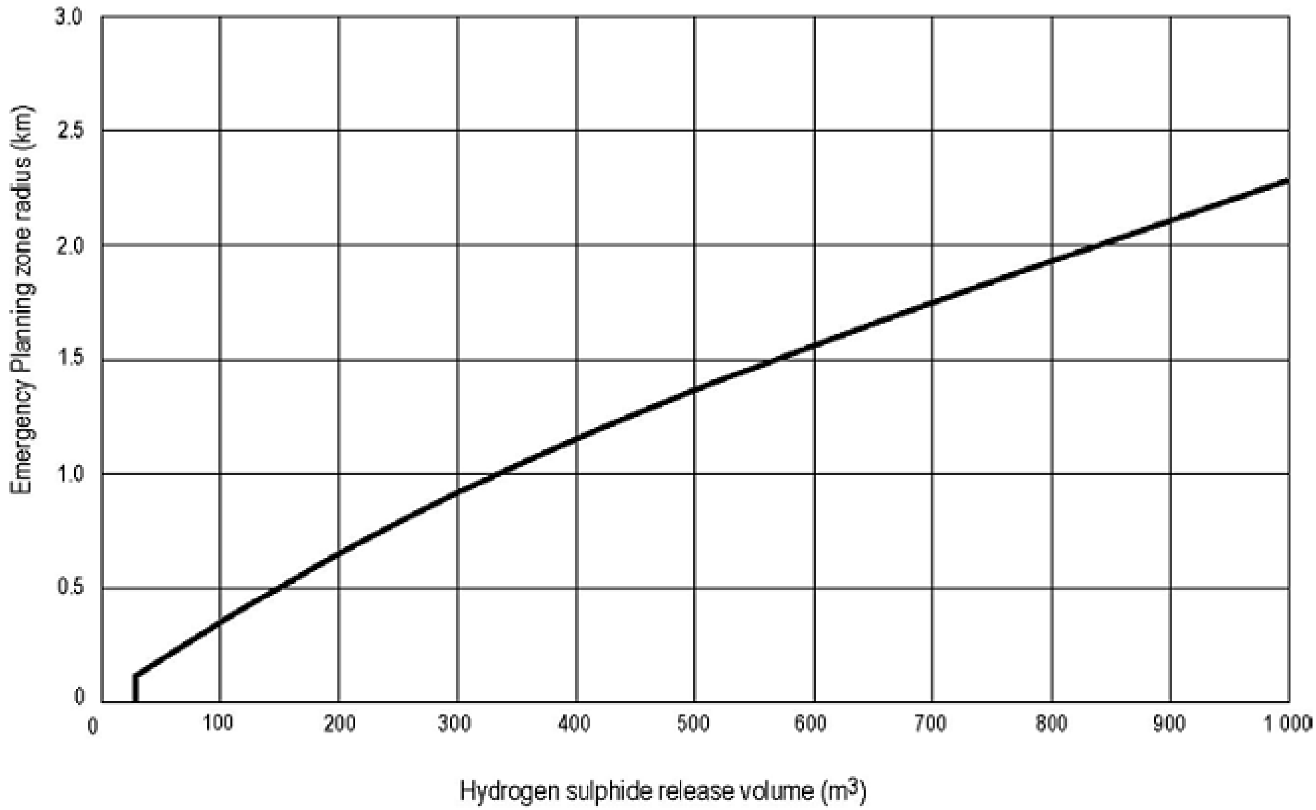


Figure E.1. Emergency Planning zones for sour gas plants, pipelines and production facilities.

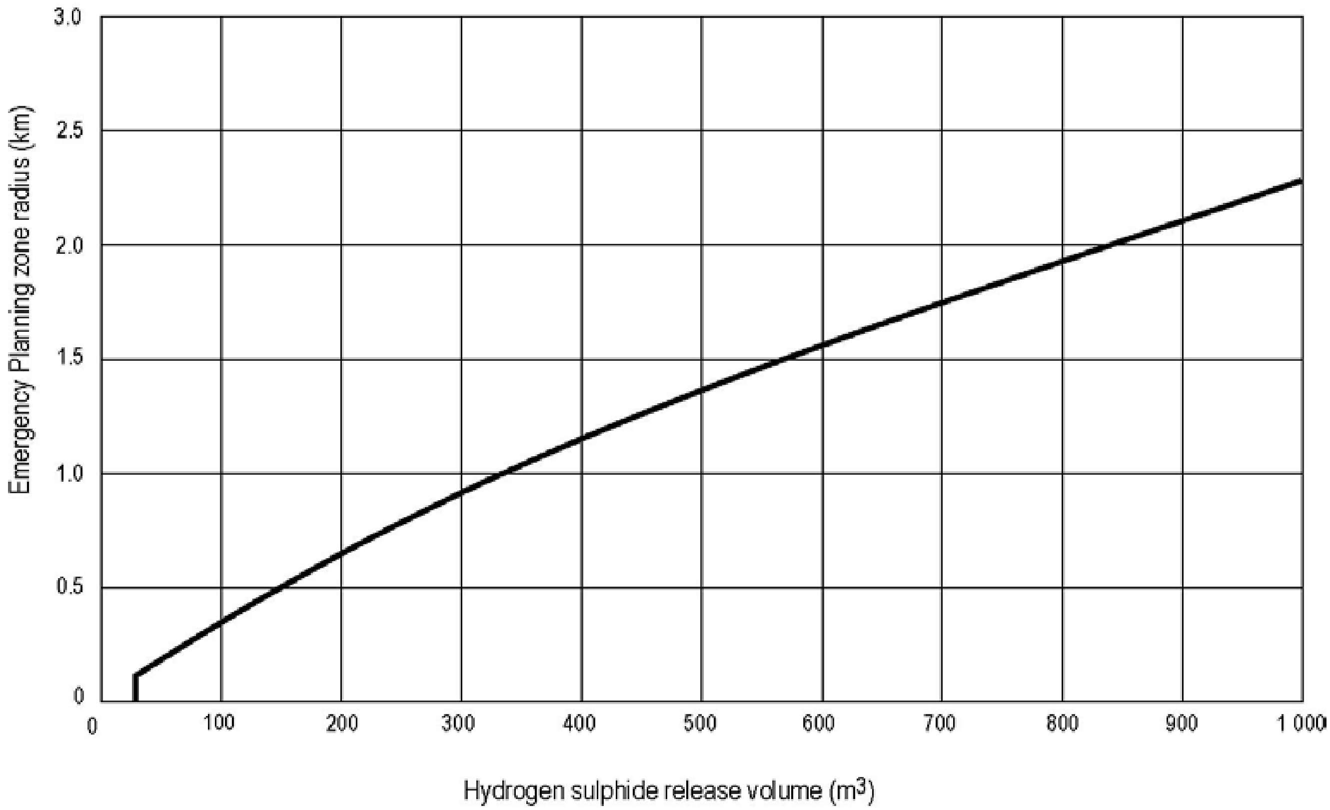


Figure E.2. Emergency Planning zones for sour gas plants, pipelines and production facilities.

Appendix E– Sour Production Facility Emergency Planning Zone

(From Section 2.1.2 of the BC Oil and Gas Commission Emergency Response Plan Requirements)

The emergency planning zone (EPZ) for a sour production facility is calculated by using the largest H_2S release volume from any pipeline entering or leaving the facility.

If the facility has an acid gas disposal well on site, the emergency planning zone for the well may determine the size of the EPZ for the sour production facility.

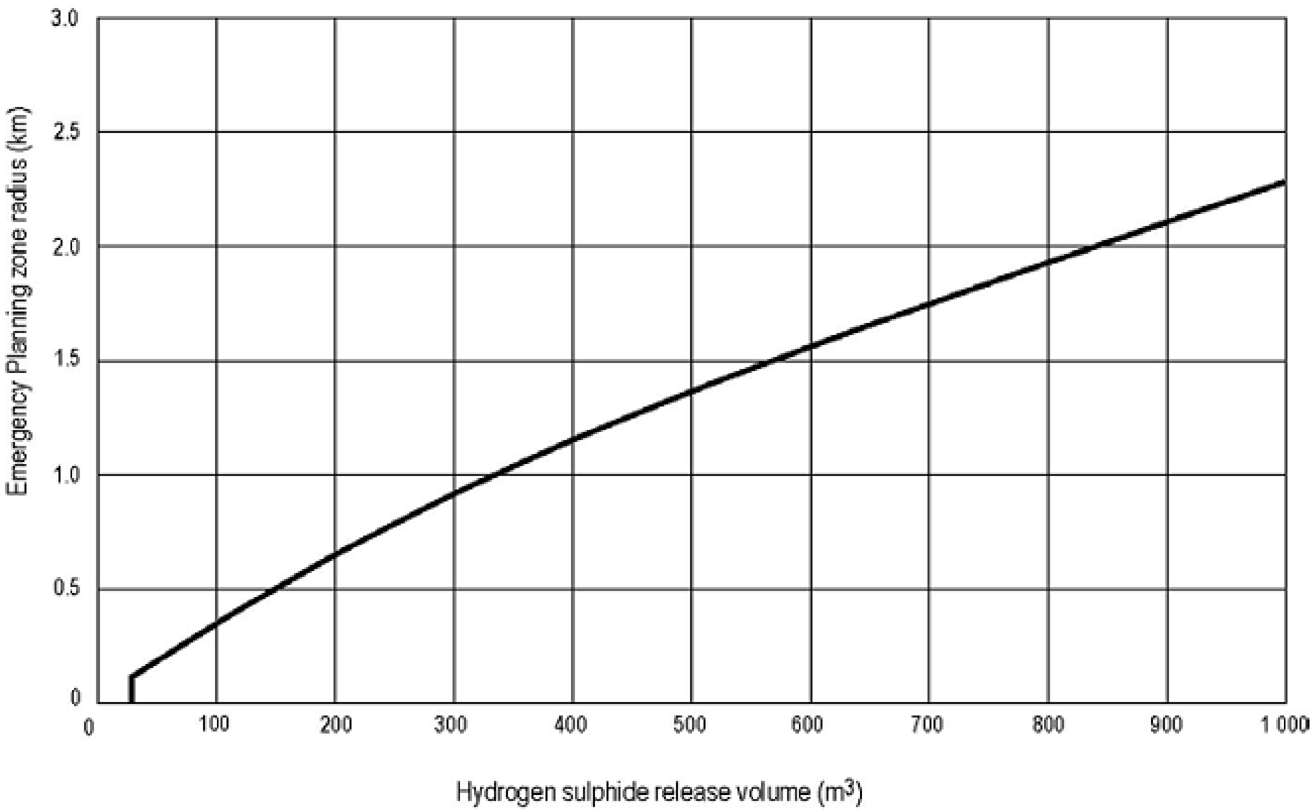


Figure F.1. Emergency Planning Zones for sour gas plants, pipelines and production facilities.

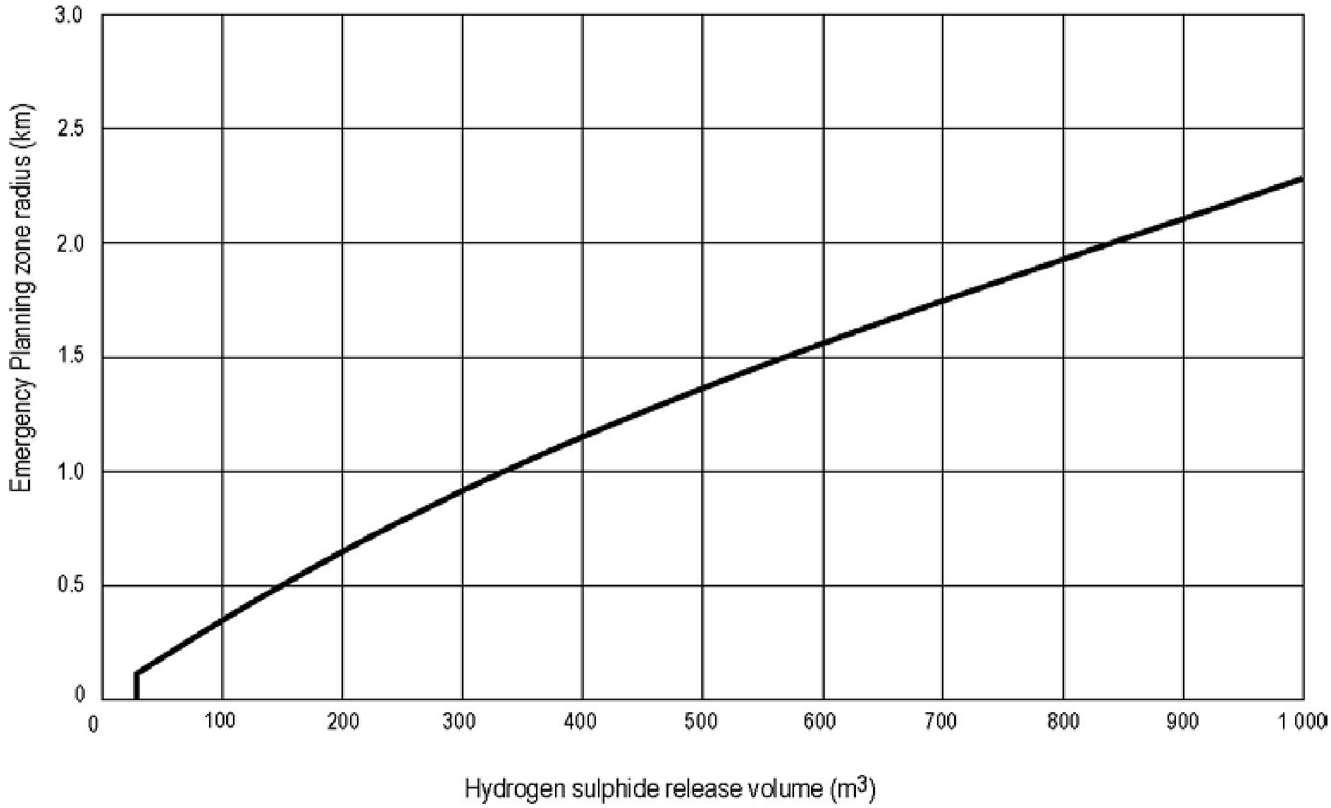


Figure F.2. Emergency Planning zones for sour gas plants, pipelines and production facilities.

Appendix F – Guideline for Gas Processing Plant Applications

Revised October 2010

Use this guideline to assist in the timely review of each application.

New Land Required – New Facility Application
If proposed construction requires new surface area for crown or private land, a Facility Permit Application must be submitted in KERMIT. The application screening package must be uploaded in KERMIT as an attachment, and a two hardcopies must also be submitted to the Commission.

If proposed construction will be on existing tenured crown land, or company owned surface area previously approved by the Commission, a Facility Permit Application - no new land must be submitted in Kermit. The application screening package must be uploaded in KERMIT as an attachment, and two hard copies must also be submitted to the Commission.

Note: The applicant must complete the application (including uploaded attachments) in KERMIT before submitting associated hard copies to the Commission. Hard copy submissions should be addressed to the attention of the Commission' s Engineering Division, Pipeline & Facilities Branch - Facilities Team.

Application Screening Package (Hard Copy)
This must be uploaded as an attachment with applications and Notice of Intent in KERMIT. Every application screening package must clearly identify the related job number and/or OGC number and include:

- Engineering Technical Review Package – 2 copies
- Construction Plan - 1 copy
- BCGS 1:20,000 scale map - 1 copy
- Gas Processing Plant fee - $ 16,000
- First Nation packages (if applicable)
- Consultation/Notification Written Report
- Agriculture Land Commission (ALC) approval or application (if outstanding), if located within the Agriculture Land Reserve.

Engineering Technical Review Package

All Excel or spreadsheet files must be included electronically in an unprotected mode.

Cover Page

- ☐ Applicant company name & contact information
- ☐ Consultant/engineering firm name & contact information
- ☐ Key contact person's name, address, phone & fax numbers
- ☐ Indicate new construction or modification to an existing plant
- ☐ List of hazardous materials that will be stored and a description of the storage method
- ☐ Total kilowatt rating of all compressor prime movers
- ☐ Total amount of CO_2 emissions from all sources at the facility in tonnes per day
- ☐ Noise Impact Assessment (Refer to the Commission Noise Control Best Practices Guideline)
- ☐ Dehydrator Engineering & Operations Sheet (DEOS)
- ☐ A plant material balance for design conditions
  - ☐ Include the H_2S content of the acid gas removed.
  - ☐ Rates must be provided in e^3m^3/d, m^3/d or t/d as appropriate

- ☐ Plant recovery efficiency of H_2S, CO_2, H_2, N_2, HE, C1 to C5+

Summaries and Descriptions

- ☐ Description of the plant and the proposed process(es), including total processing capacity and design flow rates (inlet, recovered products, fuel gas, emissions)
- ☐ If acid gas is to be discharged to a subsurface formation, a brief description of that proposal must be supplied
  - ☐ along with a copy of the reservoir approval issued by the Commission
- ☐ Summary of site surface run-off water management
- ☐ Summary of inlet separator/slug catcher capacity considerations including maximum slug volume and level controls and shutdowns
- ☐ Summary of prime mover starter systems and associated pump drives, and if natural gas is utilized, confirm that the vented gas is connected to the flare system or is conserved
- ☐ Summary of why pressure relief devices (i.e.: PSV's) are not be connected to the plant flare system, if applicable
- ☐ Description of the provisions for facility security and fire prevention and protection
- ☐ Description of how the plant has been designed to process gas from in-line testing of wells with potential liquid slugs and CO_2 spikes
- ☐ Summary of plant supervision model including operator response time if not manned 24 hrs/day

If the proposal includes a sulphur processing facility, include a written submission that:

- ☐ Describes the proposed control measures to limit the release of sulphur dust and entrained gases
- ☐ Describes the proposed method to degasify produced liquid sulphur and to dispose of sulphur compounds and other vapours associated with such processes
- ☐ Describes how sulphur volumes will be measured and reported

Drawings, Diagrams and Maps

- ☐ Plot plan drawing
- ☐ Complete plant piping and instrumentation drawings (P&ID's) Emergency Response Plan (or summary of progress to date with timeline for ERP submission)
- ☐ Process flow diagram of the plant
- ☐ Map(s) showing:
  - □ the facility being applied for
  - □ all other existing plants and sulphur handling facilities at the site or in the area (within 50 km)
  - □ all occupied dwellings and surface improvements in the area (within 5 km)
  - □ all lakes, streams, and other surface bodies of water in the area (within 5 km)
  - □ all settlements in the area (within 20 km)
  - □ general land use (forested, farming, other) in the area (within 5 km)
- ☐ Metering block diagram (i.e.: metering schematic) detailing:
  - □ All meters in the plant (production accounting and non-production accounting)
  - □ Meter types. E.g. orifice, turbine, ultrasonic, coriolis
  - □ All production accounting meters in the plan on a list or table on the metering schematic. This will typically be a subset of all of the plant meters
    - ▪ Cross reference this list to the meters shown on the metering schematic by meter number and/or meter description
    - ▪ Include types of measuring devices used to determine levels and/or volumes in tanks or production vessels for production accounting purposes. E.g. level gauge, level transmitter, pressure transmitter inlet piping header to plant inlet separators
  - □ All stream (plant and inlet header) block valves and normal operational state (normally open or normally closed), that can cause a change in fluid flow that will impact the production accounting model.
  - □ Fuel gas lines (plant and/or field)
  - □ Pilot gas and dilution gas streams to plant flare stacks. Include tie in points in the plant.
  - □ All plant piping that can impact the production accounting model

- ◻ Fluid injection streams. E.g. water, acid gas
- ◻ All delivery streams
- ◻ Flare stacks and incinerator stacks

☐ Gathering block diagram (i.e.: gathering system schematic) detailing:

- ◻ Type of primary well production (oil or gas)
- ◻ Wellsite locations, indicated by the legal surface location.
- ◻ Wellsite configuration (3 phase separation, 2 phase separation, wet meter). This may be typical if all wellsites are the same.
- ◻ All field meters and types. E.g. orifice meter, turbine, etc.
- ◻ Types of measuring devices used to determine levels and/or volumes in tanks or production vessels for production accounting purposes
- ◻ All field fuel gas streams and meters. If no meter is installed, indicate how volume is determined for reporting purposes for a given stream
- ◻ Field flare streams. If no meter is installed, indicate how volume is determined for reporting purposes for a given stream.
- ◻ All field process equipment. E.g. compressors, separators, tanks, etc.
- ◻ Gathering system offload streams that permit volumes to deliver to processing that is different from the plant applied for
- ◻ Gathering system onload streams that permit volumes to be received from other reporting facilities, gas plants or gathering systems
- ◻ Return fuel gas streams from a plant, facility or other processing equipment
- ◻ Gathering system block valves and piping that may impact the production accounting model
- ◻ All piping streams block valves and normal operational state (Normally Open or Normally Closed) that can cause a change in fluid flow that will impact the production accounting model.
- ◻ A composite analysis of the inlet gas under normal operating conditions and the maximum H_2S content of the raw inlet gas in moles per kilomole

Plans

- ☐ Fracture sand management plan. Include the strategies incorporated to capture and monitor for fracture sand returns and associated erosion from the well to the plant sales
- ☐ Air monitoring plan. This may include perimeter detection for H_2S and/or SO_2, wind speed and direction monitoring
- ☐ Storage tank secondary containment plans (production and non-production storage). Include location of truck loading lines
- ☐ Emergency Response Plan or summary of progress to date, with a timeline for ERP submission

Flare/incinerator stack data submission must include:

- ☐ Stack height and diameter
- ☐ Predicted normal and maximum emissions of SO_2/hr
- ☐ Rate and calculated volume of potential H_2S releases
- ☐ Results of gas/vapour dispersion modeling for lit and unlit conditions
- ☐ Maximum expected rates for continuous flaring, and volumes/compositions of flared streams
- ☐ Maximum stream velocity in meters per second at the flare metering point
- ☐ Description of the flare metering configuration proposed to measure both
  - ☐ the purge gas within the meter range and accuracy lower limit, and
  - ☐ the blowdown situation, within the upper limit of the manufacturers specifications and required published Commission uncertainties
- ☐ Description of how plant processing will conserve gas volumes by avoiding tie-in to the flare and/or incinerator stack (vapor recovery considerations)
- ☐ Description of how plant ESD procedures will limit emissions
- ☐ Description of the flame-out detection system configuration for the flare stack/incinerator equipment, and if it is set up to alarm and/or shutdown process
- ☐ Appropriate isopleths for the various levels of H_2S and SO_2
- ☐ Description of the design to prevent flashback of flame back into process (i.e.: positive pressure system, flame arrestor)

The Drilling and Production Regulation Section 42(1)(2)(5) states that a permit holder must ensure that the duration of flaring and the quantity of gas flared is minimized. Flaring gas should not be conducted unless it is required for emergency purposes or for drilling operations.

A facility permit holder may flare gas at a facility if :

- Flaring is required for maintenance purposes, or
- Permission to flare is included in the facility permit

Under Section 43(1)(2)(3), a permit holder must notify the commission at least 24 hours before a planned flaring event if the quantity of gas to be flared exceeds 10 000 m^3.

If an unplanned flaring event occurs and the quantity of flared gas exceeds 10,000 m^3, the permit holder must notify the Commission within 24 hours of the flaring event.

A permit holder must maintain a log of all flaring that occurs at each facility.

Production Accounting

Production accounting submissions enable the Commission to conduct a review of the production accounting model and reporting (volumetrics and allocations), for the proposed plant or facility.

Production Accounting Model submission documents must comply with:

- ☐ Commission Information Letters OGC 07-21
- ☐ Commission Information Letter OGC 08-05

Plant production accounting model systems

- ☐ Greenfield plants use production accounting model volumes and analyses based upon the plant material balance used for the design/construction basis
- ☐ Existing facilities or plants, use existing production data as a basis for the production accounting model volumes and analyses

Production accounting model submissions

- ☐ Submit the actual production accounting system to be used when the plant or facility is in operation
- ☐ Submit a formal process and documented procedure(s), detailing how production accounting is notified and updated concerning process flow changes (ie: opening or closing block valves) that affect the production accounting model (gathering system or plant). This submission provides an audit trail for recordkeeping and accounting purposes.

- ☐ Existing facilities or plants must submit existing plant recordkeeping reports, such as the daily report
- ☐ Provide a volume and fluid analysis for each production accounting meter and production vessel (tank) on the metering schematic.
- ☐ Provide volumes for each production accounting meter and production vessel (tank) used in the production accounting model submission.
  - ▫ Volumes can be hand written on the metering schematic and the gathering system schematic.
  - ▫ Include the units of measure for each volume. E.g. e^3m^3 or m^3 (l)
- ☐ Cross Border submissions may entail a review outside of the actual cross border measurement facility for production accounting model submission purposes

Consultation & Notification Written Report – 2 copies
Companies are required to complete consultation/notification prior to making program application. Documentation is required to be submitted with the application.

For more information on consultation and notification, refer to the commission's Consultation and Notification Guideline (currently in development).

Appendix G - Operational Guidelines/Manuals/Regulations

Fugitive Emissions Program
A permit holder must have a Fugitive Emissions Management Program in place prior to commencing operations at a facility. The Commission may request this program at any time in the application, construction or operations phase of a facility.

Leak Detection and Control
A permit holder must include a leak detection system with adequate controls per the Drilling & Production Regulation. The Commission may require additional levels of detection and control based on the location and specifics of a facility installation.

Sand Management Plan
If a sand fracture is carried out on a well, a sand management plan (SMP) must be submitted with the Facility Permit Application. The sand management plan is intended to be a comprehensive plan outlining the preventative steps to reduce, monitor, and capture sand returns, and incorporate leak detection and piping integrity.
This plan must include at a minimum:

- proposed de-sanding equipment
- piping configurations to minimize erosion
- velocity control
- ultrasonic testing

Overpressure protection
Designed and operated according to CSA Z662-07 and/or ASME B31.3. The Commission may require additional levels of detection and control based on the location and specifics of a facility installation. This information is currently in development.

Secondary Containment Requirements

For more information on secondary containment requirements refer to the following information letters: Secondary Containment Requirements Information Letter and Secondary Containment Requirements for Above Ground, Non-production Tanks.

All water and oil/condensate production tanks require secondary containment per Drilling and Production regulation, Section 50. There is an exemption option for produced water tanks on a case by case basis when double walled tanks of a specific design are being considered.

The design must include a second tank system capable of holding 110% of the primary tank where the interstitial space (i-space) between the tanks has level indication and high level shutdown. The main tank must also have a high level shutdown and a spill over into the i-space.

The general standards for atmospheric and low pressure petroleum storage tanks in BC are included in the following American Petroleum Institute (API) documents:

API-650	Welded Steel Tanks for Oil Storage. This document governs the construction of tanks storing products with internal pressures up to 2.5 psig.
API-651	Cathodic Protection for Above Ground Petroleum Storage Tanks
API-652	Lining of Above Ground Petroleum Storage Tanks
API-653	Tank Inspection, Repair, Alteration, and Reconstruction
API-620	Design and Construction of Large Welded Low Pressure Storage Tanks. This covers the construction of tanks with internal pressures up to 15 psig
API-2000	Venting Atmospheric and Low-Pressure Storage Tanks
API-2350	Overfill Protection for Petroleum Storage Tanks
API-2015	Cleaning Petroleum Storage Tanks
API-2550	Measurements and Calibration of Petroleum Storage Tanks

Measurement at Cross-Border Facilities
For guidance relating to measurement at cross-border facilities, refer to the Information Letter #OGC 07-21 Measurement Requirements for Upstream Oil and Gas Operations Manual.

Noise Control Guideline
For information on BC's Noise Control Best Practices Guideline, see the British Columbia Noise Control Best Practices Guideline for Oil and Gas Activity.

Consultation and Notification Manual
Consultation and Notification Manual

Flaring
For all questions related to flaring requirements, refer to the Commission's Flaring, Incinerating and Venting Reduction Guideline.

Flare System Design
In accordance with the Drilling & Production Regulation, Section 42, Flaring Performance Requirements:

Flare and incinerator systems must be designed and operated within the limits specified by a qualified professional.

The flare system design and construction must meet the minimum requirements of API Standard 521.

Oil and Gas Waste Regulation
This regulation includes parameters for air discharges from facilities.

Helpful Links

These are links that are useful in completing the Facility Permit / Facility Permit Amendment Application or related documentation.

Client Codes – 4-digit codes used for a number of purposes in the royalty management system. A "Client" may be an operator of a well (on the BC-11), a royalty payor (on the BC-12, BC-14, BC-15), a facility operator (on the BC-21), or a purchaser of oil (on the BC-30). For any particular company, the same code is used in any of these roles.

Facility Codes – Each facility is assigned a unique eight digit numeric code, and the option to search for any coded facility is available. These are also available through KERMIT, under Projects and Sites, Find Sites, and enter the legal location.

Facility/Plant Linkages - shows connections between reporting facilities and plants

Facility/UWI Linkages - shows connections between active reporting facilities and UWIs.

Field Codes - A **field** (also referred to as an "area") is the surface area underlaid (or appearing to be underlaid) by one or more pools, and includes the subsurface regions vertically beneath that surface area. Each field is assigned a unique four digit numeric code, and is usually associated with one or more pools.

Plant Codes - Each plant is assigned a unique eight digit numeric code, and the option to search for any plant code is available.

Pool Codes - A pool (also referred to as a "formation") is an underground reservoir containing an accumulation of petroleum or natural gas, or both, separated (or apparently separated) from another reservoir or accumulation. Each pool is assigned a unique pool code, and is usually associated with one or more fields.

Appendix H - Benzene Emissions from Glycol Dehydrators

This information was formerly information letter OGC-07-03

This information sets out the rationale and requirements for controlling the emissions of benzene from glycol dehydrators.

Benzene is classified as a toxic substance under the Canadian Environmental Protection Act and as a group one carcinogen by the International Agency for Research on Cancer. As a non-threshold carcinogen, there is considered to be some health risk at any level of exposure. As a result, benzene emissions must be managed to achieve the lowest levels practicable to minimize human exposure. The health risk posed by benzene is to be managed by reducing human exposure to the extent possible and practicable.

As part of the Benzene Technical Advisory Team(BTAT), the Commission is committed to reducing benzene emissions from glycol dehydrators.

In June 2006, CAPP (Canadian Association of Petroleum Producers) issued a document entitled Best Management Practices for Control of Benzene Emissions from Glycol Dehydrators (*Benzene Control BMP*). The document contains guidance on the design and operation of glycol dehydrators as well as public consultation requirements for persons in the vicinity of glycol dehydrators.

In order to reduce and manage benzene emissions from glycol dehydrators in British Columbia, operators must comply with the following requirements:

1) When evaluating dehydration requirements in order to achieve the lowest possible benzene emission levels, operators must use the Decision Tree Process in Appendix A of the *Benzene Control BMP* and retain appropriate analysis documentation for review by the Commission.
2) Operators must follow the public consultation process outlined in the *Benzene Control BMP*.
3) Operators must ensure that all their dehydrators meet the following benzene emissions limits:

Date of Installation or Relocation	**Benzene Emissions Limit**
Prior to January 1, 1999 a) Greater than 750 m to the nearest permanent resident or public facility b) Less than 750 m to the nearest a permanent resident or public facility	5 tonnes/yr 3 tonnes/yr
January 1, 1999 to June 30, 2007	3 tonnes/yr
After June 30, 2007	1 tonne/yr

a) If more than one dehydrator is located at a facility or lease site, the cumulative benzene emissions for all dehydrators must not exceed the limit of the oldest dehydrator on site. Modifications may be required to existing units to meet the site limit.

b) Any new or relocated dehydrators added to an existing site with dehydrators must operate at a maximum benzene emission limit of 1 tonne/yr or less. The cumulative benzene emissions must not exceed the limit of the oldest dehydrator on site.

c) For dehydrators that are only in operation for a portion of the year, the benzene emission rate must be prorated.

4) Operators must complete a DEOS (Dehydrator Engineering and Operations Sheet), located in Appendix B of the Benzene Control BMP, to determine the benzene emissions from each dehydrator. The sheet must be posted at the dehydrator for use by operations staff and inspection by the Commission. The DEOS must be revised once each calendar year or upon a change in operation status of a dehydrator.
5) Operators must complete and submit an annual Dehydrator Benzene Inventory List by email to benzene.tat@capp.ca in accordance with Section 12 of the Benzene Control BMP.

An electronic copy of the annual Dehydrator Benzene Inventory List is available on the CAPP website: www.capp.ca.

For further clarification and/or information, please contact the Commission's Waste Management Manager, Operations Engineering Division.

Appendix I - Engagement Log Example

First Nation Engagement Log
The Commission recommends keeping a log of all engagement and attempts to engage. An engagement log can greatly benefit the process flow when the First Nation has been advised that the applicant's engagement activities will be shared with the Commission. The engagement log may be considered in the decision making process.

Below is a description of the potential information fields in an Engagement Log and example format that may be used.

Communities	List which communities require engagement.
Attempts to Engage	Provide a description of what efforts to engage were made and whether or not engagement occurred.
Date	List the corresponding dates of attempted and actual engagement.
Meeting Successfully Held	Indicate if meetings resulted from attempts to engage.
Meeting Topics	Provide a description of what topics of discussion arose during the meeting.
Attendees/ Parties to Meeting	List all of the people attended, or were involved in the meeting. This should include parties on both sides of the discussion.
Meeting Location	Indicate where the meeting took place; for example, at a specific location or via teleconference.
Issues Raised	List any potential adverse impacts identified during discussion.
Commitments Made	List any mitigative measures, or other commitments offered.

First Nation Engagement Log										
Communities	Attempts to Engage	Date	Meeting Successfully Held?		Meeting Topics	Attendees/ Parties to Meeting	Meeting Location	Issues Raised	Commitments Made
			Y	N					

Appendix J4

FEI CONSULTATION ACTIVITIES

Huntingdon Bypass Project – First Nations Communications Log

Sto:lo Nation Tribal Council

Date	Form of Contact	Description of Content
13 Jan 2011	Phone call between First Nations Initiatives Manager, FEI and Referrals Coordinator, Sto:lo Nation Tribal Council.	FEI engages the SRRMC to conduct the Archaeological Overview Assessment for the Huntingdon Bypass Project.
06 Feb 2011	Letter from FEI to the Sto:lo Nation Tribal Council and each member band: Aitchelitz, Leq'a:mel, Matsqui, Popkum, Shxwha:y Village, Skawahlook, Skowkale, Squiala, Sumas, Tzeachten, Yakweakwioose.	FEI provides formal introduction of the Project – nature, rationale, approvals required, maps, timeframe, FEI contact information.
23 Feb 2011	Voicemail from Assistant Lands Coordinator, Skawahlook First Nation to First Nations Initiatives Manager, FEI.	Skawahlook First Nation has no issues regarding the Project.
28 Feb 2011	Meeting – First Nations Initiatives Manager, FEI; First Nations Project Coordinator, FEI; Project Director, SRRMC.	Discussion of Archaeological Overview findings. FEI confirms willingness to mitigate or avoid cultural heritage impacts identified, and confirms ground disturbing activities may be monitored by a qualified archaeologist.
21 March 2011	Meeting – First Nations Initiatives Manager, FEI; First Nations Project Coordinator, FEI; Referrals Coordinator, Sto:lo Nation Tribal Council; Director, SRRMC.	Discussion of Sto:lo Nation Tribal Council's referrals system. Discussion of development of a consultation protocol between FEI and Sto:lo Nation Tribal Council for such projects.
03 May 211	Meeting – First Nations Initiatives Manager, FEI; First Nations Project Coordinator, FEI; Referrals Coordinator, Sto:lo Nation Tribal Council; Director, SRRMC; Geomatics and GIS Specialist, SRRMC; Employee, Sto:lo Nation Tribal Council.	Discussion of topics to be addressed in an MOU between the Sto:lo Nation Tribal Council and FEI. SRRMC requests a shapefile detailing the location of FEI's pipelines throughout Sto:lo Nation Tribal Council's asserted traditional territory and a tour of FEI's Lands Department. FEI agrees to meet SRRMC's requests.

Sto:lo Tribal Council

Date	Form of Contact	Description of Content
06 Feb 2011	Letter from FEI to the Sto:lo Tribal Council and each member band: Cheam, Chawathil, Shxw'ow'hamel, Kwantlen, Kwaw'kwaw'Apilt, Soowahlie, Scowlitz, Seabird Island.	FEI provides formal introduction of the Project – nature, rationale, approvals required, maps, timeframe, FEI contact information.
22 Feb 2011	Meeting – First Nations Initiatives Manager, FEI; Lands and Resource Coordinator, Sto:lo Tribal Council; Staff Member, Sto:lo Tribal Council.	Sto:lo Tribal Council provides confirmation that they are not concerned with FEI's use of the SRRMC or the Huntingdon Bypass Project generally at this stage, but they will review the Project in greater detail later.

28 Feb 2011	Phone call between First Nations Initiatives Manager, FEI and Referrals Coordinator, Chawathil First Nation	Chawathil First Nation requests electronic version of the Project Study Area Map and Archaeological Overview Assessment. Also inquires whether FEI is conducting a Traditional Use Study.
01 March 2011	Email from First Nations Project Coordinator, FEI to Referrals Coordinator, Chawathil First Nation.	FEI provides electronic map of Project study area as requested. FEI confirms will forward Archaeological Overview Assessment once finalized.
09 March 2011	Email from First Nations Project Coordinator, FEI to Referrals Coordinator, Chawathil First Nation.	FEI confirms that Traditional Use Study has not been requested from SRRMC, but SRRMC included traditional use and other cultural heritage sites in their Archaeological Overview Assessment.
21 March 2011	Meeting – First Nations Initiatives Manager, FEI; First Nations Project Coordinator, FEI; Lands and Resource Coordinator, Sto:lo Tribal Council; Rights and Titles Manager, Sto:lo Tribal Council; Staff Member, Sto:lo Tribal Council.	Discussion of Sto:lo Tribal Council's referrals system. Discussion of development of a consultation protocol between FEI and Sto:lo Tribal Council for such projects.
22 March 2011	Email from First Nations Project Coordinator, FEI to Lands and Resource Coordinator, Sto:lo Tribal Council.	FEI requests copy of Sto:lo Tribal Council's traditional territory map and Sumas First Nation's Referrals Coordinator information.
24 March 2011	Phone call from Lands and Resource Coordinator, Sto:lo Tribal Council to First Nations Project Coordinator, FEI.	Sto:lo Tribal Council confirms their use of Sto:lo Nation Tribal Council's Map on the BC Treaty Commission Website. Sto:lo Tribal Council also confirms that they will forward letter re Sumas First Nation's interest in the Project in the near future.
11 April 2011	Email from First Nations Project Coordinator, FEI to Lands and Resource Coordinator, Sto:lo Tribal Council.	Follow up by FEI re Sumas First Nation's interest in the Project.
11 April 2011	Letter from Lands and Resource Coordinator, Sto:lo Tribal Council to FEI.	Sto:lo Tribal Council confirms affiliation with Sumas First Nation, seeks $300.00 Referral Fee from FEI, and indicates that permission is not yet granted by Sto:lo Tribal Council for FEI's Project.
13 April 2011	Email from First Nations Project Coordinator, FEI to Lands and Resource Coordinator, Sto:lo Tribal Council.	FEI agrees to pay Sto:lo Tribal Council's $300.00 Referral Fee. FEI seeks meeting with Sto:lo Tribal Council and Sumas First Nation to provide greater understanding of the Project and identify and address questions/concerns.
03 May 2011	Meeting – First Nations Initiatives Manager, FEI; First Nations Project Coordinator, FEI; Lands and Resource Coordinator, Sto:lo Tribal Council; Rights and Title Manager, Sto:lo Tribal Council.	Discussion of topics to be addressed in an MOU between the Sto:lo Tribal Council and FEI. Sto:lo Tribal Council confirms they will be meeting with the Sumas First Nation in the near future to discuss the Huntingdon Bypass Project, and also requests participation in determining the criteria to be used for the next stage Archaeological Impact Assessment. FEI agrees to Sto:lo Tribal Council's request.

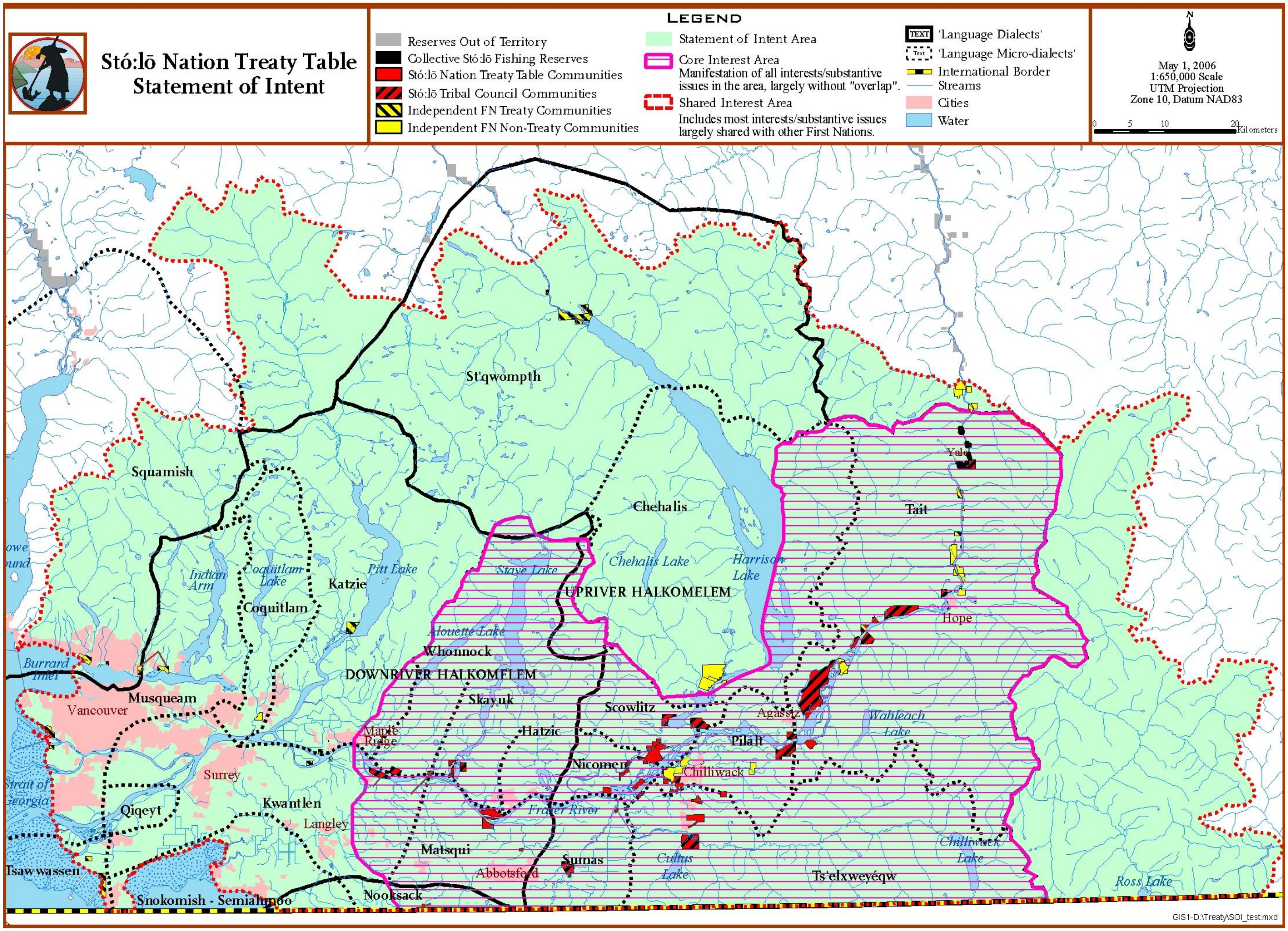
Kwikwetlem First Nation

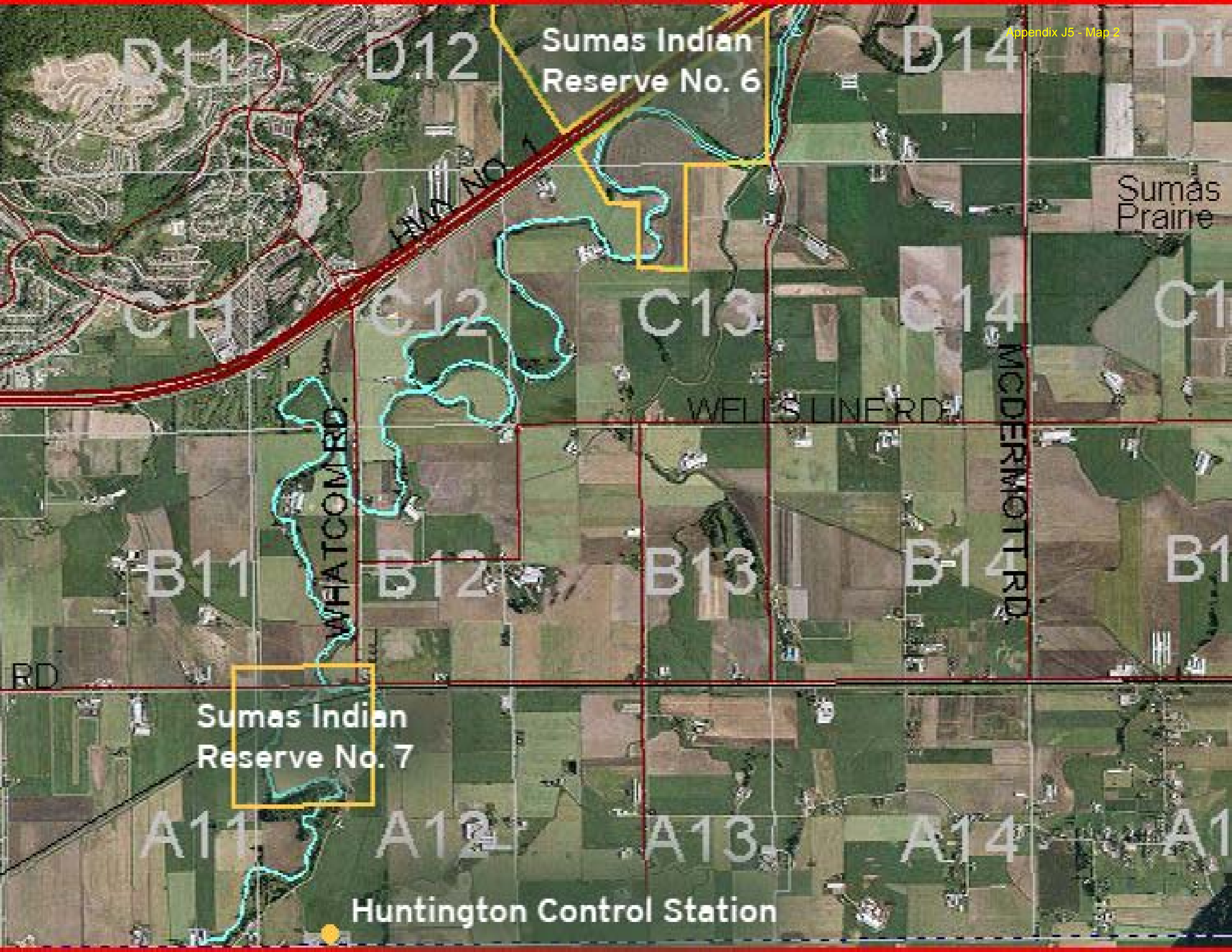
Date	Form of Contact	Description of Content
06 Feb 2011	Letter from FEI to Kwikwetlem First Nation.	FEI provides formal introduction of the Project – nature, rationale, approvals required, maps, timeframe, FEI contact information.
Date	**Form of Contact**	**Description of Content**
24 Nov 2011	Letter from FEI to all previously contacted First Nations	FEI provide an update regarding the status of the proposed Huntingdon Bypass Project
Date	**Form of Contact**	**Description of Content**
13 June 2013	Letter from FEI to all previously contacted First Nations	FEI provide an update regarding the status of the proposed Huntingdon Bypass Project. Explaining that has chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.
Date	**Form of Contact**	**Description of Content**
7 Aug 2013	Phone call between First Nations Initiatives Manager, FEI and Matsqui Referrals Coordinator, Cynthia Collins	Cynthia requested a copy of the Archeological report (provided by email) and had some general questions regarding spills and safety procedures which were answered over the phone.
Date	**Form of Contact**	**Description of Content**
7 Aug 2013	Phone call between First Nations Initiatives Manager, FEI and Matsqui Referrals Coordinator, Cynthia Collins	Cynthia requested a copy of the Archeological report (provided by email) and had some general questions regarding spills and safety procedures which were answered over the phone.
Date	**Form of Contact**	**Description of Content**
7 Aug 2013	Phone call between First Nations Initiatives Manager, FEI and Skawahlook First Nations Referrals Coordinator, Debra Snider	Debra had questions regarding the Sumas 2 power plant project that were answered over the phone. Debra also recommended FEI contact the People of the River Referrals Office at Sto Lo Nation
9 Aug 2013	Email from FEI to People of the River Referrals Office at Sto Lo Nation	FEI provides introduction of the Project and draft of letters sent to Sto Lo Nation member First Nations FEI contact information.

Stakeholder	Name	Communication Type	Purpose of the Communication	Date	Responsibility	Telephone	Cellular
Sto:lo Nation Lands	Lisa Davidson	letter	Inform about new reinforcement project	June 13 2013	BH		
Aitchelitz Band	Chief and Council	letter	Inform about new reinforcement project	June 13 2013	BH		
Seabird Island	Chief Clement Seymour	letter	Inform about new reinforcement project	June 13 2013	BH		
Scowlitz	Chief Andy Phillips	letter	Inform about new reinforcement project	June 13 2013	BH		
Kwaw-kwas-Apilt	Chief Betty Henry	letter	Inform about new reinforcement project	June 13 2013	BH		
Kwantlen First Nation	Chief Marilyn Gabriel	letter	Inform about new reinforcement project	June 13 2013	BH		
Cheam	Chief Lincoln Douglas	letter	Inform about new reinforcement project	June 13 2013	BH		
Chawathil	Chief Ruth Elizabeth Peters	letter	Inform about new reinforcement project	June 13 2013	BH		
Sto:lo Tribal Council	President -- Grand Chief Clarence Pennier	letter	Inform about new reinforcement project	June 13 2013	BH		
Yakweakwillose	Chief Frank Malloway	letter	Inform about new reinforcement project	June 13 2013	BH		
Tzeachten	Chief Glenda Campbell	letter	Inform about new reinforcement project	June 13 2013	BH		
Sumas First Nation	Chief Dalton Silver	letter	Inform about new reinforcement project	June 13 2013	BH		
Squiala First Nation	Chief David Jimmie	letter	Inform about new reinforcement project	June 13 2013	BH		
Skowkale	Chief Robert Hall	letter	Inform about new reinforcement project	June 13 2013	BH		
Skawahlook First Nation	Chief Maureen Chapman	letter	Inform about new reinforcement project	June 13 2013	BH		
Shxwha:y Village	Chief Rina Rabang	letter	Inform about new reinforcement project	June 13 2013	BH		
Popkum	Chief James Murphy	letter	Inform about new reinforcement project	June 13 2013	BH		
Matsqui	Chief Alice McKay	letter	Inform about new reinforcement project	June 13 2013	BH		
Leq'a:mel First Nation	Chief Alice Thompson	letter	Inform about new reinforcement project	June 13 2013	BH		
Shx'ow'hamel First Nation	Councillors	letter	Inform about new reinforcement project	June 13 2013	BH		

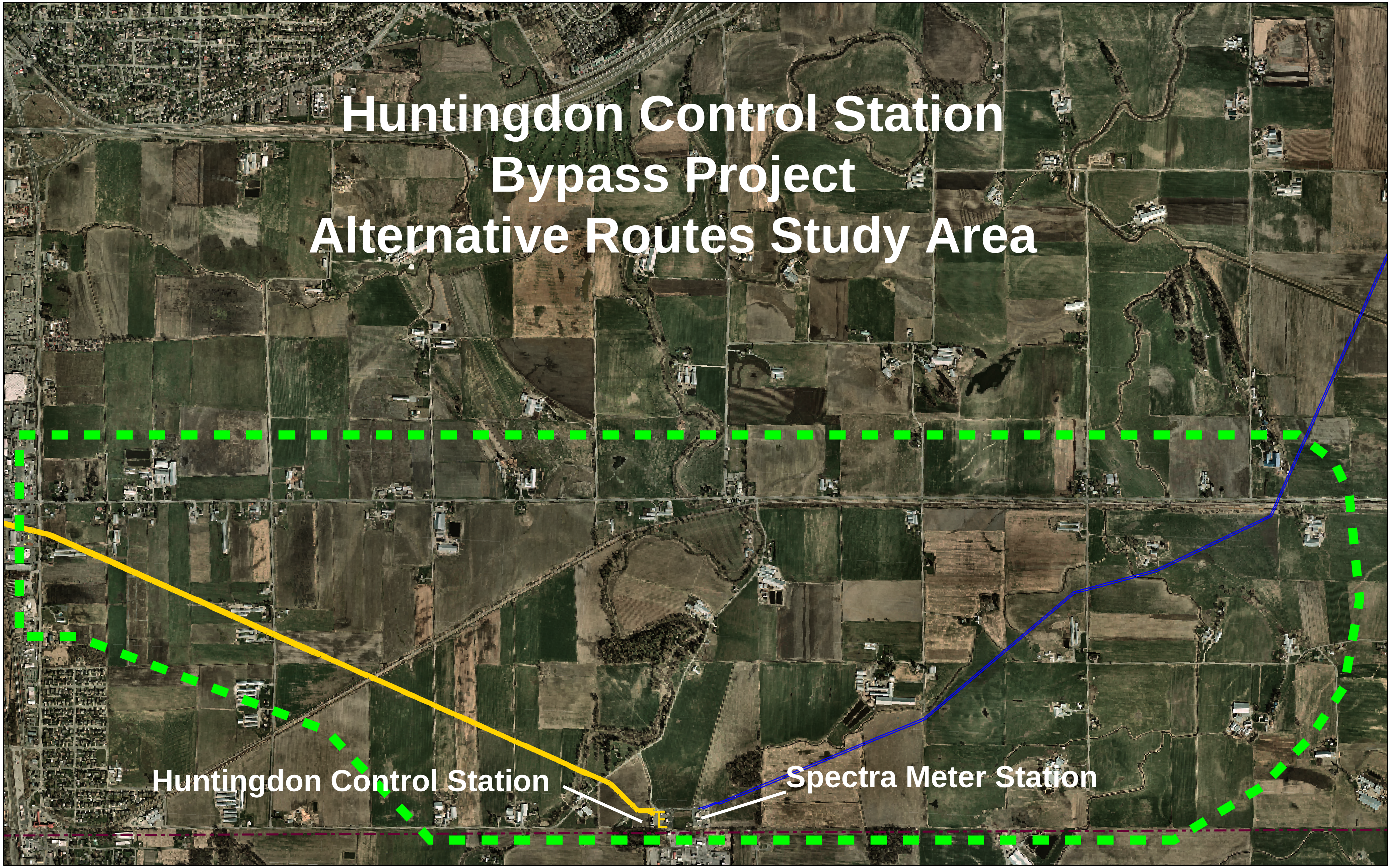
Appendix J5

CONSULTATION AREA MAPS


Stó:lō Nation Treaty Table
Statement of Intent
Legend
Reserves Out of Territory
Collective Stó:lō Fishing Reserves
Stó:lō Nation Treaty Table Communities
Stó:lō Tribal Council Communities
Independent FN Treaty Communities
Independent FN Non-Treaty Communities
Statement of Intent Area
Core Interest Area
Manifestation of all interests/substantive issues in the area, largely without "overlap".
Shared Interest Area
Includes most interests/substantive issues largely shared with other First Nations.
'Language Dialects'
'Language Micro-dialects'
International Border
Streams
Cities
Water
May 1, 2006
1:650,000 Scale
UTM Projection
Zone 10, Datum NAD83
0 5 10 20 Kilometers
St'qwompth
Squamish
Chehalis
Tait
Yale
Chehalis Lake
Harrison Lake
Stave Lake
Pitt Lake
Indian Arm
Coquitlam Lake
Katzie
Coquitlam
UPRIVER HALKOMELEM
Hope
Alouette Lake
Whonnock
DOWNRIVER HALKOMELEM
Burrard Inlet
Musqueam
Vancouver
Skayuk
Scowlitz
Agassiz
Wahleach Lake
Maple Ridge
Hatzic
Pilalt
Nicomen
Chilliwack
Surrey
Strait of Georgia
Qiqeyt
Kwantlen
Langley
Fraser River
Matsqui
Sumas
Cultus Lake
Chilliwack Lake
Abbotsford
Ts'elxweyéqw
Ross Lake
Tsawwassen
Snokomish - Semiahmoo
Nooksack
GIS1-D:\Treaty\SOI_test.mxd



Appendix J5 - Map 2
Sumas Indian Reserve No. 6
D11
D12
D14
Sumas Prairie
HWY NO 1
C11
C12
C13
C14
WELLS LINE RD.
MCDERMOTT RD.
WHATCOM RD.
B11
B12
B13
B14
RD
Sumas Indian Reserve No. 7
A11
A12
A13
A14
Huntington Control Station



Terasen Gas Transmission Pipe

Spectra Transmission Pipe

0km 0.5km 1km 1.5km 2km

Appendix J6

FIRST NATIONS CONSULTATION LETTERS

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Chief Jimmy George
Aitchelitz Indian Band
8161 Aitken Road
Chilliwack, BC V2R 4H4

Dear Chief Jimmy George:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

I look forward to working with you to address appropriate consultation with the Aitchelitz Indian Band. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Chief Ruth Elizabeth Peters
Chawathil Indian Band
4 - 60814 Lougheed Highway
Hope, BC V0X 1L3

Dear Chief Ruth Elizabeth Peters:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

Terasen Gas

I look forward to working with you to address appropriate consultation with the Chawathil Indian Band. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

Terasen Gas

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Chief Lincoln Douglas
Cheam Indian Band
52130 Old Yale Road
Rosedale, BC V0X 1X0

Dear Chief Lincoln Douglas:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

I look forward to working with you to address appropriate consultation with the Cheam Indian Band. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

Terasen Gas

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Chief Marilyn Gabriel
Kwantlen First Nation
23690 Gabriel Lane
PO Box 108
Fort Langley, BC V1M 2R4

Dear Chief Marilyn Gabriel:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

Terasen Gas

I look forward to working with you to address appropriate consultation with the Kwantlen First Nation. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Chief Betty Henry
Kwaw-kwaw-Aplit Indian Band
PO Box 2065 Stn Main
Chilliwack, BC V2R 1A5

Dear Chief Betty Henry:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

I look forward to working with you to address appropriate consultation with the Kwaw-kwaw-Aplit Indian Band. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Chief Ronald Giebrecht
Kwikwetlem First Nation
2 - 65 Colony Farm Road
Coquitlam, BC V3C 5X9

Dear Chief Ronald Giebrecht:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

I look forward to working with you to address appropriate consultation with the Kwikwetlem First Nation. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Chief Alice Thompson
Leq'a:mel First Nation
43101 Leq'a:mel Way
Deroche, BC V0M 1G0

Dear Chief Alice Thompson:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

Terasen Gas

I look forward to working with you to address appropriate consultation with the Leq'a:mel First Nation. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

Terasen Gas

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Chief Alice McKay
Matsqui First Nation
PO Box 10
Matsqui, BC V4X 3R2

Dear Chief Alice McKay:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

I look forward to working with you to address appropriate consultation with the Matsqui First Nation. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

Terasen Gas

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Chief James Murphy
Popkum Indian Band
PO Box 2, RR1
Rosedale, BC V0X 1X0

Dear Chief James Murphy:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

I look forward to working with you to address appropriate consultation with the Popkum Indian Band. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

Terasen Gas

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Chief John Pennier
Scowlitz Indian Band
PO Box 76
Lake Errock, BC V0M 1N0

Dear Chief John Pennier:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

I look forward to working with you to address appropriate consultation with the Scowlitz Indian Band. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

Terasen Gas

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Chief Clement Seymour
Seabird Island Indian Band
PO Box 650
Agassiz, BC V0M 1A0

Dear Chief Clement Seymour:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

I look forward to working with you to address appropriate consultation with the Seabird Island Indian Band. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Chief William Sr. Rabang
Shxwha:y Village Indian Band
44680 Schweyey Road
Chilliwack, BC V2R 5M5

Dear Chief William Sr. Rabang:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

I look forward to working with you to address appropriate consultation with the Shxwha:y Village Indian Band. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

Terasen Gas

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Attention: Councillors
Shxw'ow'hamel First Nation
58700A St. Elmo Road
Hope, BC V0X 1L2

Dear Councillors:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

I look forward to working with you to address appropriate consultation with the Shxw'ow'hamel First Nation. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

Terasen Gas

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Chief Maureen Chapman
Skawahlook First Nation
58611A Lougheed Highway
Agassiz, BC V0M 1A2

Dear Chief Maureen Chapman:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

I look forward to working with you to address appropriate consultation with the Skawahlook First Nation. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

Terasen Gas

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Chief Robert Hall
Skowkale First Nation
PO Box 2159
Sardis, BC V2R 1A7

Dear Chief Robert Hall:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

I look forward to working with you to address appropriate consultation with the Skowkale First Nation. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

Terasen Gas

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Chief Otis Kelly
Soowahlie Indian Band
4172 Soowahlie Road
Cultus Lake, BC V2R 4Y2

Dear Chief Otis Kelly:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

I look forward to working with you to address appropriate consultation with the Soowahlie Indian Band. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Chief David Jimmie
Squiala First Nation
8528 Ashwell Road
Chilliwack, BC V2P 7Z9

Dear Chief David Jimmie:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

I look forward to working with you to address appropriate consultation with the Squiala First Nation. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Chief Joe Hall
Sto:lo Nation
Building #7 - 7201 Vedder Road
Chilliwack, BC V2R 4G5

Dear Chief Joe Hall:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

I look forward to working with you to address appropriate consultation with the Sto:lo Nation. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

Terasen Gas

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Grand Chief Clarence Pennier
Sto:lo Tribal Council
#2855 Chowat Road
PO Box 440
Agassiz, BC V0M 1A0

Dear Grand Chief Clarence Pennier:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

I look forward to working with you to address appropriate consultation with the Sto:lo Tribal Council. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Chief Dalton Silver
Sumas First Nation
2788 Sumas Mountain Road, RR4
Abbotsford, BC V3G 2J2

Dear Chief Dalton Silver:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

I look forward to working with you to address appropriate consultation with the Sumas First Nation. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Chief Joseph Hall
Tzeachten First Nation
45855 Promontory Road
Chilliwack, BC V2R 0H3

Dear Chief Joseph Hall:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

I look forward to working with you to address appropriate consultation with the Tzeachten First Nation. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

Terasen Gas

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 592-7677
Toll Free: 1-800-773-7001
www.terasengas.com

February 7, 2011

Chief Frank Malloway
Yakweakwioose Indian Band
RR2, 7176 Chilliwack River Road
Sardis, BC V2R 1B1

Dear Chief Frank Malloway:

RE: Huntingdon Bypass Project

Terasen Gas is in the preliminary planning stages to seek approval to construct a new emergency bypass pipeline and control station near the existing Huntingdon Control Station, located adjacent to the Canada/US border approximately 3 km east of the Huntingdon, British Columbia/Sumas, Washington border crossing. When completed, this addition to our existing pipeline will increase the reliability of our system, and minimize the potential outage of the existing Huntingdon Station in the event of equipment malfunction or system damage. The existing Huntingdon Station and pipeline serves over 600,000 customers in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island, and the implications of a loss of the existing facility would be significant. Terasen is planning to move forward with this project after a recent review of its critical assets, and this upgrade will help to ensure ongoing reliability for our customers.

Terasen is currently assessing several route options for the bypass pipeline. Engineering assessment personnel will be in the area in conjunction with environmental and archaeological assessments in order to determine the best route possible. All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land. The attached map is of the general study area. Once our field assessments are completed, the project details and mapping information will be shared with you.

Terasen requires approvals from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission to construct the proposed emergency bypass pipeline. Terasen will be requesting regulatory approval for the project this summer. The expected in-service date of the pipeline is winter 2012. All required environmental permits and approvals for the project will be identified and applied for during the planning phase of the project. Agency notifications, permits and approvals are anticipated under, but not limited to: the Fisheries Act, Species at Risk Act, Navigable Waters Protection Act, Water Act, Forest and Range Practices Act, Heritage Conservation Act and Land Act.

The Research and Resource Management Centre of the Sto:lo Nation is working with Terasen in regards to conducting archaeological studies.

I look forward to working with you to address appropriate consultation with the Yakweakwioose Indian Band. I will be your main contact for the planning and permitting stages of this project and I can be reached at my office at 604-592-7686, or on my cell phone at 604-785-8947. I am also always available to discuss the project in person.

Charles Littledale will also be assisting with Communications and can be reached at 604-202-7337.

Respectfully;

Bruce Falstead
Aboriginal Relations Manager

cc: Oil and Gas Commission

Attachment: Site Maps

Sto:lo Tribal Council
2855 Chowat Road
Aggasiz, BC V0M 1A
Phone: (604) 796-0627
Fax: (604) 796-0643

Invoice #6

Friday, April 1, 2011

Referral ID: 2011RTS29-0329 Reference Number: Huntingdon Bypass Project
RTS #: 29
Date: Wednesday, March 30, 2011

FortisBC
16705 Fraser Highway
Surrey BC V4N 0E8

Attention: Bruce Falstead

Stó:lō Tribal Council received your letter of introduction initiating consultation on the Huntington Bypass Project, within S'olh Temexw, Sto:lo homeland. Sto:lo Tribal Council represents 8 Sto:lo First Nations: Seabird Island, Scowlitz, Soowahlie, Kwa'kwaw'Apilt, Shxw'ow'hamel, Chawathil, Kwantlen and Cheam. The location of this project falls within the Core Territory of the Sumas First Nation an affiliation of the Sto:lo Tribal Council.

In respect to the proposed activity as per section 6(b)(iii) of the Consultation and Accommodation Policy (CAP) the Stó:lō Tribal Council need to understand the potential scope of this project, including both impacts and opportunities for our communities.

We are invoicing for a Referral Application fee of $300.00. This fee is a requirement to begin the initial assessment and determine the next steps. This payment would in no way equal consent to the project and does not create an obligation for Stó:lō Tribal Council to approve the project in the future.

At this point FortisBC does not have the permission of the Stó:lō Tribal Council to move ahead with their Hunting Bypass Project . For further information on this matter please contact me directly at 604-796-0627 ext. 248 or by email at Frank.Andrew@stolotribalcouncil.ca.

We look forward to your response in this very important matter.

Sincerely,

Frank Andrew,
Land and Resource Coordinator
Stó:lō Tribal Council

June 13, 2013

Lisa Davidson
Sto:lo Nation Lands
Building #7
7201 Vedder Road
Chilliwack, BC V2R 4G5

Dear Ms. Davidson,

Re: Huntingdon Bypass Project

Further to our letter of November 24, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project. The Huntingdon Station provides reliable gas service to more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island. The Bypass project is designed to increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

FortisBC has now chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project in 2013. With approval to proceed, the expected in-service date of the reinforcement pipeline is 2014.

Please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Respectfully,

Bruce Falstead
Manager Aboriginal Initiatives

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

November 24, 2011

«Customer_Name»
«Mailing_Address_1» «Mailing_Address_2»
«Mailing_City» «Postal_Code»

Dear ____,

Re: Huntingdon Bypass Project

Further to our letter of February 7, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project and the preliminary archaeological work undertaken to date.

The Sto:lo Research and Resource Management Centre has now completed the Archaeological Overview Assessment and has provided feedback regarding the three route options that were under consideration. It has been concluded that the Huntingdon Bypass Project lies in an area close to known archaeological sites, and this information combined with the input received from affected parties, has led FEI to examine alternate options.

FEI still believes that an upgrade to the Huntingdon Control Station is necessary, however we are now examining options that would further minimize the impact to the land of private owners and the Sumas River.

We will get back to you once we have more news. In the meanwhile, please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Jennifa James, FEI's First Nations Project Coordinator, will be assisting with communications and can be reached at 604-592-7746.

Respectfully,

Bruce Falstead
First Nations Initiatives Manager

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

June 13, 2013

Chief and Council
Aitchelitz Band
8161 Aitken Road
Chilliwack, BC V2R 4H4

Dear Chief and Council,

Re: Huntingdon Bypass Project

Further to our letter of November 24, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project. The Huntingdon Station provides reliable gas service to more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island. The Bypass project is designed to increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

FortisBC has now chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project in 2013. With approval to proceed, the expected in-service date of the reinforcement pipeline is 2014.

Please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Respectfully,

Bruce Falstead
Manager Aboriginal Initiatives

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

November 24, 2011

«Customer_Name»
«Mailing_Address_1» «Mailing_Address_2»
«Mailing_City» «Postal_Code»

Dear ____,

Re: Huntingdon Bypass Project

Further to our letter of February 7, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project and the preliminary archaeological work undertaken to date.

The Sto:lo Research and Resource Management Centre has now completed the Archaeological Overview Assessment and has provided feedback regarding the three route options that were under consideration. It has been concluded that the Huntingdon Bypass Project lies in an area close to known archaeological sites, and this information combined with the input received from affected parties, has led FEI to examine alternate options.

FEI still believes that an upgrade to the Huntingdon Control Station is necessary, however we are now examining options that would further minimize the impact to the land of private owners and the Sumas River.

We will get back to you once we have more news. In the meanwhile, please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Jennifa James, FEI's First Nations Project Coordinator, will be assisting with communications and can be reached at 604-592-7746.

Respectfully,

Bruce Falstead
First Nations Initiatives Manager

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

June 13, 2013

Chief Clement Seymour
Seabird Island
PO Box 650
Agassiz, BC V0M 1A0

Dear Chief Seymour,

Re: Huntingdon Bypass Project

Further to our letter of November 24, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project. The Huntingdon Station provides reliable gas service to more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island. The Bypass project is designed to increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

FortisBC has now chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project in 2013. With approval to proceed, the expected in-service date of the reinforcement pipeline is 2014.

Please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Respectfully,

Bruce Falstead
Manager Aboriginal Initiatives

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

November 24, 2011

«Customer_Name»
«Mailing_Address_1» «Mailing_Address_2»
«Mailing_City» «Postal_Code»

Dear ____,

Re: Huntingdon Bypass Project

Further to our letter of February 7, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project and the preliminary archaeological work undertaken to date.

The Sto:lo Research and Resource Management Centre has now completed the Archaeological Overview Assessment and has provided feedback regarding the three route options that were under consideration. It has been concluded that the Huntingdon Bypass Project lies in an area close to known archaeological sites, and this information combined with the input received from affected parties, has led FEI to examine alternate options.

FEI still believes that an upgrade to the Huntingdon Control Station is necessary, however we are now examining options that would further minimize the impact to the land of private owners and the Sumas River.

We will get back to you once we have more news. In the meanwhile, please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Jennifa James, FEI's First Nations Project Coordinator, will be assisting with communications and can be reached at 604-592-7746.

Respectfully,

Bruce Falstead
First Nations Initiatives Manager

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

June 13, 2013

Chief Andy Phillips
Scowlitz
PO Box 76
Lake Errock, BC V0M 1N0

Dear Chief Phillips,

Re: Huntingdon Bypass Project

Further to our letter of November 24, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project. The Huntingdon Station provides reliable gas service to more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island. The Bypass project is designed to increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

FortisBC has now chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project in 2013. With approval to proceed, the expected in-service date of the reinforcement pipeline is 2014.

Please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Respectfully,

Bruce Falstead
Manager Aboriginal Initiatives

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

November 24, 2011

«Customer_Name»
«Mailing_Address_1» «Mailing_Address_2»
«Mailing_City» «Postal_Code»

Dear ____,

Re: Huntingdon Bypass Project

Further to our letter of February 7, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project and the preliminary archaeological work undertaken to date.

The Sto:lo Research and Resource Management Centre has now completed the Archaeological Overview Assessment and has provided feedback regarding the three route options that were under consideration. It has been concluded that the Huntingdon Bypass Project lies in an area close to known archaeological sites, and this information combined with the input received from affected parties, has led FEI to examine alternate options.

FEI still believes that an upgrade to the Huntingdon Control Station is necessary, however we are now examining options that would further minimize the impact to the land of private owners and the Sumas River.

We will get back to you once we have more news. In the meanwhile, please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Jennifa James, FEI's First Nations Project Coordinator, will be assisting with communications and can be reached at 604-592-7746.

Respectfully,

Bruce Falstead
First Nations Initiatives Manager

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

June 13, 2013

Chief Betty Henry
Kwaw-kwaw-Apilt
PO Box 2065 Stn Main
Chilliwack, BC V2R 1A5

Dear Chief Henry,

Re: Huntingdon Bypass Project

Further to our letter of November 24, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project. The Huntingdon Station provides reliable gas service to more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island. The Bypass project is designed to increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

FortisBC has now chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project in 2013. With approval to proceed, the expected in-service date of the reinforcement pipeline is 2014.

Please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Respectfully,

Bruce Falstead
Manager Aboriginal Initiatives

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

November 24, 2011

«Customer_Name»
«Mailing_Address_1» «Mailing_Address_2»
«Mailing_City» «Postal_Code»

Dear ____,

Re: Huntingdon Bypass Project

Further to our letter of February 7, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project and the preliminary archaeological work undertaken to date.

The Sto:lo Research and Resource Management Centre has now completed the Archaeological Overview Assessment and has provided feedback regarding the three route options that were under consideration. It has been concluded that the Huntingdon Bypass Project lies in an area close to known archaeological sites, and this information combined with the input received from affected parties, has led FEI to examine alternate options.

FEI still believes that an upgrade to the Huntingdon Control Station is necessary, however we are now examining options that would further minimize the impact to the land of private owners and the Sumas River.

We will get back to you once we have more news. In the meanwhile, please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Jennifa James, FEI's First Nations Project Coordinator, will be assisting with communications and can be reached at 604-592-7746.

Respectfully,

Bruce Falstead
First Nations Initiatives Manager

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

June 13, 2013

Chief Marilyn Gabriel
Kwantlen First Nation
23690 Gabriel Lane
PO Box 108
Fort Langley, BC V1M 2R4

Dear Chief Gabriel,

Re: Huntingdon Bypass Project

Further to our letter of November 24, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project. The Huntingdon Station provides reliable gas service to more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island. The Bypass project is designed to increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

FortisBC has now chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project in 2013. With approval to proceed, the expected in-service date of the reinforcement pipeline is 2014.

Please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Respectfully,

Bruce Falstead
Manager Aboriginal Initiatives

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

November 24, 2011

«Customer_Name»
«Mailing_Address_1» «Mailing_Address_2»
«Mailing_City» «Postal_Code»

Dear ____,

Re: Huntingdon Bypass Project

Further to our letter of February 7, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project and the preliminary archaeological work undertaken to date.

The Sto:lo Research and Resource Management Centre has now completed the Archaeological Overview Assessment and has provided feedback regarding the three route options that were under consideration. It has been concluded that the Huntingdon Bypass Project lies in an area close to known archaeological sites, and this information combined with the input received from affected parties, has led FEI to examine alternate options.

FEI still believes that an upgrade to the Huntingdon Control Station is necessary, however we are now examining options that would further minimize the impact to the land of private owners and the Sumas River.

We will get back to you once we have more news. In the meanwhile, please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Jennifa James, FEI's First Nations Project Coordinator, will be assisting with communications and can be reached at 604-592-7746.

Respectfully,

Bruce Falstead
First Nations Initiatives Manager

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

June 13, 2013

Chief Lincoln Douglas
Cheam
52130 Old Yale Road
Rosedale, BC V0X 1X0

Dear Chief Douglas,

Re: Huntingdon Bypass Project

Further to our letter of November 24, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project. The Huntingdon Station provides reliable gas service to more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island. The Bypass project is designed to increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

FortisBC has now chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project in 2013. With approval to proceed, the expected in-service date of the reinforcement pipeline is 2014.

Please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Respectfully,

Bruce Falstead
Manager Aboriginal Initiatives

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

November 24, 2011

«Customer_Name»
«Mailing_Address_1» «Mailing_Address_2»
«Mailing_City» «Postal_Code»

Dear ____,

Re: Huntingdon Bypass Project

Further to our letter of February 7, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project and the preliminary archaeological work undertaken to date.

The Sto:lo Research and Resource Management Centre has now completed the Archaeological Overview Assessment and has provided feedback regarding the three route options that were under consideration. It has been concluded that the Huntingdon Bypass Project lies in an area close to known archaeological sites, and this information combined with the input received from affected parties, has led FEI to examine alternate options.

FEI still believes that an upgrade to the Huntingdon Control Station is necessary, however we are now examining options that would further minimize the impact to the land of private owners and the Sumas River.

We will get back to you once we have more news. In the meanwhile, please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Jennifa James, FEI's First Nations Project Coordinator, will be assisting with communications and can be reached at 604-592-7746.

Respectfully,

Bruce Falstead
First Nations Initiatives Manager

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

June 13, 2013

Chief Ruth Elizabeth Peters
Chawathil
#4 - 60814 Lougheed Highway
Hope, BC V0X 1L3

Dear Chief Peters,

Re: Huntingdon Bypass Project

Further to our letter of November 24, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project. The Huntingdon Station provides reliable gas service to more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island. The Bypass project is designed to increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

FortisBC has now chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project in 2013. With approval to proceed, the expected in-service date of the reinforcement pipeline is 2014.

Please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Respectfully,

Bruce Falstead
Manager Aboriginal Initiatives

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC™

November 24, 2011

«Customer_Name»
«Mailing_Address_1» «Mailing_Address_2»
«Mailing_City» «Postal_Code»

Dear ____,

Re: Huntingdon Bypass Project

Further to our letter of February 7, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project and the preliminary archaeological work undertaken to date.

The Sto:lo Research and Resource Management Centre has now completed the Archaeological Overview Assessment and has provided feedback regarding the three route options that were under consideration. It has been concluded that the Huntingdon Bypass Project lies in an area close to known archaeological sites, and this information combined with the input received from affected parties, has led FEI to examine alternate options.

FEI still believes that an upgrade to the Huntingdon Control Station is necessary, however we are now examining options that would further minimize the impact to the land of private owners and the Sumas River.

We will get back to you once we have more news. In the meanwhile, please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Jennifa James, FEI's First Nations Project Coordinator, will be assisting with communications and can be reached at 604-592-7746.

Respectfully,

Bruce Falstead
First Nations Initiatives Manager

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

June 13, 2013

President – Grand Chief Clarence Pennier
Sto:lo Tribal Council
#2855 Chowat Road
PO Box 440
Agassiz, BC V0M 1A0

Dear President – Grand Chief Pennier,

Re: Huntingdon Bypass Project

Further to our letter of November 24, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project. The Huntingdon Station provides reliable gas service to more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island. The Bypass project is designed to increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

FortisBC has now chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project in 2013. With approval to proceed, the expected in-service date of the reinforcement pipeline is 2014.

Please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Respectfully,

Bruce Falstead
Manager Aboriginal Initiatives

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC™

November 24, 2011

«Customer_Name»
«Mailing_Address_1» «Mailing_Address_2»
«Mailing_City» «Postal_Code»

Dear ____,

Re: Huntingdon Bypass Project

Further to our letter of February 7, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project and the preliminary archaeological work undertaken to date.

The Sto:lo Research and Resource Management Centre has now completed the Archaeological Overview Assessment and has provided feedback regarding the three route options that were under consideration. It has been concluded that the Huntingdon Bypass Project lies in an area close to known archaeological sites, and this information combined with the input received from affected parties, has led FEI to examine alternate options.

FEI still believes that an upgrade to the Huntingdon Control Station is necessary, however we are now examining options that would further minimize the impact to the land of private owners and the Sumas River.

We will get back to you once we have more news. In the meanwhile, please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Jennifa James, FEI's First Nations Project Coordinator, will be assisting with communications and can be reached at 604-592-7746.

Respectfully,

Bruce Falstead
First Nations Initiatives Manager

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

June 13, 2013

Chief Frank Malloway
Yakweakwioose
RR 2
7176 Chilliwack River Road
Sardis, BC V2R 1B1

Dear Chief Malloway,

Re: Huntingdon Bypass Project

Further to our letter of November 24, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project. The Huntingdon Station provides reliable gas service to more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island. The Bypass project is designed to increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

FortisBC has now chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project in 2013. With approval to proceed, the expected in-service date of the reinforcement pipeline is 2014.

Please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Respectfully,

Bruce Falstead
Manager Aboriginal Initiatives

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

November 24, 2011

«Customer_Name»
«Mailing_Address_1» «Mailing_Address_2»
«Mailing_City» «Postal_Code»

Dear ____,

Re: Huntingdon Bypass Project

Further to our letter of February 7, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project and the preliminary archaeological work undertaken to date.

The Sto:lo Research and Resource Management Centre has now completed the Archaeological Overview Assessment and has provided feedback regarding the three route options that were under consideration. It has been concluded that the Huntingdon Bypass Project lies in an area close to known archaeological sites, and this information combined with the input received from affected parties, has led FEI to examine alternate options.

FEI still believes that an upgrade to the Huntingdon Control Station is necessary, however we are now examining options that would further minimize the impact to the land of private owners and the Sumas River.

We will get back to you once we have more news. In the meanwhile, please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Jennifa James, FEI's First Nations Project Coordinator, will be assisting with communications and can be reached at 604-592-7746.

Respectfully,

Bruce Falstead
First Nations Initiatives Manager

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

June 13, 2013

Chief Glenda Campbell
Tzeachten
45855 Promontory Road
Chilliwack, BC V2R 0H3

Dear Chief Campbell,

Re: Huntingdon Bypass Project

Further to our letter of November 24, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project. The Huntingdon Station provides reliable gas service to more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island. The Bypass project is designed to increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

FortisBC has now chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project in 2013. With approval to proceed, the expected in-service date of the reinforcement pipeline is 2014.

Please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Respectfully,

Bruce Falstead
Manager Aboriginal Initiatives

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

November 24, 2011

«Customer_Name»
«Mailing_Address_1» «Mailing_Address_2»
«Mailing_City» «Postal_Code»

Dear ____,

Re: Huntingdon Bypass Project

Further to our letter of February 7, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project and the preliminary archaeological work undertaken to date.

The Sto:lo Research and Resource Management Centre has now completed the Archaeological Overview Assessment and has provided feedback regarding the three route options that were under consideration. It has been concluded that the Huntingdon Bypass Project lies in an area close to known archaeological sites, and this information combined with the input received from affected parties, has led FEI to examine alternate options.

FEI still believes that an upgrade to the Huntingdon Control Station is necessary, however we are now examining options that would further minimize the impact to the land of private owners and the Sumas River.

We will get back to you once we have more news. In the meanwhile, please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Jennifa James, FEI's First Nations Project Coordinator, will be assisting with communications and can be reached at 604-592-7746.

Respectfully,

Bruce Falstead
First Nations Initiatives Manager

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

June 13, 2013

Chief Dalton Silver
Sumas First Nation
2788 Sumas Mountain Road
RR4
Abbotsford, BC V3G 2J2

Dear Chief Silver,

Re: Huntingdon Bypass Project

Further to our letter of November 24, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project. The Huntingdon Station provides reliable gas service to more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island. The Bypass project is designed to increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

FortisBC has now chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project in 2013. With approval to proceed, the expected in-service date of the reinforcement pipeline is 2014.

Please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Respectfully,

Bruce Falstead
Manager Aboriginal Initiatives

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

November 24, 2011

«Customer_Name»
«Mailing_Address_1» «Mailing_Address_2»
«Mailing_City» «Postal_Code»

Dear ____,

Re: Huntingdon Bypass Project

Further to our letter of February 7, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project and the preliminary archaeological work undertaken to date.

The Sto:lo Research and Resource Management Centre has now completed the Archaeological Overview Assessment and has provided feedback regarding the three route options that were under consideration. It has been concluded that the Huntingdon Bypass Project lies in an area close to known archaeological sites, and this information combined with the input received from affected parties, has led FEI to examine alternate options.

FEI still believes that an upgrade to the Huntingdon Control Station is necessary, however we are now examining options that would further minimize the impact to the land of private owners and the Sumas River.

We will get back to you once we have more news. In the meanwhile, please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Jennifa James, FEI's First Nations Project Coordinator, will be assisting with communications and can be reached at 604-592-7746.

Respectfully,

Bruce Falstead
First Nations Initiatives Manager

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

June 13, 2013

Chief David Jimmie
Squiala First Nation
8528 Ashwell Road
Chilliwack, BC V2P 7Z9

Dear Chief Jimmie,

Re: Huntingdon Bypass Project

Further to our letter of November 24, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project. The Huntingdon Station provides reliable gas service to more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island. The Bypass project is designed to increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

FortisBC has now chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project in 2013. With approval to proceed, the expected in-service date of the reinforcement pipeline is 2014.

Please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Respectfully,

Bruce Falstead
Manager Aboriginal Initiatives

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

November 24, 2011

«Customer_Name»
«Mailing_Address_1» «Mailing_Address_2»
«Mailing_City» «Postal_Code»

Dear ____,

Re: Huntingdon Bypass Project

Further to our letter of February 7, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project and the preliminary archaeological work undertaken to date.

The Sto:lo Research and Resource Management Centre has now completed the Archaeological Overview Assessment and has provided feedback regarding the three route options that were under consideration. It has been concluded that the Huntingdon Bypass Project lies in an area close to known archaeological sites, and this information combined with the input received from affected parties, has led FEI to examine alternate options.

FEI still believes that an upgrade to the Huntingdon Control Station is necessary, however we are now examining options that would further minimize the impact to the land of private owners and the Sumas River.

We will get back to you once we have more news. In the meanwhile, please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Jennifa James, FEI's First Nations Project Coordinator, will be assisting with communications and can be reached at 604-592-7746.

Respectfully,

Bruce Falstead
First Nations Initiatives Manager

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

June 13, 2013

Chief Robert Hall
Skowkale
PO Box 2159
Sardis, BC V2R 1A7

Dear Chief Hall,

Re: Huntingdon Bypass Project

Further to our letter of November 24, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project. The Huntingdon Station provides reliable gas service to more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island. The Bypass project is designed to increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

FortisBC has now chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project in 2013. With approval to proceed, the expected in-service date of the reinforcement pipeline is 2014.

Please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Respectfully,

Bruce Falstead
Manager Aboriginal Initiatives

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

November 24, 2011

«Customer_Name»
«Mailing_Address_1» «Mailing_Address_2»
«Mailing_City» «Postal_Code»

Dear ____,

Re: Huntingdon Bypass Project

Further to our letter of February 7, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project and the preliminary archaeological work undertaken to date.

The Sto:lo Research and Resource Management Centre has now completed the Archaeological Overview Assessment and has provided feedback regarding the three route options that were under consideration. It has been concluded that the Huntingdon Bypass Project lies in an area close to known archaeological sites, and this information combined with the input received from affected parties, has led FEI to examine alternate options.

FEI still believes that an upgrade to the Huntingdon Control Station is necessary, however we are now examining options that would further minimize the impact to the land of private owners and the Sumas River.

We will get back to you once we have more news. In the meanwhile, please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Jennifa James, FEI's First Nations Project Coordinator, will be assisting with communications and can be reached at 604-592-7746.

Respectfully,

Bruce Falstead
First Nations Initiatives Manager

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

June 13, 2013

Chief Maureen Chapman
Skawahlook First Nation
58611A Lougheed Hwy.
Agassiz, BC V0M 1A2

Dear Chief Chapman,

Re: Huntingdon Bypass Project

Further to our letter of November 24, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project. The Huntingdon Station provides reliable gas service to more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island. The Bypass project is designed to increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

FortisBC has now chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project in 2013. With approval to proceed, the expected in-service date of the reinforcement pipeline is 2014.

Please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Respectfully,

Bruce Falstead
Manager Aboriginal Initiatives

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

November 24, 2011

«Customer_Name»
«Mailing_Address_1» «Mailing_Address_2»
«Mailing_City» «Postal_Code»

Dear ____,

Re: Huntingdon Bypass Project

Further to our letter of February 7, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project and the preliminary archaeological work undertaken to date.

The Sto:lo Research and Resource Management Centre has now completed the Archaeological Overview Assessment and has provided feedback regarding the three route options that were under consideration. It has been concluded that the Huntingdon Bypass Project lies in an area close to known archaeological sites, and this information combined with the input received from affected parties, has led FEI to examine alternate options.

FEI still believes that an upgrade to the Huntingdon Control Station is necessary, however we are now examining options that would further minimize the impact to the land of private owners and the Sumas River.

We will get back to you once we have more news. In the meanwhile, please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Jennifa James, FEI's First Nations Project Coordinator, will be assisting with communications and can be reached at 604-592-7746.

Respectfully,

Bruce Falstead
First Nations Initiatives Manager

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

June 13, 2013

Chief Tina Rabang
Shxwha:y Village
44680 Schweyey Road
Chilliwack, BC V2R 5M5

Dear Chief Rabang,

Re: Huntingdon Bypass Project

Further to our letter of November 24, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project. The Huntingdon Station provides reliable gas service to more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island. The Bypass project is designed to increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

FortisBC has now chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project in 2013. With approval to proceed, the expected in-service date of the reinforcement pipeline is 2014.

Please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Respectfully,

Bruce Falstead
Manager Aboriginal Initiatives

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

November 24, 2011

«Customer_Name»
«Mailing_Address_1» «Mailing_Address_2»
«Mailing_City» «Postal_Code»

Dear ____,

Re: Huntingdon Bypass Project

Further to our letter of February 7, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project and the preliminary archaeological work undertaken to date.

The Sto:lo Research and Resource Management Centre has now completed the Archaeological Overview Assessment and has provided feedback regarding the three route options that were under consideration. It has been concluded that the Huntingdon Bypass Project lies in an area close to known archaeological sites, and this information combined with the input received from affected parties, has led FEI to examine alternate options.

FEI still believes that an upgrade to the Huntingdon Control Station is necessary, however we are now examining options that would further minimize the impact to the land of private owners and the Sumas River.

We will get back to you once we have more news. In the meanwhile, please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Jennifa James, FEI's First Nations Project Coordinator, will be assisting with communications and can be reached at 604-592-7746.

Respectfully,

Bruce Falstead
First Nations Initiatives Manager

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

June 13, 2013

Chief James Murphy
Popkum
PO Box 2, RR1
Rosedale, BC V0X 1X0

Dear Chief Murphy,

Re: Huntingdon Bypass Project

Further to our letter of November 24, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project. The Huntingdon Station provides reliable gas service to more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island. The Bypass project is designed to increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

FortisBC has now chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project in 2013. With approval to proceed, the expected in-service date of the reinforcement pipeline is 2014.

Please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Respectfully,

Bruce Falstead
Manager Aboriginal Initiatives

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

November 24, 2011

«Customer_Name»
«Mailing_Address_1» «Mailing_Address_2»
«Mailing_City» «Postal_Code»

Dear ____,

Re: Huntingdon Bypass Project

Further to our letter of February 7, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project and the preliminary archaeological work undertaken to date.

The Sto:lo Research and Resource Management Centre has now completed the Archaeological Overview Assessment and has provided feedback regarding the three route options that were under consideration. It has been concluded that the Huntingdon Bypass Project lies in an area close to known archaeological sites, and this information combined with the input received from affected parties, has led FEI to examine alternate options.

FEI still believes that an upgrade to the Huntingdon Control Station is necessary, however we are now examining options that would further minimize the impact to the land of private owners and the Sumas River.

We will get back to you once we have more news. In the meanwhile, please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Jennifa James, FEI's First Nations Project Coordinator, will be assisting with communications and can be reached at 604-592-7746.

Respectfully,

Bruce Falstead
First Nations Initiatives Manager

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

June 13, 2013

Chief Alice McKay
Matsqui
PO Box 10
Matsqui, BC V4X 3R2

Dear Chief McKay,

Re: Huntingdon Bypass Project

Further to our letter of November 24, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project. The Huntingdon Station provides reliable gas service to more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island. The Bypass project is designed to increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

FortisBC has now chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project in 2013. With approval to proceed, the expected in-service date of the reinforcement pipeline is 2014.

Please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Respectfully,

Bruce Falstead
Manager Aboriginal Initiatives

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

November 24, 2011

«Customer_Name»
«Mailing_Address_1» «Mailing_Address_2»
«Mailing_City» «Postal_Code»

Dear ____,

Re: Huntingdon Bypass Project

Further to our letter of February 7, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project and the preliminary archaeological work undertaken to date.

The Sto:lo Research and Resource Management Centre has now completed the Archaeological Overview Assessment and has provided feedback regarding the three route options that were under consideration. It has been concluded that the Huntingdon Bypass Project lies in an area close to known archaeological sites, and this information combined with the input received from affected parties, has led FEI to examine alternate options.

FEI still believes that an upgrade to the Huntingdon Control Station is necessary, however we are now examining options that would further minimize the impact to the land of private owners and the Sumas River.

We will get back to you once we have more news. In the meanwhile, please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Jennifa James, FEI's First Nations Project Coordinator, will be assisting with communications and can be reached at 604-592-7746.

Respectfully,

Bruce Falstead
First Nations Initiatives Manager

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

June 13, 2013

Chief Alice Thompson
Leq'a:mel First Nation
43101 Leq'a:mel Way
Deroche, BC V0M 1G0

Dear Chief Thompson,

Re: Huntingdon Bypass Project

Further to our letter of November 24, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project. The Huntingdon Station provides reliable gas service to more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island. The Bypass project is designed to increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

FortisBC has now chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project in 2013. With approval to proceed, the expected in-service date of the reinforcement pipeline is 2014.

Please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Respectfully,

Bruce Falstead
Manager Aboriginal Initiatives

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

November 24, 2011

«Customer_Name»
«Mailing_Address_1» «Mailing_Address_2»
«Mailing_City» «Postal_Code»

Dear ____,

Re: Huntingdon Bypass Project

Further to our letter of February 7, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project and the preliminary archaeological work undertaken to date.

The Sto:lo Research and Resource Management Centre has now completed the Archaeological Overview Assessment and has provided feedback regarding the three route options that were under consideration. It has been concluded that the Huntingdon Bypass Project lies in an area close to known archaeological sites, and this information combined with the input received from affected parties, has led FEI to examine alternate options.

FEI still believes that an upgrade to the Huntingdon Control Station is necessary, however we are now examining options that would further minimize the impact to the land of private owners and the Sumas River.

We will get back to you once we have more news. In the meanwhile, please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Jennifa James, FEI's First Nations Project Coordinator, will be assisting with communications and can be reached at 604-592-7746.

Respectfully,

Bruce Falstead
First Nations Initiatives Manager

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

June 13, 2013

Councillors
Shxw'ow'hamel First Nation
58700A St Elmo Road
Hope, BC V0X 1L2

Dear Councillors,

Re: Huntingdon Bypass Project

Further to our letter of November 24, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project. The Huntingdon Station provides reliable gas service to more than 600,000 natural gas customer in the Lower Mainland, Squamish, Whistler, the Sunshine Coast and Vancouver Island. The Bypass project is designed to increase the reliability of the system and minimize the potential outage of Huntingdon Station in the event of equipment malfunction or system damage.

FortisBC has now chosen an option that will only have impact to the property of one private land owner and no impact to the Sumas River.

Before we proceed with any final decisions on this project, FortisBC requires approval from both the British Columbia Utilities Commission and the British Columbia Oil and Gas Commission. FortisBC will be requesting regulatory approval for the project in 2013. With approval to proceed, the expected in-service date of the reinforcement pipeline is 2014.

Please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Respectfully,

Bruce Falstead
Manager Aboriginal Initiatives

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

FORTIS BC

November 24, 2011

«Customer_Name»
«Mailing_Address_1» «Mailing_Address_2»
«Mailing_City» «Postal_Code»

Dear ____,

Re: Huntingdon Bypass Project

Further to our letter of February 7, 2011, as attached for your reference, we are writing to provide an update regarding the status of the proposed Huntingdon Bypass Project and the preliminary archaeological work undertaken to date.

The Sto:lo Research and Resource Management Centre has now completed the Archaeological Overview Assessment and has provided feedback regarding the three route options that were under consideration. It has been concluded that the Huntingdon Bypass Project lies in an area close to known archaeological sites, and this information combined with the input received from affected parties, has led FEI to examine alternate options.

FEI still believes that an upgrade to the Huntingdon Control Station is necessary, however we are now examining options that would further minimize the impact to the land of private owners and the Sumas River.

We will get back to you once we have more news. In the meanwhile, please feel free to contact me directly if you have any questions or would like any further information. I can be reached at my office at 604-592-7686 or on my cell phone at 604-785-8947. I am also available to discuss the Project in person.

Jennifa James, FEI's First Nations Project Coordinator, will be assisting with communications and can be reached at 604-592-7746.

Respectfully,

Bruce Falstead
First Nations Initiatives Manager

cc: Oil and Gas Commission
Attachment: FEI letter dated 07 February 2011

Appendix K

DRAFT ORDERS

British Columbia Utilities Commission

Order Number

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

DRAFT PROCEDURAL ORDER

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Application by FortisBC Energy Inc.
for a Certificate of Public Convenience and Necessity for the Huntingdon Station Bypass

BEFORE:

(Date)

WHEREAS:

A. On October 25, 2013, FortisBC Energy Inc. (FEI) applied (the Application) to the British Columbia Utilities Commission (the Commission), pursuant to sections 45 and 46 of the *Utilities Commission Act* (the Act), for a Certificate of Public Convenience and Necessity (CPCN) to construct a bypass pipeline around FEI's Huntingdon Flow and Pressure Control Station (the Station) as described in the Application (the Project);

B. The Project has two main components:
   1. Construction of a new Nominal Pipe Size (NPS) 36 (inch) transmission pressure bypass pipeline by conventional construction methods; and
   2. Installation of an in-line pressure control valve and four isolation valves to tie into the existing FEI NPS 30 and NPS 42 pipelines, and to tie into the existing pipeline of Westcoast Energy Inc., doing business as Spectra Energy Transmission, adjacent to the Huntingdon Station;

C. FEI proposes to start construction of the Project in May, 2015 and to have the Project in-service by October, 2015;

D. FEI has estimated the capital cost of Project to be approximately $8.0 million including Allowance for Funds Used During Construction (AFUDC);

E. FEI has recommended a written hearing process for the review of the Application and has proposed a regulatory timetable;

F. The Commission has determined that a written public hearing is appropriate for the review of this Application.

BRITISH COLUMBIA UTILITIES COMMISSION **ORDER NUMBER**

NOW THEREFORE the Commission orders as follows:

1. A written public hearing process is established for the review of the Application according to the Regulatory Timetable attached as Appendix A.

2. FEI will publish, as soon as possible, in display-ad format, the Notice attached as Appendix B to this Order, in the Vancouver Sun, the Province, and such other appropriate local news publications in the vicinity of the Station that will provide adequate notice to the public that may be affected by the Project.

3. The Application, together with any supporting materials, will be made available for inspection at the FortisBC Energy Utilities, 16705 Fraser Highway, Surrey, BC, V4N 0E8, and at the British Columbia Utilities Commission, Sixth Floor, 900 Howe Street, Vancouver, BC, V6Z 2N3 and will also be available on the FortisBC Energy Utilities website at www.fortisbc.com and on the BCUC website at www.bcuc.com.

4. Interveners or Interested Parties should register with the Commission, in writing or electronic submission, by Monday, December 9, 2013. Interveners should specifically state the nature of their interest in the Application and identify generally the nature of the issues that they may intend to pursue during the proceeding and the nature and extent of their anticipated involvement in the review process.

DATED at the City of Vancouver, In the Province of British Columbia, this day of <month> 2013.

BY ORDER

Attachment

Application by FortisBC Energy Inc.
for a Certificate of Public Convenience and Necessity for the Huntingdon Bypass Station

REGULATORY AGENDA AND TIMETABLE

ACTION	DATE (2013)
Commission Information Request No. 1	Thursday, November 28
Intervener and Interested Party Registration	Monday, December 9
Intervener Information Request No. 1	Monday, December 9
	DATE (2014)
FEI Response to Information Requests No. 1	Friday, January 10
FEI Written Final Submissions	Friday, January 17
Intervener Written Final Submissions	Friday, January 24
FEI Written Reply Submissions	Friday, January 31

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Application by FortisBC Energy Inc.
for a Certificate of Public Convenience and Necessity for the Huntingdon Station Bypass

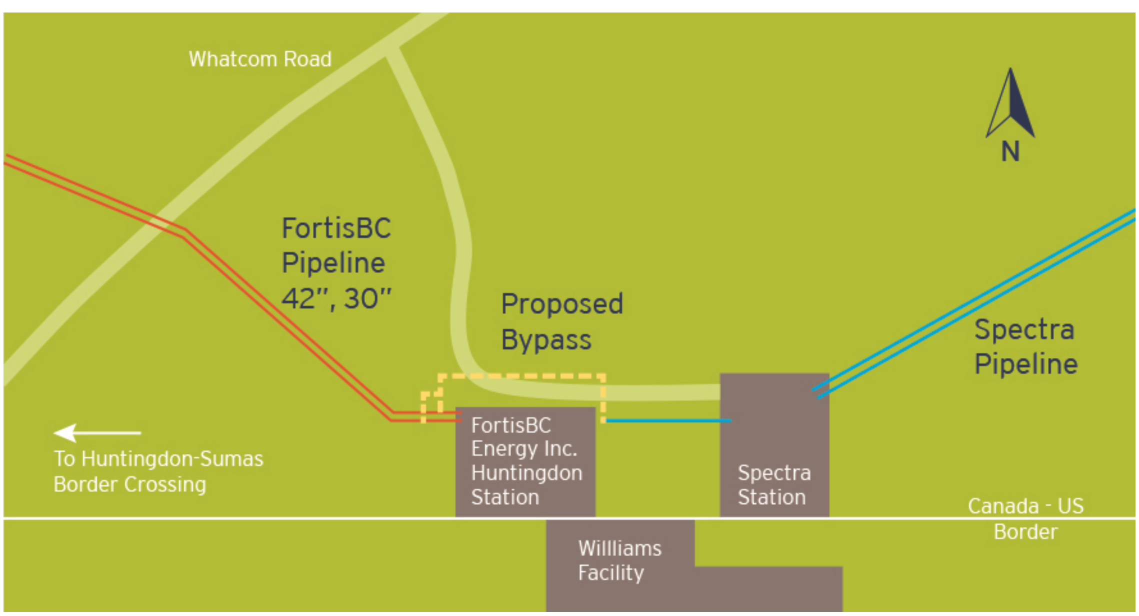
NOTICE OF APPLICATION

THE APPLICATION

On October 25, 2013, FortisBC Energy Inc. (FEI) applied to the British Columbia Utilities Commission (the Commission) for a Certificate of Public Convenience and Necessity (the Application) for the Huntingdon Station Bypass to provide an alternate gas supply for approximately 660,000 FEI customers residing in the Lower Mainland, Whistler, Squamish, the Sunshine Coast and Vancouver Island. The existing Huntingdon Station is located south of Abbotsford, B.C. approximately 3 km east of the Huntingdon, British Columbia and Sumas, Washington border crossing.

The proposed bypass will provide redundancy to the Huntingdon Station, remove the Huntingdon Station as a single point of failure on the system and reduce the risk of loss of natural gas supply to 600,000 customers downstream of the Huntingdon Station in the event of a Station shutdown.

In its Application, FEI considered several alternatives ranging from bypass piping within the existing Station to various bypass pipeline routes external to Huntingdon Station. The location of the bypass routes are shown on the map below.



THE REGULATORY PROCESS

Commission Order G-xx-13 established a Regulatory Timetable for the review of the Application by way of a Written Public Hearing.

The detailed Regulatory Timetable can be reviewed on the Commission's website at www.bcuc.com>Current Applications>Huntingdon Bypass CPCN.

REGISTERING TO PARTICIPATE

Persons who wish to actively participate in this proceeding should register as Interveners with the Commission in writing by Monday, December 9, 2013, and should identify the issues that they intend to pursue as well as the nature and extent of their anticipated involvement in the review process. Interveners will receive email notice of all correspondence and filed documents. An e-mail address should be provided if available.

Persons not expecting to actively participate, but who have an interest in the proceeding, should register as Interested Parties with the Commission in writing, by Monday, December 9, 2013 identifying their interest in the Application. Interested Parties will receive an Executive Summary of the Application and a copy of the Commission's Decision when issued.

PUBLIC INSPECTION OF DOCUMENTS

This Application and supporting material will be made available for inspection at the FortisBC Energy Utilities Office, 16705 Fraser Highway, Surrey, BC, V4N 0E8, and at the British Columbia Utilities Commission, Sixth Floor, 900 Howe Street, Vancouver, B.C., V6Z 2N3 and will also be available on the BCUC website at www.bcuc.com and the FortisBC Energy Utilities website at www.fortisbc.com.

All submissions and/or correspondence received from active participants or the general public relating to the Application will be placed on the public record and posted to the Commission's website.

FURTHER INFORMATION

For further information, please contact Ms. Erica Hamilton, Commission Secretary, by telephone (604) 660-4700 or B.C. Toll Free at 1-800-663-1385, by fax (604) 660-1102, or by Email Commission.Secretary@bcuc.com.

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

DRAFT ORDER

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Energy Inc.
For a Certificate of Public Convenience and Necessity for the Huntingdon Station Bypass

BEFORE:

(Date)

WHEREAS:

A. On October 25, 2013, FortisBC Energy Inc. (FEI) applied (the Application) to the British Columbia Utilities Commission (the Commission), pursuant to sections 45 and 46 of the *Utilities Commission Act* (the Act), for a Certificate of Public Convenience and Necessity (CPCN) to construct and operate a bypass pipeline around FEI's Huntingdon Flow and Pressure Control Station (the Station) as described in the Application (the Project);

B. FEI has also asked for Commission approval under sections 59-61 of the Act for

- deferral treatment of costs for preparing this CPCN Application and to amortize these costs over a three year period starting in 2015,

- deferral treatment of prefeasibility costs which will be recorded on a net-of-tax basis attracting AFUDC until December 31, 2015, and amortization of the prefeasibility costs over a three year period starting in 2016;

C. FEI has identified the Station as a single-point-failure facility and has proposed the Project to reduce risks resulting from potentially severe consequences of the single point of failure;

D. The Project as applied for consists of two main components:

1. Construction of a new Nominal Pipe Size (NPS) 36 (inch) transmission pressure bypass pipeline by conventional construction methods; and
2. Installation of an in-line pressure control valve and four isolation valves to tie into the existing FEI NPS 30 and NPS 42 pipelines, and to tie into the existing pipeline of Westcoast Energy Inc., doing business as Spectra Energy Transmission, adjacent to the Huntingdon Station;

E. FEI has estimated the capital cost of the Project to be approximately $8.0 million, including Allowance for Funds Used During Construction (AFUDC), and has proposed to start construction of the Project in May, 2015 and to have the Project in-service by October, 2015.

F. By Order G-XX-13 dated <date>, the Commission established a Written Public Hearing process for the review of the Application and a Regulatory Timetable;

G. The Written Public Hearing process concluded with the filing of FEI's Reply Submission in accordance with the established Regulatory Timetable;

H. The Commission has reviewed and considered the Application, the evidence and submissions and has determined that the Project is in the public interest and that a CPCN for the Project should be granted to FEI for the Project.

NOW THEREFORE pursuant to Sections 45 and 46 and 59-61 of the Utilities Commission Act, the Commission orders as follows:

1. A Certificate of Public Convenience and Necessity is granted to FEI for the entirety of the Project, as applied for in the Application.

2. FEI shall record the costs of preparing the Application in a deferral account and then amortize the costs over a three year period from 2015 through 2017, and the prefeasibility costs in a non-Rate Base deferral account (the Prefeasibility Deferral) on a net-of-tax basis which will attract AFUDC until December 31, 2015. On January 1, 2016, the Prefeasibility Deferral will be included in Rate Base and will be amortized over a three year period starting in 2016 through 2018.

3. FEI shall file with the Commission within 30 days of the end of each reporting period Quarterly Progress Reports on the Project using a format similar to that used in the Kootenay River Crossing Upgrade Project. The Quarterly Progress Reports will address in some detail the risks that the Project is experiencing, the options available to address the risks, the actions that FEI is taking to deal with the risks and the likely impact on the Project schedule and cost.

4. FEI shall file with the Commission a Final Report, within six months of the end or substantial completion of the Project, that provides a complete breakdown of the final costs of the Project, compares these costs to the cost estimate in the Application, and provides an explanation and justification of material cost variances.

DATED at the City of Vancouver, In the Province of British Columbia, this XX day of <MONTH>, 2014.

BY ORDER