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January 10, 2014

Via Email
Original via Mail

British Columbia Utilities Commission
Sixth Floor
900 Howe Street
Vancouver, B.C. 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)

Response to the British Columbia Utilities Commission (BCUC or the Commission) Information Request (IR) No. 1

On October 25, 2013, FEI filed the Application as referenced above. In accordance with Commission Order G-185-13 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (e-mail only): Registered Parties

A. PROJECT NEED, ALTERNATIVES AND JUSTIFICATION

1.0 Reference: A FURTHER RELIABILITY CONCERN

Exhibit B-1, Section 3.3, p. 12

Maintenance and Replacement of Single Point of Failure Components

In the Application FortisBC Energy Inc. (FEI) states:

"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." (Exhibit B-1, p. 12)

1.1 Please provide a Table of all the maintenance tasks which are recommended, usually by a Professional Engineer, to be performed on components at Huntingdon to ensure cost effective reliable operation. Please include the recommended frequency of the task and the expected duration of those tasks. Please separate the list between single point of failure components and non-single point of failure components and please include whether or not a temporary station outage is required to perform the task. An example of the table which is requested in response to the above question is provided in Table 1 below.

Table 1. Example of a Table Requested in Response to the Above Question

Component	Single Point of Failure	Task	Outage Required	Duration	Frequency
Valve X	Yes	Operate	Yes	1 hr	Quarterly
Pipe Z	No	Wall thickness	No	5 hr	4 years
Flange W	Yes	Visual	No	15 min	Monthly
…	…	….	…	…	…
…					
…					

Response:

The planned routine maintenance activities for the Huntingdon Station are being filed confidentially under separate cover with the Commission as the information relates to asset security and should not be publicly disclosed.

1.1.1 Please discuss if FEI or its predecessor companies have ever performed the maintenance tasks which require an outage, as identified by FEI in response to the above question.

Response:

To perform the planned routine maintenance at the Huntingdon Station as identified in the table provided in the response to BCUC IR 1.1.1, a temporary outage is not required; therefore, all of these tasks have been completed according to plan, as stated in the Application in Section 3.3. However, if unplanned corrective maintenance is deemed necessary on a component that is a single point of failure, a temporary outage may be required.

1.1.1.1 If so, please indicate which tasks were performed that required an outage and please explain how FEI or its predecessor companies did those tasks at that time. Please elaborate on the work that was performed, the time it took to do the work, the length of the outage required, the costs and the impacts to the customers, if any. Please include isolation schematics, piping and instrumentation diagrams (P&ID), valve identifications and procedures to aid in your explanation.

Response:

Please refer to the response to BCUC IR 1.1.1.1. All planned preventative maintenance is completed without an outage.

1.1.1.2 If FEI has not performed the maintenance tasks which require an outage before, please explain how FEI would perform those maintenance tasks, if they had to be performed. Again, please include isolation schematics, P&IDs, valve identifications and procedures to aid in explanation.

Response:

Routine valve preventative maintenance does not require a station outage and is completed in the planned preventative maintenance program. A major repair or replacement of a single point of failure valve (please refer to the Application, Figure 3-4, page 12) would involve isolating the section of pipe, bypassing the Huntingdon Station and completing the corrective work. The bypass procedure would be of similar scope as described in the response to BCUC IR 1.6.1.

1.1.2 Please discuss if, in the past, FEI or its predecessor companies have replaced single point of failure components at Huntingdon Station.

Response:

Several single point of failure components at the Huntingdon Station have been replaced since the initial installation. Some recent examples include:

- In 2013, FEI removed a power gas line located on the Station inlet header piping feeding the odorant injection system. This work was planned in conjunction with the Odorant Injection System capital upgrades. The inlet to the Huntingdon Station was bypassed and the CTS was fed through the Williams Import Line. The cost associated with the scope of work was under $100 thousand. There was no impact to supply to customers;
- In 2003, FEI (then BC Gas) upgraded the Huntingdon Station outlet piping and installed a pigging barrel for the 30 inch CTS pipeline. The station outlet piping and the 30 inch CTS pipeline were isolated from the system. The CTS was supported through the 42 inch pipeline and fed from the outlet header in Station #1 via a temporary hard bypass. The cost associated with the installation of the temporary bypass is unavailable. There was no impact to supply to customers; and
- In 1994, FEI (then BC Gas) replaced the Stations #1 and #2 outlet piping for capacity reasons. The outlet of Station #1 along with the single point of failure was isolated while the CTS was supported through the Station #2 outlet via a temporary hard bypass. The

cost associated with the installation of the temporary bypass is unavailable. There was no impact to supply to customers.

These single-point-of-failure components were removed in a planned, controlled and safe manner.

1.1.2.1 If so, please elaborate on how they did it, how long the replacement took, how much it cost and discuss the gas supply impacts to customers, if any.

Response:

Please refer to the response to BCUC IR 1.1.1.2.

1.1.3 Please describe the measures that would be taken and explain the maximum time that the natural gas supply to the Coastal Transmission System (CTS) and FortisBC Energy (Vancouver Island) Inc. FEVI could be maintained, if a planned outage was scheduled at Huntingdon Station during the lowest demand period.

Response:

Due to the lack of line pack available in the CTS even in the lowest demand period, FEI will not schedule a planned outage on a non-redundant critical component within the Huntingdon Station that cannot be completed, with a high level of confidence, within a period of 2 to 3 hours. For a brief outage the following measures would be considered in advance of the outage:

1. Ensure line pack in the CTS is increased to the maximum allowable 4017 kPa (583 psig) at Huntingdon outlet (requires Spectra to be supplying at a greater pressure and above their minimum contractual delivery pressure);
2. Negotiate/coordinate with firm large volume customers such as BC Hydro's Burrard Thermal generating facility and Island Co-generation Plant to be off line during the outage;
3. Interrupt large volume interruptible customers on the CTS;

4. Enable LNG sendout from the Tilbury LNG facility;
5. Reverse flow of FEVI linepack and Mt Hayes LNG sendout into the CTS via Eagle Mountain Reverse Flow Facility; and
6. Northward flow from Williams.

2.0 Reference: POTENTIAL CAUSES OF FAILURE AT THE HUNTINGDON STATION

Exhibit B-1, Section 3.4.1, p. 13

Corrosion, Sub-surface Piping

In the Application, FEI explains:

"A substantial amount of non-redundant piping within 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." (Exhibit B-1, p. 13)

2.1 Please identify the steel grade, the coatings and the corrosion protection used on the piping, flanges and valves that are single point of failure components at Huntingdon Station. Please explain how those materials, coatings and corrosion protection equipment could be expected to reduce the rate of corrosion of the single point of failure components.

Response:

The material information for the single point of failure components at the Huntingdon Station are found in a table being filed confidentially as it contains information relating to the location and size of certain single point of failure components at the Station.

The coating applied for a majority of the installation is coal tar enamel with a minimum applied thickness of 2.4mm. The cathodic protection system is an impressed current system that protects the station piping and both pipelines. The nearest anode bed is at Angus Campbell Road in Abbotsford.

In accordance with FEI's Integrity Management Program, the hazard of external corrosion for below-grade facility piping is managed through external coating application, cathodic protection, and condition monitoring digs where warranted. External coatings in conjunction with cathodic protection are considered by FEI as standard practice to mitigate this hazard for these assets. Cathodic protection is generally considered as the secondary measure, as external coatings may be damaged or degrade over time.

However, meeting a cathodic protection criterion does not necessarily establish that corrosion is not occurring at an unacceptable rate. Disbonded coatings, large rocks, or foreign structures are examples of situations where "CP shielding" can occur, preventing the CP current from reaching the pipeline and possibly resulting in corrosion. Despite mitigation measures implemented through FEI's Integrity Management Program to reduce the likelihood of failure due to hazards including external corrosion, FEI has assessed the potential consequences as being significant in the event that in-service repairs are not possible (e.g. loss of customer supply).

There is substantial risk by completing direct inspection on non-redundant sections of the piping. If the inspection discovers a piping defect, there are limited methods of maintaining gas supply without shutting down the entire station. Please also refer to the Application, page 22.

The Huntingdon Station bypass will enable FEI to conduct a direct inspection of sub-surface assets and maintain supply to customers in the event that a possible future repair cannot be performed in-service.

2.2 Please explain how material imperfections and weld flaws are mitigated from being threats to piping through the procurement, installation and maintenance processes. Please elaborate on the quality control, quality assurance, selection and testing activities that were performed on the single point of failure components at Huntingdon prior to their installation. For example, were ultrasonic, dye penetrate, magnetic particle or x-ray testing performed on the welds prior to installation and/or during commissioning? In addition, was hydrostatic pressure testing performed on the assembled components at Huntingdon Station during commissioning?

Response:

Material flaws are mitigated from being threats to piping integrity by the Company's Quality Control/Quality Assurance program in the procurement process. Piping and fittings are only accepted from qualified manufacturers and must be received with Material Test Reports (MTR) identifying the chemical and mechanical properties of the pipe. These MTRs need to be reviewed and approved by the Engineer of Record (EOR) prior to acceptance to inventory. An inspection of the pipe includes verification of pipe size, wall thickness, and coating and matching the MTR to the component.

Weld flaws are mitigated from being threats to piping through requiring joining processes, such as welding, and having an established welding procedure and welders that have been qualified to perform the procedure. Each weld conducted on a pipeline is non-destructively inspected by a qualified testing technologist. Radiographic testing or magnetic particle inspection are the two primary inspection techniques to ensure successful joining processes are conducted.

A strength and leak test, typically using water or air, is conducted on the piping network in place after construction but prior to commissioning, as required by CSA Z-662 Oil and Gas Pipeline

Systems. The strength test will expose any material or weld flaws and allow certainty that the piping system will be able to operate at the maximum operating pressure.

2.2.1 Please discuss what quality control, quality assurance, selection and testing activities will be performed on the proposed bypass, prior to installation.

Response:

As discussed in the response to BCUC IR 1.2.2, the quality control (QC), quality assurance (QA), selection and testing activities will meet FEI construction practices.

Similarly, QC/QA activities will include a review of the Material Test Reports (MTR) by the Engineer of Record to ensure that the chemical and mechanical properties meet the code requirements. An inspection of the material will be conducted prior to acceptance into inventory, including verification of pipe size, thickness (if applicable) and matching MTR to the component.

Qualified welding procedures will be specified for welding the pipe and components and only welders qualified to the procedures will be able to complete the welding process. Each weld conducted will be non-destructively inspected by a qualified testing technologist. Radiographic testing will be conducted on 100% of all butt-welds and 100% magnetic particle inspection on all fillet welds.

A strength and leak test will be conducted on the piping network in place after construction but prior to commissioning, as required by CSA Z-662 Oil and Gas Pipeline Systems. The entire fabricated assembly will be tested to a minimum hydrostatic pressure of 7125 kPa and a maximum hydrostatic pressure of 10,900 kPa for a period no less than one hour.

3.0 Reference: POTENTIAL CAUSES OF FAILURE AT THE HUNTINGDON STATION

Exhibit B-1, Section 3.4.1, p. 14

Natural Hazards

In the Application FEI states:

"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." (Exhibit B-1, p. 14)

3.1 Please discuss how having a bypass would improve the reliability of Huntingdon Station subject to failures resulting from a major seismic or flood event. Please elaborate on the differences between the proposed bypass and the existing station that provide the expectation that the bypass would survive a major seismic or flood event but the existing station would not.

<u>Response:</u>

The proposed bypass will reduce the risk and improve the reliability of the Huntingdon Station during major events (catastrophic, natural hazard).

The proposed bypass would be constructed to meet FEI's current design standards, which have evolved since the time that the Huntingdon Station was first constructed. Standards, regulations, and industry standard practices are continually being developed and improved within the pipeline industry and at FEI with the primary goal of improving safety and reliable performance. As an example, FEI has had an internal seismic design standard since 2004, which has been subject to periodic review and updating since that time. The proposed bypass would meet FEI's current design standards, which will allow the bypass' ability to survive or sustain lesser damage during natural hazard event. Although the design may not completely eliminate the seismic risk, it should allow FEI to continue the supply of natural gas to the CTS and FEVI systems.

Additionally, the bypass valves will be located above the flood level and allow for the operation, inspection and maintenance during a natural hazard event (flood). While certain components have already been adapted and relocated above the flood level in the existing station (i.e. regulators, compressed air building, odourant building), not all components are built to this new standard.

3.2 Please also elaborate on the conditions and materials used in Spectra Energy Transmission's (Spectra) facilities and pipelines that provide the expectation Spectra's facilities and pipelines would survive a major seismic or flood event but the existing FEI Huntingdon station would not.

Response:

FEI has no detailed knowledge of the design of Spectra's facilities and is therefore unable to comment on the details requested.

4.0 Reference: CONSEQUENCES OF FAILURE OF HUNDINGTON STATION

Exhibit B-1, Section 3.4.2, p. 16, Appendix A

Potential Business and Economic Losses

In the Application FEI states: "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." (Exhibit B-1, p. 16)

4.1 Please explain FEI's current risk mitigation strategy if there is a failure of a single point of failure component at Huntingdon Station.

Response:

If an emergency, such as a failure of a critical component or section of pipe occurs, FEI will endeavor to minimize injuries to employees and the public, impacts to customers and damage to the station. In the case of a complete shutdown of the Huntingdon Station, the following actions may be taken to minimize customer impacts:

- Survival on line pack;
- Lower Mainland industrial customer curtailment;
- LNG sendout from the Tilbury LNG facility;
- Reverse flow of FEVI linepack and Mt Hayes LNG sendout into the CTS via Eagle Mountain Reverse Flow Facility; and
- Northward flow from Williams.

However, these measures all have limitations as discussed on pages 14 and 15 of the Application.

FEI's proposed bypass will build redundancy, remove the facility as a single point of failure and significantly reduce the consequence of large-scale service disruption.

4.2 Please discuss the inventory of spare parts for the single point of failure and non-single point of failure components currently available at Huntingdon Station.

Response:

This response addresses both BCUC IRs 1.4.2 and 1.4.3. The spare supplies are available to address emergencies either during operation or construction.

FEI has emergency supplies stored in a Lower Mainland facility in the event of any pipeline or station incident on the FEI system. The emergency supplies and repair equipment include:

- Pre-tested pipe;
- Reinforcing sleeves;
- PLIDCO repair sleeves;
- Clock spring repair kits;
- Valves NPS 2 and below;
- Valve Sealant and Sealant Equipment for valves greater than NPS 2;
- Spare sealing components (i.e. o-rings) for equipment;
- Control Valve Actuator components such as drive knuckles and pilot parts; and
- Tubing, ball valves and miscellaneous fittings for control and power gas lines (NPS 1 and smaller).

4.3 Please elaborate on the spares strategy for the proposed bypass if it is put in service and elaborate on the spares strategy during the construction of the proposed bypass.

Response:

Please refer to the response to BCUC IR 1.4.2.

4.4 Please discuss the different risks, complexities and scales of operations of the gas and petroleum processing facilities in the Australian incident described in Appendix A, versus the risks, complexities and scales of operations of FEI's Huntingdon gas distribution control and metering station.

Response:

The case study (refer to the Application, Appendix A) was referenced in the Application for the purposes of demonstrating the potential consequences and impacts resulting from a large-scale service disruption from a vulnerable piece of infrastructure such as the Huntingdon Station (refer to the Application, page 16). Like the Huntington Station, the Australian facility, the Longford plant, was a single source of supply to a very large number of customers. However, FEI did not intend the case study as a detailed comparison between the Longford plant and the Huntingdon Station.

The $1 billion estimate is a very high level, order of magnitude estimate intended to reflect the potential economic losses resulting from a complete, prolonged, service disruption if the Huntingdon Station is shutdown due to a lack of redundancy. The Company did not prepare a detailed estimate.

4.5 Please elaborate on the upper and lower bounds of the accuracy range of FEI's proposed $1 billion estimate.

Response:

Please refer to the response to BCUC IR 1.4.4.

4.6 Please elaborate on the assumptions used in the above $1 billion economic loss estimate.

Response:

Please refer to the response to BCUC IR1.4.4.

4.6.1 Please confirm, or otherwise explain, if the station is assumed to have failed based on a greater than four inch rupture of a single point of failure component with ignition which causes the complete destruction of Huntingdon Station.

Response:

Not confirmed. Please refer to the response to BCUC IR 1.4.4 for an explanation for the $1 billion estimate.

The $1 billion high-level estimation is not confined to a particular scenario. Rather, it considers a scenario which results in a prolonged shutdown of the station. Depending on the nature, location, and time of the failure, the repair or replacement time will vary. The scenario described in this IR is an example of a very serious event which would result in the shutdown of the station for weeks to complete the necessary repairs. The efforts to restore customer service following a prolonged shutdown will take approximately 4 months.

4.6.1.1 Please discuss the probability that this failure would occur based on the age, design, maintenance and operations of FEI's Huntingdon Station.

Response:

Please refer to the response to BCUC IR 1.4.4.

FEI wants to stress with both internal station upgrades and external bypass as proposed, the risk is reduced but not completely eliminated.

5.0 Reference: RISK ASSESSMENTS BY THIRD PARTIES

Exhibit B-1, Section 3.4.3, p. 17

Social and Environmental Factors

In the Application, FEI states: "For CoF, equal weightings of social, environmental and financial factors were used." (Exhibit B-1, p. 17)

5.1 Please discuss how changes to the social, environment and financial factor weightings would result in different Business Risk Exposure (BRE) rankings. Please provide a sensitivity analysis of the BRE rankings by changing the weightings for each of social, environmental and financial factors, each from 0 to 100 percent.

<u>Response:</u>

The statement in Exhibit B-1, Section 3.4.3, page 17 and quoted above in the preamble is related to Appendix B, GHD Consulting "Terasen Transmission Phase 1 Risk Assessment Report".

The GHD Phase 1 Risk Assessment Report was a one-time screening study to identify areas of potential higher business risk which warranted further detailed assessment. This study acknowledged the potential for refinement and further assessment. Subsequent to the GHD assessment, FEI engaged Dynamic Risk Assessment Systems (DRAS) to conduct three quantitative risk assessments. FEI considers DRAS work to present more relevant and useful information due to its application of more refined risk assessment methods. FEI is thus not planning further updates to the GHD Phase 1 Risk Assessment Report at this time and the Company does not believe there is value in performing the requested analysis. FEI also believes that further discussion and information requests (if required) regarding risk assessment of the Huntingdon Station and proposed bypass should focus on the DRAS's analysis presented as Confidential Appendices C1, C2 and C3 to the Application.

6.0 Reference: OPTIONS ANALYSIS

Exhibit B-1, Section 4.1, p. 20

Constructability

In the Application FEI states: "The option should also consider constructability, operations and safety factors, such as limiting interruption of flow of gas during construction…" (Exhibit B-1, p. 20)

6.1 Please explain the procedure for how FEI will connect the new bypass to the existing system and what, if any, impacts these connection activities will have to the supply of natural gas to CTS and FEVI customers. Please include details regarding uncovering pipe, cutting pipe, possible gas supply interruption times and/or the curtailments required to complete the tie-ins, if applicable. Please also discuss the risks associated with tie-in activities and how FEI will mitigate these risks.

Response:

A gas work procedure will be required to ensure that the work to connect the new bypass to the existing system is performed safely and that gas supply will be maintained. The following is a draft, high level, gas tie-in procedure for the bypass:

1. Utilize Williams gas supply through FEI's NPS 24 Import valve for temporary gas supply. Please note that a similar procedure was used in 2013 as part of the Huntingdon odourant replacement project;
2. Hydro-vacuum tie-in excavation areas, slope and/or shore up appropriately;
3. Shut-in NPS 36 Spectra supply pipeline and FEI inlet to Station 1, Station 2 and Export line;
4. Blow down shut-in segment, monitor and exhaust as required;
5. Cut out section of NPS 36 Spectra supply pipeline;
6. Install and tie-in new NPS 36 section with valves;
7. Radiograph and magnetic particle test new welds, soap test tie-in welds;
8. Complete fittings, purge and gasify shut-in pipeline; and
9. Return to normal operating conditions.

Customer interruption or curtailments are not anticipated as tie-in activities are presently scheduled to occur during the lower demand summer season. The gas procedure will be finalized prior to the installation of the bypass.

The risks associated with the procedure are safety and customer service interruption. These risks will be mitigated through the planning process and review of the operational procedure when contingency plans are developed in the period leading up to the finalization and implementation of the gas procedure.

7.0 Reference: OPTIONS DESCRIPTION AND NON-FINANCIAL CONSIDERATIONS

Exhibit B-1, Section 4.2, pp. 20-26; Section 4.3.2, pp. 28-29; Appendix J6

First Nations Input on Alternatives

In its February 7, 2011 letter to various First Nations (provided in Appendix J6), FEI (then Terasen Gas) wrote:

"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… 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." (Exhibit B-1, Appendix J6)

7.1 Please confirm, or explain otherwise, that the only description of the Project Options FEI provided to First Nations was the above letter with the statements that "Terasen is currently assessing several route options for the bypass pipeline" and "All of the route options will likely require a new crossing of the Sumas River and a new Right-of-Way on Crown Land".

<u>Response:</u>

As explained in the Application, FEI (then Terasen Gas) provided information to First Nations in February 2011, outlining FEI's plan for a bypass at that time, which included longer, larger bypass options (refer to the response to BCUC Confidential IR 1.6.1). The statements quoted in the question above and contained in the February 2011 letters thus reflected FEI's then plan.

In November 2011, FEI provided a further Project update to First Nations. In the November letter, FEI stated that it was "examining options that would further minimize the impact of the land of private owners and the Sumas River." In June of 2013, FEI informed First Nations that FEI "has now chosen an option that will only impact to the property of one private land owner and no impact to the Sumas River."

7.1.1 If confirmed, please explain why FEI did not provide more detailed information on the Project Options to First Nations.

Response:

Please refer to the response to BCUC IR 1.7.1 in regard to FEI's efforts to provide updated information to First Nations on potential pipeline alignment options. Please refer to the response to BCUC IR 1.14.1 for updated engagement and information provision activities with First Nations.

7.2 Did FEI request input or feedback from any First Nations on the Project Options? If so, please provide evidence to the fact. If not, why not?

Response:

Please refer to the response to BCUC IR 1.7.1 for the discussions of letters provided to the First Nations. Please also refer to the response to BCUC IR 1.14.1 for information provision and engagement activities with First Nations.

7.3 Please confirm, or explain otherwise, that FEI did not receive any input from First Nations on any of the Project Alternatives considered.

Response:

Please refer to the response to BCUC IR 1.14.1 for updated FEI's activities with respect to providing Project information to and engagement of First Nations. No First Nations contacted by FEI to date have expressed any issues with respect to the pipeline alignments.

7.4 In FEI's view, would the degree of potential impact to First Nations differ between Option 3 and 4? If yes, please explain how the impacts to First Nations would differ between the two options. If not, please explain why not.

Response:

FEI believes there is no impact to First Nations for either Option 3 or Option 4 because the work will take place on private land, not crown land.

8.0 Reference: OPTIONS DESCRIPTION

Exhibit B-1, Section 4.2.2, p. 22

Recoating and Inline Inspection of Piping

In the Application FEI states:

"A full evaluation and inspection of the existing facility piping could be conducted…the sub-surface piping…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 too.

However, there is a substantial risk by completing this activity on the non-redundant sections of the piping. If the inspection…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 by pass to complete the work. Costs would be incurred to develop and execute contingency plans to build the temporary bypass." (Exhibit B-1, p. 22)

8.1 Please explain how a temporary bypass could be constructed to allow for recoating and repair of the defect of the buried sections of pipe. Please provide a detailed cost estimate to construct the temporary bypass, a detailed cost estimate to inspect the buried single point of failure pipe and a detailed cost estimate to recoat and repair the buried single point of failure pipe. Please elaborate on what age/condition one would normally expect to take these actions to refurbish a buried pipeline such as the single point of failure pipeline.

Response:

Depending on the section of piping that would require isolation, there are a variety of methods to recoat or repair the buried sections of pipe, including installation of a temporary bypass. For example, to complete inspection, repair and recoating of the Huntingdon Station inlet piping, please refer to the response to BCUC IR 1.6.1.

To isolate the outlet piping of the Huntingdon Station will require a hard bypass to be installed from the outlet of either Station #1 or Station #2 into one of the CTS pipelines (30 inch or 42 inch). This would require fabricating and testing a large, above grade temporary pipeline to maintain gas flow to the CTS during the inspection and repair activities.

A detailed cost estimate to complete the bypass work, the excavation, inspection, repair and recoating can be found in Attachment 8.1.

To enable accurate pipeline assessment during condition monitoring digs of below-grade piping, it is standard practice to remove the existing coating of excavated pipe, necessitating re-coating.

Any pipe imperfections that may be found are evaluated against defect criteria established by CSA Z662-11 Clause 10.10 "Permanent Repair Methods" to determine the need for and method of repair. Repair criteria is condition-based (i.e. not based on age), and varies depending on the type of imperfection. As an example, corrosion greater than 80% of wall thickness is considered a defect irrespective of the dimensions. Corrosion greater than 10% and up to 80% of wall thickness is subject to an assessment to determine if the estimated failure pressure has sufficient factor of safety.

8.2 Please confirm, or otherwise discuss, that FEI has not provided provision for launching inline inspection tools in the emergency bypass. Please discuss the maintenance and operations consequences of that decision and please explain how the emergency bypass will be inspected, considering there is no provision for launching inline inspection tools.

Response:

Confirmed. The permanent emergency bypass at the Huntingdon Station will not have provisions for launching in-line inspection tools. The Company's practice is that facilities such as stations are not designed for in-line inspection capability because the required components and piping sections are not physically capable of passing an in-line inspection tool (i.e. elbows, reducer, tees, certain types of valves). FEI considers the Huntingdon Station Bypass as facility piping, and the hazard of external corrosion will be managed in accordance with the relevant Integrity Management Program activities. These typically include valve maintenance, leak survey, cathodic protection, instrumentation and vegetation management (refer to the response to BCUC Confidential IR 1.2.2). The bypass will be inspected by direct inspection, which means buried sections of piping will be exposed prior to inspection.

8.3 Please confirm, or otherwise explain, that the proposed bypass pipeline external to the Huntingdon Station is to be a permanent emergency bypass, and that the existing station will continue to be the main source of supply to the FEVI and CTS systems.

Response:

Confirmed. The Huntingdon Station Bypass will continue to be the main source of supply to the CTS and FEVI systems. The proposed bypass will be permanent and will be utilized for emergency operations and planned maintenance activities of components where a station shut-down is required.

Please also refer to the response to BCUC Confidential IR 1.7.3.

9.0 Reference: OPTIONS EVALUATION

Exhibit B-1, Section 4.3.1, Tables 4-1 and 4-2

Financial Comparison

9.1 Please provide a breakdown and description of the Total Direct Capital Cost of $6.3 million for Option 3. Please include these amounts in a fully functioning excel spreadsheet.

Response:

Please refer to the response to BCUC Confidential IR 1.11.2.

9.2 Please provide a breakdown and description of the $13 thousand Gross O&M for Option 3 and the $14 thousand Gross O&M for Option 4.

Response:

Information regarding the breakdown and description of the Gross O&M activities for Option 3 and Option 4 are presented in the tables below:

Option 3 - Internal Station Upgrades						
Additional O&M Breakdown	Frequency	Resource	Duration (days)	Quantity (ea)	Rate ($/day)	Total
Block Valve Maintenace	yearly	Operaitons	0.50	4	1200	2400
Actuator Maintenance	yearly	Operations	1.00	8	1200	9600
Cathodic Survey	yearly	Corrosion Control	1.00	1	1200	1200
					Total	$ 13,200.00

Option 4 - External Bypass Pipeline						
Additional O&M Breakdown	Frequency	Resource	Duration (days)	Quantity (ea)	Rate ($/day)	Total
Control Valve Mantenance	yearly	Operations	1.00	2	1200	2400
Block Valve Maintenace	yearly	Operations	0.50	4	1200	2400
Actuator Maintenance	yearly	Operations	1.00	4	1200	4800
Odorant Injection Maintenance	yearly	Operations	0.25	1	1200	300
Cathodic Survey	yearly	Corrosion Control	2.00	1	1200	2400
Right of Way Survey	yearly	Operations	0.50	1	1200	600
Right of Way Clearing	yearly	Operations	1.00	1	1200	1200
					Total	$14,100.00

9.3 Please provide the following information for Option 3 in a fully functional excel spreadsheet which includes the detailed calculations:

- 25-Year Levelized Rate Impact
- 60-Year Levelized Rate Impact
- PV Incremental Cost of Service – 25 Year
- PV Incremental Cost of Service – 60 Year

Please ensure that the amounts agree to the amounts provided in Table 4-1.

Response:

The fully functional excel spreadsheets are provided confidentially in CONFIDENTIAL Attachment 9.3, as they contain detailed cost information that must be kept confidential at this time in order to preserve FEI's ability to negotiate.

CONFIDENTIAL Attachment 9.3a contains the detail requested for the 25 Year present value of the incremental cost of service and levelized rate. CONFIDENTIAL Attachment 9.3b contains the same detail for the 60 year forecast.

Refer to CONFIDENTIAL Attachment 9.3 tabs entitled 'Levelized Rate Calculation', the Present Value of the Incremental Cost of Service is in cell D31 and the Levelized Rate Impact is in cell D61.

9.4 Please provide the calculations and detailed breakdown of the estimates for the figures shown in Table 4-2. Please include the calculations in the form of a fully functional excel spreadsheet.

Response:

Please refer to the Attachment 9.4.

9.5 Please provide the accuracy range for the estimates provided in Tables 4-1 and 4-2. Please provide a sensitivity analysis of the PV Operational Risk + PV Incremental Cost of service 25 Year by varying the PV Operational Risk 25 Year from the lower to the upper bound.

Response:

The accuracy range for Table 4-1 is provided in the following table.

Table 4-1 Upper & Lower Bound Range	Option 3 – Internal Station Upgrades		Option 4 – External Bypass Pipeline	
Estimate Accuracy	Class 4 (+50%/-30%)		Class 3 (+30%/-20%)	
	Upper Bound	Lower Bound	Upper Bound	Lower Bound
Total Direct Capital Costs excluding AFUDC 2013$	9.4	4.4	8.9	5.5
Gross O&M (2013$ / year)	18.8	8.8	18.3	11.3
Levelized Rate Impact $ / GJ – 25 Yr.	$0.006	$0.003	$0.006	$0.004
Levelized Rate Impact $ / GJ – 60 Yr.	$0.005	$0.003	$0.008	$0.005
PV Incremental Cost of Service – 25 Yr.	$11.4	$5.6	$12.3	$7.8
PV Incremental Cost of Service – 60 Yr.	$13.4	$6.5	$15.5	$9.8

There is no range available for Table 4-2 because the Impact Cost values contained in the Application, Appendix C1, Tables 1, 2 and 3 were nominal best-estimates that were derived on the basis of case histories, knowledge of system operating configuration, operating experience, and subject matter expert judgment. This approach is typical when deriving estimates of impacts for events that lack a large statistically-significant incident database to draw upon. Please also refer to the response to BCUC Confidential IR 1.5.2.

B. CONSULTATION

10.0 Reference: PUBLIC CONSULTATION

Exhibit B-1, Section 8.3, p. 46

Landowner Engagement

On page 46 of the Application FEI states:

"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." (Exhibit B-1, p. 46)

10.1 Please confirm, or otherwise explain, that the November 16, 2012 letter was the only written communication FEI has had with the two farmers whose land is adjacent to the proposed bypass. If not confirmed, please provide dates of any follow-up letters sent to either or both farmers. If confirmed, please explain why FEI has not followed-up with the farmers since November 16, 2012.

Response:

Not confirmed. FEI followed up with both farmers after November 16, 2012. Both were contacted to arrange for meetings. The meetings took place with the farmers on October 30, 2013 and December 10, 2013.

10.1.1 To date, has FEI met or spoken with either of the two farmers to discuss the acquisition of Right-of-Way (ROW) on their properties? If so, please provide the dates and a summary of the conversation. If not, please specify when FEI plans to meet with the farmers.

Response:

Yes, FEI met with each of the farmers. The Company met with the first farmer on October 30, 2013 and the other farmer on December 10, 2013. Both farmers understand the necessity of the infrastructure and are willing to work with the Company.

Please also refer to the response to BCUC IR 1.21.3.

11.0 Reference: FIRST NATION CONSULTATION

Exhibit B-1, Section 9, pp. 49-50

Identification of Potentially Affected First Nations

On page 49 of the Application FEI states:

"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…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." (Exhibit B-1, p. 49)

Also on page 49 FEI states:

"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."

"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"

"The original Statement of Intent Map was submitted in 1995 with twenty-one Sto:lo First Nations" (Exhibit B-1, p. 49)

On page 50 FEI states:

"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 <u>the closest unaffiliated Sto:lo First Nation</u>." [emphasis added] (Exhibit B-1, p. 50)

11.1 Please provide the asserted traditional territory maps for each of the 4 Sto:lo First Nations (Matsqui, Shxwha:y Village, Squiala, and Sumas) who are represented by the Sto:lo Nation Tribal Council but are presently not participating in the Treaty process. Please explain how and where FEI obtained their asserted traditional territory maps or otherwise identified their traditional territory.

Response:

Asserted traditional territory maps are not available to FEI for Matsqui, Shxwha:y Village, Squiala, and Sumas. Only a collective map of asserted Sto:lo territory is available and is located on the BC Treaty Commission website at: http://www.bctreaty.net/nations/stolo.php.

11.2 Besides Kwikwetlem, please list all Sto:lo bands that are unaffiliated with either tribal council. Please explain why FEI has not identified these unaffiliated Sto:lo bands as groups that may have interests affected by the proposed project. Please provide maps of these unaffiliated Sto:lo bands asserted traditional territories. Please indicate where FEI obtained these maps.

Response:

The Sto:lo bands that are unaffiliated with either Sto:lo First Nation or Sto:lo Nation Tribal Council are as follows:

- Skwah First Nation
- Qayqayt First Nation
- Kwikwetlem First Nation
- Union Bar First Nation
- Peters Band
- Katzie First Nation

FEI did not contact these bands because of their location and lack of evidence that they had interest in the area. Asserted traditional territory maps are not available to FEI for these bands.

12.0 Reference: FIRST NATION CONSULTATION

Exhibit B-1, Section 7, p. 41; Appendix E; Appendix G, pp. i, 4, 11 and 12

Potential Environmental Impacts

On page 41 of the Application FEI states:

"The [preliminary environmental] 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." (Exhibit B-1, p. 41)

Page i of Appendix G states:

"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." (Exhibit B-1, Appendix G, p. i)

Page 4 of Appendix G indicates that several fish species, including Coho Salmon, are present in an agricultural ditch within the study area.

Page 11 of Appendix G states:

"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.” (Exhibit B-1, Appendix G, p. 11)

In Table 5 on page 12 of Appendix G, for certain construction activities, namely pipeline trench excavation, pipeline installation and backfilling trench, the potential effect on surface water and fish and fish habitat was evaluated as “High Magnitude”.

The Risk Analysis Calculation table in Appendix E indicates that probability and consequence are scored on a 5 point scale, with 1 as the lowest score and 5 as the highest. FEI gives “contaminated groundwater” a probability score of 2 and a consequence score of 5.

12.1 Please explain how FEI determined that the probability of “contaminated groundwater” is 2 out of 5.

Response:

The probability of encountering contaminated groundwater was determined based on the consensus of the attendees of a risk analysis workshop that included personnel from FEI’s Environment and Operations departments who are familiar with the site.

12.2 Were any First Nations notified in advance of Hemmera’s “initial field study” or invited to participate in the field study? If so, please identify which First Nations were notified, and any First Nations that participated in the field study. If not, why not?

Response:

No. Since the proposed Project will be confined to private land, First Nations were not notified in advance of Hemmera’s initial field study, or invited to participate in the field study.

12.3 Please confirm, or explain otherwise, that there was no First Nations input into the potential Mitigation Measures described in Section 6.0 of the Preliminary Environmental Assessment provided in Appendix G.

Response:

Confirmed based on FEI's understanding. As indicated in Appendix G, the report is based on a desktop review and site visit, and further discussions will be required. (See executive summary of Appendix G).

12.4 Does FEI intend to require the successful contractor to seek First Nations input on the development of the Environmental Management Plan (EMP)? Why or why not?

Response:

FEI does not intend to require the successful contractor to seek First Nations input on the development of the Environmental Management Plan as the Project as proposed will be confined to private land. However, the Sto:lo Research and Resource Management Centre (SRRMC) will provide input to the archeological protection measures as discussed in section 7.2 of the Application. The SRRMC is a professional service centre with an understanding of, and respect for, Stó:lō First Nation protocols.

13.0 Reference: FIRST NATION CONSULTATION

Exhibit B-1, Section 7, pp. 42-43; Appendix E

Archaeology

On page 42 of the Application FEI states:

"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 and to determine the requirements for an Archaeological Impact Assessment (AIA) prior to ground disturbing activities." (Exhibit B-1, p. 42)

On page 43 FEI states:

"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…

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…

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." (Exhibit B-1, p. 43)

The Risk Analysis Calculation table in Appendix E indicates that probability and consequence are scored on a 5 point scale, with 1 as the lowest score and 5 as the highest. FEI gives "archaeology-chance, find" a probability score of 2, and a consequence score of 2.

13.1 Please explain how FEI determined that the probability of "archaeology-chance, find" is 2 out of 5.

Response:

The probability of encountering a chance archaeological find was determined based on the consensus of the attendees of a risk analysis workshop that included personnel from FEI's Environment department who are familiar with the Archaeological Overview Assessment.

13.2 Does FEI intend to engage SRRMC to conduct the detailed AIA? If not, why not and will First Nations still have opportunity to participate in the development of the detailed AIA?

Response:

Confirmed. FEI intends to engage SRRMC to conduct the detailed AIA.

14.0 Reference: FIRST NATION CONSULTATION

Exhibit B-1, Section 9.4, pp. 50-52; Appendix J1, p. 86; Appendix J4 Consultation Log

On page 48 of the Application it states: "The evidence of First Nation engagement is current to August 30, 2013." (Exhibit B-1, p. 48)

Page 86 of Appendix J1 to the Application states:

"The [Oil and Gas] 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." (Exhibit B-1, Appendix J1)

FEI provides its First Nations Communications Log in Appendix J4. For Sto:lo Nation Tribal Council and Sto:lo Tribal Council the last entries are for 3 May 2011.

14.1 Please provide an updated Communication/Consultation Log that includes any correspondence with Sto:lo Nation Tribal Council and Sto:lo Tribal Council in 2012 and 2013.

Response:

The requested information is included in Attachment 14.1.

14.1.1 Please include all correspondence with SRRMC in the Log, under a separate heading from Sto:lo Nation Tribal Council and Sto:lo Tribal Council.

Response:

Please refer to Attachment 14.1 provided in response to BCUC IR 1.14.1. All correspondence with SRRMC is under a separate heading. The correspondence with SRRMC included in the log is in relation to communication and relationship building between FEI and SRRMC.

14.1.2 Please include any and all correspondence with First Nations not represented by either Sto:lo Nation Tribal Council and Sto:lo Tribal Council in the log, under a separate heading for each First Nation.

Response:

Please refer to Attachment 14.1 provided in response to BCUC IR 1.14.1.

14.1.3 Please ensure that all correspondence from FEI to First Nations filed in Appendix J6, including letters dated November 24, 2011 and June 13, 2013, are documented in the Log.

Response:

Please refer to Attachment 14.1 provided in the response to BCUC IR 1.14.1.

14.1.4 Please ensure all correspondence from any First Nation to FEI filed in Appendix J6, including the letter/invoice from Sto:lo Tribal Council dated April 1, 2011, is documented in the Log.

Response:

Please refer to Attachment 14.1 provided in the response to BCUC IR 1.14.1.

14.2 Please explain why FEI's Communications Log is not in the same format as that dictated on pages 86 to 87 of the OGC's Pipeline Permit Application Manual.

Response:

FEI has chosen a format that it has used for previous CPCN projects filed with the Commission. The log encompasses much of the same information dictated in the format outlined on pages 86 to 87 of the OGC's Pipeline Permit Application Manual.

14.3 Please clarify why the August 7, 2013 phone calls between FEI and the Matsqui Referrals Coordinator and the Skawahlook Referrals Coordinator, and the August 9, 2013 email from FEI to People of the River Referrals Office at Sto:lo Nation are listed in the Communications Log under Kwikwetlem First Nation. Should these be listed under Sto:lo Nation Tribal Council? If so, please correct the Log accordingly.

Response:

Please refer to Attachment 14.1 provided in the response to BCUC IR 1.14.1, for updated information.

14.4 Did FEI notify any First Nations when it filed its CPCN Application to the Commission? If yes, did FEI also inform any First Nations that they may participate as interveners in the proceeding? If not, why not?

Response:

In compliance with Order G-185-13 (Order), FEI mailed a copy of Order G-185-13 to the following First Nations on November 28, 2013:

- Sto:lo Nation Lands
- Aitchelitz Band
- Leq’a:mel First Nation
- Matsqui
- Popkum
- Shxwha:y Village
- Skawahlook First Nation
- Skowkale
- Squiala First Nation
- Sumas First Nation
- Tzeachten
- Yakweakwioose
- Sto:lo Tribal Council
- Chawathil

- Cheam
- Kwantlen First Nation
- Kwaw-kwaw-Apilt
- Skowlitz
- Seabird Island
- Shxw'ow'hamel First Nation

Due to an oversight, Kwikwetlem and Soowahlie First Nations were omitted from the November 28, 2013 mailing. A copy of the Order was mailed to them on January 9, 2014. With the mailing on November 28, 2013 and January 9, 2014, the Order was provided to the same First Nations that received the project information initially in February 2011.

When mailing the Order to the First Nations, FEI did not specifically inform the First Nations that they can register as interveners in the BCUC proceedings as this has not been the Company's practice. However, the Company has provided the First Nations with contact information and invited input to the Project, and has been in contact with the First Nations. To date, no First Nation has expressed any concerns with the Project. Usually, if the First Nation has expressed an interest or a concern in a project, FEI would set up a meeting to discuss the project, which would involve a discussion of the entire process, including the opportunity to become an intervener in the BCUC proceedings. In this Project, if the OGC in its consultation process identifies any First Nation that will need to be consulted, FEI will have further discussions with these identified First Nations and will update the First Nations of the BCUC proceedings.

Moreover, the Order provides websites to obtain further information if desired.

14.5 Please confirm that FEI has provided a copy of Order G-185-13 to all affected local First Nations communities, including those outlined in Appendices J4, J5 and J6 of the Application.

Response:

Please refer to the response to BCUC IR 1.14.4.

15.0 Reference: FIRST NATION CONSULTATION

Exhibit B-1, Section 9.4, p. 51; Appendix J4

Consultation with Sto:lo Nation Tribal Council

On page 51 of the Application FEI states:

"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…. 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" (Exhibit B-1, p. 51)

The First Nations Communications Log filed as Appendix J4 states that on February 23, 2011 FEI received a voicemail from the Assistant Lands Coordinator of Skawahlook First Nation indicating that Skawahlook First Nation "has no issues regarding the project".

15.1 Did FEI make any effort to follow up with the Sto:lo Nation Tribal Council between February 7, 2011 and June 13, 2013 to determine whether Sto:lo Nation Tribal Council or any of its member nations had any questions and concerns with respect to the Project? If yes, please describe these efforts. If not, why not?

Response:

FEI attended meetings between February 7, 2011 and June 13, 2013 with Sto:lo Nation Tribal Council members to discuss the Project. Meetings took place on February 28th, March 21st and May 3rd. 2011. For details on these meetings, please refer to Attachment 14.1, provided in response to BCUC IR 1.14.1.

15.2 Has FEI made any efforts to follow up with Sto:lo Nation Tribal Council or any of its member nations since its June 13, 2013 letter? If yes, please describe these efforts. If not, why not.

Response:

FEI has not followed-up with Sto:lo Nation Tribal Council regarding the Project since June 13, 2013, as the Company considered the communications to date were adequate in light of the scope of the proposed bypass.

As indicated in the Application, FEI will continue its engagement with First Nations as the Project progresses, including during the regulatory process when appropriate.

15.3 Please confirm, or explain otherwise, that the Skawahlook First Nation is the only Sto:lo Nation Tribal Council First Nation that expressly indicated that it had no issues with respect to the project or FEI's consultation to date.

Response:

Confirmed. Skawahlook referred FEI to the People of the Rivers Referrals office for future referrals to their nation.

16.0 Reference: FIRST NATION CONSULTATION

Exhibit B-1, Section 9.4, pp. 51-52; Appendix J4

Consultation with Sto:lo Tribal Council

On page 51 of the Application FEI states:

"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." (Exhibit B-1, p. 51)

On page 52 FEI states:

"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….

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." (Exhibit B-1, p. 52)

The First Nations Communications Log filed as Appendix J4 states that in an April 13, 2011 email from FEI to Sto:lo Tribal Council FEI requested a "meeting with Sto:lo Tribal Council and Sumas First Nation to provide greater understanding of the Project and identify and address questions/concerns." In a May 3, 2011 meeting between FEI and Sto:lo Tribal Council the "Sto:lo Tribal Council confirms they will be meeting with the Sumas First Nation in the near future to discuss the Huntingdon Bypass Project."

16.1 Did FEI make any effort to follow up with the Sto:lo Tribal Council between February 22, 2011 and June 13, 2013 to determine whether Sto:lo Tribal Council or any of its member nations had any questions and concerns with respect to the Project? If yes, please describe these efforts. If not, why not?

Response:

Please refer to Attachment 14.1 provided in the response to BCUC IR 1.14.1 for the updated consultation log.

16.2 Has FEI made any efforts to follow up with Sto:lo Tribal Council or any of its member nations since its June 13, 2013 letter? If yes, please describe these efforts. If not, why not?

Response:

Please refer to Attachment 14.1 provided in the response to BCUC IR 1.14.1 for the updated consultation log.

16.3 To FEI's knowledge has Sto:lo Tribal Council had a meeting with Sumas First Nation to discuss the Huntingdon Bypass Project?

Response:

FEI is not aware whether or not Sto:lo Tribal Council held a meeting with Sumas First Nation to discuss the Huntingdon Bypass Project. The People of the River Referrals office, an office within the Sto:lo Research and Resource Management Centre, is now responsible for referrals for Sumas First Nation.

16.3.1 To date, has FEI been able to meet or speak by phone with Sumas First Nation to discuss the Huntingdon Bypass Project? If so, please summarize the communication. If not, why not?

Response:

Please refer to Attachment 14.1 provided in response to BCUC IR 1.14.1 for the updated consultation log, specifically under the "Sto:lo Tribal Council" section, between March 22, 2011 and May 3, 2011.

17.0 Reference: FIRST NATION CONSULTATION

Exhibit B-1, Section 9.4, p. 52; Appendix J4

Consultation with Kwikwetlem First Nation

On page 52 FEI states:

"The Kwikwetlem First Nation was first made aware of a potential project by a formal introductory letter dated February 7, 2011. …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." (Exhibit B-1, p. 52)

According to the Communications Log in Appendix J4, FEI sent a letter to Kwikwitlem First Nation on November 24, 2011 to "provide an update regarding the status of the proposed Huntingdon Bypass Project."

17.1 Did FEI follow up with Kwikwetlem First Nation as to whether Kwikwetlem has any interests and/or concerns with respect to the Project between November 24, 2011 and June 13, 2013? If yes, please describe these efforts. If not, why not?

Response:

Kwikwetlem First Nation has showed no interests or concerns in the proposed Project as indicated through no response to FEI's letters.

FEI continues to meet regularly with Kwikwetlem First Nations regarding other potential initiatives, and issues and/or interests in the Project have not been raised in these meetings.

17.2 Has FEI made any efforts to follow up with Kwikwetlem First Nation since its June 13, 2013 letter? If yes, please describe these efforts. If not, why not?

Response:

Please refer to the response to BCUC IR 1.17.1.

18.0 Reference: FIRST NATION CONSULTATION

Exhibit B-1, Section 9, pp. 52-53;

Delegation of Consultation Responsibilities

On pages 52 to 53 of the Application FEI states:

"The OGC is the Crown agency responsible for First Nations consultation, and, if necessary, accommodation of First Nations' interests…. 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." (Exhibit B-1, pp. 52 and 53)

18.1 Besides the OGC manuals provided in Appendix J 1-3, has OGC provided FEI with any other instruction as to FEI's responsibilities to consult with First Nations prior to its application to the OGC? If yes, please provide a copy.

<u>Response:</u>

The OGC has further provided FEI with the following documents, a copy of which is included in Attachment 18.1, related to FEI's role in engaging First Nations in projects subject to the OGC's jurisdiction:

- the Consultation & Notifications Manual, November 2013, Version 1.19,
- the Consultation and Notification Regulation (BC Reg 56/2013, June 3, 2013), and
- the Oil and Gas Activities Act (SBC 008) Chapter 36

19.0 Reference: FIRST NATION CONSULTATION

Exhibit B-1, Section 9.6, p. 54

First Nation Concerns

On page 54 of the Application FEI states: "No significant concerns, with the exception of the mitigation and avoidance of archaeological and heritage sites, have been raised as of August 30, 2013." (Exhibit B-1, p. 54)

19.1 Have any First Nations brought any concerns to FEI with respect to the proposed project since August 30, 2013? If yes, please describe the concerns and how FEI intends to mitigate them.

<u>Response:</u>

No concerns have been raised by First Nations with respect to the proposed Project since August 30, 2013.

C. PROJECT DESCRIPTION

20.0 Reference: PROJECT COMPONENTS

Exhibit B-1, Sections 5.1 and 5.2, p. 31

Capacity of Huntingdon Station to Handle Future Loads

In the Application FEI states:

> "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. ...The bypass will have a capacity of 1,635 mmcfd." (Exhibit B-1, p. 31)

and

> "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…" (Exhibit B-1, p. 31)

20.1 What is the current combined capacity of the existing FEI Nominal Pipe Size (NPS) 30 and NPS 42 pipelines?

Response:

The CTS is composed of multiple pipelines, a compressor station (Langley), and a peak shaving LNG facility at Tilbury. As the NPS 30 and NPS 42 pipelines form just two components of those inter-related assets, it is challenging to assign specific capacity to these two pipelines in isolation and it is more meaningful to look at the capacity of the system as a whole. The current available capacity in the CTS is 1723 mmcfd with 150 mmcfd available from Tilbury LNG, subject to storage constraints. The balance of 1573 mmcfd is provided by the CTS pipeline network.

20.2 What is the current combined peak day load requirement for the existing FEI NPS 30 and NPS 42 pipelines?

Response:

The current peak day load requirement leaving the Huntingdon Station and flowing through the existing NPS 30 and NPS 42 pipelines is 1496 mmscfd.

20.3 There have been reports of plans to build a world scale liquefied natural gas (LNG) export facility in southwestern British Columbia (e.g. at Woodfibre, BC) that would be supplied with natural gas through the FEI system. There have also been reports of FEI expanding Tilbury. With these additional loads, plus other additional load growth in the CTS and FEVI systems, when the LNG export facility and the expanded Tilbury would be expected to be in service, for example in 2020, what would be the peak day load requirement for the FEI NPS 30 and NPS 42 pipelines?

Response:

FEI is exploring projects that may result in load increase. Also, there have been recent public announcements that may result in load reduction (i.e. Burrard Thermal). However, the specific load impacts and timing cannot be confirmed at this time.

There are no anticipated improvements required on the CTS NPS 30 and NPS 42 pipelines to support the load demand that FEI can confirm or be relatively certain about for the foreseeable future.

The bypass has been sized to manage the confirmed and relatively certain future throughput for the foreseeable future through prudent design. If required and necessary in the future, the Huntingdon Station and the bypass are expandable. The increase in capacity to the Huntingdon station can be accomplished through the addition of a fourth control valve run on Stations #1 and #2 and an upgrade to the Station #2 flow meter. The bypass is for the most part an emergency provision and its design basis is relatively conservative; peak day flow at minimum Spectra pressure. That said, its capacity could be increased as needed by replacing or modifying the control valves.

20.4 Please outline the changes and upgrades that will be required on the FEI NPS 30 and NPS 42 pipelines to handle the increased load resulting from providing service to the world scale LNG facility, the expanded Tilbury, and other additional load growth.

Response:

Please refer to the response to BCUC IR 1.20.3.

20.5 Please confirm the current capacity of Huntingdon Station. Which components are limiting the capacity?

Response:

The current capacity of Huntingdon Station is 1,500 mmscfd with the minimum contractual pressure from Spectra at 3,447kPa (500 psi). The control valves on Station #1 and #2 as well as the turbine flow meter downstream of Station #2 are the limiting components.

20.6 Please outline the changes to the existing Huntingdon Station that will be required to handle the increased load resulting from providing service to the expanded Tilbury, the world scale LNG facility and additional load growth, and include a diagram of the upgraded station.

Response:

In addition to the response to BCUC 1.20.3, Attachment 20.6 is a diagram showing the changes to expand the capacity of the Huntingdon Station based on the increased load that is relatively certain in the foreseeable future. The changes, however, are outside the scope of this Project.

20.7 Please outline the changes to the Huntingdon Station *with the proposed bypass*, that will be required to handle the increased load resulting from providing service to the expanded Tilbury, the world scale LNG facility and additional load growth. Please include a diagram of the upgraded station.

Response:

Please refer to the response to BCUC IRs 1.20.3 and 1.20.6.

20.8 Please outline the changes and upgrades that will be required on the FEI NPS 30 and NPS 42 pipelines to handle the increased load resulting from providing service to normal load growth and the expanded Tilbury.

Response:

Please refer to the response to BCUC IR 1.20.3.

21.0 Reference: ACQUISITION OF PROPERTY

Exhibit B-1, Section 5.3.2, p. 33

Proposed Right-of-Way

In the Application FEI states:

"The Project will require acquisition of a new Right-of-Way. The approximate size of the ROW is 182m long by 18m wide." (Exhibit B-1, p. 33)

21.1 Please confirm, or otherwise explain, that FEI will be acquiring a ROW large enough to support safe distances between the proposed bypass and surrounding development, now, and in the future, and that FEI has reasonably taken into account future potential development growth and future potential expansions at Huntingdon.

Response:

Confirmed. Based on the currently available information, the ROW to be acquired will be large enough to support safe distances between the proposed bypass and surrounding development, now, and in the future. When acquiring the ROW, FEI has also reasonably taken into account future potential development growth (particularly considering the Project site and surrounding area are in the Agricultural Land Reserve) and future potential expansions at Huntingdon.

21.2 Please confirm what Class Location, pursuant to Clause 4.3.2 of CSA Standard Z662 Oil and Gas Pipeline Systems, the pipeline will be designed to comply with.

Response:

The pipeline will be designed to comply with location Class 3 of CSA Standard Z662 Oil and Gas Pipeline Systems. The Location Factor utilized in the design calculations is L=0.625, as found in CSA Standard Z662-11 Oil and Gas Pipeline Systems, Table 4.2 for station applications.

21.2.1 Please discuss the risk that encroaching development poses, in the future, in relation to a future potential change in Class Location. Please discuss the steps FEI will take to ensure that the bypass, as installed, will be suitable for the long term.

Response:

FEI believes that the risk of encroaching development in relation to a future potential change in Class Location is very low. The pipeline will be designed to comply with Class 3 of CSA Standard Z662 Oil and Gas Pipeline Systems. An increase to Class 4 would involve a prevalence of buildings intended for human occupancy with 4 or more storeys above ground, a significant shift from the current rural setting.

Please also refer to the response to BCUC IR 1.21.1.

21.3 Please provide an update on the status of ROW discussions.

Response:

Spectra has agreed to the area of right of way on the east side of Huntingdon Station and is in receipt of FEI's standard statutory right of way agreement. It is reviewing the document and is expected to respond back shortly.

FEI met with the property owner on the north side on October 30, 2013. The property owner is aware that an 18m right of way is required along the property line. The property owner has been advised that they will be able to continue to farm the right of way area upon completion. As currently discussed, FEI would pay compensation for 3 years' crop loss for the right of way and temporary working space area, and the Company will negotiate with regard to compensation for the right of way.

FEI met with the property owner on the east side on December 10, 2013. The property owner is expected to submit a proposal for compensation shortly.

Please also refer to the response to BCUC IR 1.10.1.1.

22.0 Reference: OTHER APPLICATIONS AND APPROVALS

Exhibit B-1, p. 36

Potential Screening under the Canadian Environmental Assessment Act

In the Application FEI states:

"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*." (Exhibit B-1, p. 36)

22.1 Please explain the process and timelines that will determine whether screening is required under the CEAA.

Response:

FEI has now determined that a screening under the Canadian Environmental Assessment Act (CEAA) is not required due to the recent changes to the Fisheries Act and CEAA, 2012. At the time of writing the Application, it was unclear whether or not a screening under CEAA would be required as the meaning and impact of the recent changes to the Fisheries Act and the Canadian Environmental Assessment Act, 2012 were not yet clarified.

22.2 Please explain what criteria will determine whether or not screening is required.

Response:

Please refer to the response to BCUC IR 1.22.1.

22.2.1 If screening is required, please confirm when this will be known and what the expected impacts will be to the project schedule and costs.

Response:

Please refer to the response to BCUC IR 1.22.1.

D. PROJECT COST ESTIMATE

23.0 Reference: RISK ANALYSIS AND MANAGEMENT
Exhibit B-1: Section 5.7, p. 37; Appendix E
Risk Analysis and Contingency Calculation

FEI states that it "conducted a risk analysis of the Project using internal resources, and has used the results of the analysis to calculate a contingency amount." (Exhibit B-1, p. 37)

FEI states: "The risk analysis generated a contingency amount of $721,750." (Exhibit B-1, p. 37)

23.1 Please describe the internal resources used to develop the risk analysis.

Response:

The risk analysis for this Project followed the American Association of Cost Engineers "Total Cost Management Framework" (TCM) section 7.6 (Risk Management) as well as Recommended Practice No. 40R-08 "Contingency Estimating – General Principles" and Recommended Practice No. 44R-08 "Risk Analysis and Contingency Determination Using Expected Value."

Expert Judgment combined with an Expected Value calculation were chosen as the methodologies for risk identification, planning of risk responses and calculation of contingency for the Project budget. This combined methodology is considered adequate as the proposed Project is contained within a relatively small footprint immediately outside of the Huntingdon Station where FEI has a long operating history, only three adjacent landowners are affected and standard construction practices will be employed.

In accordance with the TCM, a diverse project team was utilized to complete risk identification and analysis. The project team was assembled for a workshop held on May 13, 2013. The participants included representatives from the following FEI departments: Project Management, Regulatory, Environment, Procurement, Pipeline Operations, Property Services, Engineering and Community/First Nation Relations.

The team brainstormed and discussed potential Project risks using aerial photos, Project plans, past Project risk analyses and Project risk categories to facilitate identification of a comprehensive list. The team then assigned relative probability and consequence by consensus. Potential mitigation measures were identified and evaluated to determine their impact on probability and consequence. The risks were then ranked in order of the product of their relative risk and consequence (exposure). Starting with the highest ranked risks, the team proceeded to link the risk drivers and outputs by identifying which components of the Project budget would be impacted by the particular risk. The highest ranked risk scored a 12 out of a possible 25, which reflects that based on the consensus of the group, the risks for this Project are relatively low.

23.2 Please discuss if the method used to calculate the contingency amount for the Project is a method commonly used by FEI when developing a contingency for its CPCN projects.

<u>Response:</u>

FEI does not have a sufficient number of CPCN projects to have developed a single methodology as commonly used by FEI to estimate a contingency amount.

Please also refer to the response to BCUC IR 1.23.1 for a discussion of the risk analysis process used by FEI and to BCUC IR 1.23.2.1 for a discussion on how the contingency was developed for this Project.

23.2.1 If this is not a commonly used method, please explain how FEI typically determines contingency amounts for CPCN projects and why FEI did not use this method for the Project.

<u>Response:</u>

The risk analysis methodology should be chosen to address the size and complexity of each project and should take into account other project specific issues such as potential environmental risk.

Expected value was chosen as the contingency estimating methodology because of its simplicity, which is appropriate for a project of relative low complexity such as the proposed bypass here, and because it has allowed for the use of the project team's expertise. This methodology explicitly links risk drivers with their impacts, leading to mitigation to be addressed at an appropriate level for the risk exposure (expected value).

As mentioned in the response to BCUC IR 1.23.3, AACE has recommended practices, which include expected value.

23.3 What alternative methods can be used to determine a project contingency? Please discuss.

Response:

There are many other methodologies and combinations of methodologies that can be employed to determine a project contingency. AACE recommended practices include range estimating and Monte Carlo analysis techniques, parametric methods, and expected value. Parametric methods require considerable past data to draw on to be effective. FEI does not complete a sufficient number of similar projects in order to generate this database. Range estimating and Monte Carlo techniques can be effective but are complex, generally requiring third party facilitation and modelling. FEI made a determination that these methodologies are not appropriate for a project of this relative small scale and low complexity and risk. FEI has chosen the expected value methodology for reasons described in the response to BCUC IR 1.23.2.1.

23.4 Why does FEI believe that this method is most appropriate for the Project? Please discuss.

Response:

Please refer to the response to BCUC IR 1.23.2.1.

23.5 Please discuss why line items for events that are unlikely to result (e.g. the 10 percent and 25 percent probabilities in Appendix E) were included in the contingency calculation, provided the AACE definition of contingency excludes these types of items. Please provide the contingency calculation including only specific cost items that will likely result, but which are not yet quantifiable due to the incomplete nature of the project definition.

Response:

The AACE definition of contingency (Recommended Practice No. 10S-90) does not exclude events below a particular threshold of probability.

> *CONTINGENCY – An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs. Typically estimated using statistical analysis or judgment based on past asset or project experience. Contingency usually excludes: 1) Major scope changes such as changes in end product specification, capacities, building sizes, and location of the asset or project; 2) Extraordinary events such as major strikes and natural disasters; 3) Management reserves; and 4) Escalation and currency effects. Some of the items, conditions, or events for which the state, occurrence, and/or effect is uncertain include, but are not limited to, planning and estimating errors and omissions, minor price fluctuations (other than general escalation), design developments and changes within the scope, and variations in market and environmental conditions. Contingency is generally included in most estimates, and is expected to be expended.*

Appendix E, as filed in the Application, provides the specific cost items considered likely enough by the Project team based on its collective experience to have an impact on the Project budget.

23.6 Please discuss why line items for escalation factors (i.e. lines 3, 4, 6, 7 and 11 in Appendix E) were included in the contingency calculation, provided the AACE definition of contingency excludes these types of items. Please provide the contingency calculation excluding escalation factors.

Response:

While escalation is stated as *usually* excluded from contingency amounts, the risk drivers identified are in some cases linked directly to potential escalation costs. Therefore, since it is uncertain that the risk will occur or not, FEI believes that it is best addressed in the risk analysis and contingency. The general escalation amount that is known to occur due to the multi-year duration of the Project is addressed elsewhere in the budget. Also, while escalation is specifically mentioned as one of the impacts of schedule delay, it is not the only impact. There may also be extra costs incurred if a delay is imposed during the execution of construction.

23.7 Please provide the detailed benchmarking data that was used to calculate the expected value of the contingencies listed in Appendix E. Please provide details on the scope of those other projects and on the costs incurred as a result of those contingencies occurring during those other projects.

Response:

Benchmarking data was available to estimate the expected value of the contingency for item 2: Contaminated groundwater and item 5: Large amount of groundwater. These items are based on actual costs incurred during construction of the SF5 site on the Gateway project (temporary pipeline bypass and relocations in Burns Bog, Delta). That project required dewatering a trench of just under 300m in length using wellpointing due to high volumes encountered, and treating the water for high levels of naturally occurring iron prior to discharge. The actual costs incurred were $250 thousand for dewatering and $340 thousand for the construction and operation of the on-site treatment system. Detailed benchmarking data was not available for the other items in the risk register.

23.8 Appendix E includes "work in proximity to gas line" as a risk. As the work will be carried out in and near Huntingdon Station, where the location of all gas lines should be well known, please explain why this is considered a risk rather that a known factor to be incorporated into plans for the execution of the project.

Response:

Work in proximity to gas lines is included in the risk analysis due to potential but uncertain cost implications such as consequences for final design and construction implications such as the potential need to build crossing structures and contractor chosen methodologies used to expose and work on the pipeline.

23.9 Table 5-2 on page 37 refers to "electrostop fittings". Please explain what these fittings are, what they are needed for, how many are needed and the typical cost of a fitting.

Response:

Electrostop fittings are used to provide cathodic isolation between pipelines. The budget pricing the Company received for these items is $105 thousand each, and three are required to achieve the cathodic isolation needed for the installation of the bypass.

Cathodic isolation between pipelines and pipeline facilities is an integral component of an effective cathodic protection system. Cathodic protection for buried metallic pipelines is required by the oil and gas pipeline code CSA Z662. Since a cathodic protection system follows the principles of DC electric circuits and more specifically, Ohms law, it is important in the design of a cathodic protection system that the circuit resistance is controlled. The installation of cathodic isolation between pipelines allows for the greater control of the cathodic protection system circuit resistance as well as providing separation between two or more independent cathodic protection systems. In the case of facilities, cathodic isolation from facility grounding, gradient control mats, electrical systems and building foundations is required to ensure that sufficient cathodic protection current reaches the buried pipeline as intended rather than these other components. All buried piping within a facility is electrically connected to the cathodic protection system.

23.10 Table 5-2 on page 37 refers to "Late delivery of electrostop fittings" and "Late delivery of pipe" as key risks. Please explain how FEI will manage procurement contracts to mitigate the financial consequence in the event of late deliveries. For example, will FEI include penalties for the suppliers if the suppliers do not supply the materials on time? Please elaborate.

Response:

FEI prequalifies vendors and monitors delivery performance. When the materials are put out for bid, the final selection of award is based on best value including performance schedule. The standard terms and conditions for material purchase require that vendors supply bi-weekly updates on the delivery schedule and allow for actions such as the use of overtime to make up for a projected late delivery.

23.11 Please confirm that the Expected Value of the "consequence" of a risk is the estimated total cost of dealing with the problem in the event it materializes, or explain otherwise.

Response:

The Expected Value is the product of the probability of the risk occurring and the impact if it occurs (Consequence). Therefore, the Consequence column in Appendix E is the Company's estimated total cost of dealing with the problem if the event materializes based on current available information.

23.12 Please confirm that the "consequence" of a delay is intended to include all the costs related to the later completion of the project, including extended construction costs, extended project team costs, extended monitoring costs and AFUDC, or explain otherwise.

Response:

Confirmed.

23.13 Please discuss how FEI reviewed the "consequence" Expected Values for consistency from risk to risk. For example, please explain why risks with a "consequence" rating of 4 are shown to have Expected Value consequences ranging from $100,000 to $380,000.

Response:

In accordance with the AACE Recommended Practice No. 44R-08 "Risk Analysis and Contingency Determination Using Expected Value," the initial estimate of consequence chosen by the Project team in the workshop is used for screening and to rank the relative priority of the risks. Those that were ranked highest and were determined to potentially have a significant impact on the cost of the Project were subjected to a refined scope and cost estimate after the risk analysis session, which led to a range of estimated cost impacts within same level of initial consequence rating.

Please also refer to the response to BCUC IR 1.23.1 for a discussion on FEI's process for risk analysis.

23.14 Please explain if applying a more consistent cost to all risks with similar consequence ratings would result in a materially different total contingency amount.

Response:

Applying the average cost for each consequence rating will result in a calculated contingency amount of $714,990, as compared to the $721,750 amount as stated in the Application, a difference of 1%. This is not a material difference.

The following table shows the recalculated contingency.

Project: Huntingdon Station Bypass CPCN Application
Risk Analysis and Contingency Calculation: Modified Using Average Consequence

	Relative Risk (1 Low 5 High)			Expected Value			
Risk (description)	Probab	Conseq	Exposure	Probability	Estimated Consequence	Average Consequence	Contingency
Market conditions - high bids	3	4	12	50%	250,000	207,500	103,750
Contaminated groundwater	2	5	10	25%	250,000	325,000	81,250
Late delivery of electrostops	3	3	9	50%	100,000	137,500	68,750
Late delivery of pipe	2	4	8	25%	100,000	207,500	51,875
Large amount of groundwater	2	4	8	25%	380,000	207,500	51,875
Delayed start due to OGC	2	4	8	25%	100,000	207,500	51,875
Species at risk - increased permits and monitoring	2	3	6	25%	150,000	137,500	34,375
Late delivery of valves - fisheries window	3	2	6	50%	150,000	132,400	66,200
Small amount of groundwater	5	1	5	80%	25,000	25,000	20,000
Significant chance find	1	5	5	10%	400,000	325,000	32,500
work in proximity to gas line	2	2	4	25%	200,000	132,400	33,100
Right of way acquisition costs, potential expropriation, temporary workspace costs	2	2	4	25%	87,000	132,400	33,100
archaeology - chance find,	2	2	4	25%	200,000	132,400	33,100
HR - Project team member leaves	3	1	3	50%	25,000	25,000	12,500
Contractor non performance	1	3	3	10%	150,000	137,500	13,750
Contaminated soils (asbestos...)	1	3	3	10%	150,000	137,500	13,750
work in proximity to power lines - damage	1	2	2	10%	25,000	132,400	13,240
US regulatory interference	1	2	2				
No bids for contract	1	2	2				
Contractor insolvency	1	2	2				
Changes to Spectra station - gates	1	2	2				
AIA increases monitoring requirements	2	1	2				
work in proximity to Kinder Morgan	1	1	1				
Bird nesting window	1	1	1				
						Total	714,990

Consequence Rating	Average Consequence
5	325,000
4	207,500
3	137,500
2	132,400
1	25,000

23.15 Please confirm if the potential need for a screening under the *Canadian Environmental Assessment Act* is included as a risk in Appendix E. If yes, please identify where. If no, please provide a similar analysis for this potential risk.

Response:

With recent changes to the Fisheries Act and the Canadian Environmental Assessment Act, 2012, a screening under the CEAA will not be required. As such, it has not been included as a risk in Appendix E.

Please also refer to the response to BCUC IR 1.22.1.

23.16 Please explain why line items 18 through 24 are listed in Appendix E without probabilities, consequences or contingencies. Please update Appendix E such that all fields are filled out, including fields which should be listed as 0 percent or $0.

Response:

In accordance with the AACE Recommended Practice No. 44R-08 “Risk Analysis and Contingency Determination Using Expected Value,” the risks for which the calculated probability times impact yields a value that is not significant to costs are dropped from consideration but kept in the register. Thus items 18 through 24 are listed to track that they have been considered but not included in the contingency amount. An updated Appendix E is provided in Attachment 23.16 which has all fields filled out as determined by the risk analysis.

23.17 Did FEI evaluate the risk of First Nations opposing the project prior to or during construction of the project? If yes, please describe FEI’s evaluation of the probability and consequence of First Nations’ opposition. If not, why not.

Response:

FEI did not evaluate the risk of First Nations opposing the Project. Discussions to date have not indicated any opposition to the Project from the contacted First Nations.

23.17.1 If First Nations were to raise opposition to the Project during the permitting/authorization phase of the Project, what would be the impact on the project? Please explain.

Response:

FEI places significant importance on ongoing engagement with First Nations in our operating area. The Company is in contact with the affected First Nations on a regular basis, and began engagement of them on this Project in early 2011. Please see section 9.5 of the Application for further discussion on FEI's continuing engagement efforts.

If First Nations were to raise opposition to the Project, there would likely be an effect on schedule and budget and potentially on scope as well. However, without any indication of specific issues of concern raised to date, it is difficult to gauge the level of impact to the Project should First Nations raise opposition to the Project during the permitting and authorization phase of the Project. If an issue were raised, FEI would treat it very seriously and work together with the First Nations to mitigate or resolve it.

23.17.2 If First Nations were to raise opposition to the Project during the construction phase of the Project, what would be the impact on the project? Please explain.

Response:

Please refer to the response to BCUC IR 1.23.17.1.

23.18 Please confirm that FEI has listed all risks that will likely result, but which are not yet quantifiable due to the incomplete nature of the project definition, in the contingency calculation (i.e. risks that are 33 percent or more likely of occurring). If not, please update the contingency calculation.

<u>Response:</u>

FEI has listed all risks that were identified in the risk workshop by the Project team, and no additional risks have been identified since the workshop was held.

Please also refer to the response to BCUC IR 1.23.1 for a discussion on FEI's risk analysis process.

24.0 Reference: COST ESTIMATE DETAILS

Exhibit B-1, Section 6.1, p. 38 and Appendix F3

Control Budget

In the Application FEI states: "The expected accuracy class of the cost estimate is +30 percent to -20 percent." And "The estimated capital cost of $8.0 million will be the control budget…" (Exhibit B-1, p. 38)

In Appendix F3, FEI lists contingency as $802,000 in as spent dollars.

24.1 Please confirm, or otherwise explain, that the control budget proposed is actually $7.2 million, that is, the control budget being proposed by FEI is actually $8.0 million minus the proposed contingency.

Response:

In accordance with the AACE definition of contingency as referred to in the response to BCUC IR 1.23.5 the control budget for the capital costs are is $7.6 million including the contingency (and excluding AFUDC). Inclusion of the contingency in the control budget is consistent with FEI's CPCN projects such as FEI's Kootenay River Crossing (Shoreacres) Upgrade which the Commission approved in order C-9-10 dated November 15, 2010.

In addition to the capital costs, the deferred prefeasibility costs of $0.6 million (before-tax and excluding AFUDC) will also be included in the control budget, for a total control budget of $8.2 million.

For additional clarity, the total cost of the project (i.e. capital and deferred prefeasibility costs, including AFUC and contingency) as provided in Appendix F3 is the summation of Lines 13 and 5 of Appendix F3.

24.2 Please provide the dollar amounts for the upper and lower bound of the proposed control budget estimate.

Response:

The expected accuracy range of the capital cost estimate is $9.9 million ($7.6 million +30%) to $6.1 million ($7.6 million -20%).

When the deferred prefeasibility costs are included, the accuracy range for the control budget is $10.5 million ($9.9 million capital costs + $0.6 million prefeasibility costs) to $6.7 million ($6.1 million capital costs + $0.6 million prefeasibility costs).

24.2.1 Please confirm, or otherwise explain, that as the project definition matures, FEI never expects the dollar amount of any new upper bound on the control budget to exceed the initial upper bound of the initial baseline point estimate of $7.2 million plus 30 percent, including the event that any of the contingencies listed in Appendix E occur.

Response:

FEI does not expect the upper bound of the expected accuracy range to exceed the upper bound stated in BCUC IR 1.24.2 as the Project definition matures.

25.0 Reference: COST ESTIMATE DETAILS

Exhibit B-1, p. 38 and Table 4-1, p. 27

Detailed Cost Estimate — Percentage of Engineering Design and O&M Costs

In Table 4-1, FEI lists the Gross O&M costs in 2013$/year.

In the Application FEI states: "The Company prepared the Project cost estimate based on AACE Class 3 specifications, in accordance with the CPCN Guidelines." and "The expected accuracy of the cost estimate is +30 percent to -20 percent." (Exhibit B-1, p. 38)

25.1 Please provide the percentage of the engineering design for the proposed bypass project that was completed at the time that the cost estimate was prepared.

Response:

The percentage of engineering that was complete at the time the cost estimate was prepared was 40%.

25.2 Please provide the percentage of the engineering design that is complete to date.

Response:

The percentage of engineering that is complete to date remains at 40%.

25.3 Please provide the current operations, maintenance and administrative (OM&A) costs for Huntingdon Station.

Response:

The annual cost of operating and maintaining the Huntingdon Station varies from year to year depending on the planned operational and preventative maintenance activities that are scheduled for that year and on the corrective work that is identified. The average annual cost of operating and maintaining the Huntingdon Station, based on 2009-2013 actuals, is $51 thousand. This cost includes preventive maintenance, corrective maintenance, and operational activities. It does not include any capital upgrades to the station or grounds.

25.4 If the bypass is built, please provide the additional costs or savings on the OM&A expense for the existing station.

Response:

If the bypass is built, additional costs will be incurred on an annual basis to complete operating and maintenance activities on the newly installed components. It is estimated that the additional cost will be approximately $14,100 per year. For a description and breakdown, please refer to the response to BCUC IR 1.9.2.

25.5 If the bypass is built, please provide the OM&A cost for the station including the bypass.

Response:

The overall O&M cost for the station including the bypass is $65,100 ($51 thousand for the station + $14,100 for the bypass). Please also refer to the responses to BCUC IRs 1.25.3 and 1.25.4.

26.0 Reference: COST ESTIMATE DETAILS

Exhibit B-1: Section 6.1, p. 38; Appendix F3

Detailed Cost Estimate — As Spent Dollars

FEI states: “The total capital cost of the Project, filed confidentially in Appendix F3, is estimated to be $8.0 million in <u>as spent dollars</u>.” (emphasis added) (Exhibit B-1. p. 38)

FEI further states: “An escalation rate of 4.5 percent per annum is used based on the ten year average escalation rates from Statistics Canada for construction contracts.” (Exhibit B-1, p. 38)

26.1 Please confirm, or explain otherwise, that the term “as spent dollars” means that the amounts have been inflated by a rate of 4.5 percent per annum based on the year the costs are forecasted to be incurred.

<u>Response:</u>

The ‘As-Spent’ dollars means the Deferred Prefeasibility Costs and the Capital Project costs have been escalated by 4.5%. The Operating and Maintenance Expenses and Property Taxes have been escalated by 2%.

27.0 Reference: COST ESTIMATE DETAILS

Exhibit B-1: Section 6, pp. 38-40; Appendix F3

Detailed Cost Estimate — Assumption, Allowances, Exclusions, Management Reserves and Performance Baseline Measurement

27.1 Please list, describe, justify and quantify all assumptions, allowances, exclusions and management or other reserves used in developing the cost estimate discussed in Section 6 and Appendix F3.

Response:

Assumptions

The 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. Cost estimates include 7 percent PST on materials. 2012 market prices have been used for the material supply and construction contracts. An escalation rate of 4.5 percent per annum is applied to Project capital costs and is based on the ten year average escalation rates from Statistics Canada for industrial construction and line pipe from 2002 to 2012.

Allowances

There are no allowances included in the cost estimate.

Exclusions

The estimate excludes GST. 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. The cost estimates exclude First Nations Capacity Funding and Accommodation Costs as no such costs are anticipated at this time.

Management Reserves

There are no management reserves included in the cost estimate.

27.2 Please provide FEI's proposed performance measurement baseline upon which the Commission is expected to evaluate the prudency of FEI's expenditures. Please list, describe, justify and quantify all the components that FEI proposes to include in this performance measurement baseline.

Response:

The list and quantification of all components that FEI proposes to include in the control budget are included in Appendix F3. The components in the control budget comply with current accounting rules except as described in Section 6.3 of the Application. AACE defines Performance Measurement Baseline as the total allocated budget less management reserve. There is no management reserve included in the control budget.

FEI notes that the concept of prudence in the rate setting process applies to capital planning to the extent that such planning consists of decisions to make expenditures and has cost consequences. FEI acknowledges that it should exercise prudency in all such decisions. FEI further notes that the question of whether or not FEI has prepared its budget prudently does not determine whether it, acting reasonably, should have incurred costs included within the budget.

28.0 Reference: ACCOUNTING TREATMENT

Exhibit B-1, Sections 6.2 and 6.3, Table 6-1, p. 39

Depreciation and Negative Salvage Provisions

FEI states: "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." (Exhibit B-1, p. 39)

28.1 Please describe when depreciation and negative salvage would commence based on FEI's current policies.

Response:

Under current accounting policies, depreciation and negative salvage would commence the month after the Project's costs are closed to Gas Plant in Service. With an October 2015 in-service date as currently planned, the cost of service model would calculate depreciation and negative salvage starting in November 2015.

28.2 Please recreate Table 6-1 (if any of these amounts would change) under the assumption that depreciation and negative salvage treatments are based on FEI's current policies.

Response:

With an in-service date of October 2015, current (2013) accounting policies would result in the Project Capital costs being included in Gas Plant in Service and Rate Base in 2015 as well as the depreciation provision and negative salvage treatment commencing in November, 2015. The following table presents the same type of summary results as found in Table 6-1 with the values in Table 6-1 reproduced in the right hand column. As can be seen below, the change in accounting policy does not have a significant impact on this Project.

	AACE Class 3 Current Acct'g Policies	Table 6-1
Total Direct Cost ($million) - As Spent	$ 7.6	$ 7.6
AFUDC ($million)	$ 0.3	$ 0.3
2016 Rate Impact ($ / GJ)	$ 0.006	$ 0.007
Levelized Rate Impact 25 Years ($ / GJ)	$ 0.005	$ 0.005
Levelized Rate Impact 60 Years ($ / GJ)	$ 0.006	$ 0.006
Levelized Incremental Revenue Requirement ($million)	$ 0.4	$ 0.4
Incremental Revenue Requirement PV 25 Years ($million)	$ 9.4	$ 9.6
Incremental Revenue Requirement PV 60 Years ($million)	$ 12.1	$ 12.1
Net Cash Flow NPV 25 Years ($million)	$ 0.2	$ 0.1
Net Cash Flow NPV 60 Years ($million)	$ 0.1	$ -
2016 Incremental Rate Base	$ 8.3	$ 8.3

29.0 Reference: ACCOUNTING TREATMENT

Exhibit B-1, Section 6.3, p. 39

Deferral of Application Costs

FEI states: "The Application costs include costs for legal review, expenses for consultant, Commission costs and Commission approved intervener costs… FEI is forecasting the Application costs to be about $100 thousand (after tax $74 thousand)." (Exhibit B-1, p. 39)

29.1 Please separate out the forecasted Application costs to show the amounts related to each of the following categories: (i) legal review, (ii) expenses for consultant, (iii) Commission costs and (iv) Commission approved intervener costs.

Response:

Estimated Application costs are broken down as follows:

Publish Notice	$15,000
Legal review	15,000
Consultant	40,000
Commission Costs	15,000
Intervener PACA costs	15,000
	$100,000

This is an estimate only. FEI will only record actual costs incurred in the proposed deferral account.

29.2 Please explain the nature of the "expenses for consultant" which make up part of the Application costs.

Response:

Expenses for consultant include costs for support in answering and reviewing (where appropriate) IRs related to environmental, archaeological, and risk assessments.

29.2.1 Please explain why FEI requires a consultant to assist in the preparation of the Application.

Response:

As stated in the response to BCUC IR 1.29.2, consultants with subject matter expertise (i.e. environmental, archaeological, risk assessments) are required to prepare the necessary documents to support the Application because FEI does not have the internal resources with the required appropriate expertise. The $100 thousand estimate for the Application Costs Deferral Account includes an estimate of approximately $40 thousand for consultants to assist FEI with responding to and reviewing (where appropriate) some of the technical Information Requests. As with all deferral accounts, only the actual costs of the application will be captured in the deferral account and recovered from customers.

Consultant costs for the studies that have been filed in the Application have been charged to the Deferred Prefeasibility Costs Account and are not included in the $100 thousand estimate of Application costs.

29.3 Please explain whether or not FEI considers the Application costs to be "non-capital" costs.

Response:

FEI did not base its recommendation for deferral account treatment on an assessment of the nature of the costs being capital versus non capital. Rather. this recommendation was based on FEI's usual practice for application costs. Consistent with other applications, FEI requests that the costs of regulatory applications be recorded in a deferral account. Although there is no difference in the rate of return afforded to capital assets as compared to deferral accounts, including the costs in the capital asset would result in the Application costs being recovered over the life of the asset, which FEI considers to be an inappropriately long recovery period.

To respond fully to the question, FEI has reviewed US GAAP guidance related to capitalization of costs as follows:

360-10-30 Property, Plant, and Equipment – Initial Measurement

Paragraph 835-20-05-1 states that the historical cost of acquiring an asset includes the costs necessarily incurred to bring it to the condition and location necessary for its intended use. As indicated in that paragraph, if an asset requires a period of time in which to carry out the activities necessary to bring it to that condition and location, the interest cost incurred during that period as a result of expenditures for the asset is a part of the historical cost of acquiring the asset. Activities necessary to bring an asset to the condition and location necessary for its intended use is defined as follows in the glossary for section 360-10-30:

> *The term activities is to be construed broadly. It encompasses physical construction of the asset. In addition, it includes all the steps required to prepare the asset for its intended use. For example, it includes administrative and technical activities during the preconstruction stage, such as the development of plans or the process of obtaining permits from governmental authorities. It also includes activities undertaken after construction has begun in order to overcome unforeseen obstacles, such as technical problems, labour disputes, or litigation.*

Based on this guidance, FEI believe that Application costs could be considered capital costs.

FEI states: "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." (Exhibit B-1, p. 39)

FEI further states that it "anticipates the application costs will all be incurred in 2013 and 2014 and amortization will commence in 2015." (Exhibit B-1, p. 39)

29.4 If the amortization of the Application costs will actually commence in 2015, why has FEI commenced the amortization of the Application costs in 2017 in Appendix F? Please explain.

Response:

The first year in the financial analyses is the year 2016 to align with the commencement of depreciation and the inclusion of the Project capital in rate base. For presentation purposes and in order to capture the full, net-of-tax cost in the financial analyses, FEI showed the Application Deferred costs delayed to 2016 and the three years of amortization from 2017 through 2019 (Schedule 10). Otherwise, the full net of tax cost and the first year of the amortization expense would not be included in the financial analyses, i.e. it would then understate the full cost. With the Commission's approval, FEI will commence the three year amortization in 2015.

29.5 Please explain why FEI believes that a three-year amortization period is most appropriate for the Application costs.

Response:

FEI believes that a three-year amortization period is most appropriate for the Application costs deferral account as it aligns with the recovery period requested for the Prefeasibility Costs deferral account. The reasons for requesting a three-year amortization period for both these accounts are discussed further in BCUC IR 1.30.3.

29.6 Please compare the rate impact if the Application costs are amortized over the following time periods: (i) one year, (ii) two years, and (iii) the proposed three years.

Response:

The following table shows the average cost of service for the Project for the years 2017 through 2019 for a one year, two year or a 3 year amortization period for the deferred Application costs.

	Average Cost of Service $/GJ		
	2017	**2018**	**2019**
1 Year Amortization	$0.007	$0.006	$0.005
2 Year Amortization	$0.007	$0.007	$0.005
3 Year Amortization	$0.007	$0.007	$0.005

.

29.7 Please explain what rate of return FEI is requesting for the Application Costs Deferral Account and why FEI believes this is most appropriate.

Response:

Once included in rate base in 2015, the application costs will attract the Commission approved return on rate base. FEI has not requested a return for the Application Costs Deferral Account prior to inclusion in rate base in 2015.

Application cost deferrals have historically been included in rate base and accordingly have attracted the approved return on rate base.

A rate base return is required to compensate the utility for amounts invested in net utility plant and other items, such as regulatory assets (deferral accounts) and working capital. The treatment of deferral accounts and working capital is consistent, compensating the utility for the time lag between when expenditures occur and when they are recovered from customers.

29.8 Please provide examples of deferral accounts that were approved for CPCNs in the past two years for any of the FortisBC companies (i.e. FEI, FAES or FBC) where the Commission determined that either Fortis' Weighted Average Cost of Debt (WACD) or Fortis' short-term interest rate was the most appropriate carrying cost to be applied to the deferral account(s).

Response:

FortisBC Energy Utilities (FEU)

FEU (FEI, FEVI, FEW and FEFN) cannot provide any examples for the past two years for CPCN projects where the Commission ordered the use of either WACD or short-term interest for deferral accounts approved as part of a CPCN.

FortisBC Alternative Energy Services (FAES)

For FAES, the Delta School District deferral account is afforded an AFUDC return, but the Telus Garden and Kelowna District Energy System deferrals attract a WACD return. These accounts, although approved as part of CPCN applications, hold revenue variances and not costs related to developing CPCN applications. Costs related to developing these FAES applications are charged to the Thermal Energy Services Deferral Account (TESDA) in FEI, which attracts an AFUDC return. Based on the amount and nature of feasibility costs incurred, it is clear that this Project goes beyond the sustainment capital that is captured within the PBR formula. FEI does not have a provision in its O&M formula for the feasibility costs related to this type of work, nor in the capital formula for the capital costs related to this type of work

FortisBC Inc. (FBC)

In Order G-110-12 with regard to FBC' s 2012 – 2013 Revenue Requirements Application, the Commission directed FBC to use short-term interest for deferrals that are amortized in less than one year and to use FBC's WACD for deferrals that are amortized beyond one year. This resulted in Preliminary Survey and Investigation costs related to CPCN projects attracting a WACD return until the projects were placed into service; and being included in rate base and attracting a rate base rate of return after being placed into service.

In Commission Decision C-7-13 with respect to FBC's Advanced Metering Infrastructure (AMI), the Commission approved all costs related to the approved AMI project (including application and preliminary survey and investigation costs) as part of the capital project that attracts an AFUDC return.

29.8.1 Please compare the proposed Application Costs Deferral Account to these deferral account examples.

Response:

Specifically relating to Application costs, these costs have generally been included in a rate base deferral account (for the FEU), in a non-rate base deferral account attracting AFUDC (the TESDA for FAES) or as part of the capital costs of the project earning a rate base return (for FBC). There have been no instances of application costs not earning a rate base/AFUDC return that FEI is aware of. This is the appropriate and consistent treatment for deferral accounts and capital costs, regardless of whether they are in rate base or out of rate base.

Please also refer to the responses to BCUC IRs 1.29.7 and 1.30.6.

30.0 Reference: ACCOUNTING TREATMENT

Exhibit B-1, Section 6.3, pp. 39-40

Deferral of Prefeasibility Costs

FEI states that it 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." (Exhibit B-1, p. 39)

30.1 Please explain why FEI believes that a three-year amortization period is most appropriate for this requested deferral account.

Response:

Please refer to the response to BCUC IR 1.30.3.

30.2 Please compare the rate impact if the deferral account was amortized over the following time periods: (i) one year, (ii) two years, (iii) the requested three years and (iv) five years.

Response:

The following table provides the average cost of service of the Project for the years 2016 through 2020 for a one year, two year, three year or a five year amortization period (all commencing in 2016) for the deferred prefeasibility costs.

	Average Cost of Service $ / GJ				
	2016	**2017**	**2018**	**2019**	**2020**
1 Year Amortization	$0.010	$0.005	$0.005	$0.005	$0.005
2 Year Amortization	$0.008	$0.007	$0.005	$0.005	$0.005
3 Year Amortization	$0.007	$0.007	$0.007	$0.005	$0.005
5 Year Amortization	$0.006	$0.006	$0.006	$0.006	$0.006

30.3 Please explain why it makes sense that the proposed amortization periods are the same for both the Application Costs Deferral Account and the Prefeasibility

Costs Deferral Account given that the forecasted costs in the respective deferral accounts are quite different ($100 thousand versus $573 thousand).

Response:

The proposed amortization periods for both the Application Costs and Prefeasibility Costs deferrals are the same for administrative ease. FEI would also be agreeable to having only one deferral account that captures both the Application costs and the Prefeasibility costs.

In recommending amortization periods for deferral accounts, FEI considers the benefits of rate smoothing, the matching of the amortization period to the benefits of the project, and avoiding an inordinately long amortization period (the maximum amortization period for deferral accounts is usually 10 years).

FEI considers that for the cost amount and nature of the accounts under consideration here, an amortization period of anywhere from three to five years is appropriate, consistent with the amortization period approved for similar deferral accounts in the past and in consideration of the rate impacts shown in the response to BCUC IR 1.30.2.

30.4 Please explain the factors that FEI considers when determining the appropriate amortization period for deferral accounts.

Response:

Please refer to the response to BCUC IR 1.30.3.

30.5 Please confirm, or explain otherwise, that the Allowance Funds Used During Construction (AFUDC) rate and FEI's Weighted Average Cost of Capital (WACC) are the same.

Response:

The FEI AFUDC rate is the same as FEI's **after-tax** WACC.

30.6 Please explain why FEI believes it is most appropriate to earn its WACC on the Prefeasibility Costs Deferral Account (as opposed to FEI's WACD or short term interest rate).

Response:

FEI believes it is appropriate to earn WACC, as opposed to WACD or the short-term interest rate, on its non-rate base deferral accounts, including the Huntingdon Prefeasibility Costs deferral account requested in this Application.

FEI's affiliate, FortisBC Energy (Vancouver Island) Inc., discussed this treatment specifically relating to feasibility costs in response to BCUC IR 1.4.1.1 (filed on April 16, 2013) in its Application for Approval of a Deferral Account in Connection with a Development Agreement Between FEVI and Pacific Energy Corporation. An excerpt from that response is reproduced below:

> *FEVI believes that the only "just and reasonable" treatment of a prudently incurred expenditure to be included in rate base is one where the financing costs reflect the allowed return on rate base. In this case in particular, the weighted average cost of capital, or AFUDC rate, is appropriate for amounts carried in the non-rate base deferral account because the Company is expending funds in support of a fixed asset (AFUDC is used for fixed assets) that additionally is expected to generate benefits for all customers.*
>
> *The passage quoted from Exhibit A2-3 addresses financial treatment by distinguishing between whether amounts are capital or expense in nature. That issue is not raised by this particular project since all expenditures are in support of a capital project. However, it should be noted that the Commission's determination in that proceeding was based on an error that is evident in the above quoted passage. The passage states "Expenses and capital costs attract different rates of return, expenses generally receiving a Cost of Debt rate of return and capital costs receiving a Return on Equity (ROE) from rate base level of return." FEVI does not believe that this is a correct statement, and it does not justify treating deferred feasibility and development costs differently. To the extent that expenses receive a return, it is a rate base rate of return. That is, since expenses that are treated as O&M in a utility's revenue requirements are recovered from customers in the same period in which the utility incurs them, they are not subject to a direct return. However, to compensate the utility for the time lag between when the expenses are paid out and when they are recovered from customers, they affect the working capital of the utility, and the working capital receives a rate base rate of return. In a consistent manner, any amounts expended by the utility that are not recovered from customers until a later period should receive a return to compensate the utility for the time lag between when the funds are expended and when they are recovered. This treatment is not*

affected by whether the amounts affect working capital, are held in deferral accounts (for items that would otherwise be period expenses), are captured in work in progress (for capital items) or are held in rate base itself.

As stated in that response, FEI believes that the nature of the amounts recorded in these deferrals should not impact the type of return the deferral account should earn. This is because the moment an item is placed into a deferral account for future recovery or refund, it ceases to be a non-capital item. It has now become akin to a capital item in that costs are being incurred in one period and not being recovered from ratepayers until a future period. In fact, even non-capital (or operating items) that are expensed and recovered within the same test year receive a rate base return through the allowance for working capital component of rate base to the extent there is a time lag in their recovery during the year.

The original nature of an item is not relevant, because the nature of the expenditure has been changed by recording it into the deferral account. Allowing deferrals to attract a rate base rate of return (WACC) recovers the costs associated with the timing difference when there is an outlay of funds and when those costs are recovered from ratepayers. A rate base rate of return is the only logical and consistent approach to be applied; providing consistency between those deferrals that are in rate base and those that are held outside of rate base.

Further, the application of WACC is consistent with the Commission's approval of the Uniform System of Accounts that gas utilities must follow in recording costs and is consistent with the Commission's determinations in the FEI (formerly BC Gas) 1992 RRA and has been applied and approved in numerous applications and approvals from the Commission over the past two decades. This approach is also consistent with the approach of the Generic Cost of Capital decisions by the BCUC, that it is the total net assets financed by all of the sources of capital financing; i.e. both debt and equity.

30.7 Please provide examples of deferral accounts that were approved for CPCNs in the past two years for any of the FortisBC companies (i.e. FEI, FAES or FBC) where the Commission determined that either Fortis' WACD or Fortis' short-term interest rate was the most appropriate carrying cost to be applied to the deferral account(s).

<u>Response:</u>

Please refer to the response to BCUC IR 1.29.8.

30.7.1 Please compare the proposed Prefeasibility Costs Deferral Account to these deferral account examples.

Response:

For the FEU, the only example in the past two years that FEI is aware of is FEVI's feasibility costs for the development agreement between FEVI and Pacific Energy Corporation, which receives an AFUDC return. Prior to 2011, these prefeasibility costs were included in work-in-progress where they attracted an AFUDC return and have attracted a rate base rate of return after being placed into service. Similar costs for FAES CPCN projects have been included initially in the TESDA which attracts an AFUDC return, and then in the capital costs of the project upon transfer to FAES, where they attract a rate base return. Similar costs for FBC CPCN projects have historically been included in work-in-progress where they attracted an AFUDC return prior to 2012 and have attracted a WACD return since 2012, until the related assets go into service, and then attract a rate base rate of return after being placed into service.

A rate base or AFUDC return is the appropriate treatment for deferral accounts and capital costs, regardless of whether they are in rate base or out of rate base. Please also refer to the responses to BCUC IRs 1.29.7 and 1.30.6 for a discussion of why this is the case.

31.0 Reference: ACCOUNTING TREATMENT

Exhibit B-1, pp. 2 and 39; Appendices B, C1, C2 and C3

Request for Deferral Treatment of Prefeasibility Costs

In the Application FEI states:

"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." (Exhibit B-1, p. 2)

FEI also states:

"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." (Exhibit B-1, p. 39)

31.1 Considering that the GHD Consulting Phase 1 Risk Assessment Report is a high level risk assessment of ALL transmission assets that was completed in 2010, please explain why FEI is now requesting deferral account treatment for this expenditure rather than treating it as a normal expense of operating its transmission system and considering it a regular O&M expense.

Response:

The cost of the GHD Consulting Phase 1 Risk Assessment Report was expensed in 2013 and has not been charged to the deferral account.

31.1.1 Please explain how this expenditure has been recorded to date, and how will it be dealt with if the Commission denies the request for deferral account treatment.

Response:

Please refer to the response to BCUC IR 1.31.1.

31.2 For each of the three reports in Appendix C, please explain why FEI is now requesting deferral account treatment for these expenditures rather than treating these as normal expenses of operating its transmission system and considering these regular O&M expenses.

Response:

The costs related to the reports in Appendices C1 and C2 have not been charged to the deferral account as they were originally completed for the other alternative routes option described in Section 4.2.4.2 of the Application, which is no longer under consideration. The costs related to the Appendix C3 report were charged to the deferral account because they specifically relate to the Application and are not regular O&M expenses.

31.2.1 Please explain how these expenditures have been recorded to date and how will they be dealt with if the Commission denies the requested deferral account treatment.

Response:

The costs for the reports in Appendices B, C1 and C2 have already been expensed by FEI.

If the Commission was to deny deferral treatment of the costs related to the report in Appendix C3, then these costs would be expensed, but without a method for recovery from customers, resulting in the shareholder absorbing these costs. It would not be appropriate to deny recovery of these costs, because the costs have been prudently incurred to support the Project and were necessary to establish the preferred option and to support the CPCN requirements.

FEI's proposed method of recovery of these costs is through the creation of a deferral account. Alternatively, the Commission may order FEI to include these costs in the capital costs of the Project. Although FEI would be agreeable to this treatment, FEI notes that this would result in the costs being recovered from customers over the long life of the associated assets and ultimately result in higher costs for customers.

31.3 Please explain why FEI proposes that prefeasibility costs related to the Application and initial work on the project should be deferred and recovered over a three-year period, rather than being held in work-in-progress as part of Project expenditures.

Response:

Please refer to the responses to BCUC IRs 1.30.3 and 1.31.2.1.

E. MISCELLANEOUS

32.0 Reference: FEI 2014-2018 MULTI-YEAR PERFORMANCE BASED RATEMAKING APPLICATION

Exhibit B-1, pp. 2, 39;

FEI 2014-2018 Revenue Requirements Application, Exhibit B-1, p. 210[1]

Accounting Treatment Under FEI 2014-18 Revenue Requirements Application

In the Application FEI states:

"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." (Exhibit B-1, p. 39)

In the 2014-2018 Revenue Requirements Application (2014-18 RRA), FEI states:

"The expenditures within sustainment capital include gas system improvements to ensure adequate capacity within the transmission and distribution system in order to meet forecast load and to ensure the safety, reliability and integrity of the system.

Sustainment capital includes expenditures for meter recall or meter exchange programs; system reinforcements to the distribution and transmission systems to maintain capacity to meet existing and forecast load; replacements and upgrades to the distribution and transmission systems to ensure safety, integrity and reliability; and expenditures for mains and service renewals and alterations." (FEI 2014-18 Revenue Requirements Application Exhibit B-1, p. 210)

32.1 Please confirm that the Huntingdon Bypass Project falls within the scope of expenditures that are "sustainment capital" as stated above, or explain if it does not.

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[1] In the Matter of FortisBC Energy Inc.'s Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018, Application dated June 10, 2010, p. 210.

Response:

This response addresses BCUC IRs 1.32.1, 1.32.2 and 1.32.3.

As FEI has explained in the Application, the Company believes that the Project is necessary to create the required redundancy, to reduce the risk of the single-point-of-failure risk, and to allow more reliable gas supply to 600,000 customers. As such, the Company believes that the Project is in the public interest and should be approved. The Company plans to proceed with the Project if approved.

The Huntingdon Bypass Project is a sustainment capital type of expenditure; however, it is not included in the regular sustainment capital expenditures to which FEI has proposed that the PBR formula be applied in the 2014-2018 PBR RRA. CPCN expenditures are excluded from the formula and continue to be subject to the minimum $5 million cost threshold. Based on the amount and nature of feasibility costs incurred, it is clear that this Project goes beyond the sustainment capital that is captured within the PBR formula. FEI does not have a provision in its O&M formula for the feasibility costs related to this type of work, nor in the capital formula for the capital costs related to this type of work.

FEI notes that when the Application was filed, FEI complied with the established guidelines and accepted regulatory treatment applicable in 2013. At the time of the filing, the established CPCN threshold for FEI is $5 million; thus, this Project, with an estimated capital cost of $8 million, will be a CPCN project. As proposed in the 2014-2018 PBR RRA that was filed in 2013, this CPCN threshold remains, and a CPCN project is not subject to the formula treatment as proposed in the 2014-2018 PBR RRA. FEI does not have a provision in its O&M formula for the feasibility costs related to this type of work, nor in the capital formula for the capital costs related to this type of work. Additionally, the PBR formula was created on the assumption that projects above $5 million in estimated cost would be approved under a separate CPCN process. If this and similar projects were to be captured within the PBR formula, the formula itself may need to be revisited, or other work may have to be deferred.

32.2 If the Huntingdon Bypass project does not fall within the scope of expenditures that are "sustainment capital" because its estimated cost exceeds $5 million and the project is the subject of a CPCN application, please confirm that the project expenditure would meet the definition and description of sustainment capital if not for this exclusion, or explain otherwise.

Response:

Please refer to the response to BCUC IR 1.32.1.

32.3 In the event that the Decision on FEI's 2014-18 RRA does not exclude the Huntingdon Bypass Project expenditure from sustainment capital as determined by formula under Performance Based Regulation (PBR), will FEI proceed with the project? Please explain why or why not.

Response:

Please refer to the response to BCUC IR 1.32.1.

Attachment 8.1

Inspection & Recoating of Piping **(2013 $)**

Description	Category	Source	Estimate	Proportion	Notes
Dewatering Activities	465	PM, based from historical	$ 50,000.00	2%	
Excavation (Hydrovac)	465	PM, interpolated from historical	$ 502,112.20	20%	
Backfill	465	PM, based from historical	$ 79,628.05	3%	
NDT - Inspection	465	Integrity, interpolated from histc	$ 188,292.07	8%	
NDT X -ray Radiography	465	Stantec, quote	$ 128,000.00	5%	Assumed 16 weeks of construction, daily rate $1600
Recoating	465	Integrity, interpolated from histc	$ 251,056.10	10%	
Project Management	465	PM, best practices	$ 104,761.80	4%	Based on 1/3 time for 1 year
Construction Supervision	465	PM, best practices	$ 96,000.00	4%	Assumed 16 weeks of construction, daily rate $1200
Engineering	465	Eng, best practices/historical	$ 175,000.00	7%	
Bypass Operations	465	Ops, best practices	$ 661,741.52	27%	
Materials for Repairs	465	Eng, moving cost averages/est	$ 31,995.57	1%	Assume 80% of estimated work will proceed; All materials costs include 7% PST
Labour for Repairs	465	Ops, moving cost averages/est	$ 190,041.34	8%	Assume 80% of estimated work will proceed
Sub-total			**$ 2,458,628.64**		
Escalation		PM	81,330		
Contingency		PM	282,742	10.0%	
Total Capital			**$ 2,822,700.64**		

Inspection & Recoating of Piping

Description	Source	Estimate	2013 1st	2013 2nd	2013 3rd	2013 4th	2014 1st	2014 2nd	2014 3rd	2014 4th	Total	Notes
Dewatering Activities	PM, based from historical	$ 50,000.00	0	0	0	0	0	20000	30000	0	$ 50,000.00	
Excavation (Hydrovac)	PM, interpolated from historical	$ 502,112.20	0	0	0	0	0	301267	200845	0	$ 502,112.20	
Backfill	PM, based from historical	$ 79,628.05	0	0	0	0	0	0	79628	0	$ 79,628.05	
NDT - Inspection	Integrity, interpolated from histo	$ 188,292.07	0	0	0	0	0	37658	150634	0	$ 188,292.07	
NDT X -ray Radiography	Stantec, quote	$ 128,000.00	0	0	0	0	0	25600	102400	0	$ 128,000.00	Assumed 16 weeks of construction, daily rate $1600
Recoating	Integrity, interpolated from histo	$ 251,056.10	0	0	0	0	0	0	251056	0	$ 251,056.10	
Project Management	PM, best practices	$ 104,761.80	5238	5238	5238	15714	20952	20952	20952	10476	$ 104,761.80	Based on 1/3 time for 1 year
Construction Supervision	PM, best practices	$ 96,000.00	0	0	0	0	0	48000	48000	0	$ 96,000.00	Assumed 16 weeks of construction, daily rate $1200
Engineering	Eng, best practices/historical	$ 175,000.00	0	0	8750	17500	35000	52500	43750	17500	$ 175,000.00	
Bypass Operations	Ops, best practices	$ 661,741.52	0	0	0	0	0	165435	496306	0	$ 661,741.52	
Materials for Repairs	Eng, moving cost averages/esti	$ 31,995.57	0	0	0	0	6399	22397	3200	0	$ 31,995.57	Assume 80% of estimated work will proceed; All materials costs include 7% PST
Labour for Repairs	Ops, moving cost averages/esti	$ 190,041.34	0	0	0	0	0	66514	123527	0	$ 190,041.34	Assume 80% of estimated work will proceed
Sub-total		**$ 2,458,628.64**	5238	5238	13988	33214	62351	760325	1550298	27976	$ 2,458,628.64	
Escalation	PM	81,330										
Contingency	PM	282,742										
Total Capital		**$ 2,822,700.64**										

Doc. No.: FBC111.043	HUNTINGDON BYPASS PROJECT	Date: 2012-08-27
Rev.: A	TOTAL PROJECT COSTS	File: FBC111 / 1.2

BOM #	Description	Quantity	Units	Unit Rate	Total	Comments
1	PIPE - ERW, NPS 36 x 12.7 mm W.T., CSA Z245.11, GR. 483, CAT II, M5C	18	meters	$798.00	$14,364.00	Wilson Quotation dated Aug 17th, 2012
2	PIPE - ERW, NPS 30 x 12.7 mm W.T., CSA Z245.11, GR. 483, CAT II, M5C	12	meters	$689.00	$8,268.00	Wilson Quotation dated Aug 17th, 2012
3	PIPE - ERW, NPS 16 x 9 .5 mm W.T., CSA Z245.11, GR. 290, CAT II, MSC	6	meters	$165.00	$990.00	Stock Fortis BC pipe
4	PIPE - SMLS, NPS 3/4 SCH 160, CSA Z245.11, ASTM A106, GR B, YELLOW JACKET	18	meters	$26.00	$468.00	Wilson Quotation dated Aug 17th, 2012
8	ELBOW - NPS 36, LR, 90o BW, TO MATCH 12.7 mm W.T., CSA Z245.11, GR. 483, CAT II, M5C	1	each	$6,150.00	$6,150.00	Wilson Quotation dated Aug 17th, 2012
10	ELBOW - NPS 30, LR, 90o BW, TO MATCH 12 .7 mm W.T ., CSA Z245.11, GR. 483, CAT II, M5C	1	each	$4,000.00	$4,000.00	Wilson Quotation dated Aug 17th, 2012
12	ELBOW - NPS 16, LR, 90o BW, TO MATCH 9.5 mm W.T., CSA Z245.11, GR. 290, CAT II, M5C	1	each	$3,000.00	$3,000.00	Wilson Quotation dated Aug 17th, 2012
14	ELBOW - NPS 3/4, 90o SW, SCH. XS, 3000 #, ANSI B16.11	6	each	$23.00	$138.00	CEL estimated
				Total	**$37,378.00**	

			Hydrovac	Inspection	Recoat
		Rate	$40/m/in	$15/m/in	$20/m/in
Dia (inch)	ft	m			
42	121	37	$ 61,975.61	$ 23,240.85	$ 30,987.80
36	468	143	$ 205,463.41	$ 77,048.78	$ 102,731.71
30	308	94	$ 112,682.93	$ 42,256.10	$ 56,341.46
24	373	114	$ 109,170.73	$ 40,939.02	$ 54,585.37
16	5	2	$ 1,014.63	$ 380.49	$ 507.32
2	457	139	$ 11,146.34	$ 4,179.88	$ 5,573.17
6	9	3	$ 658.54	$ 246.95	$ 329.27
		531	$ 502,112.20	$ 188,292.07	$ 251,056.10

Mobilize	Yes	2	2	22	1	-	1,542.99	1,439.89	131.755	819.37	1,045.00	-	$4,979.00
Demobilize	No	2	2	22	1	-	1,805.49	1,439.89	131.76	819.37	1,045.00	-	$5,241.51
Indirect Totals:	*	3	232	2,552			$15,934.56	$6,711.59	$2,767.44	$5,577.05	$5,711.03	$317.07	**$37,018.73**
DIRECT COSTS:							0	0	0	0	0		
Stripping and Grading	No	2	2	22	1		1,672.45	1,214.03	-	795.65	245.00	-	$3,927.13
String, Weld and Coat	Yes	2	10	110	5		29,831.40	9,984.10	145.85	6,136.40	14,934.50	6,250.00	$67,282.25
Crane Support Crew	Yes	-	-	-	5	-	-	-	-	-	-	50,750.00	$50,750.00
Hydrovac Excavation (	No	-	-	-	0	-	-	-	-	-	-	0.00	$0.00
Excavation / Backfill C	Yes	0	0	0	0	-	0.00	0.00	0	0.00	0.00	-	$0.00
Pipe Installation Suppo	Yes	2	10	110	5	-	19,350.63	4,367.60	300.78	2,601.95	3,086.15	-	$29,707.10
Hydro Test Operations	Yes	2	4	44	2	-	4,538.42	1,879.92	45.50	1,388.48	3,638.02	-	$11,490.34
Hydro Test Operations	Yes	0	0	0	0	-	-	-	-	-	-		$0.00
Support Owner Tie-Ins	Yes	3	3	33	1	-	$6,067.98	$1,059.59	$17.50	$626.71	$286.50		$8,058.28
Cleanup Operations - I	Yes	2	2	22	1	-	$1,642.45	$1,214.02	-	$795.65	$645.00	-	$4,297.12
Cleanup Operations - (	Yes	2	2	22	1	-	$1,211.76	$163.38	-	$114.40	$570.00	-	$2,059.54
Direct Totals:	*	4	33	363			$64,315.09	$19,882.64	$509.63	$12,459.24	$23,405.17	$57,000.00	**$177,571.76**
GRAND TOTALS:		7	265	7,251			$406,206.79	$139,293.80	$41,911.41	$113,775.64	$160,277.19	$207,060.00	214,590.49
			Overhead and Profit Markup:			12.00%	$48,744.81	$16,715.26	$5,029.37	$13,653.08	$19,233.26	$24,847.20	22,961.18
* Duplicate Crews not included in Crew Size Total												**PIPELINE TOTAL:**	**$237,551.67**

Cost Estimate: **Huntingdon Phase 1 - Internal Reinforcement Station Upgrades**

					0%	30%		
2.0	**TEMPORARY NPS 16 BYPASS PIPELINE (Above Grade)**							
					15%	30%		
MATERIALS:		Unit's	Labour:	Unit Cost	Cost Adjus	Cost Adjus	Subtotal:	**TOTALS:**
- MECH:			Man-Days		design vari	accuracy		273,400
Pipe	NPS 16 (bare)	155		274	0	82.2	55,211	
Pipe		0		1	0	0.3	0	
Fittings	Tees	2		1700	0	510	4,420	
Fittings	90 Elbows	12		1219	0	365.7	19,016	
Fittings	Bends	2		4700	0	1410	12,220	
Valves - Ball: NPS 16 WxW		2		47705	0	14311.5	124,033	
Valves - Remote Control		0		1	0	0.3	0	
Swamp Weights		0		1	0	0.3	0	
Temporary support		3		15000	0	4500	58,500	
Coating, Misc. Materials		0		1	0	0.3	0	
- ELEC/INST:								0
Lighting		0		0			0	
Dist. / MCC, power		0		0			0	
Controls, SCADA, Telem		0		0	0	0	0	
Elec. Heaters & HVAC		0		0			0	
Misc. Materials		0		0			0	
CONTRACTS:								141,487
Fabrication		0		1	0	0.3	0	
On-site Piping Construction		1		88836	0	26650.8	115,487	
Radiography		1		10000	0	3000	13,000	
E & I Contractor		0		1	0	0.3	0	
Enviromental Protection		0		1	0	0.3	0	
Security Services		1		10000	0	3000	13,000	
DESIGN ENGINEERING:								67,184
Project Management			9	1320	0	396	15,444	
Civil/Structural (External EPC)			5	1320	0	396	8,580	
Mechanical Design (External EPC)			10	1320	0	396	17,160	
Elec./Inst./Controls - (External EPC)			0	1	0	0.3	0	
Drafting - all dwg's. (External EPC)			15	1000	0	300	19,500	
PLC5, RTU & HMI Programming (External EPC)			0	1	0	0.3	0	
Travel / Expenses			5	1000	0	300	6,500	
CONSTRUCTION INSPECTION/SUPER:								12,012
Mech. / Civil			7	1320	0	396	12,012	
Elec. / Inst.			0	1	0	0.3	0	
Travel / Expenses			0	1	0	0.3	0	
IBEW LABOUR:								96,200
Ties-ins (incl. materials)(Trans crew)			3	17000	0	5100	66,300	
Commissioning			1	13000	0	3900	16,900	
Operations Training			0	1	0	0.3	0	
Material Control			1	10000	0	3000	13,000	
COPE LABOUR:								1,300
ICS - pressure test			1	1000	0	300	1,300	
COMMUNITY RELATIONS:								0
COST ALLOWANCE FOR LOST GAS:								10,000
				COST ESTIMATE TOTAL :				601,583.20
							10 % cont	60,158.32
								$ 661,741.52

Attachment 9.3

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

FILED CONFIDENTIALLY

Attachment 9.4

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 14.1

Huntingdon Bypass Project – First Nations Communications Log – Updated January 2014

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.
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 2011	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.
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
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.
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 Tribal Council	FEI provides introduction of the Project and draft of letters sent to Sto Lo Nation member First Nations FEI contact information.
28 Nov 2013	Letter from FEI to inform FN of Order G-185-13.	Notice of Order mailed to notify that First Nations that FEI has filed its CPCN application with the commission.

The Sto:lo Research and Resource Management Centre

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.
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 2011	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.
9 Aug 2013	Email from FEI to People of the River Referrals Office at Sto Lo Nation Tribal Council	FEI provides introduction of the Project and draft of letters sent to Sto Lo Nation member First Nations FEI contact information.
28 Nov 2013	Letter from FEI to inform FN of Order G-185-13	Notice of Order mailed to notify that First Nations that FEI has filed its CPCN application with the commission.

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	Chawathil First Nation requests electronic version of the Project Study Area Map and

	Coordinator, Chawathil First Nation	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.
1 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.
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.
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.
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

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.
28 Nov 2013	Letter from FEI to inform FN of Order G-185-13	Notice of Order mailed to notify First Nations that FEI has filed its CPCN application with the commission.
9 Jan 2014	Letter from FEI to inform Soowahlie FN of Order G-185-13	Notice of Order mailed to notify Soowahlie First Nations that FEI has filed its CPCN application with the commission.

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.
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
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.
9 Jan 2014	Letter from FEI to inform Kwikwetlem FN of Order G-185-13	Notice of Order mailed to notify Kwikwetlem First Nations that FEI has filed its CPCN application with the commission.

Matsqui First Nations

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.

Attachment 18.1

CONSULTATION AND NOTIFICATION MANUAL
November | 2013

Version 1.19

Contents

Manual Revisions

Summary of Revisions

The Consultation and Notification Manual has been updated. Changes by section in the updated manual are highlighted below.

Effective Date	Section	Description/Rationale
1-March-2013	Section 2	Added clarity to Information to be Provided to the Recipient (p.8).
	Section 7	Added clarity to Major Amendments information (p.30).
	Section 8	Added clarity to Block B & C information (p.35).
	Section 8	Added clarity to Written Report Line List section including, Recipient Address and Distance to Consultation/Notification Feature (p.38).
1-July-2013	Section 2	Updated Chapter 2, who must provide consultation or notification and who does not have to provide consultation or notification to reflect the Oil and Gas Road Regulation (p.5).
	Section 3	Updated Table 3.1 and 3.2, to reflect road construction distances (p.18 & 19).
1-August-2013	Section 4	Removed the Prior to the Consultation and Notification Process section (p.23).
1-December-2013	Section 8	Updated the Written Report Line List instructions to reflect the changes made to the template (p.36).

1 Preface

Purpose

This manual was developed to provide additional clarification of Consultation and Notification requirements and processes established under the Consultation and Notification Regulation to oil and gas companies, and those affected by oil and gas activities.

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.

This manual does not provide information on legal responsibilities outside of the Commission's jurisdiction. It is the responsibility of the applicant to be familiar with and uphold its other legal responsibilities.

This manual outlines the minimum legal requirements for consultation and notification.

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

The Consultation and Notification Manual provides detailed information on how to conduct consultation and notification.

Beginning with the Consultation and Notification Overview, the manual first provides information that applies to both consultation and notification. Sections 4 and 5 provide detailed information that applies exclusively to each type of engagement. Sections 6 and 7 detail requirements after initial engagement. Section 8 details the requirements for submitting a Written Report to the Commission.

Section 2 **Consultation and Notification Overview** provides the basic information required to conduct both consultation and notification activities.

Section 3 **Calculating Consultation and Notification Distances** provides information on how to calculate consultation and notification distances in conjunction with EPZ requirements.

Section 4 **Notification** provides detail on steps that are unique to the notification process, including who must be notified, and notification before entry when fixing the site of the pipeline.

Section 5 **Consultation** provides detail on steps that are unique to the consultation process including who must be consulted, including consultation in municipalities and consultation with Forest Act rights holders.

Section 6 **Replying to Recipients** describes what steps must be taken and what information must be provided when replying to the recipient.

Section 7 **Revisions and Amendments** covers significant revisions**,** consultation after revision and amendment requirements.

Section 8 **Written Report** details what is required when submitting the Written Report to the Commission and includes information on how to complete each deliverable, including the Written Report Cover Sheet, Written Report Line List, Consultation and Notification Map.

Section 9 **Extensions** provides a summary of how consultation and notification is applied to permit extensions.

Section 7 **Compliance** provides a summary of compliance expectations and potential penalties associated with non-compliance.

Additional Guidance

The Consultation and Notification Recipient Guide (scheduled for release in March, 2011) is a source of information that can be used as a reference for any party who receives an Invitation to Consult or notification concerning oil and gas activity.

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.

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 website. The information provided is categorized into topics which reflect the manuals for easy reference.

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@bcogc.ca.

2 Consultation and Notification Overview

OGAA and the Consultation and Notification Regulation require oil and gas applicants to conduct consultation and/or notification with recipients prior to submitting an application for activity.

In addition to the requirements listed in this manual, Commission staff may request additional information to complete their review.

Who must provide consultation or notification?

As of June 3, 2013, construction and maintenance of an oil and gas road are considered oil and gas activities under the Oil and Gas Activities Act.

Any person intending to submit an application for a prescribed oil and gas activity permit, including applications for major amendments and permit extensions, must carry out the prescribed consultation or provide the prescribed notices, as per the Consultation and Notification Regulation prior to submission of the application.

Additionally, any person intending to submit an application to carry out maintenance activities on an oil and gas road on private land or Crown land where there is a lease or licence for intensive use or occupation, must carry out the prescribed consultation or provide the prescribed notification prior to submission of the application.

The Consultation and Notification Regulation does not apply to related activities as defined under the Act. Refer to Section 4 of the Crown Land Application Manual for specific information regarding rights holder engagement on Crown Land Applications.

Who does not have to provide consultation or notification?

When not located on property owned by the landowner (typically Crown land), certain activities or temporary structures not intended for continued use do not require consultation or notification. These are:

- Water or gas pipeline for well testing
    - if the pipeline is located on the surface of the wellsite and

  - the pipeline is not for use after the associated well is constructed
- Operating a pipeline
- The maintenance of an oil and gas road on Crown land

Potential Recipients of Consultations or Notification

Depending on proximity to the proposed activities and other factors (see Determining Consultation and Notification Obligations), permit holders may have to consult or notify the following persons or entities:

- Band councils for First Nation Indian Reserves, under C&N Regulation Section 4 (1) (d).
- The Government of Canada, under C&N Regulation Section 4 (1) (c).
- Landowners, under C&N Regulation Section 4.1(a),(e).
- Local authorities, under C&N Regulation Section 4 (1) (b).
- Ministry responsible for administering the Transporation Act, under C&N Regulation Section 4 (3).
- Municipal Councils, under C&N Regulation Sections 4 (3) and 4 (4).
- Persons who have entered into agreement with a landowner to rent a residence or a structure used for livestock on the land under C&N Regulation Section 4 (1) (f).
- Person, other than Landowner in section 4(1)(a) who is registered owner of land surface or as its purchaser under an agreement for sale, under C&N Regulation Section 4 (1) (e).
- Rights holders under Consultation and Notification Regulation Section 4 (g).

Differentiating between Landowners and Rights Holders

Landowners

A landowner is:

- A person registered in the land title office as the registered owner of the land surface or as its purchaser under an agreement for sale, and
- A person to whom a disposition (the disposition of Crown land involves either the lease or rental of property or its outright sale) of Crown land has been issued under the Land Act

A landowner is not:
The Government, or a person who holds a permit for Temporary Occupation of Crown Land or a Licence of Occupation for non-intensive occupation.

Notification When Fixing the Site of a Pipeline (Notice Before Entry)
If entry onto private land is required to determine the location of a proposed pipeline, notification is required two days before entirety (under Section 23 of OGAA).

Rights Holders
A rights holder is a person granted non-intensive occupation or use of Crown land by permit, license or approval as indicated in Table 2.0.

The document A Practical Guide to Effective Coordination of Resource Tenures provides a helpful description of resource tenures in B.C.

Table 2.0 Rights holders under various legislation.

Legislation	Permission
Land Act	Temporary Occupation of Crown Land, non-intensive use
	Licence of Occupation, non-intensive use
Forest Act	Forest licence
	Forestry licence to cut (major)
	Community forest agreement
	Timber sale licence
	Tree farm licence
	Woodlot licence
Range Act	Grazing permit
	Grazing license
Wildlife Act	Guide outfitter's licence
	Guiding territory certificate for Crown land
	Registered trapline
Mineral Tenure Act	Mineral claim
Water Act	Water licence

Best Practices

The Commission considers recreation sites established under Section 56 of the Forest and Range Practices Act as tenure holders. For these tenures, the applicant should contact the Ministry of Tourism, Culture and the Arts.

The Province also makes every effort to ensure that resource management is coordinated. A description of collaboration between tenure holders is provided in A Practical Guide to Effective Coordination of Resource Tenures.

The Oil and Gas Trapper's Notification and Compensation Program is a useful tool for industry and trappers and sets out conditions for both parties.

Information to be Provided to the Recipient

Consultation and Notification Documentation Requirements
Both an Invitation to Consult and notice documents provided to a recipient must include:

Contact Information

- The name of the applicant (applicant company's legal name).
- Contact information of the applicant (or land agent representing the applicant) with:
  - Contact name.
  - Phone number.
  - Fax Number
  - Email address (if available).

Description of

- The location of proposed activities. All legal locations that will be impacted by the contemplated activities must be noted. This is also required in cases where a project will be carried out on an area covering more than one legal location, but owned by the same land owner.
- The proposed oil and gas activities and any significant structures and equipment to be added (constructed or used) for the activity.
- Any roads that will be constructed to carry out the proposed activities.
- If and how the proposed activities relate to any existing oil and gas activities being carried out within the notification or concultation distances.
- The approximate order in which the proposed activities will be carried out.
  - For multiwell pads, include the entire schedule of activities over various years, where applicable.

Statement

A statement indicating to the recipient:

- That the recipient may respond, in writing, to the applicant within 21 days of receiving notice or Invitation to Consult to:
    - Advise the applicant that the recipient does not object to the applicant's application, or.
    - Set out reasons why the proposed activities should be modified or should not be carried out.
    - That the recipient may request a meeting with the applicant to discuss the proposed activities (required for Invitation to Consult only).
- That the recipient may make a Written Submission directly to the Commission, regarding an application at any time.
- That if a permit is obtained, the applicant will provide information to anyone who falls within the Emergency Planning Zone (EPZ) regarding the development of an Emergency Response Plan (ERP) for the proposed activities if they are to include a pipeline, facility or well.
- If no one falls within the EPZ, the initial recipients must be advised that the activity is covered instead by a corporate, or other named plan.

Additional Consultation Information Requirements

In addition to the requirements listed above, consultation also requires the applicant to include:

- A description for each phase of proposed oil and gas activities, including:
    - The nature and extent of reasonably foreseeable dust, noise and odours associated with the activities.
    - Any mitigation measures that will be undertaken.
    - The nature and extent of vehicle traffic on oil and gas roads that relate to the proposed activity within the consultation distance.

Consultation and Notification Map

A consultation and notification map that shows the proposed activities in relation to dwellings, facilities and nearby urban centres.

For small projects encompassing relatively small areas, a 1:20,000 scale map is acceptable. Larger projects must be at an appropriate scale to show clearly the activities in relation to dwellings, facilities and nearby urban centers.

Written Submissions

Recipients who state they have no objection maintain their right to make Written Submissions under Section 22 (5) of OGAA.

In addition to the Consultation and Notification processes, OGAA conveys the right for persons who have an interest in or concern about a proposed activity and/or its proposed location to make a Written Submission to the Commission detailing their concerns.

Written Submissions, under Section 22 (5) of OGAA, differs from Written Responses in that they are sent directly to the Commission and may be submitted at any time by any person. Instructions on how to complete a Written Submission Form are included in Appendix B of the Consultation and Notification Recipient Guide.

Under Section 22 (6) of OGAA, the Commission forwards any Written Submissions received to the applicant. The applicant is not required to reply, however may be encouraged to by the Commission in order to assist in resolution of issues.

Written Submissions can be sent by email to OGC.WrittenSubmissions@bcogc.ca, or submitted directly to the Commission's Fort St. John or Dawson Creek offices.

6534 Airport Road	#3, 1445 – 102nd Ave
Fort St. John, B.C.	Dawson Creek, B.C.
V1J 4M6	V1G 2E1
Fax: 250.794.5378	Fax: 250.795.2149

Conflict Resolution

Conflicts that cannot be resolved before submitting an application affect the Commission's review process, and may determine whether an application is approved with changes, without changes, or is refused.

If issues remain unresolved between the applicant and recipient(s) after all reasonable efforts are made; facilitation services are available through the Community Relations staff within the Operations Division of the Commission. Contact the Dawson Creek office of the Commission by phone at (250) 795-2140 or in person or via mail at:

#3-1445 102 Avenue
Dawson Creek, BC V1G 2E1

This non-mandatory process exists to aid communication, and resolve interest-based differences between applicants and consultation and notification recipients.

An assessment of the processes and activities completed as well as the specific circumstances will determine the type of facilitation service that will be most effective.

3 Determining Obligations to Consult or Notify

Obligations to carry out consultation or notification are based on proximity to the proposed activities as well as other factors, such as presence on an area subject to the right of a rights holder, or the presence of a residence or structure within the consultation or notification zone.

The following table outlines a series of tests that may be used to determine a potential applicant's obligations to notify or consult. The table is intended to highlight the different factors which create obligations to notify or consult among the various persons and entities identified in the Consultation and Notification Regulation. Figures 3.0 through 3.3 illustrate examples of the application of the consultation and notification tests.

Table 3.0 Persons or Entities Potentially Owed Notification or Consultation

Person / Entity	Test for obligation to provide notification	Test for obligation to provide an Invitation to Consult	Exclusions
Landowner 4 (1) (a)		Landowner of land on which activities are planned.	None
Local Authority 4 (1) (b)	(i)(A) Unless obligated to consult, if an existing building or structure owned by the local authority is within applicable notification distance. (i)(B) If an area identified in Official Community Plan is within applicable notification distance. (i)(C) If a known community watershed is within applicable notification distance.	(ii) If an existing building or structure owned by the local authority is within applicable consultation distance.	Consultation not applicable to geophysical activities, as there is no prescribed consultation distance for geophysical activities.
Government of Canada 4 (1) (c)	i) Unless obligated to consult, if an existing building or structure owned by the government of Canada is within applicable notification distance.	ii) If an existing building or structure owned by the government of Canada is within applicable consultation distance.	Consultation not applicable to geophysical activities, as there is no prescribed consultation distance for geophysical activities.
First Nations 4 (1) (d)	i) Unless obligated to consult, if all or a portion of the First Nation's Indian reserve is located within the applicable notification distance.	ii) If all or a portion of the First Nation's Indian reserve is located within the applicable consultation distance.	Consultation not applicable to geophysical activities, as there is no prescribed consultation distance for geophysical activities.
Person, other than Landowner in section (a) who is registered owner of land surface or as its purchaser under an agreement for sale. 4 (1) (e)	(i) Unless obligated to consult, if all or a portion of the land is located within the applicable notification distance.	ii) If all or a portion of a residence that the person occupies or a structure the person uses to shelter livestock is located within the applicable consultation distance iii) if the person is a school board and a	Consultation not applicable to geophysical activities, as there is no prescribed consultation distance for geophysical activities.

		school or related structure within the applicable consultation distance.	
Person who has entered into agreement with landowner to lease or rent a residence or a structure used for livestock on the land. 4 (1) (f)		ii) If all or a portion of a residence or structure for which the person has entered into an agreement with landowner is within the applicable consultation distance.	Consultation not applicable to geophysical activities, as there is no prescribed consultation distance for geophysical activities.
Rights Holders 4 (1) (g)	(i) Unless obligated to consult, if the proposed activities are to be carried out on an area subject to a right of the rights holder.	ii) if the proposed activities are to be carried out on an area subject to a right of the rights holder, and it is known to the applicant that the ability of the rights holder to exercise their right will be directly and adversely affected by the proposed activities.	None
Ministry of Transport 4 (3)		A pipeline proposed within municipality within the right-of-way of a highway, and is to be used for transporting petroleum, natural gas or both.	Only applicable to pipelines.
Municipal Council 4 (3) and (4)		(3) Unless subsection 4 applies, a pipeline proposed within a municipality and within the right-of-way of a highway. (4) If the proposed activities is for a pipeline permit including permission construct and operate a pressure regulating station on land owned by the applicant within municipality.	Only applicable to pipelines.

Figure 3.0

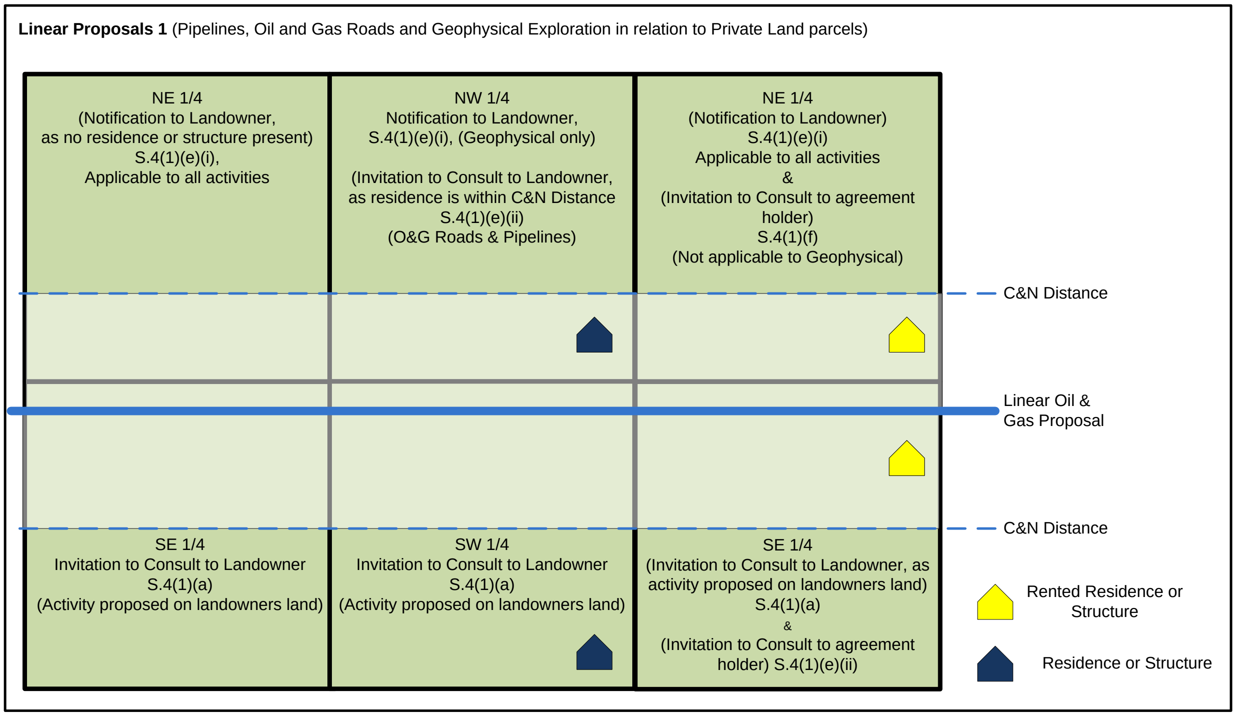


Figure 3.1

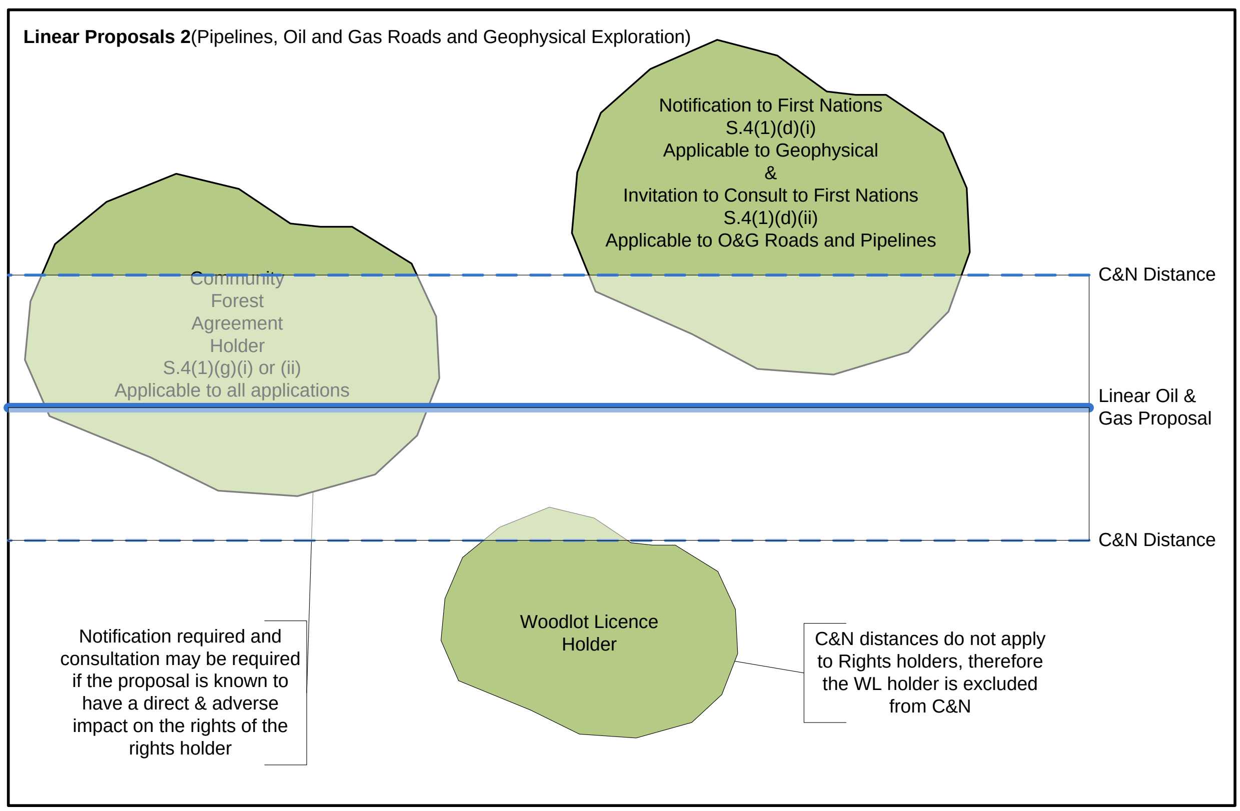


Figure 3.2

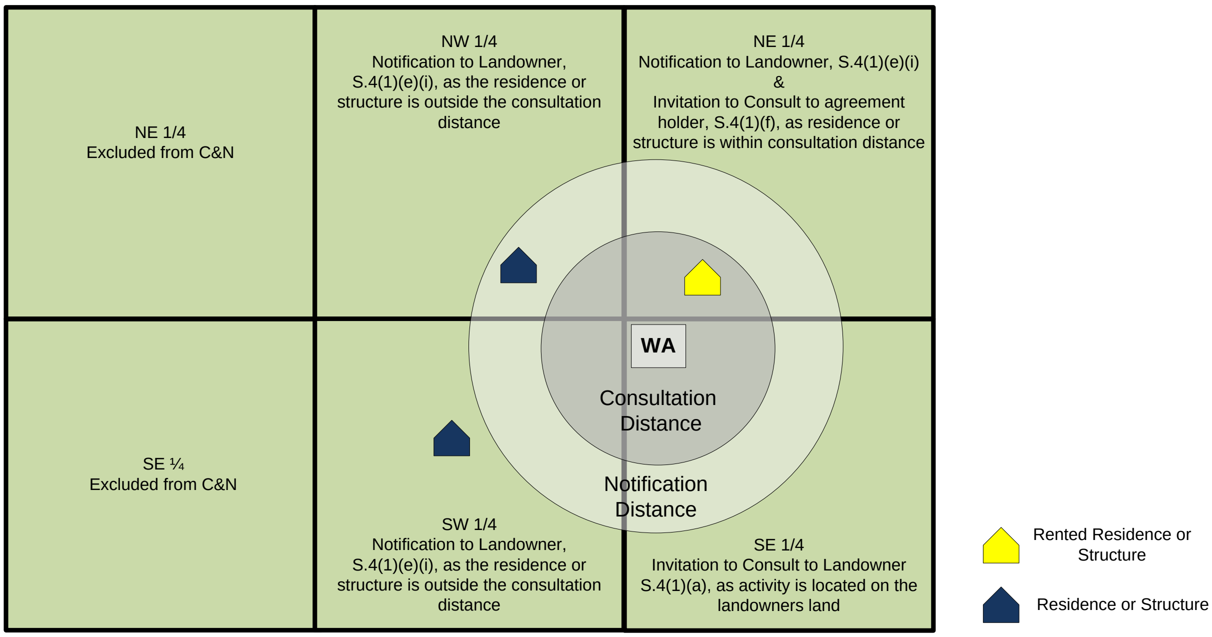
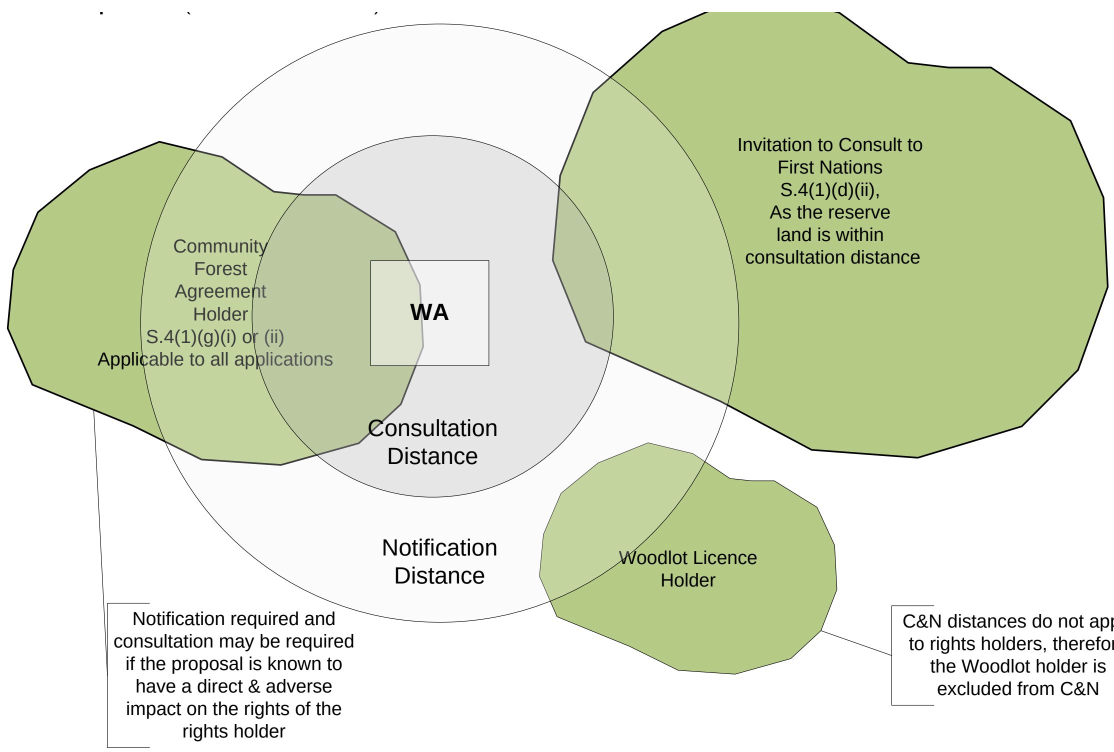


Figure 3.3



Calculating Consultation and Notification Distances
Minimum distances have been set for consultation and notification distances associated with specific activities. These distances are found in the Consultation and Notification Regulation, sections six through ten.

Distances are measured as horizontal distances from:

- The centre point of a facility area (if no well is located on, or proposed to be located on, the same cleared area as the facility)
- The centre point of a wellsite (if one or more wells or facilities are located on or proposed to be located on the wellsite
- The centre of the right-of-way of a pipeline, oil and gas road, or centre line of a seismic line

For each category of activity, there is a minimum distance where notification or consultation is required, as outlined in the following two tables.

Table 3.1. Notification Distances for Oil and Gas Activity

Oil and Gas Activity	Notification Distance
Processing plant, compressor station or pump station	3300 metres (or calculated distance from Appendix* D, whichever is greater)
Facility with area is less than five hectares	1500 metres (or calculated distance from Appendix* D, whichever is greater)
Facility with area is more than five hectares. One facility only.	1800 metres (or calculated distance from Appendix* D, whichever is greater)
Facility greater than or equal to five hectares in size; more than one facility.	1800 metres (or calculated distance from Appendix* D, whichever is greater)
Wellsite less than 5 hectares**; fewer than nine wells.	1500 metres (or calculated distance from Appendix* D, whichever is greater)
Wellsite greater than or equal to five hectares; nine or more wells.	1800 metres (or calculated distance from Appendix* D, whichever is greater)
Pipeline	200 metres (or calculated distance from Appendix* D, whichever is greater)
Road Construction	200 metres
Geophysical	400 metres

*Appendix D provides safety distances for the purposes of making persons contacted aware that they may at a later date be contacted with regards to emergency management planning.

**If an applicant has an existing permit for eight wells, and an additional application is made for a ninth well as a separate application, the ninth well must use the consulting distance for nine or more wells (1800 metres).

Table 3.2. Consultation Distances for Oil and Gas Activity

Oil and Gas Activity	Consultation Distance
Processing plant, compressor station or pump station	3300 metres (or calculated distance from Appendix* D, whichever is greater)
Facility with area is less than five hectares	1000 metres (or calculated distance from Appendix* D, whichever is greater)
Facility with area is more than five hectares. One facility only.	1300 metres (or calculated distance from Appendix* D, whichever is greater)
Facility greater than or equal to five hectares in size; more than one facility.	1300 metres (or calculated distance from Appendix* D, whichever is greater)
Wellsite less than 5 hectares**; fewer than nine wells.	1000 metres (or calculated distance from Appendix* D, whichever is greater)
Wellsite greater than or equal to five hectares; nine or more wells.	1300 metres (or calculated distance from Appendix* D, whichever is greater)
Pipeline	200 metres (or calculated distance from Appendix* D, whichever is greater)
Road Construction	200 metres

*Appendix D provides safety distances for the purposes of making persons contacted aware that they may at a later date be contacted with regards to emergency management planning.

**If an applicant has an existing permit for eight wells, and an additional application is made for a ninth well as a separate application, the ninth well must use the consulting distance for nine or more wells (1800 metres).

Figures 3.1 and 3.2 provide a visual reference of how the consultation or notification zone is applied.

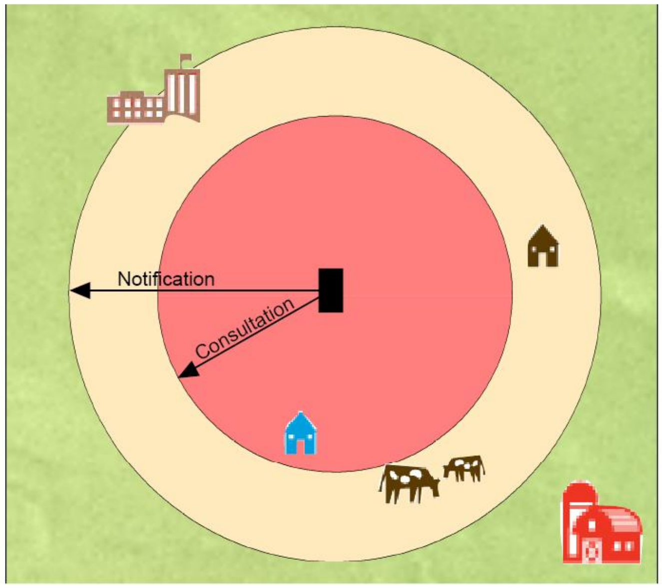


Figure 3.1. Illustration of consultation and notification distances surrounding a well or facility.

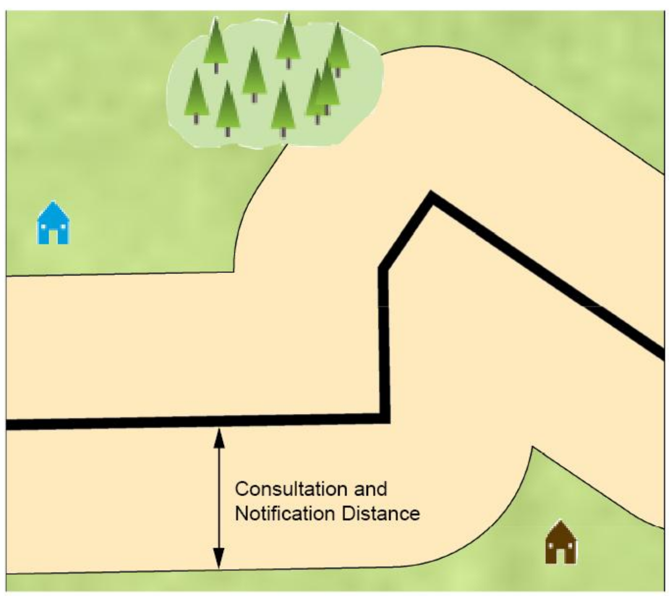


Figure 3.2. Illustration of consultation notification and distances along a pipeline.

4 Notification

Notification provides written information regarding proposed oil and gas activities to recipients within the identified notification distance.

Notification Process
Figure 4.1 summarizes the notification process leading up to submission of an application to the Commission.

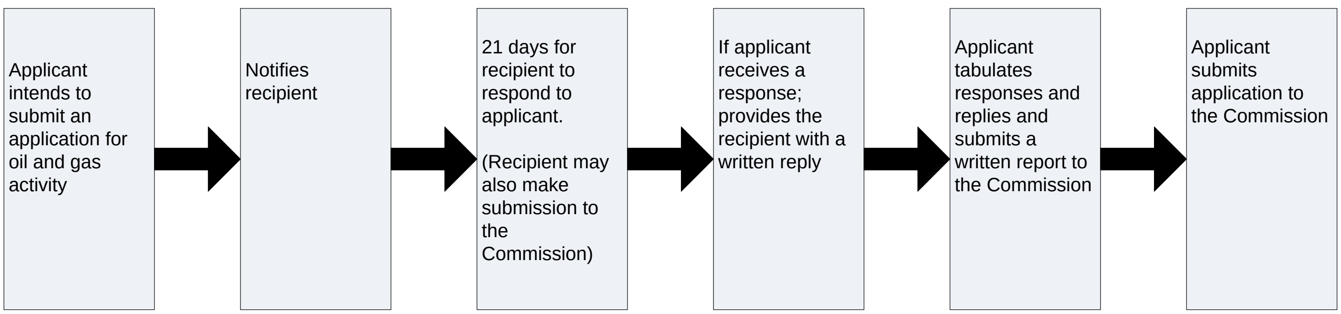


Figure 4.1. Notification Process.

Major Amendments
Notification must also be provided when applying for major amendments.

Who must be provided with notification?
Where required under the Consultation and Notification Regulation, the applicant must provide notice to:

- Other landowners whose property is within the notification distance
- First Nations for any Indian Reserve within the notification distance
- Local authority, if any of the following are within the notification distance:
    - Buildings or structures owned by the authority
    - An area identified in an official community plan in respect of which a statement and map designation has been made in accordance with section 877 (1) of the Local Government Act; Official Community Plan or
    - A known community watershed, all or a portion of which is within the boundary of the local authority's territory
- The Government of Canada for any federal buildings or structures within the notification distance
- Rights holders (other than Forest Licence or Tree Farm Licence holders), if the proposed activities on the area subject to the right of the rights holder.

Notification Requirements
The notice must advise:

- Of the person's intention to submit the application.
- The landowner that he or she may make a Written Submission to the Commission with respect to the application or proposed application.

For a full list of what information need to be included, refer to Consultation and Notification Requirements in Section 2.

Methods of Service
Detailed information on the rules governing the service and receipt of consultation and notification documentation is located in Appendix B , as well as Section 79 of OGAA and Section 16 of the Consultation and Notification Regulation.

Notice before Entry

Notification Before Fixing the Site of a Pipeline
Notification requirements specific to fixing the site of a pipeline are indicated in Section 23 (3) of OGAA.

Section 15 of the Consultation and Notification regulation. This notification precedes the consultation and notification associated with the pipeline permit application.

A person is required to notify the landowner of the intent to enter onto the landowner's property. The notice must include:

- The name of the person intending to enter the land
- The name, phone number, fax number and email address (if available), of the contact person for the company/agent providing notification
- A copy of the 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 company intends to submit an application to the Commission for a pipeline permit on the their land, the company or their representative will notify and consult the owner in accordance with Section 22 of OGAA and this regulation

A person intending to enter on land in accordance with Section 23 (2) must provide notice to the landowner at least two clear days after the information is deemed to have been received, before entering the land.

5 Consultation

Consultation is the exchange of information regarding proposed oil and gas activities between applicants and parties within the identified consultation distance. These parties (recipients) become engaged in the exchange when they receive an Invitation to Consult from an applicant.

Consultation may include discussion as well as documented materials, to ensure full understanding of the proposal and any associated interests.

Where consultation is conducted with recipients, notification is not required.

Consultation Process
The consultation process is outlined in Figure 5.1.

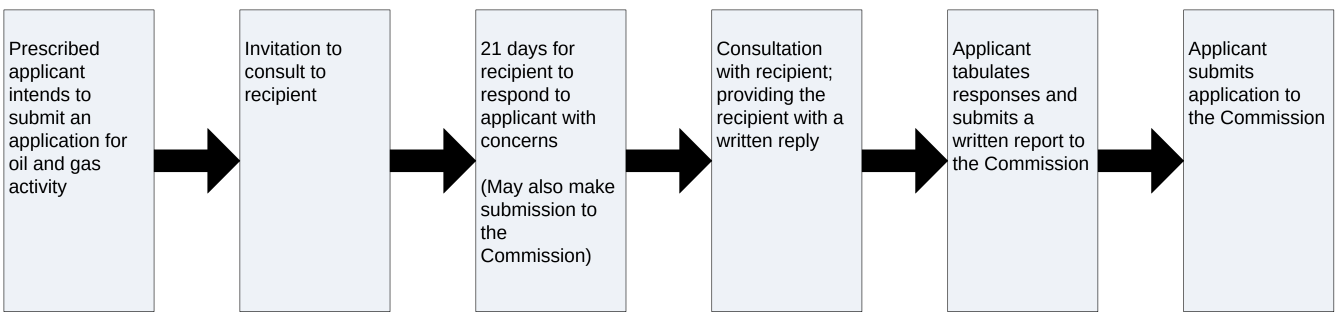


Figure 5.1. Consultation Process.

Who must be consulted?

This consultation is separate from consultations related to surface land leases between landowners and applicants.

Applicants making an initial application for a permit must provide an Invitation to Consult to parties that fall within the prescribed consultation distances(figures 3.1 and 3.2).

Invitation to Consult must also be provided when applying for major amendments.

Invitation to Consult must be provided to:

- The owner of the land on which the proposed activity will take place Other landowners whose residence, school or related structure, is within the consultation distance.
- Renters or leasers of a residence or structure used for livestock within the consultation distance.
- The local authority for their buildings or structures within the consultation distance.
- First Nations for any Indian Reserve within the consultation distance.
- The Government of Canada for any federal buildings or structures within the consultation distance.
- Rights holders, excluding agreements under the Petroleum and Natural Gas Act where:
    - The proposed activities are on an area subject to a right of the rights holder, and
    - It is known to the applicant that the ability of the rights holder to exercise their right will be directly and adversely impacted.

Consultation in Municipalities

Because of higher population density, consultation in municipalities differs in practice. When proposing a pipeline in a municipality the applicant must provide an Invitation to Consult to the ministry responsible for the Transportation Act and the local municipal council when it:

- Is to be located within a municipality and
- Is within the right-of-way of an arterial highway or municipal highway and
- Is to be used for transporting petroleum, natural gas, water or a combination.

As per Section 4(4) of the Consultation and Notification Regulation, the applicant must provide an Invitation to Consult to the local municipal council for applications for a pressure regulating station on the applicant's land for distribution pipelines in municipalities.

Rights Holders

Under OGAA, if it is known to the applicant that a rights holder, will be directly and adversely affected by a proposed activity, the applicant must provide an Invitation to Consult. The applicant must also summarize the results of the invitation or subsequent consultation as part of the written report.

Methods of Service

Detailed information on the rules governing the service and receipt of consultation and notification documentation is located in Appendix B, as well as Section 79 of OGAA and Section 16 of the Consultation and Notification Regulation.

6 Replying to Recipients

Recipients of consultation or notification with interests in or concerns about a company's proposed oil and gas activity may submit a Written Response to the applicant or the applicant's designated contact.

This response may detail concerns and any proposed recommendations for mitigation. If the response is received within the 21-day consultation and notification period the applicant must reply, in writing, as soon as possible.

Where a Written Response to consultation includes a request for a meeting, the applicant must make reasonable efforts to meet with the recipient.

Applicant Written Reply

The applicant written reply to the recipient must

- Provide a description of any revisions to the proposed activities resulting from the recipient's response.
- State that the Written Response from the recipient, and the written reply from the applicant will be included in the written report submitted to the Commission.
- State that the recipient may also make a Written Submission to the Commission.

All responses from the recipient as well as all replies from the applicant must be compiled and submitted to the Commission.

Line List

The Line List is provided as a useful template for the applicant to submit required information, including recipient concerns. Its purpose is to ensure that all required information is included for review.

The Line List Template can be found on the Commission website and includes an example for guidance.

The Line List must be included in the Consultation Package.

7 Revisions and Amendments

Revisions

Proposals may be revised because of the consultation processes. If the revisions are not significant, no further consultation or notification is required. However, if the revisions to the proposal are significant, the applicant may need to carry out further notification and consultation activities.

Significant Revisions
A significant revision is defined as:

- Adding one or more of the following activities
  - Drilling or constructing a petroleum or natural gas well or facility, or
  - Constructing a pipeline for petroleum, natural gas or both, or
- A change in the proposed area with
  - An increase in project area 1 hectare or more, or
  - A shift in direction 100 m or more in any direction.

A significant revision may result in a different applicable consultation distance than the initial proposal. For example:

- Incorporating a facility onto a wellsite .
- Consolidate wellsites to a single wellsite exceeding five hectares.

Significant Revisions and Consultation Distance

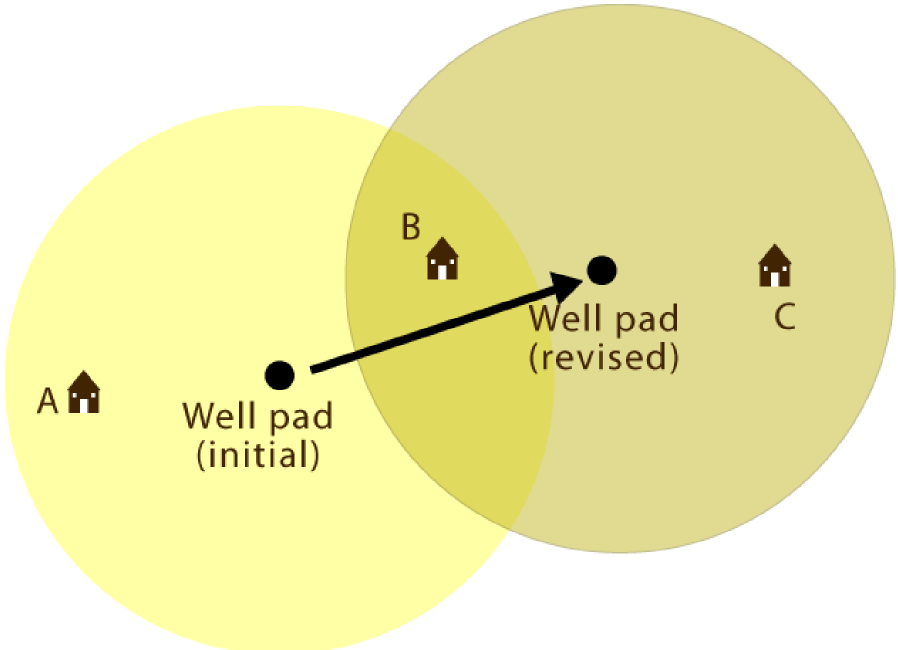


Figure 7.1. Revised consultation distance.

Consultation After Revisions

When additional distance is created, the recipients in the new area require consultation or notification. In addition, those who are affected by the revision and were previously consulted or notified, require information informing them of the revision.

All recipients within the consultation and notification distances must be consulted with or notified again when revisions include a new well, facility or pipeline.

Amendments

An applicant submitting an amendment to a permit must first provide notice to the landowner on whose land the oil and gas activity is permitted (under Section 31 (1) of OGAA). The notice must provide a description of the proposed amendment. The notice must also advise the recipient that they may send a Written Submission (within 15 days of receiving the notice) to the Commission regarding the amendment.

After receiving the application for amendment, the Commission may require the permit holder to carry out prescribed notices or consultations (under Section 31 (5) of OGAA). The prescribed notices and consultations are the same as those given in Sections 3 and 4. The Commission recommends that applicants carry out consultation and notification prior to submitting an application for a major amendment.

Non-Major Amendments
Non-major amendments do not require consultation or notification with the exception of the landowner on whose property the activity is taking place. The landowner must be notified in all cases.

Major Amendments
A major amendment is a change to a permit to:

For amendments on Private land, ancillary site area should **not** be included in the one hectare guideline; however, it must be referenced on the construction plan..

- Increase (by one hectare or more) the approved area on a wellsite, facility, pipeline, oil and gas road or seismic line and/or
- Shift (by 100 meters or more) the approved area associated with the above listed and/or
- Change the approved activities under the permit by adding approval with respect to a petroleum or natural gas well, facility or pipeline.

After an application for a major amendment has been submitted, the Commission may require, under Section 31(5) of OGAA, a permit holder to conform to the Consultation and Notification Regulation. If the permit holder is required to consult and/or notify, a 21-day review period is in effect, unless the below engagement-before-application criteria are met.

A major amendment does not include adding approval for:

Blow case	Odourization pot
Chemical pump	Pig trap
Chemical tank	Pipeline for flow reversal
Coalescer	Propane tank
Condensate pump	Recycle pump
Cooler	Regulator
De-sand tank	Regulator vault
Field header	Sand filter
Filter pot	SCADA
Flare knock out drum	Scrubber
Fresh water tank	Separator
Gas boot	Vapour recovery unit
Generator under 200 kW	Valve
Line heater	Valve vault
Meter	Water injection pump
Facility linkage change from a well or facility	

Engagement Before Application
If consultation and notification requirements are met before applying for a major amendment, an applicant may submit the amendment application to the Commission before the end of the 21-day review period. This is only an option if:

- The applicant has provided an opportunity for consultation and notification to all potentially affected parties.
- The applicant has replied to responses from all recipients.
- There are no objections to the application or requests for meetings.

If the criteria above are not met, then the applicant must wait the full 21-day period before submitting the amendment.

Exclusion from the requirements of the Consultation and Notification Regulation

Non-Major Amendments
Non-major amendments do not require consultation or notification.

In addition, the following activities when located on Crown Land are excluded from Consultation and Notification Regulation requirements:

- The construction of temporary water or gas pipeline for well testing if located on the surface of the wellsite, and not intended for continued use after the associated well construction.
- The operation of a pipeline, and use of a road.

Notification to Landowners
Even where an activity is excluded from the consultation and notification regulation, the applicant must provide notification to the landowner on whose land the activity is proposed under Section 22 (2) of OGAA (for initial applications) or Section 31 (1) of OGAA (for amendment applications).

Exemption from Consultation and Notification

Upon written request from the applicant, the Commission may exempt an application from consultation and notification. In doing so, the Commission may also substitute other consultation and notification requirements.

Exemptions can only be granted for new applications.

8 Written Report

Each permit application subject to consultation and notification requirements must submit a written report to the Commission, summarizing the results of consultation and notification activities. The written report consists of:

- Written Report Cover Sheet.
- Written Report Line List.
- Consultation and Notification Map.
- All Written Responses from recipients and replies from the applicant.

It is recommended that the report include a sample copy of the Notification and Invitation to Consult letters sent to the recipient.

Consultation and Notification Map

A consultation and notification map that shows the proposed activities in relation to dwellings, facilities and nearby urban centers.

For small projects encompassing relatively small areas, a 1:20,000 scale map is acceptable. Larger projects must be at an appropriate scale to clearly show the activities in relation to dwellings, facilities and nearby urban centers.

Written Report Cover Sheet

This section provides instructions on how to complete the Written Report Cover Sheet.

Block A – Applicant Information

Applicant Name Enter the legal name of applicant company conducting the required consultation and notification.

Applicant Contact Information Enter the full name and contact information for representative who performed the consultation and notification activities.

Block B – Consultation and Notification Information

The information within this block helps to highlight any submissions or outstanding concerns received in association with the permit application. The information is forwarded to the statutory decision maker when outstanding concerns are noted.

For well, facility and petroleum/natural gas pipeline applications, indicate the EPZ distance. For pipeline applications with multiple segments and multiple EPZ distances, indicate the greatest EPZ distance.

Block C – Summary of Written Report

Activity Type Check the box that indicates the proposed oil and gas activity. Choose from:

- Well
- Pipeline
- Facility
- Geophysical
- Other; specify what the activity is

Location Indicate the location of proposed oil and gas activity.

Commission File No. Enter the seven digit tracking number used by the Commission. Example: 9000000.

Distance Applied Enter the distance for both consultation and notification. Applicants must consult and notify to the distances outlined in the Consultation and Notification Regulation, or to the EPZ distance (if applicable); whichever is greater.

Comments Include any additional comments or explanation as required.

Block D – Written Report Deliverables

Written Report Cover Sheet A completed Written Report Cover Sheet to summarize what consultation and notification activities have taken place must be submitted with every written report.

Written Report Line List A Written Report Line List to summarize interactions with recipients must be submitted with every written report.

Package of Replies and Responses The package of responses must include any recipient responses to consultation or notification and replies sent from the applicant. This must be submitted with the written report in every instance that the information is available. Select N/A if no responses have been received.

C&N Map For small projects encompassing relatively small areas, a 1:20,000 scale map is acceptable. Larger projects must be at an appropriate scale to clearly show the activities in relation to dwellings, facilities and nearby urban centers.

The Commission recommends that a sample copy of the letters provided to recipients for notification or Invitation to Consult be submitted with the written report deliverables.

Block E – Signature

This information field may only be signed by an employee or agent of the applicant with signing authority. By signing in this block, the applicant or authorized signatory attests that all of the information provided on the application is true and correct.

Written Report Line List

To summarize the consultation and notification activities performed with each recipient, applicants must submit a line list as part of the written report.

A Written Report Line List Template is available on the Commission website. The template provides a convenient and orderly format for submitting required line list information.

Company Name Enter the applicable company submitting the application.

Project Location Enter the legal description for the project location.

Company File No. Enter the internal company file number for the application (if applicable).

Cross Reference This block is intended to identify the items on the C&N map for quick reference when cross referencing the line list.

Application Type Select the application type from the dropdown menu. Choose from:

- Initial Proposal
- Permit Amendment
- Permit Extension
- Application Revision

Activity Type Select the oil and gas activity type for which engagement was conducted, from the dropdown menu. Choose from:

- Geophysical exploration
- Pipeline
- Well
- Facility
- Related activity
- Multiple activities

Recipient Select the recipient type from the dropdown

Type menu. Choose from the following types detailed in the Consultation and Notification Regulation:

- Landowner, under section 4(1)(a).
- Local Authority, under section 4(1)(b).
- Government of Canada, under section 4(1)(c).
- First Nations, under section 4(1)(d).
- Person, under section 4(1)(e).
- Person, under section 4(1)(f).
- Rights Holder, under section 4(1)(g).
- Municipal Council
- Ministry Responsible for the Transporation Act
- Other; additional recipients notified under company best practices.

Recipient Name Enter the full name of the recipient, including first and last names where applicable.

Recipient Address Enter the legal location of the recipient's property using the legal land/parcel description.

All legal locations that will be impacted by the contemplated activities must be noted. This is also required in cases where a project will be carried out on an area covering more than one legal location, but owned by the same land owner.

Recipient Preferred Method of Service and Contact Information Indicate the recipients preferred method of service - address and contact information, email address, etc. for each directly impacted land owner.

Engagement Type Choose from the dropdown menu:

- Invitation to Consult
- Invitation to Consult under C&N Reg s. 4 (2)
- Notification

Construction Plan Map No. Revision No and Revision date	Enter the internal job number, revision number and revision date of the construction plan map used during engagement.
Date Consultation Commenced	Enter date upon which notification or invitation to consult was sent.
Method of Service	Choose from: • Left copy with person (s. 79 (1)(a) OGAA) • Fax • Left copy with persons agent (s. 16(1)(a) C&N Reg.) • Sent by ordinary or registered mail (s. 16(1)(b) C&N Reg.) • Email (s. 16(1)(c) C&N Reg.) • Left copy in residence mailbox (s. 16(1)(d) C&N Reg.) • Attached copy to door or conspicuous place at residence (s. 16(1)(e) C&N Reg.)
Date Deemed Received	Enter the date upon which the notification or Invitation to Consult is received, or deemed to be received, under section 79 of OGAA.
Estimated Distance to Residence	Enter the linear distance (in metres) of the recipient's residence / location from the proposed oil and gas activity.
Summary of Engagement	Summarize what consultation or notification activities occurred; any responses, replies or meetings; and what actions were taken to address concerns raised by the recipient.
Outstanding Concerns	Either provide a detailed description of any unresolved concerns at the time of line list submission, or indicate that there are no outstanding concerns.
Written Submission	Indicate if a Written Submission was received; yes or no. This enables the Commission to link pre-application Written Submissions to the submitted application.

Best Practice

If there is a major schedule change for oil and gas activities, or the permit holder decides not to carry forward a planned oil and gas activity, all recipients should be notified of the change.

9 Extensions

A permit holder applying for a permit extension may be required to carry out the prescribed notices or consultations (under Section 32 (3) of OGAA).

The Commission reviews each application on a case-by-case basis.

If the Commission requires consultation, notification, or both, the applicant will proceed through the process as though it were an initial application for a new permit.

10 Compliance

OGAA
A person found by the Courts, to have contravened the Oil and Gas Activities Act may be subject to a fine not exceeding the amount specified in Section 86 of the act. A person found by the Commission, to have contravened OGAA may be liable to an administrative penalty not exceeding the amount specified in the Administrative Penalties Regulation.

C&N
A person who contravenes the Consultation and Notification Regulation (as specified in the Administrative Penalties Regulation, Section 4), may be liable to an administrative penalty ranging from $5,000 to $100,000.

Appendix A – Safety

Safety

Consultation, notification and planning in relation to safety is addressed through emergency planning requirements and are not part of the Consultation and Notification regulation.

Safety distances (Emergency Planning Zones) in this manual are referenced for the purposes of making recipients aware that they may later be contacted concerning emergency management planning.

In cases where the safety distances encompass more area than the standard consultation and notification distance, those within the safety distance will be included in the consultation and notification process.

Appendix B – Consultation and Notification Timelines

Determining Consultation and Notification Timelines

In accordance with Section 22(3) of OGAA, the applicant must carry out the prescribed consultations and notification, which includes a 21- day review period. Applications submitted prior to the end of the 21- day review period are in contravention of OGAA s. 22(3).

If the applicant has a Written Response stating “no objection” from all recipients, they may submit the application prior to the application submission dates indicated above.

It is important that applicants correctly determine the consultation and notification timelines required, based on the method of service used.

Methods of Service

The methods of service are the same regardless of notification, consultation or who is serving the documentation.

Documentation Service Methods

All documentation must follow the methods of service set out in Section 79(1) of OGAA and as prescribed within the Service Regulation:

- Leave a copy with the person.
- Leave a copy with the agent of the person.
- Send a copy by ordinary mail or registered mail to the address at which that person resides or carries out business.
- Send a copy by electronic mail to the person’s e-mail address.
- Leave a copy in a mail box or mail slot for the address at which the person carries out business.
- Attach a copy to the door or other conspicuous place at the address at which the person carries out business.
- Fax a copy to the person.

Documentation Receipt

A document given or served in accordance with the above methods is deemed to be received as follows, as per Section 72(2) of OGAA and the Service Regulation:

- On the 5th day after it is mailed, if given or served by sending a copy via ordinary or registered mail.
- On the 3rd day after it is sent, if given or served by sending a copy via email or fax.
- On the 3rd day after it is left, if given or served by leaving a copy in a mail box or mail slot.
- On the 3rd day after it is attached, if given or served by attaching a copy to a door or other conspicuous place.

Subject to Section 25 of the Interpretation Act, the 21-day period begins once the documents are deemed received in accordance with the prescribed method of service.

Table B.1 Methods of Service Dates

Method of Service	Deemed Received
Mail	5^{th} day after sent
Email	3^{rd} day after sent
Fax	3^{rd} day after transmitted
Mail Box	3^{rd} day after left
Attach	3^{rd} day after attached
Agent	Immediately after left

Determining C&N Timelines – Service Period and 21-day Response Period

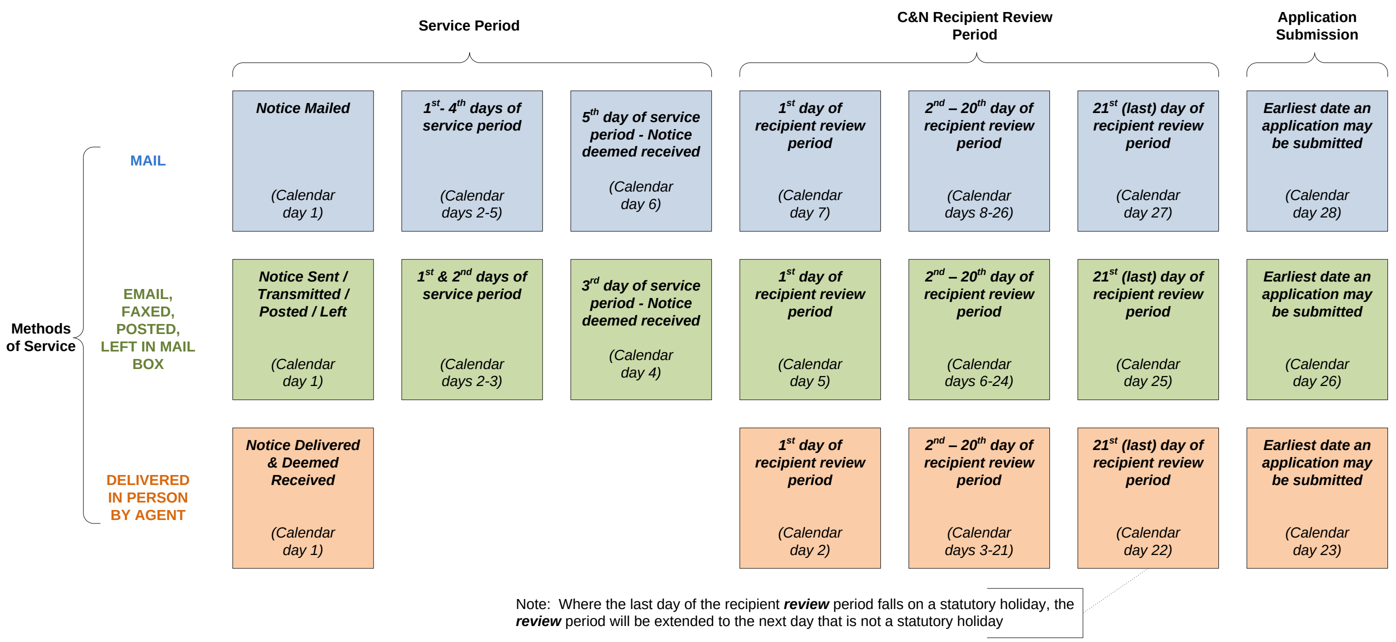


Figure B.1 Using service period and response period to determine consultation and notification timelines.

No Further Obligation
The applicant is not required to pursue any further consultation or notification activities under the Regulation:

- 21 days after consultation or notification was provided If no Written Responses were received.
- 21 days after the last required consultation or notification was provided, or the date the last Written Response is received; whichever is the earlier date.
- When a Written Response has been received from every recipient, and none contain reasons why the proposed activities should not be carried out:
    - 21 days after the last required consultation or notification was provided or the date that the last recipient withdraws all objections; whichever is the earlier date.
- When a Written Response has been received from every recipient, and all objections have been withdrawn:
    - 21 days after the last required consultation or notification was provided or the date the last Written Reply is provided to the recipient(s).

Where a recipient has requested a meeting in their Written Response to an Invitation to Consult, the obligation to consult is not met until the applicant has met with or made reasonable efforts to arrange a meeting with the recipient.

Appendix C - Consultation and Notification Regulation

The Consultation and Notification Regulation (the Regulation) provides consistency and predictability for consultation and notification requirements, and the permit decision process.

Under the Regulation, the acts of consultation and notification are separate and distinct processes, aimed at separate and distinct recipients.

Applicants must carry out consultation, provide notice or both, with respect to the proposed oil and gas activities and related activities (under Section 22 (3) of OGAA).

The Consultation and Notification Regulation:

- Specifies who must carry out consultations and notifications before submitting an application to the Commission.
- Specifies who must be contacted .
- Defines the consultation and notification requirements for oil and gas permit applicants.
- Defines the rights of recipients .
- Establishes requirements for potential quality of life impacts.

Related Regulations

The Consultation and Notification Regulation relates to the following OGAA sections:

- Section 21 (Permit required).
- Section 22 (Consultation and notification).
- Section 23 (Preliminary plan).
- Section 24 (Application for permit and authorization).
- Section 25 (Permits and authorization issued by Commission).
- Section 31 (Amendment of permit).
- Section 32 (Expiration of permit and authorization).
- Section 72 (Appeal).
- Section 79 (How to serve documents and notices).
- Section 107 (Consultations and notifications).
- Section 112 (1) (l) (General).

Other Provincial legislation that this regulation is linked to includes the following:

- The Petroleum and Natural Gas Act.
- The Land Act regarding the Integrated Land Management Bureau.
- The Forest and Range Practices Act regarding forest tenures.
- The Local Government Act.
- The Transportation Act.

Appendix D – EPZ Distance Calculation

Facility Distances – Schedule A

EPZ distances for the purposes of Section 6 of the Consultation and Notification Regulation are determined by reference to the maximum H_2S release volume from any pipeline entering or leaving the facility, calculated in accordance with the applicable of the following formulas.

The EPZ distance for the purposes of Section 6 is the distance indicated on the vertical axis of Chart A that corresponds to the release volume indicated on the horizontal axis of the chart, as indicated by the graph line on the chart.

Equations

Gas Pipeline H_2S Release Volume

The equation for calculating the maximum potential H_2S release volume from a pipeline is as follows:

$$V = \frac{2.232 \times 10^{-6} D^2 L(P+101.325)H}{Z(T+273)}$$

Where

V = maximum potential H_2S release volume in m^3

D = internal diameter of pipe in millimetres (mm)

L = length of pipeline between block valves (km)

P = licensed maximum operating pressure in kilopascals (kPa)

H = licensed H_2S content (moles/kilomole) for the pipeline

Z = compressibility factor at reduced pressure and reduced temperature

T= pipeline minimum operating temperature (°C)

Liquid Multiphase Pipeline H_2S Release Volume

For sour liquid multiphase pipelines, the volume of H_2S is determined by the following equation:

$$V = \frac{(GLR \times GVF)}{1000(GLR + GVF)} \times V_{p1} \times H$$

Where

V = potential H_2S release volume at standard condition (m^3)

GLR = produced gas-liquid ratio at maximum operating pressure (MOP) (m^3/m^3)

GVF = ratio of produced gas volume at standard conditions to the volume of gas at MOP (m^3/m^3)

V_{p1} = volume of the pipeline (m^3)

H = licensed H_2S content (moles/kilomole) for the pipeline

Gas Multiphase Pipeline H_2S Release Volume

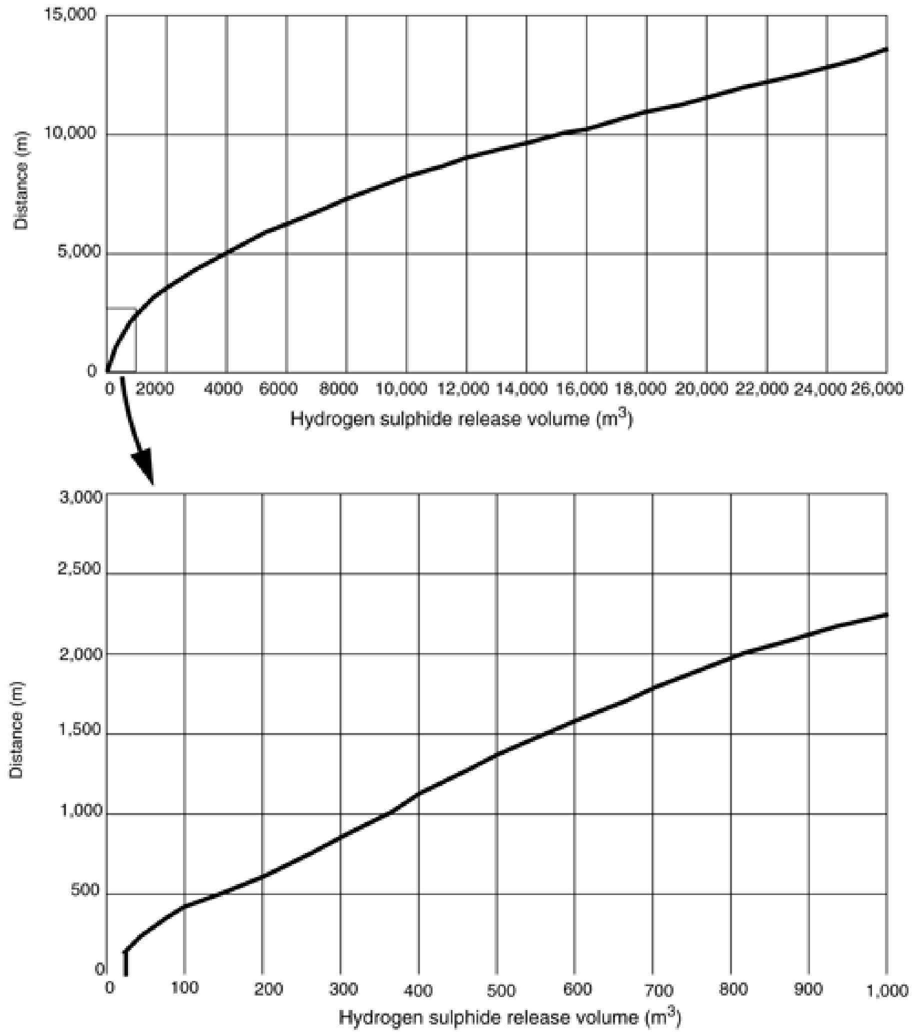
$$V = 0.785 \times 10^{-6} D^2 L \frac{(GLR \times GVF)}{(GLR + GVF)} \times H$$

Where

D = internal diameter of pipe in millimetres (mm)

L = length of pipe between block valves (km)

CHART A: FACILITY DISTANCES



Well Distances – Schedule B

EPZ distances for the purposes of Section 7 are determined by reference to potential H_2S release rates from a well during either drilling or completion or re-completion operations.

H_2S release rates

Drilling operations

H_2S release rates during drilling operations must be determined in accordance with the following equation and the notes that follow:

$$H_2S \text{ Release rate} = \frac{H_2S\% \times AOFP}{8{,}640{,}000}$$

Where

AOFP = maximum gas rate (m^3/d)

$H_2S\%$ = volume of H_2S expressed as a percentage of the total volume of gas

Gas Wells

For gas wells, if an AOFP test has been conducted and value determined for a formation in a well, that value must be used. If an AOFP test value has not been determined, a theoretical AOFP must be calculated using the following formula:

$$AOFP = \frac{\text{Gas Test Rate} \times Pr^2}{(Pr^2 - Pf^2)}$$

Where

AOFP = maximum gas rate (m^3/d)

Gas Test Rate = gas flow rate during testing (m^3/d)

Pr = reservoir pressure (kPa)

Pf = flowing bottom hole pressure (kPa)

Oil wells

For oil wells, the AOFP must be calculated using the following formula:

$$AOFP = \frac{\text{Oil Test Rate x GOR}}{[1 - 0.2 \text{ x } (Pf / Pr) - 0.8 \text{ x } (Pf / Pr)^2]}$$

Where

Oil test rate = oil flow rate during testing (m^3/d)

GOR = gas oil ratio from oil test rate well (m^3/m^3)

Pr = reservoir pressure (kPa)

Pf = flowing bottom hole pressure (kPa)

For a proposed well, the maximum gas rate (AOFP) values and maximum H_2S concentrations for each H_2S-bearing formation, must be determined for each of at least 5 wells drilled and tested in an analogous geological area or pool within 5 kilometres of the proposed well.

The H_2S release rates for all potential H_2S-bearing formations in the proposed well must be determined based on the highest AOFP and highest H_2S concentration for each formation and the sum of the H_2S release rates for all the formations that will be open to the well bore during drilling operations.

If appropriate data does not exist or is otherwise inadequate, the consultation and notification distance is three km from the proposed well or well site.

Completion or re-completion operations

For completion or re-completion operations in an existing well, data from the appropriate formation in the well must be used to determine H_2S release rates. If the appropriate data does not exist or is otherwise inadequate, H_2S release rates must determined in accordance with the equations and notes set out above for drilling operations.

Determining Well Distances
The distance for the purposes of Section 7of the Consultation and Notification Regulation is the distance indicated on the vertical axis of Chart B that corresponds to the release rate indicated on the horizontal axis of the chart, as indicated by the graph line on the chart.

Chart B: Well Distances for Higher H_2S Release Rates

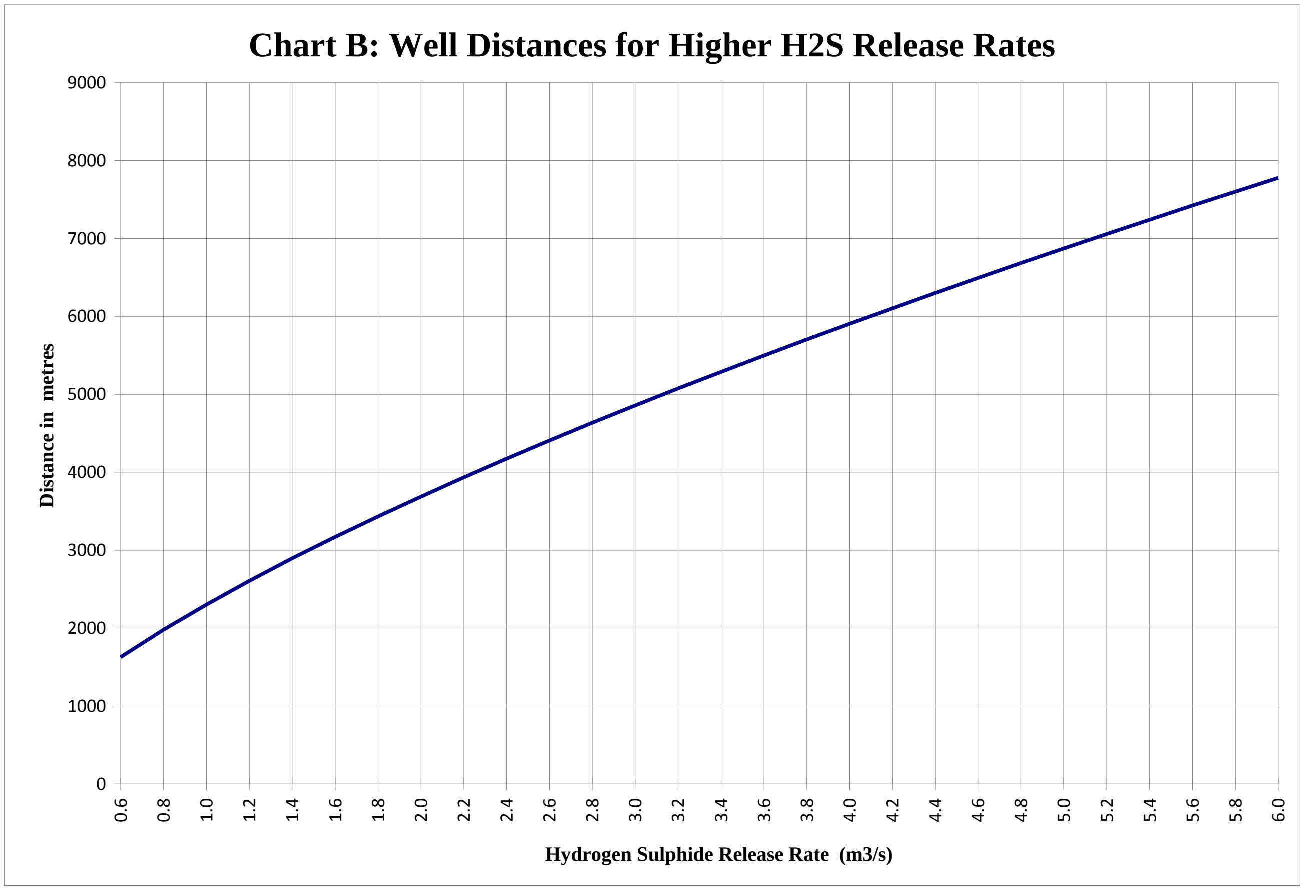
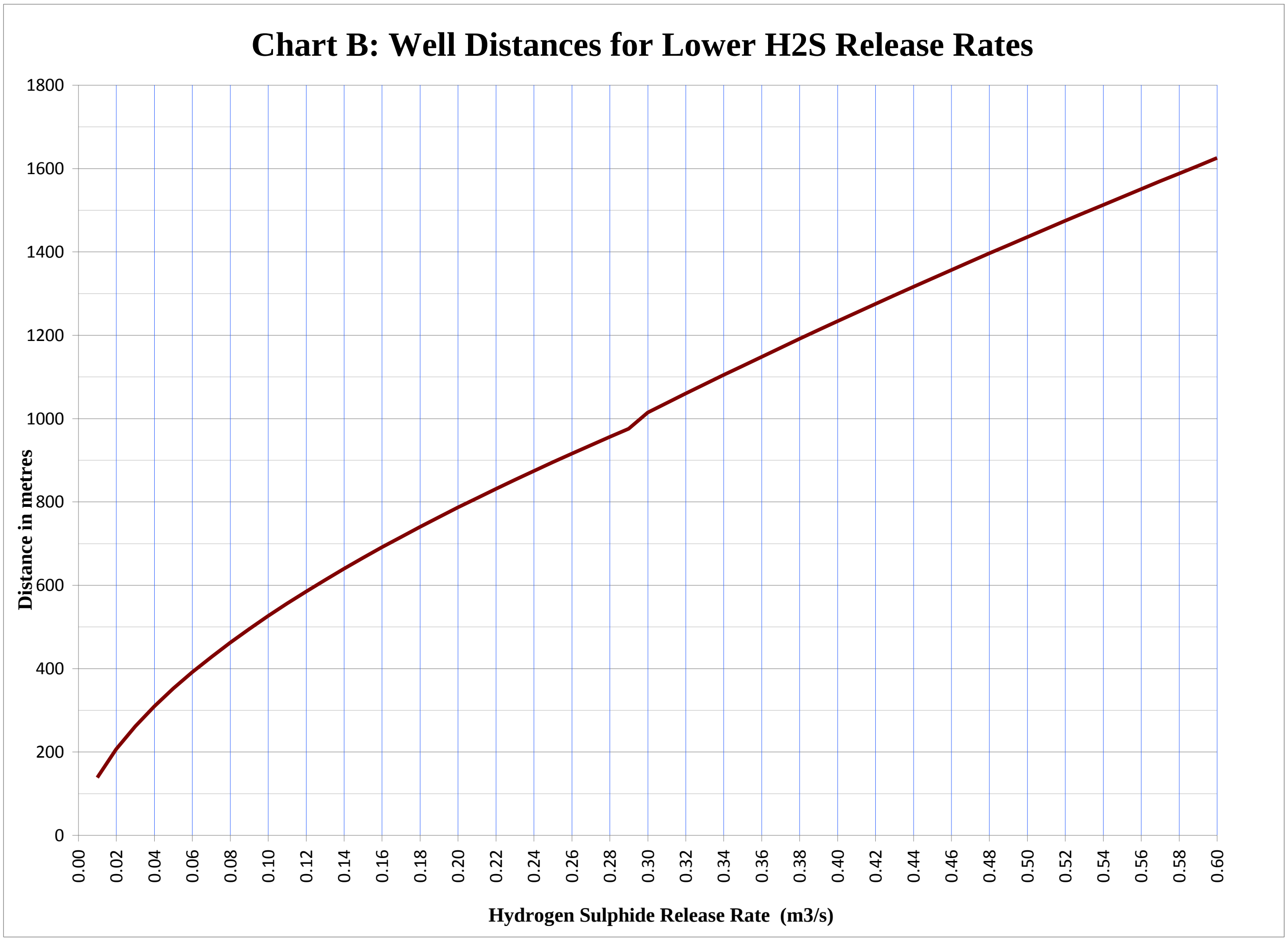


Chart B: Well Distances for Lower H_2S Release Rates



Pipeline Distances - Schedule C

EPZ distances for the purposes of Section 8 of the Consultation and Notification Regulation are determined by reference to the maximum H_2S release volume from the pipeline, calculated in accordance with the applicable of the following formulas. The distance for the purposes of Section 8 is the distance indicated on the vertical axis of Chart C that corresponds to the release rate indicated on the horizontal axis of the chart, as indicated by the graph line on the chart.

Equations

Gas Pipeline H_2S Release Volume

The equation for calculating the maximum potential H_2S release volume from a pipeline is as follows:

$$V = \frac{2.232 \times 10^{-6} D^2 L (P+101.325) H}{Z(T+273)}$$

Where

V = maximum potential H2S release volume in m3

D = internal diameter of pipe in millimetres (mm)

L = length of pipeline between block valves (km)

P = licensed maximum operating pressure in kilopascals (kPa)

H = licensed H2S content (moles/kilomole) for the pipeline

Z = compressibility factor at reduced pressure and reduced temperature

T= pipeline minimum operating temperature (°C)

Liquid Multiphase Pipeline H_2S Release Volume
For sour liquid multiphase pipelines, the volume of H_2S is determined by the following equation:

$$V = \frac{(GLR \times GVF)}{1000(GLR + GVF)} \times V_{p1} \times H$$

Where

V = potential H_2S release volume at standard condition (m^3)

GLR = produced gas-liquid ratio at maximum operating pressure (MOP) (m^3/m^3)

GVF = ratio of produced gas volume at standard conditions to the volume of gas at MOP (m^3/m^3)

Vp1= volume of the pipeline (m^3)

H = licensed H_2S content (moles/kilomole) for the pipeline

Gas Multiphase Pipeline H_2S Release Volume

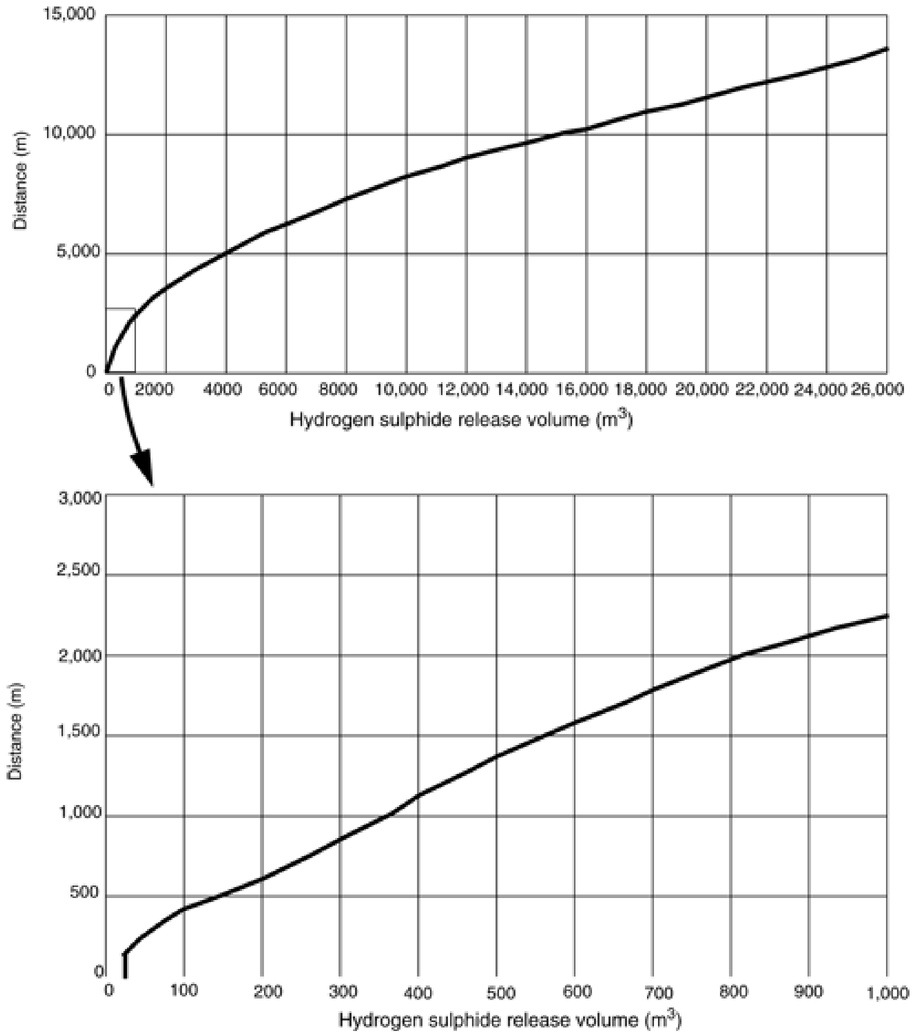
$$V = 0.785 \times 10^{-6} D^2 L \frac{(GLR \times GVF)}{(GLR + GVF)} \times H$$

Where

D = internal diameter of pipe in millimetres (mm)

L = length of pipe between block valves (km)

CHART C: PIPELINE DISTANCES



IMPORTANT INFORMATION

B.C. Reg. 279/2010 Deposited September 24, 2010

Oil and Gas Commission effective October 4, 2010

Oil and Gas Activities Act

CONSULTATION AND NOTIFICATION REGULATION

Note: Check the Cumulative Regulation Bulletin 2013

for any non-consolidated amendments to this regulation that may be in effect.

[includes amendments up to B.C. Reg. 56/2013, June 3, 2013]

Contents

Part 1 — Definitions and Interpretation

Definitions

1 In this regulation:

"Act" means the *Oil and Gas Activities Act*;

"applicant" means a person who

(a) is a prescribed person,

(b) submits an application for a major amendment under section 31 of the Act and is required by the commission under subsection (5) of that section to carry out consultations or notifications, or

(c) submits an application for an extension under section 32 of the Act and is required by the commission under subsection (3) of that section to carry out consultations or notifications;

"approved activities" means oil and gas activities for which an applicant has a permit;

"approved area" means an area, specified in a permit, on which a permit holder has permission to carry out an oil and gas activity;

"arterial highway" has the same meaning as in section 1 of the *Transportation Act*;

"community watershed" means a community watershed continued or established under the *Oil and Gas Activities Act*;

"consultation distance" means a distance, set out in section 6, 7, 8, 9 or 10 and measured in accordance with section 2, from the site of proposed activities, within which an applicant with respect to the proposed activities must carry out consultations in accordance with this regulation;

"facility area" means an area within which an applicant intends to locate one or more facilities;

"highway" has the same meaning as in section 1 of the *Transportation Act*;

"local authority" means a regional district and a municipality;

"major amendment" means an amendment to a permit to do one or more of the following:

(a) increase by one hectare or more the approved area with respect to a wellsite, facility, pipeline, oil and gas road or seismic line;

(b) shift by 100 meters or more the approved area with respect to anything referred to in paragraph (a);

(c) change the approved activities under the permit by adding approval with respect to

(i) a petroleum or natural gas well or facility, but not including an approval with respect to a blow case, coalescer, condensate pump, cooler, field header, filter pot, flare knock out drum, gas boot, meter, odourization pot, chemical pump, water injection pump, recycle pump, regulator, regulator vault, sand filter, scada, scrubber, separator, chemical tank, de-sand tank, vapour recovery unit, facility linkage change to a well or facility, generator under 200 kW, line heater, pig trap, valve, valve vault, fresh water tank, propane tank, or

(ii) a pipeline for petroleum, natural gas or both, but not including a pipeline for flow reversal;

"municipal highway" has the same meaning as in section 1 of the *Transportation Act*;

"notification distance" means a distance, set out in section 6, 7, 8, 9 or 10 and measured in accordance with section 2, from the site of proposed activities, within which an applicant with respect to the proposed activities must provide notification in accordance with this regulation;

"oil and gas road" means a road prescribed for the purposes of paragraph (f) of the definition of "oil and gas activity" in section 1 (2) of the Act;

"prescribed person" means a person in a class of persons prescribed under section 3;

"proposed activities" means oil and gas activities that are or will be the subject of an application under section 24, 31 or 32 of the Act;

"proposed area" means the area on which an applicant intends to carry out proposed activities;

"rights holder" means a person who holds any of the following rights:

(a) a

(i) permit under section 14 of the *Land Act*, or

(ii) licence under section 39 of the *Land Act*

under which the person is granted non-intensive occupation or use of the land;

(b) a community forest agreement, forest licence, timber sale licence, tree farm licence or woodlot licence under the *Forest Act*;

(b.1) a forestry licence to cut under the *Forest Act*, if the licence is a major licence as defined in section 1 of that Act;

(c) a grazing permit or grazing license under the *Range Act*;

(d) a guide outfitter's licence for Crown land, guiding territory certificate for Crown land or a registered trapline under the *Wildlife Act*;

(e) a mineral claim under the *Mineral Tenure Act*;

(f) a water licence under the *Water Act*;

"wellsite" means an area within which an applicant intends to locate one or more wells and facilities.

[am. B.C. Reg. 7/2011, s. 1.]

Interpretation

2 (1) In this regulation, notification distances and consultation distances are

(a) horizontal distances, and

(b) measured from

(i) the centre point of a facility area or wellsite, and

(ii) the centre line of a pipeline right of way, oil and gas road right of way or seismic line.

(2) In this regulation, **"known"** , when used to describe information, means that the information

(a) is contained in the Integrated Land and Resource Registry referred to in section 7.2 of the *Land Act*, or

(b) in relation to a prescribed applicant,

(i) has been made available by the commission to the prescribed applicant, or

(ii) is or ought reasonably to be known to the prescribed applicant.

Part 2 — Obligation to Notify or Consult

Division 1 — Obligations

Prescribed classes of persons

3 The following classes of persons are prescribed for the purposes of section 22 (1) of the Act:

(a) persons who intend to carry out an oil and gas activity on a land owner's land;

(b) persons who intend to carry out an oil and gas activity on land that is not owned by a land owner, but not including persons intending to carry out an oil and gas activity that is limited to

(i) the construction of a water pipeline or a gas pipeline for testing a well, if the pipeline is

(A) located on the surface,

(B) not for use after the well for which it is associated is constructed, and

(C) located on the wellsite,

(ii) the operation of a pipeline, or

(iii) the maintenance of an oil and gas road, as defined in the Oil and Gas Road Regulation.

[am. B.C. Reg. 56/2013, s. 2 (a).]

Obligation to notify or consult

4 (1) Subject to subsections (2) to (4) and section 5, an applicant must provide

(a) to a land owner who the applicant is required to notify under section 22 (2) or 31 (1) of the Act an invitation to consult with respect to the applicant's proposed activities,

(b) to a local authority

(i) a notification with respect to the applicant's proposed activities, if any of the following is within an applicable notification distance:

(A) an existing building or structure owned by the local authority;

(B) an area identified in an official community plan prepared by the local authority in respect of which a statement and map designation has been made in accordance with section 877 (1) of the *Local Government Act*;

(C) a known community watershed, all or a portion of which is within the boundary of the local authority's territory, or

(ii) an invitation to consult with respect to the applicant's proposed activities, if an existing building or structure owned by the local authority is within an applicable consultation distance,

(c) to the government of Canada

(i) a notification with respect to the applicant's proposed activities, if an existing building or structure owned by the government of Canada is within the applicable notification distance, or

(ii) an invitation to consult with respect to the applicant's proposed activities, if an existing building or structure owned by the government of Canada is within the applicable consultation distance,

(d) to a First Nation

(i) unless subparagraph (ii) applies, a notification with respect to the applicant's proposed activities, if all or a portion of the First Nation's Indian reserve is located within an applicable notification distance, or

(ii) an invitation to consult with respect to the applicant's proposed activities, if all or a portion of the First Nation's Indian reserve is located within an applicable consultation distance,

(e) to a person, other than a person referred to in section 22 (2) or 31 (1) of the Act, who is registered in the land title office as the registered owner of the land surface or as its purchaser under an agreement for sale,

(i) unless subparagraph (ii) applies, a notification with respect to the applicant's proposed activities, if all or a portion of the land is located within an applicable notification distance,

(ii) an invitation to consult with respect to the applicant's proposed activities, if all or a portion of

(A) a residence that the person occupies, or

(B) a structure that the person uses to shelter livestock

is located within an applicable consultation distance, or

(iii) an invitation to consult with respect to the applicant's proposed activities, if the person is a school board and a school or related structure owned by the school board is within an applicable consultation distance,

(f) to a person who has entered into an agreement with the land owner to lease or rent a residence or a structure used for livestock on the land, an invitation to consult with respect to the applicant's proposed activities, if all or a portion of the residence or structure is located within an applicable consultation distance, and

(g) to a rights holder

(i) a notification with respect to the applicant's proposed activities, if the rights holder is not a holder of a forest licence or tree farm licence under the *Forest Act* and the proposed activities are to be carried out on an area subject to a right of the rights holder, as listed in the definition of "rights holder" in section 1, or

(ii) an invitation to consult with respect to the applicant's proposed activities, if

(A) the proposed activities are to be carried out on an area subject to a right of the right's holder, as listed in the definition of "rights holder" in section 1, and

(B) it is known to the applicant that the ability of the rights holder to exercise a right listed in the definition of "rights holder" in section 1 will be directly and adversely affected by the proposed activities.

(2) An applicant required under subsection (1) to provide a notification may instead provide an invitation to consult under section 13.

(3) Unless subsection (4) applies, an applicant, in respect of an application for a pipeline that

(a) is to be located within a municipality and within the right of way of an arterial highway or municipal highway, and

(b) is to be used for transporting petroleum, natural gas or both,

must provide an invitation to consult to

(c) the ministry of the minister responsible for the administration of the *Transportation Act*, and

(d) the municipal council.

(4) An applicant for a pipeline permit including permission to construct and operate a pressure regulating station to be installed on land owned by the applicant within a municipality must provide an invitation to consult to the municipal council of that municipality.

[am. B.C. Reg. 7/2011, s. 2.]

Application of section 4 respecting revisions

5 (1) Section 4 does not apply to the following:

(a) an applicant who revises the proposed activities with respect to which the applicant previously complied with section 4, unless the revision adds one or more of the following activities:

(i) drilling or constructing a petroleum or natural gas well or facility;

(ii) constructing a pipeline for petroleum, natural gas or both;

(b) an applicant who revises the proposed area for proposed activities with respect to which the applicant previously complied with section 4, unless the applicant revises the proposed area by

(i) increasing the proposed area by 1 hectare or more, or

(ii) shifting the proposed area by 100 meters or more in any direction.

(2) If section 4 applies with respect to a revision referred to in subsection (1) of this section, the applicant

(a) must comply with section 4 by providing to the person or other entity referred to in that section with a notification or an invitation to consult with respect to the proposed activities, as revised, if the applicant did not previously provide the person or entity with a notification or invitation to consult with respect to the proposed activities, and

(b) may comply with section 4 by providing to the person or other entity referred to in that section with a notification or an invitation to consult only with respect to the revision, if the applicant previously provided the person or entity with a notification or invitation to consult with respect to the proposed activities.

Notification and consultation distance for facilities

6 (1) For proposed activities that

(a) include the use of a facility, other than

(i) a processing plant or pump station that is to be located in a facility area or wellsite, or

(ii) a compressor station that is to be on a wellsite and that is

(A) to be a permanent, fixed structure, or

(B) to service natural gas originating from wells not located on the wellsite, and

(b) process petroleum, natural gas or both, or water,

the notification distance and the consultation distances are as follows:

(c) if one facility is proposed and the proposed facility area or wellsite is less than 5 hectares,

(i) the notification distance is the larger of 1 500 m and the distance determined in accordance with Schedule A, and

(ii) the consultation distance is the larger of 1 000 m and the distance determined in accordance with Schedule A;

(d) if one facility is proposed and the proposed facility area or wellsite is 5 hectares or more

(i) the notification distance is the larger of 1 800 m and the distance determined in accordance with Schedule A, and

(ii) the consultation distance is the larger of 1 300 m and the distance determined in accordance with Schedule A;

(e) if more than one facility is proposed and the proposed facility area or wellsite is 5 hectares or more,

(i) the notification distance is the larger of 1 800 m and the distance determined in accordance with Schedule A, and

(ii) the consultation distance is the larger of 1 300 m and the distance determined in accordance with Schedule A.

(2) For proposed activities that

(a) include the use of a facility that is

(i) a processing plant or pump station that is to be located in a facility area or wellsite, or

(ii) a compressor station, other than a compressor station that is to be on a wellsite and that

(A) is not to be a permanent, fixed structure, or

(B) is to service only natural gas originating from wells located on the wellsite, and

(b) will process, compress or pump petroleum, natural gas or both, or water,

the notification distance and the consultation distances are both the larger of 3 300 m and the distance determined in accordance with Schedule A.

[am. B.C. Reg. 7/2011, s. 3.]

Notification and consultation distance for wells

7 Subject to section 6, for proposed activities that include the use of a well for producing petroleum, natural gas or both, or water, the notification distance and the consultation distance is as follows:

(a) if fewer than 9 wells are proposed and the wellsite on which the wells are to be located is less than 5 hectares,

(i) the notification distance for the proposed activities is the larger of 1 500 m and the distance determined in accordance with Schedule B, and

(ii) the consultation distance for the proposed activities is the larger of 1000 m and the distance determined in accordance with Schedule B;

(b) if 9 or more wells are proposed or the wellsite on which the wells are to be located is 5 hectares or more,

(i) the notification distance for the proposed activities is the larger of 1 800 m and the distance determined in accordance with Schedule B, and

(ii) the consultation distance for the proposed activities is the larger of 1 300 m and the distance determined in accordance with Schedule B.

[am. B.C. Reg. 7/2011, s. 4.]

Notification and consultation distance for pipelines

8 For proposed activities that include the use of a pipeline for transporting petroleum, natural gas, or both, or water, the notification distance and the consultation distance are both the larger of 200 m and the distance determined in accordance with Schedule C.

[am. B.C. Reg. 7/2011, s. 5.]

Notification and consultation distance for oil and gas roads

9 The notification distance and consultation distance for the construction of an oil and gas road is 200 metres.

[am. B.C. Reg. 56/2013, s. 2 (b).]

Notification distance for geophysical exploration

10 The notification distance for the carrying out of geophysical exploration is 400 metres.

Division 2 — Notifications

Content of notice

11 A notice provided under section 4 must include all of the following:

(a) the name of the applicant;

(b) the name, phone number and electronic mail address, if any, of the contact person for the applicant;

(c) a description of the location of the proposed activities and a map that shows the location in relation to dwellings, public facilities and nearby urban centres;

(d) a description of

(i) the proposed activities and any significant structures and equipment that will be used to carry them out, and

(ii) any roads that will be constructed to carry out the proposed activities;

(e) a description of how, if at all, the proposed activities relate to existing oil and gas activities being carried out within the notification distance;

(f) a description of the approximate order in which the proposed activities will be carried out;

(g) a statement advising that the person receiving the notice

(i) may provide a written response to the applicant within 21 days of receiving the notice, the written response either

(A) advising the applicant that the person does not object to the applicant's application, or

(B) setting out the reasons why the proposed activities that will be the subject of the applicant's application should not be carried out or should be modified, and

(ii) may make a submission to the commission under section 22 (5) of the Act if the notice is in relation to an application under section 24 of the Act;

(h) if the application is in relation to proposed activities that include the use of a facility, well or pipeline, a statement that the applicant will, after obtaining a permit to carry out the proposed activities, provide information respecting the development of an emergency plan for the proposed activities.

[am. B.C. Reg. 7/2011, s. 6.]

Replying to persons who responded to notice

12 (1) An applicant who, within 21 days of having provided a notice under section 4, receives from a person a written response to the notice setting out reasons referred to in section 11 (g) (i) (B) must provide, as soon as practicable, a written reply to the person.

(2) A written reply under subsection (1) must include all of the following:

(a) a description of the revisions, if any, that will be made to the proposed activities described in the notice in light of the reasons set out in the written response;

(b) a statement advising that the written response and the written reply under this section will be included,

(i) in the written report referred to in section 24 (1) (c) of the Act, if the written reply is in relation to an application under section 24 of the Act,

(ii) in the written report referred to in section 31 (6) of the Act, if the written reply is in relation to an application under section 31 of the Act, or

(iii) in the written report referred to in section 32 (4) of the Act, if the notice is in relation to an application under section 32 of the Act;

(c) a statement advising that the person receiving the written reply may make a submission to the commission under section 22 (5) of the Act, if the written reply under this section is in relation to an application under section 24 of the Act.

(3) On the applicable of the following dates, an applicant has no further obligation under this regulation respecting the provision of notice:

(a) the date 21 days after the date on which the last of the notices required to be sent under section 4 was sent, if the applicant did not receive a written response referred to in section 11 (g) (i) (B) to any of the notices;

(b) the earlier of

(i) the date 21 days after the date on which the last of the notices required to be sent under section 4 was sent, and

(ii) the date when the applicant receives the last of the written responses referred to in section 11 (g) (i),

if a written response has been received in response to every notice sent in accordance with section 4 and none of the written responses is a written response referred to in section 11 (g) (i) (B);

(c) the earlier of

(i) the date 21 days after the date on which the last of the notices required to be sent under section 4 was sent, and

(ii) the date when the last responder who sent a written response referred to in section 11 (g) (i) (B) withdraws the objections set out in that written response,

if a written response has been received in response to every notice sent in accordance with section 4 and all objections set out in the written responses have been withdrawn;

(d) the later of

(i) the date 21 days after the date on which the last of the notices required to be sent under section 4 was sent, and

(ii) the date the applicant sends the last written reply required under subsection (1).

[am. B.C. Reg. 7/2011, s. 7.]

Division 3 — Consultations

Content of invitation to consult

13 An invitation to consult provided under section 4 must contain all of the following:

(a) the name of the applicant;

(b) the name, phone number and electronic mail address, if any, of the contact person for the applicant;

(c) a description of the location of the proposed activities and a map that shows the location in relation to dwellings, public facilities and nearby urban centres;

(d) a description of

(i) the proposed activities and any significant structures and equipment that will be used to carry them out, and

(ii) any roads that will be constructed to carry out the proposed activities;

(e) a description of the approximate order in which the proposed activities will be carried out and of their approximate timing;

(f) for each phase of the proposed activities, a description of

(i) the nature and extent of reasonably foreseeable noise, dust and odours that will be caused by the proposed activities,

(ii) the measures that will be taken to mitigate the negative effects of noise, dust and odours, and

(iii) the nature and extent of vehicle traffic on oil and gas roads within the consultation distance;

(g) a description of how, if at all, the proposed activities relate to existing oil and gas activities being carried out within the consultation distance;

(h) a statement advising that the person receiving the invitation to consult

(i) may provide a written response to the applicant, within 21 days of receiving the invitation to consult, the written response either advising the applicant that the person does not object to the applicant's application or doing one or both of the following:

(A) setting out the reasons why the proposed activities that will be the subject of the applicant's application should not be carried out or should be modified;

(B) requesting a meeting with the applicant to discuss the proposed activities, and

(ii) may make a submission to the commission under section 22 (5) of the Act, if the invitation to consult is in relation to an application under section 24 of the Act;

(i) if the application is in relation to proposed activities that include the use of a facility, well or pipeline, a statement that the applicant will, after obtaining a permit, provide information respecting the development of an emergency plan for the proposed activities.

[am. B.C. Reg. 7/2011, s. 8.]

Consultation requirements

14 (1) An applicant who, within 21 days of having provided an invitation to consult under section 4, receives from a person a written response to the invitation setting out reasons referred to in section 13 (h) (i) (A) or requesting a meeting referred to in section 13 (h) (i) (B) must

(a) provide, as soon as practicable, a written reply to the person, and

(b) if the written response includes a request for a meeting, make reasonable efforts to arrange a meeting with the person.

(2) A written reply under subsection (1) must include all the following:

(a) a description of the revisions, if any, that will be made to the proposed activities described in the invitation to consult in light of the reasons set out in the written response and, if held, a description of the results of a meeting arranged under subsection (1) (b);

(b) a statement advising that the written response and the written reply under this section will be included

(i) in the written report referred to in section 24 (1) (c) of the Act, if the written reply is in relation to an application under section 24 of the Act,

(ii) in the written report referred to in section 31 (6) of the Act, if the written reply is in relation to an application under section 31 of the Act, or

(iii) in the written report referred to in section 32 (4) of the Act, if the written reply is in relation to an application under section 32 of the Act;

(c) a statement advising that the person receiving the written reply may make a submission to the commission under section 22 (5) of the Act, if the written reply under this section is in relation to an application under section 24 of the Act.

(3) On the applicable of the following dates, an applicant has no further obligation under this regulation respecting the carrying out of consultations:

(a) the date 21 days after the date on which the last of the invitations to consult required to be sent under section 4 was sent, if the applicant did not receive a written response referred to in section 13 (h) (i) (A) or (B) to any of the invitations;

(b) the earlier of

(i) the date 21 days after the date on which the last of the invitations to consult required to be sent under section 4 was sent, and

(ii) the date when the applicant receives the last of the written responses referred to in section 13 (h) (i),

if a written response has been received in response to every invitation to consult sent in accordance with section 4 and none of them is a written response referred to in section 13 (h) (i) (A) or (B);

(c) the earlier of

(i) the date 21 days after the date on which the last of the invitations to consult required to be sent under section 4 was sent, and

(ii) the date when the last responder who sent a written response referred to in section 13 (h) (i) (A) or (B) withdraws the objections or the request for a meeting set out in the written response,

if a written response has been received in response to every invitation to consult sent in accordance with section 4 and all objections and requests for meetings set out in the written responses have been withdrawn;

(d) the later of the following dates:

(i) the date 21 days after the date on which the last of the invitations to consult required to be sent under section 4 was sent;

(ii) the date the applicant sends the last written reply required under subsection (1);

(iii) the date after the date the applicant conducts the last meeting held, if any, after making the efforts required under subsection (1).

[am. B.C. Reg. 7/2011, s. 9.]

Part 3 — Notice Before Entry

Notice before entry

15 (1) A notice under section 23 (3) of the Act must contain all of the following:

(a) the name of the person intending to enter on land in accordance with section 23 (2) of the Act;

(b) the name, phone number and electronic mail address, if any, of a contact person for the person referred to in paragraph (a);

(c) a copy of the preliminary plan submitted to the commission under section 23 (1) of the Act;

(d) a description of the portion of land to be surveyed or examined and of the activities to be undertaken for the purpose of fixing the site of the pipeline;

(e) a description of the approximate order in which the activities referred to in paragraph (d) will be carried out;

(f) a statement advising the owner of the land that if the person intending to enter the land further intends to apply to the commission for a pipeline permit respecting a pipeline to be located on the land, then the person will notify or consult with the owner in accordance with the Act and the regulations.

(2) A person intending to enter on land in accordance with section 23 (2) of the Act must provide to the owner of the land a notice under section 23 (3) of the Act at least 2 clear days before entering the land.

Part 4

Repealed

16 Repealed. [B.C. Reg. 199/2011.]

Schedule A

Facility Distances

(Section 6)

Distances for the purposes of section 6 are determined by reference to the maximum H_2S release volume from any pipeline entering or leaving the facility, calculated in accordance with the applicable of the following formulas. The distance for the purposes of section 6 is the distance indicated on the vertical axis of Chart A that corresponds to the release volume indicated on the horizontal axis of the chart, as indicated by the graphline on the chart.

Equations

Gas Pipeline H_2S Release Volume

The equation for calculating the maximum potential H_2S release volume from a pipeline is as follows:

$$V = \frac{2.232 \times 10^{-6} D^2 L (P + 101.325) H}{Z(T + 273)}$$

where

V = maximum potential H_2S release volume in m^3;

D = internal diameter of pipe in millimetres (mm);

L = length of pipeline between block valves (km);

P = licensed maximum operating pressure in kilopascals (kPa);

H = licensed H_2S content (moles/kilomole) for the pipeline;

Z = compressibility factor at reduced pressure and reduced temperature;

T = pipeline minimum operating temperature (°C).

Liquid Multiphase Pipeline H_2S Release Volume

For sour liquid multiphase pipelines, the volume of H_2S is determined by the following equation:

$$V = \frac{(GLR \times GVF)}{1000(GLR + GVF)} \times V_{pl} \times H$$

where

V = potential H_2S release volume at standard condition (m^3);

GLR = produced gas-liquid ratio at maximum operating pressure (MOP) (m^3/m^3);

GVF = ratio of produced gas volume at standard conditions to the volume of gas at MOP (m^3/m^3);

V_{pl} = volume of the pipeline (m^3);

H = licensed H_2S content (moles/kilomole) for the pipeline.

Gas Multiphase Pipeline H_2S Release Volume

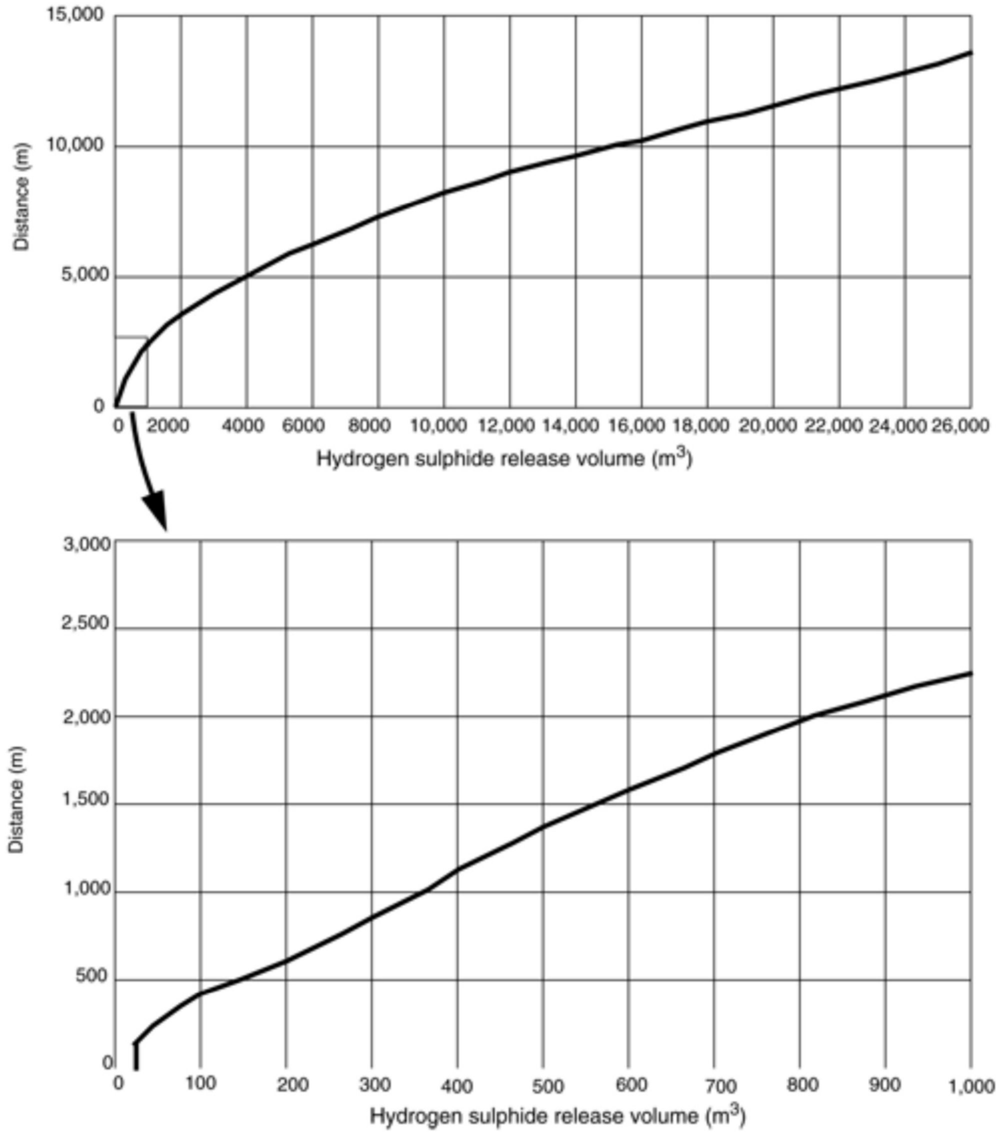
$$V = 0.785 \times 10^{-6} D^2 L \frac{(GLR \times GVF)}{(GLR + GVF)} \times H$$

where

D = internal diameter of pipe in millimeters (mm);

L = length of pipe between block valves (km).

CHART A: FACILITY DISTANCES



Schedule B

[en. B.C. Reg. 7/2011, s. 10.]

Well Distances

(Section 7)

Distances for the purposes of section 7 are determined by reference to potential H_2S release rates from a well during either drilling or completion or re-completion operations.

H_2S release rates

Drilling operations

H_2S release rates during drilling operations must be determined in accordance with the following equation and the notes that follow:

$$H_2S \text{ Release rate} = \frac{H_2S\% \times AOF}{8\,640\,000}$$

where:

AOF	=	maximum gas rate (m^3/d);
$H_2S\%$	=	volume of H_2S expressed as a percentage of the total volume of gas.

Notes:

1. For gas wells, if an AOF test has been conducted and value determined for a formation in a well, that value must be used. If an AOF test value has not been determined, a theoretical AOF must be calculated using the following formula:

$$AOF = \frac{\text{Gas Test Rate} \times Pr^2}{Pr^2 - Pf^2}$$

where:

AOF	=	maximum gas rate (m^3/d);
Gas Test Rate	=	gas flow rate during testing (m^3/d);
Pr	=	reservoir pressure (kPa);
Pf	=	flowing bottom hole pressure (kPa).

2. For oil wells, the AOF must be calculated using the following formula:

$$AOF = \frac{\text{Oil Test Rate} \times GOR}{[1 - 0.2 \times (Pf/Pr) - 0.8 \times (Pf/Pr)^2}$$

where:

Oil Test Rate	=	oil flow rate during testing (m^3/d);
GOR	=	gas oil ratio from oil test rate well (m^3/m^3);
Pr	=	reservoir pressure (kPa);

Pf = flowing bottom hole pressure (kPa).

3. For a proposed well, the maximum gas rate (AOF) values and maximum H_2S concentrations for each H_2S-bearing formation must be determined for each of at least 5 wells drilled and tested in an analogous geological area or pool within 5 kilometres of the proposed well.

4. The H_2S release rates for all potential H_2S-bearing formations in the proposed well must be determined based on the highest AOF and highest H_2S concentration for each formation and the sum of the H_2S release rates for all the formations that will be open to the well bore during drilling operations.

5. If appropriate data does not exist or is otherwise inadequate, the consultation and notification radius is 3 km from the proposed well or well site.

Completion or re-completion operations

For completion or re-completion operations in an existing well, data from the appropriate formation in the well must be used to determine H_2S release rates, but if the appropriate data does not exist or is otherwise inadequate, H_2S release rates must determined in accordance with the equations and notes set out above for drilling operations.

Determination of Well Distances

The distance for the purposes of section 7 is the distance indicated on the vertical axis of Chart B that corresponds to the release rate indicated on the horizontal axis of the chart, as indicated by the graphline on the chart.

Chart B: Well Distances for Higher H_2S Release Rates

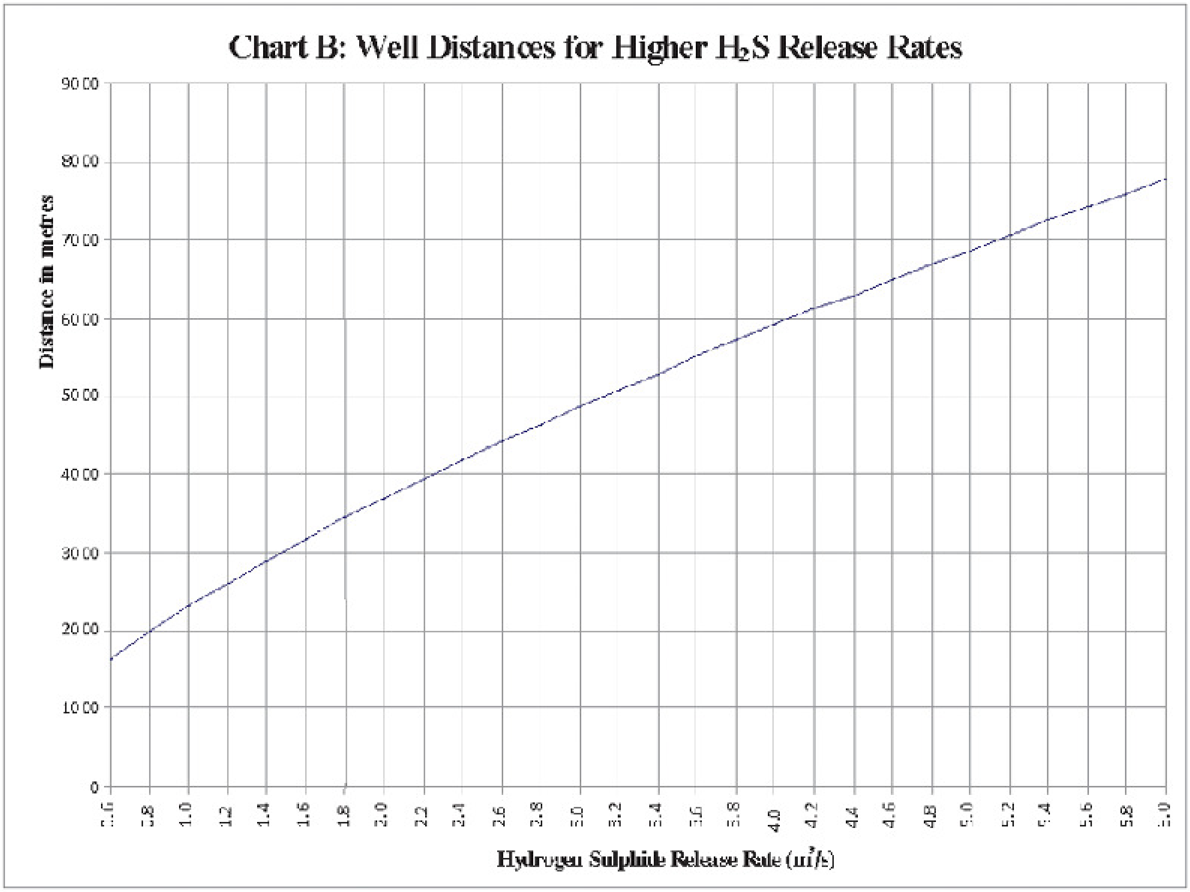
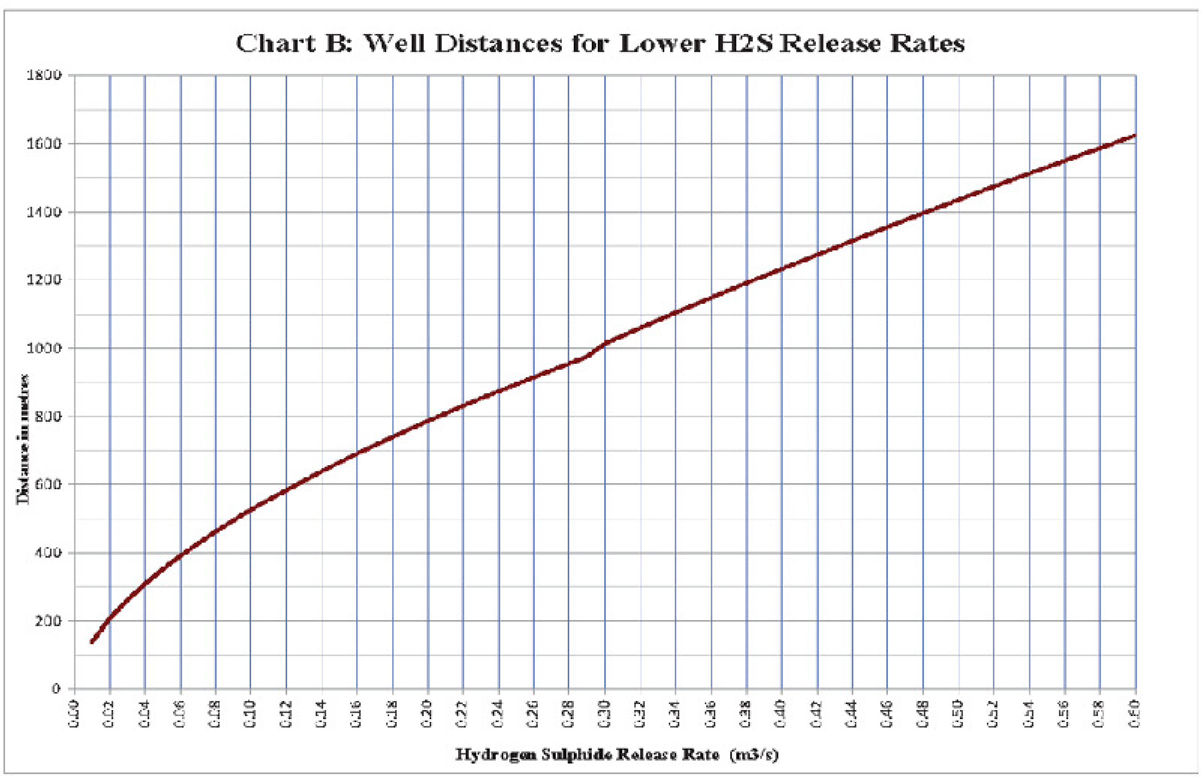


Chart B: Well Distances for Lower H_2S Release Rates



V

Schedule C

Pipeline Distances

(Section 8)

Distances for the purposes of section 8 are determined by reference to the maximum H_2S release volume from the pipeline, calculated in accordance with the applicable of the following formulas. The distance for the purposes of section 8 is the distance indicated on the vertical axis of Chart C that corresponds to the release rate indicated on the horizontal axis of the chart, as indicated by the graphline on the chart.

Pipeline Equations

Gas Pipeline H_2S Release Volume

The equation for calculating the maximum potential H_2S release volume from a pipeline is as follows:

$$V = \frac{2.232 \times 10^{-6} D^2 L (P+101.325) H}{Z(T+273)}$$

where

V = maximum potential H_2S release volume in m^3;

D = internal diameter of pipe in millimetres (mm);

L = length of pipeline between block valves (km);

P = licensed maximum operating pressure in kilopascals (kPa);

H = licensed H_2S content (moles/kilomole) for the pipeline;

Z = compressibility factor at reduced pressure and reduced temperature;

T = pipeline minimum operating temperature (°C).

Liquid Multiphase Pipeline H_2S Release Volume

For sour liquid multiphase pipelines, the volume of H_2S is determined by the following equation:

$$V = \frac{(GLR \times GVF)}{1000(GLR + GVF)} \times V_{p1} \times H$$

where

V =

potential H_2S release volume at standard condition (m^3);

GLR = produced gas-liquid ratio at maximum operating pressure (MOP) (m^3/m^3);

GVF = ratio of produced gas volume at standard conditions to the volume of gas at MOP (m^3/m^3);

V_{pl} = volume of the pipeline (m^3);

H = licensed H_2S content (moles/kilomole) for the pipeline.

Gas Multiphase Pipeline H_2S Release Volume

$$V = 0.785 \times 10^{-6} D^2 L \frac{(GLR \times GVF)}{(GLR + GVF)} \times H$$

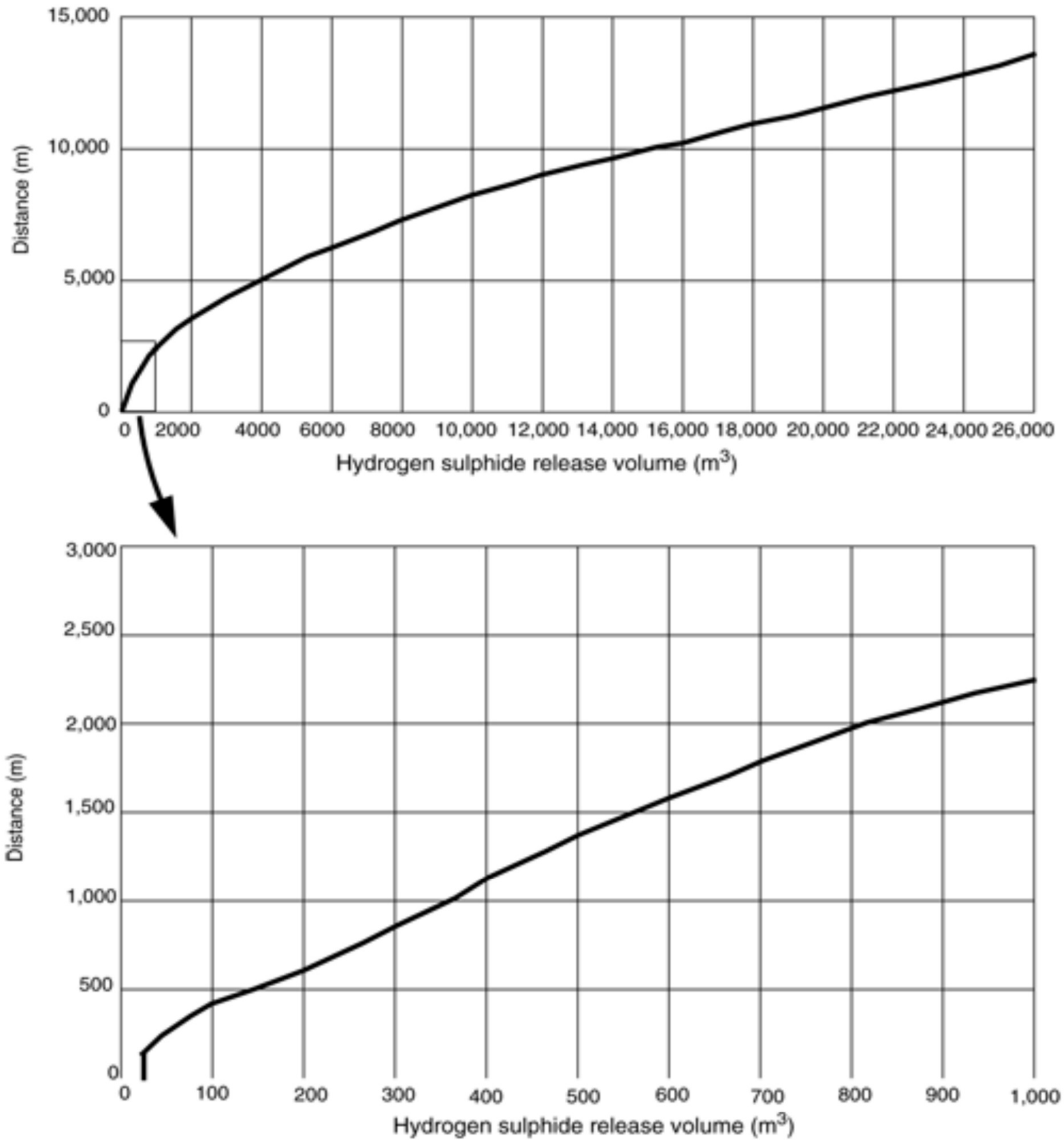
where

D = internal diameter of pipe in millimeters (mm);

L = length of pipe between block valves (km).

Chart C: Pipeline Distances

Chart C: Pipeline Distances



[Provisions relevant to the enactment of this regulation: *Oil and Gas Activities Act*, S.B.C. 2008, c. 36, sections 106 and 107]

IMPORTANT INFORMATION

This Act is Current to December 11, 2013

OIL AND GAS ACTIVITIES ACT

[SBC 2008] CHAPTER 36

Contents

Part 1 — Definitions

Definitions

1 (1) Words and expressions used but not defined in this Act or in the regulations for the purposes of this Act, unless the context otherwise requires, have the same meanings as in the *Petroleum and Natural Gas Act*, other than Part 17 of that Act.

(2) In this Act:

"appeal tribunal" means the Oil and Gas Appeal Tribunal established under section 19;

"authorization" means, except in sections 34, 39 (1) and 104 and Part 10, an authorization under a specified enactment to carry out a related activity, and includes the conditions, if any, imposed on the authorization under this Act or the specified enactment;

"board" means the board of the commission continued under section 2;

"certificate of restoration" means a certificate issued by the commission under section 41;

"commission" means the Oil and Gas Commission continued under section 2;

"commissioner" means the commissioner appointed under section 2 (3);

"environmental measure" means an action a person must take or refrain from taking for the protection or effective management of the environment;

"facility" means a system of vessels, piping, valves, tanks and other equipment that is used to gather, process, measure, store or dispose of petroleum, natural gas, water or a substance referred to in paragraph (d) or (e) of the definition of "pipeline";

"flow line" means a pipeline that connects a well head with a scrubbing, processing or storage facility and that precedes the transfer of the conveyed substance to or from a transmission, distribution or transportation line;

"former permit holder" includes a person who was a director of a corporation that

(a) held a permit with respect to which there has been a cancellation, declaration or expiry referred to in section 40, and

(b) no longer exists or has amalgamated with another corporation;

"government's environmental objectives" means the prescribed objectives of the government respecting the protection and effective management of the environment;

"highway" has the same meaning as in the *Transportation Act*;

"land owner" means

(a) a person registered in the land title office as the registered owner of the land surface or as its purchaser under an agreement for sale, and

(b) a person to whom a disposition of Crown land has been issued under the *Land Act*, but does not include the government or a person referred to in paragraph (b) of the definition of "unoccupied Crown land" in section 1 of the *Petroleum and Natural Gas Act*;

"official", except in sections 6 and 8, means a person designated as an official under section 7 (4);

"oil and gas activity" means

(a) geophysical exploration,

(b) the exploration for and development of petroleum, natural gas or both,

(c) the production, gathering, processing, storage or disposal of petroleum, natural gas or both,

(d) the operation or use of a storage reservoir,

(e) the construction or operation of a pipeline,

(f) the construction or maintenance of a prescribed road, and

(g) the activities prescribed by regulation;

"permit" means a permit issued under section 25 and includes any conditions imposed on a permit;

"permit holder" means

(a) a person who holds a permit, and

(b) a person, if any, who is the holder of a location with respect to that permit;

"pipeline" means, except in section 9, piping through which any of the following is conveyed:

(a) petroleum or natural gas;

(b) water produced in relation to the production of petroleum or natural gas or conveyed to or from a facility for disposal into a pool or storage reservoir;

(c) solids;

(d) substances prescribed under section 133 (2) (v) of the *Petroleum and Natural Gas Act*,

(e) other prescribed substances,

and includes installations and facilities associated with the piping, but does not include

(f) piping used to transmit natural gas at less than 700 kPa to consumers by a gas utility as defined in the *Gas Utility Act*,

(g) a well head, or

(h) anything else that is prescribed;

"pipeline permit" means a permit that includes a permission to construct, maintain or operate a pipeline;

"pipeline permit holder" means a permit holder of a pipeline permit;

"related activity" means an activity

(a) that, under a specified enactment, must not be carried out except as authorized under the specified enactment or that must be carried out in accordance with the specified enactment, and

(b) the carrying out of which is required for the carrying out of an oil and gas activity;

"specified enactment" means any of the following Acts:

(a) *Environmental Management Act*;

(b) *Forest Act*;

(c) *Heritage Conservation Act*;

(d) *Land Act*;

(e) *Water Act*;

"specified provision" means the following provisions:

(a) any of the following provisions of the *Environmental Management Act*:

(i) section 9 *[hazardous waste storage and disposal]*;

(ii) section 14 *[permits]*;

(iii) section 15 *[approvals]*;

(b) section 47.4 *[licence to cut for persons occupying land or for oil and gas purposes]* of the *Forest Act*, but only in relation to a master licence to cut, and section 117 *[road use permits for industrial use]* of that Act;

(c) section 12 [*permit authorizing certain actions*] of the *Heritage Conservation Act*;

(d) any of the following provisions of the *Land Act*:

(i) section 11, but only in relation to a lease or grant described in section 11 (2) (b) to (d) *[disposing of Crown land]*;

(ii) section 14 *[temporary occupation of Crown land]*;

(iii) section 38 *[lease of Crown land]*, but not to the extent that it relates to the granting of an option to purchase land;

(iv) section 39 *[licence of occupation]*;

(v) section 40 *[right of way and easement]*;

(vi) section 96 (1) *[occupational rental]*;

(e) any of the following provisions of the *Water Act*, but only in relation to an approval as defined in section 1 of the *Water Act*:

(i) section 8 *[short term use of water]*;

(ii) section 9 (1) (a) *[changes in and about a stream]*;

(iii) section 26 *[permits over Crown land]*;

(f) a prescribed regulation under a specified enactment;

"spillage" means petroleum, natural gas, oil, solids or other substances escaping, leaking or spilling from

(a) a pipeline, well, shot hole, flow line, or facility, or

(b) any source apparently associated with any of those substances.

Part 2 — Administration

Division 1 — Oil and Gas Commission

Corporation continued

2 (1) A corporation known as the Oil and Gas Commission is continued, consisting of a board with 3 directors.

(2) The deputy minister is a director and is the chair of the board.

(3) The Lieutenant Governor in Council may appoint 2 directors, for a term not longer than 5 years, one of whom is both the commissioner and vice chair of the board.

(4) A person appointed as a director under subsection (3) may be reappointed for additional terms.

(5) A vacancy in the membership of the board or the incapacity of one of the directors does not impair the power of the remaining directors to act.

(6) A majority of the directors holding office constitutes a quorum at meetings of the board.

(7) If there is a tie vote, the chair of the board, or in the absence of the chair the vice chair, has the deciding vote.

(8) If a director dies or is unable to act or if a director's position is otherwise vacant, the minister, by order, may appoint an acting director for a period not longer than 6 months.

(9) If the commissioner dies or is unable to act or if the commissioner's position is otherwise vacant, the minister, by order, may appoint a director or an acting director appointed under subsection (8) to be an acting commissioner for a period not longer than 6 months.

(10) The board may appoint a deputy commissioner.

(11) A deputy commissioner has the powers of the commissioner, unless the board otherwise directs, but does not have a vote in meetings or decisions of the board and is subject to any directions given to him or her by the commissioner.

(12) The commission may pay to a person appointed under subsection (3), (8), (9) or (10) remuneration and expense allowances at rates set by the minister.

Commission is an agent of the government

3 The commission is an agent of the government.

Purposes

4 The purposes of the commission include the following:

(a) to regulate oil and gas activities in British Columbia in a manner that

(i) provides for the sound development of the oil and gas sector, by fostering a healthy environment, a sound economy and social well-being,

(ii) conserves petroleum and natural gas resources,

(iii) ensures safe and efficient practices, and

(iv) assists owners of petroleum and natural gas resources to participate equitably in the production of shared pools of petroleum and natural gas;

(b) to provide for effective and efficient processes for the review of applications for permits and to ensure that applications that are approved are in the public interest having regard to environmental, economic and social effects;

(c) to encourage the participation of First Nations and aboriginal peoples in processes affecting them;

(d) to participate in planning processes;

(e) to undertake programs of education and communication in order to advance safe and efficient practices and the other purposes of the commission.

Direction and management of commission

5 (1) The board may pass resolutions it considers necessary or advisable to direct its affairs, exercise its powers and perform its duties, including resolutions for one or more of the following:

(a) calling and holding meetings of the board and the procedures to be followed at meetings;

(b) making regulations of the board;

(c) approving the commission's annual service plan under the *Budget Transparency and Accountability Act*, as well as the commission's annual budget estimate detailing the expected revenues and planned expenditures of the commission for the next fiscal year;

(d) establishing a plan of organization to carry out the powers of the commission.

(2) The board must

(a) establish, in accordance with the regulations, if any, a conflict of interest policy for the directors that includes provisions respecting

(i) the disclosure of interests in contracts or transactions with the commission,

(ii) the duty to account for profits,

(iii) the validity of contracts and transactions in which a director has an interest, and

(iv) the disclosure of any property owned or office held by a director that may create a conflict of interest or duty,

(b) submit the policy referred to in paragraph (a) to the minister, and

(c) establish a code of conduct, including conflict of interest provisions, that governs the conduct of employees of the commission.

(3) On receipt of a conflict of interest policy under subsection (2) (b) or on the minister's own initiative, the minister may order the board to amend its conflict of interest policy and resubmit that policy to the minister in accordance with the order.

(4) A resolution of the board that is approved by directors, whether present in person or approving by telephone, facsimile transmission, electronic mail or any other similar means of communication, confirmed in writing or other graphic communication, is as valid as if it had been passed at a meeting of the board properly called and constituted.

Capacity and powers of commission

6 (1) For the purposes of this Act, the commission may do any or all of the following:

(a) subject to subsection (2), acquire, hold and dispose of property;

(b) invest money, and, subject to the prior approval of the Lieutenant Governor in Council, borrow money;

(c) subject to subsection (2), negotiate and enter into agreements with any person, including the government of British Columbia, the government of Canada, the government of another province or of a territory, a local government, a First Nation or with an official or agency of any of them;

(d) subject to subsection (2), expend money for the purposes of administering the Act;

(e) do other things that the Lieutenant Governor in Council may authorize.

(2) In the prescribed circumstances, the commission may exercise the power referred to in subsection (1) (a), (c) or (d) only with the approval of the Lieutenant Governor in Council.

(3) With the prior approval of the Lieutenant Governor in Council, the commission may in any year pay to a municipality in which it has property a grant not greater than the amount that would be payable as taxes on

the property in that year if the property were not exempt from taxation by the municipality.

(4) If directed to do so by the Lieutenant Governor in Council, the commission must pay to a municipality in which it has property a grant not greater than the amount that would be payable as taxes on the property in that year if the property were not exempt from taxation by the municipality.

Powers of commissioner

7 (1) Subject to the direction of the board, the commissioner must manage the operations of the commission or supervise the management of those operations.

(2) The commissioner has the powers and duties of an official and of the commission under this Act, other than those powers and duties expressly given to the board under this Act.

(3) The commissioner may hire employees of the commission necessary to carry on the business and operations of the commission and may define their duties and determine their remuneration.

(4) The commissioner may designate a person as an official for the purposes of provisions of this Act specified by the commissioner in the designation.

(5) The commissioner may

(a) delegate the exercise of any power or performance of any duty conferred or imposed on the commission under this Act, other than those powers and duties expressly given to the board under this Act, to an employee or official of the commission or another public officer, and

(b) in making a delegation, provide directions that are binding on the delegate respecting the exercise of the power or the performance of the duty.

(6) A delegation under subsection (5) may be made by name or by designation of the office.

Commission's responsibilities under specified enactments

8 (1) For the regulation of oil and gas activities, the commission, instead of the official named in a specified provision,

(a) has all the powers relating to a discretion, function or duty referred to in the specified provision, including, without limiting this, the powers in the specified enactment relating to the administration and enforcement of an authorization, and

(b) is charged with all the responsibilities pertaining to that discretion, function or duty.

(2) Despite subsection (1), both the commission and the director, as the latter is defined in section 1 of the *Environmental Management Act*, have all the powers referred to in section 14 of that Act and are charged with all the responsibilities pertaining to those powers.

(3) Subject to this Act, the exercise of the powers conferred on the commission by subsection (1), the carrying out of each discretion, function and duty referred to in a specified enactment and the responsibilities with which the commission is charged under this section remain subject to the specified enactment and that specified enactment continues to apply.

(4) Despite subsections (1) and (3), the commission and the appropriate officials under the various specified enactments are each responsible for enforcing the specified enactments in relation to the matters described in the specified provisions.

Application of section 8 to pipelines under jurisdiction of Canada

9 (1) In this section:

"approval" means an approval, with any conditions imposed, under a specified enactment to carry out an activity

(a) that, under the specified enactment, must not be carried out except as approved under the specified enactment, and

(b) that is required to be carried out in order to operate or construct a pipeline;

"pipeline" has the same meaning as in the *National Energy Board Act* (Canada).

(2) The commission's powers under section 8 do not include the power to issue an approval with respect to a pipeline that is subject to the *National Energy Board Act* (Canada).

(3) Despite subsection (2), the Lieutenant Governor in Council may, by regulation, extend the commission's powers under section 8 to include the power to issue an approval under one or more specified enactments with respect to a pipeline referred to in subsection (2).

(4) If the commission's powers are extended as described in subsection (3) in relation to an approval under one or more specified enactments,

(a) section 8 applies respecting the applicable specified enactments in relation to the pipeline, whether or not the commission issued the approval,

(b) section 24 (3) does not apply to the granting of the approval, and

(c) the carrying out of the activity under the approval must be considered the carrying out of a related activity for the purposes of this Act.

Minister may order independent audit

10 (1) The minister may order an independent audit of the performance of the commission in fulfilling its purposes or exercising its powers and performing its functions and duties under this Act.

(2) The minister responsible for the *Wildlife Act* may order an independent audit of the performance of the commission in fulfilling its purposes or exercising its powers and performing its functions and duties under this Act in relation to the protection and effective management of the environment.

(3) An order under subsection (1) or (2) must include terms of reference for the audit.

(4) If requested by an auditor appointed for the purposes of subsection (1) or (2), the commission must submit records in its possession that the auditor determines are relevant to the audit.

(5) Before an audit report is finalized, the auditor must provide to the board

(a) a copy of the draft audit report, and

(b) a reasonable opportunity to review and comment on the report.

(6) As soon as practicable after completing an audit, the auditor must submit the final audit report and any comments of the board to

(a) the minister who issued the order under subsection (1) or (2), and

(b) the board.

Advisory committee

11 (1) The board may establish and appoint an advisory committee to consider or inquire into any matter and to report its findings and provide its advice to the board.

(2) The commission may pay to a person appointed as a member of an advisory committee remuneration and expense allowances at rates set by the minister.

Inquiries and recommendations

12 (1) At the request of the Lieutenant Governor in Council, the commission must, at the places and times and in a manner the Lieutenant Governor in Council considers advisable,

(a) make inquiries, conduct investigations and prepare studies and reports on any matter within the scope of this Act, and

(b) recommend to the Lieutenant Governor in Council any measures the commission considers necessary or advisable in the public interest related to oil and gas activities.

(2) Subsection (1) does not apply to a matter that is before the commission.

Public Service Act* and *Public Service Labour Relations Act

13 (1) The *Public Service Act* and the *Public Service Labour Relations Act* do not apply to the commission or to its employees.

(2) Despite subsection (1), the Public Service Pension Plan, continued under the *Public Sector Pension Plans Act*, continues to apply to the commission and to its employees.

Financial administration

14 (1) The commission must establish and maintain an accounting system satisfactory to the Minister of Finance.

(2) The commission must prepare financial statements in accordance with generally accepted accounting principles.

(3) Whenever required by the Minister of Finance, the commission must provide detailed accounts of its revenues and expenditures for the period or to the date the Minister of Finance designates.

(4) All books or records of account, documents and other financial records of the commission are at all times open for inspection by the Minister of Finance or a person designated by the Minister of Finance.

(5) The Minister of Finance may direct the Comptroller General to examine and report to Treasury Board on any or all of the financial and accounting operations of the commission.

(6) The commission, with the approval of the Minister of Finance, may budget for a deficit in a fiscal year.

(7) The Minister of Finance, for the purposes of subsection (6), may grant an approval for one fiscal year or for any other number of fiscal years.

(8) The fiscal year of the commission is a period of 12 months beginning on April 1 in each year and ending on March 31 in the next year.

(9) The Minister of Finance is the fiscal agent of the commission.

Audit

15 Unless the Auditor General is appointed in accordance with the *Auditor General Act* as the auditor of the commission, an auditor appointed by the commission must, at least once for each fiscal year, audit and report on the accounts of the commission to the Executive Council through the minister and to the board, and the costs of the audit must be paid by the commission.

Application of *Business Corporations Act*

16 (1) Subject to subsection (2), the *Business Corporations Act* does not apply to the commission.

(2) The Lieutenant Governor in Council, by order, may declare that certain provisions of the *Business Corporations Act* and *Society Act* apply to the commission.

Application of *Document Disposal Act*

17 The *Document Disposal Act* applies to the commission and, for the purposes of that Act, the commission is a ministerial office.

Appropriation

18 (1) In this section, **"revenue"** includes interest but does not include penalties.

(2) The Minister of Finance, out of the consolidated revenue fund, must pay to the commission

(a) the gross revenue received from the levies authorized under section 110,

(b) the gross revenue received from the tax under section 47, and

(c) the gross revenue received from fees in relation to

(i) applications for and issuance of permits and the prescribed authorizations issued by the commission under this Act, and

(ii) fees prescribed under section 112 (1) (c).

(3) With the approval of Treasury Board, the minister may pay out of the consolidated revenue fund, on application by the commission, money required for the purposes of sections 12, 52 and 53.

Division 2 — Oil and Gas Appeal Tribunal

Establishment of Oil and Gas Appeal Tribunal

19 (1) The Oil and Gas Appeal Tribunal is established.

(2) The appeal tribunal is to hear appeals under section 72.

(3) The appeal tribunal consists of the following members appointed by the Lieutenant Governor in Council after a merit-based process:

(a) a member designated as the chair;

(b) one or more members designated as vice chairs after consultation with the chair;

(c) other members appointed after consultation with the chair.

Application of *Administrative Tribunals Act*

20 Sections 1 to 22, 24, 26 to 33, 34 (3) and (4), 35 to 42, 44, 46.3, 47 to 57 and 59 to 61 of the *Administrative Tribunals Act* apply to the appeal tribunal.

Part 3 — Oil and Gas Activities

Division 1 — Permits

Permit required

21 Subject to section 23, a person must not carry out an oil and gas activity unless

(a) either

(i) the person holds a permit that gives the person permission to carry out that oil and gas activity, or

(ii) the person is required to carry out that oil and gas activity by an order issued under section 49, and

(b) the person carries out the oil and gas activity in compliance with

(i) this Act and the regulations,

(ii) a permit issued to the person, if any, and

(iii) an order issued to the person, if any.

Consultation and notification

22 (1) In subsection (3), **"prescribed applicant"** means a person who intends to submit an application under section 24 and who is in a prescribed class of persons.

(2) Before submitting an application under section 24, a person must notify the land owner of the land on which the person intends to carry out an oil and gas activity of the person's intention to submit the application, and the notice must advise the land owner that he or she may make a submission to the commission under subsection (5) of this section with respect to the application or proposed application.

(3) Subject to subsection (4), before submitting an application under section 24, a prescribed applicant must carry out the prescribed consultations or provide the prescribed notices, or both, as applicable, with respect to the oil and gas activities and related activities, if any, that will be the subject of the prescribed applicant's application.

(4) The commission, on written request, may exempt a person from one or more of the applicable consultation or notification requirements under subsection (3) and, on making an exemption, substitute other consultation or notification requirements than those prescribed for the purposes of subsection (3).

(5) A person, other than the applicant, may make a written submission to the commission with respect to an application or a proposed application under section 24.

(6) If a person makes a submission under subsection (5), the commission must send a copy of the submission to the applicant or to the person intending to apply for a permit, as the case may be.

Preliminary plan

23 (1) Before submitting an application under section 24 for a pipeline permit, a person may submit to the commission a preliminary plan of the proposed route of the pipeline.

(2) Subject to subsection (3), a person may enter on land as necessary for making surveys, examinations or other arrangements for the purpose of fixing the site of the pipeline referred to in subsection (1), if the person

(a) has submitted a preliminary plan under subsection (1), and

(b) has either

(i) provided the prescribed security to the commission to compensate the land owner or the Crown for any damage or disturbance that may be caused by the entry on the land by the person, or

(ii) entered into an agreement with the land owner regarding entry on the land.

(3) A person who has not entered into an agreement referred to in subsection (2) (b) (ii) must notify, in accordance with the regulations, the owner of the land of the person's intention to enter on that land.

(4) The right of entry under subsection (2) does not extend to any of the following:

(a) land occupied by a building;

(b) the curtilage of a dwelling house;

(c) protected heritage property, unless the person is authorized by the local government or the minister responsible for the protection of the protected heritage property.

(5) In subsection (4) (c), **"protected heritage property"** means land or an object that is

(a) protected under section 13 of the *Heritage Conservation Act*,

(b) designated under section 967 of the *Local Government Act* or section 593 of the *Vancouver Charter*, or

(c) included under section 970.1 (3) (b) of the *Local Government Act* in a schedule to an official community plan.

Application for permit and authorization

24 (1) Subject to subsection (4), a person may apply to the commission for a permit by submitting, in the form and manner the commission requires,

(a) a description of the proposed site of the oil and gas activity,

(b) the information, plans, application form and records required by the commission,

(c) a written report, satisfactory to the commission, regarding the results of the consultations carried out or notification provided under section 22, if any,

(d) the prescribed information,

(e) the prescribed records, and

(f) the security required under section 30.

(2) An application for a permit under subsection (1) may be consolidated with an application for an authorization.

(3) Despite anything in a specified enactment, the commission may not grant an authorization to a person for a related activity unless the person holds, or has applied for, a permit for the oil and gas activity related to that related activity.

(4) A person may not submit an application for a permit to drill or operate a well, unless

(a) the person is the owner of the petroleum and natural gas rights or is the holder of the location in respect of the well,

(b) the person has an agreement with the owner or the holder of the location referred to in paragraph (a) authorizing the drilling or operation, as applicable,

(c) the person is the holder of a storage reservoir lease issued under section 130 of the *Petroleum and Natural Gas Act*, or

(d) the minister has approved the submission under subsection (5).

(5) For the purposes of subsection (4) (d), the minister may

(a) approve the submission by a person of an application for a permit to drill a well if the well is to be drilled for exploratory or research purposes only, and

(b) in approving a submission under paragraph (a), declare that, if a permit is issued to the person on the basis of the submission, the person is not required to be an owner or holder referred to in subsection (4) or have the agreement referred to in that subsection in order to drill or operate the well for the purposes referred to in paragraph (a).

Permits and authorizations issued by commission

25 (1) Subject to subsection (1.1), on application by a person under section 24 and after considering

(a) written submissions made under section 22 (5), if any, and

(b) the government's environmental objectives, if any have been prescribed for the purposes of this section,

the commission may issue a permit to the person if the person meets the requirements prescribed for the purposes of this section.

(1.1) The Lieutenant Governor in Council, by regulation, may issue a direction to the commission with respect to the exercise of the commission's power under subsection (1), and the commission must comply with the direction despite any other provision of this Act, the regulations or an order made under this Act.

(2) In issuing a permit under subsection (1), the commission

(a) must specify the oil and gas activities the person is permitted to carry out, and

(b) may impose any conditions on the permit that the commission considers necessary.

(3) A permit and any authorizations granted to the applicant for the permit may be issued as a single document.

(4) If the commission issues a permit under subsection (1), the commission must provide notice, in accordance with subsection (5), to the land owner of the land on which an oil and gas activity is permitted to be carried out under the permit.

(5) A notice under subsection (4) must

(a) advise the land owner of the issuance of the permit and of the location of the proposed site of an oil and gas activity on the land owner's land, and

(b) state that the land owner may appeal under section 72 the decision to issue the permit, and include an address to which an appeal may be sent.

(6) A permit holder must not begin an oil and gas activity on a land owner's land before the expiry of 15 days from the day the permit was issued, unless the land owner consents in writing to the activity beginning before the expiry of that period.

Actions by commission respecting permit

26 (1) The commission may

(a) refuse to issue a permit,

(b) suspend a permit or a permission specified in a permit,

(c) cancel a permit or a permission specified in a permit, or

(d) amend a permit.

(2) Without limiting the authority of the commission under subsection (1), the commission may make a decision under subsection (1) if the applicant or permit holder does any of the following:

(a) contravenes or has contravened

(i) this Act, the regulations, a permit, an authorization or an order issued under this Act, or

(ii) the *Petroleum and Natural Gas Act* or regulations made under that Act;

(b) fails to meet or no longer meets any of the conditions of section 24 (4);

(c) fails to meet or no longer meets the requirements prescribed for the purposes of section 25 (1), if any;

(d) begins an oil and gas activity permitted by a permit but then fails to carry out or continue that oil and gas activity;

(e) engages in or has engaged in a pattern of conduct that shows, in the commissioner's opinion, that the person is unfit to have a permit;

(f) is or has been convicted of an offence under

(i) this Act or any other enactment, or

(ii) a law enacted by the government of Canada, another province of Canada or a foreign jurisdiction

for conduct that shows, in the commissioner's opinion, that the person is unfit to have a permit.

(3) Without limiting the authority of the commission under subsection (1), the commission may make a decision under subsection (1) with respect to an applicant or permit holder if the applicant or permit holder is an employer, employee, officer, director or agent of a

(a) permit holder against whom the commission has made a decision under subsection (1), or

(b) permit holder that has an employee, officer, director or agent against whom the commission has made a decision under subsection (1).

(4) Without limiting the authority of the commission under subsection (1), the commission may make a decision under subsection (1) with respect to a permit holder who holds more than one permit for any contravention by the permit holder of

(a) any of the permit holder's permits, or

(b) any order issued to the permit holder with respect to oil and gas activities permitted under any of the permit holder's permits.

(5) If the commission suspends or cancels a permit or a permission under subsection (1) (b) or (c), the commission may also suspend or cancel an authorization issued to the permit holder for a related activity of an oil and gas activity permitted by the permit, whether or not a specified enactment prohibits the suspension or cancellation of the authorization or requires the commission to make a finding other than the suspension or cancellation of a permit before suspending or cancelling an authorization.

(6) The commission must give a permit holder an opportunity to be heard before making a decision under subsection (1) (b), (c) or (d) or (5) and must notify the permit holder of its decision under any of those provisions.

(7) If the commission refuses under subsection (1) to issue a permit, the commission must provide notice, in accordance with subsection (8), to the land owner of the land on which the applicant for the permit intended to carry out an oil and gas activity.

(8) A notice under subsection (7) must advise the land owner

(a) that the commission has refused to issue a permit,

(b) that the applicant for the permit may, in relation to the refusal, request a review under section 70 or appeal under section 72, and

(c) that the land owner may, on request, be a party to an appeal referred to in paragraph (b).

Spent permit or permission

27 (1) The commission, on its own initiative or on application by a permit holder, may declare to be spent

(a) a permit, if the commission considers that the permit holder no longer requires the permit,

(b) a permission specified in a permit, if the commission considers that the permit holder no longer requires the permission, and

(c) despite anything in a specified enactment prohibiting the declaration, an authorization held by the permit holder, if the commission considers that the permit holder no longer requires the authorization.

(2) Before the commission makes a declaration under subsection (1) on its own initiative, the commission must give the permit holder an opportunity to be heard.

(3) If the commission declares a permit or permission or an authorization to be spent under subsection (1), the commission must provide written notice of that declaration to the permit holder or former permit holder.

Permitted activity under pipeline permits

28 (1) In this section:

"applicable Act" means the *Forest Act*, the *Forest and Range Practices Act*, the *Railway Act* and the *Railway Safety Act*;

"regulator" means a person authorized to grant an approval under an applicable Act.

(2) Despite anything in an applicable Act but subject to subsection (3),

(a) the commission, in a pipeline permit, may give permission to the pipeline permit holder to construct or operate a pipeline across, along, over or under any highway, road, public place, railway, underground communication or power line or another pipeline, and

(b) the pipeline permit holder may carry out the activities referred to in paragraph (a) in accordance with the pipeline permit and this Act.

(3) If, but for subsection (2), a permit holder would not be entitled to carry out the activities referred to in subsection (2) (a) without obtaining an approval under an applicable Act, the regulator, on application made by the pipeline permit holder in accordance with the applicable Act, must grant the approval to the pipeline permit holder, but may impose, with respect to the carrying out of those activities, any conditions that the regulator is authorized to impose on the approval under the applicable Act.

Transfer of permit and authorizations

29 (1) On application in writing signed by both a permit holder and a person to whom the permit holder wants the permit to be transferred, the commission

(a) may transfer the permit to that person, subject to any conditions the commission considers necessary, and

(b) if the commission transfers the permit under paragraph (a), must transfer, despite anything in a specified enactment prohibiting the transfer, all authorizations issued to the permit holder for related activities of an oil and gas activity permitted by the permit.

(2) In deciding whether to grant an application under subsection (1), the commission may consider

(a) any of the matters referred to in section 26 (2) to (4), and

(b) any other matter that may be considered under a specified enactment,

as though the person to whom the permit holder wants the permit to be transferred were an applicant for the permit and an authorization referred to in subsection (1) (b) of this section.

(3) A person to whom a permit is transferred under subsection (1)

(a) has the same rights and obligations as if the permit had been issued to that person, and

(b) if an authorization is transferred to that person, has the same rights and obligations as if the authorization had been issued to that person.

Required security

30 The commission may require a permit holder, an applicant for a permit or a transferee of a permit to provide security to the commission, in the amount the commission requires and in accordance with the regulations, to ensure the performance of an obligation under this Act, a permit or an authorization.

Amendment of permit

31 (1) Before submitting an application under subsection (4) for an amendment to a permit, a permit holder must provide notice to the land owner of the land on which an oil and gas activity is permitted to be carried out under the permit, and the notice must

(a) provide a description of the proposed amendment, and

(b) advise the land owner that he or she may make a submission to the commission under subsection (2).

(2) A land owner who receives a notice under subsection (1) may make a written submission to the commission regarding the proposed amendment within 15 days of receiving the notice.

(3) If a land owner makes a submission under subsection (2), the commission must send a copy of the submission to the permit holder.

(4) After complying with subsection (1), a permit holder may apply to the commission for an amendment to the permit holder's permit by submitting an application in writing.

(5) On receipt of an application under subsection (4), the commission may require the permit holder to carry out one or more of the prescribed consultations or provide one or more of the prescribed notices, as applicable, with respect to the proposed amendment.

(6) A permit holder required to carry out consultations or provide notice under subsection (5) must submit a written report to the commission regarding the results of the consultations or notice.

(7) On receipt of an application under subsection (4) and after considering a submission made under subsection (2), if any, and the results of consultations carried out or notices provided under subsection (5), if any, the commission may amend the permit holder's permit or refuse to amend the permit.

(8) An amendment made under subsection (7) is effective on and after the day it is made, unless the amendment changes the effect of the permit on the land of the land owner referred to in subsection (1), in which case the amendment is effective on and after the earlier of the following:

(a) the 15th day following the day it is made;

(b) the day the permit holder obtains written consent from the land owner to treat the amendment as being in effect on and after the date the consent is given.

(9) If the commission amends a permit under subsection (7) and the amendment changes the effect of the permit on the land of the land owner referred to in subsection (1), the commission must provide notice to the land owner in accordance with subsection (10).

(10) A notice under subsection (9) must

(a) advise the land owner of the amendment,

(b) state that the land owner may appeal under section 72 the decision to amend the permit, and

(c) provide an address to which an appeal may be sent.

(11) If the commission refuses to amend a permit under subsection (7), the commission must provide to the land owner referred to in subsection (1) notice in accordance with subsection (12).

(12) A notice under subsection (11) must advise the land owner

(a) that the applicant for the amendment may, in relation to the refusal, request a review under section 70 or appeal under section 72, and

(b) that the land owner may, on request, be a party to an appeal referred to in paragraph (a).

Expiration of permit and authorizations

32 (1) Subject to subsection (8), a permit and, despite anything in a specified enactment, any authorization issued to the permit holder for a related activity of an oil and gas activity permitted by the permit expire on the day after the prescribed period has elapsed if the permit holder has not by that day begun an oil and gas activity permitted by the permit.

(2) A permit holder, before the expiry of the permit holder's permit under subsection (1), may apply to the commission for an extension of the prescribed period with respect to the permit holder's permit and authorizations by submitting to the commission the information, application form and records required by the commission.

(3) On receipt of an application under subsection (2), the commission may require the permit holder to carry out one or more of the prescribed consultations or provide one or more of the prescribed notices with respect to the extension for which the application is made.

(4) A permit holder required to carry out consultations or provide notice under subsection (3) must submit a written report to the commission regarding the results of the consultations or notice.

(5) On application under subsection (2), the commission may

(a) extend by not more than one year the prescribed period with respect to the applicant's permit, and

(b) in granting an extension, impose additional conditions on the permit and the authorizations.

(6) Despite anything in a specified enactment, if the commission grants an extension under subsection (5) for a period of time, the commission may also extend the term of an authorization referred to in subsection (1), other than an authorization under section 8 of the *Water Act*.

(7) An extension with respect to a permit holder's permit and authorizations may be granted under this section only once, unless the commission is satisfied there are special circumstances to justify one or more further extensions.

(8) Despite subsection (1), a permit or an authorization does not expire under that subsection if the commission grants an extension under subsection (5) with respect to the permit or the term of the authorization is extended under subsection (6).

Surrender of permit or permission

33 (1) A permit holder may send a notice to the commission advising the commission of the permit holder's intention to surrender the permit or a permission specified in a permit.

(2) On receipt of a notice under subsection (1), the commission may

(a) cancel the permit holder's permit or permission, as the case may be, and

(b) despite anything in a specified enactment prohibiting the cancellation, cancel an authorization issued to the permit holder for a related activity of the oil and gas activity with respect to which the notice was submitted.

(3) A cancellation under subsection (2) is effective on the date specified by the commission.

Division 2 — Rights and Obligations

Required ownership, interest or authorization

34 (1) In this section:

"entry agreement" means an agreement

(a) that is between

(i) a specified permit holder, and

(ii) a land owner of an area of land, and

(b) that authorizes the specified permit holder to enter, occupy or use the land owner's area of land for the purposes of constructing and operating a pipeline other than a flow line;

"specified permit holder" means a pipeline permit holder who holds a permit respecting a pipeline other than a flow line.

(2) Subject to sections 23 and 39 and subsection (3) of this section, a permit holder must not begin or carry out an oil and gas activity on or under an area of land unless the permit holder,

(a) if the area of land is not a highway, either is the owner in fee simple of the area of land or has acquired the area of land or the necessary interests in the area of land in accordance with

(i) the *Land Act*,

(ii) Part 16 or 17 of the *Petroleum and Natural Gas Act*, or

(iii) subsection (3) of this section, or

(b) if the area of land is a highway, has obtained an authorization required under an enactment to enter, occupy or use the area of land.

(3) Subject to subsection (4), if a specified permit holder has failed to obtain an entry agreement, the specified permit holder may expropriate, in accordance with the *Expropriation Act*, as much of the land or interests in it of any person as may be necessary for constructing and operating the pipeline authorized by the permit.

(4) The land that may be expropriated under subsection (3) must not exceed 18 m in breadth.

(5) On application by a specified permit holder, the commission may authorize, on any conditions the commission considers appropriate, an expropriation, in accordance with the *Expropriation Act*, that exceeds the breadth specified in subsection (4).

Obligations in carrying out oil and gas activities

35 (1) In carrying out oil and gas activities and related activities, a permit holder or a person entering land under section 23 must minimize

(a) damage and disturbance to the sites of those activities, and

(b) waste.

(2) A pipeline permit holder must make reasonable efforts to ensure that its oil and gas activities do not prevent access to or use of a highway, road, railway or public place.

(3) A pipeline permit holder, as soon as reasonably possible after constructing a pipeline, must restore, in accordance with the regulations, if any, the land and surface disturbed by the construction.

Environmental protection and management

36 (1) A permit holder and a person carrying out an oil and gas activity must comply with environmental measures established under the authority of a regulation made under section 104.

(2) Subject to regulations made under section 98, the commission, by order, may exempt, on any conditions the commission considers necessary, a permit holder or a person carrying out an oil and gas activity from a requirement imposed by regulation under section 103.

Spillage

37 (1) A permit holder and a person carrying out an oil and gas activity must

(a) prevent spillage, and

(b) promptly report to the commission any damage or malfunction likely to cause spillage that could be a risk to public safety or the environment.

(2) If spillage occurs, a permit holder or person carrying out an oil and gas activity must promptly do all of the following:

(a) remedy the cause or source of the spillage;

(b) contain and eliminate the spillage;

(c) remediate any land or body of water affected by the spillage;

(d) if the spillage is a risk to public safety or the environment, report to the commission

(i) the location and severity of the spillage, and

(ii) any damage or malfunction causing or contributing to the spillage.

(3) A person who is aware that spillage is occurring or likely to occur must make reasonable efforts to prevent or assist in containing or preventing the spillage.

Records, reports and plans

38 (1) A permit holder must do all of the following:

(a) prepare and maintain the prescribed records, reports and plans;

(b) prepare and maintain an emergency response program and a response contingency plan satisfactory to the commission or as prescribed by regulation, if any;

(c) prepare and maintain the records, reports and plans the commission orders the permit holder to maintain;

(d) at the request of the commission, produce the records, reports and plans referred to in paragraph (a), (b) or (c) for inspection and copying;

(e) at the request of the commission or as prescribed by regulation, submit to the commission, in the form and manner the commission requires, the records, reports and plans referred to in paragraph (a), (b) or (c).

(2) The commission must disclose records, reports and plans to the public in accordance with the regulations.

Suspension of activity

39 (1) If a permit holder begins an oil and gas activity but ceases to have the interests in land or authorization referred to in section 34 necessary to carry out that activity, the permit holder must immediately suspend all oil and gas activities and related activities being carried out on that land, unless the commission approves the continuation of those activities under subsection (2).

(2) The commission, on application by a permit holder referred to in subsection (1), may

(a) approve the continuation of the permit holder's oil and gas activities and related activities, and

(b) on granting an approval under paragraph (a), impose additional conditions on the permit holder's permit and authorizations, if any.

(3) A permit holder with permission to drill or operate a well must immediately suspend its drilling and operations if

(a) the permit holder ceases

(i) to be the owner of the petroleum and natural gas rights or the holder of the location in respect of the well,

(ii) to have a valid agreement with the owner of the rights or the holder of the location referred to in subparagraph (i) authorizing the drilling or operation, as applicable, or

(iii) to hold a storage reservoir lease issued under section 130 of the *Petroleum and Natural Gas Act*, or

(b) the minister rescinds a declaration made under section 24 (5) with respect to the permit holder and those activities.

(4) A permit holder who suspends activities under subsection (1) or (3) must

(a) immediately notify the commission of the suspension,

(b) comply with the prescribed requirements, and

(c) carry out any actions as directed by the commission.

Obligations when permit, permission or authorization expires or is cancelled or spent

40 If a permit, a permission specified in a permit or an authorization

(a) is cancelled under section 26 or 33,

(b) is declared to be spent under section 27, or

(c) expires under section 32,

the permit holder or former permit holder, as the case may be, must

(d) unless otherwise ordered by the commission, perform each obligation imposed

(i) in relation to the permit, permission or authorization under this Act or a specified enactment, and

(ii) under the permit or authorization

that has not been performed by the date of the cancellation, declaration or expiry,

(e) comply with the prescribed requirements, and

(f) carry out any other actions for the purposes of restoration or the protection of public safety that the commission orders the permit holder or former holder to carry out.

Certificate of restoration

41 (1) A person, other than a person in a prescribed class of persons, to whom

(a) section 40 (a) or (b) applies, or

(b) an order has been issued under section 49

may apply to the commission for a certificate of restoration by submitting, in the form and manner the commission requires, the information and other records required by the commission.

(2) On application by a person under subsection (1), the commission, subject to section 43, may issue to the person a certificate of restoration certifying, on the basis of the information known to the commission at the time of certification, that the commission is satisfied

(a) in the case of an application by a person referred to in subsection (1) (a), that the person has complied with section 40 (d) to (f), or

(b) in the case of an application by a person referred to in subsection (1) (b), that the person has complied with the order referred to in that subsection.

(3) The issuance of a certificate of restoration does not relieve a person from any obligations under section 40 or under an order referred to in subsection (1) (b) of this section in respect of any matter that was not known to the commission at the time the certificate of restoration was issued.

Continuing liability

42 A cancellation, declaration or expiry referred to in section 40 or the issuance of a certificate of restoration under section 41 does not affect or relieve the permit holder or former permit holder from

(a) the consequences of any contravention or offence or any related fine, imprisonment, fee, charge or penalty, if the contravention or offence occurred before the cancellation, declaration or expiry, or

(b) any liability imposed on the permit holder or former permit holder under a specified enactment.

***Environmental Management Act* requirements must be met**

43 (1) This section applies to an application for a certificate of restoration under section 41.

(2) The commission may not approve an application referred to in subsection (1) with respect to a site where a site profile is required under section 40 of the *Environmental Management Act* unless at least one of the following is satisfied:

(a) the commission has received a site profile required under section 40 of the *Environmental Management Act* with respect to the site and the commission is not required to forward a copy of the site profile to a director under section 40 (4) (b) of that Act;

(b) the commission has received a site profile under section 40 of the *Environmental Management Act* with respect to the site, has forwarded a copy of the site profile to a director under section 40 (4) (b) of that Act and has received notice from the director that a site investigation under section 41 of that Act will not be required by the director;

(c) the commission has received a final determination under section 44 of the *Environmental Management Act* that the site is not a contaminated site;

(d) the commission has received notice from a director under the *Environmental Management Act* that the commission may approve an application under this section because, in the opinion of the director, the site would not present a significant threat or risk if the application were approved;

(e) the commission has received notice from a director under the *Environmental Management Act* that the director has received and accepted a notice of independent remediation with respect to the site;

(f) the commission has received notice from a director under the *Environmental Management Act* that the director has entered into a voluntary remediation agreement with respect to the site;

(g) the commission has received a valid and subsisting approval in principle or certificate of compliance under section 53 of the *Environmental Management Act* with respect to the site.

Part 4 — Orphan Sites

Definitions

44 In this Part:

"former Act" means the *Oil and Gas Commission Act*, S.B.C. 1998, c. 39, as it was immediately before its repeal;

"fund" means the fund continued under section 45 (3);

"marketable gas" means natural gas that is available for sale for direct consumption as a domestic, commercial or industrial fuel, or as an industrial raw material, or that is delivered to a storage facility, whether it occurs naturally or results from the processing of natural gas;

"orphan site" means a site designated under section 45 (2);

"restore" includes the requirements under section 40;

"surface lease" means

(a) a surface lease as defined in section 141 of the *Petroleum and Natural Gas Act*, and

(b) an order of the Surface Rights Board under the *Petroleum and Natural Gas Act*.

Reclamation of orphan sites

45 (1) The commission may restore orphan sites.

(2) The commission may designate as an orphan site

(a) a well, facility or pipeline if

(i) the operator with respect to the well, facility or pipeline is insolvent, or

(ii) the commission has not been able to identify the operator of the well, facility or pipeline, or

(b) an area, if the commission is satisfied that the area requires restoration as a direct or indirect result of the carrying out of an oil and gas activity by a person the commission has not been able to identify or by a person who is insolvent.

(3) The fund held by the commission under section 6.2 of the former Act is continued, and the purposes of the fund are to provide money as follows:

(a) to pay the costs of restoration in respect of orphan sites;

(b) to pay costs incurred in pursuing reimbursement for the costs referred to in paragraph (a) from the person responsible for paying them;

(c) to pay any other costs directly related to the operations of the commission in respect of the fund;

(d) to pay compensation for the purposes of section 46.

(4) The following must be deposited to the credit of the fund:

(a) money paid to the commission under section 18 (2) (b);

(b) money borrowed to meet any deficit in the fund;

(c) money recovered or received by the commission under subsection (7) of this section and section 46 (4);

(d) any interest or other income of the fund.

(5) The commission may do one or more of the following:

(a) pay money from the fund for any of the purposes referred to in subsection (3) in accordance with any regulations made for the purposes of this section and section 46;

(b) from the fund, repay any money borrowed by the commission for the purposes of the fund;

(c) determine the date on which an orphan site has been satisfactorily restored.

(6) For the purposes of subsection (2), an operator must be considered to be insolvent if the operator files for protection under the *Companies' Creditors Arrangement Act* (Canada) or is a bankrupt or an insolvent person under the *Bankruptcy and Insolvency Act* (Canada).

(7) If the commission restores an orphan site, the costs paid out of the fund in respect of that orphan site are a debt payable by the operator referred to in subsection (2) to the commission and the commission has a right of action against the operator for the recovery of that debt.

(8) For the purpose of restoring an orphan site, the commission has the same powers as it has under sections 53 and 57.

Compensation for land owners respecting orphan sites

46 (1) On application by a land owner on whose land the commission expends money in accordance with section 45, the commission may make payments from the fund to compensate the land owner for the loss of use of his or her land as a result of the failure by the operator referred to in section 45 (2) to restore the land, subject to the maximums, conditions and limitations prescribed by regulation.

(2) In determining the amount of compensation to be paid to a land owner under subsection (1), the commission may consider any payments due to

the land owner or a previous land owner under a surface lease with respect to the site.

(3) Before it compensates a land owner under subsection (1), the commission may require as a condition of compensation that the land owner assign to the commission the land owner's rights, if any, to overdue payments under a surface lease.

(4) If the commission provides compensation to a land owner, the commission has a right of action against the operator for the recovery of the amount paid in compensation.

Orphan site restoration tax

47 (1) For the raising of revenue for the purposes of the fund, a producer must pay to the government a tax as determined under subsection (2), unless the operation of the tax is suspended by a regulation made under section 100 (2) (d).

(2) The tax under subsection (1) must be paid by a producer at the following rates:

(a) $0.03 per 1 000 cubic metres of marketable gas produced by the producer in a production month;

(b) $0.06 per cubic metre of petroleum produced by the producer in a production month.

(3) Subject to subsection (4), sections 73 (4) and 74 to 77 of the *Petroleum and Natural Gas Act* apply to the tax under this section as if it were a royalty under those sections of that Act.

(4) If there is a conflict between a regulation made under section 100 of this Act and sections 73 (4) and 74 to 77 of the *Petroleum and Natural Gas Act* or the regulations made under those sections of that Act, the regulation made under this Act prevails.

(5) The commission must provide to a producer a notice of the tax payable by that producer under this section.

(6) A notice required under subsection (5) may be provided to a producer by including the notice in an invoice sent to the producer in respect of a levy payable under regulations made under section 110 (a) of this Act.

(7) A producer must pay the tax by the date specified under the regulations.

(8) A producer who fails to pay the tax by the date specified under the regulations must pay to the government penalties set by regulation.

Part 5 — Compliance and Enforcement

Division 1 — Reference and Application

Reference and application

48 (1) In this Part:

(a) a reference to "the Act" is to be read as a reference to both this Act and the specified enactments, other than the *Environmental Management Act* and the *Water Act*;

(b) a reference to "the regulations" is to be read as a reference to both the regulations made under this Act and to the regulations made under the specified enactments, other than the *Environmental Management Act* and the *Water Act*;

(c) a reference to an authorization does not include the following:

(i) an authorization under the *Environmental Management Act* or the *Water Act* issued by the commission under section 8 of this Act;

(ii) an approval, as defined in section 9 of this Act and as issued by the commission under that section, under the *Environmental Management Act* or the *Water Act*;

(d) a reference to a related activity does not include a related activity under the *Environmental Management Act* or the *Water Act*.

(2) Despite anything in a specified enactment,

(a) an order may be issued under Division 2 with respect to an authorization or a related activity,

(b) the powers granted under Division 3 to an official or peace officer may be exercised with respect to an authorization or a related activity, and

(c) a finding may be made under section 62 and an administrative penalty may be imposed under section 63 with respect to an authorization or a related activity.

Division 2 — Orders

Order issued by official

49 (1) An official may, in writing, issue to a person carrying out an oil and gas activity or a related activity an order under this section with respect to those activities or any of the person's obligations under the Act or the regulations or the person's permit or authorization, if any, if, in the opinion of the official,

(a) the person fails to comply with the Act, the regulations, a previous order made under the Act, or the person's permit or authorization, or

(b) the order is necessary

(i) to mitigate a risk to public safety,

(ii) to protect the environment, or

(iii) to promote the conservation of petroleum and natural gas resources.

(2) An official may issue an order to a person under subsection (1) with respect to an act or omission by the person whether or not the commission has made a finding under section 62 with respect to that act or omission.

(3) An order under subsection (1) must

(a) name the person to whom the order is addressed,

(b) specify the action to be taken, stopped or modified,

(c) state the date by which the person must comply with the order,

(d) state the reasons for the order,

(e) state that the person may request a review of the order under section 70 or appeal the decision under section 72, and include an address to which a request for a review or an appeal may be sent,

(f) be dated the day the order is made, and

(g) be served on the person to whom it is addressed.

(h) [Repealed 2010-9-31.]

(3.1) If an order under subsection (1) is addressed to an employee, agent or contractor of a permit holder, the official who served the order must serve a copy of the order on the permit holder.

(4) Without limiting subsection (3) (b), an order under subsection (1) may specify any of the following requirements:

(a) that a person must apply to obtain or amend a permit or an authorization in accordance with the Act and the regulations;

(b) that a person remedy a failure referred to in subsection (1)(a);

(c) that a person repair damage to the environment;

(d) that a person suspend or resume an oil and gas activity or any aspect of an oil and gas activity;

(e) that a person use a specified method to carry out an oil and gas activity;

(f) that a person conduct tests, take samples, conduct analyses and submit records and information to the commission;

(g) that a person control or prevent the escape of petroleum, natural gas, water, waste or other substances from a well, pipeline or facility;

(h) that a person repressure, recycle or carry out pressure maintenance of any pool or portion of it, or use any other enhanced recovery technique, including the introduction or injection of natural gas, water or other substances into any pool or part of it;

(i) with respect to water produced in relation to the production of petroleum or natural gas, that a person dispose of the water into an underground formation or as otherwise specified;

(j) that a person deepen a well beyond the formation from which production is being taken or has been taken;

(k) that a person recomplete a well;

(l) that a person restrict or cease production of petroleum, natural gas or water;

(m) that natural gas be gathered, and processed if necessary, and that the natural gas or liquid hydrocarbons extracted be marketed or injected into an underground reservoir for storage or for any other purpose;

(n) that a pipeline permit holder alter or divert its pipeline;

(o) that a permit holder prepare and implement, in a form and manner satisfactory to the official, a program of measures to contain and eliminate spillage;

(p) that a permit holder arrange for an independent audit of the permit holder's operations and activities and have the auditor's report submitted to the official.

(5) Despite subsection (3), if the official referred to in subsection (1) is of the opinion that a person's actions or omissions are of such nature that they are causing, or may imminently cause, serious damage to the environment or that they are a risk to public safety, the order under subsection (1) may be issued orally.

(6) If, under subsection (5), an official issues an order orally, an official, within 48 hours, must confirm the order in writing as required under subsection (3) or the order ceases to be effective.

(7) An official may amend an order issued under subsection (1), and subsection (3) applies to the amendment.

(8) If satisfied that the circumstances that gave rise to an order under subsection (1) are no longer present or have been affected by other circumstances, an official may terminate the order by providing the person to whom the order was addressed with written notice of the termination.

(9) An order under subsection (1) may specify a requirement that is different from a requirement in a provision of a regulation under this Act, if the regulation expressly states that the provision is subject to this section.

(10) Subject to subsection (9), if a regulation is made concerning a matter with respect to which an order has been made under this section, the order, if it has not been terminated under subsection (8), is no longer valid to the extent of any inconsistency between the order and the regulation.

Technical orders

49.1 (1) The commission may, by order related to a specific location, well or area, do any or all of the following:

(a) designate a field by describing its surface area;

(b) designate a pool by describing the surface area vertically above the pool and by naming the geological formation and the zone in which the pool occurs;

(c) control and regulate the production of petroleum, natural gas and water by restriction, proration or prohibition.

(2) After an order is made under subsection (1), the commission must publish notice of the order as prescribed.

(3) An order under subsection (1) (c) may specify a requirement that is different from a requirement in a provision of a regulation under this Act, if the regulation expressly states that the provision is subject to this section.

(4) Subject to subsection (3), if a regulation is made concerning a matter with respect to which an order has been made under subsection (1) (c), the order, if it has not been rescinded, is no longer valid to the extent of any inconsistency between the order and the regulation.

Commission may carry out action

50 (1) If an official issues an order under section 49 (1) and the person to whom the order was issued has not complied with the order by the date specified in the order under section 49 (3) (c), the commission may do one or more of the following:

(a) by order in writing, restrict or prohibit the person from carrying out an action referred to in the order;

(b) after giving the person an opportunity to be heard, carry out an action referred to in the order;

(c) by order in writing, require the person to pay to the commission the amount of all direct and indirect costs the commission determines were reasonably incurred in carrying out the action referred to in paragraph (b).

(2) An order referred to in subsection (1) (c) must provide the person to whom it is issued with an accounting of the expenditures relating to the action referred to in subsection (1) (b).

Access restricted or prohibited

51 (1) An official, by order, may restrict or prohibit, in a manner prescribed by regulation, access to a public area, including a highway, road, resource road, and railway, if the official is of the opinion that the restriction or prohibition is necessary because of hazardous conditions resulting from an oil and gas activity.

(2) If an official issues an order under subsection (1), the commission must confirm the order in writing within 24 hours or the order ceases to be effective.

Emergency measures regarding spillage

52 (1) An official may, in the case of an emergency,

(a) enter on any land or body of water and do the things the official considers necessary to implement and carry out measures to contain and eliminate spillage, and

(b) order

(i) any permit holder, and

(ii) the use of any person's equipment and the operator of that equipment,

to assist in the implementation or carrying out of measures to contain and eliminate spillage.

(2) The commission may reimburse a permit holder or person referred to in subsection (1) (b) for costs or expenses incurred as a result of an order issued under that subsection if the permit holder or person is not, in the commission's opinion, responsible for the spillage or for the likely source or cause of the spillage.

(3) If costs or expenses are incurred by the commission in implementing or carrying out measures to contain and eliminate spillage or making a reimbursement under subsection (2), the commission may do one or more of the following:

(a) take, deal with and dispose of the spillage, subject to section 55;

(b) order

(i) the permit holder, or

(ii) the person

who the commission believes is responsible for the spillage or for the likely source or cause of the spillage to pay the costs and expenses, or a part of them;

(c) order the permit holder or person referred to in paragraph (b) to indemnify the commission for costs or expenses paid by the commission;

(d) for the purpose of paragraph (b) or (c), direct the manner of payment or indemnification.

Control of oil and gas activities

53 (1) If, in the commissioner's opinion,

(a) a permit holder has engaged in a pattern of conduct that shows that the person is unfit to carry out the oil and gas activities permitted by the permit holder's permit, and

(b) there is a risk to public safety, the environment or petroleum and natural gas resources,

the commission may

(c) enter, seize and take control of any well, pipeline, facility or storage reservoir together with any associated chattel and fixture and any pertinent records,

(d) either discontinue all activity or take over the management and control of the well, pipeline, facility or storage reservoir,

(e) take the steps the commission considers necessary

(i) to prevent the flow or release of petroleum, natural gas or other substances from any stratum that a well enters, including plugging a well at any depth, or

(ii) for public safety or to protect the environment, and

(f) carry out any other prescribed actions.

(2) If the commission takes control of a well, pipeline, facility or storage reservoir,

(a) the commission may issue orders concerning the well, pipeline, facility or storage reservoir to

(i) the permit holder, and

(ii) an officer, employee, agent and contractor of the permit holder operating the well, pipeline, facility or storage reservoir,

and, if the commission issues an order to a person referred to in either subparagraph (i) or (ii), the order applies to both the person referred to in subparagraph (i) and the persons referred to in subparagraph (ii), and

(b) subject to section 55, the commission may take, deal with and dispose of all petroleum, natural gas or other substances from the well, pipeline, facility or storage reservoir.

(3) The commissioner may order by whom and to what extent costs and expenses incurred as a result of proceedings taken under this section are to be paid.

Use of proceeds

54 From the proceeds of spillage disposed of under section 52 (3) (a) or of petroleum, natural gas or other substances disposed of under section 53 (2) (b), the commission

(a) must pay royalties owed with respect to the petroleum or natural gas under Part 10 of the *Petroleum and Natural Gas Act*, and

(b) after making the payments referred to in paragraph (a), may pay

(i) costs and expenses incurred as a result of proceedings taken under section 52 or 53, as applicable, and

(ii) costs and expenses of carrying out investigations and conservation measures that the commission considers necessary in connection with the exercise of its powers under section 52 or 53.

Payment into court

55 The net proceeds of spillage disposed of under section 52 (3) (a) or of petroleum, natural gas or other substances disposed of under section 53 (2) (b) remaining after payment of the costs and expenses under section 54 must be paid by the commission into the Supreme Court, and must be paid out to the persons and in the amounts as may be determined by the court on application of a person claiming to be entitled to any of the proceeds.

Statutory immunity

56 (1) Subject to subsection (2), no legal proceeding for damages lies or may be commenced or maintained against the government, the commissioner, the commission, an official or the commission's directors or employees because of anything done or omitted

(a) in the performance or intended performance of a duty under sections 50 to 53, or

(b) in the exercise or intended exercise of a power under sections 50 to 53.

(2) Subsection (1) does not apply to a person referred to in that subsection in relation to anything done or omitted by that person in bad faith.

Division 3 — Inspections and Audits

Entry and inspection or audit

57 (1) In subsection (2), **"dwelling"** means

(a) a structure occupied as a private residence, and

(b) if only part of a structure is occupied as a private residence, that part of the structure.

(2) For any purpose related to the administration or enforcement of the Act, the regulations, a permit or an authorization, an official may enter, at any reasonable time, on land or premises, other than a dwelling, if the official has reasonable grounds to believe that

(a) the land or premises is the site of an oil and gas activity or a related activity that is regulated under the Act or the regulations or is carried on by a person who is required under this Act to hold a permit or an authorization to carry out that activity, or

(b) records concerning the activities referred to in paragraph (a) are kept on the land or premises.

(2.1) A person must admit onto land or premises referred to in subsection (2) an official entering the land or premises under that subsection, and must provide the official with the means and assistance necessary for the purpose of the entry.

(3) In order to obtain access under subsection (2), an official may enter land owned by a person other than a permit holder if the entry is reasonably necessary to obtain the access.

(4) An official who enters on land or premises under this section may

(a) inspect or audit anything or any activity that is reasonably related to the purpose of the inspection or audit,

(b) take samples and carry out tests and examinations,

(c) require production for the purposes of inspection or audit or copying of

(i) a permit or authorization that is required for the activity, and

(ii) a record required to be kept under the Act or the regulations, and

(d) make inquiries the official considers necessary.

(5) A peace officer has the powers and duties of an official under this section with respect to the enforcement of the provisions of the Act and the regulations.

Inspection of vehicle

58 For any purpose related to the administration and enforcement of the Act, the regulations, a permit or an authorization, an official or peace officer may

(a) require a person operating a vehicle to stop the vehicle, and

(b) carry out an inspection of a vehicle and its contents.

Obligation of an official

59 An official who under this Part enters onto land or premises for the purposes of administering or enforcing the Act or the regulations, stops a vehicle, requests records or plans or seizes records or plans must provide proof of identity, on the request of the person who

(a) is in possession or apparent possession of the land or premises,

(b) has apparent custody or control of the records or plans being inspected or audited,

(c) is in charge of the activity being inspected or audited, or

(d) is operating a vehicle stopped under section 58.

Obligation of person inspected or audited

60 (1) The operator of a vehicle must stop the vehicle when required to do so by

(a) an official referred to in section 58, or

(b) a peace officer

who

(c) is in uniform,

(d) displays his or her official identification card or badge, or

(e) is in or near a vehicle that is either a vehicle of a peace officer or readily identifiable as a commission or other government vehicle.

(2) A person who is described in paragraphs (a) to (d) of section 59 must produce, if and as required by the official or peace officer,

(a) proof of identity,

(b) a permit or an authorization held by the person under the Act, and

(c) a record or plan required to be maintained under section 38.

Requirement to submit to inspection or audit

61 A person must not

(a) obstruct or interfere with an official or peace officer acting under the authority of this Division to administer or enforce the Act or the regulations, or

(b) withhold, destroy, tamper with, alter, conceal or refuse to produce any information, record, plan, report, substance, sample or thing that is required to be produced by an official or peace officer administering or enforcing the Act or the regulations.

Division 4 — Contraventions and Administrative Penalties

Contraventions

62 (1) After giving an opportunity to be heard to a person who is alleged to have contravened a provision of the Act, the regulations, a permit, an authorization or an order, the commission may find that the person has contravened the provision.

(2) If a corporation contravenes a provision referred to in subsection (1), a director, agent or officer of the corporation who authorized, permitted or acquiesced in the contravention also contravenes the provision.

(3) If an employee, contractor or agent of a permit holder contravenes a provision referred to in subsection (1) in the course of carrying out the employment, contract or agency, the permit holder also contravenes the provision.

(4) If a person contravenes a provision referred to in subsection (1), any other person who

(a) is directly or indirectly responsible for the act or omission that constitutes the contravention, and

(b) is a contractor, employee or agent of the person or of an other person described in paragraph (a)

also contravenes the provision.

(5) The commission may not find that a person has contravened a provision referred to in subsection (1) if the person demonstrates to the satisfaction of the commission that

(a) the person exercised due diligence to prevent the contravention, or

(b) [Repealed 2012-27-10.]

(c) the person's actions relevant to the provision were the result of an officially induced error.

(6) If

(a) a corporation referred to in subsection (2),

(b) an employee, contractor or agent referred to in subsection (3), or

(c) a person referred to in subsection (4)

has not contravened a provision referred to in subsection (1) as a result of demonstrating to the satisfaction of the commission anything referred to in subsection (5) (a) and (c), the commission may find that any of the other persons referred to in subsections (2) to (4) has contravened the provision, unless the other person demonstrates to the satisfaction of the commission anything referred to in subsection (5) (a) and (c).

(7) Nothing in subsection (5) prevents

(a) an official from issuing an order under section 49 (1) to a person with respect to an act or omission by the person, or

(b) the commission from doing anything referred to in section 50.

(8) A person does not contravene a provision referred to in subsection (1) by doing or omitting to do something if that act or omission is reasonably necessary to conform with the requirements of the *Workers Compensation Act* or any regulations under that Act.

Administrative penalties

63 (1) If the commission finds that a person has contravened a provision referred to in section 62 (1), the commission may impose an administrative penalty on the person in an amount that does not exceed the prescribed amount.

(2) Before the commission imposes an administrative penalty on a person, the commission must consider the following:

(a) previous contraventions by, administrative penalties imposed on or orders issued to

(i) the person,

(ii) if the person is an individual, a corporation for which the individual is or was an officer, director or agent, and

(iii) if the person is a corporation, an individual who is or was an officer, director or agent of the corporation;

(b) the gravity and magnitude of the contravention;

(c) the extent of the harm to others resulting from the contravention;

(d) whether the contravention was repeated or continuous;

(e) whether the contravention was deliberate;

(f) any economic benefit derived by the person from the contravention;

(g) the person's efforts to prevent and correct the contravention;

(h) any other matters prescribed by the Lieutenant Governor in Council.

(3) If a person is charged with an offence under this Act, an administrative penalty may not be imposed on the person in respect of the same circumstances that gave rise to the charge.

Notice of contravention or penalty

64 If the commission finds that a person has contravened a provision referred to in section 62 (1) or imposes an administrative penalty on a person, the commission must give to the person a notice of the finding or administrative penalty and the notice must specify the following:

(a) the contravention;

(b) the amount of the penalty, if any;

(c) the date by which the penalty, if any, must be paid;

(d) the person's right to request a review of the decision under section 70 or to appeal the decision under section 72;

(e) an address to which a request for a review or an appeal may be sent.

Due date of penalty

65 The person on whom an administrative penalty is imposed must pay the administrative penalty

(a) if paragraph (b) does not apply, within 30 days after the date on which the notice referred to in section 64 is served on the person, or

(b) by the later of the following:

(i) if the person requests a review of the administrative penalty under section 70, 30 days after the date on which the notice referred to in section 71 (1) (b) is served on the person, unless the penalty is rescinded under section 71 (1) (a);

(ii) if the person appeals the administrative penalty under section 72 and the appeal tribunal does not make an order under section 72 (4) with respect to that appeal, 30 days after the date on which the decision of the appeal tribunal is served on the person, unless the penalty is rescinded under section 72 (6) (a) or dealt with as described in section 72 (6) (b).

Enforcement of administrative penalty

66 (1) An administrative penalty constitutes a debt payable to the government by the person on whom the penalty is imposed.

(2) If a person fails to pay an administrative penalty as required under section 65,

(a) the government may file with the Supreme Court or Provincial Court a certified copy of the notice imposing the administrative penalty and, on being filed, the notice has the same force and effect, and all proceedings may be taken on the notice, as if it were a judgment of that court, and

(b) the commission may refuse to consider applications made by the person under section 24.

Revenue from administrative penalties

67 The commission must pay all amounts derived from administrative penalties into the consolidated revenue fund.

Time limit for imposing an administrative penalty

68 (1) The time limit for making a finding under section 62 and giving a notice under section 64 is

(a) 3 years after the date on which the act or omission that is alleged to constitute the contravention occurred, or

(b) if the commissioner issues a certificate described in subsection (2) of this section, 3 years after the date on which the commissioner learned of the act or omission referred to in paragraph (a).

(2) A certificate purporting to have been issued by the commissioner certifying the date referred to in subsection (1) (b) is proof of that date.

Part 6 — Reviews and Appeals

Definitions and application

69 (1) In this Part:

"determination" means

(a) with respect to an eligible person other than a land owner referred to in paragraph (b),

(i) a decision made by the commission under section 25 or 26,

(ii) a declaration made by the commission on its own initiative under section 27,

(iii) an order made by the commission under section 40 (f),

(iv) an order issued by an official or the commission under Division 2 of Part 5,

(v) a finding made by the commission under section 62,

(vi) an administrative penalty imposed by the commission under section 63, and

(vii) a prescribed decision made under this Act, and

(b) with respect to a land owner of land on which an oil and gas activity is permitted to be carried out under this Act,

(i) a decision made by the commission

(A) under section 25 to issue a permit to carry out an oil and gas activity on the land of the land owner, and

(B) under section 31 to amend a permit, if the amendment changes the effect of the permit on the land of the land owner, and

(ii) a decision made by a review official under section 71 to vary a determination referred to in paragraph (a) (i) of this definition so that

(A) a permit is amended, if the amendment changes the effect of the permit on the land of the land owner, or

(B) a permit is issued to carry out oil and gas activities on the land of a land owner;

"eligible person" means

(a) an applicant for a permit,

(b) a permit holder or former permit holder,

(c) a land owner of land on which an oil and gas activity is permitted to be carried out under this Act,

(d) a person to whom an order under section 49 (1) has been issued, and

(e) a person with respect to whom the commission has made a finding of a contravention under section 62;

"review official" means, in relation to a determination, a person who did not make the determination but who is designated in writing by the commission to review the determination for the purposes of sections 70 and 71.

(2) Despite anything in a specified enactment, a determination may not be appealed, reviewed or otherwise reconsidered except as provided in this Part.

Review by review official

70 (1) Subject to subsection (2), an eligible person, other than a land owner of land on which an oil and gas activity is permitted to be carried out under this Act, may request, in accordance with this section, a review of a determination.

(2) An eligible person may not request a review of a determination under subsection (1) if the eligible person has appealed the determination under section 72.

(3) A request for a review under subsection (1) must be made within 30 days of receiving the later of

(a) the determination, and

(b) any written reasons respecting the determination.

(4) Despite subsection (3), a review official may extend the time to request a review, even if the time to make the request has expired, if satisfied that

(a) special circumstances existed which precluded making the request within the time period required under subsection (3), and

(b) an injustice would otherwise result.

(5) The eligible person must make the request in writing and must identify the error the eligible person believes was made or the other grounds on which a review is requested.

(6) On receipt by the review official of a request under subsection (1), the determination to be reviewed as a result of the request

(a) is stayed, if the determination is an administrative penalty imposed under section 63, and

(b) is not stayed, if the determination is not an administrative penalty referred to in paragraph (a), unless the review official orders that the determination is stayed.

(7) The review official may conduct a written, electronic or oral review, or any combination of them, as the review official, in his or her sole discretion, considers appropriate.

Powers of review official

71 (1) As soon as practicable after receiving a request under section 70 (1), the review official must

(a) confirm, vary or rescind the determination, and

(b) notify, in writing, the eligible person of the following:

(i) the review official's decision;

(ii) the reasons for the decision;

(iii) the eligible person's right to appeal the decision under section 72.

(2) If the review official varies a determination under subsection (1) so that

(a) a permit is amended and the amendment changes the effect of the permit on the land of the land owner, or

(b) a permit is issued to carry out oil and gas activities on the land of a land owner, the review official must notify the land owner of the amendment or issuance in accordance with section 25 (4) or 31 (9), as applicable.

Appeal

72 (1) Subject to subsection (2), an eligible person may appeal to the appeal tribunal

(a) a decision made under section 71, if the eligible person was a party to the review under that section, and

(b) a determination, if the eligible person has not, by the date the person commences the appeal, applied under section 70 (1) for a review of the determination.

(2) A land owner of land on which an oil and gas activity is permitted to be carried out under this Act may appeal a determination under this section only on the basis that the determination was made without due regard to

(a) a submission previously made by the land owner under section 22 (5) or 31 (2) of this Act, or

(b) a written report submitted under section 24 (1) (c) or 31 (6).

(3) Subject to subsection (4), the commencement of an appeal does not operate as a stay or suspend the operation of the determination or decision being appealed, unless the appeal tribunal orders otherwise.

(4) The commencement of an appeal with respect to an administrative penalty operates as a stay of the determination that imposed the penalty or the decision that did not rescind the penalty, unless the appeal tribunal orders otherwise.

(5) The appellant and the commission are parties to an appeal, and

(a) if a person to whom an order under section 49 (1) has been issued files an appeal and the person is not a permit holder with respect to the oil and gas activity that is the subject of the order, the permit holder is also a party to the appeal,

(b) if a land owner of land on which an oil and gas activity is permitted to be carried out under this Act files an appeal, the permit holder with respect to the oil and gas activity is also a party to the appeal,

(c) if an applicant for a permit appeals a refusal to issue a permit, the land owner of the land on which the applicant for the permit intended to carry out an oil and gas activity is, on request, also a party to the appeal, and

(d) if a permit holder appeals a refusal to amend a permit, the land owner of the land on which an oil and gas activity is permitted to be carried out under the permit is, on request, also a party to the appeal.

(6) On an appeal under subsection (1), the appeal tribunal may

(a) confirm, vary, or rescind the decision made under section 71 or the determination, or

(b) send the matter back, with directions, to the review official who made the decision or to the person who made the determination, as applicable.

(7) Despite the application of section 24 (1) of the *Administrative Tribunals Act* to the appeal tribunal, a land owner must file a notice of appeal within 15 days of the day the determination being appealed was made.

Publication

73 The commission may direct a person to publish, at the person's own cost, the facts relating to the imposition of an administrative penalty or to an order issued under Division 2 of Part 5, if the person's rights of review and appeal have elapsed without the penalty or order being rescinded or dealt with as described in section 72 (6) (b).

Part 7 — General

Lieutenant Governor in Council may order extension of pipeline

74 (1) If the Lieutenant Governor in Council considers it necessary or in the public interest, the Lieutenant Governor in Council may order a pipeline permit holder to do any or all of the following:

(a) to extend or improve its pipeline for the junction with a pipeline of a person or local authority distributing or authorized to distribute gas to the public;

(b) to sell gas to the person or local authority referred to in paragraph (a), if to do so would not impair the pipeline permit holder's ability to render adequate service to its existing customers;

(c) for the purposes in paragraph (a), to construct pipelines to communities immediately adjacent to its pipeline, if the

Lieutenant Governor in Council considers that the construction would not place an undue burden on the pipeline permit holder.

(2) The Lieutenant Governor in Council, in an order under subsection (1),

(a) may order that a person other than a pipeline permit holder referred to in that subsection must pay the costs, or a portion of the costs, incurred in carrying out the order, or

(b) may approve the payment of any of those costs from the consolidated revenue fund.

(3) If an order is made under subsection (1), the commission must amend under section 26 (1) the pipeline permit holder's permit to the extent necessary to make the permit consistent with the order.

Special projects

75 (1) The commission, on its own initiative or on application by a permit holder or an applicant for a permit, may designate, by order or in a permit, any of the following as a special project:

(a) the development or production of petroleum, natural gas, or both, from a field or pool or portion of a field or pool, using repressuring, recycling, pressure maintenance or any other technique to enhance recovery;

(b) the application of innovative technology, as defined by regulation;

(c) an innovative method of carrying out oil and gas activities and related activities;

(d) any other prescribed oil and gas activity or method of carrying out an oil and gas activity.

(2) The commission may

(a) make a designation under subsection (1) with or without conditions, and

(b) cancel or suspend a designation

(i) at the request of the permit holder to whom the designation was given, or

(ii) if it appears to the commission that there has been a contravention of this Act, the regulations, a permit, an authorization or an order respecting the designation or a condition of the designation.

(3) A permit holder with a permit for an oil and gas activity that has been designated as a special project under subsection (1) may apply to the commission for other than normal spacing under section 65.1 of the *Petroleum and Natural Gas Act*.

(4) For the purposes of a special project or of special projects generally, the Lieutenant Governor in Council and the board may each, in exercising a regulation-making power under this Act, make a regulation that is contrary to or inconsistent with a provision of this Act.

Pipeline crossings

76 (1) Subject to subsection (3), a person must not

(a) construct

(i) a highway, road or railway,

(ii) an underground communication or power line, or

(iii) any other prescribed work, or

(b) carry out a prescribed activity

along, over or under a pipeline or within a prescribed distance of a pipeline unless

(c) the pipeline permit holder agrees in writing to the construction or the carrying out of the prescribed activity, either specifically or by reference to a class of construction projects or activities,

(d) the commission, by order issued under subsection (2), approves the construction or the carrying out of the prescribed activity, either specifically or by reference to a class of construction projects or activities, or

(e) the construction or prescribed activity is carried out in accordance with the regulations.

(2) The commission, on application by a person referred to in subsection (1), may issue an order for the purposes of subsection (1) (d) and in doing so may impose any conditions that the commission considers necessary to protect the pipeline.

(3) The commission must approve

(a) the construction referred to in subsection (1) (a), and

(b) the carrying out of a prescribed activity under subsection (1) (b) by the government or a municipality, but may impose conditions referred to in subsection (2) in the order issued under that subsection.

(4) The commission, for the purposes of deciding whether to issue an order under subsection (1) or impose conditions under subsection (2), may require a pipeline permit holder to submit information regarding the pipeline permit holder's pipeline.

(5) The commission may order a pipeline permit holder whose pipeline is the subject of an order issued under subsection (2) to do one or both of the following:

(a) with the approval of the Lieutenant Governor in Council, relocate the pipeline to facilitate the construction or prescribed activity approved by the order issued under subsection (2);

(b) take the actions specified in the order that the commission considers necessary to protect the pipeline.

(6) In relation to an order of the commission referred to in subsection (5), the Lieutenant Governor in Council

(a) may order that a person other than the pipeline permit holder must pay the costs, or a portion of the costs, incurred in carrying out the commission's order, or

(b) may approve the payment of any of those costs from the consolidated revenue fund.

(7) If there is an inconsistency between an order or an approval made under subsection (6) and a regulation made under section 99 (1) (m.1), the order or approval prevails to the extent of the inconsistency.

Registry

77 The commission must maintain a registry containing the prescribed information about oil and gas activities.

Correction or clarification of a decision

78 (1) In this section, **"decision"** means any determination, declaration, order, finding or other decision made under this Act by the commission.

(2) If the commission makes a decision, the commission may

(a) correct a typographical, an arithmetical or another similar error in the decision, and

(b) correct an obvious error or omission in the decision.

(3) If the commission corrects a decision under this section, the commission must notify the person who is the subject of the decision and the correction does not take effect until that notification is given.

How to serve documents and notices

79 (1) Subject to subsections (3) and (4), all documents that are required or permitted under this Act to be given to or served on a person must be given or served in one of the following ways:

(a) by leaving a copy with the person;

(b) if the person is a permit holder or an authorization holder,

(i) by leaving a copy with an agent of that person,

(ii) by sending a copy by ordinary mail or registered mail to the address at which that person carries on business,

(iii) by sending a copy by electronic mail to the electronic mail address provided by that person,

(iv) by leaving a copy in a mail box or mail slot for the address at which that person carries on business, or

(v) by attaching a copy to a door or other conspicuous place at the address at which that person carries on business;

(c) by transmitting a copy to a facsimile number provided as an address for service by the person;

(d) by any other prescribed method of service.

(2) A document given or served in accordance with subsection (1), (3) or (4) is deemed to be received as follows:

(a) if given or served by sending a copy by ordinary or registered mail, on the 5th day after it is mailed;

(b) if given or served by sending a copy by electronic mail, on the 3rd day after it is sent;

(c) if given or served by leaving a copy in a mail box or mail slot, on the 3rd day after it is left;

(d) if given or served by attaching a copy to a door or other conspicuous place, on the 3rd day after it is attached;

(e) if given or served by transmitting a copy by facsimile, on the 3rd day after it is transmitted;

(f) if given or served by any other method of service prescribed under subsection (1) (d), as prescribed.

(3) The commission, on application by an applicant, may authorize the applicant to serve a document on a person by sending a copy of the document by registered mail to the last known address of the person if the commission is satisfied that the applicant has made a reasonable attempt to serve that person in accordance with subsection (1) but has been unable to effect the service.

(4) The commission may serve a notice, required under section 25 (4), 26 (7) or 31 (9) or (11) to be provided to a land owner, by sending a copy of the notice by registered mail to the last known address of the land owner if the commission is satisfied that service under subsection (1) of this section is impracticable in the circumstances.

Opportunity to be heard

80 (1) In any circumstances in which, under this Act, an opportunity to be heard is provided, the commission may conduct a written, electronic or oral hearing, or any combination of them, as the commission, in its sole discretion, considers appropriate.

(2) The commission may make rules respecting the circumstances and place in which and the process by which written, electronic or oral hearings may be conducted under subsection (1) and specifying the form and content of materials to be provided for written, electronic or oral hearings.

False or misleading statements

81 A person must not make a false or misleading statement in any application or other record submitted under this Act, or otherwise make a false statement to, or mislead or attempt to mislead, a person exercising a power or performing a duty or function under this Act.

Compliance with orders

82 A person to whom an order under this Act applies must comply with the order.

Application of Act to Muskwa-Kechika Management Area

83 If there is a conflict or inconsistency between this Act and the *Muskwa-Kechika Management Area Act*, the *Muskwa-Kechika Management Area Act* prevails.

Relationship with aboriginal and treaty rights

84 For greater certainty, the provisions of this Act are intended to respect aboriginal and treaty rights in a manner consistent with section 35 of the *Constitution Act, 1982*.

Part 8 — Offences and Court Orders

Time limit for commencing a prosecution

85 (1) The time limit for laying an information to commence a prosecution for an offence under this Act is

(a) 3 years after the date on which the act or omission that is alleged to constitute the offence occurred, or

(b) if the commissioner issues a certificate described in subsection (2), 3 years after the date on which the commissioner learned of the act or omission referred to in paragraph (a).

(2) A certificate purporting to have been issued by the commissioner certifying the date referred to in subsection (1) (b) is proof of that date.

Offences

86 (1) A person who contravenes section 21, 35 (1), 36 (1), 37 (1) or (2), 39 (3), 40, 61 or 81, or in relation to an order issued under section 49, section 82, commits an offence and is liable on conviction to a fine not exceeding $1 500 000 or to imprisonment for not more than 3 years, or to both.

(2) A person who contravenes section 35 (3) commits an offence and is liable on conviction to a fine not exceeding $1 000 000 or to imprisonment for not more than 2 years, or to both.

(3) A person who contravenes section 34, 38 (1) or 39 (1), or in relation to an order issued under section 53 (2) (a), section 82, commits an offence and is liable on conviction to a fine not exceeding $500 000 or to imprisonment for not more than one year, or to both.

(4) A person who contravenes section 35 (2) or 76 (1), or in relation to an order issued under a section not referred to in subsections (1) to (3) of this section, section 82, commits an offence and is liable on conviction to a fine not exceeding $100 000.

(5) A person who contravenes section 37 (3) or 60 (1) or (2) commits an offence and is liable on conviction to a fine not exceeding $25 000.

(6) The Lieutenant Governor in Council may provide by regulation that

(a) a contravention of a regulation is an offence, and

(b) a person convicted of an offence for a contravention of a regulation is liable to a fine not exceeding a maximum amount, or to imprisonment not exceeding a maximum length, or to both.

(7) If the maximum fine or imprisonment provided by a regulation under subsection (6) (b) is less than that provided by a provision of this Act, the regulation prevails.

(8) If a contravention continues for more than one day, the offender is liable to a separate penalty, without notice and without a separate count being laid, for each day that the contravention occurs.

(9) In a prosecution for an offence under this Act, it is sufficient proof of the offence to establish that it was committed by the defendant's contractor, employee or agent.

(10) Subsection (9) applies even if the contractor, employee or agent has not been identified or prosecuted for the offence.

(11) If a corporation commits an offence under this Act, a director or officer of the corporation who authorized, permitted or acquiesced in the offence also commits the offence.

(12) If a person commits an offence under this Act, any other person who

(a) is directly or indirectly responsible for the act or omission that constitutes the offence, and

(b) is a contractor, employee or agent of the person or of an other person described in paragraph (a)

also commits the offence.

(13) Due diligence, mistake of fact and officially induced error are defences to a prosecution under this Act.

(14) If

(a) a corporation referred to in subsection (11), or

(b) a person referred to in subsection (12),

has not committed an offence under this Act as a result of subsection (13), the other persons referred to in subsections (11) and (12) may be found guilty of an offence, subject to subsection (13).

(15) Section 5 of the *Offence Act* does not apply to this Act or the regulations.

Remedies preserved

87 (1) Subject to section 63 (3), a proceeding, conviction or penalty for an offence under this Part does not relieve a person from any other liability.

(2) If the commission imposes an administrative penalty on a person, a prosecution for an offence under this Act for the same contravention may not be brought against the person.

Order for compliance

88 (1) If the commission considers that a person is not complying, or has not complied, with an order issued under this Act, the commission may apply to the Supreme Court for either or both of the following:

(a) an order directing the person to comply with the order or restraining the person from violating the order;

(b) an order directing the directors and officers of the person to cause the person to comply with or to stop violating the order.

(2) On application by the commission under this section, the Supreme Court may make an order it considers appropriate.

Court order to comply

89 If a person is convicted of an offence under this Act, then, in addition to any punishment the court may impose, the court may order the person to comply with the provision.

Restitution

90 If a person is convicted of an offence under this Act, then, in addition to any other penalty, the court may order the person to pay compensation or make restitution.

Court orders

91 If a person is convicted of an offence under this Act, then, in addition to any other punishment that may be imposed, the court may, by order, do one or more of the following:

(a) prohibit the person from doing anything that may result in the continuation or repetition of the offence;

(b) direct the person to take any action the court considers appropriate to remedy or avoid any harm to the environment or public safety that results or may result from the act or omission that constituted the offence;

(c) direct the person to publish, at the person's own cost, the facts relating to the conviction;

(d) direct the person to compensate the commission for all or part of the cost of any remedial or preventative action taken by or on behalf of the commission as a result of the act or omission that constituted the offence;

(e) direct the person to pay court costs;

(f) direct the person to pay the costs of the investigation.

Penalty for monetary benefit

92 (1) If the court convicts a person of an offence under this Act, the court may increase a fine imposed on the person by an amount equal to the court's estimation of the amount of the monetary benefit acquired by or that accrued to the person as a result of the commission of the offence.

(2) A fine increased under subsection (1)

(a) applies despite any provision that provides for a maximum fine, and

(b) is in addition to any other fine under this Act.

Recovery of debts due

93 An amount that a permit holder, producer or another person is required under this Act to pay to the commission or the government is a debt due by that permit holder, producer or person to the government or the commission, as the case may be, and the debt may be recovered by the government or the commission in any court of competent jurisdiction.

Part 9 — Regulations

Division 1 — Regulations of the Lieutenant Governor in Council

General power to make regulations

94 (1) The Lieutenant Governor in Council may make regulations referred to in section 41 of the *Interpretation Act*.

(2) In making a regulation under this Act, the Lieutenant Governor in Council may do one or more of the following:

(a) delegate a matter to a person, with or without directions on how the delegated power is to be exercised;

(b) confer a discretion on a person;

(c) make different regulations for different persons, places, things, decisions, transactions or activities.

(2.1) The Lieutenant Governor in Council may make regulations establishing criteria that a person must use when exercising a discretionary or delegated power conferred on the person by a regulation under this Division.

(3) The Lieutenant Governor in Council may make a regulation defining a word or expression used but not defined in this Act.

(4) Sections 95 to 105 do not limit the authority of the Lieutenant Governor in Council to make regulations under subsection (1) of this section.

Policies and permitting authority of the commission

95 (1) The Lieutenant Governor in Council may make regulations respecting policies and procedures to be followed by the commission in conducting its affairs, exercising its powers and discretion, carrying out its functions and duties and discharging its responsibilities.

(2) The Lieutenant Governor in Council may make regulations for the purposes of section 25 (1.1).

Criteria for exercise of discretionary powers

96 (1) The Lieutenant Governor in Council may make regulations respecting the criteria that a person must use in exercising a discretionary power conferred on the person under this Act.

(2) Criteria prescribed under subsection (1) are in addition to any criteria required by this Act.

Prohibitions

97 The Lieutenant Governor in Council may make regulations as follows:

(a) prohibiting the carrying out of any oil and gas activity or related activity at any point within a specified distance of any boundary, roadway, road allowance, right of way, building of any prescribed type or any specified works;

(b) despite anything in the *Local Government Act* and the *Community Charter*, prohibiting the construction of a building or structure within a specified distance of a well, pipeline or facility, if the Lieutenant Governor in Council is satisfied that the prohibition is necessary to protect the public.

Exemptions

98 (1) The Lieutenant Governor in Council may make regulations respecting the exemption of a person, class of persons, place, thing, transaction or activity from a provision of this Act or the regulations.

(2) In making a regulation under subsection (1), the Lieutenant Governor in Council may make the exemption subject to conditions.

(3) The Lieutenant Governor in Council may make regulations restricting the commission's authority

(a) to exempt a person or class of persons from section 22 or from a requirement referred to in section 36, or

(b) to authorize an official to exempt a person from a provision referred to in section 103 (2).

General

99 (1) The Lieutenant Governor in Council may make regulations as follows:

(a) prescribing activities for the purposes of the definition of "oil and gas activity" in section 1 (2);

(b) prescribing substances for the purpose of paragraph (e) of the definition of "pipeline" in section 1 (2) and prescribing exclusions for the purposes of paragraph (h) of that definition;

(c) prescribing regulations under a specified enactment for the purposes of paragraph (f) of the definition of "specified provision" in section 1 (2);

(d) prescribing circumstances for the purposes of section 6 (2);

(e) respecting the application of the *Public Inquiry Act* for the purposes of section 12;

(f) prescribing authorizations for the purposes of section 18 (2) (c) (i);

(g) prescribing periods of time for the purposes of section 32;

(h) respecting the disclosure of records, reports and plans referred to in section 38;

(i) requiring that natural gas be gathered, and processed if necessary, and that the natural gas or liquid hydrocarbons extracted be marketed or injected into an underground reservoir for storage or for any other purpose;

(j) prescribing actions for the purposes of section 53;

(k) prescribing decisions for the purposes of the definition of "determination" in section 69;

(l) prescribing activities and methods for the purposes of section 75;

(m) prescribing works, activities and distances for the purposes of section 76 (1) and requirements for the purposes of section 76 (1) (e);

(m.1) respecting how costs incurred in relation to

(i) the construction of anything referred to in section 76 (1) (a),

(ii) the carrying out of an activity under section 76 (1) (b), or

(iii) the relocation referred to in section 76 (5) (a) and any actions referred to in section 76 (5) (b)

are to be allocated between the pipeline permit holder and the person doing anything referred to in subparagraphs (i) to (iii) of this paragraph;

(n) respecting the application of the *Mines Act* to the exploration, development and production of oil sand, oil sand products, oil shale and oil shale products;

(o) respecting surveying to be carried out with respect to an oil and gas activity;

(p) respecting information for the purposes of section 77;

(q) respecting the carrying out of activities under a master licence to cut, as defined in section 47.4 (1) of the *Forest Act*, by a permit holder, an applicant for a permit or a person carrying out an activity under an approval, as defined in section 9 (1) of this Act.

(2) The following do not apply to a master licence to cut, as defined in section 47.4 (1) of the *Forest Act*, held by a permit holder, an applicant for a permit or a person carrying out an activity under an approval, as defined in section 9 (1) of this Act:

(a) the *Forest and Range Practices Act* and the regulations and standards made under that Act;

(b) the *Forest Practices Code of British Columbia Act*, as it read immediately before section 177 of the *Forest and Range Practices Act* came into force, and the regulations made under that Code.

Regulations respecting orphan sites

100 (1) In this section, **"tax"** means the tax under section 47.

(2) The Lieutenant Governor in Council may make regulations for the purposes of Part 4 and, without limiting this, may make regulations as follows:

(a) respecting administration of the fund;

(b) respecting the designation of orphan sites;

(c) prescribing the maximums, conditions and limitations on compensation paid to land owners under section 46;

(d) suspending the operation of the tax;

(e) respecting the assessment and reassessment of tax;

(f) respecting appeals from assessment or reassessment of tax;

(g) respecting refunds of tax;

(h) providing for exemptions from payment of tax;

(i) respecting time limits and time periods related to the tax, including returns, assessments, reassessments, appeals, refunds or exemptions, and including different time limits and time periods for different classes of persons;

(j) establishing procedures for giving notice of tax payable, collection of tax, and use of the fund;

(k) setting minimum amounts to be retained in reserve in the fund;

(l) setting penalties for the purposes of section 47 (8);

(m) designating an employee of the government as the collector of the tax and providing for the collection of the tax.

Administrative penalties

101 The Lieutenant Governor in Council may make regulations respecting the imposition of administrative penalties, including, without limiting this,

(a) matters to be considered before imposing administrative penalties, the criteria for determining appropriate administrative penalties, setting different limits on different administrative penalties and setting out those provisions of this Act or the regulations which, if contravened, make a person liable to an administrative penalty, and

(b) providing for increased administrative penalties for repeated contraventions and specifying the time within which a contravention is to be considered a repeat contravention of an earlier contravention.

Collector of levy

102 The Lieutenant Governor in Council may make regulations designating an employee of the government as the collector of the levy referred to in section 110 for payment under section 18 to the commission and providing for its collection.

Environmental protection and management

103 (1) For the purposes of environmental protection and management, the Lieutenant Governor in Council may make regulations respecting actions that a permit holder and a person carrying out an oil and gas activity must take or refrain from taking to protect or effectively manage the environment.

(2) Without limiting subsection (1), the Lieutenant Governor in Council may make regulations respecting actions that a permit holder and a person carrying out an oil and gas activity must take or refrain from taking with respect to any of the following:

(a) a wildlife habitat feature, as identified under section 104 (1) (c) (i);

(b) wildlife, including fish, and wildlife habitat;

(c) temperature sensitive streams, as identified under section 104 (1) (c) (ii);

(d) streams, wetlands and lakes;

(e) riparian areas and lakeshores;

(f) lakeshore management zones;

(g) water quality;

(h) watersheds;

(i) aquifers and ground water recharge areas;

(j) old-growth management areas, as identified under section 104 (3) (a);

(k) wildlife trees;

(l) commercial timber;

(m) soils, including soil stability, disturbance and productivity;

(n) surface drainage, ground percolation and erosion control;

(o) biodiversity;

(p) invasive plants, as identified under section 104 (3) (c);

(q) resource features;

(r) range;

(s) forest resources;

(t) cultural heritage resources;

(u) scenic areas, as established under section 104 (3) (d);

(v) ungulate winter ranges, as established under section 104 (1) (a) (i);

(w) wildlife habitat areas, as established under section 104 (1) (a) (ii);

(x) fisheries sensitive watersheds, as established under section 104 (1) (a) (iv).

(3) The Lieutenant Governor in Council may make regulations

(a) for the purposes of subsection (2), classifying

(i) streams, wetlands and lakes,

(ii) riparian areas, and

(iii) wildlife habitat features, scenic features and resource features,

(b) for the purposes of subsection (2) and of section 104 (1) (a) (iv) and (2) (a), classifying watersheds,

(c) for the purposes of subsection (2) and of section 104 (2) (b) (i), classifying aquifers, and

(d) for the purposes of subsection (2) and of section 104 (4), classifying lakeshore management zones.

(4) The Lieutenant Governor in Council may make regulations prescribing objectives for the purposes of the definition of "government's environmental objectives" in section 1.

Authorizations respecting environmental protection and management

104 (1) The Lieutenant Governor in Council may make regulations authorizing the minister responsible for administering the *Wildlife Act*

(a) to establish, for the purposes of paragraph (b), one or more of the following:

(i) an area as an ungulate winter range;

(ii) an area as a wildlife habitat area;

(iii) categories of wildlife for the purposes of subparagraphs (i) to (ii);

(iv) a fisheries sensitive watershed, in accordance with regulations, if any, respecting the classification of watersheds made under section 103 (3) (b),

(b) to establish, for the purposes of section 36 (1), an environmental measure in relation to paragraph (a) (i), (ii) or (iv) of this subsection, and

(c) to identify one or both of the following:

(i) for the purposes of section 103 (2) (a), a wildlife habitat feature, in accordance with regulations, if any, respecting the classification of wildlife habitat features made under section 103 (3) (a) (iii);

(ii) for the purposes of section 103 (2) (c), a temperature sensitive stream.

(2) The Lieutenant Governor in Council may make regulations authorizing the minister responsible for administering the *Water Act*

(a) to establish, for the purposes of paragraph (c), a designated watershed or portion of a watershed, in accordance with regulations, if any, respecting the classification of watersheds made under section 103 (3) (b),

(b) to identify, for the purposes of paragraph (c), either or both of the following:

(i) an aquifer, in accordance with regulations, if any, respecting the classification of aquifers made under section 103 (3) (c);

(ii) a groundwater recharge area, and

(c) to establish, for the purposes of section 36 (1), an environmental measure in relation to paragraphs (a) and (b).

(3) The Lieutenant Governor in Council may make regulations authorizing the minister responsible for administering the *Land Act*

(a) to establish, for the purposes of section 103 (2) (j) and paragraph (b) of this subsection, an old-growth management area,

(b) to establish, for the purposes of section 36 (1), an environmental measure in relation to paragraph (a) of this subsection,

(c) to identify invasive plants for the purposes of section 103 (2) (p) and

(d) to establish, for the purposes of section 103 (2) (u), scenic areas.

(4) The Lieutenant Governor in Council may make regulations authorizing the minister responsible for administering the *Forest and Range Practices Act* to establish, for the purposes of section 103 (2) (f) and (3) (d), lakeshore management zones.

(5) The Lieutenant Governor in Council may make regulations as follows:

(a) prescribing the circumstances in which and the extent to which a discretion conferred in an authorization referred to in subsections (1) to (4) or paragraph (b) of this subsection may be exercised,

(b) authorizing a minister referred to in subsections (1) to (4) to grant an exemption from an environmental measure established by that minister and to impose one or more conditions with respect to the exemption;

(c) authorizing a minister referred to in subsections (1) to (4) to delegate any power conferred on the minister by a regulation made under this section with or without directions on how the delegated power is to be exercised,

(d) prescribing the consultations or notifications, or both, that a minister referred to in subsections (1) to (4), or a person authorized by the minister, must carry out before exercising a power conferred on the minister by a regulation made under this section;

(e) prescribing a date on which, or a period of time at the expiry of which, an order made by a minister referred to in subsection (1) to (4) in the exercise of a power conferred on the minister by a regulation made under this section comes into force.

Relation between regulations, environmental measures and other provisions

105 (1) In making a regulation under section 103, the Lieutenant Governor in Council may provide an exception to the application of the regulation, including an exception relating to the application of an environmental measure.

(2) If there is an inconsistency between

(a) either

(i) a requirement prescribed under section 103, or

(ii) an environmental measure established under section 104, and

(b) a provision of an Act administered by the minister responsible for the administration of the *Wildlife Act* or the *Water Act* or a regulation made under any of those Acts

the provision referred to in paragraph (b) prevails to the extent of the inconsistency.

Division 2 — Regulations of the Board

Board regulations generally

106 (1) In making a regulation under this Division, the board may do one or more of the following:

(a) delegate a matter to a person, with or without directions on how the delegated power is to be exercised;

(b) confer a discretion on a person;

(c) make different regulations for different persons, places, things, decisions, transactions or activities;

(d) make the regulation subject to orders issued under section 49, on any conditions the board considers appropriate.

(2) The board may make regulations establishing criteria that a person must use when exercising a discretionary or delegated power conferred on the person by a regulation under this Division.

(3) In making a regulation under section 111 or 112 (1) (a), (b), (d), (d.1) or (d.2), the board may authorize an official to exempt a person from a

provision of the regulation and to impose one or more conditions with respect to the exemption.

Consultations and notification

107 (1) The board may make regulations respecting consultations and notification for the purposes of sections 22, 31 (5) and 32 (3) and notification for the purposes of section 23 (3).

(2) Without limiting subsection (1), the board may make regulations

(a) prescribing classes of applicants for the purposes of section 22 (1),

(b) respecting the extent, nature and manner of the consultations or notifications that may be required under section 22, 31 (5) or 32 (3), including, without limiting this, regulations respecting the provision of notice to specified persons or classes of persons and the provision of replies to persons who respond to a notice, and

(c) respecting reports to be submitted under section 24 (1) (c), 31 (6) or 32 (4), including, without limiting this, regulations respecting the publication of those reports.

Permits

108 The board may make regulations as follows:

(a) respecting information for the purposes of section 24 (1) (d) and records for the purposes of section 24 (1) (e);

(b) respecting requirements for the purposes of section 25 (1).

Security

109 The board may make regulations respecting security for the purposes of sections 23 and 30, including regulations as follows:

(a) prescribing the amount of the security for the purposes of section 23 and the minimum or maximum amount, or both, of security for the purposes of section 30;

(b) respecting the type of security that is acceptable or unacceptable;

(c) respecting the form and content of the security;

(d) respecting the time by which the security must be submitted to the commission;

(e) respecting the circumstances under which the security may be realized;

(f) respecting interest on the security.

Recovery of expenses

110 The board, for the purposes of recovering expenses arising out of the administration of this Act in a fiscal year, may make regulations as follows:

(a) subject to the approval of Treasury Board,

(i) requiring permit holders or a class of permit holders to pay a levy to the government, and

(ii) establishing the amount, or the method of determining the amount, of the levy;

(b) providing for the imposition of penalties, payable to the government, to enforce payment of the levy.

Oil and gas activities

111 (1) The board may make regulations respecting the carrying out of an oil and gas activity, including, without limiting this, regulations as follows:

(a) if the commission is satisfied that there is a danger to the public, increasing a specified distance prescribed under section 97 (a), and, if a prohibition has not been prescribed under that section with respect to any area of the province, prescribing a prohibition for that area of the type referred to in that section;

(a.1) respecting actions a permit holder and a person carrying out an oil and gas activity must carry out or refrain from carrying out on completion of or while completing an oil and gas activity;

(b) respecting equipment and techniques that must be used when carrying out an oil and gas activity;

(c) respecting waste produced directly or indirectly by the carrying out of an oil and gas activity;

(d) respecting the carrying out of geophysical exploration;

(e) respecting the drilling, operation and abandonment of wells, including, without limiting this, regulations respecting

(i) the measures to be taken and the methods of operation to be used before drilling begins and during drilling or operation,

(ii) the drilling of multizone wells,

(iii) the conditioning and reconditioning of wells by mechanical, chemical or explosive means,

(iv) water source wells, and

(v) spacing areas in which wells are to be completed;

(f) respecting the exploration for and development, use and abandonment of storage reservoirs;

(g) respecting the exploration for and development and production of oil sand, oil sand products, oil shale and oil shale products;

(h) respecting the construction, operation and abandonment of a pipeline, including, without limiting this, regulations respecting measures to be taken

(i) to restore the land and surface of land after construction or removal of a pipeline,

(ii) to monitor and maintain the integrity of the pipeline and equipment, and

(iii) on suspension of operation of a pipeline;

(h.1) respecting the construction, operation and abandonment of a facility used for the purposes of producing, gathering, processing or storing petroleum, natural gas, water or a substance referred to in paragraph (d) or (e) of the definition of "pipeline" in section 1;

(i) and (j) [Repealed 2010-9-46.]

(k) determining whether a field or pool designated under section 49.1 may be operated for the production of petroleum, natural gas, or both;

(l) designating the area that is to be allocated to a well in connection with fixing allowable production;

(m) controlling and regulating the production of petroleum, natural gas and water by restriction, proration or prohibition;

(n) requiring the disposal of water produced into an underground formation or otherwise and authorizing the commission to specify the terms according to which the disposal must be done;

(o) respecting the management of petroleum or natural gas fields, pools or zones;

(p) respecting the maintenance of a pipeline, facility, well, road prescribed under subsection (2) or other structure, equipment or thing.

(2) The board may make regulations as follows:

(a) prescribing roads for the purposes of paragraph (f) in the definition of "oil and gas activity" in section 1 (2);

(b) respecting the construction, operation, maintenance and deactivation of prescribed roads;

(c) respecting the application of the *Motor Vehicle Act* to prescribed roads.

(d) respecting the use of a prescribed road by a permit holder.

General

112 (1) The board may make regulations as follows:

(a) adopting by reference, in whole or in part and with any changes the board considers necessary, any regulation, code, standard or rule

(i) enacted as or under a law of another jurisdiction, including a foreign jurisdiction, or

(ii) set by a provincial, national or international body or any other code, standard or rule making body,

as the regulation, code, standard or rule stands at a specific date, as it stands at the time of adoption or as amended from time to time;

(b) respecting the taking of samples and the conducting of tests and analyses by permit holders;

(c) subject to the approval of Treasury Board, respecting fees for the provision under this Act of a service by the commission to any person;

(d) prescribing records, reports and plans for the purposes of section 38 and respecting the maintenance and submission of those records, reports, and plans;

(d.1) respecting emergency response programs and response contingency plans for the purposes of section 38 (1) (b), including, without limiting this, regulations requiring the programs or plans to include requirements with respect to the training of persons who will carry out the programs or prepare the plans and consultations that must be carried out with respect to the programs or plans;

(d.2) respecting well samples and cores, including, without limiting this, regulations respecting the examination, storage, maintenance and submission to the commission of well samples and cores;

(e) prescribing the methods that must be used for the measurement of petroleum, natural gas, substances prescribed under section 133 (2) (v) of the *Petroleum and Natural Gas Act* and mixtures of any of them;

(f) prescribing the standard conditions to which the measurements referred to in paragraph (e) must be converted;

(g) [Repealed 2010-9-47.]

(h) prescribing requirements for the purposes of sections 39 (4) and 40 (e);

(i) prescribing classes of persons for the purposes of section 41;

(i.1) prescribing the content and manner of publication of a notice referred to in section 49.1 (2);

(j) for the purposes of section 51, respecting the restriction or prohibition of access to a public area;

(k) [Repealed 2010-9-47.]

(l) prescribing methods of service and times of deemed receipt for the purposes of section 79.

(2) For greater certainty, regulations made under subsection (1) (c) or section 110 (b) with the approval of Treasury Board may be made or adjusted at any time.

Part 10 — Transition

Repealed

113 [Repealed 2008-36-113 (3).]

Transition – appeal tribunal

114 The Lieutenant Governor in Council, when appointing the first appeal tribunal, may appoint to the appeal tribunal, without a merit-based process, a person who, at the time of the appointment, is

(a) a member of the Environmental Appeal Board continued under the *Environmental Management Act*, or

(b) a member of the Forest Appeals Commission continued under the *Forest Practices Code of British Columbia Act*.

Transition – *Oil and Gas Commission Act*

115 (1) In this section, **"former Act"** means the *Oil and Gas Commission Act*, S.B.C. 1998, c. 39, as it read immediately before being repealed.

(2) A designation made under section 6.2 (5) (a) of the former Act and in effect immediately before the repeal of the former Act is deemed to be a designation made under section 45 (2) of this Act.

Transition – *Petroleum and Natural Gas Act*

116 (1) In this section, **"former Act"** means the *Petroleum and Natural Gas Act*, R.S.B.C. 1996, c. 361, as it read immediately before this section comes into force.

(2) The following approval and authorizations are each deemed to be a permit issued under this Act if the authorization or approval is in effect immediately before the coming into force of this section:

(a) an approval issued under section 33 of the former Act;

(b) a well authorization issued under Division 1 of Part 12 of the former Act;

(c) a water source well authorization issued under Division 2.1 of Part 12 of the former Act;

(d) an authorization to construct or modify a production facility issued by the commission under the Drilling and Production Regulation, B.C. Reg. 362/98, as it read immediately before this section comes into force.

(3) Despite the repeal of Part 4 of the former Act, that Part continues to apply to a geophysical licence issued under section 32 of the former Act and in effect immediately before this section comes into force, until whichever of the following happens first:

(a) the geophysical licence is cancelled under section 35 of the former Act;

(b) a permit is issued under this Act to the holder of the geophysical licence, permitting the holder to carry out geophysical exploration;

(c) 2 years expire after the date Part 4 of the former Act is repealed.

(4) Despite the repeal of Part 12 of the former Act, that Part continues to apply to a test hole authorization issued under Division 2 of that Part until whichever of the following happens first:

(a) the test hole authorization is cancelled under Division 2 of Part 12;

(b) a permit is issued under this Act to the holder of the test hole authorization, permitting the holder to convert the test hole into a well;

(c) 2 years expire after the date Part 12 of the former Act is repealed.

(5) A drilling deposit submitted under section 85 of the former Act is deemed to be security submitted for the purposes of section 30 of this Act.

(6) An approval issued under section 100 of the former Act and in effect immediately before this section comes into force is deemed to be a designation under section 75 of this Act.

Transition – *Pipeline Act*

117 (1) In this section, **"former Act"** means the *Pipeline Act*, R.S.B.C. 1996, c. 364, as it read immediately before its repeal.

(2) Each of the following is deemed to be a pipeline permit issued under this Act:

(a) a certificate issued under section 10 of the former Act and in effect immediately before the repeal of the former Act;

(b) an authorization issued under section 22 of the former Act and in effect immediately before the repeal of the former Act;

(c) an authorization issued under section 27 of the former Act and in effect immediately before the repeal of the former Act.

(3) A leave given under section 28 of the former Act and in effect immediately before the repeal of the former Act is deemed to be an approval issued under section 76 of this Act.

(4) A leave, in relation to a pipeline, given under section 30 of the former Act and in effect immediately before the repeal of the former Act is deemed to be a permission in the pipeline permit for the pipeline.

(5) A leave given under section 31 of the former Act and in effect immediately before the repeal of the former Act is deemed to be an approval under section 76 of this Act.

(6) Despite the repeal of Part 7 of the former Act, any decision made with respect to a common carrier by the British Columbia Utilities Commission under the authority of that Part continues to apply, subject to section 65 of the *Utilities Commission Act* as amended by this enactment.

Transition – permits

118 The commission may consolidate into a single permit any or all permits held by a permit holder by operation of sections 116 and 117.

Transition – roads

118.1 Despite section 21, a person does not require a permit to maintain a road that existed immediately before January 27, 2011, and that is prescribed for the purposes of paragraph (f) of the definition of "oil and gas activity" in section 1 (2).

Part 11 — Consequential Amendments and Repeals

Consequential Amendments and Repeals

[Note: See Table of Legislative Changes for the status of sections 119 to 206.]

Section(s)	Affected Act
119-122	*Environmental Management Act*
123	*Environmental Management Amendment Act, 2004*
124	*Expropriation Act*
125	*Forest Act*
126-128	*Forest and Range Practices Act*
129	*Forest and Range Practices Amendment Act, 2003*
130	*Forests Statutes Amendment Act, 2000*
131-143	*Geothermal Resources Act*
144	*Land Surveyors Act*
145-146	*Land Title Act*
147	*Mineral Land Tax Act*
148	*Mines Act*

149	*Muskwa-Kechika Management Area Act*
150	*Oil and Gas Commission Act*
151	*Park Act*
152-199	*Petroleum and Natural Gas Act*
200	*Pipeline Act*
201	*Safety Standards Act*
202	*Securities Act*
203	*Utilities Commission Act*
204	*Water Act*
205	*Wildfire Act*
206	*Wildlife Act*

Commencement

207 This Act comes into force by regulation of the Lieutenant Governor in Council.

PIPELINE PERMIT APPLICATION MANUAL
October | 2013

Version 1.17

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
1-April-2013	Section 6	Included shoofly's in the Total of Crown Land and Total of Private Land requirements (p.42).
	Appendix A	Updated Construction Plan requirements (p.76).
	Appendix A	Updated Plan Diagram requirements (p.78).
	Section 3 & 6	Added clarification to Fibre Utilization Plan Form requirements (p. 15,48,49,65).
1-Nov-2013	Appendix A	Changed special data to spatial data (p.77).
	Various	Updated the Commission's Fort St. John office address.

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.

Section 8 **Permit Extension** details when a permit extension is required and how to apply.

Section 9 **Compliance** describes contravention of legislation and regulation and administrative penalties.

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 website. The information provided is categorized into topics which reflect the manuals for easy reference.

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@bcogc.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 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.

3 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
Physical:	6543 Airport Road, Fort St. John, B.C. V1J 4M6
Mailing:	Bag 2, Fort St. John, B.C. V1J 2B0

Preparation & Planning

When preparing a permit application, certain activities must be carried out to ensure that a complete and correct application is submitted.

In accordance with section 7(1) of PLNGFR, an IMP that complies with CSA Z662 must be prepared before the permit holder operates the pipeline.

The following sections show the steps applicants must take when planning and preparing an application.

Every applicant must:

Prepare Construction Plan(s) in accordance with OGAA Section. 24 (1) (b) and the Pipeline and Liquefied Natural Gas Facility Regulation (PLNGFR) Sections 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.

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.

Complete an archaeological assessment pursuant to the Heritage Conservation Act and the Commission's Archaeology Guidelines

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.

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.
ii. Providing the landowner(s) and affected persons with the requirements of a notification package and/or invitation to consult, as defined by the Consultation and Notification Manual. Provide any required written replies to landowners or affected parties.
iii. Submitting a Written Report in accordance with the Commission's Consultation and Notification Manual.

Conduct a site assessment if the program is located within the Agricultural Land Reserve (ALR).

Prepare Emergency Planning Zone in accordance with Pipeline and Liquefied Natural Gas Facility Regulation s.8, if necessary.

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.

Preliminary Plans and Fixing the Site of a Proposed Pipeline Route

A Pipeline Preliminary Plan is optional when applying for a pipeline permit; however, it is mandatory when entering the land to conduct preliminary surveys or examinations in order to fix the site of a proposed pipeline.

Under Section 23 of OGAA, submitting a Pipeline Preliminary Plan when applying for a pipeline permit is optional. However, if persons are planning to enter land (crown and/or private) to fix the site of a proposed pipeline route, they must:

- Submit a Pipeline Preliminary Plan to the Commission for the proposed route.
- For any proposed portions on private land, arrange access agreements with the landowner. If agreement cannot be reached, submit the prescribed security to the Commission to compensate the landowner or the Crown for any damage or disturbance that may be caused by fixing the site.
- Complete the required notifications.

Pipeline Preliminary Plan Submission Requirements
Pipeline Preliminary Plans should include a map of the proposed pipeline route at an appropriate scale, including:

- 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 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 is used for tracking purposes and should be referenced on the security submission. Additionally, applicants must submit hard copies of the Pipeline Preliminary Plan to the Commission with their security submission.

Security Calculation and Submission

Section 8(2) of the Fee, Levy and Security Regulation 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 private land portions of the proposed 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
Physical:	6543 Airport Road, Fort St. John, B.C. V1J 4M6
Mailing:	Bag 2, Fort St. John, B.C. V1J 2B0

Notification Required Before Entry

When planning to enter land to fix the site of a proposed pipeline, notification must be provided to the landowner 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 landowner of their intent to enter onto the landowner’s property two 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 the land
- The name, phone number, fax number and email 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 portion of the land to be surveyed or examined, and the activities to be completed 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
- A statement advising the landowner if the person intends to submit an application to the Commission for a pipeline permit on the their land and, if so, that the company or agent will notify and consult with the owner in accordance with Section 22 of OGAA

Return of Security

To initiate the return of a security held under Section 23 of OGAA, a person must submit a Security Return Request and any supporting documentation to demonstrate that all obligations under Section 8(4)(a) of the Fee, Levy and Security Regulation are met, in which case the Commission returns the security.

Supporting Documentation

Supporting documentation includes:

- 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 its condition before entry
- The evaluation should effectively demonstrate 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. If 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

Best management practices, as listed below, should be considered 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 and Notification Regulation
- Consult the landowner on preferred method of land access and only use motorized vehicles 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 site 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 regarding the activity of the person and/or its contractors, and of any damage incurred as a result of the entry.

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.

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 (PLNGFR).

Integrity Management Plan (IMP)

Permit holders are required to answer the IMP-related question in all new pipeline permit applications 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.

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, areas established by order under the Environmental Protection and Management Regulation).

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.

For more information on identified spatial areas and areas established by order, please refer to Spatial or Identified Areas.

Cutting Permits within Unconstructed Road Allowances

The Commission has the authority to issue Master Licenses to Cut (MLTC) and Cutting Permits (CP) for oil and gas and related activities within a Ministry of Transportation and Infrastructure (MoTI) road allowance. Applicants must submit a Fibre Utilization Plan (FUP) Form anytime there is new cut on Crown land for any timber that will be harvested within an unconstructed MoTI road allowances as a result of the planned activities.

The area within the road allowance should not be reflected in the ePASS spatial data. Applicants must have authorization from MoTI for works within road allowances.

Please refer to the Land Tab Section of this manual for information on how to complete the application in KERMIT.

4 Application Review Process

Permit Review & Approval

The following process flowchart shows the major steps in the Commission's application review and determination processes.

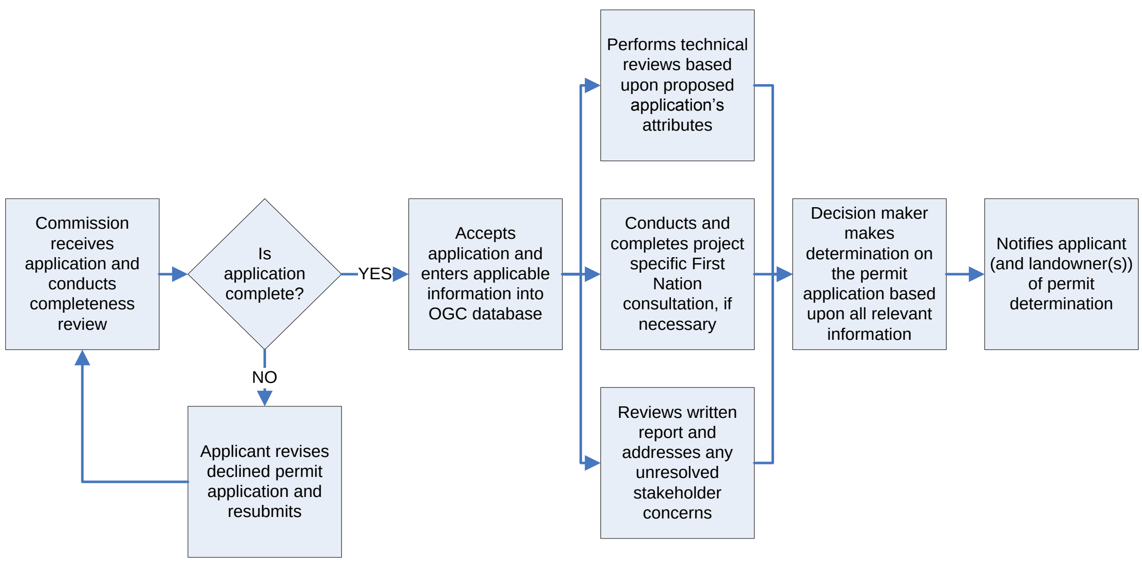


Figure 4.1. An overview of the Commission's role in the permit application review and determination processes.

Application Review and 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.

Application Screening

Once an application has been received by the Commission it will be reviewed for completeness.

Declined Applications

Applications missing requirements or 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.

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.

Completed Applications

When all requirements have been met, the application is classified as complete. It is then accepted and enters the processing and review phase

Application Review Phase

Before making a determination on the application, the Commission will consult with First Nations (where applicable), review the applicant's consultation and notification written report and perform technical reviews on areas such as archaeology and land and habitat.

Application Revision

Revised applications that undergo a change after entering the Commission's review stage, may only be resubmitted once compliant with Section 5 of the Consultation and Notification Regulation. As is the case with declined applications, revised applications once resubmitted will be reviewed in order based on the resubmission date.

Determination Phase

Application Determination

Once all internal reviews have been completed, the Commission may issue a permit with conditions attached specifying 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 an agreement cannot be reached, an application may be made to the Surface Rights Board pursuant to Part 17 of the Petroleum and Natural Gas 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

Pursuant to Section 25 of OGAA.

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 if applicable.

Commencement of Activity Timelines

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.

Term of Permit

The term of a permit is defined by regulation. To extend a permit term, the holder should consult the Commission's Permit Expiry and Extension Guideline. For more information on permit extensions, see Section 8 of this manual.

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.

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.

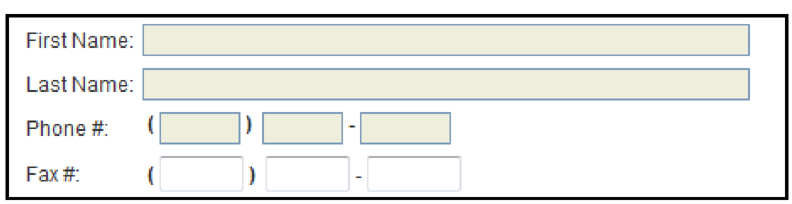


Fig. 5.1. Shaded mandatory fields in KERMIT

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.

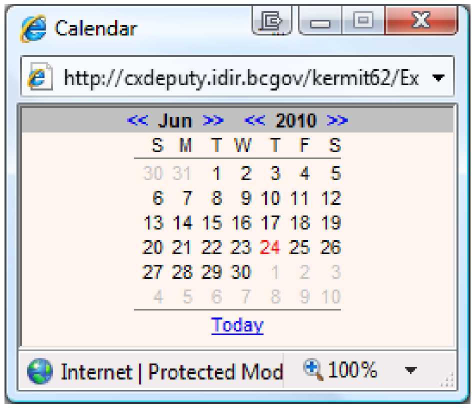


Fig. 5.2. Calendar window.

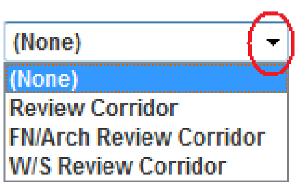
Buttons and Menus

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.

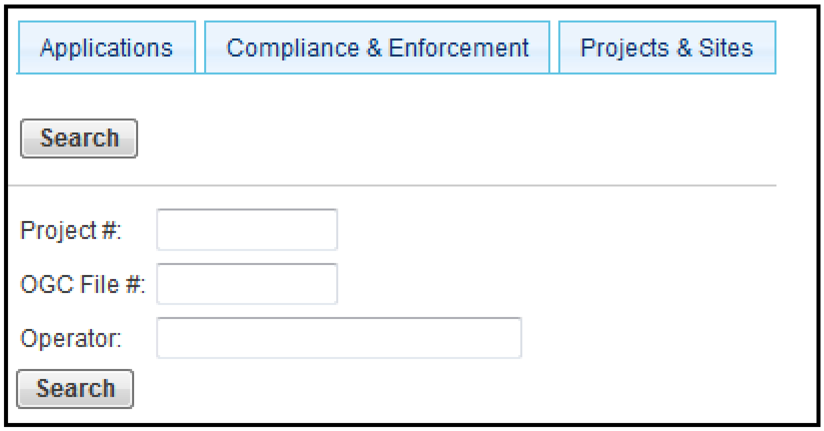


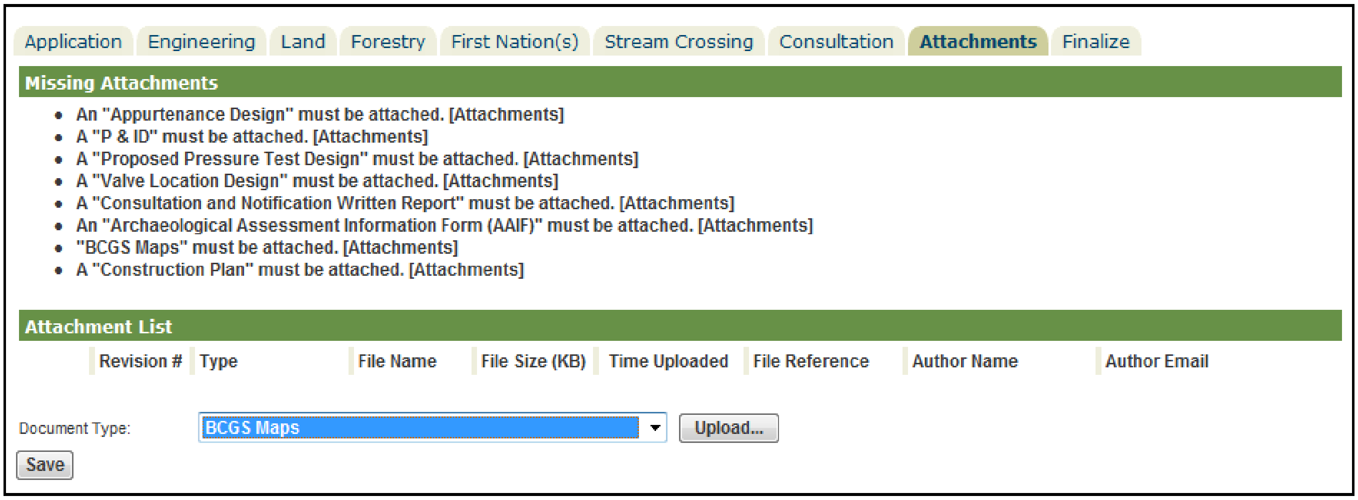
Fig. 5.3. KERMIT search fields.

Attachments Tab

The attachments tab allows a user to upload documents and relate then to the job. To attach a document:

- Choose the document type from the dropdown menu.
- Click the upload button.
- Type the name and extension of the file, or click the browse button to open a search window to search for a document.
- Click the upload button again to upload the document.
- Fill in the file reference, author name and author's email address
- 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

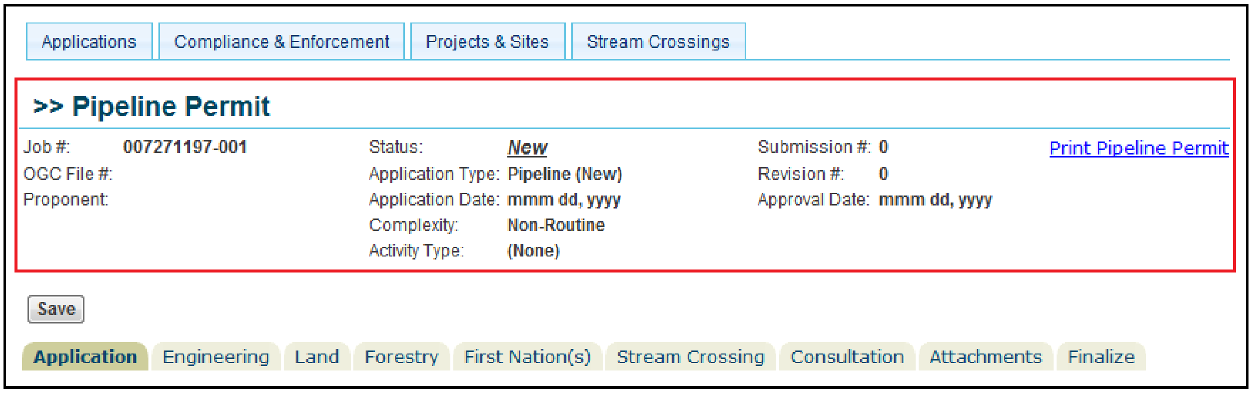


Fig. 5.5. KERMIT application header on pipeline application page.

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.

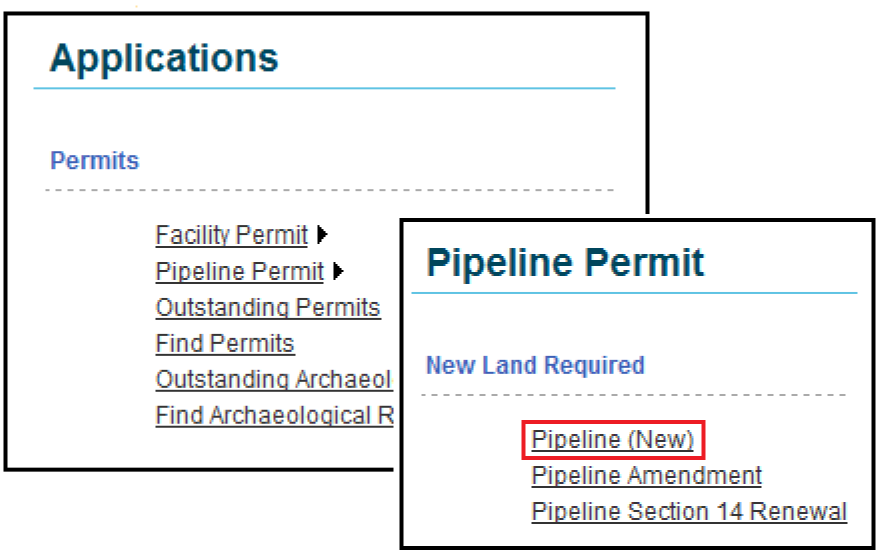
The following sections provide guidance for completing each component (or tab), of a pipeline application through KERMIT.

Where necessary, the applicant is directed to a link or specific document which will provide expanded information or explanation.

New Pipeline Permit Application

Select new application

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.

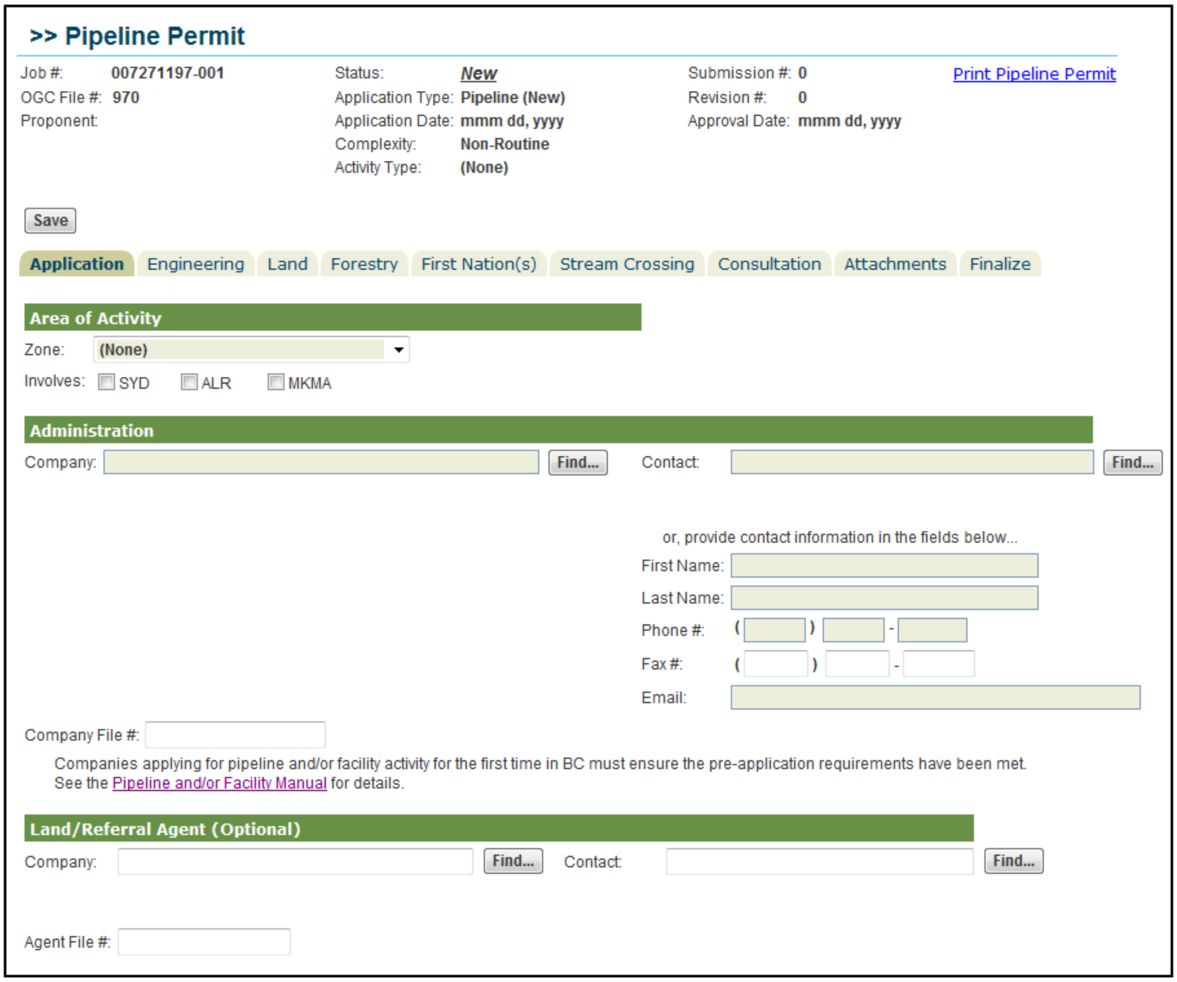


Fig. 6.1. Pipeline application page.

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.

Engineer's Details

To enter the engineering firm, click the find button and choose the applicable name. If the engineering 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 engineering 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 engineering project or file name in the appropriate field.

The engineering project or file name is provided so the engineering firm will be able to search the Commission website by their file or name.

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.

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.

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.

The following information must be entered for each segment:

- Location; actual start and end point location of the physical pipe length; not the surface tenured area start and end points.
- Pipeline product (any line greater than 0.3kPa partial pressure H2S, must be listed as sour 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.

Location

The following information must be entered for each location/segment:

1) Enter the segment number.

2) Enter the from and to location, with complete NTS or DLS descriptions for the selected segment.
Note: The from and to locations must be the exact physical location of the pipe, not the surface location.

3) Enter the UTM (NAD83 CSRS) Location for both the from and to location of the selected segment.
Note: This must be the exact physical start and end points of the pipe, not the surface location.

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).

Details Tab
The new pipeline segment button opens the details window where information regarding pipeline details, location and wells are entered.

Pipeline Details
The following information must be entered for each segment:

- Pipeline product. See Appendix C 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 H2S content by mole per cent.
- Indicate anticipated CO2 content by mole per cent.
- 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.

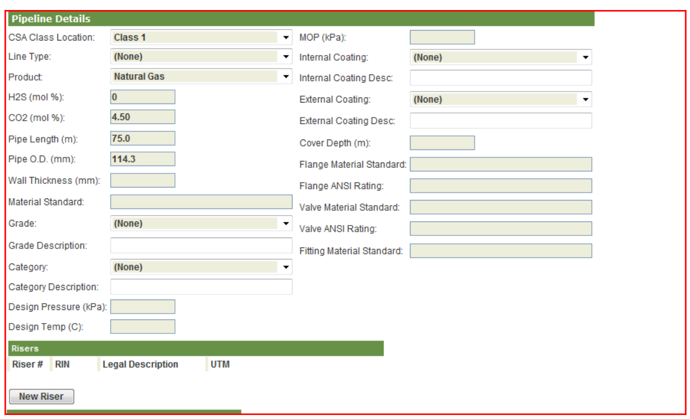


Fig. 6.2. Pipeline application page.

Riser Locations

If the riser is for the purpose of a pipeline, it is considered to be part of the pipeline. If the riser includes additional equipment from the facility equipment list, then it would be required to be applied for as a facility. For example, the addition of flare stacks and flare piping would classify it as a facility.

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.

If there is a riser associated with 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, an amendment with new land required. Please see the example on the next page for illustration.

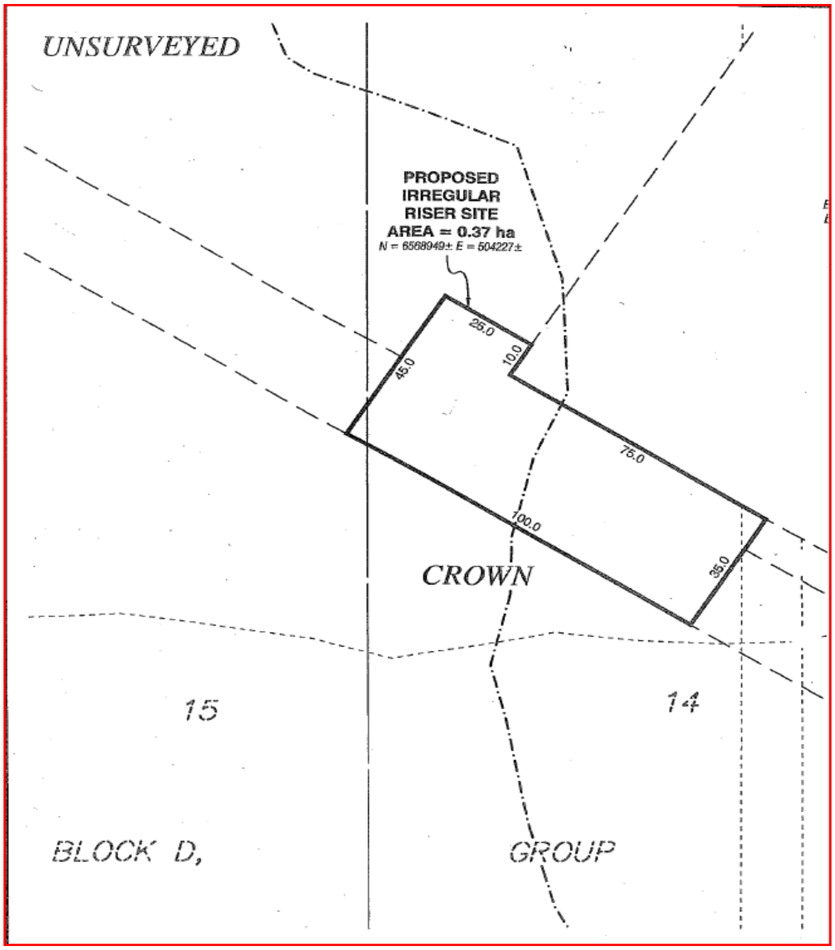


Fig. 6.3. Pipeline application page.

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 No., Site No., Project No. 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

Location notes provide space to add more information about the location at the discretion of the applicant.

Spatial Data & Construction Plan Details

Enter the Construction Plan number. as recorded on the construction plan and choose the survey company name from the dropdown box. Enter ePASS number as recorded on the construction plan.
The construction plan number and ePASS number must match the spatial data for the revision being submitted.

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.

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
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.

Technical Information and Design

Answer the engineering questions under Regulations and Requirements, Technical Information and Design, Flaring and Venting and Cross Border Requirements, as required.

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

Fig. 6.4. Pipeline application page.

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.

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.

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.

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. 6.6. 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.

Unconstructed Road Allowance:

Applicants are required to indicate that the area is within Crown land by selecting YES to the Crown land radio button. Do not include the area for unconstructed road allowances within the field, “Total Area of Crown land (ha)”.

As a Cutting Permit is required for any new cut within an unconstructed road allowance. The Forestry Tab must include the area of new cut within the unconstructed road allowance.

ePASS spatial data must not include the area for road allowances.

Construction Plans must indicate the unconstructed road allowance within the body of the plan and ensure the area table has road allowances separated from the pipeline rights-of-way and/or ancillary areas. The construction plan area table must clearly indicate the new cut and existing area for road allowances.

Where unconstructed road allowances do not require a Cutting Permit, the area must be clearly identified as no new cut on the Construction Plan and within the area table. A letter of clarification must be included with a description of the ground coverage.

Constructed Road Allowance

Applicants are required to indicate that the area is within Crown land by selecting YES to the Crown land radio button. Do not include the area for unconstructed road allowances within the field, “Total Area of Crown land (ha)”.

A Cutting Permit is not required for constructed road allowances, and should not be identified within the Forestry Tab information.

ePASS spatial data must not include the area for road allowances.

Construction Plans must indicate the constructed road allowance within the body of the plan and ensure the area table has road allowances separated from the pipeline rights-of-way and/or ancillary areas. The construction plan area table must clearly indicate the new cut and existing area for road allowances.

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, Lands and Natural Resource Operations 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

Shoofly: A temporary workspace area that allows access to a pipeline right-of-way.

Indicate the total hectares of what is included on the construction plan, including the right-of-way and any temporary workspaces, pushouts, decking sites, shoofly's, etc. Woodlot areas must be included in the total Crown land area.

Do not include the area for road allowances.

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, shoofly's, 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.

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.

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 generally must include a detailed mitigation strategy, illustrating how the proposed activity will be carried out to ensure no material adverse effect on the identified area. Where acceptable operating practices have been identified by the Commission and/or the Minister responsible for the order, the application must indicate that the appropriate operating practices will be followed. For a detailed outline of the Commission's expectations with respect to areas established by order and 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.

Currently, the Commission has not identified any streams or waterbodies that require enhanced management.

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 the Fibre Utilization Plan Guideline and must upload a Fibre Utilization Plan Form as an attachment anytime 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

Applicants must ensure that any woodlot tenures affected by the project are identified, and agreement is reached with the licensee(s).

Applicants must ensure that the woodlot area is clearly marked on the construction plan. The area within a woodlot must be included in the total area of Crown land for the land act tenure, but *not* included as area of new Crown disturbance, and it is excluded from the cutting authority.

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. The woodlot holder must obtain cutting authority for oil and gas related harvesting from the Ministry of Forests, Lands and Natural Resource Operations.

Unconstructed Road Allowances

The Commission has the authority to issue Master Licenses to Cut (MLTC) and Cutting Permits (CP) for oil and gas and related activities within a Ministry of Transportation and Infrastructure (MoTI) road allowance. Applicants must submit a Fibre Utilization Plan (FUP) Form anytime there is new cut on Crown land for any timber that will be harvested within an unconstructed MoTI road allowances as a result of the planned activities.

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.

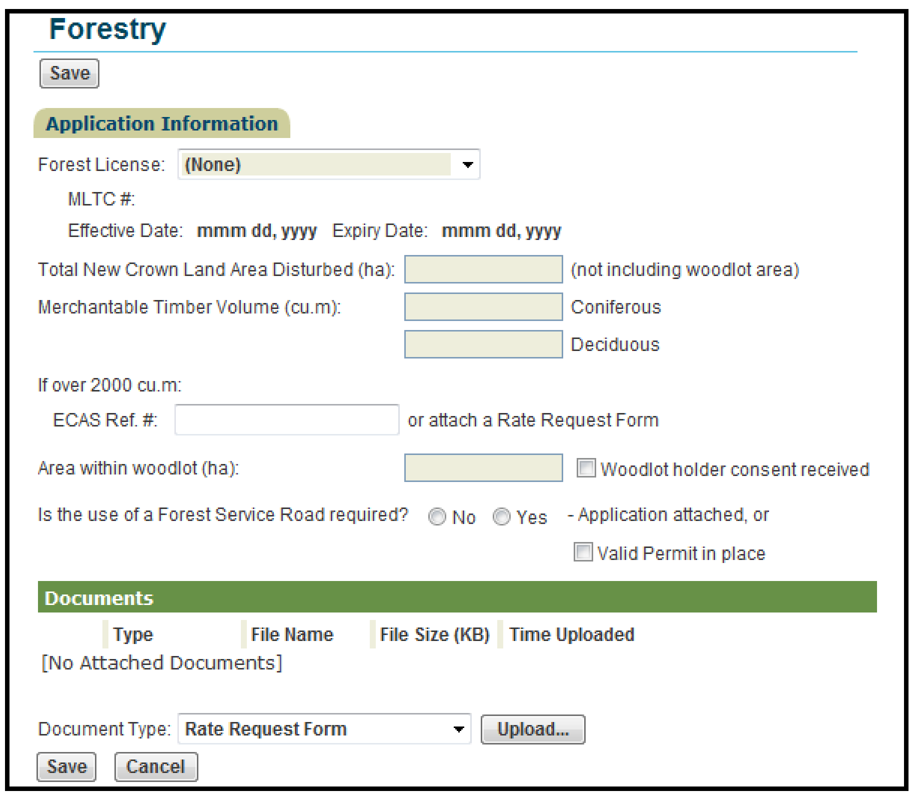


Fig. 6.7. Application information detail window on the forestry tab.

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..

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 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.

Notice packages are different from, and must not be confused with, Notification as defined within the consultation agreements with First Nations.

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.

Aboriginal Community Notice
There are four Aboriginal communities that the Commission provides information to regarding surrounding oil and gas activities in the form of an Aboriginal Community Notice.

Aboriginal Community Notice 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.

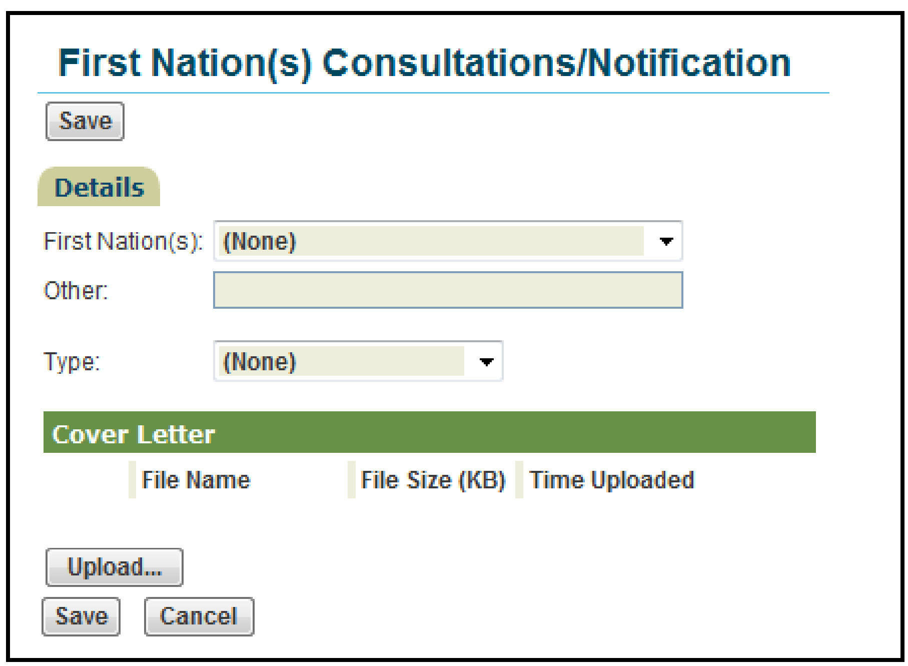
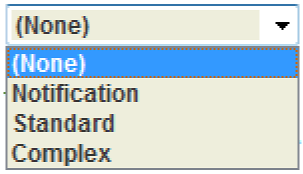


Fig. 6.8. Required information fields in First Nation consultation and notification detail window.



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.

  When in the Kaska Dena-Daylu area, three packages are required.

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.

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.

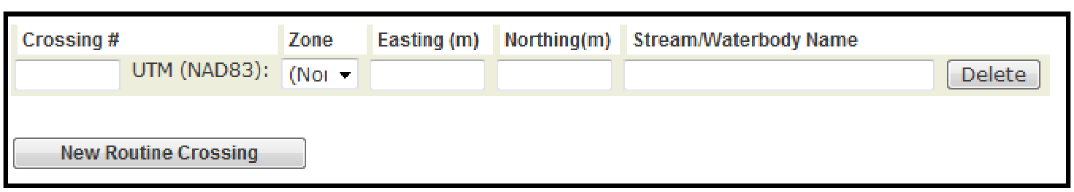


Fig. 6.9. Routine stream crossing information fields.

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.

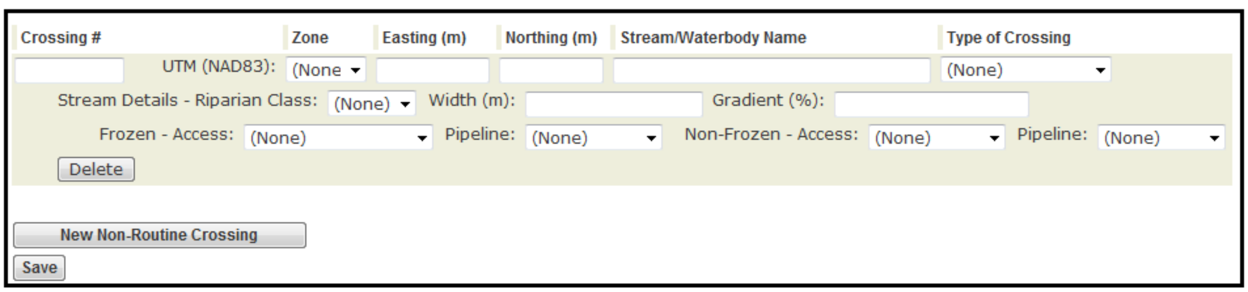


Fig. 6.10. Routine stream crossing information fields.

Consultation Tab

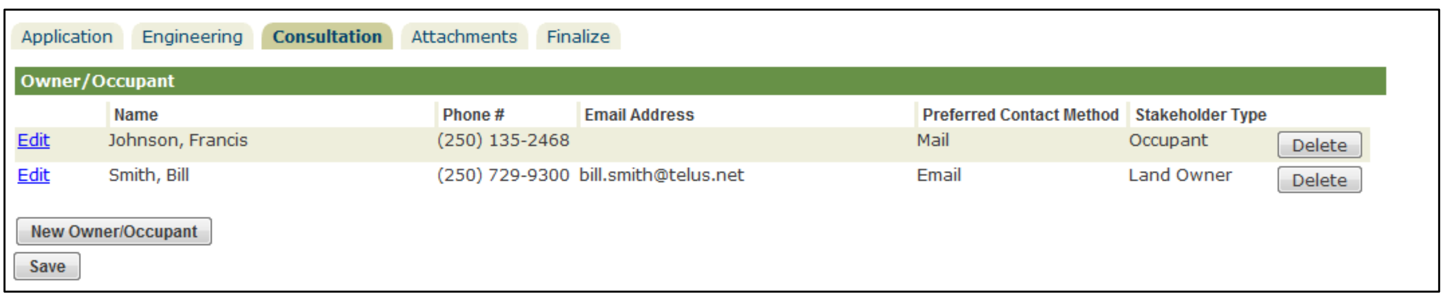
The consultation tab is where applicants must identify all directly impacted landowners of the land on which the applicant intends to carry out the oil and gas activity. Landowners and/or occupants within the consultation and notification radius, who were consulted or notified by the application but are not impacted by the application do not have to be included in this section of KERMIT.

Landowners who were consulted or notified for each application must be identified on the linelist.

Owner/Occupant

A Landowner entry must be created for each directly impacted 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.


Application Engineering Consultation Attachments Finalize

Owner/Occupant

	Name	Phone #	Email Address	Preferred Contact Method	Stakeholder Type	
Edit	Johnson, Francis	(250) 135-2468		Mail	Occupant	Delete
Edit	Smith, Bill	(250) 729-9300	bill.smith@telus.net	Email	Land Owner	Delete

New Owner/Occupant

Save

Figure 6.11. 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.

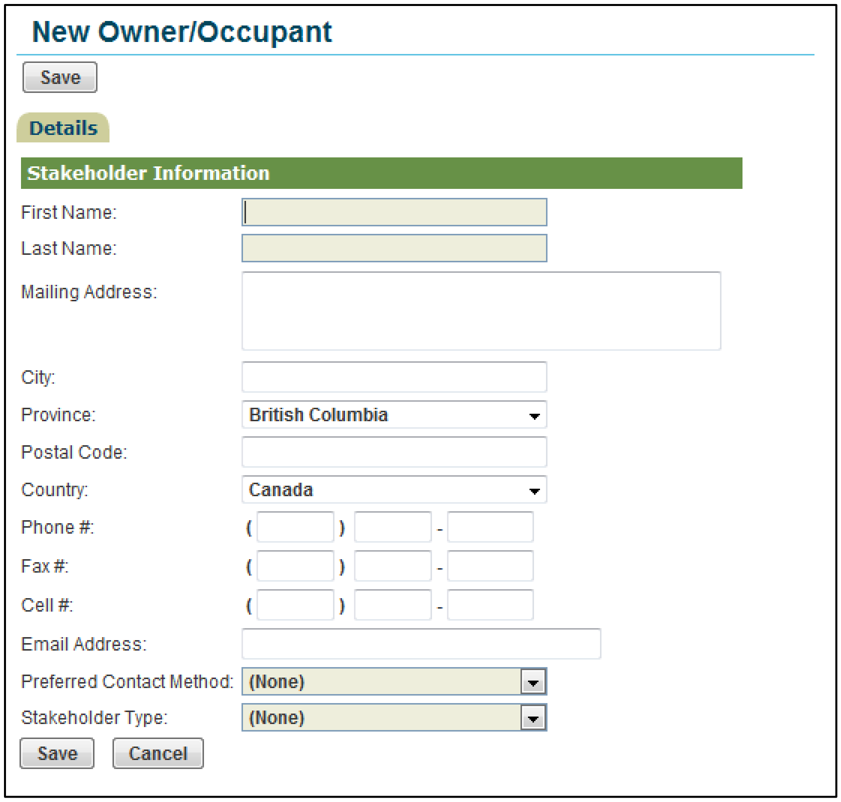


Figure 6.12. New Owner / Occupant screen.

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@bcogc.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. Section 24(1)(c) of OGAA 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.

A Permit holder must maintain the prescribed records and plans, and be able to produce records or plans at the request of the Commission.

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.

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.

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

Mapping Criteria

All maps should clearly indicate:

- Map date
- NTS and BCGS map sheet numbers indicated on legend and on the maps
- North arrow

For a detailed list of mapping criteria, please refer to Appendix A of this manual.

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

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.

Fibre Utilization Plan
A Fibre Utilization Plan Form is required with each application anytime there is new cut on Crown land, in accordance with the Fibre Utilization Plan Guideline.

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.

Fees

The fee for an application will be calculated based on information submitted within the application.

The fee that is calculated in Kermit must be submitted with the hard copy submission.

Applications found to have incorrect information that will impact the fees, will be returned with the application at the time of submission. Correct fees must be included with any resubmission.

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.

Applicants may include only the amended area of the amendment with the Area Table of the construction plans, as the previously approved area will be indicated on the application form. Permit holders must ensure that the spatial data includes both the existing approved area and the proposed amended area. Applicants within the ALR must show total disturbance.

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 two 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.

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 under Section 31 of OGAA. 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 becomes effective on and after the day it is made, unless the amendment changes the effect of the permit on the land of the land owner, in which case the amendment is effective on and after the earlier of the following:

- The 15th day following the day it is made, or
- The day the permit holder obtains written consent from the landowner to treat the amendment as being in effect on and after the date the consent is given

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 Applications from the main menu.
2) Select Pipeline Permit.
3) Select Pipeline Amendment (New Land Required).
4) Enter Project # or search application by desired method.
5) Select the application to amend by selecting New Permit Amendment.
6) Modify Application following the same procedures as a new application.
7) Attach a letter of explanation as to why the amendment is being requested.
8) Ensure the applicable amendment fee is included with the hard copy of the application.

Amendments to cancel a pipeline or a segment
If one or more segments of a pipeline project will not be constructed, an amendment for cancellation must be submitted via Kermit.

The amendment must include the following applicable information under the Engineering tab:

Activity Description:

- Whether any construction took place on the right of way

  If construction related to the pipeline has occurred, the pipeline project cannot be cancelled. It may be abandoned. For more information on abandoning a pipeline, refer to the Pipeline Operations Manual.

- Whether any clearing of vegetation took place on the right of way

If clearing of vegetation has occurred, the pipeline project can still be cancelled; however, the Ministry of Forests, Lands and Natural Resources Operations will be notified of the cancelation by the Commission and may contact the company for information about any clearing that occurred before cancelation for timber invoicing purposes.

Pipeline Specifications:

- Which segments require cancellation

For partial cancellations of pipeline projects, a Post-Construction Plan or As-Built Plan must be uploaded under the Attachments tab denoting the total area constructed on Crown and/or private land.

All other applicable information should be entered in the other sections under the Engineering tab.

After all requirements are met and the amendment is accepted, a letter will be sent to all applicable parties advising of the cancellation.

8 Permit Extension Application

It is the permit holder's responsibility to ensure that an oil and gas permit is still valid and has not expired prior to initiating an associated activity. The Commission will pursue compliance and enforcement actions for any oil and gas activity commencing after the associated oil and gas permit has expired.

The following information outlines the Commission's expectations for expiring permits and provides permit holders guidance in completing an extension request.

For more information on the expiration and extension process associated with a specific permit, contact the applicable Commission Operations Manager.

Extension

To apply for a permit extension, an applicant must submit a completed Permit Extension Application Form including the required application deliverables prior to the scheduled expiration of the oil and gas permit.

The **scheduled expiry date** is two years from the date the permit (or approval, authorization or certificate) is issued.

To ensure adequate processing time, the Permit Extension Application Form and deliverables must be received by the Commission a minimum of 30 days prior to the scheduled expiration.

The Commission may extend a permit and associated authorizations (up to one year), and may impose additional conditions.

If construction has not commenced by the end of the extension period, the permit will be removed from active records unless the Commission is satisfied that there are special circumstances to justify a further extension, based on applicant request.

A decision to extend or not extend a permit is not a reviewable or appealable determination under OGAA.

Expiration

Section 32 (1) of OGAA states that a permit and any authorization issued to the permit holder for a related activity, expires on the day after the prescribed period has elapsed (if the permit holder has not begun the permitted oil and gas activity).

Section 8 of the OGAA General Regulation defines the prescribed period for the purposes of Section 32 (1) of the Act as two years.

If the Commission has not received the Permit Extension Application prior to the scheduled expiration date, the Commission will remove the expired permit from the active records.

If the permit expires with no Permit Extension Application submitted, the former permit holder must submit a new permit application to the Commission complete with the prescribed application fee, in order to resume construction.

Consultation and Notification

Section 32 (3) of OGAA states that the Commission may require the permit holder to carry out consultation or notification (as indicated in the Consultation and Notification Regulation) in relation to the permit extension.

For more information regarding consultation and notification in relation to permit extensions, please refer to the Permit Expiry and Extension Application Guideline.

Consultation and Notification Requirements for Permit Extension

Written Report requirements are detailed in the Commission's Consultation and Notification Manual.

a) Permit holders must complete notification requirements with all landowners and/or stakeholders who were not originally notified of the project, and inform them of their intent to request an extension.

b) Permit holders must complete consultation requirements with all landowners and/or stakeholders who were not originally consulted with on the project, and inform them of the intent to request an extension.

c) Permit holders must notify all stakeholders and/or landowners who were originally notified/consulted of the project and advise them of their intent to request an extension.

d) Permit holders must submit a current Written Report to the Commission, summarizing public engagement activities under Section 32(4) of OGAA.

Information and criteria on the Written Report is available in the Commission's Consultation and Notification Guideline. This Written Report must be received before an extension is granted by the Commission.

9 Compliance

Oil and Gas Activities Act (OGAA)
A person found by the Courts, to have contravened OGAA may be subject to a fine not exceeding the amount specified in Section 86 of the act. A person found by the Commission, to have contravened OGAA may be liable to an administrative penalty not exceeding the amount specified in the Administrative Penalties Regulation.

Pipeline and Liquefied Natural Gas Facilities Regulation (PLNGFR)
A person who contravenes the PLNGFR (as specified in the Administrative Penalties Regulation, Section 6) may be liable to an administrative penalty ranging from $5,000 to $500,000.

Appendix A – Construction Plans

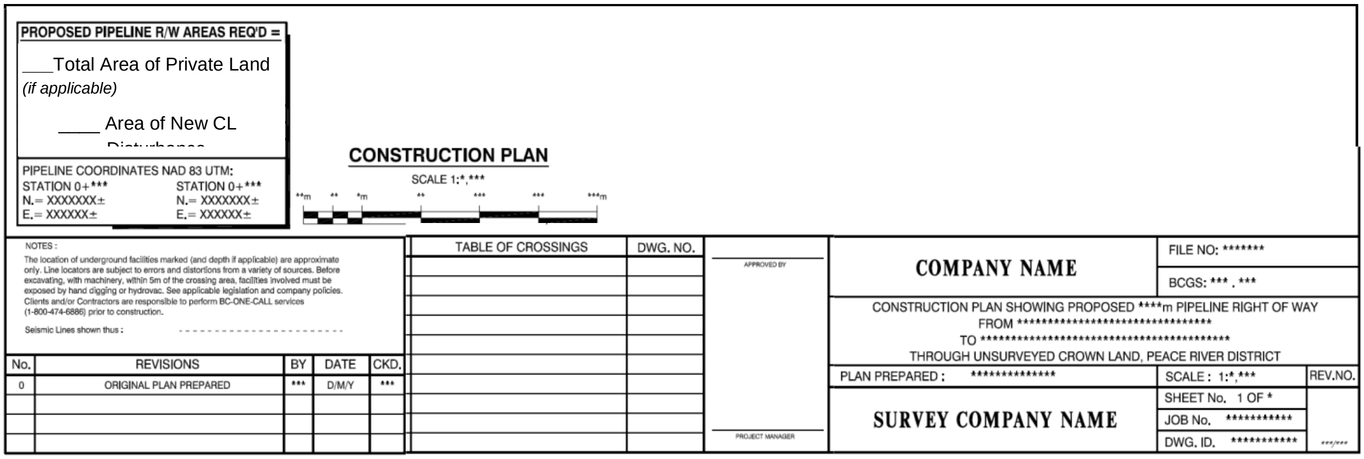


Figure B.1. Sample construction plan.

Construction Plan Requirements

Pipeline construction plans must reflect the total area required (including ancillary sites – for example, workspaces, decking sites and shoofly's) in a bold outline. Within the plans (and ePASS), each polygon is to be shown in a bold outline. The area for a shoofly must be shown in the ePASS spatial data as a shoofly.

The basic requirements for a pipeline construction plan must include the following information:

Labelling of Plan

The labelling of the plan should include:

- The NTS coordinates (units, block, group)
- Deflections
- Any crossing numbers (to correspond to the table of crossings), vegetation changes (brush/tree types)
- A north arrow

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 (where applicable) equals the total area proposed on private land.
- The total area of Crown land (where applicable) equals the total area proposed on Crown land.
- The area of new cut on Crown land (proposed) equals the area required for cutting authorities on 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, shoofly's, 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.

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.

Appendix B – 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, FSJ Corporation, pipeline Expires 2030	FSJ Corporation holds a Statutory Right of Way on File Number 9612345, expires in 2030
9601111: LOC, FSJ Corporation, well site Expires 2010	FSJ Corporation holds a Licence of Occupation for a wellsite on File Number 9601111, expires in 2010
8002475: PDR #100 – O&G Canada	O&G Canada has Petroleum Development Road #100 on File 8002475
0234547: Map Reserve, EMPR, Quarry	The Ministry of Energy and Mines has established the exclusive right to an area for quarry purposes on File Number 0234547
615-300: Company Y Cutblock	Company Y has a cutblock under Ministry of Forests, Lands and Natural Resource Operations reference number 615-300
RAN073357: Grazing Licence, Joe Farmer	Joe Farmer has a Grazing Licence (issued by Ministry of Forests, Lands and Natural Resource Operations) under Number RAN073357
A65327: Small Business TSL	The Ministry of Forests, Lands and Natural Resource Operations 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 and Mines under Licence Number 410284, expires in 2009

Figure C.1. Example Crown Land Status Sheet

Appendix C – 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 per cent 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 D- 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.

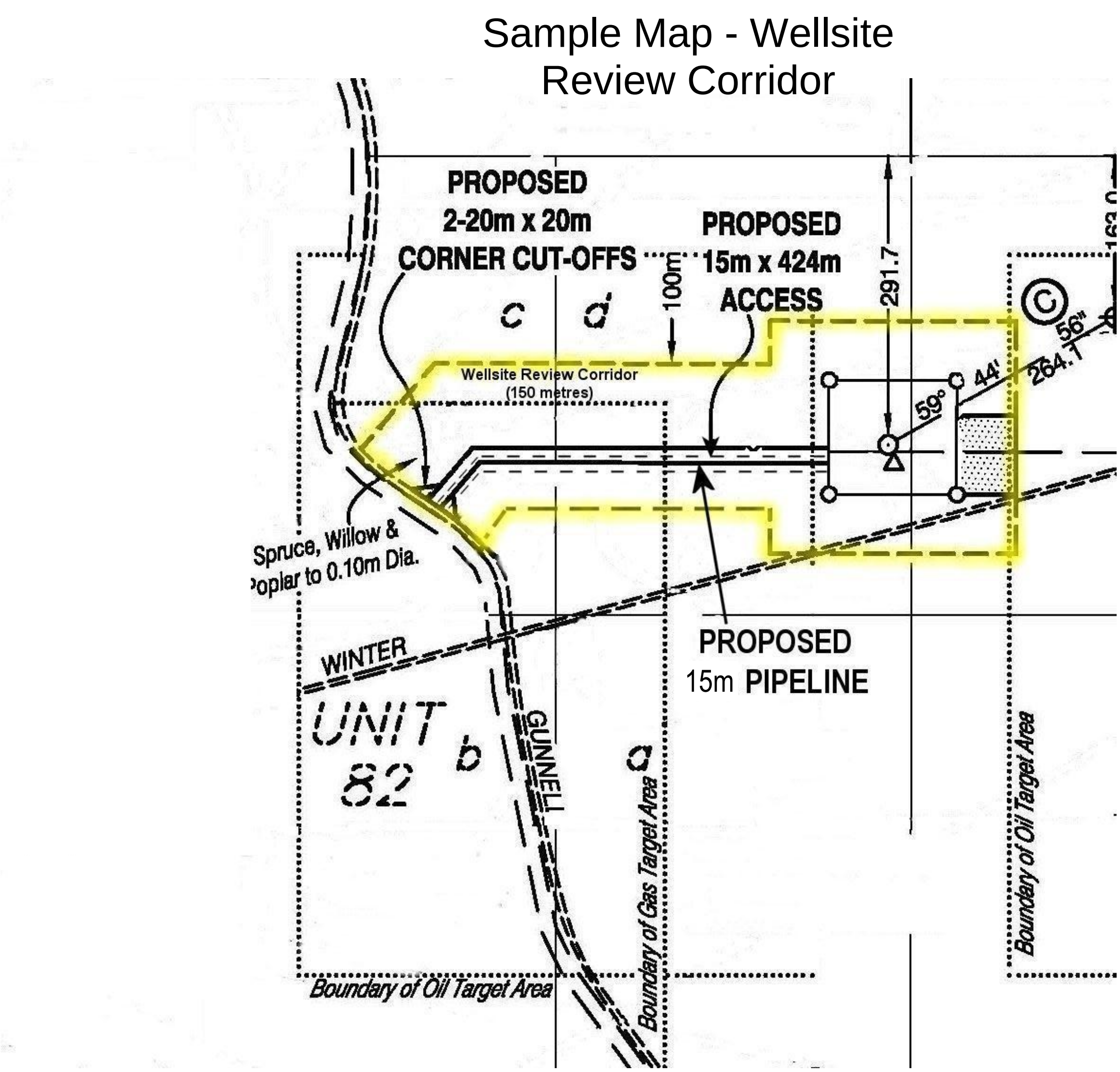


Figure E.1. Wellsite Review Corridor Map

Sample Map – Ancillary Works and New Crown Land Review Corridors

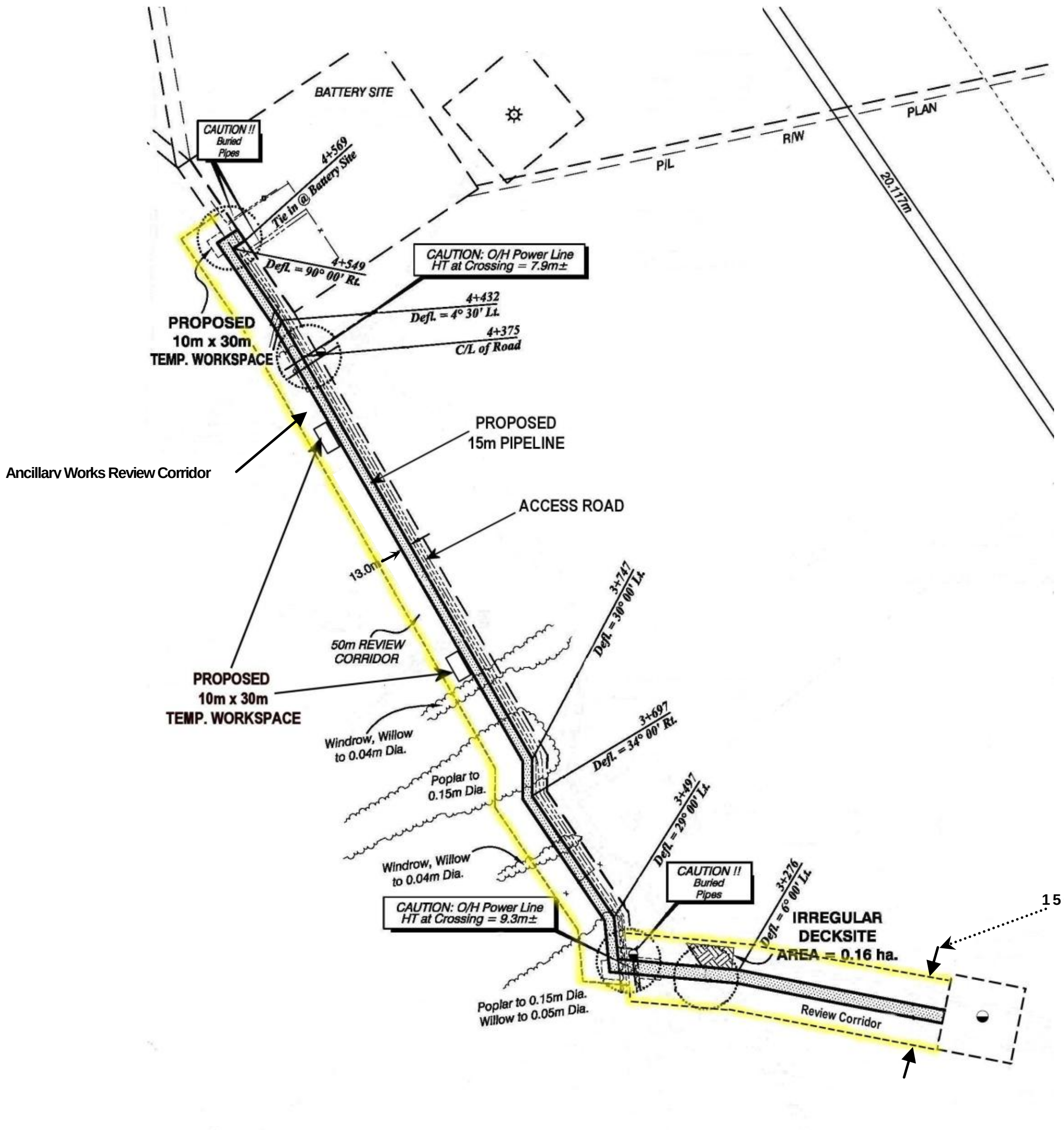


Figure E.2. Ancillary Works and New Crown Land Review Corridors Map

Appendix E- 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.

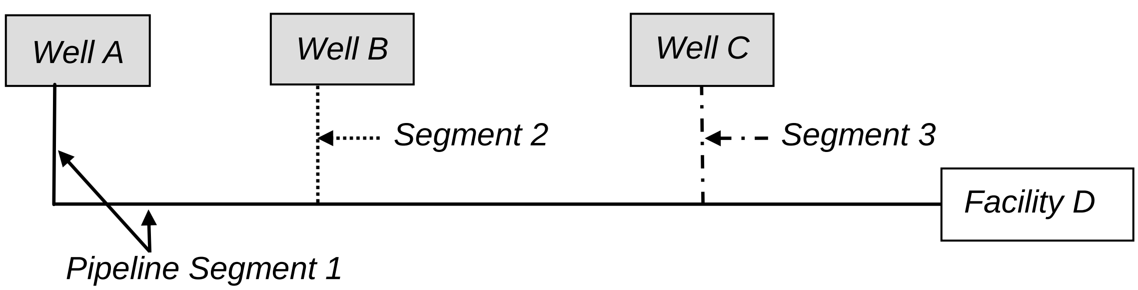


Figure F.1. How to identify known pipeline segments.

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.

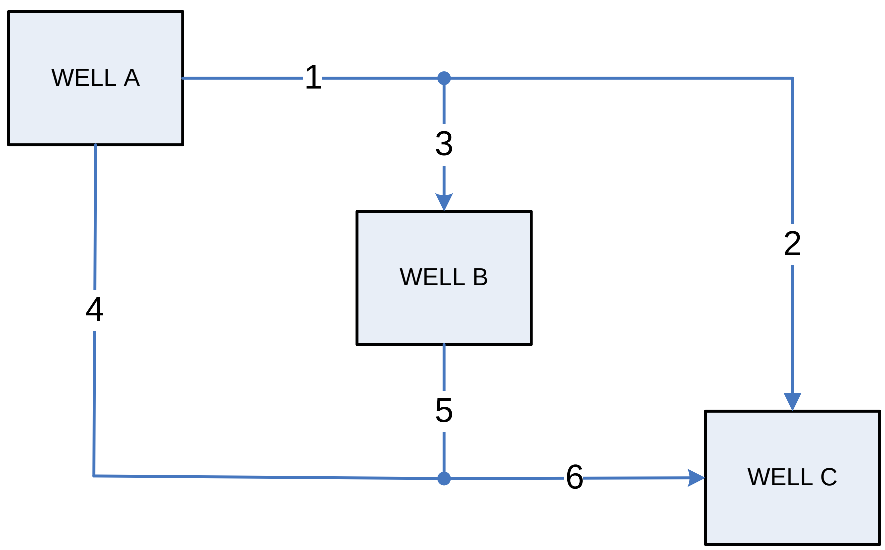


Figure F.2. How to identify potential pipeline routes/segments (example).

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 F - 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 recommended information fields in an Engagement Log, and an example format that may be used.

Communities	List which communities require engagement.
Engagement Attempts	Provide a description of what efforts to engage were made and whether or not engagement occurred.
Meeting Successfully Held	Indicate if meetings resulted from attempts to engage.
Date of Meeting	List the corresponding dates of attempted and actual engagement.
Location	Indicate where the meeting took place; for example, at a specific location or via teleconference.
Attendees/ Parties to Meeting	List all of the people attended, or were involved in the meeting. List is to include all parties to the discussion.
Topic Discussed	Provide a description of what topics of discussion arose during the meeting.
Analysis, comments, concerns, or recommendations from Nation	List any details provided by the First Nation in the analysis, comments, concerns or recommendations provided during discussions.

Commitments Made List any initiatives, options, mitigation measures, or other commitments discussed and/or offered.

First Nation Engagement Log

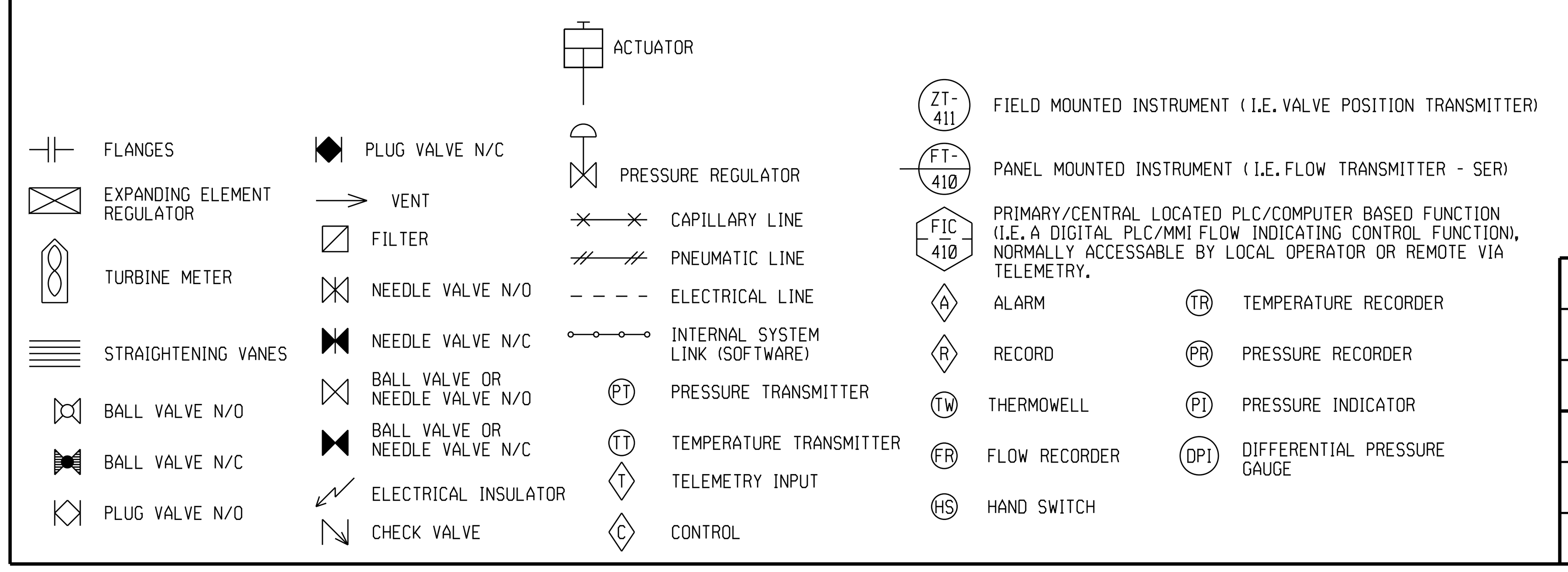
The following table provides an example template for a First Nations Engagement Log. An electronic version of the engagement log template is also available on the First Nations page of the Commission website.

Company Name:						Company File No.:			Commiss
FIRST NATIONS ENGAGEMENT LOG									
#	Communities	Engagement Attempts	Meeting Successfully Held? Y/N	Date of Meeting DD/MM/YY	Location	Attendees	Topics Discussed	Analysis, comments, concerns, or recommendations from Nation	Commitm Nation's rec
1									
2									
3									
4									
5									

Table G.1 First Nation Engagement Log Example

Attachment 20.6

LEGEND: (NOTE: ALL SYMBOLS SHOWN ON THIS DRAWING FOLLOW THE ANSI/ISA-S5.1-1984(R1992) AND ISA-S5.3-1983 STANDARDS.



BY	No.	REVISION	DRAWN	DESIGNED	CHECKED	DATE(YY-MM-DD)
PREVIOUS DR. NO.-		SAP ID:		SCANNED		SCALE-

FORTIS BC™

ENGINEER SEAL

HUNTINGDON STATION TP_TP

STATION UPGRADES WITH BYPASS PROCESS & INSTRUMENTATION DIAGRAM

DRAWING NUMBER

Attachment 23.16

Project: Huntingdon Station Bypass CPCN Application
Risk Analysis and Contingency Calculation
Updated December 17, 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	CEAA Screening Required				Early identification	team and consultant costs				
14	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
15	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
16	Contractor non performance	1	3	3	Careful wording in contract, bonding	construction contract		10%	150,000	15,000
17	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
18	work in proximity to power lines - damage	1	2	2	Proper construction methodology around power poles	construction contract		10%	25,000	2,500
19	US regulatory interference	1	2	2	Nearest neighbour has been communicated with	stakeholder management, design, construction contract		10%	25,000	2,500
20	No bids for contract	1	2	2	Communication with known contractors to ensure sufficient bidders are interested and available	construction contract		10%	25,000	2,500
21	Contractor insolvency	1	2	2	Prequalification of bidders, bonding	construction contract		10%	25,000	2,500
22	Changes to Spectra station - gates	1	2	2	Ongoing communication with Spectra	stakeholder management, design, construction contract		10%	25,000	2,500
23	AIA increases monitoring requirements	2	1	2				25%	10,000	2,500
24	work in proximity to Kinder Morgan	1	1	1	Permit to be obtained from Kinder Morgan			10%	10,000	1,000
25	Bird nesting window	1	1	1			No tree removal required	10%	-	-
									Total	**735,250**