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March 25, 2021

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary

Dear Mr. Wruck:

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

Application for a Certificate of Public Convenience and Necessity (CPCN) for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion (TLSE) Project (Application)

Revised Redacted Application and Basis of Request for Confidentiality

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On December 29, 2020, FEI filed the TLSE Project Application referenced above, which included a redacted public version and a confidential unredacted version. During the Workshop held on March 11, 2021, the Panel requested that FEI review its redactions to the Application to identify information which can be filed on a non-confidential basis and refile a revised redacted Application. The BCUC delayed the IR process to accommodate steps to consider confidentiality. On March 18, 2021 FEI advised the BCUC that it had been reviewing its redactions and would be filing a revised version. FEI has completed its review. It is now resubmitting the materials for the BCUC's consideration, having removed the redaction in many areas. FEI appreciates the BCUC adjusting the procedural timeline to accommodate consideration of this issue, as finding the right balance between disclosure and protection of sensitive information is a matter of significant importance not only for FEI and its customers but also to the public generally.

As indicated above, FEI has removed a number of the original redactions. The remaining redactions fall into two categories:

(1) security sensitive (restricted) information; and

(2) commercially sensitive information.

FEI has addressed each category separately, as the rationale for confidentiality and FEI's proposed approach for dealing with the information differs. In light of the magnitude of

potential implications and consequences from disclosure of security sensitive information, and recognizing that disclosure can occur even despite best intentions, the risk is best mitigated by limiting its circulation to the BCUC only. The commercial information at issue is sensitive only in the sense that it should be kept out of the hands of potential bidders for project construction and participants in the gas supply market; FEI has no concerns about making the commercially sensitive information available to the current interveners pursuant to a standard BCUC undertaking of confidentiality, as it appears that none of those interveners is a potential bidder or gas market participant.

Security Sensitive Information

FEI's overarching objective is to make as much information available to the public as possible, while safeguarding security sensitive information. FEI believes that, with the revised redactions, it has now struck a better balance between these objectives.

In this case, the security concern has two aspects: (a) specific information about how to cause the greatest harm to FEI and its customers, and (b) quantification of the harm that could result. Specifically, the security risk relates to risks and vulnerabilities of the energy supply resources and infrastructure systems supporting FEI's customers and the Pacific Northwest Region generally. Interference with key energy infrastructure and systems by malicious actors would cause significant harm to FEI and its customers, the public, and other operators in the region. The Black Hills Energy incident[1] discussed during the Workshop is an example of the type of harm that can be done by vandalism. The Pricewaterhouse Coopers (PwC) report included as Appendix B (all of which had been redacted in the initial Application and portions of which have now been unredacted) quantifies the potential harm.

FEI recognizes that a certain degree of public discussion about vulnerabilities and the extent of harm is unavoidable. The Application is, after all, premised on the need for additional resiliency as a result of reliance on the T-South system that was highlighted by the 2018 T-South Incident. FEI's concern increases, however, as the information moves from the general to the specific. There is no bright line; however, it is clear that, at some point, specific information would provide a malicious actor with a road map as to how to inflict the maximum amount of harm on BC and the U.S. Pacific Northwest.

FEI is equally cognizant that some of the information redacted might be available in public sources for a malicious actor that was sufficiently motivated to seek it out and had the ability to compile it. However, in FEI's respectful submission, FEI and the BCUC should not be making it unduly easy for a malicious actor by compiling and publishing a comprehensive road map.

In the revised redactions, based on the Panel's guidance at the Workshop, FEI has taken the approach of un-redacting most of the qualitative language, while maintaining redactions over specific information that is not widely available (e.g., specific volumes, shortfalls, locations, quantum of harm etc.). This approach has produced an outcome that significantly reduces the number of security-related redactions.

[1] https://www.blackhillsenergy.com/news/aspen.

In considering FEI's approach, FEI respectfully asks the BCUC (and interveners) to consider the analogy to how security sensitive information related to important components of the electric grid is addressed. The analogy is apt in this case because the T-South system is the backbone of the gas system for BC and much of the U.S. Pacific Northwest, and FEI's own LNG facilities are also important for reliability and resiliency. The BCUC has imposed blanket confidentiality over critical electric infrastructure information designated as Restricted Information under its Mandatory Reliability Standards (MRS) framework.[2] Mr. Sam also explained at the Workshop the interplay between the resiliency of the gas system and BC's electric systems.[3] There is general recognition in FortisBC Inc.'s policies and procedures that compilations of information that would not, considered individually, be security sensitive can become security sensitive through aggregation.

FEI is proposing to have the remaining portions that have been redacted for security reasons be accessible to the BCUC only. FEI wishes to be clear that it is not suggesting the potential for any deliberate disclosure or malicious use on the part of the registered interveners in the present proceeding. The proposal is simply recognizing that the best way to effectively mitigate the risk of inadvertent disclosure of security sensitive information is to restrict its circulation. This is the approach taken in the context of MRS, for example. As the BCUC is aware, inadvertent disclosure is not a theoretical risk. There have been instances in recent years where confidential information in BCUC processes has been inadvertently disclosed by consultants and recipients with the best intentions. (There was also an instance in the Site C inquiry where someone deliberately published sensitive information provided to an intervener by BC Hydro pursuant to a signed undertaking.) The more refined approach to redaction that FEI has taken, which publishes most qualitative information, will ensure that interveners still have access to ample information to participate meaningfully in this CPCN proceeding.

Other Commercial Information

Some of the redacted elements of the Application are commercially sensitive, rather than security sensitive. The commercially sensitive information falls into two main categories, both of which are routinely kept confidential and made available to interveners in the manner that FEI is proposing:

(1) information about FEI's gas portfolio procurement strategies, the disclosure of which would harm FEI's ability to procure gas cost-effectively for customers; and

(2) information about the TLSE Project budgeting which, if disclosed, could compromise FEI's ability to achieve fair and reasonable pricing for equipment and services during the Project procurement.

[2] BCUC Rules of Procedure for Reliability Standards in British Columbia, Revised September 1, 2017 by Order R-40-17, section 6, available online at: https://www.bcuc.com/Documents/MRS/2017/09-01-2017_BCUC-MRS-Rules-Procedure_ROP.pdf; and BCUC Letter dated December 12, 2012 regarding MRS Confidentiality Orders CIP (Log No. 40590).

[3] Workshop Transcript Vol. 1, p. 89, l. 3 to p. 90, l. 16.

As such, if this information is publicly disclosed, it could reasonably result in compromise, prejudice, or influence in contract negotiations between FEI and suppliers and would result in higher costs for customers.

FEI has no concern about this commercially sensitive information being made available to interveners who sign the BCUC's confidentiality undertaking. Although the impacts of disclosure would be material, the harm would not reach the same level as the potential harm from disclosure of security sensitive information.

Next Steps

A revised redacted version of the Application and all public appendices (Revised Redacted Application) is attached to this letter for public filing on the proceeding record replacing Exhibit B-1 in its entirety for ease of referencing. The Revised Redacted Application makes public a significant amount of information that had previously been redacted and consists of:

a. Application – with revised redactions;
b. Appendix A – Guidehouse Report – with revised redactions;
c. Appendix B – PwC Report (partially un-redacted);
d. Appendix C – ACP Compliance Filing – with revised redactions; and
e. Remaining public Appendices D and O through T, unchanged from the original filing but included to complete the Revised Redacted Application for ease of referencing.

FEI has also prepared two compilations of excerpts from the Application in order to facilitate the BCUC's consideration of the confidentiality issue, and to facilitate submissions by interveners on the issue:

(1) **BCUC compilation in support of confidentiality request:** A confidential compilation Application and Appendices A, B, and C for the BCUC only that identifies through colour coding: (a) portions where redactions have been removed (green highlighting); (b) commercially sensitive information that remains redacted, but available to interveners on undertakings (yellow highlighting); and (c) security sensitive information that remains redacted (red highlighting). This colour coded version is being filed confidentially under separate cover concurrently with the BCUC only to facilitate the Panel's future determination on confidentiality. It is accompanied by a detailed listing with explanations of each remaining redaction.

(2) **Intervener Confidential compilation in support of confidentiality request:** A compilation of the Application and Appendices A, B, and C which shows: (a) portions where redactions have been removed (green highlighting); and (b) commercially sensitive information available to interveners on undertakings of confidentiality (yellow highlighting). The security sensitive/restricted information (i.e. the portions that are red in the BCUC's compilation) remain redacted in this Intervener Confidential version of the compilation. FEI has no concerns about making the commercially sensitive information available to the current interveners who have already filed the BCUC's form of Confidential Declaration and Undertaking in this proceeding as it appears that

none of those interveners represent parties participating in the natural gas market or as potential bidders for the provision of materials or services related to the Project, should it be approved.[4] FEI will also review any new undertakings of confidentiality filed on the record on the basis of those same considerations. Concurrent with the filing of this letter, the interveners with filed confidentiality undertakings will be provided the Intervener Confidential version of the Application as well as a version of the detailed listing with explanations for each commercially sensitive redaction.

The Intervener Confidential version will include access to Appendices E through N filed confidentially on the basis set out in the cover letter to the original Application as quoted below for ease of reference:

> Appendices E, F, G, H, I, J, K and L are engineering documents and should be kept confidential on the basis that they contain operationally sensitive information pertaining to FEI's assets as well as market-sensitive information. In particular, these appendices identify areas of risk to the Project including detailed information that if disclosed, could impede FEI's ability to work safely and reliably operate its gas system assets and could risk the safety of both its workers and the public. These documents also include cost estimates and identify Project risks. They should be kept confidential on the basis that FEI may be going to the market to seek competitive bids for the materials and construction work for the Project. If the estimated costs for the material and construction work are disclosed, FEI reasonably expects that its negotiating position may be prejudiced. For instance, the bidding parties with knowledge about the estimated costs may use these costs as a reference for their bidding.
>
> Appendices M and N include financial analysis and schedules with sensitive information on the Project costs and related cost of service components that should be kept confidential on the basis that FEI may be going to the market to seek competitive bids for the materials and construction work for the Project. If the estimated costs for the material and construction work are disclosed, FEI reasonably expects that its negotiating position may be prejudiced. For instance, the bidding parties with knowledge about the estimated costs may use these costs as a reference for their bidding.

FEI submits that the BCUC need not make a final determination on confidentiality prior to recommencing the regulatory review process. With both the Revised Redacted Application on the record and with the interveners who have already provided their undertakings receiving access to the Intervener Confidential version, there is ample evidence on the record to facilitate recommencement of the regulatory review process. As such, FEI proposes the following regulatory timetable for recommencement of the proceeding while also addressing submissions for the Panel's consideration on the issue of confidentiality.

[4] Residential Consumer Intervener Association (Exhibit C1-2), the Commercial Energy Consumers Association of British Columbia (Exhibits C5-2, C5-3, C5-4), and the British Columbia Old Age Pensioners' Organization *et al.* (Exhibit C4-2).

Action	Date (2021)
Intervener Submissions on Confidentiality	Thursday, April 1
FEI Reply Submissions on Confidentiality	Wednesday, April 7
BCUC Information Request (IR) No. 1	Wednesday, April 14
Intervener IR No. 1	Monday, April 19
FEI Response to IRs No. 1	Tuesday, May 18
BCUC and Intervener IRs No. 2	Wednesday, June 9
FEI Response to IRs No. 2	Friday, July 9
Procedural Conference	Wednesday, July 21

FEI also wishes to extend the offer to make representatives available for a formal *in camera* technical session with the Panel to answer questions on the rationale for specific security sensitive redactions if the Panel believes that would be of assistance. If such an approach is necessary, FEI would respectfully request that it occur within the time parameters identified above.

Concluding Comments

FEI appreciates the BCUC's and interveners' consideration of this important issue.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Interveners

FORTISBC ENERGY INC.

Application for a Certificate of Public Convenience and Necessity for the Tilbury Liquefied Natural Gas Storage Expansion Project

Volume 1 - Application

December 29, 2020

Table of Contents

List of Appendices

Index of Tables

Index of Figures

1. APPLICATION

1.1 INTRODUCTION

FortisBC Energy Inc. (FEI or the Company) applies to the British Columbia Utilities Commission (BCUC), pursuant to sections 45 and 46 of the *Utilities Commission Act* (UCA), for a Certificate of Public Convenience and Necessity (CPCN) for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion Project (referred to as the TLSE Project or the Project) as described in this application (the Application). FEI also seeks related approvals pursuant to sections 59 to 61 of the UCA: approval of a depreciation and net salvage rate for the proposed new LNG storage tank; and, approval of two new deferral accounts.

The Project, which entails replacing the 50-year old Tilbury Base Plant with a new 3 Bcf LNG storage tank and 800 MMcf/day of regasification capacity at a cost of $768.998 million in as-spent dollars and including AFUDC, is a *resiliency* investment. That is, it will significantly improve FEI's ability to maintain continuity of service in the event of a disruption in the supply of natural gas to FEI's system. While primarily targeted at improving resiliency, it will also bring valuable ancillary benefits for system operations and customers.

FEI obtains most of its natural gas via Westcoast Energy's T-South system (T-South system), making a disruption on the T-South system the greatest supply risk facing FEI at present. The 2018 pipeline rupture on the T-South system (T-South Incident), and the challenges it presented for maintaining service to customers, underscored the importance of making new investments in system resiliency. Without additional investment in resiliency, future supply disruptions that may occur could have significant consequences in terms of cost to customers and socio-economic impacts to society generally.

The T-South Incident resulted in a 2-day "no-flow"[1] period, despite favourable conditions that facilitated Westcoast's efforts to restore gas flows on the T-South system. After the T-South Incident, supply to FEI's system remained constrained for approximately 14 months. The experience informed FEI's determination of a specific minimum resiliency objective for prospective planning:

> *Having the ability to withstand, and recover from, a 3-day "no-flow" event on the T-South system without having to shut down portions of FEI's distribution system or otherwise lose significant firm load.*

FEI uses the term "**Minimum Resiliency Planning Objective**" in this Application to signify this identified prospective minimum resiliency need. FEI has characterized this planning objective as a *minimum* objective because (i) a "no-flow" event could last longer than 3 days, and (ii) supply

[1] FEI uses "no-flow event" in this Application to refer to an incident affecting regional pipeline infrastructure that results in the total interruption of gas flows on the pipeline. Similarly, the "no-flow" period is the period following the event that results in a total interruption of gas flows from that pipeline.

can remain constrained even after the resumption of flows (as occurred with the T-South Incident); during this subsequent period, commonplace gas supply and peak demand events take on greater significance from the standpoint of maintaining uninterrupted service to customers.

FEI's current capabilities, which include load management tools and various supply options, fall well short of the Minimum Resiliency Planning Objective. FEI considered a variety of options to meet or exceed the Minimum Resiliency Planning Objective, including regional pipeline infrastructure, enhanced capabilities to shed load, and different storage options that could supply FEI during and following the "no-flow" period. The unique attributes of on-system LNG storage, the fact that it dovetails with FEI's efficient gas supply portfolio, and the opportunity to use the existing Tilbury site, all make the Project the best option for meeting the identified Minimum Resiliency Planning Objective.

Based on Lower Mainland system load, meeting the Minimum Resiliency Planning Objective would require 2 Bcf of LNG storage at Tilbury and 800 MMcf/day of regasification capacity. However, the economies of scale associated with LNG tank construction justify a 3 Bcf tank to capture significant additional resiliency benefits, as well as significant optionality and other ancillary benefits for customers.

FEI submits that the information provided in this Application, which meets the requirements of the BCUC's CPCN Guidelines[2], demonstrates that the Project is in the public interest and asks that it be approved as set out in the Application. A draft Procedural Order and draft Final Order are included in Appendices T-1 and T-2, respectively.

1.2 EXECUTIVE SUMMARY

Resiliency – the ability to respond to, survive and recover from significant adverse events – is an essential consideration in system planning. The Project will significantly improve FEI's ability to maintain continuity of service and avoid widespread and lengthy service outages in the event that the supply of upstream natural gas is disrupted. FEI recognizes that the Project cost is significant, but based on the experience of the T-South Incident, it is evident that a significant investment of some kind is required – i.e., doing nothing is unrealistic. The Project represents the best way to achieve the targeted resiliency cost-effectively, and it provides ancillary benefits for customers.

1.2.1 FEI Has Identified an Appropriate Minimum Resiliency Planning Objective

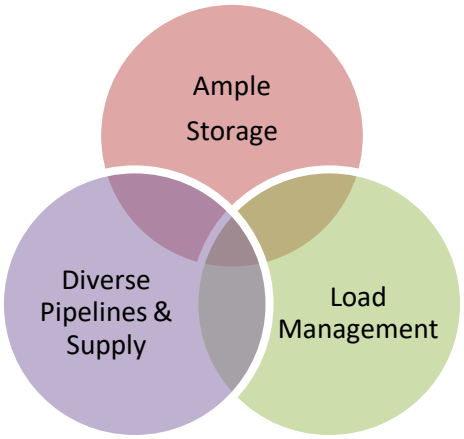
Section 3 of this Application explains resiliency, addresses the need for additional resiliency investments, and explains the rationale underlying the identified Minimum Resiliency Planning Objective.

[2] Appendix A to Order G-20-15.

1.2.1.1 Resiliency Depends on Ample Storage, Diverse Pipelines and Load Management Capabilities

Natural gas system resiliency is built on three elements: (1) ample storage, (2) diverse pipelines and supply, and (3) load management. These elements have different attributes, and thus utilities will seek an efficient mix of these elements. In the case of FEI, all three elements exist at present to some extent. The Mt. Hayes LNG facility on Vancouver Island and FEI pipeline projects in the Lower Mainland are examples of infrastructure that has contributed to system resiliency. FEI is currently planning to introduce Automated Metering Infrastructure (AMI), which is an example of infrastructure that contributes to resiliency by enhancing FEI's load management capabilities.

Figure 1-1: Key Elements of a Resilient Gas System



1.2.1.2 Upstream Supply Disruptions, While Rare, Do Occur and the Consequences Can Be Significant

The fact that FEI must obtain much of its natural gas supply via Westcoast's T-South system presents resiliency challenges. The potential for an interruption of supply from the T-South system is currently the largest supply risk facing FEI. Mitigating that risk is the objective of the Project.

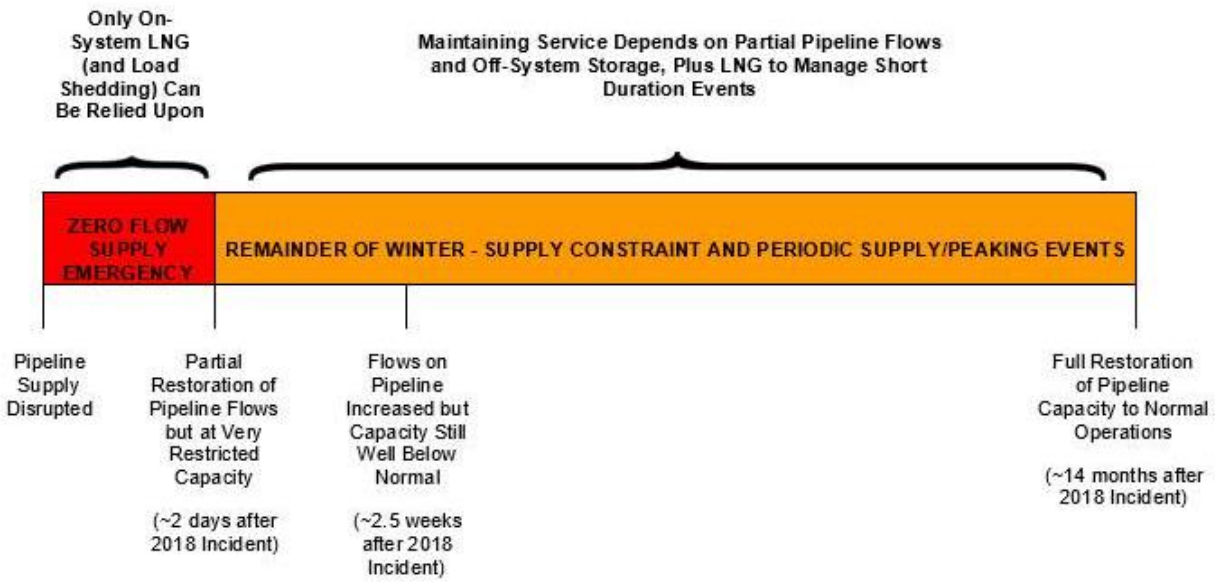
The extent of FEI's reliance on Westcoast's T-South system is a product of the limited pipeline infrastructure in the region, the limited interconnectedness of that regional infrastructure, and the location of FEI's service territory in relation to it. A major disruption on the T-South system leaves FEI with insufficient supply to meet the daily Lower Mainland load at most times of the year. It leaves the system vulnerable to a hydraulic collapse (i.e., an uncontrolled, total depressurization) unless FEI can bridge the shortfall through adequate alternate supply from storage and mutual aid agreements with utilities in the Pacific Northwest, and load management (public appeals to curb usage, curtailment and closing off whole segments of the system).

The T-South Incident highlighted the resiliency challenge posed by the extent of FEI's reliance on the T-South system. No supply reached FEI's system for a period of approximately two days, during which a hydraulic collapse was a material risk. FEI relied heavily on its on-system

storage resources to manage through the "no-flow" supply emergency, along with supply from US utilities under mutual aid agreements, appeals to the public to reduce consumption, and curtailing customers. FEI was helped greatly by the mild October weather that year, which suppressed load in the region and facilitated Westcoast's ability to repair its system quickly. Even after gas began flowing on the T-South system, the flows remained significantly constrained for approximately 14 months. Cold winter weather and other normal supply-related events that occurred during this time took on much greater significance from the perspective of ensuring continuity of service.

The following figure illustrates, conceptually, how the T-South Incident unfolded and the resources available to FEI.

Figure 1-2: Illustrative Timeline of T-South Supply Emergency and Available Resources



Pipeline disruptions are rare, but the T-South Incident was not unique. During the past decade, there have been ten other supply disruptions in North America of varying severity.

FEI retained PricewaterhouseCoopers (PwC) to assess the consequences of a widespread system outage on FEI's customers and society. PwC's report, included as Appendix B, examined three natural gas disruption scenarios to model the social, environmental and economic impacts of natural gas system disruptions. The magnitude of these potential impacts, considered in concert with the non-negligible risk of a significant disruption on the T-South system, justifies new investments in resiliency.

1.2.1.3 FEI's Minimum Resiliency Planning Objective: Withstand, and Recover from, a 3-Day No-flow Event on the T-South System

As stated previously, FEI has determined the specific Minimum Resiliency Planning Objective for prospective planning to be:

Having the ability to withstand, and recover from, a 3-day "no-flow" event on the T-South system without having to shut down portions of FEI's distribution system or otherwise losing significant firm load.

The 3-day duration identified in this Minimum Resiliency Planning Objective is informed by the T-South Incident, which resulted in a 2-day "no-flow" period despite very favourable conditions from the perspective of Westcoast's ability to react and restore flows on the T-South system.

FEI has characterized this resiliency planning objective as a *minimum,* in recognition of:

- the potential for the "no-flow" period to exceed 3-days, and
- the fact that a significant interruption will result in ongoing pipeline supply constraints that can pose challenges when responding to common demand and supply events.

FEI aims to avoid shutting down portions of FEI's distribution system or otherwise losing significant firm load because large scale load shedding has significant customer and broader socio-economic impacts. Shutting down portions of the system is irreversible in the short term, as customer restoration is a manual process that can take weeks.

1.2.1.4 FEI's Current Capabilities Need to Be Enhanced to Meet the Minimum Resiliency Planning Objective

FEI's current capabilities fall well short of the prospective Minimum Resiliency Planning Objective, such that additional measures are appropriate. Currently, the regasification capacity at Tilbury is substantially less than peak day design load. Mutual aid agreements and other potential sources of off-system supply cannot be relied upon for planning purposes because FEI's ability to access them depends on there being physical flows on the T-South system or low demand in the US Pacific Northwest. In the event of a disruption occurring during FEI's peak load period, FEI would have to quickly shed most of its Lower Mainland load.

1.2.2 FEI Considered Various Pipeline and Storage Options and Sizing Alternatives

Section 4 of the Application addresses the Project alternatives. FEI arrived at the preferred option, a new 3 Bcf tank and 800 MMcf/day of regasification capacity at Tilbury that will replace the original Tilbury Base Plant facilities, following a two-step assessment. The assessment steps are depicted in Figure 1-3 below.

Figure 1-3: Two-Step Alternatives Analysis

1.2.2.1 Step One Options Encompassed All Three Elements of a Resilient Gas System

The step one evaluation screened alternatives for meeting the Minimum Resiliency Planning Objective. FEI examined options representing all three of the key elements of system resiliency: pipeline diversity, storage, and load management. The outcome of the step one analysis was that on-system LNG has unique value from a resiliency perspective, and that load management and diversity of pipelines are complementary, rather than substitutes, for on-system storage.

1.2.2.1.1 FEI SCREENED 11 LOAD MANAGEMENT, PIPELINE AND STORAGE ALTERNATIVES IN STEP ONE

The following table summarizes the list of alternatives considered in step one, along with a high-level description of why they were screened out as alternatives to a new facility at Tilbury comprised of 2 to 3 Bcf of LNG storage and up to 800 MMcf/day of regasification capacity. FEI provides more information on each alternative in Section 4.3 of the Application.

Table 1-1: Summary of Step One Alternatives Considered to Meet Minimum Resiliency Planning Objective

Resiliency Elements	Alternatives	Reason Why Not an Alternative to On-System Storage at Tilbury
Load Management	Automated Metering Infrastructure (AMI)	AMI remote shut-off capability will add resiliency by reducing the potential for an uncontrolled shutdown, but is best viewed as complementing supply-side solutions. Without additional supply in event of a "no-flow" event, large scale load shedding would be required, leaving many non-interruptible customers without service.
Diversified Pipeline Supply	T-South Expansion	Expansion in the same corridor would still leave FEI subject to single point of failure risk, such that new storage would still be required to meet FEI's Minimum Resiliency Planning Objective even if the pipeline was constructed.
	Expansion to Northwest Pipeline's (NWP) Gorge Capacity	Expansion would add little resiliency for FEI. FEI must rely on displacement to access Gorge capacity, such that T-South gas must be physically flowing. Even if Gorge expansion was constructed, new storage would still be required to meet FEI's Minimum Resiliency Planning Objective.
	SCP Expansion to Kingsvale (i.e., interconnecting with the T-South system 172 km north of FEI's Lower Mainland system)	New regional pipeline would add resiliency by reducing single point of failure risk north of Kingsvale on the T-South system. Even if constructed, new storage would still be required to address single point of failure risk for the 172 km south of Kingsvale on the T-South system.
	SCP Expansion to Huntingdon	New regional pipeline adds resiliency by diversifying supply into the Lower Mainland. Some gas will still be available if there is a failure on one pipeline system (T-South or expanded SCP). However, even if constructed, new storage would still be required to supplement remaining pipeline flows and avoid significant load shedding. Cost savings from reducing the size of on-system LNG are limited due to inherent economies of scale.
Storage	Contract Additional Off-System Storage	Contracting additional off-system storage would still leave FEI subject to single point of failure risk, since FEI would remain dependent on the T-South system to access the storage resource. (Access to JPS and Mist is only by displacement and the displacement commercial transactions require physical flows on the T-South system.)
	On-System Underground Storage	Not feasible within the FEI service territory.
	On-System Storage at a New Site	Would provide resiliency but is more costly than expansion at an existing brownfield site, and would require construction of liquefaction in addition to storage and regasification.
	Use the Existing Base Plant Storage (including regasification) and Add Additional Storage	This option would not leverage the economies of scale of a single, larger tank. It would be more costly over time because the existing Base Plant facilities would still require replacement at some point.
	On-System Storage at Tilbury (< 2 Bcf)	Does not meet the Minimum Resiliency Planning Objective described in Section 3.
	On-System Storage at Tilbury (> 3 Bcf)	Diminishing economies of scale beyond 3 Bcf due to constructability challenges.

1.2.2.1.2 MEETING MINIMUM RESILIENCY PLANNING OBJECTIVE WITH ON-SYSTEM STORAGE ALIGNS WITH AN EFFICIENT SUPPLY PORTFOLIO

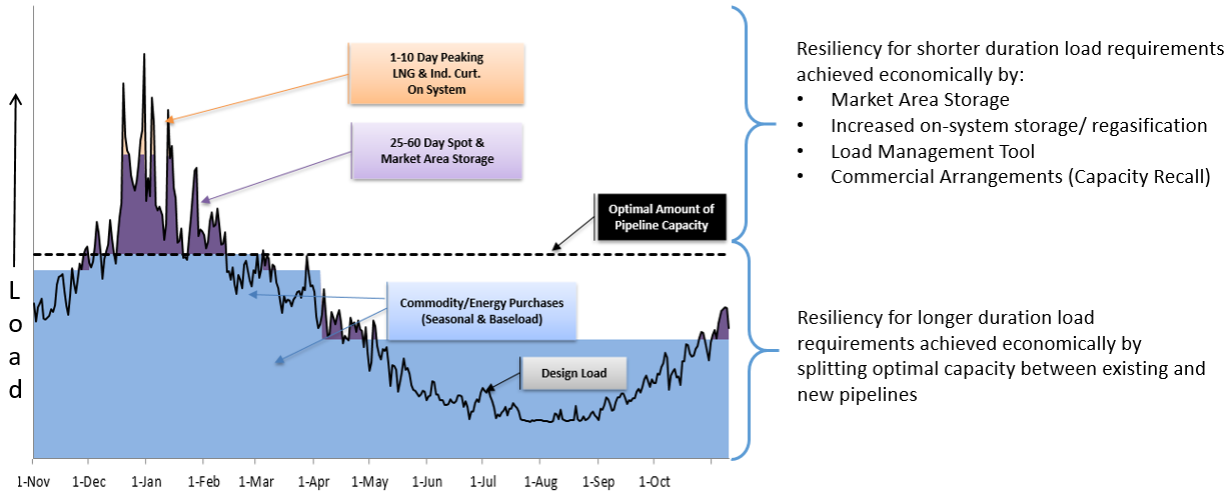
The principles of supply portfolio design – in particular, matching the resource characteristics to the characteristics of demand – are also applicable to the resiliency context, and help to explain why certain resiliency options were screened out in step one of the alternatives evaluation process. The efficient supply portfolio as reflected in FEI's Annual Contracting Plans (ACP) consists of:

- holding pipeline capacity to address base load, i.e., consistent demand throughout the year;
- off-system underground storage to provide short to medium duration seasonal supply; and
- on-system LNG storage resources for short duration supply to cover events such as winter peak demand, which occur for short periods driven by weather conditions.

Similarly, the most efficient resources for targeting a short-duration resiliency objective (i.e., bridging a 3-day "no-flow" event) are those that improve FEI's ability to deliver short-duration supply. It is neither efficient, nor in the interest of customers, to try to build resiliency by holding year-round diverse pipeline resources in quantities that would only be required if a "no-flow" event occurred during a short-duration peaking period.

This principle is illustrated in Figure 1-4 below. It shows FEI's winter load profile and the supply resources that FEI has acquired to match the system load throughout the year. In other words, it shows the efficient composition of FEI's ACP supply portfolio, discussed above. The text to the right of the graphic depicts how various resiliency options can be used efficiently.

Figure 1-4: Resiliency Measures Should Reflect Optimal ACP Supply Portfolio



Among short-duration resiliency options, on-system storage, combined with adequate regasification capacity, enables a utility to inject supply directly into the load centre to maintain system pressure and avoid hydraulic collapse during a "no-flow" event. The utility has direct control over the asset. This brings a high expectation of deliverability in a supply emergency, since it is not dependent on the physical or contractual availability of alternate pipeline capacity upstream of FEI's system.

FEI concluded that, among on-system storage options, only LNG development at Tilbury is feasible and only within certain parameters: a tank size between 2 and 3 Bcf, and regasification capacity equal to or less than 800 MMcf/day.

1.2.2.2 Step Two Considered Optimal Sizing of Tilbury Storage and Regasification Capacity

The second step of the alternatives analysis involved consideration of options for the size of tank and regasification capacity. FEI focused on the feasible tank sizes of 2 Bcf and 3 Bcf, with regasification capacity of 600 and 800 MMcf/day. The feasible sizing alternatives were assessed against specific criteria that align with the decision framework outlined by Guidehouse (formerly Navigant), which is discussed in Section 4.3.5 of the Application.

LNG storage and regasification capacity (to convert the LNG back to gas for delivery to customers) are interlinked when it comes to providing resiliency:

- The regasification capacity determines how much of FEI's daily load can be served by LNG (and, by implication, how much load must be shed to maintain the operating pressure and avoid hydraulic collapse).
- Tank size is a key determinant of how long FEI can continue to serve load during a supply emergency.

The figure below summarizes how the 2 Bcf and 3 Bcf tank size alternatives compare when evaluated against five criteria identified by FEI (referred to as "Tank Criteria"), which align with the analytical approach adopted by Guidehouse. The 3 Bcf storage alternative stands out as the best option, capable of meeting all the technical objectives and delivering other benefits, while being the most balanced from a financial perspective.

Table 1-2: Evaluation of Tank Sizes Against Tank Criteria

Project Criteria	Superior Option	Comments
Functionality Across a Range of Emergencies and Gas Supply Events	3 Bcf	• Both tank sizes are able to meet the Minimum Resiliency Planning Objective. • 2 Bcf tank provides no margin during winter conditions beyond the 3-day "no-flow" event, whereas 3 Bcf tank can either: ○ provide additional capacity to address subsequent gas supply events beyond the initial 3-day "no-flow" event; or ○ backstop a "no-flow" event for approximately 5 days during winter conditions.

Project Criteria	Superior Option	Comments
Capital Cost and Economies of Scale	3 Bcf	• 3 Bcf tank provides economies of scale. The total capital cost of the Project with a 3 Bcf tank is $50 million greater in 2020 dollars (approximately 8.4 percent) than one with a 2 Bcf tank, but provides 50 percent more storage. The 3 Bcf tank yields a much lower cost/Bcf.
Constructability	Equivalent	• Both tanks can be safely constructed.
Flexibility to Accommodate Future Load Growth	3 Bcf	• 3 Bcf tank will accommodate some future load growth on the system while still meeting the Minimum Resiliency Planning Objective; 2 Bcf tank will not.
Ancillary Benefits	3 Bcf	• Both the 2 Bcf and 3 Bcf tanks provide ancillary benefits. The additional 1 Bcf within the 3 Bcf tank allows FEI to access additional ancillary benefits, including some that the 2 Bcf tank cannot provide.

Regasification is a key element of storage in that it provides the ability to vapourize the LNG to send into FEI's Coastal Transmission System (CTS). The determination of the regasification capacity is a straightforward exercise based on the following:

- The incremental capacity of the selected regasification units; and
- The amount of supply required to support the Lower Mainland daily load during a gas supply disruption.

Regasification capacity of 800 MMcf/day significantly reduces the risk of disruption by covering the Lower Mainland daily demand on all but one day in the design year.

FEI's preferred alternative of a 3 Bcf tank and 800 MMcf/day of regasification capacity will provide a much greater ability to manage a range of emergency and gas supply events. The Project will serve FEI's Lower Mainland winter design load for 3 days without depleting the entire inventory of LNG. The remaining margin would be available to manage through demand or gas supply events that might occur once flows have been partially restored, or to cover a further 2 days of "no-flow". It should nevertheless be understood that even a 3 Bcf tank and 800 MMcf/day regasification is not a total resiliency solution or a guarantee that FEI will be able to meet load following a "no-flow" event. Significantly more on-system storage and regasification capacity would be required to accomplish that outcome, and attempting a project on that scale would be both challenging and very costly for FEI's customers. There are more efficient ways of adding resiliency over and above what will be provided by the Project. It is thus important to consider this Project, as FEI has done, within the context of a portfolio of resiliency measures that includes not only storage but also load management tools and any future regional pipeline infrastructure.

1.2.3 Project Timeline, Costs, and Rate Impacts

Upon BCUC approval, FEI plans to initiate the execution phase for the Project in Q1 of 2022, which would result in Project completion occurring in Q3 of 2026. The detailed Project schedule and milestones are described in Section 5.5 of the Application.

The Project expenditures, estimated at $768.998 million (as-spent), include the cost to demolish the existing Base Plant and construct the new 3 Bcf tank with 800 MMcf/day of regasification capacity.

As described in Section 6 of the Application, the Project will result in a cumulative delivery rate impact of 9.07 percent compared to FEI's 2021 approved delivery rates when all construction is completed and all capital costs have entered FEI's rate base. The average annual delivery rate impact over the six years from 2022 to 2027 is estimated to be 1.47 percent annually or $0.068 per GJ annually. For a typical FEI residential customer consuming 90 GJ per year, this would equate to an average bill increase of approximately $6.12 per year over the six years. The levelized delivery rate impact is 6.67 percent, which is equivalent to $0.301 per GJ for a typical FEI residential customer over the life of the assets.

1.2.4 FEI Will Account for Environmental and Archaeological Considerations

Section 7 provides an overview of the Project environment, including a discussion of the environmental and archaeological impacts the Project may have and FEI's plans to mitigate those impacts. FEI has retained experts to provide preliminary environmental and archaeological assessments for the Project. Based on the assessments, FEI expects that the potential impacts from the Project can be mitigated through additional assessments, standard permitting processes, and the implementation of standard best management practices and mitigation measures. There is an ongoing Environmental Assessment process that will account for such considerations.

1.2.5 FEI Will Continue to Engage With Indigenous Groups and Stakeholders

Section 8 discusses FEI's stakeholder and public consultation and communication efforts regarding the Project and FEI's consultation with Indigenous groups potentially impacted by the Project. FEI has developed an overarching Engagement Plan to ensure stakeholders and Indigenous groups are informed and engaged about the Project. The ongoing Environmental Assessment process also incorporates a significant amount of engagement.

1.2.6 Conclusion

Based on the information put forth in the Application, FEI believes it has demonstrated that the Project is in the public interest and should be approved as set out in the Application.

1.3 SUMMARY OF APPROVALS SOUGHT

FEI is seeking the necessary approvals to construct and operate the Project as proposed and ensure the appropriate financial treatment of costs for regulatory purposes. The key approvals are summarized below. The specific form of approvals sought is set out in the draft order in Appendix T-2.

1.3.1 Certificate of Public Convenience and Necessity

Pursuant to sections 45 and 46 of the UCA, FEI requests that the BCUC grant a CPCN for the construction and operation of the TLSE Project, as described in the Application. Granting a CPCN for the Project will encompass the components of the Project as summarized in the table below and described in detail in Section 5 of the Application.

Table 1-3: Overview of Project Components

Key Project Component	How Component Serves Project Objective
Regasification capacity of 800 MMcf/day.[3]	800 MMcf/day of regasification capacity allows FEI to inject sufficient natural gas from Tilbury into the Lower Mainland system each day to retain an acceptable percentage of load service capability to FEI's customers. The proposed equipment will provide quicker response time than the present configuration. The response time will be two hours (between notification from FEI Gas Control to gas delivered to the system).
LNG storage Tank of 3 Bcf (142,400 m^3).	A 3 Bcf tank provides sufficient LNG supply at the above regasification rate to serve FEI's Lower Mainland winter design load for 3 days without depleting the entire inventory of LNG. This will allow FEI to respond to an initial 3-day "no-flow" event. It will also leave a margin to respond to more common subsequent winter peak loads and gas supply events (such as those occurring following the T-South Incident) that take on greater significance during an ongoing period of pipeline supply constraint. The new LNG tank will be designed according to current design standards to provide safe and reliable operations.
Addition or modification of any necessary auxiliary systems including power supply, utility pipe racks, in-tank pumps, piping, cable trays, instrument air compressors, boil-off gas compressors, connectivity to Tilbury 1A LNG storage tank, and connections to the sendout gas pipeline.	These systems are required to provide the necessary power, control, monitoring, and interconnection systems to safely and reliably operate the facility.
Demolition of above-ground portion of the Tilbury Base Plant LNG storage tank and liquefaction facilities (Base Plant).	As explained in Section 4, it makes practical and economic sense to replace the Base Plant as part of the Project.

[3] 4x200 MMcf/day. Each unit is capable of an output range of 50 to 200 MMcf/day. That is, 50 MMcf/day is the lowest capacity at which a vapourizer can operate.

1.3.2 Related Financial Approvals

As explained in Section 6 of the Application, FEI seeks related approvals pursuant to sections 59 to 61 of the UCA to ensure the appropriate financial treatment of Project costs.

1.3.2.1 Depreciation and Net Salvage Rate for LNG Tank

FEI is seeking approval, pursuant to sections 59 to 61 of the UCA, for a depreciation rate of 1.67 percent and a net salvage rate of 0.67 percent applicable to the new 3 Bcf LNG tank as part of the Project.

1.3.2.2 TLSE Application and Preliminary Stage Development Costs Deferral Account

FEI is seeking approval of a new non-rate base deferral account, the "TLSE Application and Preliminary Stage Development Costs" deferral account. This non-rate base deferral account would attract financing at FEI's weighted average cost of capital until it enters rate base. Consistent with FEI's previous CPCN applications, FEI proposes to transfer the balance in the deferral account to rate base on January 1 of the year following BCUC approval of the Application and commence amortization over a three-year period thereafter.

1.3.2.3 TLSE Foreign Exchange (FX) Mark to Market Deferral Account

FEI is seeking approval of a deferral account to capture the mark-to-market valuation of any foreign currency forward contracts entered into related to construction of the Project. The deferral account, titled the "TLSE FX Mark to Market" deferral account, will not attract a financing return, as the mark-to-market adjustments are non-cash. Further, at the end of the Project the amount of the deferral account will be zero, since the deferral account only captures any unrealized gains and losses related to the requirement to mark-to-market the foreign exchange derivative contracts for financial accounting purposes.

1.3.3 Confidential Filings Request

This Application includes information that is either security or commercially sensitive. As discussed below, FEI is proposing an approach that respects the need to make information available to the extent possible, while protecting confidential information where disclosure could cause harm to FEI, customers and the broader public. A draft Procedural Order that incorporates the confidentiality-related terms is included in Appendix T-1.

1.3.3.1 Access to Security-Sensitive Information Should Be Managed Carefully

The Application contains operational and security-sensitive information that, if disclosed, could expose FEI's system to the risk of interference by malicious actors. FEI has redacted portions of Sections 3 and 4, as well as Appendices A (Guidehouse Report), B (PwC Report) and C (ACP Compliance Filing) for this reason.

The Application is premised on the need to make resiliency investments to address existing exposure to disruption in regional pipeline flows. It describes in detail where the greatest vulnerabilities lie and lays out the implications of a disruption for FEI's system operations. PwC's independent expert report also quantifies the follow-on effects on customers and British Columbia more generally.

Some of the information on pipeline flows in the region, and the extent of FEI's reliance on the T-South system, is in the public domain and could be compiled by a motivated individual through detailed research. However, this Application not only consolidates otherwise disparate information, but also goes further than any other public documents in terms of articulating system vulnerabilities and the implications. While FEI has published in the Application more general information and directional indications of FEI's resiliency capabilities and consequences of supply disruptions, it has taken care to redact more specific statements. FEI strongly believes that it is in the public interest to control access to this type of security-sensitive information in a manner that can be tracked and managed, while still making it available to parties with a legitimate interest in access for the purposes of participating in this BCUC proceeding.

1.3.3.2 Market Sensitive Project Information Should Be Kept Out of the Hands of Bidders

As well, certain Application sections and appendices contain market sensitive information on pricing and budgeting that should be kept confidential so as not to influence the construction contractor selection process and bids for work on the Project. Disclosing information about budgets or expected costs and scope can result in potential bidders increasing their bids to fit the budget, thus undermining the efficacy of the bidding process as a means to control costs.

FEI will mark all confidential information as such, where applicable. FEI has no concerns about interveners that are not involved in the bidding process accessing the budget, cost and scope information.

In accordance with the BCUC's amended Rules of Practice and Procedure established by Order G-15-19 regarding Confidential Documents, FEI requests that the interveners requesting access to confidential information execute an Undertaking of Confidentiality. A sample of the Undertaking of Confidentiality is included as Appendix T-3.

1.3.3.3 Confidential Gas Supply Portfolio Information

Information relating to FEI's efficient supply portfolio in the 2020/2021 Annual Contracting Plan (in Section 4 of the Application and section 5.2 of Appendix C), which if disclosed could reasonably be expected to harm FEI's position in the market, has been redacted. The redacted sections contain confidential, commercially sensitive information related to FEI's natural gas resource portfolio and potential future portfolio strategies to enhancing system resiliency. FEI procures its natural gas resources in a competitive market and it is customary for competing gas purchasers to keep their gas supply procurement strategies confidential.

1.4 PROPOSED REGULATORY REVIEW OF THE APPLICATION

FEI proposes the following preliminary regulatory timetable:

Table 1-4: Proposed Preliminary Regulatory Timetable

ACTION	DATE (2021)
BCUC Issues Procedural Order	Week of January 25
FEI Publishes Notice by	Week of February 8
Intervener Registration	Thursday, February 25
Workshop	Thursday, March 11
BCUC and Intervener Information Request No. 1	Thursday, March 25
FEI Response to Information Request No. 1	Monday, April 26
Procedural Conference	Thursday, May 13

1.5 ORGANIZATION OF THE APPLICATION

The Application provides detailed information in support of the Project. The remainder of the Application is organized into the following sections:

- **Section 2** provides an overview of FEI, and its financial and technical capabilities for the Project;
- **Section 3:**
  - defines system resiliency as a vital system attribute and explains how on-system storage, controlled load shedding, and regional pipeline infrastructure each contribute to system resiliency;
  - explains why FEI's Minimum Resiliency Planning Objective is appropriate; and
  - demonstrates that FEI is currently unable to meet the Minimum Resiliency Planning Objective, thereby supporting the need for additional investments in resiliency;
- **Section 4** describes the evaluation process, explores alternatives considered, and explains the basis for selecting the Project as the preferred alternative;
- **Section 5** provides a detailed description of the Project, including design, construction, resource planning and management, schedule and basis of the cost estimate, as well as setting out a risk analysis and discussing potential Project impacts;
- **Section 6** provides details on the Project cost estimate, the assumptions upon which the financial analysis is based, and the rate impacts;

- **Section 7** provides an overview of the Project environment, including a discussion of the environmental and archaeological impacts the Project may have, and FEI's plans to mitigate those impacts;
- **Section 8** discusses FEI's communication efforts and consultation with the public and stakeholders regarding the Project, including FEI's engagement with Indigenous groups potentially impacted by the Project;
- **Section 9** describes how the Project supports BC's energy objectives, including the Project's positive impact on economic development and employment, as well as how the Project aligns with FEI's most recent long-term gas resource plan; and
- **Section 10** concludes that the Project is in the public interest and should be approved.

2. APPLICANT

FEI provides the following information in accordance with the requirements of the BCUC's CPCN Guidelines. It demonstrates that FEI is capable of financing, constructing and operating the proposed Project facilities.

2.1 NAME, ADDRESS AND NATURE OF BUSINESS

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

FEI is the largest natural gas distribution utility in BC, providing sales and transportation services to residential, commercial and industrial customers in more than 100 communities throughout BC, with more than 1 million customers served throughout BC. FEI's distribution network provides more than 95 percent of the natural gas energy delivered to customers in BC.

2.2 FINANCIAL CAPACITY

FEI is regulated by the BCUC and is capable of financing the Project. FEI has credit ratings for senior unsecured debentures from Dominion Bond Rating Service (DBRS) Morningstar and Moody's Investors Service of A and A3, respectively, which support the issuance of debt in the capital markets. Additionally, FEI has access to equity injections, as required, from Fortis Inc. to finance the equity portion of the costs of projects. The liquidity of Fortis Inc.'s common shares in the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE), together with its other share plans, provide an equity platform for FEI and affiliated companies to draw upon to finance its major capital projects.

2.3 TECHNICAL CAPACITY

FEI has the technical capacity to undertake the Project, having designed and constructed a system of integrated high, intermediate and low-pressure pipelines as well as plant facilities associated with those pipelines.

FEI operates approximately 50,000 kilometres of natural gas transmission and natural gas distribution mains and service lines in BC. This transmission and distribution infrastructure serves over 1 million customers in BC. The FEI system already includes two LNG storage facilities, the Mt. Hayes LNG facility near Ladysmith on Vancouver Island[4], and the Tilbury LNG facility in Delta, BC. FEI personnel operate these facilities as part of FEI's overall system operations. FEI has a long history of safe and effective operations at these facilities.

[4] The Mt. Hayes LNG facility is owned by Mt. Hayes Limited Partnership, a sister organization to FEI. The facilities are operated by FEI as part of its system under long-term agreements.

FEI has, over the years, successfully developed and completed a number of significant infrastructure projects. These projects include the Southern Crossing Pipeline, the Mt. Hayes LNG facility, the Tilbury 1A LNG expansion, system reinforcements on the Coastal Transmission System, the Fraser River South Arm Crossing, and the Whistler pipeline. In developing significant infrastructure projects, FEI contracts with experienced construction firms or relies on internal resources. Further, when required, FEI augments its internal engineering, environmental, project management, and communications and consultation resources with experienced external consultants who provide specialist support.

FEI will engage in a procurement process to identify the appropriate general contractor(s) for the LNG tank and other Project components. The procurement process will incorporate key considerations such as prior experience, safety, environmental compliance, Indigenous and local inclusion, cost, and allocation of risk.

The key senior positions on the current Project team are outlined in Section 5.6. The Executive Sponsor of the Project is the Vice President, Major Projects. The team will be augmented and adjusted as the Project proceeds through the development and construction phases.

2.4 COMPANY CONTACT

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3. PROJECT NEED AND JUSTIFICATION

3.1 INTRODUCTION

This Section demonstrates the need for the Project, which is to enhance the resiliency of FEI's system. The Project will provide immediate backup gas supply to FEI customers, primarily in the Lower Mainland, in the event of a supply emergency (i.e., lack of supply to the FEI system). Access to new on-system storage will improve FEI's ability to manage through a supply emergency and reduce the risk of widespread outages or a lengthy and costly system-wide hydraulic collapse.

In the following sections, FEI will:

- define system resiliency as a vital system attribute (Section 3.2);
- explain how on-system storage, controlled load shedding and regional pipeline infrastructure each contribute to system resiliency in different ways (Section 3.3);
- demonstrate that FEI's minimum resiliency objective for future planning should be*: Having the ability to withstand, and recover from, a 3-day "no-flow" event on the T-South system without having to shut down portions of FEI's distribution system or otherwise lose significant firm load*. The 3-day "no-flow" period is only one day longer than the interruption during the 2018 T-South Incident that occurred in favourable conditions (Section 3.4); and
- describe how, at present, a 3-day "no-flow" supply emergency occurring at most times of the year would require proactively shutting down material portions of the system to prevent a system-wide prolonged outage, despite FEI accessing all of its existing tools to influence demand and access supply (Section 3.5).

The information regarding the importance of resiliency and the role of on-system storage in delivering resiliency is supported by the independent report commissioned from Guidehouse (formerly Navigant) titled "Report on Natural Gas System Resiliency" (Guidehouse Report). It is included as Appendix A. PwC's independent evaluation of the potential socio-economic consequences of a supply disruption is provided as Confidential Appendix B (PwC Report).

3.2 RESILIENCY IS A VITAL SYSTEM ATTRIBUTE

Resiliency refers to the ability to prevent, withstand and recover from system failures or unforeseen events. As discussed below, resiliency differs from reliability and integrity. All three of these attributes are necessary for providing service to customers. FEI also explores these concepts in the context of both gas and electricity delivery systems to illustrate the differences in in infrastructure and service levels experienced by customers.

3.2.1 Resiliency Differs from Reliability and Integrity – All Are Necessary Features of an Energy System

In the context of energy networks, the terms reliability and resiliency are sometimes used interchangeably, but they are not synonymous. Reliability and resiliency, as well as system integrity, are all desirable attributes of service to customers. This Project is best characterized as a resiliency project, but it does contribute ancillary benefits that can be characterized as enhancing reliability of service.

3.2.1.1 Defining Integrity: Having System Components Meet Design Specifications throughout Lifecycle

Although the Project is not a system integrity project, it is useful to understand how the concepts of integrity and resiliency interrelate.

The **integrity** of system assets is the foundation of the reliability and resiliency of the natural gas system. In the context of gas transmission and delivery, integrity refers to the ability of individual system elements to meet their original design specifications, and to fulfil their intended purpose or application. The concept of integrity applies throughout the entire lifecycle of gas system assets including planning, design, procurement, fabrication, construction, commissioning, operations, maintenance, and retirement.

FEI manages the integrity of its gas system assets in order to achieve its goal of zero incidents of significant consequences. An incident of significant consequence can be generally defined as an event involving the functionality of a gas system asset which materially impacts safety, the environment, or continuity of service to a large number of customers.

In the context of reliability and resiliency, the focus of integrity management on avoiding service disruption is key. Integrity management is concerned with avoiding incidents such as leaks or ruptures that would undermine the ability of the assets to deliver service. FEI uses tools and technology to detect and mitigate threats to system assets, such as corrosion, third party damage, and external forces such as landslides, floods, and seismic events. Consistent with industry practice, FEI is continually seeking improved methods to address these threats. By reducing the likelihood of these threats materializing, integrity management ensures that it is highly likely that the gas assets will be available to serve customers. Ensuring the ongoing fitness for service of FEI's gas assets is foundational to delivering safe and reliable service.

3.2.1.2 Defining Reliability: Adequacy and Security of Supply throughout the Year

Reliability refers to designing and operating a system to ensure it meets the expected customer demand at all times, and is a combination of two concepts: **adequacy** and **security**. Adequacy refers to the ability to ensure a sufficient supply of energy, whereas security refers to the ability to consistently deliver that supply to customers.

- From the perspective of **adequacy**, maintaining reliability requires utility operators to have sufficient resources to balance their energy supply capacity with customer demand

throughout the year. This is necessary to ensure adequate energy supply even during peak demand periods, while also being able to deal with the expected variability in customer demand at other times. To assist with this balance, energy can be stored directly (e.g., natural gas can be compressed, liquefied, or stored underground), or as a different form (e.g., in the electricity context, water held behind a hydroelectric dam).

- The **security** aspect of reliability is a combination of the concepts of integrity and redundancy. As discussed above, integrity is concerned with (among other things) preventing disruptions to service. Due to the nature of the assets and the success of integrity management in the natural gas industry, disruptions to natural gas service are relatively rare. In the electric industry, where the integrity of electric assets is more difficult to maintain, and disruptions are thus more frequent, redundancy is a mandatory requirement for reliable systems. While no mandatory redundancy requirements have been developed in the natural gas industry, gas assets such as storage and pipeline systems do incorporate a level of redundancy in their design and operation.

3.2.1.3 Defining Resiliency: The Ability to Manage through and Recover from Unexpected Events (Avoiding an Uncontrolled Shutdown / Hydraulic Collapse)

Resiliency refers to the ability to prevent, withstand, and recover from system failures or unforeseen events. Resiliency is directly linked to the concept of reliability in the sense that a system cannot be resilient without first having reliable components. However, resiliency also encompasses concepts such as preparing for, operating through, and recovering from significant disruptions, no matter the cause.

Section 1.1 of the Guidehouse Report differentiates resiliency from reliability in the following way:[5]

> In the context of natural gas pipeline transport and distribution systems, resiliency and reliability are two discrete concepts. Natural gas utility companies plan for and target outcomes of resiliency and reliability in their systems. …
>
> - Reliability is the ability of the energy delivery system to provide customers with an expected natural gas service on a consistent basis.
>
> - Resiliency is the ability to prevent, withstand and recover from system failures or unforeseen events such as damage and/or operational disruption that impact the operations of the system.
>
> As the cornerstone of this report, resiliency comes from the ability of the natural gas system to offer services, backed by physical assets, that enable market participants to prevent, withstand and recover from man-made or natural events that interrupt the flow of gas. The natural gas utility is charged with the responsibility to manage these risk of system disruptions on behalf of end-users by constructing a portfolio of natural gas transportation, on and off-system

[5] Appendix A, page 6.

> storage resources and supply contracts that will enable it to address unforeseen events.
>
> Infrastructure combined with contractual assets are the backbone of reliability. Achieving the backbone requires appropriate system sizing coupled with commercial agreements and experienced operators. When all of this is taken together, it increases the probability of achieving the expected reliability of gas delivery.
>
> In a similar fashion, resiliency is achieved by selectively building system redundancy via commercial agreements with tangible upstream physical assets and on-system physical assets to respond to unexpected physical events. Resiliency embedded in the system enables the system to manage and recover from unexpected events more effectively and expeditiously.

It is worth highlighting two aspects of the above quotation from the Guidehouse Report:

- **First, resiliency requires not just acquiring contractual rights to supply, but also backing by physical assets.** This is a critically important concept. In essence, the point is that no amount of contracted supply from off-system sources, or offers of mutual aid from neighbouring utilities, will assist unless the physical infrastructure required to get the supply to the utility's own system is in place. As Guidehouse states, "if the underlying physical asset is not operational due to a disruption, the contractual arrangements do not provide, in and of themselves, resiliency."[6] Similarly, a significant adverse event in the region could mean that regional supply resources are unavailable, with suppliers having declared *force majeure* under supply agreements. As discussed later, this scenario materialized during the T-South Incident, where normal market transactions and contractual arrangements were suspended and utilities in the region were left largely with whatever natural gas was stored on-system or was still physically capable of flowing to their systems by another path.
- **Second, Guidehouse notes that building system redundancy is a key way to improve resiliency.** This type of redundancy may not increase reliability performance in any given year, but will enable the utility to withstand system failures and unforeseen events and prevent disruptions to gas supply when such events occur. Redundancy can take the form of, for instance, redundant technology in a piece of infrastructure, excess capacity through larger sizing of a piece of infrastructure (e.g., a larger storage tank to supply more load if a pipeline fails), or duplicate infrastructure that can support loads in the event of one failing (e.g., two transmission lines or two pipelines to a source of supply).

Resiliency, as the ability to prevent, withstand, and recover from system failures or unforeseen events, is critical for natural gas systems because the consequences of a lack of resiliency can

[6] Appendix A, page 17.

be significant. Specifically, insufficient resiliency poses a risk of an **uncontrolled shutdown** of the distribution system (also called **hydraulic collapse**). An uncontrolled shutdown or hydraulic collapse occurs when parts or all of the gas distribution system are naturally lost due to a collapse of system pressure and gas supply. An uncontrolled shutdown is a serious scenario both in terms of service disruptions to customers as well as the potential for safety concerns:

- When the pressure in a portion of the gas system experiences a hydraulic collapse, FEI is unable to directly determine which customers are receiving sufficient pressure to operate their appliances or equipment safely. These pressure variations can vary both in time (as the event progresses) and location (from area to area or even street to street). This uncertainty greatly complicates the ability of FEI to localize, manage and respond to the supply deficiency.
- From a safety perspective, the uncontrolled drop in gas pressure can also introduce the possibility of air being drawn into the gas distribution grid. This is a potentially hazardous situation as the gas-air mixture can result in fire or explosion risks. Entrained air can also blow out the flames in customer appliances or equipment, resulting in misoperation and possible gas odour calls. Consequently, any air within the gas distribution pipes must be carefully purged by technicians attending each customer premise prior to relighting any appliances. This purge and regasification process could take days to months, depending on both the scale of outages and access to qualified resources.

As discussed in Section 3.4.3, the PwC report (Confidential Appendix B) addresses in greater detail the consequences of a severe supply disruption.

Given these significant consequences, a key aspect of resiliency is being able to manage through extreme events in a way that avoids uncontrolled shutdowns, including, if necessary, a **controlled shutdown** and restoration of the system. For example, a system exhibits resiliency if there is sufficient on-system storage to bridge the period of upstream supply disruption. If sufficient on-system storage resources are not available to bridge the entire period of disruption, they still provide a level of resiliency by providing time to implement a controlled shutdown of the system. A controlled shutdown is a planned and safe depressurization of a part of the gas system using strategic control points, including stations and valves. It is far better from the perspective of customers, FEI, and society generally, if FEI has time to implement a controlled shutdown. In a controlled shutdown, FEI is aware of which areas and customers are no longer supplied with natural gas, which allows for safe regasification and relights of customer appliances and equipment. While a controlled shutdown is considered a measure of “last resort”, it provides valuable flexibility to the operator when all supply options are exhausted, and improves customer service by minimizing the scale and duration of any necessary outages.

Controlled shutdowns require time to implement. It is necessary to assess the supply shortfall, analyze and plan the extent of shutdown to meet the shortfall, and execute the plan. Guidehouse explains:[7]

> …it would require significant time for FEI to ascertain the supply/demand on its system and develop the appropriate response, i.e., curtailment of customers, in order to mitigate long-term impacts, including catastrophic operational and economic failure. On-system storage would allow FEI to more effectively implement a controlled shutdown that minimizes the impact to at-risk customers if a major interruption event occurred.

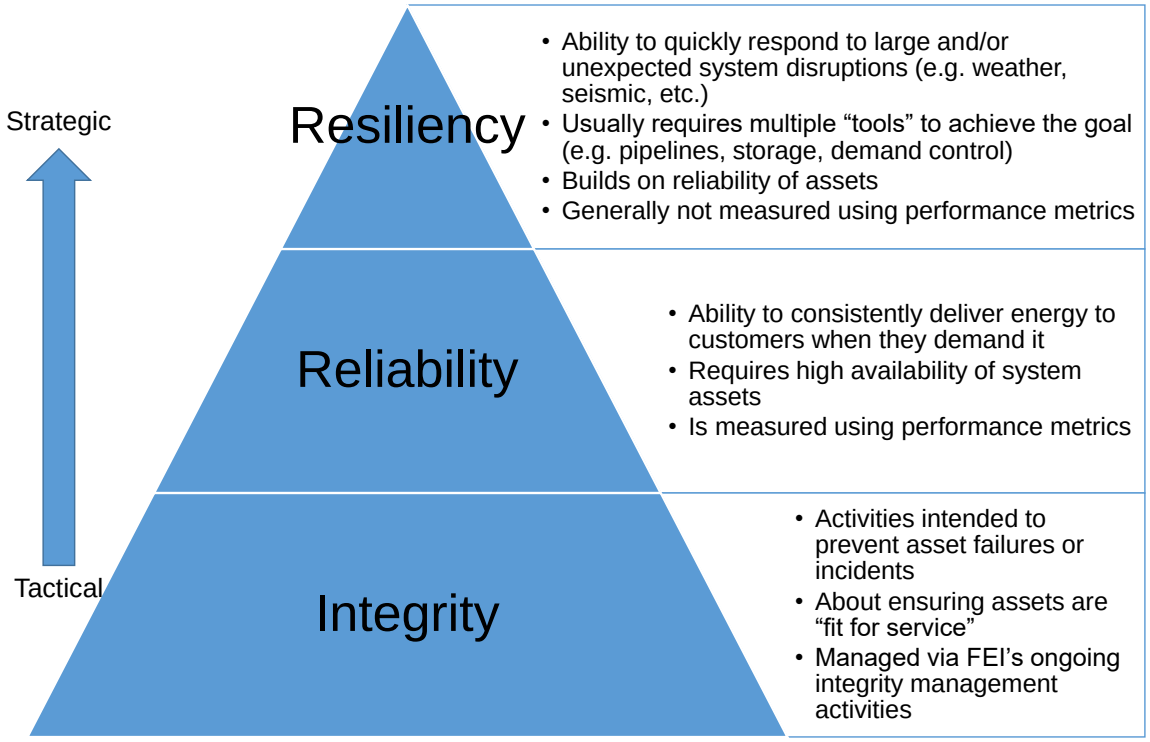
The potential duration of a supply disruption, the daily demand that would need to be served by on-system storage, and the time required to initiate a controlled shutdown all play into FEI's analysis of resiliency options. These factors, among others, are addressed in Section 4 of the Application.

Figure 3-1 below depicts the concepts of integrity, reliability and resiliency as building blocks of customer service. As discussed in the figure and in the above sections:

- **Integrity** (Section 3.2.1.1) is ongoing on a day-to-day basis, as it is focused on detecting and mitigating ongoing threats to system assets; it is more "tactical" in nature.
- **Reliability** (Section 3.2.1.2) is built upon or includes system integrity, and tends to be more of a strategic consideration (e.g., securing contracted assets for each gas year and infrastructure capital planning).
- **Resiliency** (Section 3.2.1.3) is a higher level strategic consideration that typically requires longer-term planning and solutions. It is concerned with the capability of the system to withstand a large and/or unforeseen event, such as an upstream pipeline failure. Resiliency depends on having an appropriate combination of physical assets that can provide (a) continuity of supply to withstand the disruption or buy time to shut down the system in a controlled manner, and (b) the means to quickly and effectively shed enough load to stabilize the system before hydraulic collapse of the entire system occurs.

[7] Appendix A, page 44.

Figure 3-1: Integrity, Reliability and Resiliency as Building Blocks of Customer Service



3.2.2 Gas Systems Exhibit a Much Higher Level of Reliability than Electric Systems, but Failures Do Occur

In general, gas transmission and distribution systems experience significantly fewer outages than electric networks[8]. However, when gas customer outages do occur, they tend to be longer in duration (due to the need for purging and appliance relighting, as described above). Resiliency investments for the natural gas system are consequently focused on addressing low probability events. But events can and do occur, and they can give rise to significant consequences.

The vast majority of electric transmission in North America is via overhead power lines, which are more exposed to disruptive events including lightning, wind, ice, trees and third-party contacts. Consequently, electric power lines have considerably higher outage rates than underground gas lines.

[8] Industry surveys and studies conducted by the US Gas Technology Institute have demonstrated gas customer average reliability/availability levels (due to unplanned causes) of 0.9999978. (Gas Technology Institute, Topical Report (July 19, 2018) "Assessment of Natural Gas and Electric Distribution Service Reliability," p. 10.) This is consistent with the service availability levels of the Canadian Gas Association when comparing outage incidents. In contrast, the comparable average availability for most electric customers in BC is approximately 0.99959. In other words, on average the gas system is 186 times more reliable than the electric system.

Based on industry experience, on average, a typical 80 km overhead electric transmission circuit is expected to experience one unplanned outage event per year[9]. Since circuit outages are an expected occurrence in electric networks, asset redundancy is commonly employed to ensure compliance with minimum standards of reliability. The BC Mandatory Reliability Standards (MRS) require that the bulk electric system be planned and operated to withstand an unexpected outage of the single most critical system element, coincident with the forecast system peak load, while not experiencing any firm customer outages[10]. This is referred to as the *N*-1 reliability criterion and is based on North American industry standards. These industry standards were developed and mandated following two major Northeast blackouts, one in 1965 and one in 2003. In other words, the cost of this necessary system redundancy is broadly accepted by electric operators and regulators in order to ensure adequate levels of customer service.

In contrast, large-diameter, high-pressure pipelines may operate for long periods without experiencing any unplanned outage events. As such, regional gas transmission systems are typically designed and operated to transport a contracted quantity of gas, as opposed to being explicitly planned to achieve an expected level of reliability. To FEI's knowledge, there are no specified regulatory requirements for gas system reliability anywhere in North America equivalent to the electric utility *N*-1 criterion. However, in interconnected gas networks with numerous supply points interspersed with multiple delivery points, a reliable network is a consequential outcome. Thus, in many areas of North America, the redundancy afforded by multiple gas supplies, storage, and transportation paths results in an inherently resilient system.

The rates of reliability would suggest that, on average, a typical natural gas customer would expect 69 seconds of service outage per year,[11] compared to almost four hours per year for a typical electric customer in BC (even with the high standards of redundancy on the electric system).[12] In practice, the vast majority of FEI's customers have never experienced a single natural gas outage, other than for planned reasons such as a meter exchange.

Gas pipeline failures are thus relatively rare occurrences; however, they can be high consequence events. If a rupture followed by ignition occurs, the result may be significant property damage, or harm to individuals in the vicinity of the failure. Further, if there is insufficient pipeline redundancy in the region, the reduced transportation capacity can potentially lead to gas shortages or outages to large numbers of downstream customers. This

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[9] North American Electric Reliability Corporation (NERC). "Outage Metrics, 2019 WECC AC Circuit." Total Circuit Outage Frequency of 1.97 per 100 mi·yr (for 200-299kV circuits). https://www.nerc.com/pa/RAPA/tads/Pages/OutageMetrics.aspx

[10] BCUC Order R-27-18 (June 28, 2018). "British Columbia Hydro and Power Authority Mandatory Reliability Standard TPL-001-4 Assessment Report." P. 8, Attachment D.

[11] Gas Technology Institute, Topical Report (July 19, 2018), "Assessment of Natural Gas and Electric Distribution Service Reliability." Online: https://www.gti.energy/wp-content/uploads/2018/11/Assessment-of-Natural-Gas-Electric-Distribution-Service-Reliability-TopicalReport-Jul2018.pdf

[12] "BC Hydro F2020 Annual Reporting of Reliability Indices", p. 3, https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/2020-05-04-f05-f06-directive-26-f20120.pdf

was demonstrated during the T-South Incident in October 2018, which restricted supply to BC and the US Pacific Northwest.

The ability of a natural gas system to withstand and recover from extreme or prolonged events is becoming increasingly relevant. Much of the infrastructure in the region is aging[13], which increases the risk of failures due to time-dependent threats. It is also possible that disruptive events, such as wildfires, landslides and floods, are becoming more frequent and severe, which increases the risk of damage to the pipeline infrastructure.

In summary, it is common for electric networks to experience frequent, but relatively low-consequence outage events. In contrast, gas systems typically exhibit low-probability, but potentially high-consequence failures. This Application reflects consideration of the risk and consequences of a gas supply disruption.

3.3 GAS SYSTEM RESILIENCY DEPENDS ON A COMBINATION OF DIVERSE PIPELINES, AMPLE STORAGE AND LOAD MANAGEMENT CAPABILITIES

Broadly speaking, and leaving aside adequacy of natural gas production, there are three elements that contribute to natural gas system resiliency:

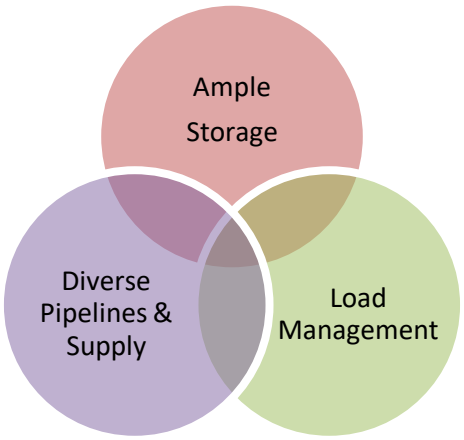
1. **Diverse Pipelines and Supply:** Pipelines can continuously transport a significant amount of gas supply to the market centres on a daily basis, and therefore address customers' baseload and seasonal demand requirements. Having access to multiple regional pipelines, preferably separated geographically, to serve the distribution system improves a utility's ability to dependably collect and deliver gas supply to consumers.
2. **Ample Storage:** Access to storage, preferably located on a utility's own system, allows a utility to manage expected or unexpected changes in supply for a period of time. It can bridge a shortfall in supply entering the utility system, or if necessary, provide time to shed load or implement a controlled shutdown of portions of the system to avoid hydraulic collapse. Two common gas storage methods are underground and LNG. Underground storage uses natural geological formations to hold supply in gaseous form, and (in FEI's case where underground storage is off-system) requires a functioning regional pipeline to transport stored natural gas to the utility distribution system. LNG is held in above ground storage facilities that are accompanied by adequate regasification capability (to convert the LNG back to gas for delivery to customers). On-system LNG storage has the benefit of being able to inject supply close to the load centres, and is not reliant on functioning regional pipeline infrastructure.
3. **Load Management Capabilities:** The ability to manage load during a period of supply constraint allows an operator to shed load in a controlled shutdown, while ensuring the

[13] As explained in Section 1.5.1.3 "Increasing Investments Needed for System Integrity" of the FEI 2020-2024 Multi-Year Rate Plan Application, over half of FEI's transmission pressure gas lines are more than 30 years old and over one third were installed prior to 1970. Additionally, this is consistent with the vintage of the T-South system which was commissioned in 1957.

constrained supply of gas is maintained for the maximum number of customers. Until recently, the only options for gas load curtailment were through broad public appeals to reduce consumption, or direct curtailment requests to large volume and/or interruptible customers. The former has no certainty of customer compliance, while the latter may not be sufficient to prevent a system-wide hydraulic collapse. Neither may be timely enough during a rapid-onset supply disruption. Even measures directly in the control of the utility (e.g., closing valves or shutting-in stations supplying entire communities), may not be sufficiently responsive. Newer technology (for example, the deployment of Advanced Metering Infrastructure (AMI) with remote-shutoff valves) instead allows the utility operator to quickly, accurately, and directly target any required customer load shedding. Relying on load management inherently means disrupting service to customers, and is ideally used in conjunction with other supply-based solutions. FEI's ability to manage load is discussed further in Section 3.3.2.

Since each of the three elements adds resiliency in distinct, but complementary ways, FEI views resiliency as a combination of the above three elements, as depicted in Figure 3-2.

Figure 3-2: Key Elements of a Resilient Gas System



The sections below expand on the role of each of the three elements in the context of FEI's system.

3.3.1 Diverse Pipelines and Supply: FEI's System Incorporates Pipeline Redundancy, but Regional Pipeline Diversity Depends on Factors beyond FEI's Control

Having access to multiple regional pipelines, preferably separated geographically, to serve the distribution system improves a utility's ability to dependably collect and deliver gas supply to consumers. FEI's own transmission system, including the Vancouver Island Transmission System (VITS), and the Coastal Transmission System (CTS), incorporates some pipeline redundancy, providing a degree of resiliency, but there is less diversity upstream at the regional level where infrastructure development is influenced by considerations outside of FEI's control.

3.3.1.1 FEI's Transmission System Incorporates Pipeline Redundancy

FEI's own transmission system has a degree of resiliency due to the redundancy incorporated into its design. This redundancy has been incorporated as the need arose for additional system capacity to supply customers during peak load periods.

Over the years, FEI has looped[14] various segments of the transmission system to increase capacity. For example, FEI added an NPS[15] 42 pipeline to the CTS in parallel with existing NPS 18 and NPS 30 pipelines in 1977 and 1992, and looped existing NPS 20 and NPS 24 pipelines with an NPS 36 pipeline during the Coastal Transmission System Upgrade project in 2017. While each of these projects was undertaken to increase the available capacity at peak times, a secondary benefit is that they also allow one of the parallel pipeline sections to be removed from service during light-load periods if required for maintenance, inspection, or repair.

Similarly, in the application for the Fraser River South Arm Crossing Upgrade project[16], the BCUC supported the need to replace two existing, seismically-vulnerable NPS 20 and NPS 24 pipelines with two new pipelines. In its determination, the BCUC noted that this solution was not the "least-cost" alternative (for example, as compared to replacement with a single pipeline), but agreed it was the most cost-effective alternative and would address the seismic, erosion, and dike settlement risks.

Finally, in the Lower Mainland Intermediate Pressure System Upgrade project[17], the integrity-driven need to replace an NPS 20 pipeline between Coquitlam and Vancouver also presented the unique, one-time opportunity to increase the pipe size to NPS 30 and consequently enhance capacity and hence the resiliency of supply to customers in the Vancouver, Burnaby, Coquitlam and North Shore areas. Once again, the BCUC was satisfied that the increased flexibility and resiliency benefits justified the added project costs associated with the pipe size increase. Prior to the new NPS 30 being placed in service, customers in those areas were at risk of an outage if a disruption occurred on the CTS.

Today, the CTS is configured to serve the northwest portion of the Lower Mainland from the south or the east (Fraser or Coquitlam Gate Stations respectively). The two pipelines do not provide full redundancy to the entire Lower Mainland, and the natural gas flowing on both lines ultimately comes from the same place (the T-South system). However, either of the CTS pipelines can provide full back-up flows to customers in the Vancouver, Burnaby, Coquitlam and North Shore areas in the event that flows on one of the branch lines is disrupted. In other words, the supply from either Coquitlam or Fraser Gate Station can independently support all downstream customers.

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[14] Looping refers to the construction and operation of two or more gas lines in parallel with each other, typically in the same right of way.

[15] Nominal Pipe Size diameter, in inches.

[16] Certificate of Public Convenience and Necessity (CPCN) for the Upgrade of the Transmission Pipeline Crossing of the South Arm of the Fraser River granted by the BCUC pursuant to Order C-2-09, dated March 12, 2009.

[17] CPCN for the Lower Mainland Intermediate Pressure System Upgrade granted by the BCUC pursuant to Order C-11-15, dated October 16, 2015.

These projects demonstrate how FEI considers the requirement to maintain or enhance system resiliency where it can be achieved cost-effectively.

3.3.1.2 Holding Capacity on Diverse Regional Pipelines Is Valuable When Achievable and Complementary with Other Supply Resources

The addition of new regional pipeline infrastructure, preferably constructed in different corridors from the T-South system, would help ensure that some supply is available during an event that involves a sustained loss of pipeline capacity. The continued availability of some supply through a redundant pipeline, even at volumes less than what is required to serve FEI's system load, can augment on-system storage to buy additional time to allow the supply constraint to resolve, to implement load shedding or to permit a controlled shutdown for a portion of the system.

In practice, the considerations that come into play when considering new regional pipeline infrastructure as a resiliency tool for FEI include: (1) FEI's ability (or inability) to drive investment in new pipelines on its own; and (2) FEI's efficient gas supply portfolio.

- **Regional infrastructure development usually requires backing of multiple stakeholders:** Developing regional pipeline capacity is not entirely within FEI's control; building a new pipeline, or even (less ideally from a resiliency perspective) expanding an existing pipeline, is a large undertaking that requires broad regional support[18], backed by firm transportation contracts, to underwrite the cost of the new pipeline infrastructure. On this point, Guidehouse states:[19]

> Given the high cost of pipeline construction, pipeline projects require scale and most often need multiple customers to enter into long-term transportation agreements to support the economics. In addition, the U.S. FERC requires a demonstration of market need, i.e., precedent transportation agreements, before it will issue a certificate of public convenience and necessity to authorize pipeline construction. In Canada, interprovincial pipeline proposals receive similar consideration by the [Canadian Energy Regulator] CER while intra-provincial pipeline projects in British Columbia are reviewed by the BC Oil and Gas Commission and the BCUC. Regional pipeline construction in BC and the U.S. PNW region will only happen if large industrial projects that require natural gas come to fruition.

- **Resiliency measures should complement FEI's efficient supply portfolio:** FEI has, over a number of years, managed to the objectives of its Annual Contracting Plans (ACPs), to build an optimal gas supply portfolio. The ACPs identify a mix of resources that best fit FEI's annual and winter (i.e., seasonal) load profile. The mix of resources incorporated in the ACPs reflects what is available in the marketplace, which is dynamic

[18] In this Application the term "region" broadly refers to the Pacific Northwest, which includes BC.
[19] Appendix A, page 40.

and evolves over time. In general terms, pipeline capacity is held to meet annual and seasonal demand (i.e., 151 day winter), while market-area storage (15-60 days) and LNG storage are utilized to manage peak demand periods. Ideally, resiliency investments complement this optimal mix of resources. A cost-effective way to build resiliency is to employ a mix of pipeline redundancy and expanded storage and peaking resources that dovetails with the optimized supply portfolio. This is discussed further in Section 4.2 of the Application.

3.3.2 Load Management: Controlled Load Shedding Is Partially within FEI's Control Today, and Control Will Be Enhanced by AMI

As FEI described above, the ability to shed load effectively in the event of a supply disruption is another important element of a resilient system.

Shedding load helps to maintain the pressure on the system by restoring the balance of gas supply and demand in the event of a supply emergency. FEI employed this option following the T-South Incident in October 2018. FEI responded to the significant gas supply deficiency by curtailing load in two ways: directing large volume and/or interruptible customers to immediately disconnect from the system, and by making public appeals for all customers to reduce their gas usage. These actions, helped by a spell of mild weather, were important in avoiding hydraulic collapse in 2018.

There are several considerations that support the use of load shedding as part of a balanced mix of resiliency measures, complementing (rather than replacing) other solutions.

- **Interruptible loads provide a valuable peaking resource:** FEI's efficient supply portfolio has been constructed in recognition that some of FEI's industrial customers take service on an interruptible basis. FEI has also entered into peaking supply agreements with certain customers, like Island Generation[20], that allow FEI to recall supply and capacity during peak periods (i.e., cold winter days when residential and commercial customers turn-up the heat). These are valuable resources and FEI continues to use them as part of an efficient supply portfolio.
- **Load shedding in a supply emergency involves interrupting service to those who want uninterrupted service:** In cases where customers have taken interruptible service or entered peaking gas agreements, the customer has made an economic decision that it can do without the gas supply for periods of time. Planning for broader load shedding as a means of improving resiliency inherently means planning to disrupt service to segments of customers who want a consistent gas supply. Resiliency solutions that aim to preserve continuity of service for those customers who want firm supply (e.g., on-system storage or pipeline redundancy) are, other things being equal, preferable to disruptions. However, a controlled disruption, as enabled by AMI technology, is preferable to an uncontrolled hydraulic collapse of the system. As indicated above, an

[20] Located in Campbell River, Island Generation is a 275 MW natural gas-fired combined-cycle power generation facility. https://www.capitalpower.com/operations/island-generation/

uncontrolled and widespread hydraulic collapse[21] is a worst-case scenario for customers, the utility and society generally. It results in undefined customer outages and unknown outage propagation. Hydraulic collapse can create safety situations on the customer level. It can take months to reinstate service to all customers following hydraulic collapse.

- **Control is currently an issue:** FEI currently has no direct ability to remotely or automatically disconnect or otherwise curtail gas supply to customers. This has two significant implications for FEI's ability to rely on load shedding in a supply emergency:
  - First, a significant amount of load must be shed in a very short period of time to make a difference in a supply emergency. FEI's customer profile has evolved over time such that it has fewer large industrial customers like pulp mills that can be quickly curtailed in a supply emergency. This means that the necessary volumes to make a difference have to be obtained from a larger pool of smaller customers, many of which would not have professional staff on hand 24/7 to immediately reduce gas consumption.
  - Second, it would take too long for FEI to manually disconnect individual customers from the system. As a practical matter, short of manually closing valves supplying entire segments of the system (and allowing those segments to depressurize), FEI must rely on customers to take the necessary steps. As such, compliance with load curtailment directives and appeals is not assured. Customer responses can only be measured after the fact by observing changes in transmission gas flow measurements. Even then, determining the impact of public appeals is very difficult to separate out from normal day-to-day load variability caused by weather and consumption pattern changes.

In 2021, FEI expects to file an application for a CPCN to install AMI. The AMI project would include the installation of new gas meters equipped with remotely-operable shutoff valves for the vast majority of FEI's customers. These shutoff valves could be used to provide more direct and near real-time ability to flexibly manage load during times of system constraint, thereby reducing the probability of a hydraulic collapse or uncontrolled shutdown of the entire gas system. The AMI project would thus complement the Project as a resiliency tool.

3.3.3 Ample Storage: On-System Storage Is Critical for Resiliency and Is within FEI's Control

On-system storage has unique value from a resiliency perspective. These unique attributes are summarized below, and discussed in greater detail in the context of the Project in Section 4. As a practical matter, on-system storage for FEI means LNG storage, since (as discussed in Section 4) underground gas storage is unavailable.

[21] Hydraulic collapse is also referred to as "system collapse", which is the term used by Guidehouse.

3.3.3.1 On-System Storage Provides a Controllable Resource with High Deliverability

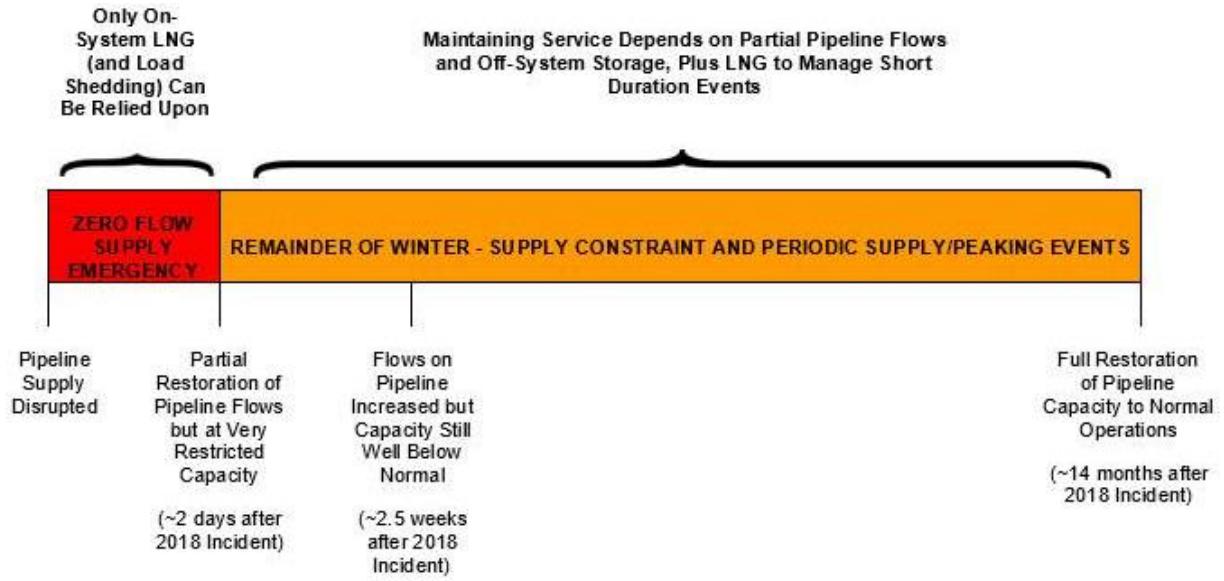
On-system storage provides a controllable supply resource with a high expectation of deliverability. This type of storage enables a utility to inject supply directly into the load centre to avoid a hydraulic collapse of the system. FEI's ability to draw on on-system resources in the event of a supply disruption does not depend on the physical or contractual availability of alternate pipeline capacity upstream of FEI's system.

3.3.3.2 On-System Storage Buys Critical Time in a Supply Emergency, and Provides Ongoing Support in the Aftermath, That Other Resources Cannot Provide

On-system storage buys additional response time until the flow of gas from pipelines can be partially or fully restored, or a new supply-demand balance can be achieved by shedding load. Even once flows resume, pipeline capacity can remain constrained for long periods of time; therefore, on-system storage remains important for managing the more typical peaking load events (cold weather). These events take on greater significance during the period that pipelines remain constrained.

The two roles played by on-system storage are depicted in the following diagram, which uses the actual timeline of the T-South Incident. Further discussion follows the figure.

Figure 3-3: Illustrative Timeline of T-South Supply Emergency and Available Resources



3.3.3.2.1 IMMEDIATE PRIORITY: WITHSTANDING THE "NO-FLOW" PERIOD

Time is critical when a utility like FEI faces a "no-flow" supply emergency due to a disruption in pipeline flows. The utility must first assess the situation to determine the nature of the emergency. As in the T-South Incident, explained in more detail in Section 3.4.2.2, there can be significant delays until reliable details are known about the emergency event. During this critical period, the supply from on-system storage is buying the utility time to gather information and make plans while avoiding a hydraulic collapse.

By buying time, the utility can assess its options to bring supply and demand back into balance moving forward. Tools available to the utility may include:

- Curtailing customer load;
- Communicating conservation messaging to customers;
- Using on-system storage resources;
- Accessing off-system storage resources, assuming it is both commercially available and can be physically accessed;
- Purchasing incremental supply, assuming it is both commercially available and can be physically accessed[22]; and
- Enlisting mutual aid arrangements, assuming supply is not required by other parties to mutual aid agreements and supply is physically accessible.

FEI's ability to access these other tools at present is discussed further in Section 3.5.

Where these tools are insufficient to restore the supply-demand balance, the utility must begin planning to "shut-in" (disconnect) parts of the system. Without AMI technology, the shut-in process is crude. It requires technicians to visit valves and gate stations across the system to manually shut off the flow of gas to large geographic areas. This process not only stops supply to all customers in a given area, but also depressurizes the distribution system in that area. The benefits of having sufficient on-system supply to delay a shut-in are desirable; once a shut-in has been undertaken, this measure is irreversible in the short-term as it requires FEI's technicians to:

- Visit each premise to turn off the valve at the meter to isolate customer piping from the depressurized distribution system;
- Verify that 100 percent of individual customer valves are shut off;
- Purge the distribution system to remove air;
- Repressurize the distribution system once gas flows to FEI's system have resumed; and
- Revisit each premise to reopen the valve at the meter, purge air from customer piping, and relight each customer appliance.

Guidehouse emphasizes the value of the time that on-system storage provides:[23]

> … In the event of an unforeseen supply interruption, it will take several hours to discern the location and magnitude of the disruption. Additional time is required to plan and execute an appropriate curtailment response to prevent a system collapse. For example,

[22] Commercial operations were halted in the T-South Incident. Similarly, they may not be available in future incidents.
[23] Appendix A, page 48.

additional time will also afford FEI the ability to: communicate with regional utilities to coordinate a response, notify interruptible customers and provide sufficient time to make their own preparations, mobilize alternative forms of short term fuel supply (e.g. mobile LNG), mobilize FEI workforce to prepare for curtailment of customers and emergency response, etc.

3.3.3.2.2 NEXT PRIORITY: BALANCING SUPPLY AND DEMAND DURING PERIODS OF DECREASED PIPELINE CAPACITY

It is unlikely that the end of a "no-flow" event on the T-South system will mean full resumption of supply for FEI. Rather, it can be expected that the pipeline system will continue to operate at significantly reduced capacity for an extended period. This occurred following the T-South Incident in 2018. Natural gas resumed flowing on the T-South system after two days, but capacity on that system was held to approximately 50 percent of firm capacity for about 45 days (i.e., until December 1, 2018). The T-South system did not return back to full firm capacity for approximately 14 months (i.e., until December 1, 2019), which included the entirety of the 2018-19 winter load period. During this subsequent period of constraint, access to on-system LNG remained important to FEI from a resiliency standpoint.

Each winter in BC there are periods where demand peaks due to cold weather. A decrease in supply may also occur when pipeline capacity is limited during certain periods due to necessary integrity work on a transmission pipeline (such as the T-South system or the CTS). In the normal course, on-system LNG provides FEI with the supply to manage through these peaks and supply events. When pipeline capacity is significantly constrained already, and flows are reduced, these relatively routine events can take on much greater significance without sufficient on-system LNG "left in the tank" after bridging the "no-flow" supply emergency.

3.4 FEI'S MINIMUM RESILIENCY PLANNING OBJECTIVE IS REASONABLE

As described in Section 1, FEI has identified the following Minimum Resiliency Planning Objective:

> *Having the ability to withstand, and recover from, a 3-day "no-flow" event on the T-South system without having to shut down portions of FEI's distribution system or otherwise lose significant firm load*.

The subsections below set out the analytical framework through which FEI arrived at the Minimum Resiliency Planning Objective, and explain why it is an appropriate objective from the standpoint of customers, the Company and British Columbians generally. The considerations include:

- a risk assessment framework for resiliency investments should consider both the potential for a supply emergency to occur, and the magnitude of the associated consequences (Section 3.4.1);

- the characteristics of the regional infrastructure are such that FEI is dependent on the Westcoast T-South system, which detracts from the resiliency of FEI's system and elevates the risk that its customers and British Columbians will experience negative consequences in the event of a disruption on the T-South system (Section 3.4.2);
- the potential consequences of various supply interruption scenarios are significant, as reflected in the findings of PwC's evaluation (Section 3.4.3);
- the 3-day "no-flow" period is only one day longer than the interruption during the 2018 T-South Incident that occurred in favourable conditions, both in terms of the time to repair the damaged T-South pipe and the mild weather that reduced demand on FEI's system and in the region generally (Section 3.4.4);
- while load shedding is an important resiliency tool, excessive load loss is undesirable (Section 3.4.5); and
- FEI's approach to quantifying resiliency requirements is consistent with industry examples identified by Guidehouse (Section 3.4.6).

3.4.1 Assessment Framework for Resiliency Investments Should Consider the Likelihood of an Event and Potential Consequences

In analysing the need for investment in on-system storage, FEI has considered both the risk that a supply emergency will occur, and the potential consequences in the event that a supply emergency does occur. Other considerations, such as cost and ancillary benefits, inform the ultimate decision as well.

Guidehouse characterizes resiliency investments as akin to insurance. It articulates a risk-based approach consistent with what FEI has applied to the Project. For example:[24]

> … As a component of system redundancy in the form of reserve supply, the Tilbury Tank expansion project can be viewed as insurance that mitigates the risk of a significant supply disruption.
>
> The critical factors to consider when purchasing insurance include defining the risk, both in terms of the probability of the risk and the consequences of the risk and identifying prudent means to manage the risk. In other words, it is important to understand the likelihood, i.e., the probability of a major system disruption, and the significance, i.e. the potential cost and socio-economic implications of a major system disruption. Another critical consideration in managing risk is the cost to mitigate the risk, e.g. the cost of building infrastructure, or the cost of insurance.
>
> …

[24] Appendix A, page 46.

> Section 3.2 of this paper demonstrates that on-system storage provides an effective means to address the risk of a failure on the Enbridge BC pipeline by enabling FEI to respond to such a situation with the appropriate operational control, redundancy and emergency actions and capabilities. In keeping with the abovementioned principles that define risk and effective risk management, Guidehouse concludes that on-system storage is the most effective means of risk management for FEI to mitigate the risk of an upstream supply disruption.

The next section focuses on the risk that FEI faces of experiencing a supply disruption, with particular attention to the limited pipeline infrastructure in BC. Section 3.4.3 addresses the potential consequences in the event a supply emergency occurs, with particular attention to the PwC assessment.

3.4.2 The Objective Focuses on the Greatest Source of Risk: Interruption on the T-South System

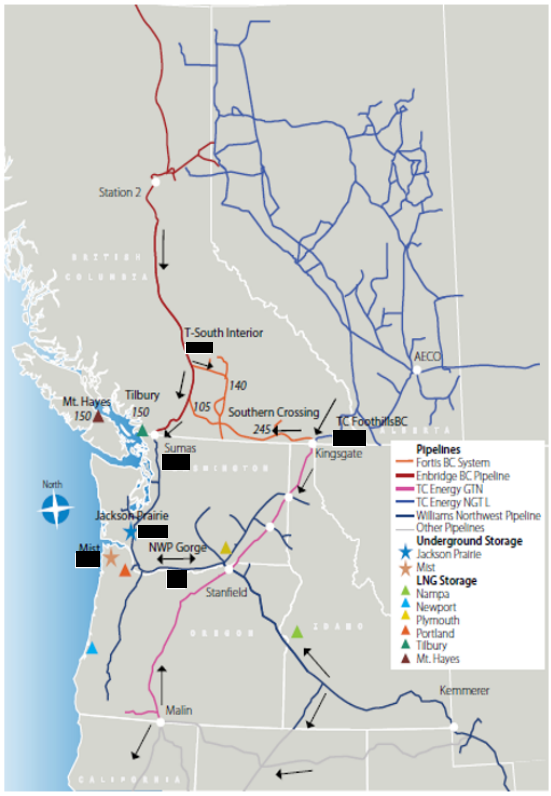
FEI's Minimum Resiliency Planning Objective focuses on a "no-flow" event on the T-South system. This focus on the T-South system makes sense because of the extent of FEI's reliance on the T-South system for supply: approximately [redacted] of the gas entering the FEI system during 2018 was shipped on the T-South system. As discussed below:

- FEI will need to continue relying on the T-South system, given the limited pipeline infrastructure in the region, the limited interconnectedness of that infrastructure, and the location of FEI's service territory in relation to it;
- The T-South Incident in 2018 underscored that FEI's current need to rely on a single pipeline system for most of its supply creates a challenge for FEI's system resiliency; and
- FEI and its customers remain at risk of experiencing a "no-flow" supply emergency resulting from a supply disruption on the T-South system with the potential for significant consequences.

3.4.2.1 FEI Must Rely on the T-South System Due to Limited Pipeline Interconnectivity in the Region

The Westcoast T-South and TC Energy (collectively, Nova Gas Transmission, Foothills BC and Gas Transmission Northwest) transmission systems serving FEI and the broader Pacific Northwest Region are predominantly in north-south corridors with limited interconnectivity between them, as shown in Figure 3-4 below.

Figure 3-4: Regional Gas Infrastructure



Pipeline	Daily Deliverability[1] (MMcf/day)
Enbridge T-South (Huntingdon Delivery Area)[2]	[redacted]
Enbridge T-South (BC Interior)	
FortisBC ITS (Oliver North)	140
FortisBC SCP (Oliver to Kingsvale)	105
FortisBC SCP (Yahk to Oliver)	245
TC FoothillsBC	[redacted]
NWP Gorge	

Market Area Storage	Daily Deliverability (MMcf/day)	Storage Capacity (Bcf)
Jackson Prairie (JPS)	[redacted]	25
Mist		19

On System Storage	Daily Deliverability (MMcf/day)	Storage Capacity (Bcf)
Mt. Hayes LNG	150	1.5
Tilbury LNG	150	1.35

1. Daily deliverability is the maximum amount of gas that can flow on the pipeline or the maximum amount of gas that can be withdrawn out of storage. It is important to note that the daily deliverability out of the market area storage is assuming storage inventories are full. These resources do have withdrawal rates decline as working gas volumes decline.

2. Including 105 MMcf/day T-South Kingsvale to Huntingdon capacity.

The T-South system consists of two looped gas transmission pipelines operating as a single system. The T-South system connects production fields in northeast BC with the Lower Mainland (Huntingdon) and Williams Northwest Pipeline (NWP) at Sumas, Washington. The T-South system flows north to south and runs approximately 916 km between Station 2 and Huntingdon. The two pipelines comprising the system are tied together by common headers and compressor stations and hence are operated as a single pipeline; [redacted]

US utilities along the Interstate 5 (I-5) Corridor also receive gas supply from the T-South system, but their dependency is lessened by virtue of greater pipeline diversity and access to on-system storage. An east to west interconnecting pipeline in the Columbia River Gorge corridor provides 534 MMcf/day of interconnecting capacity between the two north-south pipeline systems in the US. Moreover, underground gas storage facilities at Mist and Jackson Prairie (JPS) provide approximately 44 Bcf of on-system storage and up to 1,798 MMcf/day of capacity to the I-5 corridor load centres[25]. In other words, the amount of physical storage located and available to the Washington and Oregon State distribution utilities during a pipeline capacity reduction is considerably more than the amount of on-system storage in the Lower Mainland.

[25] The 44 Bcf is only 13 percent of the total amount of gas that can be delivered by WEI T-South (Huntington Delivery Area) and NWP Gorge during the winter period (151 Days).

In contrast, there is limited connectivity between the two north-south pipeline systems in BC (Westcoast T-South and TC Energy), as Figure 3-4 illustrates above. FEI sources a small portion of supply from the TC Energy system in southeast BC, which is transported east to west through FEI's Southern Crossing Pipeline (SCP) to serve the various communities in the Interior of BC. Approximately 105 MMcf/day of east to west connectivity from SCP can also be utilized to provide gas supply to customers in the Lower Mainland, via FEI's interconnect with the T-South system at Kingsvale. However, 105 MMcf/day represents [redacted] of the total Lower Mainland design day demand for 2019/2020. The SCP pipeline system has limited capacity at this time, and also relies on a 172 km segment of the T-South system (Kingsvale to Huntingdon) to deliver gas to the Lower Mainland. The FEI coastal demand centre makes up the vast majority of the FEI load and also precludes any system reinforcement other than from the northeast, east or south. This places a constraint on how much FEI is able to diversify its sourcing of gas supply away from northeast BC, so as to reduce its reliance on Westcoast's T-North[26] and T-South systems.

Guidehouse highlights that BC "has a relatively low amount of interconnectedness compared to other regions of North America"[27] and "is highly dependent on a single midstream pipeline for natural gas supply and has minimal on- and off-system storage, resulting in a system that does not have an abundance of inherent resiliency."[28] Guidehouse explains that for "end-of-pipe" utilities, where resiliency is an issue and connectivity is challenging, investments must be made in on-system storage options:

> Some LDCs are located where access to greater connectivity can be established, such as those that are located in the middle of network systems. Redundancy can more easily be arranged through commercial terms in these situations. However, for LDCs characterized as "end-of-pipe" utilities, there are often greater challenges associated with achieving multiple connections and access to physical resiliency. In these cases, where resiliency is identified as an issue, investments must be made to both enhance connectivity where possible and develop on-system storage options.[29]

3.4.2.2 The 2018 T-South Incident Posed a Significant Challenge for FEI despite Occurring in Favourable Conditions

The T-South Incident, which occurred on October 9, 2018, brought into sharp focus the risk of supply interruption for FEI's customers.

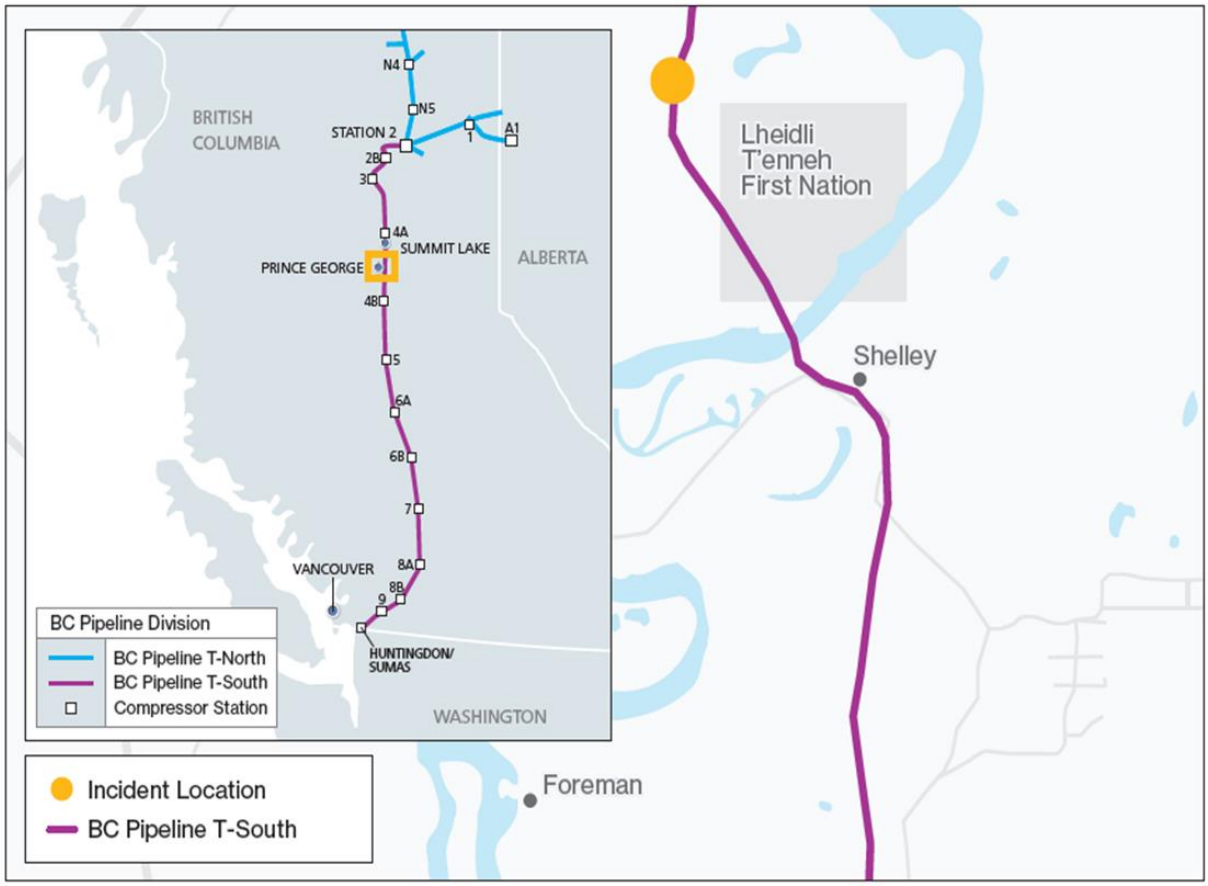
On that date, an NPS 36 natural gas pipeline forming part of the T-South system ruptured near Prince George, BC. The NPS 36 pipeline that ruptured shared the right-of-way with a second

[26] FEI contracts T-North Capacity to transport gas supply to and from the Aitken Creek storage facility. Aitken Creek is currently connected to the T-North section of the WEI pipeline system, which is supplied from several major gas processing plants.
[27] Appendix A, page 30.
[28] Appendix A, page 51.
[29] Appendix A, page 24.

NPS 30 pipeline (as described above, the two pipelines are operated as part of a single system). While only the NPS 36 pipeline had ruptured, the natural gas escaping from that pipeline had ignited and Westcoast shut down the adjacent NPS 30 pipeline as a precaution and monitored it to evaluate its condition. On October 10, 2018, Westcoast declared *force majeure*, effective as of October 9, 2018 at 24:00 MST. Westcoast's *force majeure* notice indicated that service was interrupted as a result of the rupture of the 36-inch pipeline, and that flow was restricted to zero on all delivery points on the T-South system between Compressor Station 4B and Huntingdon, as shown in Figure 3-5 below.[30]

Given FEI's dependence on the T-South system, as discussed in the previous section, this incident was a test of FEI's system resiliency.

Figure 3-5: Location of Rupture on the T-South Pipeline



The following subsections will discuss the T-South Incident in three phases.

1. The first phase refers to the events that occurred in the 48 hours immediately following the rupture of the NPS 36 pipeline where gas supply on the T-South system was restricted to zero.

[30] The rupture occurred between Compressor Stations 4A and 4B. Huntingdon is located south of Compressor Station 4B, and it is where the FEI Lower Mainland system connects to Westcoast's T-South System.

2. The second phase refers to the approximately 3 week period following the first phase where gas supply remained constrained, as Westcoast reinstated the NPS 30 pipeline at a reduced capacity and the ruptured NPS 36 pipeline remained out of service and was undergoing repair.

3. The third phase refers to the approximately 13 month period following the second phase, where the NPS 36 pipeline was returned to service; however, capacity restrictions remained in place on the T-South system, until Westcoast lifted its *force majeure* on December 2, 2019.

All told, the T-South Incident significantly affected FEI's access to supply for approximately 14 months.

3.4.2.2.1 PHASE 1 OF THE T-SOUTH INCIDENT (OCTOBER 9, 2018 TO OCTOBER 11, 2018)

The T-South Incident underscored the value that additional resiliency in FEI's system would provide as it resulted in a complete loss of gas supply from the two T-South pipelines. As discussed below, FEI's system was at risk of hydraulic collapse for a period of approximately 48 hours, and that outcome was narrowly avoided as a result of FEI's efforts and due to mild weather that had reduced heating load in the broader PNW region, thereby allowing some gas to physically flow northwards across the border.[31]

On October 10, 2018, Westcoast declared *force majeure*, effective as of October 9, 2018. Westcoast's *force majeure* notice indicated that service was interrupted as a result of the rupture of the NPS 36 pipeline, and that flow was restricted to zero on all delivery points on the T-South system between Compressor Station 4B and Huntingdon, as shown in Figure 3-5 above.

The incident first affected communities such as [redacted] as a result of the rupture of the NPS 36 pipeline. System pressure south of the isolated and depressurized pipeline segment continued to drop in the hours that followed. As the timeline and content below demonstrates, there was a significant delay before reliable and actionable information was available following the pipeline rupture. The information delay was caused by a number of factors, including the relatively remote location of the rupture, as well as Westcoast's inability to physically inspect the site due to the fire that occurred.

Approximately 24 hours passed before reliable information became available to FEI, preventing FEI from understanding and fully assessing the situation, including the status of Westcoast's NPS 30 pipeline adjacent to the ruptured pipeline. The following timeline was constructed from the perspective of FEI's Emergency Operations Centre (EOC), which was activated to manage the incident. This timeline highlights the challenges that FEI faced to maintain service during a period of severely constrained supply compounded by a lack of definitive information.

[31] As described later, there are normally physical constraints on the ability of gas to flow northwards during periods of higher demand in Washington and Oregon.

[redacted]

[redacted]

FEI, and the region as whole (i.e., utilities along the I-5 corridor), managed through the initial event by (among other things) initiating action under a mutual aid agreement. FEI is a voluntary member of the Northwest Mutual Assistance Agreement (NWMAA), which is comprised of 18 member organizations that utilize, operate or control natural gas transportation and/or storage facilities in the Pacific Northwest[32]. The support provided by the NWMAA is on a best effort basis by the parties, and there are no commercial charges for a service that a party may provide. All participants within the agreement have a vested interest in maintaining a secure, reliable regional natural gas system, and recognize that combined assistance will minimize the impact and duration to affected regional markets under emergency conditions.[33]

Figure 3-7 below provides a snapshot of FEI's supply/demand balance for October 10, 2018. This was the first gas day following the T-South Incident and the region was under mutual aid. Triggering mutual aid suspended all commercial transactions for parties in the region, including most of FEI's commercial supply agreements, leaving the physical resources under mutual aid to meet physical demand.

[32] Includes BC, Alberta, Washington, Oregon, Nevada and Idaho.

[33] On October 13, 2018 the T-South Incident transitioned out of Mutual Aid and back into commercial business operations with transactions and nominations restored on the Westcoast system. Despite this return to commercial business operations, the event continued to challenge FEI and the region through the remainder of the 2018/19 winter and until Westcoast lifted its Force Majeure on December 2, 2019.

[redacted]

As depicted in Figure 3-7 above, demand on FEI's system was met using a combination of resources. Even as mutual aid began flowing gas northward into FEI's system (which, as described later, was only possible due to particular system conditions in the US Pacific Northwest), LNG storage continued to play a significant role in the supply-demand balance as depicted in Figure 3-8 below. Due to low Vancouver Island load associated with mild temperatures, FEI's Mt. Hayes LNG facility was able to supply approximately [redacted] of the load on FEI's system during this critical period of October 10, 2018.

[redacted]

[redacted]

Factors Contributing to the Avoidance of a Pressure Collapse

Significant portions of FEI's system were at risk of hydraulic collapse for a period of approximately 48 hours, which was avoided due to the following circumstances:

1. The time of year (i.e., not in winter load period);
2. Mild weather immediately following the incident, resulting in continued low demand;
3. Given the low Vancouver Island load associated with mild weather, FEI's Mt. Hayes LNG on-system storage facility was able to supply all of the demand for the Vancouver Island system while also providing some supply to the Lower Mainland (by physically reversing flow as compared to normal operations);[36]
4. SCP was able to supply the Kootenay and the southern/central Okanagan and part of the northern Interior. SCP also delivered a quantity of supply at Kingsvale on the T-South system;
5. The level of mutual aid response from parties in the US, in particular NWP. The mutual aid response by the US entities enabled the curtailment of natural gas based power plants on the NWP system as well as imports of supply at Huntingdon. US utilities were supported, in part, by access to a higher capacity (as compared to FEI's SCP) east to west pipeline through the Columbia River Gorge to supplement the loss of T-South

[redacted]

[36] Tilbury LNG was on standby during the event and was reserved for use as a last resort due to its limited capacity. Given the increased storage capacity at Mt. Hayes, FEI would send out LNG from Mt. Hayes first over Tilbury.

supply. The Mist and JPS storage facilities with a total capacity of 44 Bcf also provided supply into the region; and

6. Curtailment of FEI's interruptible and large industrial customers following the event, and their timely response to the curtailment notice.

[redacted]

3.4.2.2.2 PHASE 2 OF THE T-SOUTH INCIDENT (T-SOUTH CAPACITY AT ~50 PERCENT UNTIL NOVEMBER 1, 2018)

The zero supply period in Phase 1 ended on October 11, 2018 when Westcoast returned the NPS 30 pipeline to service, ramping the NPS 30 pipeline up to 80 percent of its 60 day high pressure prior to the incident as permitted by the National Energy Board (NEB) order (restoring overall T-South system capacity to approximately 50 percent of firm capacity).

The total capacity of the T-South system during this period was constrained, with only one of two pipes in service and at a reduced capacity. Mild weather throughout Phase 2, and a positive response from FEI residential and commercial customers to requests for conservation, resulted in lower than normal demand. This mitigated the gas supply risk during the supply constraint. Phase 2 concluded with the return to service of the ruptured NPS 36 pipeline on November 1, 2018, at a reduced capacity.

3.4.2.2.3 PHASE 3 OF THE T-SOUTH INCIDENT (T-SOUTH CAPACITY RESTRICTIONS IN PLACE FOR ANOTHER 13 MONTHS UNTIL DECEMBER 2, 2019)

The third major development of the T-South Incident occurred when Westcoast notified all of its shippers that the T-South system would be back in service at a reduced pressure of 80 percent of its normal operating pressure.[37] A return to full maximum operating pressure took another 13 months. During the Phase 3 period, the NEB allowed Westcoast to increase the restricted operating pressure of the NPS 36 pipeline from 80 percent to 85 percent, and then to 88 percent of the previous 60 day high pressure by pipeline segment. Westcoast restored the T-South system to full capacity on December 2, 2019, almost 14 months from the date of the incident.

Given that the T-South to Huntingdon pipeline segment is normally fully utilized during the winter by customers along the I-5 corridor, the risk of a gas supply shortage persisted throughout the 2018/19 winter, not just for FEI and its customers, but for the region as a whole. Peaking events are typical during the winter in the Pacific Northwest, normally associated with cold temperatures increasing customer demand for heating. From FEI's perspective, managing through those peaking events generally requires FEI to do all of the following:

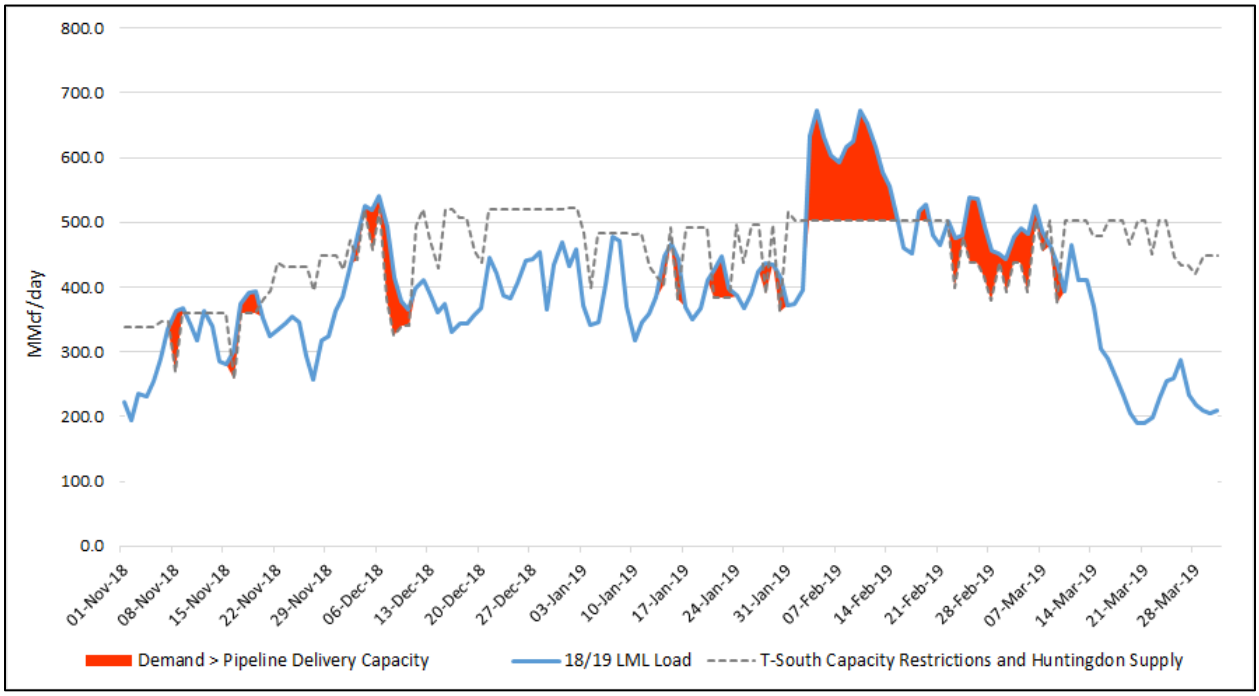
[37] Enbridge Critical Notice (October 18, 2018, 2018) "BC Pipeline Operational Upset – Transmission South Update." Transportation Safety Board Report, section 1.6.1: "Once Westcoast received NEB approval, the NPS 30 L1 pipeline was returned to service on 11 October 2018 at a restricted operating pressure of 80% of its previous 60-day high pressure. On 01 November 2018, repairs were complete: the NPS 36 L2 pipeline was returned to service with a restricted operating pressure of 80% of its previous 60-day high pressure, as approved by the NEB."
On November 16, 2018, the NEB allowed Westcoast to increase the reduced operating pressure from 80% to 85%.

- maximize its utilization of contracted pipeline capacity on the T-South system;
- call for supply from off-system storage at JPS and/or Mist; and
- regasify stored LNG at FEI's on-system LNG facilities.

FEI mitigated some of this risk prior to the 2018/19 winter season by securing 120 TJ/day of Huntingdon supply to replace the lost physical supply that was contracted by FEI to flow on the T-South system. The Huntingdon supply, which FEI was indirectly buying from shippers that had contracted T-South capacity, was the only available short-term option. This additional supply was critical for FEI to handle the load requirements during the 2018/19 winter season.

Figure 3-9 below illustrates FEI's actual winter load requirements (Lower Mainland, Whistler, and Vancouver Island) compared to the combination of T-South capacity available to FEI on a daily basis as well as the additional Huntingdon supply noted above.

Figure 3-9: FEI's T-South Capacity Restrictions vs Mainland Winter Load (Actuals)[38]



In addition to purchasing the Huntingdon supply prior to the winter season, FEI took a conservative approach to handling its off-system storage resources throughout the winter. This was done by refilling the JPS and Mist resources throughout the winter when capacity became available or when the load decreased. The high cost of filling off-system storage during winter would, under normal circumstances, cause FEI to avoid this approach. However, in the uncertain circumstances of the 2018/19 winter, this conservative approach kept FEI's contracted

[38] FEI's T-South capacity includes the 428 MMcf/day of T-South to Huntingdon Delivery Area and 50 MMcf/day of Kingsvale to Huntingdon. The winter load profile does not include the Interior region because it was less severely impacted by the T-South operational constraints, given the availability of supply across FEI's SCP.

inventory levels high, which allowed FEI to have high deliverability when it was required.[39] The value of this approach was affirmed during the record cold weather the region experienced during February and early March of 2019 (see Figure 3-9 above). These periods are represented in Figure 3-9 above by the red shaded portions where the blue line is above the dashed grey line, which was a period of several weeks. FEI required that stored supply to meet load during these periods.[40]

[redacted]

While FEI and the utilities along the I-5 corridor were able to manage through the T-South Incident and its aftermath, the incident resulted in higher gas supply costs for all market participants. As Figure 3-11 below shows, the commodity prices at the Sumas/Huntingdon market in winter 2018/19 were higher compared to the previous winter 2017/18, and volatile, including the highest daily settlement price on record between March 2 and 4, 2019 ($200 per GJ). It is important to note that the T-South Incident was not the only market condition that led to the volatile commodity prices experienced in February and early March. Additional factors that led to these high prices included:

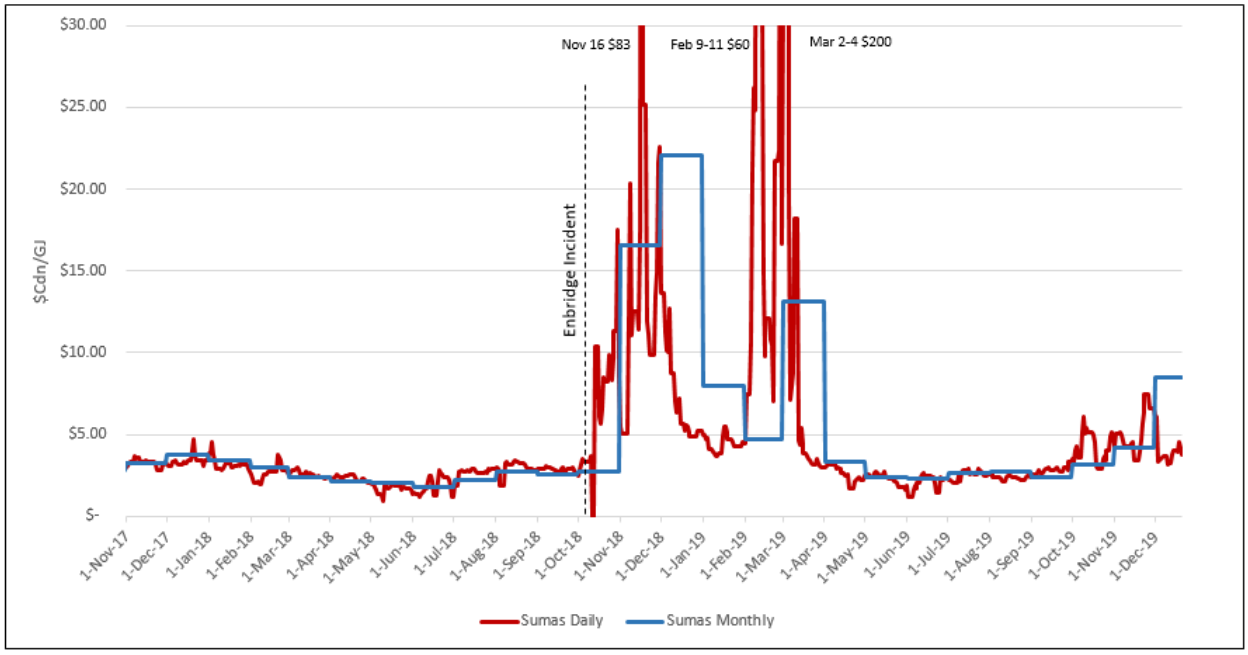
[39] JPS and Mist have withdrawal rates which decline as working gas volumes decline.

[redacted]

- Record cold weather in February in the Lower Mainland and throughout the Pacific Northwest region caused higher than normal heating load requirements;
- Increased demand for electricity in the Pacific Northwest caused competing demand for natural gas supply to generate electricity; and
- A reduction of deliverability from the off-system storage facilities at JPS and Mist due to certain operational issues during this time period.[41]

The Sumas/Huntingdon market price was a key factor in reducing demand at various times during the T-South restrictions, especially during the winter season. The high Sumas/Huntingdon prices resulted in customers, including natural gas power generators along the I-5 corridor, using alternative fuel sources where possible.

Figure 3-11: Sumas Daily and Monthly Settlement Prices



3.4.2.3 The Potential for Supply Interruption on the T-South System Remains

The T-South Incident highlighted that, although supply emergencies are rare, they do occur. [redacted] The T-South Incident supported a re-examination of the resiliency of FEI's system, and the regional system as a whole. FEI's assessment demonstrated that:

[41] The JPS facility experienced a compressor failure which limited the deliverability of natural gas from its facility between February and March, 2019. The Mist facility experienced a loss of compression that resulted in a Force Majeure between March 2, 2019 and March 4, 2019.

- Additional regional pipeline infrastructure, if alternative pipeline routes can be developed, could add resiliency by reducing FEI's reliance on the T-South system;
- FEI should evaluate the potential to construct more on-system storage resources, which is a tool that can be used to prevent impacts to customers in the period immediately following a severe supply constraint or a "no-flow" event; and
- New tools to facilitate load shedding in a controlled and flexible fashion, a benefit associated with AMI, would complement on-system storage to mitigate the impacts of an outage on customers and society.

These options, and others, are assessed in Section 4.

3.4.2.4 The T-South Incident Is Not an Isolated Occurrence

FEI retained PwC to provide information and analysis that would inform future resiliency investment decisions. A copy of the PwC report is attached confidentially as Appendix B. PwC noted that the T-South Incident was not an isolated incident. Although relatively rare, PwC identified three additional incidents of a similar nature to the T-South Incident that have occurred in BC over the past decade. PwC identified an additional five natural gas disruption events which occurred in other Canadian jurisdictions and two in US jurisdictions over the same period. PwC also examined the consequences of a widespread system outage on FEI's customers and society, which is the subject of the next section.

3.4.3 The Consequences of an Outage (Controlled or Otherwise) on FEI's System Would Be Significant

As indicated previously, planning for resiliency involves consideration of the likelihood of occurrence and the potential consequences if the risk materializes. The previous section demonstrated the elevated risk that FEI faces, relative to other utilities in the Pacific Northwest, of significant supply disruptions due to FEI's heavy dependence on a single pipeline system (T-South). This section addresses the consequences of a supply disruption for FEI, customers and society generally. PwC confirmed in its report (Confidential Appendix B) that the consequences of a widespread outage are significant.

An outage can result from hydraulic collapse (uncontrolled) due to the system having insufficient pressure to continue functioning. However, it can also result from deliberate actions taken by FEI to isolate and depressurize certain portions of the system in order to prevent hydraulic collapse on the system as a whole. Load shedding in this controlled manner should be (and is) a last resort option, but it is preferable to an uncontrolled collapse. PwC's report illustrates that, controlled or otherwise, the implications of an outage would be significant.

PwC examined three natural gas disruption scenarios to model the social, environmental and economic impacts of natural gas system disruptions. [redacted]

The summary table from PwC's report is reproduced below:[42]

[redacted]

[redacted] As discussed in Section 3.4.2.2, favourable circumstances assisted FEI in narrowly avoiding this type of incident. However, PwC's analysis highlights the significant consequences of a natural gas supply disruption. Moreover, it highlights the benefits of investing in resiliency.

3.4.4 The 3-Day Criterion Reflects FEI's Actual Experience with the T-South Incident

FEI's Minimum Resiliency Planning Objective incorporates the concept of "*Having the ability to withstand, and recover from, a 3-day "no-flow" event on the T-South system without having to shut down portions of FEI's distribution system or otherwise lose significant firm load"*. FEI's determination that three days is an appropriate minimum planning duration for a "no-flow" emergency event was informed by the experience with the T-South Incident. In particular, FEI considered: the length of the "no-flow" event in 2018; whether or not the T-South Incident occurred in favourable or unfavourable conditions from the perspectives of resuming flows and system demand and supply; and, the time that FEI required to assess the situation and re-establish a balance between supply and demand.

[42] Confidential Appendix B, PwC Report, p. 9.

3.4.4.1 Hindsight: T-South Incident Lasted Two Days with the Benefit of Favourable Conditions

To recap, the initial T-South "no-flow" situation lasted approximately two days. The speed with which Westcoast was able to resume service was a function of very favourable conditions:

[redacted]

In FEI's assessment, the very real potential exists under somewhat less favourable conditions for a "no-flow" supply emergency to last three days, and it could conceivably last longer.

The T-South Incident also occurred in favourable conditions from a demand and alternate supply perspective. As described in Section 3.4.2.2, the rupture occurred during October, not mid-winter when regional demand is at its highest; higher regional load would have depleted supply faster. The rupture occurred far to the north, leaving the maximum potential line pack available, in addition to being relatively accessible. FEI was able to physically access supply through mutual aid agreements because load in Washington and Oregon was sufficiently low that the physical flows could be reversed northwards across the border.

3.4.4.2 Real-Time: There Is a Limited Horizon to Make Critical Decisions in a Supply Emergency

The length of the T-South Incident is known with hindsight, but FEI's system operations decisions are made in real time based on the information available. The speed with which FEI receives information about the nature and duration of the interruption is critical. Any resource that is sufficiently reliable so as to delay initiating a controlled shut-down has significant value from a resiliency perspective.

As indicated in Section 3.4.2.2, in a pipeline supply emergency, FEI must obtain reliable data, perform an assessment, and initiate its response through the following steps:

1. Obtain reliable data and assess the situation to determine the nature of the emergency. Only as reliable information regarding the emergency becomes known will FEI begin to understand the extent of the impact, including which parts of the system may be impacted, the potential duration of the emergency, the impact on supply, etc. This information also helps FEI reconcile the expected impacts versus those that are occurring in real-time on the system.
2. With this critical information, FEI can assess its options to bring supply and demand back into balance. Tools available include the following:
   - Curtailment of customer load;

- Messaging to customers on conservation[43];
- On- and off-system storage resources and line pack;
- Incremental supply from available purchases[44]; and
- Mutual aid arrangements.

3. Where these tools are insufficient to restore the supply-demand balance, FEI would need to begin planning to shut-in parts of the system. Today, this requires technicians to visit valves and gate stations across the system to manually shut off the flow of gas. This measure is irreversible in the short-term as it requires an extensive and time consuming process to restore service to customers on the shut-in segments, as described in Section 3.3.2.

Shutting-in a section of the system is generally the method of last resort for restoring the supply-demand balance. FEI would seek to delay the decision to shut in sections of the system as long as possible. Not only does restoring the system take significant time and effort, but the utility cannot control which customers lose gas as a result of the shut-in. If a shut-in had become necessary during the T-South Incident, customers such as hospitals, care homes, emergency services, etc. would lose gas along with all other customers on a shut-in segment. Buying as much response time as possible maximizes the chance that some or all of the gas flow will be restored or, if necessary, minimize the number of customers whose gas flow is interrupted for a prolonged period by acting on the latest available information.

In the case of the T-South Incident, the favourable conditions outlined above also facilitated the flow of information to FEI about the nature and severity of the supply emergency. As it was, it took almost a day to obtain reliable information. There would have been a more significant delay in receiving information and restoring the flow of gas if, for example, the event occurred during the colder parts of the winter, during inclement weather, or in a less accessible location. In any of these scenarios, FEI would likely have had to shut-in large parts of its system. FEI would need more on-system storage to manage through more adverse scenarios.

3.4.4.3 "Minimum" Means No Margin for Subsequent Supply / Demand Events

FEI's judgment that 3 days should be a *minimum* target is also informed by the fact that it would still leave FEI with little in the way of on-system storage resources to serve winter peaking requirements following partial resumption of pipeline flows. Demand spikes and supply events are not uncommon during the winter. FEI noted previously the importance of on-system storage during the cold weather the region experienced during February and early March following the T-South Incident.

These considerations play a part in determining the Project facilities, which is addressed in Section 4.

[43] Message to customers on October 9, 2018 as an example. https://www.fortisbc.com/news-events/media-centre/bc-s-natural-gas-supply-may-be-limited-this-winter-reducing-your-use-will-help

[44] Commercial activities were halted in the T-South Incident and may not be available.

3.4.5 The Objective Recognizes That Load Shedding Is a Resiliency Tool, but Excessive Load Loss Is Undesirable

FEI's Minimum Resiliency Planning Objective incorporates the concept of "*Having the ability to withstand, and recover from, a 3-day "no-flow" event on the T-South system without having to shut down portions of FEI's distribution system or otherwise lose significant firm load*".

The Minimum Resiliency Planning Objective is framed in recognition of the fact (described in Section 3.3) that the capability to manage load – controlled load shedding – is an important element of a resilient system. FEI has peaking agreements with some customers that allow for interruption of load during periods of constrained capacity, and some load is interruptible. These customers have made an economic decision that periodic interruption is worth the lower cost service. Beyond interruptible customers, FEI's capabilities to engage in load management will improve with the AMI project, which is in its planning stages.

However, planning for broader load shedding as a means of improving resiliency inherently means planning to disrupt service to segments of customers who want a consistent gas supply. Resiliency solutions that aim to preserve continuity of service for those customers who want firm supply (e.g., on-system storage or pipeline redundancy) are, other things being equal, preferable to customer disruptions. This is particularly true when load management decisions are irreversible in the short-term. Once a segment of the system is shut-in and depressurized, it can take weeks to resume service. The PwC Report describes the types of impacts that can occur when gas supply is interrupted, and quantifies the implications of broader outages.

3.4.6 FEI's Approach to Resiliency Planning Is Aligned with Guidehouse's Considerations and Industry Examples

As outlined in Section 4.3 of the Guidehouse Report, there is no single industry standard approach to determining resiliency requirements. Guidehouse suggests this is for two primary reasons:[45]

- Access to Existing Infrastructure: Gas supply redundancy varies across different natural gas utilities and is a function of access, both physical and contractual, to existing pipeline and underground storage infrastructure.
- Demand Profile: Design day and peak load requirements are a function of a natural gas utility's customer count, profile and seasonality of demand.

However, in Section 4.2 of its Report, Guidehouse provides a framework for determining resiliency requirements, with which FEI's approach is consistent. Guidehouse's framework is based on the following defining factors:[46]

[45] Appendix A, page 49.
[46] Appendix A, pages 47-49.

- **<u>Preparation</u>:** ***The ability to prepare for and prevent initial system disruption.***
  - The anticipated time required to conduct a planned shutdown, i.e., an orderly curtailment of customers to reduce the amount of work and time required to restore service.

On this factor, Guidehouse noted that "[i]n the event of an unforeseen supply interruption, it will take several hours to discern the location and magnitude of the disruption" and that "[a]dditional time is required to plan and execute an appropriate curtailment response to prevent a system collapse".

- **<u>Withstanding</u>:** ***The ability to withstand, mitigate, and manage system disruption***.
  - The amount of load on the system at the time of disruption.
  - The amount of load needed to be retained in the event of a supply disruption in order to prevent a collapse of the system, i.e., hydraulic failure.

Discussing the "withstanding" consideration in the context of natural gas storage, Guidehouse stated:

> The minimum size should also be correlated to the estimated amount of time FEI would require emergency back-up supply in the event of a significant upstream supply disruption, and the relative access to other equivalent options to manage the system. It should also factor in the anticipated time to restore supply.
>
> FEI estimates that the most probable duration of total gas delivery outage in the LML is at least three days. FEI arrived at this estimate by evaluating the October 2018 Enbridge outage duration and response, weather, terrain variability factors, and time required for FEI operational teams to manage a controlled curtailment. The amount of load on the system and the time of year of the disruption are also key considerations when determining the minimum size of the tank, as these will impact how much gas is needed, and how much flexibility FEI has to refill the tank. FEI developed its recommendations for the storage size and regasification requirements through consideration of the estimated design peak for 2019/2020. 600 MMcfd would serve [redacted] This analysis indicates that approximately 800 MMcf/day of would be able to support about [redacted] of the system load during a no-flow scenario to the LML at the design peak of 2019/2020. In addition, this solution would also serve approximately 100% of the customers under the 2019/2020 normal winter load scenario.

- **Recovery**: ***The ability to quickly recover normal operations and repair system damage.***
  - The time of year, i.e., a disruption in the beginning of winter may exhaust the stored gas, requiring time to refill and limits the ability to respond to subsequent disruptions. A disruption in the summer will have a different impact.
  - The anticipated time, level of effort and expense required to restore a supply disruption.

  With respect to recovery, Guidehouse emphasized that a supply disruption "can require significant work to restore service", including initial shutoffs, work to repair damage, and customer appliance relights, for which "a general rule of thumb used in the gas industry is that one trained service technician can relight up to four residential customers per hour".

  Guidehouse also listed the following key factors that influence recovery time and cost:

  1. Extent of hydraulic collapse.
  2. Ability of the utility to mobilize its workforce to execute the emergency response plan (availability of personnel with proper safety and procedure training and vehicle access).
  3. Ability to execute on mutual aid agreements with adjacent utilities to secure additional resources.
  4. Travel distance between customers.
  5. Ability to access the customer premise.

The Guidehouse Report also identifies industry examples where utilities have used similar approaches to FEI in determining resiliency objectives. In particular, these utilities assessed on-system storage as a tool for building resiliency with reference to duration and load and the potential consequences of an outage.

- New Jersey Natural Gas identified an objective of meeting customer load for a period of 5.88 days by adding new liquefaction to existing on-system storage:[47]

  NJNG completed a Liquefaction Project in 2016 that allowed the company to convert natural gas to LNG and store the LNG at the company's existing tanks in Howell and Stafford, New Jersey. The project cost $36.5 million and was approved for rate recovery in 2016.[48] The two LNG plants have an aggregate estimated maximum deliverability of approximately 170 MMcf/day and 1 Bcf of total storage. [Approximately 5.88 days]

  In 2019, NJNG applied to reconfigure its LNG assets to connect the Howell LNG facility directly to its natural gas transmission system. The stated intention of this project was to enhance system reliability and improve the Howell LNG facility's ability to provide peak-

[47] Appendix A, page 27.
[48] http://investor.njresources.com/static-files/14a4896d-872a-45b1-9899-9d676093172a

shaving supply and pressure support during periods of high natural gas demand, curtailments of pipelines or downtime due to maintenance and inspection.[49]

- Dominion Energy identified an objective of meeting customer load for a period of 8 days having regard to historical load data and consideration of the potential consequences of an adverse event:[50]

  As summarized in Section 1.8, Dominion Energy Utah gained approval from the utility commission for an LNG facility for reliability purposes. Dominion used historical weather and supply limitation analysis to show that shortfalls of 100 million cubic feet (MMcf) were possible in the company's service territory. After determining that demand is expected to grow in the region, Dominion concluded that 150 MMcf for **eight days** of services (totalling 1.2 Bcf square feet [*sic*] of supply) was required for this facility.

  Dominion's project was also supported by several economic analyses, including one carried out by a third party, the Kem C. Gardner Policy Institute. The study analysed the impact of severe a natural gas system outage due to cold weather, under high and low scenarios. The study expects such an event would result in approximately 390,000 to 650,000 natural gas customers in Dominion's Utah service territory without power, some up to a period of 28 days. The overall impact to gross state product ranges from $1.45 billion to $2.38 billion in the low and high scenario respectively.[51] Dominion's own analysis shows that restoring service to 650,000 customers would cost the utility between $10.45 million and $104.60 million. [Emphasis added.]

3.5 FEI CANNOT CURRENTLY MEET THE MINIMUM RESILIENCY PLANNING OBJECTIVE

While waiting for reliable information and a situation assessment following an event on a regional pipeline (it took 24 hours in the case of the T-South Incident), FEI must prepare to implement the limited tools available to help bridge a "no-flow" event. In this section, FEI describes the tools currently available to FEI to help bridge a "no-flow" event, the time they take to implement, and the extent to which they provide support. The information demonstrates that FEI is currently only capable of bridging a 3-day "no-flow" supply emergency in the most favourable summer conditions.

3.5.1 Overview of FEI's Existing Response Tools and the Time They Take to Implement

Each tool or resource available to FEI requires varying levels of preparation and time to implement. They are listed below in order of how quickly they can be available for use (fastest to slowest):

[49] https://www.njng.com/regulatory/pdf/NJNG%20IIP%20Petition.pdf
[50] Appendix A, page 50.
[51] https://pscdocs.utah.gov/gas/19docs/1905713/308019DEUEx4.04%e2%80%934-30-2019.pdf

- **Curtailment of Customer Load:** The curtailment of customer load is typically the first measure implemented following an emergency event. In order to curtail customers, FEI must contact each customer and request that they curtail gas use. The customers must then begin the process of transferring to an alternate energy source or shutting down. Depending on the nature of the customer's business, the time of day that the request is made, and the expediency of their compliance, it may take some customers several hours to fully curtail.
- **Messaging to Customers on Conservation:** In addition to curtailment of customers, FEI would also be issuing communication to customers to reduce their use of natural gas to help stabilize and prolong system life during an emergency event. The response time could vary, e.g., during the night people are less likely to be on social media or watching television.
- **On- and Off-System Storage Resources:** Once FEI anticipates the need to use on-system storage resources at Mt. Hayes or Tilbury, it must begin the process of cooling the plant piping systems in preparation for regasification and send out. This process takes a few hours. In addition, FEI may not be able to rely on line pack and off-system storage assets during a supply emergency.
- **Incremental Supply from Available Purchases:** Depending on the nature of the emergency, there may not be any available resources for purchase as was the case during the "no-flow" phase of the T-South Incident. However, where commercial operations are not interrupted, FEI can begin contacting its suppliers and other gas users to determine if alternate supplies of gas are available. Depending on the circumstances and if available, it may take hours or days for FEI to secure additional gas for its customers.
- **Mutual Aid Arrangements:** Mutual aid requires the cooperation and collaboration of industry participants. This requires scheduling of emergency meetings, discussion of potential strategies, internal approval within each organization and a coordinated implementation. Initial actions, such as curtailment in neighbouring jurisdictions, may be implemented within hours while more complex forms of mutual aid may take a day or more.

The above timelines exemplify the need for FEI to act quickly in preparing its response following an emergency event. Curtailment and the use of on-system storage resources are valuable tools that can be enacted relatively quickly.

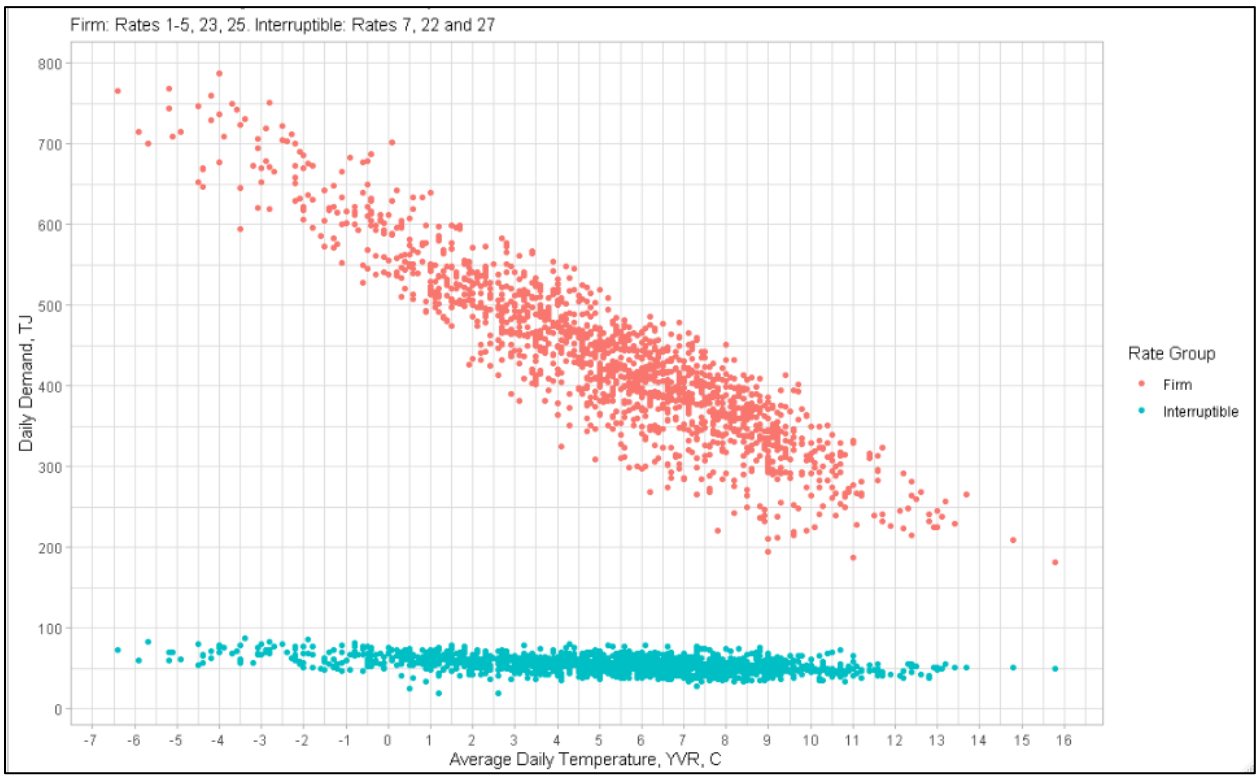
In the following sections, FEI will examine each of its tools in detail to demonstrate that its current capability is limited to withstanding a 3-day outage in only the most favourable summer conditions. FEI has excluded available purchases from this analysis because they are unlikely to be available during the "no-flow" portion of an incident.

3.5.2 Curtailment of Interruptible Customer Load Provides Limited Support in a Supply Emergency

During the T-South Incident, FEI curtailed its interruptible loads. This is an important step to conserve gas. However, based on FEI's customer composition there is insufficient interruptible load for this step to support the system on a sustained basis.

The following chart plots 10 years of winter (November through March) daily demand data for both the firm and interruptible rate schedules in the Lower Mainland versus average daily temperatures recorded at Vancouver International Airport (YVR). It shows that the amount of interruptible demand is proportionally small on colder days relative to the firm load or total load. For example, the interruptible volumes represent only approximately 10 to 15 percent of FEI's load when the temperature is below minus 5 degrees Celsius. Therefore, on these colder days, curtailing interruptible load will not provide a sustained solution to FEI's system given the magnitude of the firm load. The only practical solution to manage a supply emergency on colder days without significant curtailments of firm service is to have a resource such as on-system storage, which can be called upon to send out supply in a timely manner.

Figure 3-12: Weather Sensitivity of Firm and Interruptible Lower Mainland Loads



Guidehouse, in the context of a general discussion regarding load management, alludes to this potential challenge of relying on curtailment of interruptible load as a solution in a supply emergency:[52]

> … The utility may make voluntary arrangements with certain customers who have the ability to either curtail their consumption and/or switch to an alternative fuel (e.g., switch to oil) and calls on these customers to curtail usage. <u>One drawback to this is that the utility may not have enough non-firm customers to make a meaningful impact on demand when voluntarily curtailed.</u> In addition, it may take a significant amount of time to get interruptible customers to reduce their usage. [Emphasis added.]

3.5.3 Impact of Public Appeals for Conservation Is Inherently Limited

During the T-South Incident, FEI made public appeals, starting on the evening of October 9, 2018, for customers to limit their natural gas use to the greatest extent possible.[53] FEI's public messaging included suggestions to reduce thermostat set points and minimize other non-essential uses of gas. As discussed below, customer response to public appeals positively contributed to the conservation of gas during the 2018 "no-flow" event and subsequent periods of constrained gas supply; however, there are inherent limitations on FEI's ability to rely on such appeals.

FEI has estimated that natural gas use reduced by approximately 39 MMcf/day (approximately 20 percent of expected load of 193 MMcf/day) on October 10, 2018 for customers in Rate Schedules 1 through 7 within the Lower Mainland. FEI estimated the reduction by comparing the actual natural gas consumption for October 10, 2018 to the forecast natural gas consumption for a day when the temperature was 11 degrees Celsius, which was the observed temperature on October 10, 2018. Quantifying the portion of the reduction that is related to public messaging alone is not possible; customer natural gas use can vary for many reasons, particularly during this time of year. For example, actual versus predicted gas use for an 11 degrees Celsius day can vary by as much as 20 percent due to other factors such as cloud cover and sunshine.

Customer demand is highly weather dependent. The majority of the energy used for space heating and hot water is vital to the health and safety of customers. The non-discretionary nature of this load imposes inherent limitations on the extent to which load can be managed during a supply emergency. It is reasonable to expect that the customer response to public appeals for conservation would have been materially reduced had the event occurred during cold winter weather.

[52] Appendix A, page 16.

[53] E.g., "Until the situation is resolved, we are asking all our customers to continue avoiding non-essential use of natural gas."

3.5.4 Existing on- and off-System Storage Cannot Meet the Minimum Resiliency Planning Objective

The following describes why FEI's Minimum Resiliency Planning Objective cannot be met with existing on- and off-system storage assets, including supply from the Tilbury and Mt. Hayes LNG facilities, line pack, and off-system storage at JPS and Mist. Each of these are described in detail below.

3.5.4.1 The Tilbury Facility Can Only Support a Portion of the Lower Mainland Load in a Supply Emergency

The Tilbury facility's ability to support the FEI system load in a supply emergency is constrained by the current regasification and storage capacity. The resiliency of the system can thus be improved by expanding the regasification capacity and storage at Tilbury.

3.5.4.1.1 LIQUEFACTION, STORAGE AND REGASIFICATION ALL DETERMINE AVAILABILITY OF LNG AS A SUPPLY RESOURCE

The ability of an LNG facility to provide emergency supply and capacity (and also peaking supply, LNG supply, and operations support/flexibility) is a function of three components of an LNG facility: liquefaction, storage and regasification. The role of each of these three components in providing FEI with access to on-system LNG can be conceptualized as follows:

- **Liquefaction capacity determines how fast a storage tank can be refilled:** Liquefaction capacity, measured in MMcf/day, is the rate at which natural gas can be liquefied for storage. Typically, utilities liquefy natural gas in periods of low demand (e.g., summer, when heating loads are reduced).
- **Storage capacity determines how long that portion of daily load can be served:** Storage capacity, commonly measured in Bcf, is best conceptualized as dictating the duration, or number of days, that FEI can continue to support some or all of the daily load.
- **Regasification capacity determines percentage of daily load served**: Regasification capacity, measured in MMcf/day, determines the rate at which the LNG in the tank can be converted back into a gas, and thus determines the extent to which LNG storage can serve daily requirements.

Note that storage capacity and regasification capacity are interlinked: a higher rate of regasification necessary to support a more significant percentage of the daily requirements means that more storage is required to provide the necessary supply of LNG.

The liquefaction capacity at Tilbury has recently been expanded, primarily to serve LNG sales (e.g., RS 46 customers); however, a portion has been designated to provide peaking supply and resiliency.

3.5.4.1.2 TILBURY BASE PLANT AND TILBURY 1A SERVE DIFFERENT FUNCTIONS

The Tilbury facility has been operating for 50 years with an excellent safety and reliability record. The facility today consists of:

- the original Base Plant designed and built between 1969 and 1971; and
- the recent addition of liquefaction and storage referred to as Tilbury 1A.[54]

As discussed below, these two components were designed to serve distinct functions.

The original Tilbury **Base Plant** was built and sized to support peak demand. Thus, its purpose was to ensure that adequate natural gas supply was available to provide service to FEI customers on the coldest days, managing the very short durations when demand during cold weather events exceeded contracted supply. Because Tilbury is located on-system, it also provides benefits related to security of supply, reliability and flexibility to serve loads within FEI's system. Although it was not designed to provide supply in the event of a gas supply disruption to the Lower Mainland, it did fulfill that function during the latter phases of the T-South Incident.

The **Tilbury 1A facilities** were built pursuant to an Order in Council (OIC)[55] to support LNG sales and came into service in 2019. They consist of a new liquefaction plant with a capacity of 33 MMcf/day of LNG and 1 Bcf of storage capacity, with new LNG truck loading facilities. The commercial operation of the Tilbury 1A facilities effectively separated LNG sales under RS 46 from the Base Plant, allowing both facilities to serve their distinct purposes.

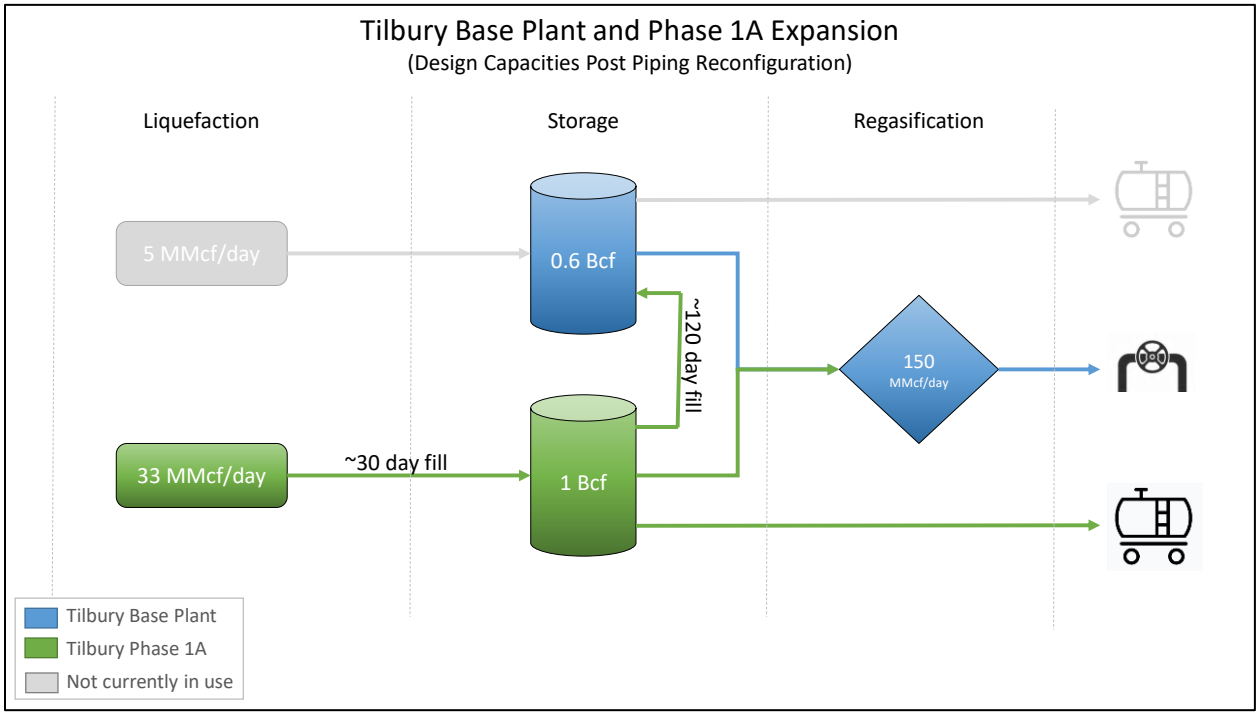
Although the Tilbury 1A facilities are intended to serve LNG customers, FEI has recently constructed an interconnecting line between the Tilbury 1A tank and the Base Plant tank in recognition of the age of the Base Plant facilities and the increased potential for equipment reliability issues. The Base Plant liquefaction equipment reliability has been declining due to equipment condition and it is preferable to utilize 5 MMcf/day of liquefaction from the new Tilbury 1A liquefaction unit to fill the Base Plant tank. This interconnecting line also allows FEI to regasify LNG from either the Base Plant tank or the Tilbury 1A tank in the event that there is an equipment failure or issue with the Base Plant equipment.

The figure below provides a simplified description of the current components and configuration of the Tilbury LNG facilities.

[54] Tilbury 1A is also referred to as "Tilbury Expansion" in FEI's Annual Reviews; we have used Tilbury 1A to distinguish it from this Project.

[55] Order in Council (OIC) No. 557/2013 Direction No. 5 to the BCUC. Direction No. 5 also required the BCUC to approve a new Rate Schedule for the sale of LNG (RS 46).

Figure 3-13: Tilbury Base Plant and Tilbury 1A Facilities[56] – Current Configuration (2020)



Although the design capacity of the Base Plant tank is 0.6 Bcf as shown in Figure 3-13 above, FEI is currently operating the tank at a reduced capacity while it assesses the future operability of the tank.[57] In the interim, FEI will temporarily utilize a portion of the capacity of the Tilbury 1A tank to replace the reduction in the Base Plant tank storage.[58] FEI's interim operating strategy, relying in part on the Tilbury 1A facilities, has several advantages, including increased equipment reliability, decreased time to replenish LNG inventory, and improved environmental performance.

The following table summarizes the design capability of the Tilbury LNG facility today:

Table 3-2: Summary of Tilbury LNG Facility Design Capabilities

Plant	Liquefaction	Storage	Regasification	LM Peak Design Load
Base Plant	5 MMcf/day 120 days to fill	0.6 Bcf 0.69 days reserve	150 MMcf/day	871 MMcf/day
Tilbury 1A	28 MMcf/day 36 days to fill	1.0 Bcf Storage reserve to support RS 46 sales only	Zero	N/A - Facility designed to support RS 46 sales only

[56] Note that in this figure "Tilbury 1A" is referred to as "Phase 1A".
[57] At 50 years old, the Base Plant tank is nearing the end of its useful life.
[58] Capacity in the Tilbury 1A tank is temporarily available until further expansion of Tilbury 1A facilities is complete (per OIC No. 557/2013 Direction No. 5 to the BCUC) and volumes are sold out.

3.5.4.1.3 TILBURY FACILITY PROVIDES LIMITED RESILIENCY FROM A PLANNING PERSPECTIVE

The regasification capacity and storage at Tilbury are currently limiting the extent to which the Tilbury facility provides resiliency from a planning perspective.

3.5.4.1.4 TILBURY 1A FACILITIES ARE REQUIRED TO SERVE LNG SALES CUSTOMERS

While the LNG in the Tilbury 1A tank may be used during an emergency to avoid widespread outages, FEI cannot plan on the availability of LNG in the Tilbury 1A tank (leaving aside its interim operating strategy noted above) during the normal course of business. Inventory levels in the Tilbury 1A tank are expected to fluctuate with the needs of the LNG sales customers; therefore, Tilbury 1A facilities cannot be relied upon from a planning perspective to meet FEI's resiliency objectives.

3.5.4.1.5 REGASIFICATION IS INSUFFICIENT TO SUPPORT LOWER MAINLAND LOAD ON MOST DAYS OF THE YEAR

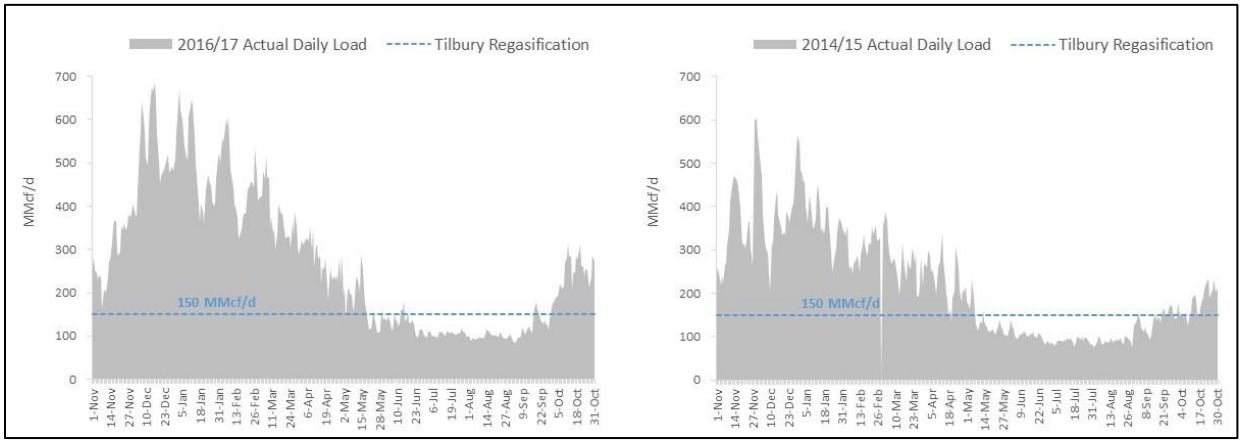
The regasification capacity at Tilbury (150 MMcf/day) would provide only 17 percent of gas required to meet the Lower Mainland design day load (871 MMcf/day). It is insufficient to support the daily Lower Mainland load on most days of the year, with the greatest shortfall occurring during the winter months. In the event of a "no-flow" event on the pipelines feeding FEI's Lower Mainland system (i.e., where on-system LNG is the only supply resource available) occurring during months where load exceeds Tilbury's regasification capacity, most of the system load would have to be shed in very short order to maintain adequate pressure on the system to avoid hydraulic collapse.

Figure 3-14 shows the extent of the shortfall in Tilbury regasification capacity relative to actual Lower Mainland load in 2016/17 (left side) and 2014/15 (right side). The 2016/17 year was the coldest winter season in the last 10 years; it was very close to FEI's winter design curve for the Lower Mainland Service area. The 2014/15 year was the warmest winter season in the last 10 years. [redacted]

[redacted]

[redacted]

Figure 3-14: Tilbury Regasification Capacity Relative to Lower Mainland Load



Expanding the regasification capacity at Tilbury will accomplish two things from a resiliency standpoint:

1. It will increase the number of days during the year when the entire Lower Mainland daily load can be met by on-system supply; and
2. On the other remaining days, it will reduce the extent to which and/or pace at which FEI must shed load in the event of a supply emergency.

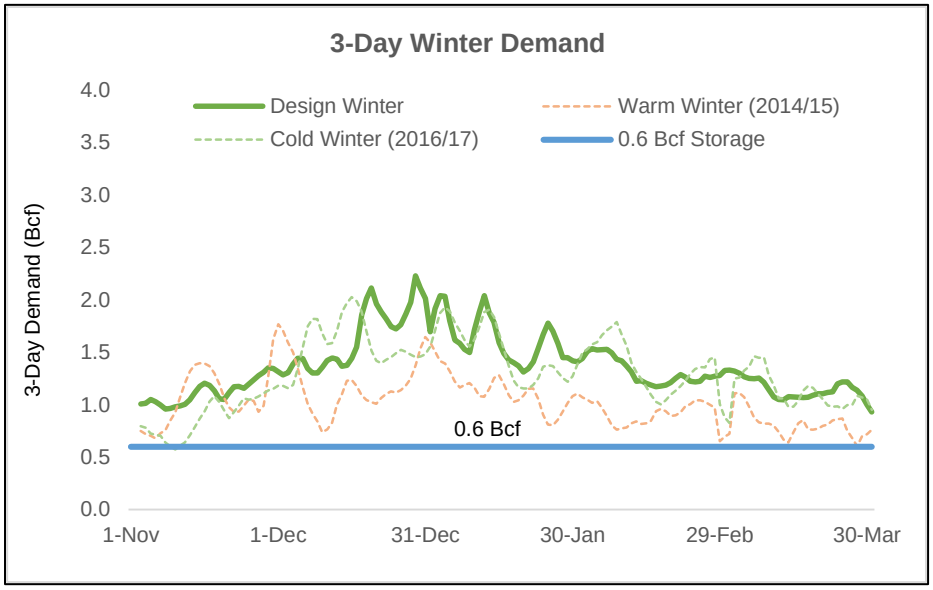
Note that the storage tank capacity needs to be considered in tandem with expanded regasification, since a higher rate of regasification will empty a tank faster. As an illustration, if the regasification constraint was removed without addressing the size of the tank, then the 0.6 Bcf Base Plant tank would [redacted] of resiliency support during peak winter load conditions.

3.5.4.1.6 STORAGE CAPACITY WOULD BE CONSUMED VERY QUICKLY

From a planning perspective, only the storage associated with the Base Plant tank (0.6 Bcf) is considered to provide resiliency. The Tilbury 1A tank (1.0 Bcf) was built to support RS 46 sales from Tilbury 1A, and is earmarked for that purpose when FEI plans the system. Although the new configuration of the Tilbury site provides some emergency access to storage as well as alternate liquefaction capacity, from a planning perspective the Tilbury 1A storage capacity is dedicated to supporting RS 46 sales when liquefaction equipment is periodically out of service for maintenance.

The following figure depicts when, and the extent to which, the current storage facilities are sufficient to bridge significant pipeline supply interruptions. The figure depicts the portions of a 151-day winter period when the current 0.6 Bcf tank at Tilbury could, and could not, bridge a 3-day “no-flow” supply emergency. This analysis assumes that the existing regasification constraint has been removed.

Figure 3-15: Cumulative 3-Day Lower Mainland Load



The figure presents the Lower Mainland rolling 3-day winter loads, not only for a design winter (solid green line), but also data from the warmest (orange dashed line 2014/15) and coldest (green dashed line 2016/17) winters in the last 10 years. A shortfall exists during any times where the winter load lines are above the horizontal blue 0.6 Bcf line, which represents the amount of load that Tilbury can serve during the 3-day period if it was completely full to start with.

The figure demonstrates that a 0.6 Bcf tank would have been insufficient to meet customer demand over a 3-day interruption throughout the entire winter, even in the warmest winter of the past decade.

In summary, increasing the regasification capacity as part of the Project will allow FEI to serve a greater portion of the daily Lower Mainland load and reduce or (at certain warmer times of the year) eliminate the need to shed load immediately. The storage tank capacity needs to be increased in tandem, otherwise the higher regasification capacity would empty the tank very quickly.

3.5.4.2 The Mt. Hayes LNG Facility Provides Significant Resiliency for Vancouver Island but Limited Resiliency for the Lower Mainland

The Mt. Hayes LNG facility is located near Ladysmith on Vancouver Island (see Figure 3-16 below). It consists of a 1.5 Bcf storage tank and ancillary facilities, including liquefaction and regasification components. As explained below, the Mt. Hayes LNG facility provides significant resiliency for Vancouver Island but cannot be relied on to adequately support the Lower Mainland in a supply emergency occurring during the winter months.

The Mt. Hayes LNG facility design capacities are summarized as follows:[59]

Table 3-3: Summary of Mt. Hayes LNG Facility Design Capabilities

Plant	Liquefaction	Storage	Regasification[60]	VI Peak Design Load
Mt. Hayes	8 MMcf/day 200 days to fill	1.5 Bcf 10 days reserve	150 MMcf/day 100% of VI daily design load	150 MMcf/day

The Mt. Hayes LNG facility was constructed to provide new storage capacity in the Vancouver Island region, to alleviate supply and infrastructure capacity constraints, and to improve system reliability. The Mt. Hayes LNG facility was first proposed in FortisBC (Vancouver Island) Inc.'s[61] 2004 Resource Plan as the preferred option to meet growing gas demand on Vancouver Island. The 2004 proposal included a 1.0 Bcf storage tank based on meeting system capacity requirements. The 2007 CPCN application increased the proposed size of the storage tank to 1.5 Bcf for a number of reasons, including:

- The availability of an on-system resource would reduce the dependence on other off-system storage or pipeline capacity resources; and
- The economies of scale that could be realized by constructing the larger tank would allow FEI to offer competitive on-system storage services and reduce the cost impact to its customers.

The BCUC granted a CPCN based on the revised sizing in 2007.[62]

Figure 3-16 below shows the location of the Mt. Hayes facility on FEI's system.

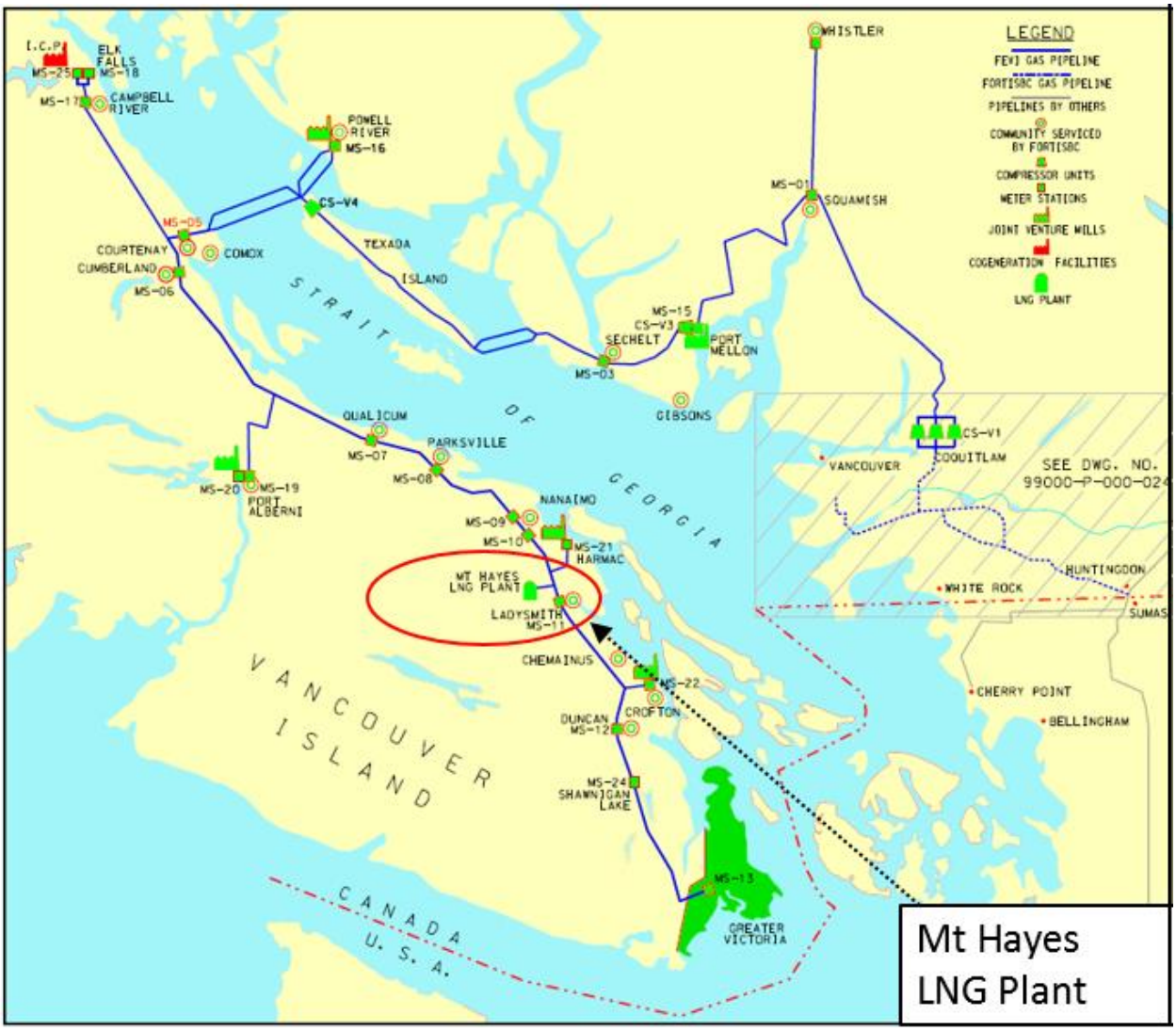
[59] TGVI Mt. Hayes LNG CPCN.

[60] The regasification capacity is the amount of supply that can be sent out from the facility into FEI transmission system over a 24-hour period at maximum rates.

[61] At that time known as Terasen Gas (Vancouver Island) Inc. The company has been amalgamated as part of FortisBC Energy Inc.

[62] Order C-9-07. The Mt. Hayes facility is now owned by Mt. Hayes Limited Partnership (a "sister" entity, also regulated by the BCUC), but is fully integrated into the FEI system and operated by FEI.

Figure 3-16: Vancouver Island Transmission System



The Mt. Hayes LNG facility is well positioned on the Vancouver Island Transmission System (VITS) to provide peaking supply, gas supply support and to supplement VITS capacity shortfalls in winter load periods. As shown in Table 3-3 above, the Mt. Hayes LNG facility can regasify sufficient LNG to support 100 percent of the peak demand of firm customers on Vancouver Island for a period of 10 days. Therefore, the Mt. Hayes LNG facility addresses the Vancouver Island system's resiliency requirements in terms of being able to bridge a short-duration "no-flow" pipeline supply emergency.

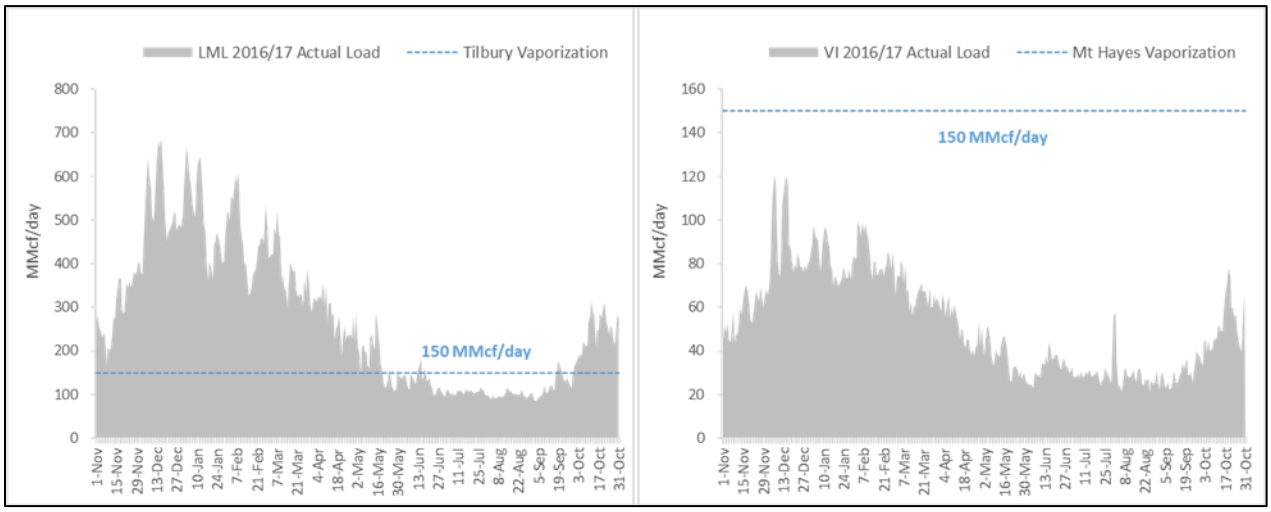
However, the location of the Mt. Hayes LNG facility on FEI's system constrains the extent to which it can support load in the Lower Mainland. During the low demand months of the year where the Mt. Hayes LNG facility is not required to meet VITS firm system requirements, it can

move some gas onto the CTS. During winter months when system demand increases, the Mt. Hayes LNG facility is not able to support CTS requirements.[63]

3.5.4.2.1 DIFFERENCES IN CAPABILITIES OF TILBURY AND MT. HAYES MEANS THERE ARE DIFFERENT LEVELS OF RESILIENCY IN LOWER MAINLAND AND VANCOUVER ISLAND

The Tilbury and Mt. Hayes LNG facilities have the same regasification capacity of 150 MMcf/day; however, each LNG facility serves significantly different loads. Figure 3-17 below shows the existing regasification capacity for the Tilbury and Mt. Hayes LNG facilities relative to their 2016/17[64] actual loads. The figure shows how the Mt. Hayes LNG facility can provide 100 percent of the daily load on the VITS at any time of the year, [redacted]

Figure 3-17: Tilbury vs Mt Hayes: Regasification Capacity Relative to Actual Local Load



Even if the Tilbury regasification constraint was removed, the Base Plant tank at its original capacity of 0.6 Bcf would [redacted] of resiliency support to the Lower Mainland during peak demand periods.

3.5.4.3 FEI Cannot Rely on Off-system Storage and Line Pack When Planning for Supply Emergencies

Off-system storage and line pack also have value as resources, but can be of limited assistance when pipeline flows are disrupted in an emergency. For this reason, FEI is cautious about relying on significant volumes from these sources when planning for resiliency.

[63] The Mt. Hayes LNG facility was able to provide some support during the period following the T-South Incident due to the mild temperature conditions that kept load on Vancouver Island relatively low.

[64] FEI notes that it has shown the 2016/17 year as that was the coldest winter season that FEI experienced in the last 10 years and also the 2016/17 winter season was very close to FEI's winter design curve for the Lower Mainland Service area.

3.5.4.3.1 ACCESS TO JPS AND MIST DEPENDS ON GAS PHYSICALLY FLOWING ON T-SOUTH

FEI maintains off-system storage contracts with JPS and Mist. These underground storage facilities are located near load centres in Washington and Oregon and far from FEI's service area (see Figure 3-18). They are not connected to FEI's CTS and as such are only available to support gas supply requirements during normal operations via displacement, a process which will be described in the paragraphs that follow. The important point is that commercial arrangements involving displacement require gas to be physically flowing on the T-South system, which (as was the case in the T-South Incident) may not be possible in an emergency scenario.

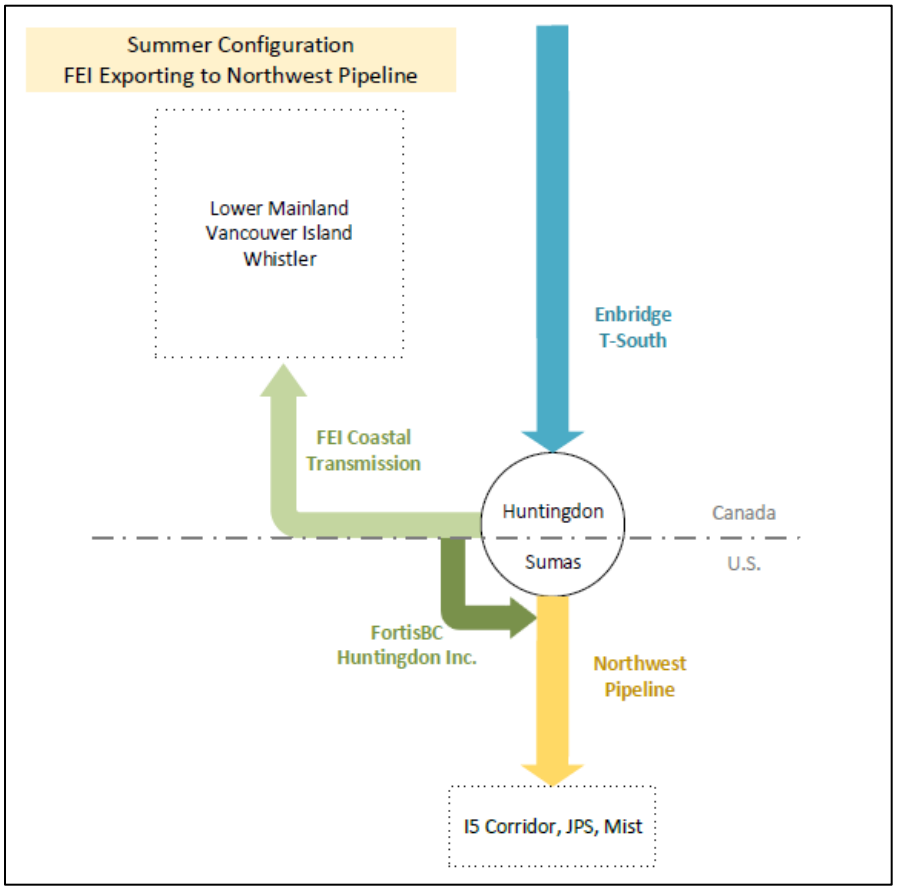
Figure 3-18: Regional Storage and Gas Infrastructure Map

The T-South system terminates at the Enbridge Huntingdon Station located on the Canada-US border (near Sumas). At Huntingdon, gas transported on the T-South system is delivered to both FEI's CTS in Canada and to US shippers at the Sumas Hub in Washington State.

Storage Injection to JPS and Mist: FEI's contracted supply may exceed its Lower Mainland customer load during various times through the year. Excess supply is transported into the

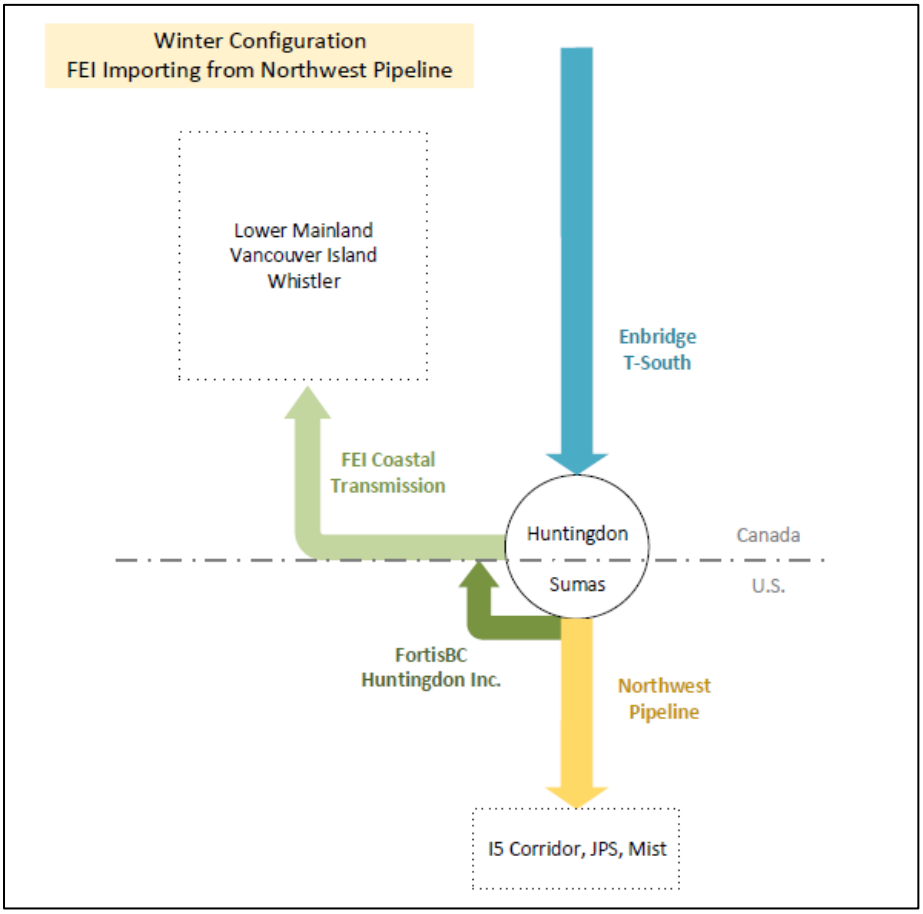
Northwest Pipeline (NWP) at Sumas. The gas may move directly to the NWP pipeline from the T-South system or may move through an FEI affiliate (FortisBC Huntingdon Inc.) to the border. From Sumas, the exported gas is physically transported to the Mist and JPS storage facilities via the NWP system. See Figure 3-19 below.

Figure 3-19: Summer Configuration of Gas Flows at Huntingdon for Storage Injection



Storage Withdrawal from JPS and Mist: At times, primarily during the winter, customer loads in the Lower Mainland often exceed FEI's contracted supply on the T-South system, creating a supply shortfall. The quantity of this supply shortfall (or, more specifically, that portion of the shortfall not covered by the Tilbury and Mt. Hayes LNG facilities) is delivered to FEI from NWP via a process known as "displacement". First, a portion of T-South gas supply exported to Sumas for US shippers is physically redirected back to Canada utilizing the import assets of FEI's affiliate, FortisBC Huntingdon Inc. Second, the gas supply redirected to FEI from the Sumas Hub is replaced with physical gas withdrawals from the JPS and Mist underground storage facilities that are used to meet the demand in Washington and Oregon. See Figure 3-20 below.

Figure 3-20: Winter Configuration of Gas Flows at Huntingdon for Storage Withdrawal



It is important to note that this displacement process is dependent on physical gas flow on T-South to Huntingdon and to the Sumas hub. As Guidehouse states: "…from the perspective of resiliency, the inherent value of a natural gas supply contract to provide commodity in the event of a system disruption rests upon the functionality of the delivery asset."[65] An interruption on T-South, in effect, negates the resiliency value of contracts for supply that rely on displacement.

Following the T-South Incident, in the October 9 to October 12 timeframe, there was no gas flowing on T-South that could be obtained contractually by displacement. Gas from JPS was only made available to FEI due to the level of cooperation exhibited by mutual aid partners and due to low demand in the region. The low demand in Washington and Oregon, which was assisted by mild weather and the utilities there curtailing significant loads, meant that the regional system pressure allowed for gas to physically flow northwards into BC for use by FEI.

Depending on the nature and timing of the supply disruption or emergency event, FEI cannot rely on the ability to access JPS or Mist storage supply assets. For example, these supply assets would not have been physically available to FEI during the T-South Incident if it had occurred during colder weather leading to higher demand in the I-5 corridor. The additional

[65] Appendix A, page 18.

demand in the I-5 corridor due to colder temperatures would exceed supply into the region, thereby preventing any gas from physically flowing northward.

Guidehouse emphasizes the importance of storage as a resiliency resource, while also pointing out the limitations on relying on off-system storage that requires pipeline resources to transport gas to the utility's service area. For instance:[66]

> From the perspective of resiliency, natural gas storage not only provides a supply buffer but also provides a utility vital time to respond to unplanned supply constraints in the pipeline and distribution network. As result, utilities may be afforded sufficient time to avoid an uncontrolled shutdown.
>
> …
>
> Off-system natural gas storage is dependent on the transmission system for delivery to the natural gas system and provides less resiliency to an LDC than on-system storage.

3.5.4.3.2 ACCESS TO LINE PACK DEPENDS ON WHERE THE SUPPLY DISRUPTION OCCURS

Line pack is the amount of gas in the pipe. As Guidehouse explains, line pack is a valuable resource from an operational perspective.[67] However, including line pack as a storage resource is problematic from a resiliency planning perspective. The amount of line pack available will be dependent on the location of the supply disruption as well as the system demand at that time. Guidehouse highlighted the limited time that line pack buys for FEI as follows:[68]

> A 50-mile (80km) section of 42-inch (107 cm) transmission line operating at about 1,000 pounds of pressure contains about 200 million cubic feet of gas, which is enough to power a kitchen range for more than 2,000 years. However, when considering the peak design day demand in FEI's service territory, approximately 871 million cubic feet per day, this translates into about 5.5 hours of supply.
>
> …
>
> Because the amount of linepack available for intra-day flexibility is directly correlated to the amount of demand and the amount of gas in the pipeline segment, linepack has limited capability to serve resiliency in the event of a prolonged supply disruption.

[66] Appendix A, page 14.

[67] Appendix A, page 12: "Linepack helps to minimize supply disruptions in the short-term and deliveries to be maintained for a short period of time in the event of an outage or other emergency. Additionally, linepack provides stabilization of the system as demand can fluctuate based upon hourly changes in weather and or usage."

[68] Appendix A, page 12.

FEI's CTS has very little line pack, given its operating pressure and size.[69] As such, Guidehouse notes that "Absent on-system storage, the resilience of the distribution system is a function of upstream resiliency, i.e., the network of transmission pipelines and natural gas storage that serve the natural gas utility or region."[70]

The T-South Incident provided a best-case scenario from a line pack perspective. Demand was low and the incident occurred in the north. FEI could continue to access gas held in the T-South system to the south of where the incident occurred. During the winter load period, the quantity of expected line pack would only serve a small fraction of a single day's load.

3.5.5 Incremental Supply Is Not Commercially Available During a "No-Flow" Event

FEI is not able to rely on incremental supply to purchase in the commercial marketplace during a "no-flow" event. This is illustrated by what occurred in the aftermath of the T-South Incident. As noted in Section 3.4.2.2, all commercial transactions for parties in the region, including most of FEI's commercial supply agreements, were suspended with the triggering of mutual aid on October 9, 2018. This left the physical resources and operational balancing agreements to meet physical demand of FEI and the region. The suspension continued until the beginning of the October 13, 2018 gas day (i.e., more than 3 days), when the region transitioned out of mutual aid and back into commercial business operations with transactions and nominations restored on the Westcoast system. As such, FEI works with the best efforts nature of the mutual aid agreements, which are discussed next.

3.5.6 Mutual Aid Agreements Are Essential but Depend on the Availability of Gas to Share and Infrastructure to Move It

As noted in Section 3.4.2, FEI is a voluntary member of the Northwest Mutual Assistance Agreement (NWMAA), an 18-member organization that utilizes, operates or controls natural gas transportation and/or storage facilities in the Pacific Northwest. It includes utilities, pipeline operators, storage operators and gas-fired power plants. Utilities provide gas on a "best efforts" basis without financial compensation, and the physical gas that is received or given is managed through Operating Balancing Agreements. There is a mutual interest in avoiding a hydraulic collapse in one area that could affect the entire regional system. During the T-South Incident, FEI received an extraordinary response from the NWMAA.

Participation in this organization is a key aspect of emergency planning for potential issues on the gas supply system in the Pacific Northwest; however, similar to other points made above, it does not provide FEI with certainty in the event of a supply disruption. As Guidehouse states, "if the underlying physical asset is not operational due to a disruption, the contractual

[69] Guidehouse noted that this is a common feature of distribution systems: "Distribution systems have limited linepack due to the reduced pressures and volumes of the gas on a distribution system compared to a transmission system." Appendix A, page 15.

[70] Appendix A, page 15.

arrangements do not provide, in and of themselves, resiliency."[71] Mutual aid agreements rely on one or more of the members having physical access to gas that (a) is in excess of what is required to prevent hydraulic collapse on their own systems, and (b) can be physically moved to where it is most needed. Following the T-South Incident, supply could be made available to FEI because low demand in Washington and Oregon allowed gas to physically flow northwards. There was access to additional gas supply in the region from the Gorge NWP and from market area storage at Mist and JPS, and the curtailment of customers (i.e., power plants). Under different circumstances, such as colder weather that causes higher gas heating load and greater gas-fired electricity demand for heating, this supply may not have been available to FEI under mutual aid.

3.6 CONCLUSION: RESILIENCY INVESTMENTS ARE NECESSARY

In the sections above, FEI has explained the basis for the Minimum Resiliency Planning Objective, which is based on FEI's actual experience with the T-South Incident. Meeting that objective will provide FEI with the ability to withstand, and recover from, a 3-day "no-flow" event on the T-South system without having to shut-down portions of FEI's distribution system or otherwise losing significant firm load. Although the "no-flow" phase of the T-South Incident lasted for approximately 48 hours, it could have occurred in less favourable weather conditions or in a less favourable location with significant consequences.

FEI is currently not capable of meeting the Minimum Resiliency Planning Objective during the majority of the year, providing a compelling rationale for new resiliency investments. In Section 4, FEI explains why replacing the 50-year old Tilbury Base Plant facilities with larger facilities will support FEI's system and its customers' energy needs throughout a range of emergency and gas supply events.

[71] Appendix A, page 17.

4. DESCRIPTION AND EVALUATION OF ALTERNATIVES

4.1 INTRODUCTION

This section describes the alternatives that FEI considered to augment system resiliency to meet the Minimum Resiliency Planning Objective, its approach to assessing those alternatives, and the outcome of that analysis. The information provided demonstrates why constructing new on-system storage and regasification capacity is the best resiliency option for addressing FEI's ability to withstand and recover from a gas supply interruption, and that siting a facility at Tilbury is the only feasible option.

New storage and regasification at Tilbury will meet FEI's Minimum Resiliency Planning Objective by:

- Expanding the portion of FEI's daily load that can be served during a supply disruption (determined by regasification capacity72);
- Extending the number of days during which that portion of the daily load can be served (determined by storage volume73); and
- Enhancing FEI's ability to rapidly respond to a supply emergency (determined by the technical capabilities and reliability of a facility).

FEI has also considered different sizes of storage and regasification at Tilbury. FEI's analysis demonstrates that the preferred alternative of a 3 Bcf tank with 800 MMcf/day of regasification capacity is in the public interest, as it provides a resiliency margin above the Minimum Resiliency Planning Objective and a number of other benefits for customers.

FEI's evaluation of alternatives was a two-step process, and this section is organized accordingly. FEI will:

- Explain how, in **step one**, FEI evaluated options for adding system resiliency to address a pipeline emergency, including storage (above and below ground, and on- and off-system), diversity of regional pipelines, and load management, and determined that:
  - load management and pipeline development would complement, but would not provide a suitable substitute for, on-system storage; and
  - the only feasible storage option that would meet the resiliency need identified in Section 3 is a new LNG storage tank of at least 2 Bcf and associated regasification capacity on the existing Tilbury site. (Section 4.2)

[72] Regasification capacity (MMcf/day) determines the rate at which the LNG in the tank can be regasified, and thus determines the extent to which on-system LNG can serve daily and peaking requirements. The regasification capacity needs to be sufficient to provide enough supply into the system in a given 24 hour period, after accounting for any load that can be shed, to avoid collapse.

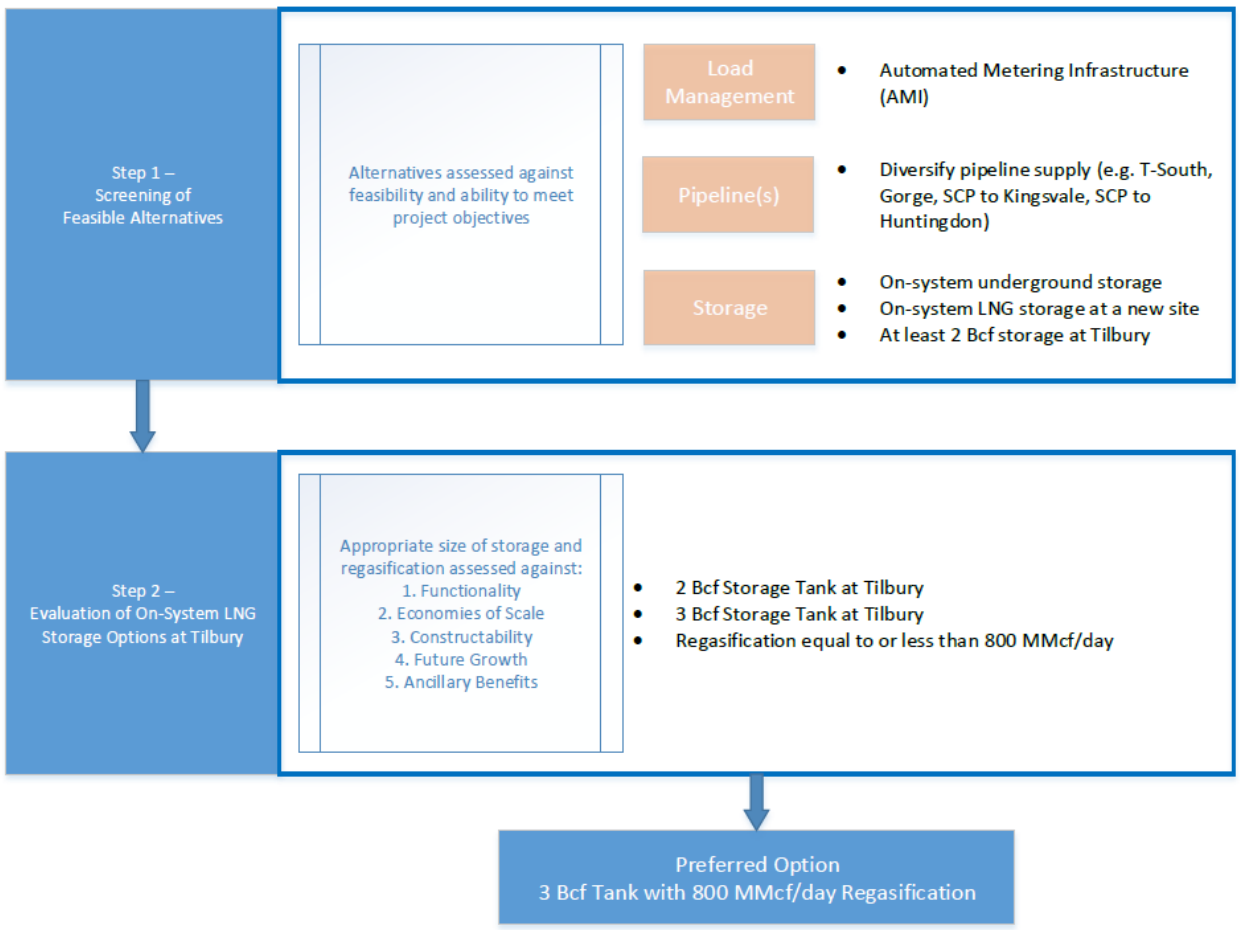
[73] Storage capacity (Bcf) is best conceptualized as dictating the number of days that FEI can continue to support the portion of FEI's daily load that is determined by the regasification capacity. For example, the Mt. Hayes LNG facility has a storage capacity equivalent to approximately 10 days of peak daily demand on Vancouver Island.

- Explain how, in **step two**, FEI assessed feasible storage tank sizes and regasification capacities at the Tilbury site, yielding the preferred option: replacing the Tilbury Base Plant with a new facility consisting of a 3 Bcf tank and 800 MMcf/day of regasification capacity. (Section 4.3)

4.2 OVERVIEW OF TWO-STEP ALTERNATIVES ANALYSIS

FEI's two-step evaluation process is summarized in Figure 4-1 below, and detailed in the following sections.

Figure 4-1: Two-Step Alternatives Analysis



4.3 STEP ONE: FEI CONSIDERED MULTIPLE OPTIONS TO INCREASE RESILIENCY

In step one, FEI screened alternatives for meeting the Minimum Resiliency Planning Objective. The step one screening examined all three of the key elements of system resiliency discussed in Section 3.3 - pipeline diversity, storage and load management. Specifically, the screening considered:

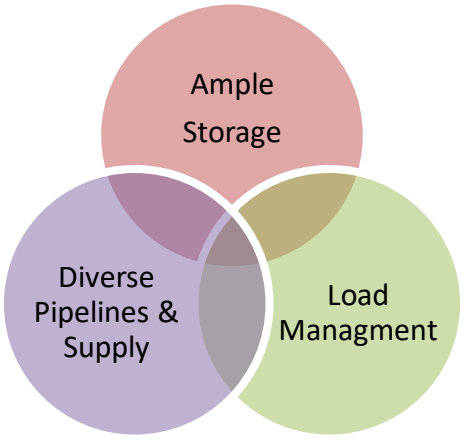
- whether there are complete alternatives to building any storage at all, relying on either load management or improved pipeline diversity in the region to deliver additional resiliency and enable FEI to withstand the type of interruption on the T-South system reflected in the Minimum Resiliency Planning Objective; and
- a range of on- and off-system storage options and locations.

The outcome of the step one analysis, discussed below, was that load management and diversity of pipelines are complementary to, rather than substitutes for, on-system storage as a means of achieving the Minimum Resiliency Planning Objective. Among the storage options and locations considered, FEI concluded that only LNG development at Tilbury was feasible and only within certain parameters: tank size between 2 and 3 Bcf and regasification capacity equal to or less than 800 MMcf/day.

4.3.1 Step One Considered All Three Elements of a Resilient Gas System in the Context of an Efficient Gas Supply Portfolio

At its heart, the step one assessment is concerned with determining whether an efficient portfolio of resiliency measures includes new on-system storage and regasification, and if so, whether it should be located at Tilbury. As discussed in Section 3.3, the resiliency of a natural gas system is derived from a combination of diverse pipelines and supply, ample storage,[74] and load management (Figure 3-2 from Section 3 is copied below). It is thus necessary to consider whether it would be feasible to meet the additional resiliency requirements identified in Section 3 by focusing exclusively on improving FEI's load management capabilities or increasing pipeline diversity in the region. FEI also examined the feasibility of various storage options.

Figure 4-2: Key Elements of a Resilient Gas System



The portfolio of resiliency measures must dovetail with the efficient supply portfolio outlined in the ACP, so as to avoid driving inefficient supply decisions that could be detrimental to

[74] Including re-delivery into the gas system.

ratepayers. FEI's analysis in step one reflects consideration of the optimal ACP portfolio, screening out resiliency alternatives that would drive inefficient supply decisions.

4.3.1.1 Resiliency Investments Should Match Characteristics of the Efficient Supply Portfolio

In reviewing and assessing the various resiliency options, it was important to recognize a fundamental design principle of constructing an efficient gas supply portfolio of resources that FEI has used for many years in the ACP: ***match the resource characteristics to the characteristics of demand***.

FEI has determined, in the context of its ACP, the optimal amount of various supply resources to achieve an efficient portfolio. In broad terms, that efficient supply portfolio consists of:

- holding pipeline capacity to address base load, i.e., consistent demand throughout the year;
- off-system underground storage to provide short to medium duration seasonal supply; and
- on-system storage resources for short duration supply to cover events such as winter peak demand which occurs for short periods driven by weather conditions.

This is a standard approach to developing a gas supply portfolio in a system that has pronounced seasonality of demand (peak in winter, low load in summer), and it is driven by the economics and technical capabilities of each element of the portfolio. For example:

- Pipeline capacity is expensive, and it must be purchased for long durations (generally year round). It would not make economic sense to try to hold sufficient pipeline capacity to serve a winter demand peak lasting only a few days each winter, while leaving significant capacity unused for approximately 350+ days each year. Instead, it makes economic sense to buy capacity for the more consistent year-round loads, and supply the winter peak demand with other shorter term resources like on- and off-system storage.
- Off-system underground storage, such as at JPS or Mist in the US Pacific Northwest, is a relatively cost-effective solution for seasonal load. FEI can fill the storage in the summer when load is lower, and draw on it in the winter. However, deliverability from these storage assets declines as they are depleted and access to that deliverability is only by displacement, which requires physical flows on the T-South system. Due to these limitations, it makes sense to have resources with high deliverability such as on-system LNG storage to serve peak days. The Tilbury Base Plant has always served this peaking supply purpose. The Mt. Hayes facility serves a similar function, particularly on Vancouver Island.
- LNG is well suited to serving the peak demand during the winter from an efficient supply portfolio standpoint, but it would not be cost effective (and likely would not be feasible in

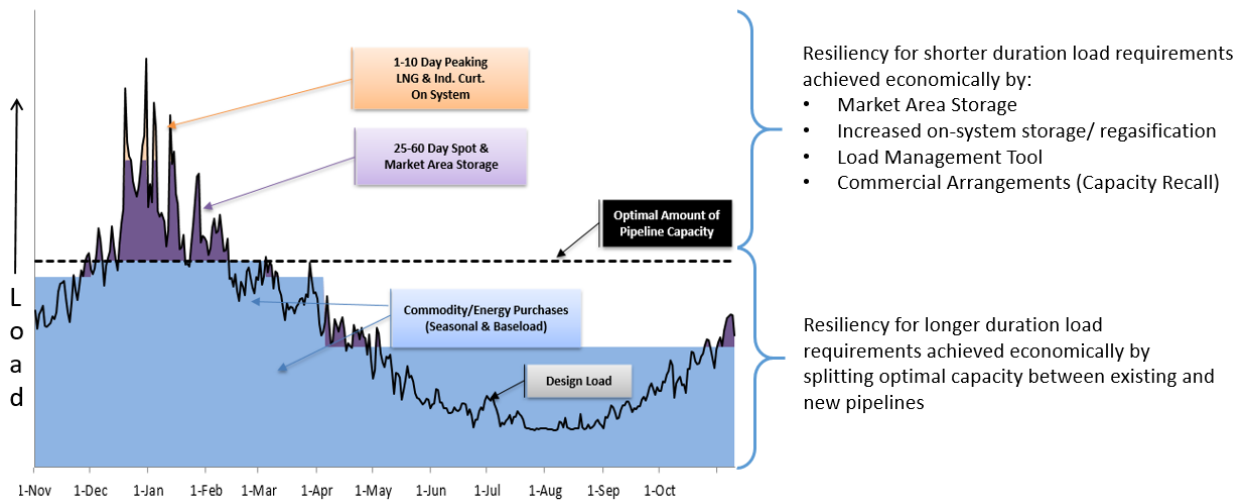
FEI's service territory in any event) to construct a tank(s) at a scale sufficient to allow FEI to replace off-system underground storage with LNG.

The principles of supply portfolio design – particularly, matching the resource characteristics to the characteristics of demand – translate directly to the resiliency context, and help to explain why certain resiliency options were screened out in step one of the alternatives evaluation process.

4.3.1.2 Short Duration Resources Should Be Used to Protect Against Short Duration Supply Events and Emergencies

Figure 4-3 below shows FEI's winter load profile and the supply resources that FEI has acquired to match the system load throughout the year. In other words, it shows the efficient composition of FEI's ACP supply portfolio, discussed above. The text to the right of the graphic depicts how redundant pipeline capacity can be used efficiently, in combination with expanded peaking resources like on-system LNG storage, to build resiliency.

Figure 4-3: Resiliency Measures Should Reflect Optimal ACP Supply Portfolio



This figure shows that the most efficient resources for targeting a short-duration resiliency objective are those that improve FEI's ability to deliver short-duration supply. It is unlikely to be efficient, or in the interest of customers, to try to build resiliency by holding year-round diverse pipeline resources in quantities that would only be required if a "no-flow" event occurred during a short-duration peaking period. Conversely, it is unlikely to be feasible or economic to attempt to manage long-duration supply events or exposures with on-system LNG storage, since the amount of storage required would be too large. FEI's Minimum Resiliency Planning Objective is a short-duration objective, which suggests a solution that is geared to short-duration supply or short-duration load management.

As discussed in the remainder of Section 4.2, the only feasible means of improving the resiliency of FEI's system for the short-duration requirements inherent in the Minimum Resiliency Planning Objective is to develop new on-system LNG at Tilbury that will:

- Expand the portion of FEI's daily load that can be served during a supply disruption by increasing regasification capabilities;
- Extend the number of days, during which that portion of the daily load can be served by expanding storage capabilities; and
- Enhance FEI's ability to rapidly respond to a supply emergency through the technical capabilities and reliability of its facilities.

The Project aims to accomplish all three of these objectives.

4.3.2 Summary of Step One Assessment Results: On-System Storage at Tilbury Is the Only Feasible Option to Meet the Minimum Resiliency Planning Objective

The following table summarizes the list of alternatives considered in step one, along with a high-level description of why they were screened out as alternatives to a new facility at Tilbury comprised of 2-3 Bcf of storage and up to 800 MMcf/day of regasification capacity. On-system storage at Tilbury emerged as the only feasible option for meeting the Minimum Resiliency Planning Objective. FEI provides more information on each alternative in the sections that follow.

Table 4-1: Summary of Step One Alternatives Considered to Meet Minimum Resiliency Planning Objective

Resiliency Elements	Alternatives	Reason Why Not an Alternative to On-System Storage at Tilbury
Load Management	Automated Metering Infrastructure (AMI)	AMI remote shut-off capability will add resiliency by reducing the potential for an uncontrolled shutdown, but is best viewed as complementing supply-side solutions. Without additional supply in event of a "no-flow" event, large scale load shedding would be required, leaving many non-interruptible customers without service.
Diversified Pipeline Supply	T-South Expansion	Expansion in the same corridor would still leave FEI subject to single point of failure risk, such that new storage would still be required to meet FEI's Minimum Resiliency Planning Objective even if the pipeline was constructed.
	Expansion to Northwest Pipeline's (NWP) Gorge Capacity	Expansion would add little resiliency for FEI. FEI must rely on displacement to access Gorge capacity, such that T-South gas must be physically flowing. Even if Gorge expansion was constructed, new storage would still be required to meet FEI's Minimum Resiliency Planning Objective.

Resiliency Elements	Alternatives	Reason Why Not an Alternative to On-System Storage at Tilbury
	SCP Expansion to Kingsvale (i.e., interconnecting with the T-South system 172 km north of FEI's Lower Mainland system)	New regional pipeline would add resiliency by reducing single point of failure risk north of Kingsvale on the T-South system. Even if constructed, new storage would still be required to address single point of failure risk for the 172 km south of Kingsvale on the T-South system.
	SCP Expansion to Huntingdon	New regional pipeline adds resiliency by diversifying supply into the Lower Mainland. Some gas will still be available if there is a failure on one pipeline system (T-South or expanded SCP). However, even if constructed, new storage would still be required to supplement remaining pipeline flows and avoid significant load shedding. Cost savings from reducing the size of on-system LNG are limited due to inherent economies of scale.
Storage	Contract Additional Off-System Storage	Contracting additional off-system storage would still leave FEI subject to single point of failure risk, since FEI would remain dependent on the T-South system to access the storage resource. (Access to JPS and Mist is only by displacement and the displacement commercial transactions require physical flows on the T-South system.)
	On-System Underground Storage	Not feasible within the FEI service territory.
	On-System Storage at a New Site	Would provide resiliency but is more costly than expansion at an existing brownfield site, and would require construction of liquefaction in addition to storage and regasification.
	Use the Existing Base Plant Storage (including regasification) and Add Additional Storage	This option would not leverage the economies of scale of a single, larger tank. It would be more costly over time because the existing Base Plant facilities would still require replacement at some point.
	On-System Storage at Tilbury (< 2 Bcf)	Does not meet the Minimum Resiliency Planning Objective described in Section 3.
	On-System Storage at Tilbury (> 3 Bcf)	Diminishing economies of scale beyond 3 Bcf due to constructability challenges.

The results of the screening analysis are consistent with the discussion above that each of the three key elements of resiliency – storage, pipeline diversity and load management – adds resiliency in distinct, but complementary ways that dovetail with an efficient gas supply portfolio.

4.3.3 Load Management Alternative – AMI Will Support Resiliency but Is Not an Alternative to the Project

In the following section, FEI explains why load management alone is not an alternative to the Project.

Alternatives	Reason Why Not an Alternative to On-System Storage at Tilbury
Automated Metering Infrastructure (AMI)	AMI remote shut-off capability will add resiliency by reducing the potential for an uncontrolled shutdown, but is best viewed as complementing supply-side solutions. Without additional supply, large scale load shedding would be required in event of a "no-flow" event, leaving many non-interruptible customers without service.

In 2021, FEI expects to file an application for a CPCN to install AMI. The AMI project would implement an AMI network that will deliver improved information about natural gas consumption and pipeline operating conditions to FEI and its customers. The AMI project is primarily driven by the need to address the declining viability of manual meter reading, but will also provide ancillary benefits including improving FEI's ability to manage system load during a loss of gas supply. However, AMI is not an alternative to the TLSE Project.

In the event of an extended loss of natural gas supply, AMI will provide FEI with more granular information regarding the demand on its system. The remote shut-off valve in the AMI meter will enable FEI to shut off gas to selected customers based on factors other than their location in proximity to an isolated section of pipeline. AMI will also help FEI keep the natural gas system pressurized, thereby reducing recovery time for customers that experience service interruption.

While load management is an important tool that can assist in avoiding an uncontrolled collapse of the system and speed the recovery process of a system shutdown, it has its limitations. Load management does not increase supply; therefore, it is limited in its ability to prevent widespread controlled outages, unlike on-system storage.

This limitation is exemplified by the fact that, as previously explained in more detail in Section 3.5.4.1, the existing regasification capacity at Tilbury is substantially lower than the daily design peak demand. This means that FEI's existing on-system storage and regasification capacity would be insufficient to avoid shedding most of FEI's system load during a "no-flow" event occurring in less favorable conditions than was experienced during the T-South Incident. The result would be widespread customer outages.

This demonstrates that the enhanced load management capability enabled by AMI cannot replace the Project, including the need to enhance on-system storage and regasification capabilities.

4.3.4 Diversified Pipeline Supply – Regional Pipeline Development Would Complement, But Would Not Represent an Economic Alternative to, Storage

FEI assessed whether some possible future pipeline development in the region could provide an alternative to the Project for meeting the Minimum Resiliency Planning Objective. Although future regional pipeline developments could enhance the resiliency of FEI's system, FEI would

still require new storage to supplement the remaining pipeline flows during a "no-flow" event. In fact, the new storage requirements would remain the same under three of the four options described below. The reduction in new storage requirements associated with the final option – SCP expansion to Huntingdon – results in only limited cost savings for the TLSE Project by virtue of the economies of scale associated with constructing on-system storage.

For the purposes of this Project and consistent with the Project objective, FEI has assessed the pipeline alternatives described below from a resiliency perspective, not a commercial perspective. As noted below, commercial considerations can impose limitations on feasibility as well.

4.3.4.1 FEI Assessed Four Possible Pipeline Projects

It is important to note that there are currently no open seasons[75] for regional pipeline infrastructure, making this a conceptual analysis. There can be significant barriers to the development of linear pipeline infrastructure; however, based on FEI's past evaluations of opportunities and the existing infrastructure in the region, there are generally four possibilities for pipeline projects within two main categories:

- An expansion to the existing T-South system; or
- A new regional pipeline, including the following:
  - An expansion to Northwest Pipeline's (NWP) Gorge capacity;
  - An expansion of SCP to Kingsvale (i.e., interconnecting with the T-South system 172 km north of FEI's Lower Mainland system); or
  - An expansion of SCP to Huntingdon (i.e., the delivery point to FEI's Coastal Transmission System).

Figure 4.4 below shows where the four possible expansions are located in the region and their conceptual pipeline routes. Each of these expansions would help support load growth in the region as well as reduce the gap between the Sumas/Huntingdon forward market prices and the Station 2 prices plus fixed transportation costs to get to the Sumas/Huntingdon market. The following sections describe how the level of resiliency that each expansion might provide differs and explain why none of the projects are an alternative to the TLSE Project from a resiliency standpoint. FEI notes that its evaluation of the four alternatives is focused on resiliency; however, there may be many other considerations that influence which pipeline project is ultimately brought forward to the market.

[75] Open season is a process undertaken by the pipeline company that is offering the new pipeline to the market. Customers who are interested in the project (i.e., service) must comply to the business rules of the open season and the pipeline company awards the service to customers based on winning bids.

Figure 4-4: Potential Regional Pipeline Infrastructure Expansions

4.3.4.2 Expansion of the Existing T-South System: Not a Project Alternative Because FEI Remains Exposed to a Single Point of Failure Risk

In this section, FEI explains why an expansion of the T-South System is not an alternative to the Project.

Alternatives	Reason Why Not an Alternative to On-System Storage at Tilbury
T-South Expansion	Expansion in the same corridor would still leave FEI subject to single point of failure risk, such that new storage would still be required to meet FEI's Minimum Resiliency Planning Objective even if the pipeline was constructed.

The last open season for an expansion of the T-South system that Westcoast conducted was in April 2017, which offered shippers to contract for 190 MMcf/day of T-South to Huntingdon Delivery capacity. Out of the 190 MMcf/day, 90 MMcf/day was existing capacity on the T-South system that had been made available on an interruptible basis and an additional 100 MMcf/day was new firm year-round capacity. This small-scale expansion is being completed mainly through major compression upgrades along the T-South system route. While the project was planned to be in-service by late 2020, it has been delayed by one year due to the work needed to restore the system following the T-South Incident. The expansion provides very little new resiliency from FEI's perspective, since it does not reduce the current single point of failure risk and adds no pipeline diversity. FEI expects that any future T-South expansions would be in the same corridor.

4.3.4.3 Expansion of NWP Gorge Capacity: Not a Project Alternative Because Negligible Benefits in the Event of Supply Disruption on the T-South System

In this section, FEI explains why an expansion of the NWP Gorge system is not an alternative to the Project.

Alternatives	Reason Why Not an Alternative to On-System Storage at Tilbury
NWP Gorge Expansion	Expansion would add little resiliency for FEI. FEI must rely on displacement to access Gorge capacity, such that T-South gas must be physically flowing. Even if Gorge expansion was constructed, new storage would still be required to meet FEI's Minimum Resiliency Planning Objective.

Another possibility for future pipeline development is an expansion of the Gorge capacity on the NWP system, which would increase the physical capacity to bring supply westbound from Stanfield or the Rockies into the I-5 corridor.

Expanding the NWP Gorge capacity would allow gas to flow west into the Seattle and Portland region and decrease demand at Huntingdon/Sumas. While this project has merit and would provide increased physical supply into the region, it would not be FEI's preferred choice for a new pipeline into the region because of the limited resiliency benefits it would provide to FEI directly.

FEI would need to rely on displacement or notional deliveries to make use of any new NWP Gorge capacity. The displacement process is dependent on physical gas flow on the T-South system to Huntingdon. However, in a "no-flow" event such as the T-South Incident, gas flows on the T-South system to Huntingdon are interrupted. Therefore, FEI cannot rely on displacement to deliver gas to its system (the displacement process is detailed in Section 3.5.4.3). Rather, FEI must rely on the cooperation and effort of mutual aid partners in order to physically flow gas northward. This can only occur when demand in the US Pacific Northwest is low, such that FEI cannot rely on the same mutual aid response during cold weather conditions. Therefore, this pipeline expansion project would have very limited benefits to FEI under a "no-flow" event from

the T-South system. FEI's storage and regasification needs would, from a resiliency standpoint, remain unchanged under this scenario.

4.3.4.4 Expansion of SCP to Kingsvale: Adds Resiliency but Storage Would Still Be Required

In this section, FEI explains why an expansion of SCP to Kingsvale is beneficial and complementary to the Project, but not an alternative to the Project. The Project is still required to meet the Minimum Resiliency Planning Objective.

Alternatives	Reason Why Not an Alternative to On-System Storage at Tilbury
New SCP to Kingsvale Pipeline (i.e., interconnecting with the T-South system 172 km north of FEI's Lower Mainland system)	New regional pipeline would add resiliency by reducing single point of failure risk north of Kingsvale on the T-South system. Even if constructed, new storage would still be required to address single point of failure risk for the 172 km south of Kingsvale on the T-South system.

An expansion of the SCP system provides an opportunity for FEI to diversify away from its dependence on the T-South and T-North systems. As such, FEI has previously evaluated SCP expansions, including an expansion of SCP to Kingsvale to deliver incremental gas supply to Huntingdon.

This project would consist primarily of new compressor stations and a 161 km, NPS 24 or greater pipeline expansion from Oliver to Kingsvale, BC, extending the existing SCP so that it interconnects with the T-South system 172 km north of FEI's Lower Mainland system. FEI estimates that the incremental volume to Huntingdon could increase by approximately 300 to 400 MMcf/day via Westcoast's T-South Kingsvale to Huntingdon capacity.

An expansion of SCP to Kingsvale, with some of FEI's required supply being shifted from the T-South system to SCP, would mitigate a significant portion of FEI's reliance on the T-South system. However, it would not provide redundancy for the 172 km section of the T-South system between Kingsvale and Huntingdon, since all of the gas from SCP would have to travel on that segment to reach the load centre in the Lower Mainland. As a result of this exposure, an expansion of SCP to Kingsvale would not change FEI's storage requirements from a resiliency standpoint.

4.3.4.5 Expansion of SCP to Huntingdon: Provides Greatest Resiliency Benefit Amongst Pipeline Options but Storage Would Still Be Required

In this section, FEI explains why an expansion of SCP to Huntingdon is beneficial and complementary to the Project, but does not replace the need for the Project to meet the Minimum Resiliency Planning Objective.

Alternatives	Reason Why Not an Alternative to On-System Storage at Tilbury
New SCP to Huntingdon Pipeline	New regional pipeline adds resiliency by diversifying supply into the Lower Mainland. Some gas will still be available if there is a failure on one pipeline system (on T-South or SCP). However, even if constructed, new storage would still be required to supplement remaining pipeline flows, and avoid significant load shedding. Cost savings from reducing the size of on-system LNG are limited due to inherent economies of scale.

An expansion of SCP to Huntingdon would be FEI's preferred choice of pipeline development from a resiliency standpoint, given that this solution would entail an entirely different path from the T-South system and would allow FEI to split the optimal amount of pipeline capacity between T-South and the new pipeline. This project would involve an expansion of SCP through the construction of additional compressor stations and a new pipeline connecting SCP near Oliver, BC to the Sumas/Huntingdon market. This project would amplify the resiliency benefits of the SCP expansion to Kingsvale.

4.3.4.5.1 IT IS MORE COST-EFFECTIVE TO RETAIN FULL STORAGE AND THE RISK MITIGATION THAT COMES WITH IT

The additional resiliency that comes with a new SCP pipeline to Huntingdon in the Lower Mainland following an entirely separate corridor from the T-South pipeline would reduce FEI's minimum storage needs.[76] However, as FEI explains below, the additional resiliency does not reduce storage requirements enough to overcome the risk that the facility will be undersized if a new regional pipeline is not constructed or delayed. Constructing new pipeline infrastructure, such as an expansion of SCP to Huntingdon, is a long process and is unlikely to be in service before 2030, even if successfully developed. Regardless, any expansion of SCP should be viewed as a complementary asset, part of an efficient resiliency portfolio. [redacted]

[redacted]

[76] A diversified pipeline supply into the Lower Mainland reduces the storage demand during an emergency disruption on one of the pipelines thereby increasing the probability that storage will not be fully depleted. The remaining inventory of LNG storage would be used to manage gas supply and peaking events after the initial disruption.

[redacted]

[redacted]

[redacted]

[redacted] The economies of scale associated with tank sizing mean that a reduction in tank size will result in proportionately low cost savings. In other words, the risk mitigation benefits decrease faster than the associated costs. Considering the uncertainty over whether a pipeline expansion will be constructed, which alternative is constructed, and when such an expansion will be in service, FEI believes that maintaining a larger tank size will maximize benefits to customers while mitigating significant uncertainty regarding future pipeline expansions.

4.3.4.5.2 DOUBLING THE AMOUNT OF PIPELINE CAPACITY FEI HOLDS USING SCP IS UNECONOMIC AND STILL REQUIRES STORAGE

The discussion above contemplates splitting the optimal amount of pipeline capacity between T-South and a new SCP to Huntingdon pipeline, such that a disruption on one pipeline would still leave access to partial supply. In theory, a different approach could be to forego an expansion of on-system storage and contract the optimal amount of pipeline capacity on <u>both</u> pipelines, [redacted] Redundancy to this extent would mitigate a significant amount of risk during the winter if one of the regional pipelines were shut down due to an emergency situation. However, FEI

[redacted]

would incur significantly higher annual costs compared to the portfolio approach. It would also still not eliminate the need for on-system LNG storage at Tilbury, which the cost analysis in Table 4-3 below does not take into account.

[redacted]

In addition to the higher expected costs, there are several other considerations that favour a portfolio approach that includes on-system storage, including:

- **FEI exercises greater control over on-system storage development**. As previously discussed, the development of regional pipeline infrastructure is uncertain and FEI exercises greater control over the development and timing of on-system storage, thereby greater certainty over enhancing system resiliency.
- **Uncertainty whether FEI would be able to contract for the required amount of new regional pipeline capacity**. [redacted] Capacity on a new

[redacted]

pipeline could be secured through ownership of the regional pipeline, for instance. Otherwise, a standard open season includes a process where the bids for capacity are submitted confidentially. Other participants could outbid FEI, which could result in FEI holding less than the desired amount of contracted capacity.

- **FEI's portfolio will still require on-system storage**. [redacted]

4.3.5 Among On-System Storage Options, Only 2 to 3 Bcf of LNG Storage at Tilbury is Feasible

As discussed in Section 3.4, FEI assessed that 3 days is a reasonable duration for an emergency event when identifying the Minimum Resiliency Planning Objective, given its experience with the T-South Incident and the time required to establish a balance between supply and demand after the emergency. In this section, FEI explains why its design and actual load curves demonstrate that storage of at least 2 Bcf is required to bridge a 3-day "no-flow" period, without a margin to address any supply or demand events in the period following resumption of service. FEI also describes the following four potential storage alternatives considered to provide this coverage:

1. Underground on-system storage in the Fraser Valley;
2. Acquiring a new site for on-system LNG storage;
3. Using a combination of the Tilbury Base Plant LNG tank and constructing a second tank; and
4. Constructing a new LNG tank at the existing Tilbury site to replace the Base Plant tank.

The assessment demonstrated that the only feasible storage option from both an economic and technical perspective that would meet the resiliency need identified in Section 3 is a new LNG storage tank on the existing Tilbury site sized between 2 and 3 Bcf.

[redacted]

4.3.5.1 On-System Storage Has Unique Benefits in this Context

FEI's review of various options highlighted that on-system storage has unique benefits for FEI from the perspective of meeting the Minimum Resiliency Planning Objective. FEI outlined some of the attributes of on-system storage in Section 3.3.3. Critical among the benefits that would come with new on-system storage in the Lower Mainland is buying FEI time to respond to a supply emergency before having to initiate a controlled shut-down. Guidehouse similarly views on-system LNG as a tool that buys FEI vital time in the event of an interruption on the T-South system. It states for example:[86]

> From the perspective of resiliency, natural gas storage not only provides a supply buffer but also provides a utility vital time to respond to unplanned supply constraints in the pipeline and distribution network. As result, utilities may be afforded sufficient time to avoid an uncontrolled shutdown.
>
> …
>
> The FEI system is susceptible to a single point of upstream natural gas transmission failure as demonstrated in the incident of October 2018. [redacted] In addition, Guidehouse observes that it would require significant time for FEI to ascertain the supply/demand on its system and develop the appropriate response, i.e., curtailment of customers, in order to mitigate long-term impacts, including catastrophic operational and economic failure. On-system storage would allow FEI to more effectively implement a controlled shutdown that minimizes the impact to at-risk customers if a major interruption event occurred.
>
> It is for these reasons that on-system storage provides an effective means to address the impact of a failure on the Enbridge BC pipeline [i.e. T-South system] by giving FEI time to serve customers while remedying the situation with the appropriate operational control, redundancy and emergency response capabilities.

4.3.5.2 Determining the Necessary Storage and Regasification Reflects the Distinction Between Energy and Capacity Planning

One of the threshold questions requiring an answer when FEI assessed on-system storage options was: how much storage and (for LNG) regasification are required to meet the Minimum Resiliency Planning Objective? This assessment requires consideration of the amount of

[86] Appendix A, pages 14, 44.

customer load in the Lower Mainland that would have to be served from the storage during a "no-flow" event. The way in which one must determine the load to be served differs depending on whether one is considering regasification capacity or storage.

- ***Regasification should be determined with reference to peak demand:*** System capacity planning for infrastructure is typically done with reference to the design peak demand[87] to ensure adequate delivery to the customer. In this case, "capacity" refers to the capability of regasification equipment to convert stored LNG back into gas for use by customers. This conversion rate is driven by the need to serve the customer's peak demand and hence, regasification capacity is directly related to the overall design peak demand. For this reason, the discussion of regasification capacity focuses on the extent to which it can serve overall design peak demand in the Lower Mainland.

- ***Storage volume should be determined with reference to cumulative demand:*** In contrast to regasification capacity, stored LNG represents the "energy" that could be delivered to customers over a period of time. The amount of stored "energy" required is related to the expected demand over the period of delivery (i.e., over the 3-day Minimum Resiliency Planning Objective). The exercise involved in determining the minimum tank size to cover a 3-day "no-flow" period includes applying the empirical load duration curve to the weather year that FEI uses for system and gas portfolio planning, resulting in the design curve (as described in Section 4.2.1.2). In other words, the design curve assigns each of the days on the load duration curve to a day in the calendar year. Next, FEI translates the design curve into the cumulative load over a 3-day period to determine the highest expected load occurring over that period to establish a minimum tank size (see Figure 4-6 below). However, given the potential variability of actual weather conditions from day to day, FEI also considered actual winter load data from the past 10 years. The experience during the coldest winter of the last 10 years (2016/17) is used to validate that the three-day cumulative load has established a reasonable minimum tank size.

4.3.5.3 2 Bcf Is Necessary to Meet the Minimum Resiliency Planning Objective Without Any Margin for Subsequent Supply or Demand Events

As described below, FEI's design and actual load curves demonstrate that storage of at least 2 Bcf is required to bridge a 3-day "no-flow" period. Storage below 2 Bcf would not meet demand over the course of a 3-day outage. At 2 Bcf, the storage would provide minimal margin to assist in responding to any supply or demand events occurring during the period following resumption of flows (as occurred following the T-South Incident).

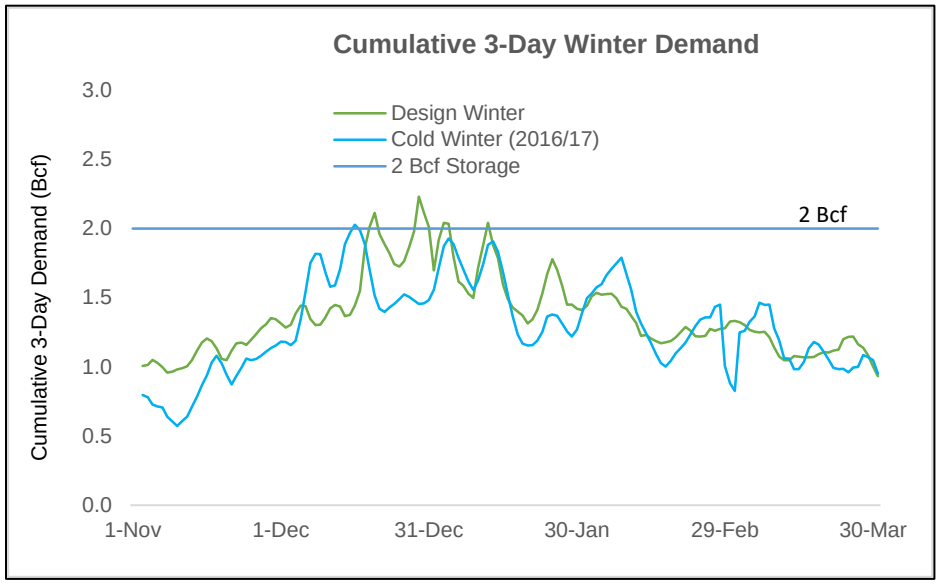
4.3.5.3.1 FEI'S CUMULATIVE 3-DAY DEMAND IS EQUIVALENT TO APPROXIMATELY 2 BCF

As illustrated in Figure 4-6 below, the maximum calculated cumulative design load over a 3-day period (extrapolated from FEI's load duration curve) is approximately 2.2 Bcf, while the maximum actual cumulative load over a 3-day period during the coldest winter in the past 10

[87] Design demand represents the expected customer demand in a very cold year. The coldest day in a design year is referred to as the peak day.

years (i.e., the 2016/17 winter) was approximately 2.0 Bcf. This analysis reinforces that, even when using actual demand values that provide a lower level of resiliency than those based on the design curve, the minimum storage capacity to serve the Lower Mainland can be no less than 2.0 Bcf in order to meet FEI's 3-day Minimum Resiliency Planning Objective.

Figure 4-6: Storage Capacity Based on Winter Conditions



4.3.5.3.2 STORAGE OF 2 BCF LEAVES LITTLE MARGIN TO ADDRESS EVENTS IN THE SUBSEQUENT PERIOD

Section 3 described how the 3-day Minimum Resiliency Planning Objective was chosen in recognition of the circumstances of the T-South Incident. Storage of 2 Bcf meets that need, but with little margin during parts of the year. The margin is important when it comes to being able to manage through more common supply or demand events that take on greater importance in the period following resumption of flows but before full pipeline capacity is restored.

In the T-South Incident, supply on the T-South system was restored to the 50 percent level after 48 hours; however, supply was constrained at 50 percent for approximately 20 days. Full service was not restored on the T-South system for 14 months. There were several periods during that time when demand on FEI's system exceeded pipeline supply (see Section 3.4.2.2.3). At 2 Bcf, there is little additional capacity to support ongoing supply constraints beyond the initial event, especially where the initial emergency event results in "no-flow" for a period close to 3 days. In other words, at 2 Bcf, FEI may bridge the initial event, but may not have sufficient storage to support customer demand through subsequent events.

These issues are explored further in the context of step two of the alternatives analysis, which addresses sizing.

4.3.5.3.3 GUIDEHOUSE HAS A SIMILAR ANALYTICAL APPROACH TO DETERMINING SIZING OF ON-SYSTEM STORAGE

In Section 4.1 of its Report, Guidehouse provides a framework for determining necessary storage and regasification capacity. FEI's approach to determining the minimum level of on-system storage for meeting the Minimum Resiliency Planning Objective aligns with Guidehouse's framework.

Guidehouse's framework for determining necessary storage and regasification capacity is based on the following defining factors:[88]

- **Preparation**: ***The ability to prepare for and prevent initial system disruption.***
  - *The anticipated time required to conduct a planned shutdown, i.e., an orderly curtailment of customers to reduce the amount of work and time required to restore service.*

  On this factor, Guidehouse noted that "[i]n the event of an unforeseen supply interruption, it will take several hours to discern the location and magnitude of the disruption" and that "[a]dditional time is required to plan and execute an appropriate curtailment response to prevent a system collapse".

- **Withstanding**: ***The ability to withstand, mitigate, and manage system disruption***.
  - *The amount of load on the system at the time of disruption.*
  - *The amount of load needed to be retained in the event of a supply disruption in order to prevent a collapse of the system, i.e., hydraulic failure.*

  In discussing the "withstanding" factor, Guidehouse stated:

> The minimum size should also be correlated to the estimated amount of time FEI would require emergency back-up supply in the event of a significant upstream supply disruption, and the relative access to other equivalent options to manage the system. It should also factor in the anticipated time to restore supply.
>
> FEI estimates that the most probable duration of total gas delivery outage in the LML is at least three days. FEI arrived at this estimate by evaluating the October 2018 Enbridge outage duration and response, weather, terrain variability factors, and time required for FEI operational teams to manage a controlled curtailment. The amount of load on the system and the time of year of the disruption are also key considerations when determining the minimum size of the tank, as these will impact how much gas is needed, and how much flexibility FEI has to refill the tank. FEI developed its recommendations for the storage size and regasification requirements through consideration of the estimated design peak for 2019/2020. 600 MMcfd would serve [redacted] This

[88] Appendix A, pages 47-48.

analysis indicates that approximately 800 MMcf/day of would be able to support about [redacted] of the system load during a "no-flow" scenario to the LML at the design peak of 2019/2020. In addition, this solution would also serve approximately 100% of the customers under the 2019/2020 normal winter load scenario.

- **Recovery**: ***The ability to quickly recover normal operations and repair system damage.***
  - *The time of year, i.e., a disruption in the beginning of winter may exhaust the stored gas, requiring time to refill and limits the ability to respond to subsequent disruptions. A disruption in the summer will have a different impact.*
  - *The anticipated time, level of effort and expense required to restore a supply disruption.*

With respect to recovery, Guidehouse emphasized that a supply disruption "can require significant work to restore service", including initial shut offs, work to repair damage, and customer relights, for which "a general rule of thumb used in the gas industry is that one trained service technician can relight up to four residential customers per hour". Guidehouse also listed the following key factors that influence recovery time and cost:

1. Extent of system collapse.
2. Ability of the utility to mobilize its workforce to execute the emergency response plan (availability of personnel with proper safety and procedure training and vehicle access).
3. Ability to execute on mutual aid agreements with adjacent utilities to secure additional resources.
4. Travel distance between customers.
5. Ability to access the customer premise.

4.3.5.4 Storage Option 1 – Underground On-System Storage in the Fraser Valley

Underground on-system storage in the Fraser Valley is not a feasible storage option, for the reasons discussed below. It is not an alternative to the Project.

Alternatives	Reason Why Not an Alternative to On-System Storage at Tilbury
On-System Underground Storage	Not feasible within the FEI service territory

Natural gas can be stored underground in depleted petroleum reservoirs or aquifers if suitable geological formations exist. The principal advantages of this type of storage are low unit cost and very high volumetric capacity. There are a number of underground storage facilities in the petroleum-producing region of the Western Canadian Sedimentary Basin, the basin from which

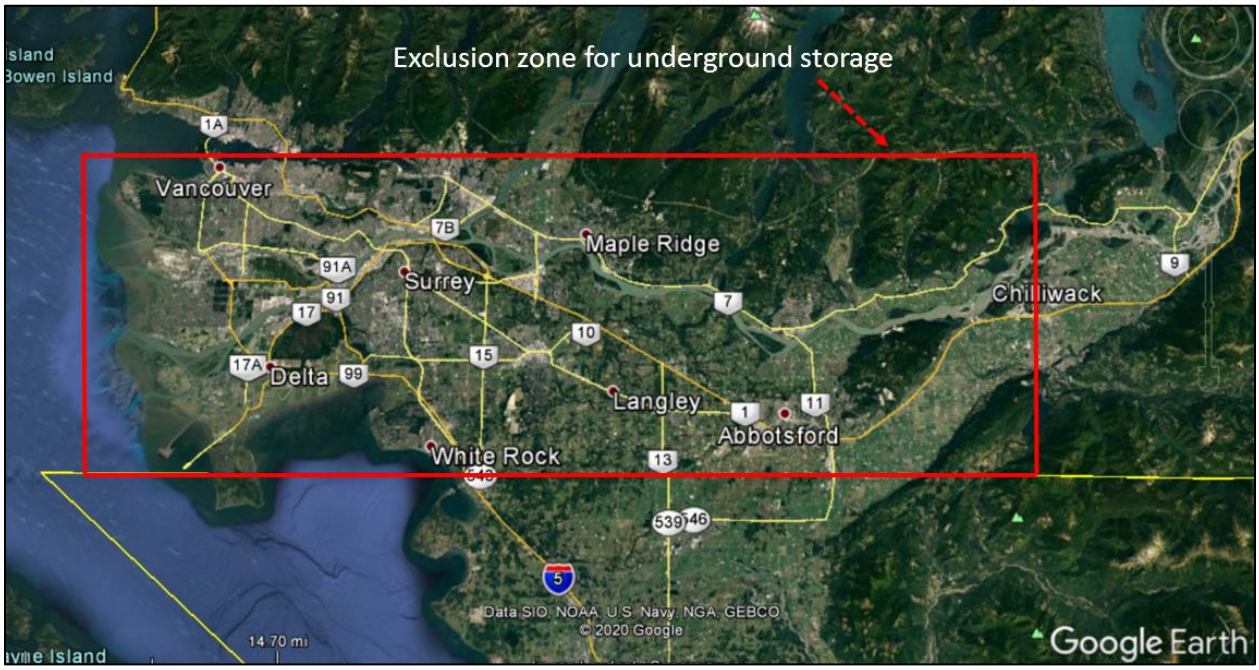
FEI receives virtually all of its gas supply. However, the Western Canadian Sedimentary Basin is located hundreds of kilometres away from FEI's service territory, and the load centre in the Lower Mainland in particular.

JPS and Mist are underground storage facilities in Washington and Oregon, respectively. The shortcomings of FEI relying on those facilities for emergency supply have been previously discussed in Section 3.5.4.3.

Suitable geological formations may exist for on-system underground storage in the Fraser Valley area; however, the geology is largely unproven. Moreover, underground natural gas storage in the Fraser Valley is not considered a realistic alternative to the Project due to government policy considerations. Exploratory drilling took place in the late 1980s and early 1990s by a consortium called the Fraser Valley Gas Project, which included BC Gas (now FEI). Since 1991, following considerable public outcry regarding exploratory drilling, successive governments have indicated an unwillingness to consider underground natural gas storage in the Fraser Valley. Since 1997, the regulations under the *Petroleum and Natural Gas Act* do not allow for the exploration of or the granting of a lease for an underground natural gas storage reservoir in the Fraser Valley.[89]

The area of the Fraser Valley that has been deemed inapplicable for underground storage is shown in Figure 4-7 below:

Figure 4-7: Exclusion Zone for Underground Storage



FEI therefore rejected on-system underground storage as being infeasible.

[89] *Petroleum and Natural Gas Storage Reservoir Regulation*, B.C. Reg. 350/97, s. 3 (deposited October 16, 1997).

4.3.5.5 Storage Option 2 – Acquire New Site for On-System Above Ground Storage

In this section, FEI describes why constructing new above ground on-system storage at an alternate site from Tilbury was discarded early in the evaluation process.

Alternatives	Reason Why Not an Alternative to On-System Storage at Tilbury
On-System Above Ground Storage at a New Site	Would provide resiliency but is more costly than expansion at an existing brownfield site, and would require construction of liquefaction in addition to storage and regasification.

While a new site could conceivably be used, the existing Tilbury site has significant advantages, providing economic benefits as compared to constructing a new facility at a different site, namely:

- The site is connected to existing gas and electric supply infrastructure and does not require large capital investments to provide the natural gas and electrical supply required to produce and store LNG;
- The liquefaction capacity already in place on the Tilbury site can be used to fill a new tank or tanks. Should a facility be constructed in a different location, the construction of liquefaction capacity would add significant cost to the Project;
- The Tilbury site has sufficient space to construct a new LNG storage tank and regasification equipment; and
- FEI already owns sufficient land at the Tilbury site to accommodate the Project. Purchase of new land in the Lower Mainland region adds substantial cost to any project due to the high property prices in the area.

The combination of existing infrastructure located on a developed site already purposed for LNG service with available space is unique. The additional costs required to acquire land, extend gas supply and power and construct liquefaction capacity to supply the LNG would render a new site uneconomic and challenging relative to a project at the Tilbury site.

4.3.5.6 Storage Option 3 – Using a Combination of the Tilbury Base Plant LNG Tank and a New Tank

In this section, FEI describes why using the Tilbury Base Plant LNG tank and adding a second storage tank is not a feasible alternative for the Project.

Alternatives	Reason Why Not an Alternative
Use the Existing Base Plant Storage (including regasification) and Add Additional Storage	This option would not leverage the economies of scale of a single, larger tank. It would be more costly over time because the existing Base Plant facilities would still require replacement at some point.

FEI could, in theory, achieve the desired storage capacity with a combination of the existing 0.6 Bcf Tilbury Base Plant tank and a new storage tank. This combination might, on first blush, look like it would reduce the overall cost of the Project. In reality, the analysis is more complex; both the technical considerations and the economics are unfavourable. FEI discarded this as an alternative early in the step one process for the reasons explained below. The analysis demonstrates that it is more cost effective to construct a single, larger tank as compared to using and ultimately replacing the existing Tilbury Base Plant tank and constructing a second tank.

As discussed in Section 3.5.4.1, the Tilbury Base Plant is currently 50 years old and is approaching the end of its useful life. By the time the tank is replaced in 2025 as part of this Project, it will be nearly 55 years old. By comparison, the design life of a new, modern tank would be approximately 60 years (i.e., only 5 years longer). While FEI expects the tank to last beyond 55 years, it makes economic and practical sense to replace the tank now to capture available economies of scale in the construction of a single, larger tank.

FEI prepared a simplified analysis below to demonstrate that, leaving aside other benefits of a modern tank and regasification package, building a single, larger tank now is the best course of action from an economic perspective. The analysis compares the incremental difference in capital costs as well as annual revenue requirements associated with building:

- 2.0 Bcf tank with 800 MMcf/day regasification now; versus
- 1.4 Bcf tank with 650 MMcf/day of regasification now, and replacing the existing 0.6 Bcf tank and 150 MMcf/day of regasification capacity at some point in the future.

Table 4-4: Comparison of the Capital Costs to Build a Single, Larger Tank (2020$)

Scenario	Comparison	Tilbury Base Plant Tank Age at Replacement			
		~55 Years (2025)	~60 Years (2030)	~65 Years (2035)	~70 Years (2040)
2 Bcf Tank and 800 MMcf/d regasification now	PV of Capital Costs ($ millions)	588	588	588	588
1.4 Bcf Tank and 650 MMcf/day now + second 0.6 Bcf tank and 150 MMcf/day in the future	PV of Capital Costs ($ millions)	785	742	706	676
Difference	PV of Capital Costs ($ millions)	**(197)**	**(154)**	**(118)**	**(88)**
2 Bcf Tank and 800 MMcf/d regasification now	PV of Annual Rev. Requirements ($ millions)	951	951	951	951
1.4 Bcf Tank and 650 MMcf/day now + second 0.6 Bcf tank and 150 MMcf/day in the future	PV of Annual Rev. Requirements ($ millions)	1263	1,145	1,093	1,049
Difference	PV of Annual Rev. Requirements ($ millions)	**(312)**	**(194)**	**(142)**	**(98)**

The above analysis confirms that it is more economic to build a single, larger tank now rather than continuing to rely on the existing 0.6 Bcf tank and other Base Plant facilities only to replace them at some point in the future. The analysis also shows the existing Base Plant facilities at Tilbury would need to remain in place for another 44 years (i.e., to an age of 94) with no further sustainment capital expenditures to the Base Plant facilities for that scenario to make economic sense. Given that the Base Plant is currently 50 years old, FEI believes it is neither desirable nor likely that the Base Plant will remain in operation for another 44 years.

Further, a modern tank and regasification package has several advantages over the Tilbury Base Plant equipment. These advantages include:

- **Decreased maintenance costs:** while not quantified in the simplified analysis above, a new tank will decrease maintenance costs as compared to the 50-year old Tilbury Base Plant tank;
- **Improved environmental performance:** a new LNG tank will incorporate modern design standards which further minimize the potential for venting of methane to the atmosphere;
- **Improved reliability and response time:** a new tank and regasification package is expected to respond more quickly and more reliably than the existing Tilbury Base Plant; and
- **Decreased time to fill the tank:** a new LNG tank could be filled more quickly than the existing Tilbury Base Plant tank, which is limited by its boil off gas system.

Additionally, replacing the 0.6 Bcf tank at some point in the future presents other disadvantages. For example, in order to maintain resiliency and uninterrupted service to FEI's customers, FEI would need to complete the construction of the replacement 0.6 Bcf tank (i.e., a fourth LNG tank onsite[90]) before it could demolish the existing Base Plant tank. As an operating, brownfield site, this would create significant additional constraints on space for construction activities and siting new facilities.

As a result, building a single, larger tank and regasification package is superior to relying on the aging Base Plant facilities and a second smaller tank and regasification package.

4.3.5.7 Storage Option 4 – Adding Storage at Existing Tilbury Site

New on-system LNG storage located at the existing Tilbury site is the only feasible approach from an economic and technical perspective to meet the Minimum Resiliency Planning Objective. The existing site is already permitted for LNG use, is located in an existing industrial area within the municipality of Delta and has sufficient space to site a new LNG storage tank of between 2 Bcf and 3 Bcf and related regasification equipment. FEI has previously discussed in Section 4.2.5.3 how 2 Bcf is the minimum tank size required to meet the Minimum Resiliency

[90] Includes the Tilbury Base Plant tank, Tilbury 1A tank, the resiliency tank (this Project) and a new 0.6 Bcf replacement tank.

Planning Objective. In this section, FEI discusses how it determined that a tank size of 3 Bcf was the upper limit at Tilbury due to technical and cost considerations.

Alternatives	Reason Why Preferred Option
On-System Storage at Tilbury	New storage at Tilbury is the only feasible storage option to meet the Minimum Resiliency Planning Objective, but only within size parameters of between the minimum of 2 Bcf and 3 Bcf. There are diminishing economies of scale beyond 3 Bcf due to constructability challenges.

The volume of a storage tank is a function of both its height and diameter. FEI has identified that strong economies of scale exist for the tank up to the point where either (a) the tank diameter requires a larger foundation and more complex roof structure or (b) the tank walls become sufficiently high that new construction methods are required and new constructability risks are introduced.

Aside from the impact of a larger diameter on the foundation and roof structure, FEI must also consider other constraints regarding the tank footprint and placement on the site. The Tilbury site is uniquely situated with existing access to key supporting infrastructure. The site has been carefully optimized, including allowing for the location and spacing of key infrastructure. Current standards require specific distances from the edge of the tank to property lines and between storage tanks. The application of these site distance constraints results in a tank location that limits the maximum tank diameter to approximately 77 metres. At this diameter, the height of the tank walls can be considered standard for a tank of 3 Bcf. As the tank size increases, the overall height of the tank must increase to accommodate the increased volume.

Building a tank with increased volume beyond 3 Bcf by increasing the height of the tank walls introduces unique design and constructability challenges, including:

- A higher tank will impose a greater load on the ground which will increase the complexity of ground improvements required to limit tank settlement;
- The higher design loads will also increase the complexity and cost of the tank slab to prevent what is referred to as “dishing”, or the deflection in the bottom of the tank;
- The greater tank height will require a more complex foundation and slab to meet seismic requirements;
- Thicker concrete walls will be required to accommodate the increased heights;
- The consideration of construction techniques will be non-standard as the tank will need to be designed to accommodate larger and taller equipment within the tank during construction; and
- There will be increased safety considerations and rescue plans for working within the tank.

The technical challenges noted above are not insurmountable; however, they would require additional engineering and costs to overcome. It is desirable to construct a tank that maximizes resiliency benefits without reaching the point where technical challenges introduce costs and uncertainties that erode the economies of scale. Accordingly, given the constraints of designing, siting and constructing a new tank within an operating brownfield site, FEI has determined that tank sizes at the Tilbury site at 3 Bcf or below are preferred.

4.3.6 Step One Conclusion: Storage of Between 2 Bcf and 3 Bcf at the Existing Tilbury Site is the Only Feasible Project Alternative

The step one assessment demonstrated that a single new on-system LNG storage tank of between 2 Bcf and 3 Bcf located at the existing Tilbury site is the only feasible approach to meeting the Minimum Resiliency Planning Objective. As discussed next, constructing a tank and regasification package at the upper end of this range maximizes the resiliency and other benefits for customers.

4.4 STEP TWO: OPTIMAL SIZING OF TILBURY STORAGE AND REGASIFICATION

The step two analysis builds on the outcome of step one, which was that on-system LNG storage at the existing Tilbury site in the range of 2 to 3 Bcf is the only feasible option that will meet the Minimum Resiliency Planning Objective. The second step of the alternatives analysis involves consideration of options for the size of tank and regasification capacity. FEI focused on tank sizes of 2 Bcf and 3 Bcf, with regasification capacity of 600 and 800 MMcf/day. The feasible tank sizing alternatives are assessed against specific criteria. FEI's overall approach aligns with the decision framework outlined by Guidehouse, which is discussed in the following sections.

The outcome of the review was a preferred alternative of a 3 Bcf tank and 800 MMcf/day of regasification capacity:

- A 3 Bcf tank is most appropriate given the additional resiliency and ancillary benefits of the larger tank and the economies of scale associated with increasing the size from 2 Bcf to 3 Bcf; and
- 800 MMcf/day significantly reduces the risk of widespread outages by covering the Lower Mainland daily demand on all but one day in the design year.

4.4.1 Evaluation of Storage Capacity: 3 Bcf Tank Is the Superior Option

FEI's preferred alternative regarding tank sizing is 3 Bcf. For this determination, FEI applied five criteria (Tank Criteria), encompassing a broad range of considerations. The Tank Criteria include:

- Functionality across a range of emergencies and gas supply events;
- Capital cost and economies of scale;

- Constructability;
- Flexibility to accommodate future load growth; and
- Ancillary benefits.

The table below summarizes how the 2 Bcf and 3 Bcf alternatives compare when evaluated against the Tank Criteria. The 3 Bcf storage alternative stands out as the best option, capable of meeting all of the technical objectives and delivering other benefits, while being the most balanced from a financial perspective.

Table 4-5: Evaluation of Tank Sizes Against Tank Criteria

Project Criteria	Superior Option	Comments
Functionality Across a Range of Emergencies and Gas Supply Events	3 Bcf	• Both tank sizes are able to meet the Minimum Resiliency Planning Objective. • 2 Bcf tank provides no margin during winter conditions beyond the 3-day "no-flow" event, whereas 3 Bcf tank can either: ○ provide additional capacity to address subsequent gas supply events beyond the initial 3-day "no-flow" event; or ○ backstop a "no-flow" event for approximately 5 days during winter conditions.
Capital Cost and Economies of Scale	3 Bcf	• 3 Bcf tank provides economies of scale. The total capital cost of the Project with a 3 Bcf tank is $50 million greater in 2020 dollars (approximately 8.4 percent) than one with a 2 Bcf tank, but provides 50 percent more storage. The 3 Bcf tank yields a much lower cost/Bcf.
Constructability	Equivalent	• Both tanks can be safely constructed.
Flexibility to Accommodate Future Load Growth	3 Bcf	• 3 Bcf tank will accommodate some future load growth on the system while still meeting the Minimum Resiliency Planning Objective; 2 Bcf tank will not.
Ancillary Benefits	3 Bcf	• Both the 2 Bcf and 3 Bcf tanks provide ancillary benefits. The additional 1 Bcf within the 3 Bcf tank allows FEI to access additional ancillary benefits, including some that the 2 Bcf tank cannot provide.

The following subsections discuss in greater detail FEI's evaluation of the range of tank sizes between 2 and 3 Bcf against the five Tank Criteria, demonstrating why 3 Bcf is the preferred alternative.

4.4.1.1 Criterion 1 – Functionality: 3 Bcf of Storage Provides Better Functionality

Functionality refers to the ability to provide FEI customers with adequate protection for a range of emergencies and gas supply events. A 3 Bcf tank provides significantly better functionality

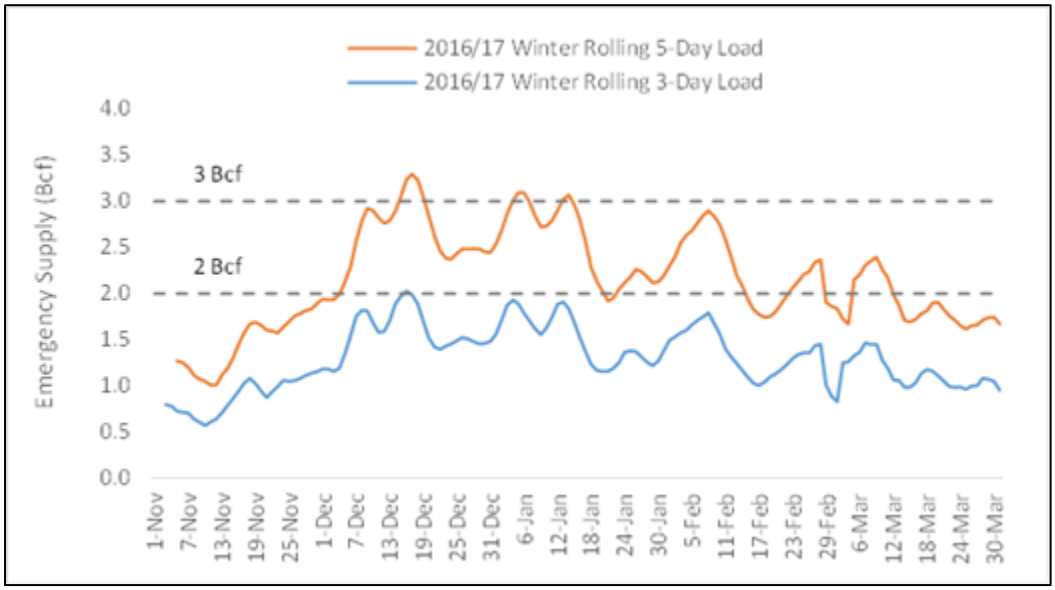
than a 2 Bcf tank, for the reasons outlined below. This remains true regardless of whether a new regional pipeline is constructed in the future.

4.4.1.1.1 3 BCF PROVIDES SUPERIOR FUNCTIONALITY TO COVER EXTENDED "NO-FLOW" EVENTS

The following figure, using real data from a recent cold winter (2016/17), illustrates why FEI believes that a 3 Bcf tank is supported from a functionality standpoint. The orange line shows the five-day rolling load, while the blue line shows the three-day rolling load. Two inferences can be drawn from the figure:

- A 2 Bcf tank is sufficient to meet demand over a 3-day "no-flow" event, but is insufficient to cover a 5-day event for more than half of the winter period (the portion of the orange line above the 2 Bcf horizontal dotted line). Moreover, there would be little if any storage inventory remaining to manage supply constraints and peaking requirements after the initial interruption; and
- Even with a 3-day interruption, there were four or five instances where a 2 Bcf tank would have been just able to meet demand, and one instance with no margin.

Figure 4-8: Storage Capacity versus 2016/17 Winter Conditions



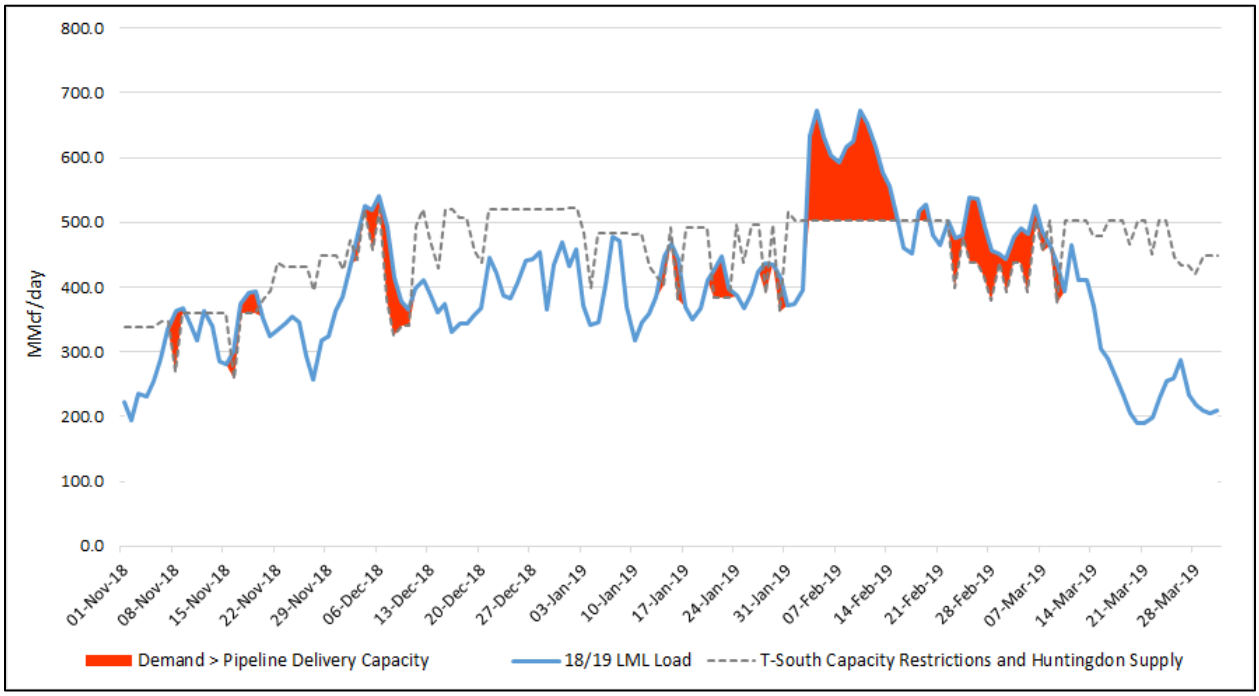
4.4.1.1.2 3 BCF TANK PROVIDES SUPERIOR FUNCTIONALITY TO COVER SUBSEQUENT GAS SUPPLY EVENTS

All else being equal, a 3 Bcf tank provides FEI with superior functionality, as compared to a 2 Bcf tank, to cover subsequent gas supply events that occur following the initial emergency.

While the initial "no-flow" event may be resolved in as little as two or three days, there is a very real potential for gas supply events or shortfalls to occur following the initial "no-flow" event. This was demonstrated during the T-South Incident, when demand exceeded pipeline supply at times during the following winter while pipeline supply remained constrained. The figure below,

which is copied from Section 3.4.2.2.3, is repeated below for ease of reference. The periods during that winter where demand exceeded available pipeline capacity are represented by the red shaded portions where the blue line is above the dashed grey line, which was a period of several weeks.

Figure 4-9: FEI's T-South Capacity Restrictions vs Mainland Winter Load (Actuals)



When the T-South Incident initially occurred, FEI had recognized that using Tilbury to bridge the "no-flow" supply emergency might cause a significant problem later in the winter, since FEI likely would be unable to refill the tank before the peak; therefore, FEI reserved its supply of LNG at Tilbury for the winter period. As discussed in Section 3.4.2.2.3, this supply proved to be key to cover the colder periods in February when demand exceeded available pipeline supply.

It should be noted that the winter of 2018/19 (following the T-South Incident) was an average winter, and yet FEI experienced these supply shortfalls for several weeks. In a colder winter like 2016/17, the demand would be higher. It would give rise to the potential for larger and longer shortfalls.

While a larger tank size will not eliminate system risk, it will provide a much greater ability to manage a range of emergency and gas supply events. Investments in other infrastructure, i.e., new pipeline infrastructure, as part of an overall portfolio approach could further mitigate the remaining risk during a subsequent period of constraint.

4.4.1.1.3 CONCLUSION REGARDING FUNCTIONALITY: 3 BCF OF LNG STORAGE IS SUPERIOR

A tank size of 3 Bcf provides superior functionality with or without a diversified pipeline supply. From a functionality perspective, 2 Bcf will meet the Minimum Resiliency Planning Objective.

However, after 3 days of a "no-flow" event the LNG storage resources will be depleted, and the ability to respond to any other gas supply events which may occur in the subsequent days and months will be limited. Constructing a 3 Bcf tank will provide FEI with much greater flexibility to respond to subsequent events and manage the inherent unpredictability of cold weather events which may follow a "no-flow" event.

4.4.1.2 Criterion 2 – Capital Cost and Economies of Scale: Additional Benefits of 3 Bcf Can Be Achieved for Limited Additional Cost

It is important to assess the relative cost and added benefits of different LNG tank sizes. The cost of a 2 Bcf tank and 3 Bcf tank are both significant; however, the incremental difference between 2 Bcf and 3 Bcf is small relative to the Project cost as a result of inherent economies of scale. The same is true for customer rate impact.

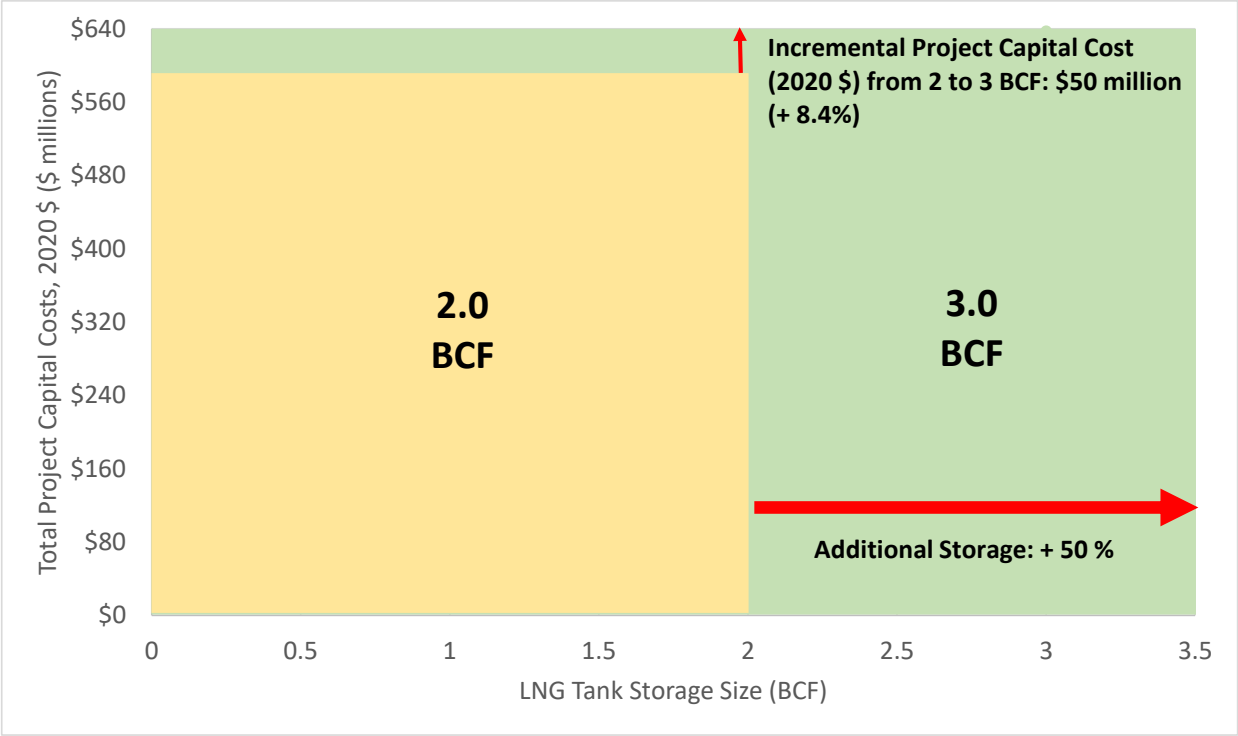
Resiliency investments are, as Guidehouse notes,[91] akin to purchasing insurance, where it is necessary to balance risk against cost of purchasing that insurance. It is impossible to eliminate all risk of system collapse, and it would be prohibitively expensive for customers to attempt to do so. FEI's approach to resiliency has kept cost in mind, having regard to the nature and extent of the risk.

As previously discussed, LNG storage infrastructure at Tilbury is characterized by significant economies of scale up to 3 Bcf, such that the capital cost per unit of storage decreases as the size of the LNG storage increases up to that point. As such, it is important to assess whether the added benefits resulting from increasing storage size up to 3 Bcf potentially outweigh the impact of the additional costs. However, 3 Bcf represents an inflection point in terms of costs; tank sizes greater than 3 Bcf would increase the design and construction complexity, drive up the overall capital cost of the tank, and thereby reduce the economies of scale.

Figure 4-10 below illustrates graphically the strength of the economies of scale for a 3 versus a 2 Bcf tank. The financial comparison demonstrates that 50 percent more storage can be achieved for approximately $50 million in 2020 dollars, or an additional 8.4 percent in capital cost. The unit cost for the Project with a 3 Bcf tank (including ground improvement, auxiliary systems, and regasification) is approximately $81 million per Bcf in 2020 dollars lower than the unit cost with a 2 Bcf tank. Thus, the economies of scale significantly favour a 3 Bcf tank versus a 2 Bcf tank.

[91] Appendix A, page 46.

Figure 4-10: Graphical Illustration of Economies of Scales Between 2 and 3 Bcf Tank Sizes



The same pattern emerges when assessing customer impacts. The incremental levelized delivery rate impact to customers associated with selecting the larger tank is $0.026 per GJ. For a typical FEI residential customer consuming 90 GJ per year, the additional levelized delivery rate impact for a 3 Bcf tank is approximately $2.30 per year. See Table 4-6 below.

Table 4-6: Financial Evaluation of Alternatives (2 and 3 Bcf Tanks)[92]

	2 BCF	3 BCF	Incremental from 2 BCF to 3 BCF
AACE Class Estimate	Class 3	Class 3	
Total Project Capital Costs, 2020 dollars ($ millions)	588	637	50
Capital Cost per unit of storage ($ millions/BCF)	294	212	(81)
PV of Incremental Revenue Requirement 67 years ($ millions)	951	1,042	91
Levelized Delivery Rate Impact 67 years (%)	6.09%	6.67%	0.58%
Levelized Delivery Rate Impact 67 years ($/GJ)	0.275	0.301	0.026
Average Residential Use per Customer (GJ)	90.0	90.0	90.0
Average Annual Residential Bill Increase ($)	24.8	27.1	2.3
Average Annual Residential Bill Increase (%)	4.10%	4.49%	0.39%

[92] Details of the Financial Analysis for both the preferred 3 BCF tank and the 2 BCF tank can be found in Confidential Appendix M1 and M2, respectively.

4.4.1.3 Criterion 3 – Constructability: Marginal Difference in Constructability Between 2 and 3 Bcf Tanks

Constructability considers the ability to safely and economically construct the LNG storage and regasification equipment as well as the potential impact of construction on FEI's existing LNG operations and the area surrounding the Tilbury site. Constructability also considers any design risks associated with constructing different sizes of LNG storage tanks.

Engineering work completed to date does not indicate any significant safety risks or constructability risks associated with building a 2 or 3 Bcf tank.

From a safety perspective, both tank sizes can be constructed to meet all relevant regulatory requirements including CSA Standard Z276 Liquefied Natural Gas (LNG) Production, Storage and Handling. This standard ensures that all aspects of the installation are designed to meet stringent safety requirements.

The larger tank will require some additional considerations during detailed design to manage tank settlements expected with the larger ground loading associated with a higher tank. From a constructability perspective, the 3 Bcf tank will require a slightly longer construction window due to its larger size and height.

4.4.1.4 Criterion 4 – Flexibility to Accommodate Future Load Growth: 3 Bcf of Storage Best Addresses Growth

The average service life of a new LNG storage tank is 60 years and the average service life of new regasification equipment is approximately 40 years. Over that time, FEI expects that the annual and peak demand on the system will continue to grow. As such, FEI considered the flexibility to accommodate future load growth within different tank sizes, thereby ensuring the infrastructure that is built today will meet its intended purpose in future years.

As presented in FEI's 2017 Long-term Gas Resource Plan (LTGRP), annual demand for natural gas is projected to grow by at least 3.1 Bcf (3,560 TJ)[93] per year on average across the FEI system over the 20 year planning horizon as per the reference case demand forecast. Peak demand on the CTS serving the Lower Mainland is expected to grow by approximately 9 MMcf/day (10 TJ per day)[94] in the same period increasing peak daily demand from 871 to 880 MMcf/day. FEI expects new infrastructure will be built in the region to support new load on FEI's system and in the region.[95]

A larger 3 Bcf tank and regasification capacity not only provides better functionality to meet current demands, but also provides greater flexibility than a 2 Bcf tank to accommodate future

[93] Appendix B of the 2017 FEI Long Term Gas Resource Plan (LTGRP), Page 1 and 7, and Section 4, page 103. This value includes reference case residential, commercial and industrial demand, plus reference case demand for transportation, less the estimated energy savings from demand-side management activities in year 20 of the planning horizon.

[94] 2017 FEI LTGRP, Figure 6-7, page 167.

[95] Appendix C, p. 31. "In the next few years, additional demand for gas at Huntingdon may come from major industrial projects such as Woodfibre LNG, methanol production plants and more gas-fired plants to replace coal plants for power generation in the PNW."

load growth. Further, even with the construction of new pipeline into the region, a larger 3 Bcf storage tank is complementary to new pipelines and would play a critical role in ensuring both short-term system planning and gas supply in the event of a future supply disruption.

Additionally, the 2017 LTGRP examined the impact of a number of technology advancements that could lead to a substantially decarbonized energy system, utilizing the natural gas infrastructure within the Province to continue delivering gas in a diversified energy future.[96] A range of demand growth opportunities that reduce global GHG emissions through conversion from higher carbon emitting fuels in the transportation sector, improved energy efficiency within the built environment and lower carbon gas supplies, all in varying amounts, will make up such a low carbon energy future while maintaining a diverse and robust energy system in BC. There are a wide range of combinations of these resources that could be employed to help meet Provincial emission reduction targets, making a flexible natural gas storage and distribution system essential long into the future. A 3 Bcf tank maximizes the opportunity to meet Provincial energy needs in a cost-effective way by accommodating future growth and expanding FEI's ability to store and deliver renewable natural gas.

4.4.1.5 Criterion 5 – Ancillary Benefits: 3 Bcf Provides Greater Benefits for Customers

This section describes how a 3 Bcf tank provides FEI and its customers with greater ancillary benefits over and above enhancing system resiliency associated with expanding on-system LNG at Tilbury. Additional storage allows FEI to access ancillary benefits, which can mitigate future risks. These benefits include:

- Mitigation of third-party storage risk;
- Improved security of supply;
- Enhanced daily balancing capability;
- Increased operational flexibility and efficiency; and
- Potential to reduce customer rates through storage lease opportunities.

As illustrated in Figure 3-1 on page 14 of Appendix C, FEI's current LNG facilities at Tilbury and Mt. Hayes serve multiple purposes. To the extent that FEI's emergency supply and capacity needs are met, additional storage resources at Tilbury can be deployed to capture these ancillary benefits. As such, FEI describes the benefits that are enabled by the investment in one additional Bcf of storage at Tilbury.

4.4.1.5.1 LARGER TANK MITIGATES THIRD-PARTY STORAGE RISK

The addition of on-system storage above FEI's Minimum Resiliency Planning Objective mitigates the risk of losing access to third-party off-system storage assets at JPS and Mist, which are both critical components of FEI's resource stack to balance seasonal supply and demand.

[96] Appendix E of the 2017 FEI LTGRP.

FEI contracts for both of these assets, but does not have renewal rights for Mist. FEI expects increased competition and there is a risk that it may not be able to retain its off-system storage assets. FEI expects the value of storage to increase, driven by the increased need for firming of electricity supply using natural gas power generation in support of the increase in renewable power generation (wind and solar) in the US.

As noted in Section 3.4.3.1 of Appendix C, power burns[97] in the US Pacific Northwest have increased over the past few years as coal-fired power plants are increasingly being retired, thereby increasing the utilization of gas-fired power generation. Given the relatively low cost of storing natural gas energy relative to the expensive and limited ability to store electricity, FEI believes gas storage assets will be increasingly valuable to power producers. For instance, NW Natural's 2018 Integrated Resource Plan indicates future load growth in its service regions (Oregon and Washington) as factors that could lead to recalling contracted capacity at its Mist underground storage facility from third parties. As market participants compete for existing resources in the region, it will be a challenge to acquire additional short-duration storage and the value of those resources is expected to increase over time.

4.4.1.5.2 LARGER TANK PROVIDES IMPROVED SECURITY OF SUPPLY

Enhanced security of supply, a key element of reliable service, is an important ancillary benefit of adding on-system LNG at Tilbury. There are two aspects to this additional supply security:

- First, additional on-system storage and regasification backstop existing off-system storage resources (e.g., JPS and Mist) in the event of a failure at those facilities. While reliability at those off-system storage facilities is generally good, interruptions can occur; and
- Second, and more significantly, new on-system LNG will improve FEI's physical security of peaking supply as FEI's customer demand grows. Existing resources in the region are constrained. The costs of acquiring resources has increased over time as market participants compete for resources. For instance, FEI has recently experienced a rise in costs to renew its market area storage resources.98 Going forward, it is reasonable to expect that contracting peaking resources could be challenging and costly absent new infrastructure being built.

Table 4-7 below highlights the extent to which existing resources in the region are constrained. All of the key pipeline and off-system storage resources are fully contracted. Given the winter demand profile in the region and the current market conditions, FEI expects that these resources will be fully contracted into the future and parties will renew their contracts as their renewal rights come due.

[97] Power burns refers to natural gas-fired electricity generation.

[98] FEI recently came to terms for an extension of an existing JPS deal and the unit price rose from $3.00 US/MMbtu for the service to $3.75 US/MMbtu.

Table 4-7: Existing Pipeline and Storage Resources in the Region

Pipeline	Daily Deliverability[1] (MMcf/day)	Total Winter Supply (Bcf)	Contract Status
Enbridge T-South (Huntingdon Delivery Area)	1702	257	Fully Contracted
Enbridge T-South (BC Interior)	224	34	Fully Contracted
FortisBC SCP (Oliver North)	140	21	Fully Contracted
FortisBC SCP (Oliver to Kingsvale)[2]	105	16	Fully Contracted
TCPL (FoothillsBC)	2930	442	Fully Contracted
NWP Gorge	534	81	Fully Contracted
Market Area Storage	**Daily Deliverability (MMcf/day)**	**Storage Capacity (Bcf)**	
Jackson Prairie (JPS)	1161	25	Fully Contracted
Mist	637	19	Fully Contracted
On System Storage	**Daily Deliverability (MMcf/day)**	**Storage Capacity (Bcf)**	
Mt. Hayes LNG	150	1.5	Fully Utilized on Peak Day
Tilbury LNG	150	1.35	Fully Utilized on Peak Day

1. Daily deliverability is the maximum amount of gas that can flow on the pipeline or the maximum amount of gas that can be withdrawn out of storage. It is important to note that the daily deliverability out of the market area storage is assuming storage inventories are full. These resources do have withdrawal rates decline as working gas volumes decline.

2. The 105 MMcf/day is included in the 1,702 MMcf/day Huntingdon Deliveries (i.e. Kingsvale to Huntingdon).

There are other alternatives for future peaking supply; however, new on-system LNG storage provides the greatest flexibility as a potential supply resource. New on-system LNG storage also avoids assuming additional resiliency risk associated with peaking call options and off-system storage.

4.4.1.5.3 LARGER TANK PROVIDES ENHANCED DAILY BALANCING CAPABILITY

Constructing more regasification capacity and storage at Tilbury will allow FEI to deliver a large amount of supply within a short period of time, providing FEI with additional operational flexibility to manage daily balancing.

Daily balancing is, in essence, the exercise of maintaining the pressure on the system in the face of variances between planned and delivered volumes from pipelines feeding the system. Keeping the system in balance is vital to maintaining line pack pressure within operating parameters, as well as preserving flexibility and response time.

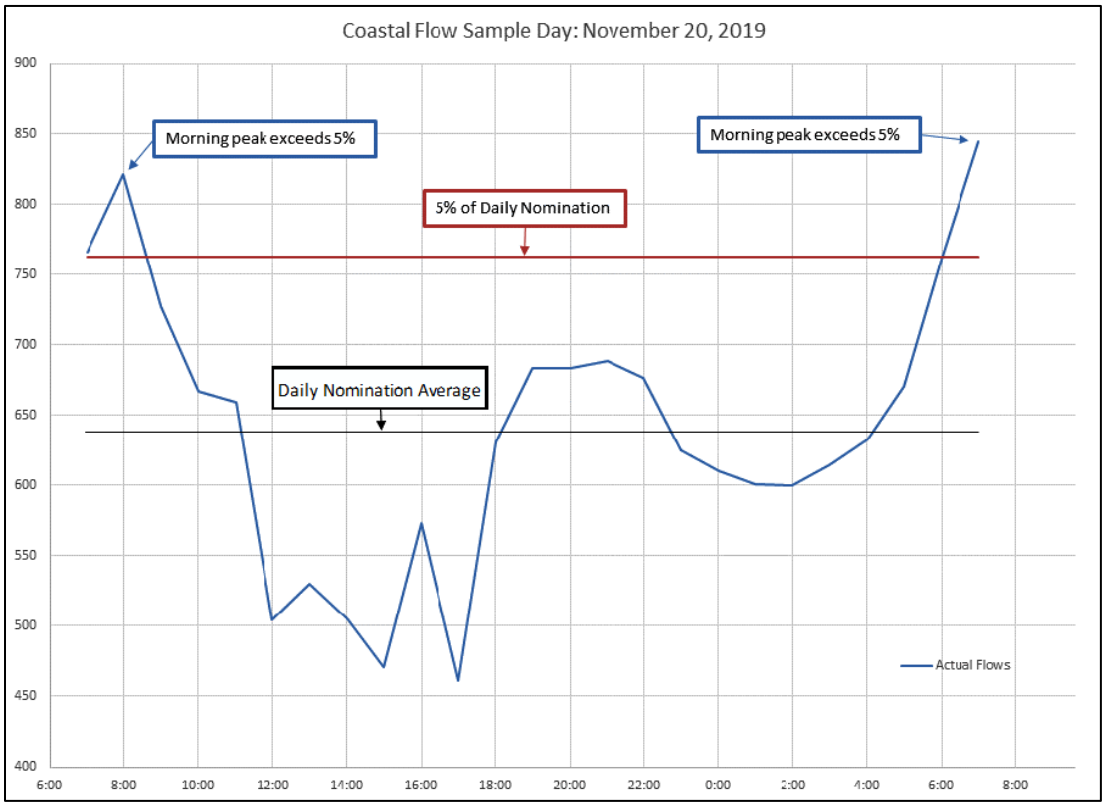
FEI plans the next-day gas supply based on a weather forecast, which can deviate significantly from the actual weather experienced during the day as Lower Mainland demand increases by approximately 25 MMcf/day when temperature decreases by one degree Celsius. [redacted] as depicted in the illustrative figure below. When this happens, one of four things must

[redacted]

happen to keep the system in balance: (1) Westcoast refrains from enforcing the 5 percent limit; (2) FEI sheds load by interrupting service to interruptible customers; (3) FEI isolates the VITS to reduce flow and uses limited line pack to meet the load; or (4) FEI injects supply from Tilbury or Mt. Hayes.

Figure 4-11: Daily Balancing Example

Lower Mainland Load (MMcf/day) vs Hours (24 Gas Day)[100]



Traditionally, Westcoast has assisted FEI in managing these instances by refraining, where it can, from enforcing the 5 percent limitation in the OBA. However, Westcoast's ability to provide this additional flexibility to FEI has become more limited in recent years as the Westcoast system has become fully contracted and capacity has become harder to obtain. FEI has

[redacted]

[100] In the graph, the Daily Nomination Average line (in black) represents the official Nomination value for the day, divided equally over a 24-hour period. The 5 percent of Daily Nomination line (in red) represents the 5 percent OBA rule, which is upper limit of hourly consumption allowed in the provisions of the OBA, and is significantly higher than the average line. This allows FEI to overtake gas during peak hours and compensate with lower consumption during off-peak hours, as long as the total consumption rate-out at the end of the day. As demonstrated on the graph, the actual measure flows on this particular day exceeded the 5 percent OBA limit twice, once during the early morning peak and a second time during the morning peak at the end of the same day. Note that the 5 percent of Daily Nomination is calculated as: Daily Nom x 0.05. The Daily Nomination Average is calculated as: Daily Nom ÷ 24. Hence the difference between the two lines is 20 percent.

received occasional requests from Westcoast to reduce peak hourly flows to keep within the 5 percent rule.

FEI has limited options when this occurs, and the options will potentially become more limited in the coming years for two reasons:

- First, if the construction of the Woodfibre LNG project proceeds, it will change the demand profile on FEI's transmission system, reducing line pack and making daily load balancing more challenging.
- Second, FEI's ability to rely on Westcoast's waiver of the 5 percent requirement into the future is less certain than it has been in the past. FEI expects that Westcoast will be operating in an increasingly constrained pipeline environment in the winter given the existing market conditions, such that the provision of the 5 percent term within the OBA may become more strictly enforced.

Short of shutting-in customers to reduce demand, the use of on-system supply from Tilbury would be the preferred and most reliable solution to address this operational need. Therefore, the construction of storage above the minimum requirement at Tilbury enhances FEI's ability to meet OBA balancing obligations.

4.4.1.5.4 LARGER TANK PROVIDES INCREASED OPERATIONAL FLEXIBILITY AND EFFICIENCY

Additional storage capacity at Tilbury could be used to support maintenance activities on FEI's pipelines, without necessarily waiting for a period of low demand on the system to perform maintenance activities. FEI is currently developing a CPCN application for the Transmission Integrity Management Capabilities (TIMC) Project. A primary driver for this project is that it will improve FEI's ability to manage the integrity of its transmission pipelines by using new inline inspection (ILI) tools able to detect stress corrosion cracking and other crack-like features. In order to effectively gather data using ILI technology, specific gas velocities are required. This is because ILI tools typically have a limited range of travel speeds within which they collect accurate data.

Normally, the flow rates in FEI's transmission pipelines are dictated solely by the customer demand on the system. Consequently, there are extended periods during the year when gas flow rates in pipelines supplying the Lower Mainland are too high to accommodate running ILI tools. This is particularly true with the NPS 42 and NPS 30 transmission pipelines originating at the Huntingdon Station. By regasifying the LNG stored at the Tilbury facility and injecting it into the CTS, the upstream gas flow rates (i.e., the supply from the Huntingdon Station) would be reduced. This is because the gas supplied from Tilbury would be used to supply a portion of the customer load, and hence reduce the supply requirement from the Huntingdon Station. The reduced flow rates could provide greater timeframes during which ILI tools and other necessary pipeline maintenance could be accommodated, without having to wait for customer consumption to be reduced.

Therefore, construction of additional storage capacity above the amount required to meet FEI's Minimum Resiliency Planning Objective provides FEI with greater operational flexibility to inspect and perform maintenance activities on its pipelines.

4.4.1.5.5 LARGER TANK PROVIDES THE POTENTIAL TO REDUCE CUSTOMER RATES

The construction of a 3 Bcf tank versus a 2 Bcf tank provides opportunities for load growth that would have the potential to reduce rates for customers.

The construction of a new pipeline in BC will proceed when supported by load growth in the region. Additional pipeline capacity into the region could provide the opportunity for further expansion of the Tilbury site with additional liquefaction to support LNG for export. Discussions have been ongoing over the past number of years with several overseas customers who have interest in exporting LNG from Tilbury to destinations in Asia. LNG from Tilbury has a production carbon intensity up to 30 percent lower than global average LNG. Its use can reduce GHG emissions from marine shipping by up to 27 percent compared to petroleum-based fuels. Further, its use can reduce industrial GHG emissions in China by 30 to 50 percent compared to domestic energy sources such as coal.[101]

This potential scenario provides significant future optionality and a potential reduction in FEI's customer rates in the scenario where a new pipeline into the Lower Mainland is constructed that follows an entirely separate corridor from the T-South system along with an expansion at the Tilbury site. FEI explains in further detail below.

While an uncertain and contingent event, the expansion of the Tilbury LNG site would likely include a large amount of liquefaction capacity up to 3 million tonnes per annum (approximately 12 times the size of Tilbury 1A and 60 times the size of the Tilbury Base Plant liquefaction). This amount of liquefaction capacity at the Tilbury LNG site could change FEI's operating paradigm, including its storage needs. For example, FEI could enter into a commercial arrangement to utilize a small amount of the bulk export liquefaction capacity to backstop liquefaction outages associated with Tilbury 1A and 1B liquefaction, thereby freeing up 1 Bcf of storage capacity from the Tilbury 1A tank. With the additional pipeline supply into the Lower Mainland, as discussed in Section 4.2.4.5 above, FEI could potentially further reduce its storage needs by entering into commercial arrangements to provide access to other contingency resources. This could potentially allow FEI to lease storage space to the export entity, thereby recovering a portion of the cost of service of the Project while maintaining an enhanced level of resiliency. Should this opportunity materialize, there is the potential to reduce FEI customers' costs; however, it is unlikely that a 2 Bcf tank under this scenario would free up enough space to take advantage of such an opportunity. Therefore, the construction of storage capacity above the minimum requirements enhances FEI's potential to reduce rates through storage lease opportunities.

[101] https://talkingenergy.ca/topic/analysis-highlights-environmental-benefits-tilbury-lng-marine-fuel

4.4.1.6 Step Two Conclusion: 3 Bcf of Storage Provides Superior Value When All Criteria Are Considered

The above analysis demonstrates that a 3 Bcf LNG storage tank provides superior value to customers relative to a 2 Bcf tank when measured against the five Tank Criteria.

4.4.2 Evaluation of Regasification Capacity: 800 MMcf/day Provides the Necessary Coverage of Daily Load

Regasification is a key element of storage in that it provides the ability to vapourize the LNG to send into FEI's Coastal Transmission System. The determination of the regasification capacity is a straightforward exercise based on the following:

- The incremental capacity of the selected regasification units; and
- The amount of supply required to support the Lower Mainland daily load during a gas supply disruption.

4.4.2.1 Vapourizers[102] in Units of 200 MMcf/day are Optimal

A regasification package consists of several components (refer to Section 5.3), one of which is the vapourizer. FEI considered a range of vapourizer sizes and technologies to achieve the required level of regasification required. The preferred technology was selected on the basis of a number of factors, including:

- **Response time:** the ability to start up the unit and provide gas to the system in the shortest amount of time;
- **Proven technology:** ensuring the equipment selected has a history of performing well in other installations around the world;
- **Physical size:** included an assessment of both the physical size of the units as well as the number of units required to achieve the desired capacity; and
- **Reliability:** the ability to consistently perform their intended function.

FEI selected submerged combustion vessel technology because it provided the best performance having regard to the above factors. While consideration was given to using a larger number of smaller units, the unit capacity chosen was 200 MMcf/day due to its ability to provide an output range of 50 to 200 MMcf/day. This provides adequate flexibility while also minimizing the number of units required, thus minimizing costs and space requirements.

[102] Vapourizers are a core component of the regasification system which heat the liquefied natural gas, thereby changing it back into a gas for injection into the pipeline system.

4.4.2.2 Regasification Capacity Requirements Were Determined with Reference to Lower Mainland Peak Demand

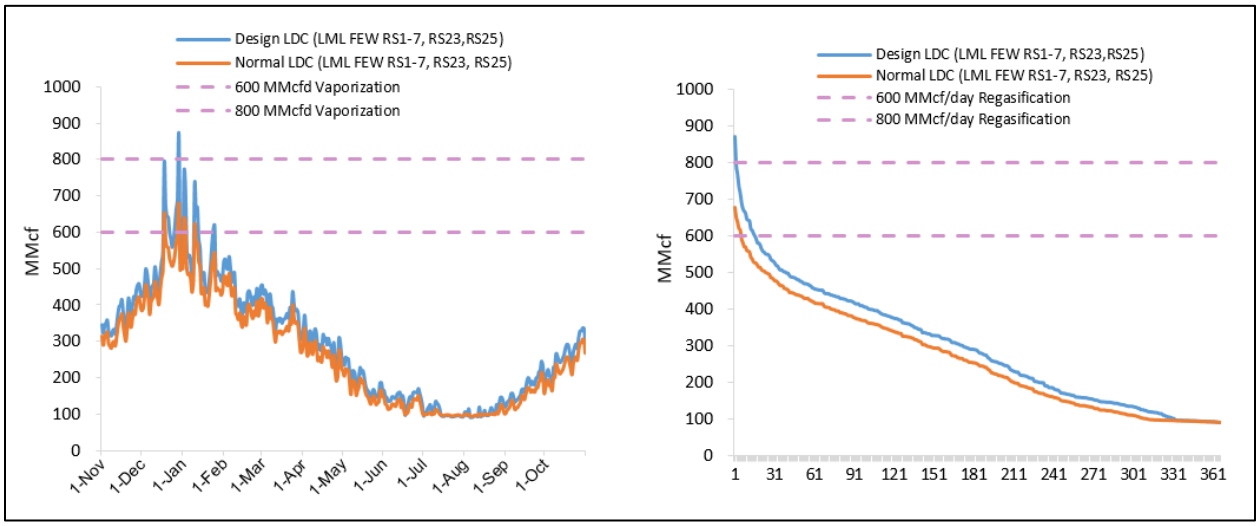
For planning purposes, FEI develops load forecasts based on historical demand and future customer growth. These forecasts can depict the normal demand and/or the design demand. Normal demand represents the expected customer demand in an average weather year while design demand represents the expected customer demand in a very cold year. The coldest day in a design year is referred to as the peak day. FEI used design demand to determine the range of regasification capacity. Regasification capacity is similar to pipeline capacity, which is designed using the design demand curve to ensure deliverability to customers thereby supporting the daily load requirements. As an additional data point, FEI also reviewed actual demand (last 10 years) in considering a reasonable level of regasification capacity.

4.4.2.2.1 LOAD DURATION CURVES SHOW DESIGN PEAK OF 871 MMCF/DAY

The load duration curves for sales customers (Rate Schedule 1 to 7 customers plus Firm Rate Schedules 23 and 25) were used to assess the required emergency supply from Tilbury LNG. A load duration curve is a graphic representation of customer daily demand over a weather year. Design load duration curves provide daily demand estimates during the coldest years derived from historical weather data. Similarly, normal load duration curves provide the daily demand estimates based on the most recent 10 years of weather data.

As shown below, load duration curves can be plotted in chronological order, or by decreasing magnitude, with the greatest load (peak day) at the left and the lowest load at the right.

Figure 4-12: Lower Mainland Load Duration Curves[103]



Based on the load duration curve above, the design peak demand for the Lower Mainland is 871 MMcf/day for 2019/20. FEI notes that the load duration curve declines steeply, such that the second coldest day on the design load duration curve (blue) is 793 MMcf/day. The figures

[103] Load duration curves based on 2019/20 forecast for Lower Mainland RS 1-7, RS 23 and RS 25 customers.

above demonstrate that a regasification capacity of 800 MMcf/day is adequate to cover Lower Mainland load during a complete T-South outage if it occurred on the coldest days of the winter, with the exception of the single peak design day. FEI believes regasification capacity at this level is reasonable given the remote probability of a "no-flow" event occurring simultaneously with the design peak day. Further, regasification capacity at this level will allow FEI to supply enough load so as to make it more realistic to balance the system through targeted load shedding or other emergency measures at times when it is colder.

4.5 CONCLUSION

In this section, FEI has demonstrated that developing new on-system storage at Tilbury is the only feasible option from an economic and technical standpoint.

A new 3 Bcf tank provides the greatest functionality to withstand a 3-day "no-flow" event as well as subsequent gas supply, demand, and operational events that occur. The construction of a larger 3 Bcf tank takes advantage of economies of scale, providing customers with significantly greater resiliency benefits relative to the incremental cost. A larger tank also better accommodates future load growth, mitigates the potential loss of valuable storage resources, improves the security of supply, enhances FEI's ability to perform daily load balancing, increases operational flexibility to maintain its pipelines, and provides opportunities to capture cost savings should an expansion of both regional pipelines and a further expansion at Tilbury occur in the future.

Finally, FEI has demonstrated that regasification capacity of 800 MMcf/day provides reasonable functionality, meeting Lower Mainland load on all but the design peak day. This would provide FEI with sufficient supply such that other tools to balance supply and demand can be used.

5. PROJECT DESCRIPTION

5.1 INTRODUCTION

In this section, FEI describes the Project in more detail, focusing on the proposed alternative identified in Section 4 of the Application: replacing the existing Base Plant with 3 Bcf of storage and 800 MMcf/day of regasification capacity.

Specifically, FEI will:

- Provide an overview of the key Project components and how they advance the Project objectives (Section 5.2);
- Provide a technical discussion of the Project components, and explain how they were developed with the assistance of industry leading experts and in accordance with sound engineering practices (Section 5.3);
- Explain the basis for the cost estimate, and the processes being undertaken to validate the estimate (Section 5.4);
- Discuss how the Project schedule allows FEI reasonable time to complete the Project, while ensuring that resiliency benefits are realized as soon as possible (Section 5.5);
- Outline FEI's assessment of the required resources to complete the Project (Section 5.6);
- Demonstrate that FEI has identified the key Project risks and is taking a prudent approach to risk management (Section 5.7); and
- Show that FEI has identified the key regulatory permits and approvals that are required to construct the Project (Section 5.8).

The existing Tilbury LNG facility is located on Tilbury Island in Delta, BC. The TLSE Project will be constructed within the existing site boundaries. The following picture illustrates the location of the existing infrastructure on FEI's Tilbury property. The green line indicates property boundaries, while the red lines show the location of FEI's existing transmission pipelines.

Figure 5-1: FEI Existing Assets, Tilbury Island, Delta, BC

Source: Google Earth (image date 7/31/2020) overlaid with FEI asset location data

5.2 OVERVIEW OF KEY PROJECT COMPONENTS AND HOW THEY SERVE THE PROJECT OBJECTIVE

FEI, with the involvement of consultants identified in Section 5.3, completed Front End Engineering Design (FEED) studies and engineering studies to develop the design and cost estimates for a new LNG storage tank and regasification package, as well as for the demolition of the Base Plant. The proposed alternative (i.e., the Project), in broad terms, incorporates the following components described in Table 5-1 below.

Table 5-1: Overview of Project Components

Key Project Component	How Component Serves Project Objective
Regasification capacity of 800 MMcf/day.[104]	800 MMcf/day of regasification capacity allows FEI to inject sufficient natural gas from Tilbury into the Lower Mainland system each day to retain an acceptable percentage of load service capability to FEI's customers. The proposed equipment will provide quicker response time than the present configuration. The response time will be two hours (between notification from FEI Gas Control to gas delivered to the system).

[104] 4x200 MMcf/day. Each unit is capable of an output range of 50 to 200 MMcf/day. That is, 50 MMcf/day is the lowest capacity at which a vapourizer can operate.

Key Project Component	How Component Serves Project Objective
LNG storage Tank of 3 Bcf (142,400 m^3).	A 3 Bcf tank provides sufficient LNG supply at the above regasification rate to serve FEI's Lower Mainland winter design load for 3 days without depleting the entire inventory of LNG. This will allow FEI to respond to an initial 3-day "no-flow" event. It will also leave a margin to respond to more common subsequent winter peak loads and gas supply events (such as those occurring following the T-South Incident) that take on greater significance during an ongoing period of pipeline supply constraint. The new LNG tank will be designed according to current design standards to provide safe and reliable operations.
Addition or modification of any necessary auxiliary systems including power supply, utility pipe racks, in-tank pumps, piping, cable trays, instrument air compressors, boil-off gas compressors, connectivity to Tilbury 1A LNG storage tank, and connections to the sendout gas pipeline.	These systems are required to provide the necessary power, control, monitoring, and interconnection systems to safely and reliably operate the facility.
Demolition of above-ground portion of the Tilbury Base Plant LNG storage tank and liquefaction facilities (Base Plant).	As explained in Section 4, it makes practical and economic sense to replace the Base Plant as part of the Project.

With the above Project components installed and operational, FEI will be able to respond rapidly to serve customer load during a critical "no-flow" supply event.

5.3 THE PROJECT IS DESIGNED AND ENGINEERED TO MEET APPLICABLE CODES, STANDARDS AND REGULATIONS

The TLSE Project is being designed in conjunction with a number of specialized consultants with experience in the development of LNG projects. FEI will develop the Project in accordance with all applicable statutory codes and standards, including FEI's internal standards, and all British Columbia Oil and Gas Commission (BCOGC) regulations.

FEI and its consultants completed the following FEED and engineering studies listed in Table 5-2 below to develop the design and cost estimates for the Project. Each of these consultants are experts in their field.

Table 5-2: Overview of Consultants and Studies

Consultant	Project Component	Description	Confidential Appendix
Horton CBI, Limited	New LNG Storage Tank	Technical Write-up	E
Horton CBI, Limited	New LNG Storage Tank	Basis of Estimate and Cost Estimate Report	E

Consultant	Project Component	Description	Confidential Appendix
Linde	Regasification System	Basis of Estimate and Cost Estimate Report	F
Golder Associates Ltd.	Ground Improvement and Early Works	Basis of Estimate and Cost Estimate Report	G
Clough Enercore	Auxiliary Systems (Utility Rack and Equipment)	Basis of Estimate and Cost Estimate Report	H
Solaris Management Consultants Inc.	Base Plant Demolition	Basis of Estimate and Cost Estimate Report	I

In the following sections, FEI will describe the key Project components in greater detail, as well as reference key standards to which FEI will adhere. For convenience, these are the titles of the external standards[105] that are referenced below:

- CSA Z276 – *Liquefied natural gas (LNG) - Production, storage, and handling*;
- API 620 – *Design & Construction of Low-Pressure Storage Tanks*;
- API 625 – *Tank Systems for Refrigerated Liquefied Gas Storage*; and
- ACI 376 – *Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gases*.

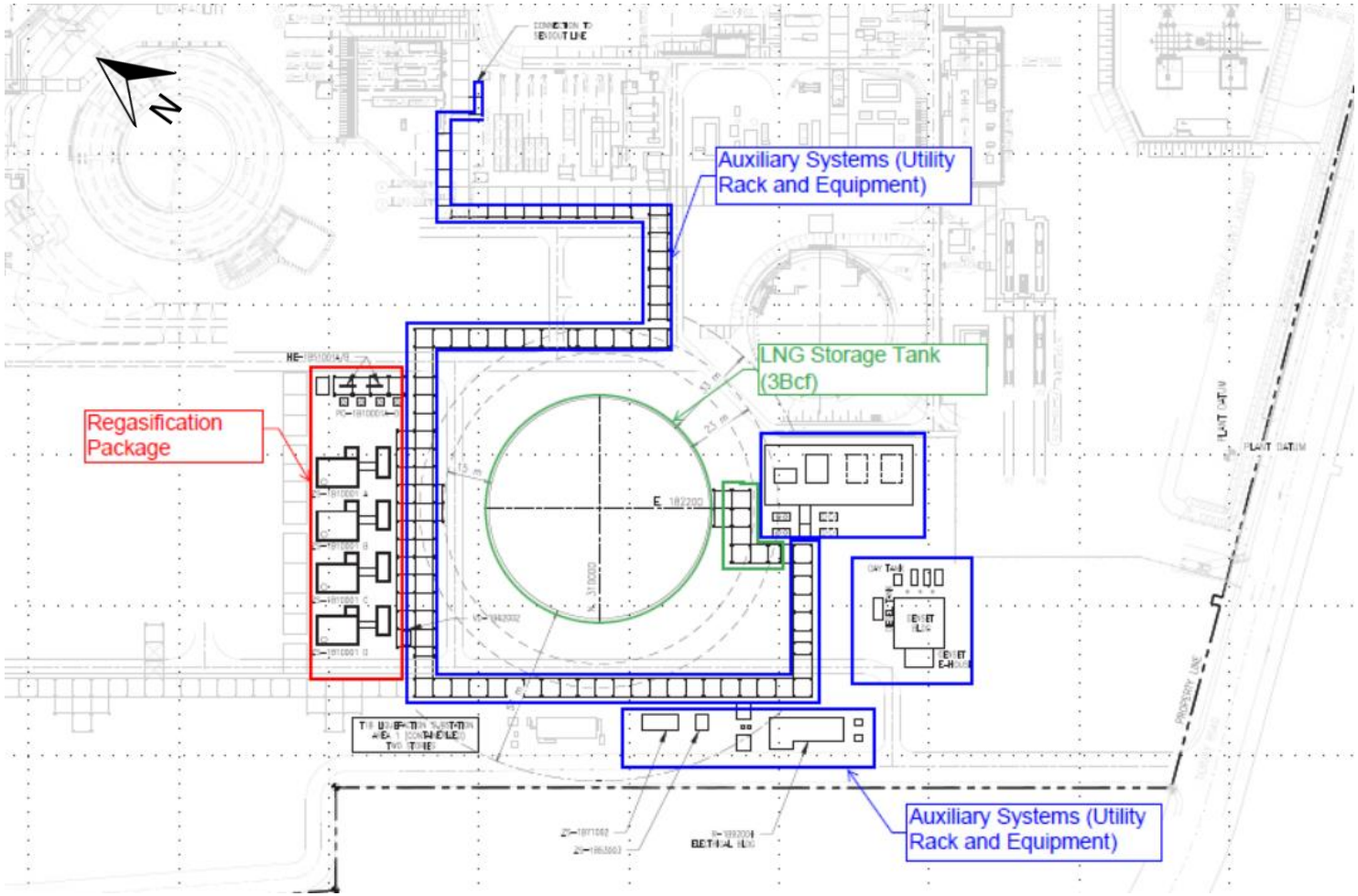
5.3.1 3 Bcf LNG Storage Tank

The proposed new LNG tank will have a volume of 3 Bcf and will be designed, constructed, and operated in accordance with all current applicable codes and standards. Modern design standards and best practices offer advantages in safety and environmental performance. This section summarizes the parameters and requirements that are taken into account for the tank design. Additional detail is available in Confidential Appendix E.

The 3 Bcf tank will be constructed on the existing Tilbury site in the location shown in Figure 5-2 (the underlying site plan in this figure is shown in the same orientation as Figure 5-1 above). The proposed locations of the new regasification facility and auxiliary systems are also shown.

[105] All reference to standards imply the most current edition of the standard unless otherwise noted.

Figure 5-2: Proposed New Equipment Locations



5.3.1.1 Tank Design Parameters

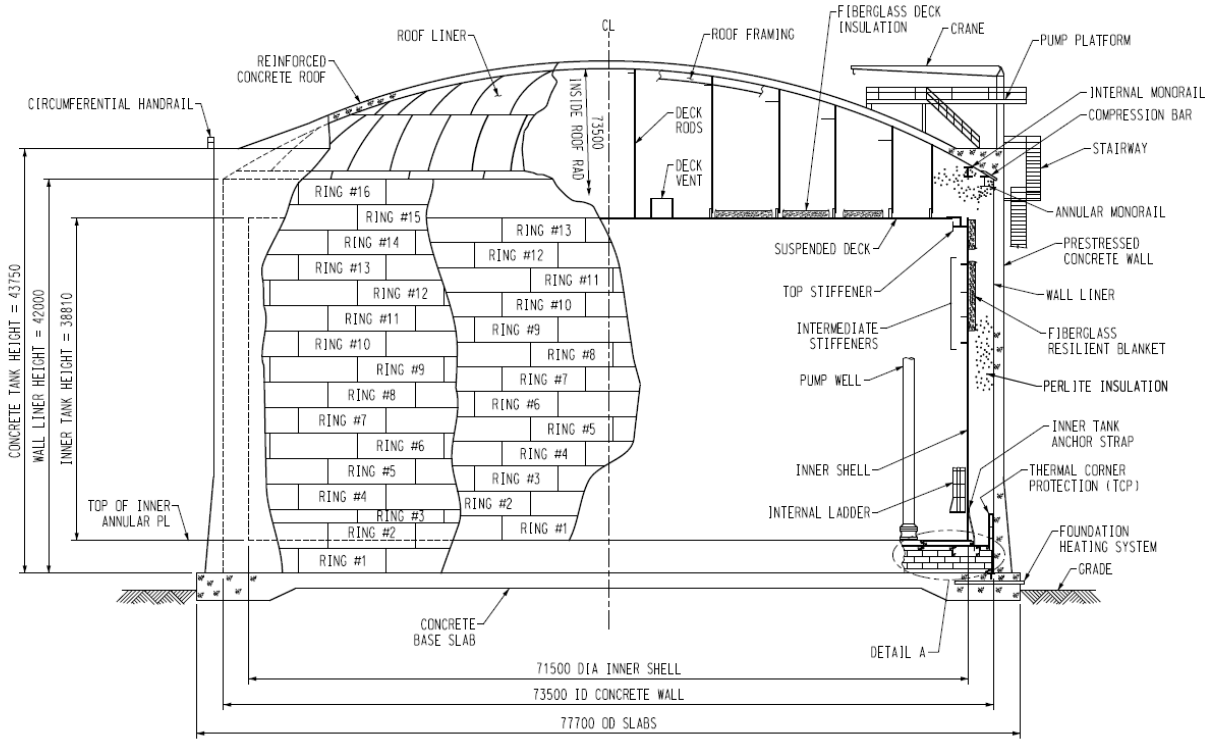
The 3 Bcf LNG tank is being designed according to the key parameters listed in Table 5-3 below. In general terms, the tank assembly will consist of a double-wall, insulated storage tank. A cryogenic steel inner vessel will contain the LNG liquid. This will be further enclosed by a concrete outer tank, also lined with steel, which will provide protection from the environment and external elements. The space between the two tanks will be filled with thermal insulation to maintain the LNG storage temperature of approximately minus 168 degrees Celsius. This design is consistent with current world-wide practices for construction of above-ground LNG storage tanks.

Table 5-3: 3 Bcf Tank Design Parameters

Parameter	Value
Working Volume	142,400 cubic metres (m^3)
Outer Diameter of Foundation Slab	77.70 metres (m)
Concrete Tank Heights	43.75 metres (m)
Inner Tank Height	38.81 metres (m)
Design Temperature	Minus 168 degC
Internal Maximum Design Pressure	28.9 kPag
External Maximum Design Pressure	0.5 kPag

Figure 5-3 below illustrates key features of the proposed tank.

Figure 5-2: Proposed 3 Bcf Tank: Elevation View



Additional details for the design of the proposed 3 Bcf LNG storage tank are provided below.

Tank Physical Characteristics

- The LNG tank will have a working volume of 142,400 m3 between the minimum normal operating level and the maximum normal operating level;
- The inner tank will be 71.5 m diameter x 38.8 m high;
- The outer concrete tank inside diameter will be 73.5 m and the outer tank overall wall height will be 43.75 m above the top of the foundation;
- The foundation will be a concrete base slab on grade with ground improvement. The slab will be 1.10 m thick at the edge and will be supported on improved ground. The top of the slab is approximately 0.45 m above grade;
- The inner tank will consist of a 9 percent nickel steel wall with an aluminum suspended deck. The tank will include Thermal Corner Protection, which consists of a 9 percent nickel steel system protecting the lower 5.0 m of concrete wall from subzero temperatures should an LNG leak occur. The outer concrete wall will be protected with an inner carbon steel wall liner, extending from the top of the slab to the roof liner;
- This is a full-containment LNG tank designed in accordance with CSA Z276, API 625 and ACI 376. Full containment refers to the ability of the tank to contain the entire volume of stored LNG even in the event of a breach of the inner steel tank;

- The LNG inner tank will be tested with water to a level according to API 620 Annex Q 6.2. Potable water will be utilized for the test. The LNG outer tank will be tested pneumatically to a pressure of 1.25 times the design vapour pressure;
- External tank lighting for maintenance and aeronautical obstruction lights for visibility will be provided; and
- Lightning protection and grounding system will be supplied in compliance with electrical codes.

Tank Insulation

- The insulation system will be designed to produce a boil-off rate of less than 0.05 percent per day of the tank gross volume based on pure methane, constant pressure, and ambient environmental conditions. This will minimize the boil-off of natural gas and therefore the need to expend energy to recompress or re-liquefy this gas.
- Insulation details:
  - The bottom insulation will consist of 400 mm of load bearing cellular glass insulation between the secondary bottom and the bottom liner/concrete slab;
  - The annular space between the outer concrete wall and inner steel wall will be filled with perlite insulation. Perlite is an inorganic and non-combustible product with very low thermal conductivity and is commonly used as cryogenic storage vessel insulation. There will be a circumferential perlite reservoir located above the annular space, which will be sized to maintain the insulation coverage after thermal shrinkage of the inner tank and settlement of the perlite occurs during service; and
  - The deck insulation will consist of a 1 metre thick fiberglass blanket.

5.3.1.2 Safety Systems

The safety systems associated with the proposed LNG tank will be designed and provided in accordance with accepted industry practices and any applicable standards.

The fire and gas detection system will consist of flame detectors, gas detectors, manual call points, audible alarms and beacons, and low temperature alarms. These detection and protection systems will be monitored 24/7 by LNG plant operators from the plant control room.

The storage tank will be designed for two levels of ground motion: the Operating Basis Earthquake (OBE) and the Safe Shutdown Earthquake (SSE). The OBE earthquake is represented by a once in 475 (500) year return period event; that is, an earthquake of this magnitude is statistically likely to occur once in a 475 year period. The SSE earthquake is represented by a once in 2,475 (2,500) year return period event. These return periods are specified in the API 625 standard.

Overpressure protection is provided by three pilot operated pressure relief valves and three pallet type vacuum relief valves. There is one spare pressure relief valve and one spare vacuum

relief valve. This design (and redundancy) will ensure that the tank pressure protection is capable of safely relieving any internal overpressure or underpressure condition to prevent damage to the inner tank vessel.

5.3.1.3 Venting Design

Venting from the new storage tank will be required during the initial fill operations (due to LNG flashing to vapour as it contacts the uncooled inner vessel). Venting following the initial tank filling would generally be a result of a process upset condition in the plant and is expected to be a rare event.

During normal operations, venting to the atmosphere is expected to be a very unlikely event. Any vapour or boil off gas (BOG)[106] from the tank will be contained by the boil off gas system and returned to the pipeline. However, in the event that there is an upset condition that exceeds the capability of the boil off gas system, the overpressure will be released to the atmosphere through pressure safety valves on the tank top. This is considered standard industry design. The other operating condition that may require minimal venting to the atmosphere would occur during maintenance activities, where equipment intended to capture the boil off gas is required to be out of service.

The Project is being designed from a reliability perspective such that there is redundant equipment to prevent situations where any venting to the atmosphere would be required. As such, venting to the atmosphere is expected to be a very unlikely event.

5.3.1.4 Filling Methodology

Construction of additional liquefaction is not within the scope of the TLSE Project. Rather, the 3 Bcf LNG tank will be filled using reserve capacity (approximately 5 MMcf/day) from the Tilbury 1A LNG liquefaction system, which has been reserved for utility use, including for peak shaving, emergency depletion, and replacement of LNG lost as boil off gas.

The initial filling of the 3 Bcf tank will utilize any available capacity from the Tilbury liquefaction facilities. These facilities are intended to provide service to LNG customers under Rate Schedule 46 (RS 46); however, the capacity of these plants may not be fully subscribed initially or periodically during the year due to the inherent peaks and valleys associated with LNG sales. In particular, as the market for LNG marine fueling matures in the Port of Vancouver, FEI expects there will be spare capacity available in the timeframe required for the initial filling of the 3 Bcf tank.

Once full, the 3 Bcf tank may be cycled by utilizing the reserve capacity from Tilbury 1A (as well as any excess capacity) as noted above. This reserve capacity could provide about 1 Bcf of liquefaction capacity each year in the time frame outside of the winter heating season (during which time FEI would work to maximize the tank fill volume).

[106] Boil off gas (BOG) is produced when stored LNG absorbs heat from the surrounding environment, evaporates, and becomes a vapour.

5.3.2 Regasification System

The proposed regasification system will be designed to provide 800 MMcf/day of regasification capacity to supply the Lower Mainland as previously described, and will include four vapourizers, four high-pressure (HP) sendout pumps, and related equipment. The new regasification facility will be designed for fast start-up (within 2 hours of an initial call for sendout) to be able to accommodate the full capacity gas sendout.

5.3.2.1 Regasification System Overview and Design Parameters

The regasification system includes numerous facility components and can be thought of as the system that moves the LNG from the storage tank, converts the natural gas from its liquid state to a gaseous state, and then injects it into the CTS. The system utilizes:

- In-tank LNG pumps to pump the LNG from the tank;
- HP sendout pumps installed externally to the tank to boost the pressure of the LNG to transmission pipeline pressure;
- Vapourizers utilizing submerged combustion bath heater technologies which convert the LNG back into a gaseous state; and
- Equipment to meter (measure) and odourize the natural gas before it is injected into the CTS.

Not included in the regasification system is the auxiliary piping and utility pipe racks, etc. which are described in Section 5.3.3.

Table 5-4 below specifies the regasification system design parameters.

Table 5-4: Regasification System Design Parameters

Parameter	Value
Total sendout capacity	800 MMcf/day
Number of vapourizers	4
Sendout capacity per vapourizer	200 MMcf/day
Number of HP sendout pumps	4
Rated capacity of HP sendout pump	473 m^3/hr
In-tank pump capacity	1,600 m^3/h

5.3.2.2 High-Pressure Sendout Pumps and Regasification Design

The regasification system includes four HP LNG sendout pumps that will operate in series with the in-tank LNG pumps. These pumps will boost the pressure of the LNG prior to regasification. Downstream of these pumps will be four LNG vapourizers with a total of 800 MMcf/day of regasification capacity.

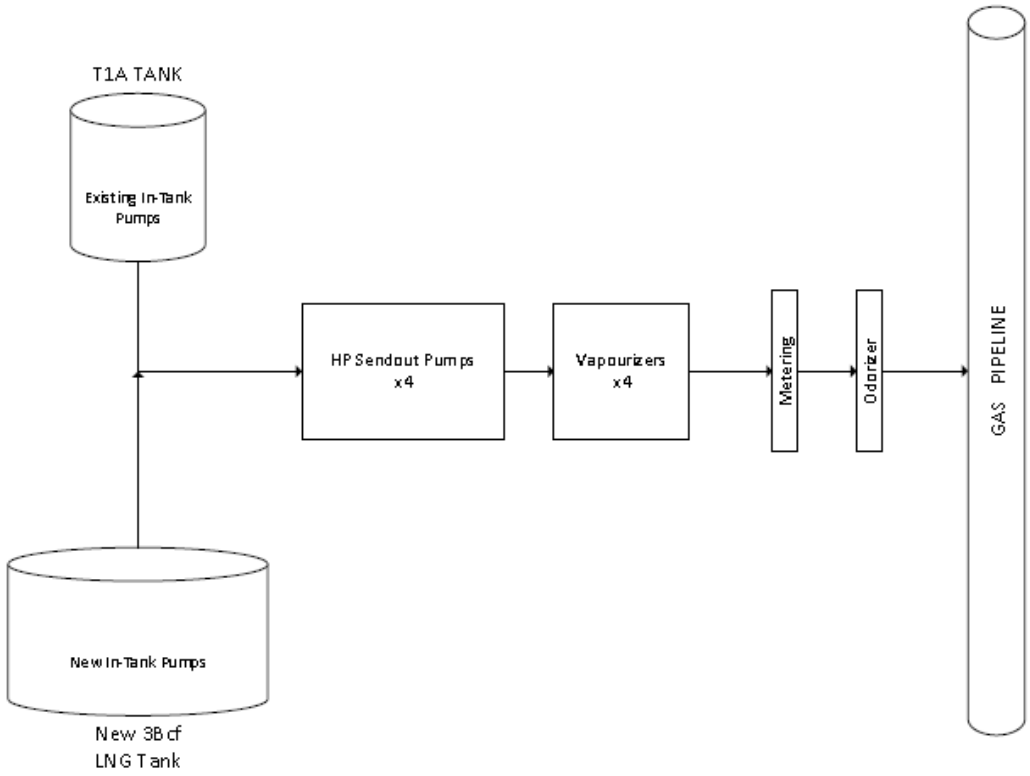
Utilities will include fuel gas (for start-up, provided from the FEI incoming gas pipeline), firewater (from municipal supply), potable water (from the existing Tilbury 1A potable water system using municipal supply), and instrument air and nitrogen for the operation of control equipment.

5.3.2.3 Fuel Gas Is Readily Accessible from the FEI CTS

Start-up fuel gas for the regasification system will be taken from the incoming FEI CTS; necessary pressure reduction and fuel gas heating will be provided within the regasification system. Once the firing has started and vapourizers are in normal operation, part of the sendout gas will be recycled as fuel gas.

A simplified process schematic for the regasification system is shown in Figure 5-4 below, and a detailed process flow diagram for the regasification system is provided in Confidential Appendix F-2.

Figure 5-4: Regasification Process Schematic



5.3.2.4 Regasification System Design Will Allow for Rapid Response

The regasification package will be designed for rapid start-up and supply of natural gas in the event of a sudden disruption to the upstream gas transmission system.

A key design consideration to allow for this rapid response is to ensure necessary LNG piping and HP sendout pumps are kept continuously cold and hence, ready for immediate operation. This will be accomplished by circulating LNG from the storage tanks though this key equipment.

Another design consideration is the response time required to achieve full sendout capacity. To ensure full sendout capacity is achieved rapidly, the regasification system will need to be designed to heat the water baths of all four vapourizers simultaneously. This, combined with pre-start activities will ensure that the time from initiating the start-up of the HP pumps and vapourizers to achieving full sendout capacity of 800 MMcf/day will be less than two hours.

5.3.2.5 No Venting Will Occur in Normal Operations

During normal operation of the regasification package, no venting is expected to occur. Only during certain emergency or process upset situations would any venting be required.

5.3.3 Auxiliary Systems

The Project includes the necessary auxiliary systems to support the LNG storage and regasification operations. These systems will be designed, constructed, and operated in accordance with all applicable standards, including FEI's internal standards and BCOGC regulations.

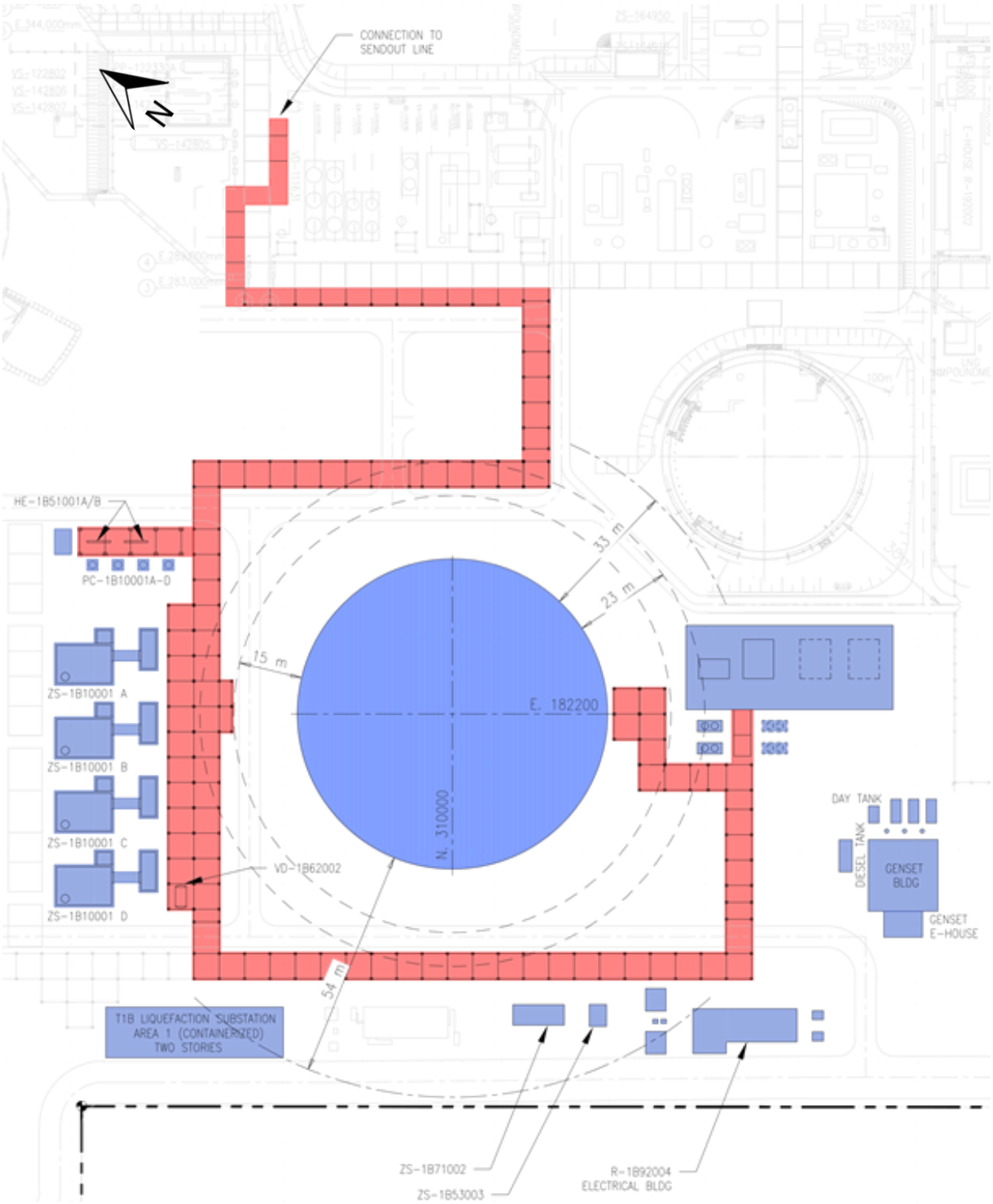
The main auxiliary systems are described below.

5.3.3.1 Utility Pipe Racks

The utility pipe racks will be designed as a network of multi-level interconnected pipe racks on which the piping, electrical and instrument cables associated with the Project, and the existing Tilbury 1A facility can be accommodated.

New utility pipe racks will be installed to connect all of the key Project equipment. Interconnect piping will also be provided from the existing Tilbury 1A LNG tank to the new regasification package. The new pipe rack will run along the southern end of the new 3 Bcf LNG storage tank, continue to the western periphery of the plant before turning and running eastwards towards the regasification package, gas metering and odourization facilities and connecting to the CTS on the eastern periphery of the plant. Refer to Figure 5-5 for a plan view of where the new pipe racks will be located.

Figure 5-5: Multipurpose Pipe Racks



5.3.3.2 Connection to Tilbury 1A Tank Permits Delivery of LNG to the New 3 Bcf Tank

In order to fill the 3 Bcf tank, a connection to the existing Tilbury 1A liquefaction facility is required. The most efficient way to achieve this connection is to construct piping interconnections between the existing Tilbury 1A tank and the new 3 Bcf tank for LNG transfer. These connections will be designed in such a way that the ability to send out through the new regasification units can be accomplished from either tank. The ability to access either tank in this manner provides important operational flexibility in a supply emergency; however, it does not change how resiliency planning occurs. Although the LNG in the Tilbury 1A tank may be available in an emergency, from a planning perspective, this capacity cannot form part of FEI's Minimum Resiliency Planning Objective.

5.3.3.3 In-Tank LNG Pumps

Two in-tank pumps (one operating and one spare) will be installed in the 3 Bcf tank as part of the Project in order to provide send-out gas to the regasification package and ultimately to the FEI transmission system. The operating pump will supply LNG to the regasification system; the other pump will remain on standby as a redundant unit for reliability.

5.3.3.4 Boil Off Gas (BOG) Compressors

Boil off gas must be removed as it is produced to prevent overpressure within the tank. Once boil off gas is removed, it must be compressed before it is either sent to the pipeline or returned to a liquefaction facility to be converted back into LNG. This compression will be performed using dedicated compressors, referred to as BOG compressors.

5.3.3.5 Utilities

The Project will require numerous utilities to support the ongoing safe and reliable operation of the regasification system and 3 Bcf storage tank. These necessary systems will include:

- Electrical power, including 13.8 kV and 4.16 kV feeder lines to supply the LNG storage tank systems, BOG compressors, and regasification package;
- Instrument air compressors and gaseous nitrogen system to operate process control devices;
- A common remote instrument building for safety instrumentation systems, distributed control systems and other hardware devices (e.g. control switches, fire and gas monitoring panels);
- An emergency generator to provide electric supply for critical loads to ensure operations even during a site-wide power failure. At a minimum, these critical loads will include one in-tank LNG pump, three HP send-out pumps, three vapourizers, and instrument air compressors, as required;
- Potable water and firewater supply from city mains;
- Pressure reduction and gas heating station for the regasification package; and

- Modifications to the central control room of the Tilbury 1A LNG facility to house the operator consoles for the TLSE Project.

5.3.3.6 Interface Systems

The inflow and outflow of gas streams from the Project to the CTS will be measured using appropriate metering devices to ensure the plant is operating as expected. Additionally, sendout gas requires odourizing prior to injection into the CTS. There will a dedicated metering station and odourization equipment constructed as part of the Project.

Other interface systems will involve connectivity to City of Delta firewater mains, potable water system, storm water and sewer systems, and the BC Hydro electrical supply.

5.3.4 Geotechnical Requirements

A preliminary geotechnical analysis was carried out by Golder Associates Ltd. for the 3 Bcf LNG storage tank, utility pipe rack, electrical building, and associated equipment to support the level of scope definition necessary to develop the Application. This analysis is provided in Confidential Appendix G.

The primary geotechnical consideration is the total uniform settlement of the 3 Bcf tank. The proposed solution for the ground improvement program is the installation of stone columns to approximately 30 m depth along with soil enhancements to increase the load carrying capacity of the soil and prevent liquefaction of the underlying soils during a seismic event. The site grade will be increased by approximately 3.5 m to mitigate any risk of equipment or site damage due to flooding of the adjacent Fraser River.

For other areas, the work will include excavation of existing solid and wood waste, installation of structural sand and installation of 1 m diameter stone columns up to a depth of 16 m.

Detailed geotechnical work will be carried out prior to commencing detailed design to ensure the proposed ground improvements will meet the limits of the ground settlement specified by the tank vendor.

5.3.5 Demolition of the Tilbury Base Plant

In Section 4, FEI explained that, due to a variety of factors including the age of the Tilbury Base Plant, it makes economic and practical sense to replace the Tilbury Base Plant with a new facility. The demolition, dismantling, and disposal of the Base Plant will include removal of the following key components:

- Containment wall;
- Base Plant LNG tank;
- Buildings (maintenance building, office/control room building, foam generation control building, emergency generator building);

- Base Plant BOG compressor and cycle compressor (including building);
- Interconnect piping from the Tilbury 1A facility;
- Parking lot;
- Electrical substation;
- Low voltage transformer; and
- Diesel tank.

Prior to commencement of demolition activities, all decommissioning, draining, purging, and isolation work must be completed to ensure the site is safe for demolition work to be executed. Following regulatory approvals, de-inventory of useable LNG, warm-up of the new tank and final decommissioning activities, the tank demolition process can begin.

All items aboveground are to be dismantled and removed. Any piping that rises aboveground will be appropriately cleaned and capped. Any structures, such as the compressor block, will be taken down to grade, with the exception of the tank base ring, which will be left in place (approximately 400 to 450 mm above grade). This will not interfere with the construction of the new facilities.

5.4 BASIS OF PROJECT COST ESTIMATE AND RISK ASSESSMENT

5.4.1 Base Cost Estimate (AACE Class 3) Developed With External Experts

FEI, in conjunction with Linde, Clough Enercore (Clough), Horton CB&I (HCBI), Golder, and Solaris Management Consultants Inc. (SMCI), developed the Project cost estimate using AACE International Recommended Practices 18R-97 and 97R-18 as guides. The AACE Class 3[107] cost estimate is based on quantities developed from designs and material take-offs completed by Linde, Clough, HCBI, Golder and SMCI, as the basis to develop the direct and indirect costs.

All consultants are experienced in their fields of practice. FEI reviewed the credentials and experience of each consultant as part of the selection process (see Appendix D).

The Linde estimate includes the following related to the regasification package:

- Engineering services;
- Supply of equipment and bulk material;
- Commissioning spare parts, two-year spare parts and capital spare parts;
- Site construction activities and supervision; and

[107] The typical variation in low and high accuracy ranges at an 80% confidence interval for an AACE Class 3 estimate fall between -10% to -20% on the low side and +10% to +30% on the high side. While these target ranges may be expected for a particular estimate, the accuracy range is determined through risk analysis of the specific project as described in Section 5.4.4.

- Site pre-commissioning, commissioning and start-up supervision assistance.

Clough's services have been retained for the engineering of the auxiliary systems (utility pipe rack and equipment). The Clough estimate includes engineering, site construction supervision, and construction sub-contracts for the auxiliary piping and equipment, including all equipment and material to tie the new regasification package to both the existing Tilbury 1A facility and the proposed 3 Bcf tank. Key aspects of the work provided by Clough include the following:

- Pipe, valves & fittings, civil/concrete, steel, electrical bulk materials;
- Electrical supply equipment;
- Emergency generators(s) required for regasification system;
- Utility pipe racks; and
- BOG compressors.

HCBI specializes in providing bulk gas and liquid storage solutions, including low-temperature and cryogenic storage tanks and systems. HCBI's services have been retained for the engineering of the 3 Bcf LNG storage tank. The HCBI estimate includes the complete design, supply, fabrication, construction, inspection, testing, drying and purging of a full containment concrete LNG tank.

Golder provides consulting, design, and construction services in the specialized areas of geotechnical and environmental modelling. Golder's services have been retained for the ground improvement and early works. The Golder estimate includes a cost estimate for ground improvement measures required to support the proposed 3 Bcf LNG storage tank and associated LNG storage expansion areas, including the necessary engineering, site construction supervision, and construction sub-contracts.

SMCI's services have been retained for the Base Plant demolition. The SMCI estimate includes a cost estimate for demolition of the Base Plant, including direct field costs, indirect field costs, and engineering services to demolish the Base Plant.

FEI completed the portion of the Project's base cost estimate related to owner's costs (Owners Costs), which include the following:

- Project management and engineering;
- Contract management;
- Community relations;
- Indigenous relations;
- Communications;
- Regulatory permits and approvals;

- Legal;
- Health & safety;
- Environmental and archaeological monitoring; and
- Inspection and operations support / coordination.

FEI's portion of the base cost estimate is attached in Confidential Appendix J.

The total Project base cost estimate includes the sum of the above-described consultants' estimates and FEI's portion of the base estimate, and is estimated to be $529.103 million in 2020 dollars. The base cost estimate includes 7 percent PST on materials. FEI provides the summary of the total Project cost estimate in Table 6-1 in Section 6 of the Application.

5.4.2 Basis of Estimate

A complete list of the Basis of Estimates and the corresponding appendices is provided in Section 5.3 (Table 5-2).

These documents detail:

- Estimate background:
  - Purpose and objective of the estimate; and
  - Estimating methodology.
- Basis of estimate:
  - Scope of the estimate;
  - Assumptions; and
  - Exclusions.
- Quantity derivation and cost basis:
  - Material and equipment cost basis;
  - Engineering costs;
  - Labour rates;
  - Contractors indirect costs;
  - Estimate allowances;
  - Other costs and indirects;
  - Engineering services; and
  - Freight.

The Project cost estimates present the following details with respect to estimate scope, procurement, construction and engineering assumptions:

- Work breakdown structure;
- Direct and indirect costs;
- Estimate pricing;
- Fabrication Costs;
- Construction costs:
  - Indirect field costs;
  - Contractor indirects, expenses and field supervision;
  - Construction services and supplies;
  - Temporary construction facilities;
  - Construction equipment and vehicles;
  - Fuel, small tools and consumables;
  - Freight;
  - Equipment; and
  - Other construction costs.
- Unit Price Items, engineering and materials costs;
- Construction:
  - Earthworks;
  - Mechanical equipment;
  - Foundations;
  - Steel structures;
  - Buildings;
  - Facility piping;
  - Electrical;
  - Instrumentation;
  - Control Automation System; and
  - Mobilization and demobilization (equipment); and
- Commissioning.

5.4.3 Cost Verification and Validation

Cost estimate quality assurance and validation reviews were completed to provide confidence that the estimate was developed based on AACE recommended practices and met the criteria for an AACE Class 3 estimate.

The quality assurance and validation consisted of a team thoroughly reviewing documents over a period of weeks as they were received by FEI. Reviews considered whether the estimate met the requirements, appropriate tools and data were used, and the estimate was complete for the respective scope. FEI discussed findings with all relevant consultants and updated the estimate as required.

Cost estimate quality assurance and validation activities included:

- Internal, Linde, Clough, HCBI, Golder and SMCI reviews that included peer reviews, document quality checks, and independent review;
- Validation reviews involving both Linde, Clough, HCBI, Golder and SMCI, and FEI team members, throughout the estimate development process to confirm that the estimate assumptions were valid and that a well-documented, reasonable and defensible estimate was developed; and
- FEI retained Validation Estimating LLC, USA (Validation Estimating), a company that provides services in estimate validation, risk analysis, and contingency estimation. Validation Estimating reviewed all the constituent estimates to confirm their suitability for inclusion in the AACE Class 3 estimate.

5.4.4 Risk Analysis – Quantitative and Qualitative with Expert Support

FEI has performed an appropriate risk assessment process for this stage of the Project, which included identifying the key Project risks, treating and mitigating risks as appropriate, and taking an approach to risk quantification that is consistent with FEI's risk management framework. The risk assessment includes both qualitative and quantitative components.

FEI has set contingency and escalation amounts in addition to the Project base cost estimate to achieve a P50 confidence level to address foreseeable risks and changes in market conditions over time. Contingency and escalation are described as follows:

- **Contingency** is typically expected to be spent and is used as an allocation for risks that are known and likely to be encountered during Project execution.[108] For the TLSE Project, FEI will set the contingency at a cost value to achieve a P50 confidence level.

[108] Contingency is defined in AACE International Recommended Practices 10S-90: *Cost Engineering Terminology* as: An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, and/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 by AACE definition is expected to be spent.

As such, the Project contingency will be $108.200 million (20 percent) at the P50 confidence level.

- **Escalation funds** per AACE is "a provision in costs or prices for uncertain changes in technical, economic, and market conditions over time. Inflation (or deflation) is a component of escalation." The base estimate was developed using 2020 pricing data and conditions and does not inherently account for escalation. Price increases/decreases beyond 2020, including contingency, must be covered by the escalation estimate. FEI will set the escalation at a cost value of $62.393 million[109], which corresponds to the P50 confidence level.

The following sections outline the methodology used to understand the risks inherent with the Project and the funding required to address the risks.

5.4.4.1 Risk Assessment Objectives and External Expert Support

The overall objectives for the risk assessment process were to:

- Identify key areas of concern requiring the Project team's attention for Project planning;
- Perform qualitative analysis to prioritize and rank the risks using a Project specific risk matrix, as described in Section 5.4.4.2;
- Identify those items that can have a critical effect on the Project outcome; and
- Articulate critical risk information that was used as an input to the Project's cost and schedule risk quantification and contingency estimation.

Qualitative risk assessment is part of day-to-day risk management activities. The process includes steps to identify and prioritize the project risks, assign risk owners, and define and track risk treatment and mitigation actions.

FEI engaged Yohannes Project Consulting Inc. (YPCI), a company specializing in risk management, to conduct a Class 3 qualitative risk assessment of the TLSE Project. YPCI conducted risk identification and mitigation exercises as detailed in subsequent sections to eliminate remaining uncertainty to the greatest extent possible and to inform the contingency and escalation analyses as per AACE Class 3 guidelines.

YPCI conducted multiple workshops with the Project team to develop a risk register for the Project to identify risks that could likely occur. A risk assessment report prepared by YPCI is included as Confidential Appendix K-1.

Validation Estimating completed the contingency estimation using a quantitative analysis by applying an integrated parametric and expected value methodology that is aligned with AACE

[109] Escalation of $62.393 million is shown in Table 6-1 as the difference between the contingency-adjusted Base Cost Estimate of $699.696 million (As-Spent $) and the contingency-adjusted Base Cost Estimate of $637.303 million (2020 $).

International Recommended Practice 42R-08: *Risk Analysis and Contingency Determination Using Parametric Estimating* and 65R-11: *Integrated Cost and Schedule Risk Analysis and Contingency Determination Using Expected Value*. This report (Validation Estimating Report) is included as Confidential Appendix K-2.

Ultimately, the risk assessment report prepared by YPCI, supplemented by the Validation Estimating Report, was used to establish a contingency estimate at the P50 confidence level.

5.4.4.2 Risk Identification Planning

The risk identification and qualitative analysis conducted by YPCI was completed using the AACE International Recommended Practice 62R-11: *Risk Assessment: Identification and Qualitative Analysis* (AACE 62R-11, Revision May 11, 2012) as a guide.

First, risks were identified through collaborative discussions between YPCI and FEI through a series of risk workshops facilitated by YPCI. Next, the team developed the risk response actions and assigned risk likelihood and consequence ratings to each risk using the matrix shown in Table 5-5.

The risk likelihood and consequence scales used for the Project are based on the 5 by 5 risk assessment matrix recommended in AACE 62R-11 which is illustrated in Tables 5-5 and 5-6 below.

Table 5-5: Risk Assessment Matrix

	Risk Impact Category (Cost, Schedule, Performance/Quality/Scope)				
	Impact				
Probability (Likelihood)	Very Low	Low	Medium	High	Very High
Very High (>75%)	Moderate	Moderate	Major	Major	Major
High (51 – 75%)	Minor	Moderate	Major	Major	Major
Medium (20 – 50%)	Minor	Moderate	Moderate	Major	Major
Low (5 – 19%)	Minor	Minor	Moderate	Moderate	Moderate
Very Low (<5%)	Minor	Minor	Minor	Minor	Moderate

Table 5-6: General Risk Management Criteria

Risk Level	Management Criteria
Major	Risk is unacceptable or exceeds tolerance threshold. If risk is red after mitigation, it requires acceptance by PM, and preparation of monitoring and controls and contingency plan. *WARNING: if risk is related to performance and HSE, do not proceed with activity. Field Supervisor and HSE personnel need to be involved in risk control plan to reduce risk level.*
Moderate	Risk controls/enablers should be applied where economical and practicable. Mitigate is most common response, else establish monitoring of risk. *ALERT: if risk is related to performance and HSE, Operations or HSE personnel shall be involved in risk control plan to reduce risk to as low as reasonably practical (ALARP).*
Minor	Risk level is tolerable as is, no response required, provided adequate monitoring and controls are in place and functioning effectively and due consideration has been given to reduce the risk.

5.4.4.3 Risk Register, Qualitative Assessment, and Action Plan

The risk identification process identified a number of risks, which were tabulated in the risk register included in Appendix 3 to the YPCI Risk Report (Confidential Appendix K-1). The risk response actions to deal with the identified risks were also recorded in the risk register. Once the risks were identified, a qualitative analysis was completed to prioritize or rank the risks so that the Project team could focus on risk response actions and recommendations. Through this qualitative process, a likelihood and consequence rating was assigned to each identified risk using the risk assessment matrix noted above.

5.4.4.4 Quantitative Risk Analysis to Determine Contingency

Following the completion of the YPCI's risk assessment report, Validation Estimating completed a quantitative analysis to evaluate the impact of the Project specific risks and systemic risks.

Validation Estimating completed a Monte Carlo simulation to determine a distribution of possible cost outcomes associated with the existing scope of the Project at different levels of confidence. The analysis was conducted using the base Project cost estimate of $529.103 million as outlined in Section 5.4.1 above and derived a risk adjusted P50 cost of $637.303 million[110]

[110] The risk adjusted P50 cost can be found in Table 6-1 of Section 6.2 and is the sum of the Base Cost Estimate of $529.103 million (2020$) and the Contingency of $108.200 million (2020$).

representing a contingency of approximately 20 percent. Please refer to Confidential Appendix K-2 for further details on Validation Estimating's contingency methodology and results.

The output of the Monte Carlo simulation is shown in tabular form in Table 5-7 below[111]:

Table 5-7: Quantitative Risk Analysis – Monte Carlo Simulation[112]

Base Estimate:	**$531,249**	Currency:	$CAN
Probability of Underrun	Indicated Funding Amount	Contingency	
		Costs (thousands)	Percent of Base Est.
Mean	644,800	113,600	21%
5%	503,700	(27,500)	-5%
10%	530,300	(900)	0%
15%	550,500	19,300	4%
20%	565,100	33,900	6%
25%	578,400	47,200	9%
30%	590,800	59,600	11%
35%	603,300	72,100	14%
40%	615,300	84,100	16%
45%	627,200	96,000	18%
50%	639,400	108,200	20%
55%	650,300	119,100	22%
60%	662,400	131,200	25%
65%	675,500	144,300	27%
70%	689,400	158,200	30%
75%	704,500	173,300	33%
80%	721,600	190,400	36%
85%	742,700	211,500	40%
90%	769,300	238,100	45%
95%	811,500	280,300	53%

Contingency is typically expected to be spent and is used as an allocation for risks that are known and likely to be encountered during Project execution. For the TLSE Project, FEI will set the contingency at a cost value to achieve a P50 confidence level. As such, the Project contingency will be $108.200 million (20 percent) at the P50 confidence level.

5.4.4.5 Escalation Risk Addressed with Additional Escalation Funding

Validation Estimating conducted a cost escalation estimate for the Project. Escalation per AACE is "a provision in costs or prices for uncertain changes in technical, economic, and market

[111] This table is taken from the Validation Estimating Report, p. 15 (Confidential Appendix K-2).

[112] Note that the Base Estimate shown in Table 5-7 of $531.249 million is slightly higher than the Base Estimate of $529.103 million shown in Table 6-1 of Section 6.2. Please refer to Section 6.2 for a reconciliation of the two amounts.

conditions over time. Inflation (or deflation) is a component of escalation." The base estimate was developed using 2020 pricing data and conditions and does not inherently account for escalation. Price increases or decreases beyond 2020, including contingency, must be covered by the escalation estimate. FEI will fund escalation at the P50 level of confidence.

FEI will fund contingency at the P50 confidence level, therefore the escalation estimate is calculated using the risk adjusted P50 cost of $637.303 million, as outlined in Section 5.4.4.4, as the basis.

The AACE "by-period" method was applied to develop the cost escalation estimate. This method uses price indices by cost account applied to the annual cash flow by cost account. The base indices are forecasts provided by the economic consulting firm IHS Markit. These indices are used to develop weighted indices that match the cost types (e.g., pipeline material, construction labour, etc.). The indices are further adjusted for forecast global and regional capital spending market conditions (i.e., adjusts for bid mark-up behaviour as well as productivity trends in hot or cold markets).

The IHS Markit Q3 2020 forecast is showing minimal cost escalation through 2022 (with the exception of pipe steel) and a slight decrease forecast for the remainder of 2020. However, global and regional capital spending is forecast to rebound by 2022 with the weighted annual price increase forecast to peak at 2.8 percent. The probabilistic analysis, which takes into account the historical standard deviation in price changes from the mean, results in a significant range as shown in Table 5-8[113] below. Please refer to Confidential Appendix K-3 for further details on Validation Estimating's escalation methodology and results.

[113] This table is taken from the Validation Estimating Escalation Report, p. 9 (Confidential Appendix K-3).

Table 5-8: Summary of Escalation Monte Carlo Simulation (2020$)

Probability of Underrun	Escalation	Percent of Base+Cont
5%	(53,852,000)	-8.4%
10%	(31,746,000)	-4.9%
15%	(16,456,000)	-2.6%
20%	(2,779,000)	-0.4%
25%	9,457,000	1.5%
30%	19,875,000	3.1%
35%	31,233,000	4.9%
40%	41,542,000	6.5%
45%	51,938,000	8.1%
50%	**62,393,000**	**9.7%**
55%	72,850,000	11.3%
60%	84,392,000	13.1%
65%	95,245,000	14.8%
70%	**107,043,000**	**16.7%**
75%	120,300,000	18.7%
80%	134,671,000	21.0%
85%	150,654,000	23.5%
90%	172,531,000	26.9%
95%	202,604,000	31.5%

FEI will fund escalation at $62.393 million[114], which corresponds to the P50 level of confidence.

5.5 CONSTRUCTION AND OPERATING SCHEDULE AND ACTIVITIES

This section outlines the preliminary Project schedule and the key Project activities. The schedule allows FEI reasonable time to complete the Project, while ensuring that resiliency benefits are realized as soon as possible.

5.5.1 Project Schedule and Milestones

Construction for the Project is divided into the following five main sub-projects:

- Ground Improvement and Early Works;
- Regasification Package;
- Auxiliary Systems (Utility Pipe Rack and Equipment);
- 3 Bcf LNG Storage Tank; and

[114] Escalation of $62.393 million is shown in Table 6-1 as the difference between the contingency-adjusted Base Cost Estimate of $699.696 million (As-Spent $) and the contingency-adjusted Base Cost Estimate of $637.303 million (2020 $).

- Base Plant Demolition

Each sub-project will have its own activities, including pre-construction, construction, and post-construction. Sub-projects will be planned and coordinated to optimize limited space on site and to ensure a streamlined process.

The preliminary Project schedule is based on receiving BCUC approval by December 2021 and the execution phase is assumed to start in Q1 2022. This schedule was created by FEI and its team of consultants to ensure that all activity durations are based on reasonable assumptions and agreed upon by experts with experience scheduling projects of this nature.

Table 5-9 below is a summary of the Project schedule and key milestones. The basis of estimate and detailed Project schedule is included in Confidential Appendix L.

Table 5-9: TLSE Project Schedule and Milestones

Activity	Date
Environmental Assessment (EA)	
Submit EA Final Application[115]	Jan 2022
Phase 2 EA Certificate - Provincial/Federal	Jul 2022
Contractor Selection and Award	
Award Engineer Procure Construct (EPC) and Engineering Contract(s)	Jul 2022
Permitting	
BC FLNRORD (HCA Inspection Permit)	Jun 2023
BCOGC Permits	Jun 2023
Boundary Bay Airport – Email Notification	Jul 2023
Ministry of Transportation and Infrastructure (Highway Use Permit)	Aug 2023
BC 1 Call Registration	Jan 2024
Port of Vancouver (Notice to Shipping)	Jan 2024
NavCanada (Land Use Program – Tower Crane)	Jan 2024
Transport Canada (Aeronautical Clearance Permit)	Jan 2024
City of Delta Permits	May 2024
WorkSafeBC - *Worker Compensation Act/OHS Regulation*	Jul 2024
Technical Safety BC - *Safety Standards Act* Permits	Dec 2024
Metro Vancouver Permits	Jan 2025
Construction	
Start of Ground Improvement work in Regasification and Auxiliary Piping Area	Jan 2023
Ground Improvement in Tank Area start of construction	Mar 2023
First Regasification Units Construction Completion	Jul 2024

[115] The following link provides a description of the EA process: https://www2.gov.bc.ca/gov/content/environment/natural-resource-stewardship/environmental-assessments/the-environmental-assessment-process/2018-act-environmental-assessment-process

Activity	Date
Balance of Regasification Units Construction Completion	Apr 2025
Auxiliary System Construction Completion	Sep 2026
LNG Storage Tank Expansion Completion	Sep 2026

5.5.2 Construction Plan and Execution

The order of construction events will be tailored to meet critical path tasks and the challenges they pose to the overall construction schedule. The construction events will take place approximately in the following order:

- Source long lead items;
- Pre-fabrication of modules;
- Earthworks;
- Civil/ground improvements;
- Regasification package;
- Auxiliary systems (utility pipe rack and equipment);
- LNG tank construction; and
- Base Plant demolition.

Construction execution plans (CEPs) will be prepared in consultation with the EPC Contractor(s) and mutually agreed upon before proceeding. The CEPs will provide specifics for each phase as to the detailed construction methodology and sequencing.

5.5.3 The Project is Divided into Several Key Activities

The Project activities will be subdivided into the following main groups:

- Contractor evaluation, selection and contract award;
- Permitting;
- Engineering detailed design;
- Procurement / manufacturing;
- Fabrication;
- Equipment Installation and Construction;
- Post-construction activities; and
- Commissioning.

5.5.3.1 Contractor Evaluation, Selection and Contract Award Managed through Procurement Processes

Given the size and complexity of the Project and the multiple interfaces between the work, FEI intends to initiate a competitive process to select and award the work to a single EPC contractor for the entirety of the scope. However, this would need to include a balance of risk and cost acceptable to both parties. FEI will also consider the possibility of awarding multiple contracts if required to properly manage the risk profile for the Project. The focus of the contracting effort will be to demonstrate competitive pricing for all Project scopes and responsible management of the capital outlay. The preference will be to award the contract(s) to a proven contractor(s) with a high level of experience in LNG and natural gas engineering projects, and a recent successful track record of execution. The successful contactor(s) will be chosen according to established procurement procedures. Methods of evaluating local opportunities and Indigenous participation in contracted scopes will form part of the contractor selection criteria.

5.5.3.2 Permitting

FEI has identified the regulatory approvals that are likely required to construct the Project, discussed further in Section 5.8. Application processes will be initiated during engineering detailed design, after the CPCN is approved.

5.5.3.3 Engineering Detailed Design

A consulting engineering firm selected through an appropriate sourcing process will complete the engineering detailed design activities, preferably as part of an EPC contract structure. Detailed design activities encompass all engineering calculations, validations, preparation of drawings and bid packages required to cover the project needs. Engineering activities will be organized in order of priority, in relation to the procurement / fabrication lead times and the construction schedule.

5.5.3.4 Procurement and Manufacturing

Material will be procured as required to meet the construction schedule. The tendering process for major materials (e.g., valves, pumps, etc.) will commence upon award of the EPC contract subsequent to the receipt of CPCN approval.

Prior to construction, starting lead items and materials will be sourced if required to maintain the Project schedule. This will include long lead equipment, such as valves, LNG pumps, structural steel for the LNG tank, and modules (e.g., pipe rack modules). Offsite structural pipe rack steel and piping spools will be pre-fabricated for installation at site. It is expected that pre-fabrication off site will be utilized as much as possible to ease labour demand at site and optimize the installation schedule.

5.5.3.5 Fabrication

Offsite shop fabrication is expected to commence prior to onsite construction, with delivery coordinated with the onsite construction schedule to allow a set in-place strategy, optimizing the Project's overall schedule and minimizing onsite risks.

5.5.3.6 Equipment Installation and Construction

The expected construction timeframe onsite, from mobilization until commissioning / start-up, is from Q1 2023 until Q3 2026.

Site assessments (regarding hazardous materials, environmental plans, WorkSafeBC, etc.), geotechnical investigations, engineering analyses, and surveying will be performed to assess all possible underground obstacles and as a basis for earthworks and the construction to follow.

Quality assurance plans will be implemented to support procurement through to construction management activities and onsite monitoring. Third-party inspection will be used to verify compliance with the quality assurance plans as well as the relevant codes and standards for all offsite fabrication.

Installation of over 4,200 stone columns will be required to support the LNG tank and other equipment such as pipe rack modules and the regasification area. The elevation of the site will be raised with imported fill, which will be compacted and topped with gravel to achieve the desired grade elevation.

The 3 Bcf storage tank, consisting of inner steel wall, perlite insulation, and an outer concrete wall, will be constructed by an experienced tank builder. Construction will involve pouring the necessary concrete base, followed by erecting the inner steel wall and then the outside concrete wall (cast and poured in place). The perlite insulation will then be installed between the inner and outer walls.

Hydrotesting of the tank will take place after construction completion. A potable water source sufficient for the large volume will be required. Similarly, disposal of the test medium (water) needs to be considered, in order to obtain any necessary permits to dispose of the appropriately treated water.

Welds will be non-destructively inspected for 100 percent of their circumferential length according to program-specific piping specifications. Welds joining pipe will be inspected using approved radiographic procedures prior to coating of the weld joints. Structural welds will be inspected via various means, including visual, magnetic particle testing, and NDT as per code.

After the piping has been installed, welded, and non-destructively tested, it will be filled with hydrotest mediums, mostly water, though some systems with proper approvals may be air tested. Piping shall be pressurized to a minimum of 1.1 or 1.5 times the maximum operating pressure, in compliance with the applicable codes and specifications. The test duration will range from a minimum of one hour and up, as required.

Painting, insulation of piping, and fireproofing will be a large site work component as well. Painting of welds prior to hydrotesting will not be done; only after piping is hydrotested will it be fully painted and insulated.

Fireproofing of applicable structural steel will be performed to avoid conflicts with other construction. Typically fireproofing will be done near the end of a project, to minimize the risk of damage, thus reducing the need for touch-ups in the final construction phases.

5.5.3.7 Post-Construction Activities

At the conclusion of construction for each Project element (e.g., tank, regasification package, auxiliary piping), the Project will undergo a pre-commissioning and commissioning plan to inspect, test, and validate the successful implementation of all control and safety modules, subsystems, and systems. Since the construction is phased, this will occur as each phase is constructed and completed to the extent possible.

After the overall facility construction is completed, a comprehensive pre-commissioning and commissioning plan will be performed and incorporate all of the items discussed above.

It is important during pre-commissioning to ensure that construction has been completed according to the Project specifications, any construction deficiencies have been cleared, and that commissioning and operation will take place safely and effectively.

The final step will involve reinstatement from hydrotest and drying of all piping systems. When construction is deemed complete, and pre-commissioning tasks performed, a final site clean-up and major demobilization will occur.

5.5.3.8 Commissioning

A methodical and reasoned commissioning plan will be drafted, reviewed, and adopted well in advance of construction completion. Part of the EPC selection process will include the requirement to demonstrate ample experience in LNG plant start-ups to ensure FEI has a sound commissioning plan for the start up of the new assets.

Along with external consultants, FEI's in-house experts will review the commissioning plan. Operating and cold / hot start procedures will be drafted and reviewed extensively well ahead of time. The initial commissioning and start-up of the Project will have appropriate vendors on hand to assist. FEI's Operations staff will be trained in advance to operate the new facilities.

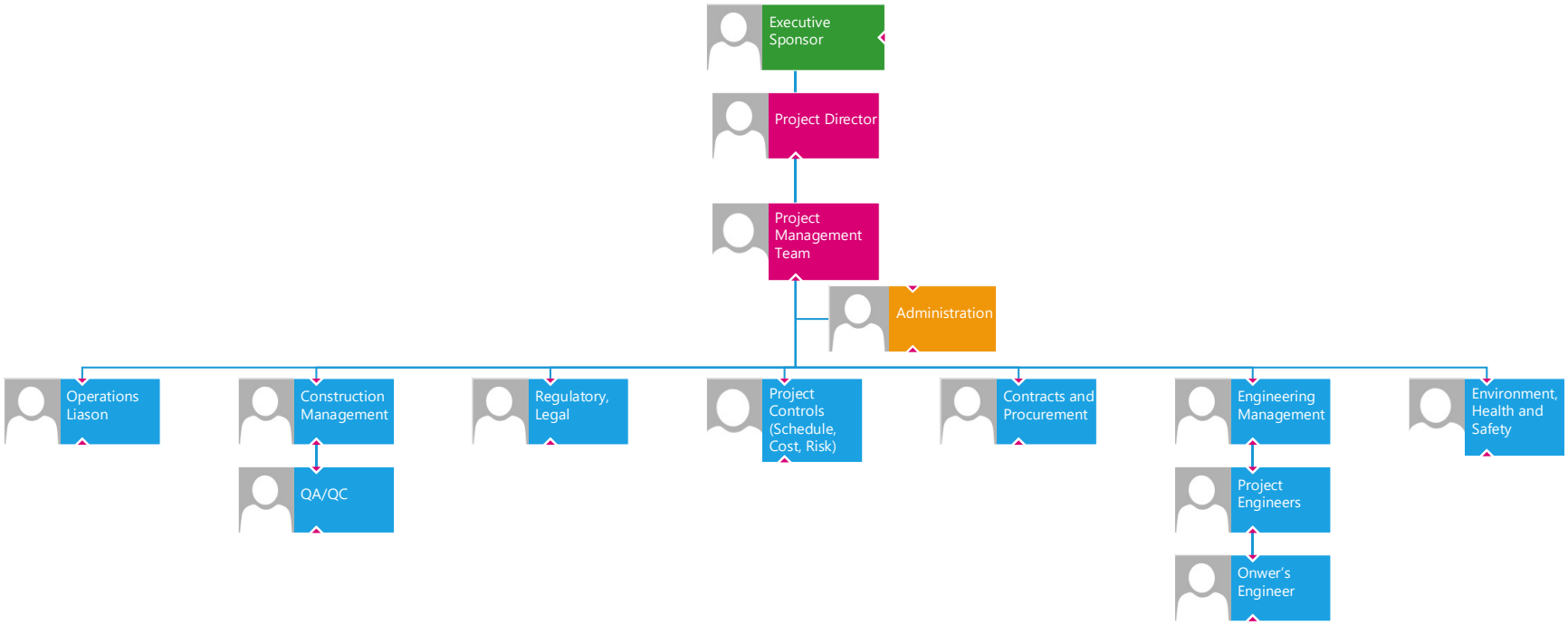
5.6 NECESSARY PROJECT RESOURCES UNDER CLEAR GOVERNANCE FRAMEWORK

As discussed in Section 2, FEI has significant experience in managing large projects. FEI will resource this Project with an appropriate mix of internal and external expertise.

5.6.1 Project Management and Human Resources Team

Figure 5-6 outlines a functional organization chart for the execution of the Project. The Project will be managed by FEI's project management team and will include both internal and external personnel and use external engineering resources as required.

Figure 5-6: Proposed Resources and Organizational Chart for TLSE Project



The key roles and personnel are as follows:

- The **Executive Sponsor** for the execution of the Project is the Vice President, Major Projects.
- FEI will have a **Project Director** who will manage all aspects of the Project including, but not limited to, permitting, engineering, procurement, and construction. The Project Director is responsible for overseeing all project activities.
- Additionally, FEI will have a **Construction Manager** on site who will ensure health and safety, quality, environment, schedule, outage staging and planning, and cost controls are all properly managed according to FEI standards.
- The **Project Management Team** will be supported by other members of the FEI Project Management Office (PMO) as required, such as Project Schedulers, Cost Analysts, and Administration. The Project will also be supported by other FEI departments, including Occupational Health and Safety, Operations, Environment, and Lands. The Project Management Team will be responsible for liaising with these other departments as required.
- FEI will have several dedicated **Project Engineers** and a supporting **Design Organization** assigned to manage the engineering component of the Project. Supplemental external engineering support will be required to complete various engineering designs, such as geotechnical, site preparation and excavation, concrete foundations and concrete containments, process piping, safety modelling and management, and logistics.

5.7 FEI IS IDENTIFYING PROJECT IMPACTS OR EFFECTS

5.7.1 External Experts Are Undertaking Environmental and Archaeological Assessments

FEI has retained consultants to conduct a preliminary Environmental Overview Assessment (EOA) and an Archaeological Overview Assessment (AOA). These assessments allow FEI to understand potential risks of the Project on the environment and cultural resources. Further assessment work will continue throughout the detailed engineering phase of the Project and a site-specific Environmental Management Plan (EMP) will be developed prior to construction to manage potential environmental and archaeological risks associated with the proposed construction activities and site conditions. The environmental and archaeological components are discussed in detail in Section 7.

5.7.2 Socio-Economic Impacts Assessment

In accordance with FEI's Statement of Indigenous Principles and long-standing community investment programs, FEI is committed to managing the socio-economic impacts and opportunities of its projects by working with Indigenous groups and local stakeholders to

understand and mitigate concerns, as well as to seek opportunities that positively benefit local communities.

FEI has considered a number of social and economic factors of the Project and has determined that the Project should have an overall positive socio-economic impact on residents and businesses. Details of FEI's socio-economic impacts assessment as they pertain to communication and consultation with Indigenous groups and stakeholders are provided in Section 8, and details of the positive economic impacts are provided in Section 9.

5.7.3 Construction Impacts and Mitigation

Short-term disruptions to the area surrounding the Tilbury site by the Project are expected to be temporary and generally minor given the location of the Project site in an industrial area. Construction of the Project will occur in a largely industrial landscape, with low population density, and within existing FEI-owned property. Short-term disruptions and impacts include minor traffic delays, and noise and dust from construction activities. In an attempt to mitigate any adverse socio-economic impacts of the Project construction, FEI will require the contractor to develop a Public Impact Mitigation Plan, which will outline strategies to minimize community impacts. The mitigation measures will be based on industry best practices and applicable requirements of local regulations. Mitigation measures may include, for example, limiting traffic access restrictions to businesses and residents during construction. FEI will continue to have discussions with landowners and stakeholder groups to understand how adverse effects may be mitigated, and to ensure efforts are made to include reasonable mitigation measures in the Public Impact Mitigation Plan. FEI does not anticipate long-term negative impacts resulting from the Project.

Section 8 of the Application describes FEI's stakeholder consultation and Indigenous engagement processes.

Anticipated Project construction impacts and FEI's planned mitigation measures are further described below.

5.7.3.1 Safety and Security

Construction site safety and security will be maintained during the course of the Project. The site is mostly fenced already and will be fully fenced at the start of construction. Security was in place 24 hours during Tilbury 1A construction and is currently still in place while the Tilbury site is being operated.

A 24-hour security system will be in place in a similar manner to control access to the site. A comprehensive safety plan will be developed by the EPC contractor to govern all those working on the Project, which will comply with FEI standards, WorkSafeBC regulations, and the requirements of any other impacted stakeholders.

5.7.3.2 Traffic Control

In order to reduce the impact on the public, traffic management plans will be prepared in consultation with the Delta municipality. The road network into the site provides good access, and limited disruption is anticipated. Busing / transport of most workers will be considered to minimize the number of personal vehicles at the site location.

Where appropriate, efforts will be made to minimize construction during peak traffic periods and to stage heavier construction load delivery to times where traffic disruption is minimized. FEI and the construction contractor(s) will work with municipalities to manage traffic delays and inform local residences and businesses of temporary traffic delays as appropriate.

The possibility of delivering some large and/or heavy modules via the Fraser River will be investigated.

5.7.3.3 Environmental Management

FEI plans to employ the services of an Environmental Inspector to be present during the Project. The Environmental Inspector will be familiar with construction techniques and applicable guidelines and standards. The Environmental Inspector will provide inspection of contractor environmental mitigation measures and respond to any environmental issues that may develop during construction.

The primary objective of environmental inspection is to determine compliance with pertinent environmental legislation, regulations, industry standards, and project permit conditions, including any notification requirements or conditions set by the regulator(s).

The purpose of environmental monitoring during construction is to verify that construction at site does not adversely impact the local environment.

5.7.3.4 Noise Control

The Project site is in the Tilbury Island industrial area where immediate neighbours are similar commercial / industrial businesses. The nearest residential neighbours are a few rural properties 600 m to the south on the other side of River Road.

A noise study was carried out in 2019, and noise monitoring and control will have regard to local guidelines throughout the Project, including with respect to construction equipment usage.

General noise control measures will be implemented during construction, including, but not limited to the following:

- Maintaining equipment prior to use and ensuring equipment is in good working order;
- Using noise abatement equipment, including ensuring mufflers on equipment are in good working order;
- Turning off equipment when not in use;

- Informing truck drivers and mobile equipment operators to be mindful of all neighbours;
- Having a transportation plan that will discourage personal vehicles for the most part and encourage transporting / busing crews to site; and
- Advising municipalities and the community of construction periods.

5.8 REQUIRED PERMITS AND APPROVALS

FEI has identified the following regulatory approvals that are likely required to construct the Project:

- Impact/Environmental Assessment, discussed further in Section 5.8.1;
- BCOGC approvals, discussed further in Section 5.8.2;
- Municipal approvals, discussed further in Section 5.8.3;
- Heritage Conservation Act permitting requirements and Indigenous heritage permits, discussed further in Section 7.3.2.3;
- Ministry of Transportation and Infrastructure (MoTI) permits for transportation corridors;
- Transport Canada notifications and approvals (to comply with the Navigable Waters Act and the Canadian Aviation Regulations);
- Technical Safety BC permits under the Safety Standards Act;116 and
- Other miscellaneous safety permits, administered by WorkSafeBC and BC 1 Call.117

A preliminary list of permits and approvals required for the proposed Project is also provided in Table 3-1 of the EOA (Appendix O). The preliminary permit and authorization requirements will be reviewed and confirmed during detailed Project design and applied for as required.

5.8.1 Impact/Environmental Assessment

5.8.1.1 Canadian Impact Assessment Agency

The Project will be subject to the Federal Impact Assessment (IA) process under the Canadian *Impact Assessment Act* (IAA). Section 38(d) of the *Physical Activities Regulations* states:

[116] Boiler and/or Pressure Vessel Registration/Approval; Boiler Plant Operating Permit; Installation Permits – Boiler; Installation Permits – Electrical System; Installation Permits – Gas; Installation Permits – Refrigeration System; Operation Permit – Electrical System; Operation Permit – Refrigeration System; Operation Permit – Boiler, Pressure Vessel; and Pressure Piping Registration/Approval.

[117] OHS Regulation Section 20.2.1 (1) and (2), Notice of project for asbestos - Ongoing work, OH&S 20.112 (WorkSafe BC); OHS Regulation Section 20.2.1 (2)(c), Notice of project - Significant disturbance of lead-containing material - OH&S 20.112 (WorkSafe BC); OHS Regulation Section 20.2.1 (2)(d), Notice of project - Other similar exposure work activities - OH&S 20.113 (WorkSafe BC); OHS Regulation Section 20.2.1 (1) and (2), Notice of Project, Section 20.2(1) of the OHS Regulation (WorkSafe BC); OHS Regulation Section 19, 30M33 Permit (WorkSafe BC); Worker Compensation Act and the OHS Regulation Section 20.3, Guidelines 20.3-2 Qualified coordinators (WorkSafe BC); and BC One Call Registration (BC One Call).

> **38** The expansion of one of the following: (**d**) an existing facility for the liquefaction, storage or vapourization of liquefied natural gas, if the expansion would result in an increase in the liquefied natural gas processing or storage capacity of 50% or more and a total liquefied natural gas processing capacity of 3 000 t/day or more or a total liquefied natural gas storage capacity of 136 000 m^3 or more, as the case may be."

FEI has met with the Impact Assessment Agency of Canada (IAAC) to provide an overview of the Project and initiated discussions related to IA process, timing and consultation.

The Project represents an increase in LNG storage capacity of more than 50 percent and total LNG storage capacity of more than 136,000 m^3. Therefore, the Project would be considered a physical activity pursuant to the *Physical Activities Regulations* and is thereby reviewable under the IAA.

Given that both the Federal and Provincial Environmental Assessment (EA) processes (see Section 5.8.1.2 below) are triggered, FEI asked that the Province request the Federal Minister of Environment and Climate Change to approve the substitution of the BC EA process for the Federal IA process. If substitution is approved for the proposed Project, it is expected that the British Columbia Environmental Assessment Office (BC EAO) will conduct the EA/IA in accordance with the conditions set out in the Substitution Decision, and at the end of the assessment process the BC EAO will provide its report to both the Provincial and Federal Ministers for their consideration.

5.8.1.2 British Columbia Environmental Assessment Office

The Project is also reviewable under BC's current *Environmental Assessment Act* (BC EAA) (*Reviewable Projects Regulation*).

The Project will trigger a Provincial EA pursuant to the BC EAA as it exceeds the trigger for assessment as follows:

> …the modification results in an increase in the capability of the project to store one or more energy resources, other than electricity, by a quantity that can yield by combustion ≥ 3 PJ of energy or, for liquefied natural gas, increase by ≥136 000 m^3.[118]

FEI has met with the BC EAO to provide an overview of the Project and initiated discussions related to EA process, timing and consultation. An initial project description and engagement plan was filed in February 2020, and the public comment period was from June 1, 2020 until July 16, 2020. As described above, a substitution has been requested for a single BC EAO led process.

[118] *Reviewable Projects Regulation*, Part 4, Table 8, Column 3, Criteria (1)(b).

FEI notes that the Tilbury Phase 2 LNG Expansion under review by the BC EAO and the IAAC encompasses a larger expansion of the Tilbury site than what FEI is seeking approval for as part of this Application, as components of the larger project will not be owned by FEI.

5.8.2 BC Oil and Gas Commission Approvals

The *Oil and Gas Activities Act* governs the construction and operation of the Project. The Project will require Facility Amendments for each of the Project Components. A Facility Amendment is a significant process with considerable technical scrutiny on the Project by the BCOGC. Indigenous and public consultation, archaeological requirements, design reviews, and environmental permits/approvals for work in and around fish bearing streams are all components of the Facility Amendment. Each component must receive BCOGC approval prior to commencing construction. Since the proposed Project is within the existing facility boundaries, the current schedule assumes a six-month approval period from the time of filing.

In addition to the Facility Amendments, the Project may require a waste discharge authorization and heritage permits from the OGC. Heritage permits are discussed further in Section 7.3.2.3.

5.8.3 Municipal Approvals

Municipalities have bylaws and guidelines related to construction and installation of facilities of this nature. FEI is currently in the process of identifying all municipal permit requirements and will determine requirements during detailed design. FEI will acquire permits and approvals and adhere to conditions during construction, subject to FEI exercising rights under section 121 of the *Utilities Commission Act* in the event requirements are expected to supersede or impair the Project or a power conferred on the BCUC.[119]

It is expected that permits from the City of Delta may be required and may include a Development Permit, a Rezoning Application, a Building Permit and a Highway Use and Inspection Permit, and/or a Demolition Permit.

As Metro Vancouver regulates the waste discharge for air and water, both a Wastewater Discharge Permit and an Air Waste Discharge Permit will be required for the Project.

Due to the proximity to the Boundary Bay Airport, an email notification detailing any aeronautical obstructions will be required.

[119] Section 121(1) provides: "Nothing in or done under the *Community Charter* or the *Local Government Act*
(a) supersedes or impairs a power conferred on the commission or an authorization granted to a public utility, or
(b) relieves a person of an obligation imposed under this Act or the *Gas Utility Act*."

A CPCN granted for the Project in this process would be an "authorization" under this section.

5.8.4 Other Permits, Licenses or Authorizations

5.8.4.1 Other Utilities

The Project will result in construction activities in proximity to existing adjacent utilities. Liaison with all stakeholders combined with onsite investigations will address stakeholder concerns during detailed design and engineering.

5.8.4.2 Other Pending or Anticipated Applications/Conditions

A qualified environmental professional working in conjunction with FEI's Environment department will assist the Project in identifying permits/approvals required in the development of an Environmental Protection Plan for the Project.

5.9 CONCLUSION

In this section, FEI has demonstrated that the Project has been developed with the assistance of industry leading experts and in accordance with sound engineering practices. FEI has further demonstrated that the Project cost estimate has been appropriately validated and a reasonable Project schedule has been developed with the necessary Project resources. Finally, FEI has identified the key Project risks and has taken a prudent approach to risk management, as well as identifying the key regulatory permits and approvals that are required to construct the Project.

6. PROJECT COSTS, ACCOUNTING TREATMENT AND RATE IMPACT

6.1 INTRODUCTION

The total cost estimate of the TLSE Project is $768.998 million in as-spent dollars and including AFUDC. This section provides a breakdown of the total Project cost estimate, summarizes the financial analysis, and details the accounting treatment and delivery rate impact of the Project.

6.2 SUMMARY OF PROJECT COSTS

Table 6-1 below summarizes the total Project estimated capital cost in both 2020 and as-spent dollars. The Project capital cost estimate meets the criteria for an AACE Class 3 Cost Estimate as required by the BCUC's CPCN Guidelines, as discussed in Sections 5.4.1 of the Application.

Table 6-1: Breakdown of the TLSE Project Cost Estimate ($ millions)

	2020 $	As-Spent $	Reference
Engineering and Development	23.653	25.609	Section 5.4.1 and Confidential Appendix J4 (2020 $)
Material	144.589	151.623	Section 5.4.1 and Confidential Appendix J4 (2020 $)
Construction - Direct and Indirect	317.043	357.325	Section 5.4.1 and Confidential Appendix J4 (2020 $)
Base Plant Demolition	12.297	13.827	Section 5.4.1 and Confidential Appendix J4 (2020 $)
FEI Project Management and Owner's Costs	31.521	32.928	Section 5.4.1 and Confidential Appendix J4 (2020 $)
Subtotal Capital Cost	529.103	581.312	See Note 1 for As-spent $
Contingency	108.200	118.384	Section 5.4.4.4 and see Note 1 for As-spent $
Subtotal Project Capital Costs w/ Contingency	637.303	699.696	Table 6-2; Row 7; Col 1 (2020 $) & Col 2 (As-spent $)
CPCN Application	0.600	0.600	Section 6.4.4
CPCN Preliminary Stage Development	1.546	1.546	Section 6.4.4
Subtotal w/ Deferral Costs	639.449	701.842	Table 6-2; Row 11; Col 1 (2020 $) & Col 2 (As-spent $)
AFUDC	-	69.796	Table 6-2; Row 11; Col 3
Tax Offset	-	(2.640)	Table 6-2; Row 11; Col 4
TOTAL Project Cost	***639.449***	***768.998***	***Table 6-2; Row 11; Col 1 (2020 $) & Col 5 (As-spent $)***

Notes:

1. *The as-spent cost is equal to the amount in 2020 dollars plus escalation. The total escalation is $62.393 million (Section 5.4.4.5), which includes $52.209 million of escalation on capital cost and $10.184 million of escalation on contingency.*

The TLSE Project cost estimate, reflected in the table above, is based on the following:

- A base cost estimate of $531.249 million in 2020 dollars developed by FEI, in conjunction with Linde, Clough, HCBI, Golder, and SMCI as described in Section 5.4.1 and Confidential Appendix J-4 of the Application. The base cost estimate includes:
  - $521.472 million of base capital costs;
  - $7.631 million of Project development costs incurred between April and December 2020 (actual from April to November 2020 and projected for December 2020); and

  - $2.146 million of actual deferred costs for the Application and Preliminary Stage Development Costs discussed in Section 6.4.4.

- A contingency estimate of $108.200 million in 2020 dollars (approximately 20 percent of the base cost estimate of $531.249 million in 2020 dollars) provides a total capital budget at a P50 confidence level as discussed in Section 5.4.4.4 of the Application;
- A P50 escalation value of $62.393 million during the Project from 2020 to 2026, as discussed in Section 5.4.4.5 of the Application applied to both the base capital cost and contingency[120]. The escalation is used to convert the Project capital cost from 2020 dollars to as-spent dollars; and
- AFUDC, assumed at FEI's 2021 AFUDC rate of 5.47 percent, which is equal to FEI's after-tax weighted average cost of capital[121].

6.3 FINANCIAL ANALYSIS

FEI has performed a financial evaluation of the Project based on the present value (PV) of the incremental revenue requirement and the levelized delivery rate impact to FEI's non-bypass customers over a 67-year analysis period. The 67-year analysis period is based on a 60-year post-Project analysis period plus seven prior years for the estimated Project schedule from 2020 to 2026 (with all new assets to be placed in-service by 2026). The 60-year post-Project analysis period is chosen based on the average service life (ASL) for a new 3 Bcf LNG tank as recommended by Concentric Advisors, ULC (Concentric), who completed FEI's most recent Depreciation Study approved by BCUC Order G-165-20 as part of FEI's 2020-2024 Multi-Year Rate Plan (MRP) Application. FEI is seeking approval for a depreciation rate of 1.67 percent (equivalent to 60 years) for the new 3 Bcf LNG tank, which is discussed in more detail in Section 6.4.1.

Table 6-2 below provides the breakdown of the Project cost of $768.998 million in as-spent dollars into the new asset components, demolition costs, deferred costs, financing costs, and tax offset.

[120] No escalation applied on actual costs incurred by FEI prior to December 2020.
[121] As approved for 2021 by Order G-319-20. The actual AFUDC will be calculated based on the approved AFUDC rate at the time of construction.

Table 6-2: Summary of Forecast Capital and Deferral Costs ($ millions)

Line	Particular	2020 $	As-Spent $	AFUDC	Tax Offset	TOTAL	Reference (Confidential Appendix M1, Financial Schedules)
		(1)	(2)	(3)	(4)	(5)	(6)
1	LNG Tank (3.0 BCF)	327.591	361.083	40.190	-	401.272	Schedule 6: Sum of Line 5 and Line 19 (2020-2026)
2	Regasification Equipment	122.084	132.876	10.978	-	143.855	Schedule 6: Sum of Line 9 and Line 23 (2020-2025)
3	Ground Improvement	42.374	47.213	8.449	-	55.661	Schedule 6: Sum of Line 4 and Line 18 (2020-2026)
4	Auxiliary System	130.995	142.440	9.022	-	151.461	Schedule 6: Sum of Line 10 and Line 24 (2020-2026)
5	Subtotal Addition to Plant	623.044	683.611	68.639	-	752.250	Sum of Line 1 to Line 4
6	Base Plant Demolition	14.260	16.085	1.043	-	17.129	Schedule 6: Sum of Line 34 (2020-2025)
7	*Subtotal Project Capital Cost*	*637.303*	*699.696*	*69.682*	-	*769.379*	Line 5 + Line 6
8	TLSE Application	0.600	0.600	0.019	(0.162)	0.457	Schedule 9: Line 6
9	TLSE Preliminary Stage Development	1.546	1.546	0.094	(2.478)	(0.838)	Schedule 9: Line 15
10	*Subtotal Project Deferral Cost*	*2.146*	*2.146*	*0.114*	*(2.640)*	*(0.381)*	Line 8 + Line 9
11	***Total Project Cost***	***639.449***	***701.842***	***69.796***	***(2.640)***	***768.998***	**Line 10 + Line 11**

Table 6-3 below summarizes the financial analysis based on the assumptions discussed in this section. Details of the financial evaluation of the Project can be found in the Financial Schedules included in Confidential Appendix M-1.

The PV of the incremental revenue requirement of the Project is approximately $1,042 million and the levelized delivery rate impact is 6.67 percent over the 67-year analysis period. The Project is evaluated financially based on delivery rate impact, as recovery through the delivery rate is consistent with the treatment of the existing Tilbury Base Plant that is proposed to be replaced by the Project. The existing Tilbury Base Plant is included in FEI's rate base and the costs are recovered through FEI's delivery rates from non-bypass customers.

Table 6-3: Financial Analysis of the Project

Line	Particular	TOTAL	Reference (Confidential Appendix M1, Financial Schedule)
1	Total Charged to Gas Plant in Service ($ millions)	752.250	Schedule 6; Line 37
2	Base Plant Demolition Costs ($ millions)	17.129	Schedule 6; Sum of Line 34 (2020 to 2025)
3	Total Project Deferral Cost, Net of Tax ($ millions)	(0.381)	Schedule 9; Line 6 + Line 15
4	***Total Project Cost ($ millions)***	**768.998**	**Sum of Line 1 to Line 3**
5			
6	Incremental Rate Base in 2027 ($ millions)	814.400	Schedule 5; Line 19 (2027)
7	Incremental Revenue Requirement in 2027 ($ millions)	79.799	Schedule 1; Line 11 (2027)
8	***PV of Incremental Revenue Requirement 67 years ($ million)***	**1,041.925**	**Schedule 10; Line 20**
9	Net Cash Flow NPV 67 years ($ million)	66.177	Schedule 11; Line 17
10			
11	Delivery Rate Impact in 2027 (%)	9.07%	Schedule 10; Line 23 (2027)
12	***Levelized Delivery Rate Impact 67 years (%)***	**6.67%**	**Schedule 10; Line 27**
13	Levelized Delivery Rate Impact 67 years ($/GJ)	0.301	Schedule 10; Line 33

The financial evaluation of the TLSE Project includes the following assumptions:

- **Inflation:** Two percent annually for incremental O&M, property tax, and future capital replacement costs during the post-Project analysis period. This is comparable to the

historical 5-year average BC CPI from 2015 to 2019 which is also approximately two percent[122];

- **O&M:** An estimate of incremental O&M costs due to the Project of approximately $3.915 million in 2020 dollars ($4.551 million in 2027 dollars[123]). These costs are comprised of:
  - approximately $6.178 million in 2020 dollars ($7.162 million in 2027 dollars) of new O&M costs, including electricity costs, associated with the new 3 Bcf LNG tank, the new 800 MMcf/day regasification equipment, and auxiliary systems;
  - offset by O&M savings, including electricity costs, of approximately $2.263 million in 2020 dollars ($2.610 million in 2027 dollars) due to the demolition of the Tilbury Base Plant as discussed in Section 5.3.5.

  The O&M estimate for the new tank, regasification equipment and auxiliary systems reflects the work of Partners in Performance (PiP)[124]. The O&M estimate for the new tank and equipment is developed based on PiP's Q4-2019 benchmark study on known and similar operations globally, normalized with information collected from interviews conducted with FEI operations on the existing Tilbury facility, third party subject matter experts on similar operations, and Engineering, Procurement and Construction Companies (EPCs) who developed the cost estimates for the Project. This detailed estimate is included in Confidential Appendix N.

  The offsetting savings reflect the average of historical O&M costs for the Tilbury Base Plant from 2008 to 2019. These costs will no longer be incurred once the Tilbury Base Plant is decommissioned.

- **Property tax:** Incremental property tax as a result of the new 3 Bcf tank based on the 2020 tax rate. The incremental property tax is assumed to occur in phases based on percentage completion of the LNG tank construction between 2023 and 2026;
- **Incremental sustainment capital:** FEI has used an estimate of sustainment capital prepared by PiP (Confidential Appendix N), which is an average of 1 percent per year for the mechanical equipment capital expenditures (LNG tank, regasification equipment, auxiliary equipment), developed based on an industry benchmark of similar operations and interviews with third party industry experts. This benchmark applies to the capital cost of the mechanical equipment only, which does not include other indirect costs such as mobilization, engineering, contingency, etc.; and

[122] https://www2.gov.bc.ca/gov/content/data/statistics/economy/consumer-price-index
[123] Based on two percent annual inflation for all O&M costs, except electricity. For electricity, annual escalation is based on current BC Hydro 5-year forecasts. Since the new LNG tank is scheduled to be in-service in 2026, the first full year of the new LNG tank in-service will be 2027.
[124] PiP is a global management consulting firm with specific expertise in industrial operations including LNG, oil and gas, and utilities. PiP has extensive experience in supporting oil and gas companies with existing LNG operations in Canada as well as globally, including Australia and the United States.

- **Future capital replacement:** The average service life for the regasification equipment and auxiliary system is both 40 years, which is shorter than the 60-year post-Project period used for the financial analysis. As such, FEI's financial analysis includes future replacement of the regasification and auxiliary systems at the end of their average service life at 40 years. The future capital replacement does not include the replacement of ground improvement work related to stone columns as discussed in Section 5.3.4. FEI does not expect the stone columns will need to be replaced within the 60-year post-Project period.

6.4 ACCOUNTING TREATMENT

In the subsections below, FEI describes the proposed depreciation and net salvage rate for the new LNG tank, proposed treatment of the Project capital costs, the proposed treatment of the Tilbury Base Plant demolition costs, and the requests for the TLSE Application and Preliminary Stage Development Costs deferral account as well as the TLSE FX Mark to Market deferral account.

6.4.1 LNG Tank Depreciation and Net Salvage Rate

FEI is seeking approval pursuant to sections 59-61 of the UCA for a depreciation rate of 1.67 percent and a net salvage rate of 0.67 percent applicable to the new 3 Bcf LNG tank as part of the Project. FEI consulted with Concentric, who recommended the average service life of a new 3 Bcf LNG tank would be 60 years (i.e., 1.67 percent = 1 / 60 x 100) based on recent experience, with a net salvage rate determined to be 40 percent of the capitalized value of the LNG tank over 60 years (i.e., 0.67 percent = 0.4 / 60 years x 100).

FEI currently has a depreciation rate of 1.23 percent (equivalent to 81 years) and a net salvage rate of 1.12 percent approved by the BCUC[125] for the Tilbury LNG tank (Account Class 44300). This rate is primarily determined based on historical assets (i.e., Tilbury Base Plant and Tilbury 1A facilities) within the same class that includes accumulated gains or losses embedded within the depreciation rates that existed at the time of the depreciation study. These historical gains or losses are unrelated to the prospective future life of the new LNG tank and the depreciation rate is not reflective of the average service life of 60 years expected from a new LNG tank as recommend by Concentric. Using the currently approved depreciation rate would result in a significant overdue cost recovery of the new LNG tank relative to the expected average service life (currently 1.23 percent for 81 years vs. the proposed 1.67 percent for 60 years). FEI believes it is more appropriate to depreciate the new LNG tank at the proposed depreciation rate of 1.67 percent with a net salvage rate of 0.67 percent that is aligned with the expected average service life of the asset. FEI notes the proposed depreciation rate and net salvage rate is for the new 3 Bcf LNG tank only. The depreciation and net salvage rates for the ground improvement, regasification, and auxiliary system will be based on the approved rates at the time they are included in rate base. The currently approved depreciation rate for ground

[125] FEI Depreciation Study approved by Order G-165-20 as part of FEI's 2020-2024 MRP Application.

improvements in asset class LNG Gas Structures & Improvements (44200) is 2.20 percent, or 45 years; and for regasification and auxiliary systems under asset class LNG Send Out Equipment (44861) is 2.41 percent, or 41 years.

6.4.2 Treatment of Capital Costs

Consistent with FEI's treatment of major project capital costs, including CPCNs:

- As the capital costs of the TLSE Project (i.e., $769.379 million set out in Line 7 and Column 5 of Table 6-2 above) are incurred, they will be recorded in Work in Progress during construction, attracting AFUDC;
- Once the assets are placed into service, the associated capital cost will enter rate base as part of the opening balance in the appropriate plant asset accounts, for inclusion in FEI's rate base on January 1 of the following year. Table 6-4 below summarizes the estimated amount of the Project capital costs to be in-service each year between 2024 and 2026. For example, $74.184 million of regasification equipment is forecast to be placed in service in 2024; thus, these costs will transfer to rate base on January 1, 2025; and
- Depreciation of the assets will begin on January 1 of the year that they enter FEI's rate base. For example, depreciation will begin in 2025 for the $74.184 million of regasification equipment that was completed and placed in-service in 2024.

The estimated amounts to be transferred to rate base each year as shown in Table 6-4 below are included in the opening balance of FEI's Gross Plant in Service as shown in Confidential Appendix M-1, Financial Schedule 7.

Table 6-4: Percentage of Project Complete and In-Service during Project Years (2024-2027)

	Project complete and in-service each year, 2024-2027 ($ millions) (To be transferred to Rate Base January 1 of each following year)			
	2024	2025	2026	TOTAL
LNG Tank (3.0 BCF)	-	-	401.272	401.272
Regasification Equipment	74.184	69.670	-	143.855
Ground Improvement	10.201	10.771	34.690	55.661
Auxiliary System	81.985	31.744	37.732	151.461
Total Charged to Gas Plant in Service	166.37	112.18	473.69	752.250
Base Plant Demolition	-	17.129	-	17.129
Total Annual Project Costs	166.371	129.313	473.694	769.379
Annual Project % In-Service	22%	17%	62%	100%

6.4.3 Treatment of Base Plant Remaining Net Book Value and Demolition Costs

As discussed in previous sections of the Application, the TLSE Project includes the demolition of the Tilbury Base Plant as part of the CPCN Application. The cost to demolish the Base Plant

is $14.260 million in 2020 dollars ($17.129 million in as-spent dollars and inclusive of AFUDC) as shown in Table 6-1. The demolition is scheduled to occur in 2025 as shown in Table 6-4. The demolition costs will be charged to FEI's existing Net Salvage Deferral Account in accordance with the treatment of removal costs as approved in Order G-44-12. The demolition costs are detailed in Confidential Appendix M-1, Financial Schedule 6. The continuity of the Net Salvage Deferral Account for the Project can be found in Confidential Appendix M-1, Financial Schedule 9.

Once the Base Plant has been demolished, the assets will be retired following normal asset retirement accounting by crediting plant in service and debiting accumulated depreciation, as shown in Confidential Appendix M-1, Financial Schedule 9 (Line 33 to 46) and Financial Schedule 10 (Line 33 to 46), respectively. This entry by itself has no impact on rate base, but without further adjustments, would result in decreased depreciation expense at the time of retirement. However, since FEI's next depreciation study will be completed prior to 2025, and, if approved, this retirement will be known, future depreciation rates for the impacted asset classes will take the retirement of the Base Plant into account. All else equal, this retirement will result in an increased depreciation rate for the impacted accounts in order to recover the remaining net book value of the retired assets. FEI has not forecast a change to the depreciation rate in the financial analysis, as the impact of the retirement on future depreciation rates is unknown and will be confirmed with the next depreciation study.

6.4.4 Application and Preliminary Stage Development Costs

FEI is seeking BCUC approval under sections 59-61 of the UCA for deferral treatment of the Application and Preliminary Stage Development costs.

The Application costs are based on a written hearing process and include expenses for external legal review, consultant and studies costs, BCUC costs, and BCUC-approved intervener costs.

The Preliminary Stage Development costs are related to expenses incurred for engaging third party-consultants for feasibility evaluation, preliminary development, and assessment of the potential design and alternatives as required to complete this Application.

FEI is seeking approval to record these costs in a new non-rate base deferral account, the TLSE Application and Preliminary Stage Development Costs deferral account, attracting FEI's weighted average cost of capital until it enters rate base. Consistent with FEI's previous CPCN applications, FEI proposes to transfer the balance in the deferral account to rate base on January 1 of the year following BCUC approval of the Application and commence amortization over a three-year period thereafter.

For the financial analysis summarized in Section 6.3 above, FEI assumed a BCUC decision in 2021, thus the balance in the deferral account will be transferred to rate base on January 1, 2022. Table 6-5 below shows the net-of-tax balance, forecast to December 31, 2021, for the TLSE Application and Preliminary Stage Development Costs deferral account is a credit of $0.381 million, which FEI will return to non-bypass customers through the amortization of the

deferral account. The tax offset on capitalized costs is related to the development costs incurred in 2020 that are capitalized but are eligible for deduction for tax purposes in the year incurred. The continuity of the TLSE Application and Preliminary Stage Development Costs deferral account can be found in Confidential Appendix M-1, Financial Schedule 9.

Table 6-5: Forecast TLSE Application and Preliminary Stage Development Costs Deferral Account ($ millions)[126,127]

	Forecast to Dec 31, 2021 ($ millions)		
Particular	Application	Preliminary Stage Development	TOTAL
Pre-Tax Costs	0.600	1.546	2.146
WACC Return	0.019	0.094	0.114
Total Before Tax Offset	***0.619***	***1.640***	***2.260***
Tax Offset - Costs held in Deferral Account	(0.162)	(0.417)	(0.579)
Tax Offset - Capitalized Costs	-	(2.061)	(2.061)
Total	***0.457***	***(0.838)***	***(0.381)***
Annual Amortization for 3 years	(0.152)	0.279	0.127

6.4.5 TLSE Foreign Exchange (FX) Mark to Market Valuation

FEI is seeking BCUC approval under sections 59-61 of the UCA for a deferral account, entitled the "TLSE FX Mark to Market" deferral account, to capture the mark-to-market valuation of any foreign currency forward contracts entered into related to construction of the Project. The deferral account is an important tool to avoid uncontrollable external income statement volatility, as well as to avoid additional exposure to foreign currency exchange rate risk during the Project, and is similar to what the BCUC approved for the Mt. Hayes LNG Facility CPCN[128] as well as the Customer Care Enhancement CPCN[129].

A portion of the price of the Project may include US Dollar (USD) payments to the main Project contractor, giving rise to exchange rate risk. If a portion of the price is denominated in USD, then FEI would plan to hedge the risk by locking in the foreign exchange rate exposure using foreign exchange forward contracts to mitigate the risk of fluctuations in the value of USD/Canadian currency exchange rate differences.

While utilizing foreign exchange forward contracts will help mitigate the risk of exchange rate differences, these types of contracts are considered derivative instruments under FASB Accounting Standards Codification 815, Derivatives and Hedging, which would require FEI to

[126] Income tax offset on the deferred costs (i.e., $0.579 million) equals to the sum of $0.600 million for the Application costs and $1.546 million for the development costs times the income tax rate of 27 percent.
[127] Income tax offset on the capitalized costs are related to the development costs that were capitalized but are eligible for deduction for tax purposes. The amount (i.e., $2.061 million) is equal to the capitalized costs of $7.631 million times the income tax rate of 27 percent.
[128] Order G-145-08.
[129] Order G-96-10.

fair value (mark-to-market) at the end of each accounting period. In the absence of an approved deferral account, those mark-to-market adjustments would be included in FEI's earnings for the period.

Due to the potential volatility in FEI's external financial statements arising from the required recognition of mark-to-market valuation of foreign exchange forward contracts, FEI requests approval of a deferral account to capture these mark-to-market adjustments over the course of the Project. The deferral account will not attract a financing return, as the mark-to-market adjustments are non-cash.

As stated previously, the BCUC approved a similar account for the Mt. Hayes Storage Facility Project and the Customer Care Enhancement Project.

The deferral account treatment of the mark-to-market adjustments related to the foreign exchange rate hedging for the Project will have no impact on customer rates. The use of the requested deferral account will not increase or decrease the expected cost of the Project because the hedging fixes the exchange rate for the USD denominated cost components and thus mitigates the foreign exchange risk upon settlement, or payment. The forward contracts will provide cost certainty as they lock in the foreign exchange rate for USD denominated cost components obtained by FEI for this Project. At the end of the Project, the amount of the deferral account will be zero, since the deferral account only captures any unrealized gains and losses related to the requirement to mark-to-market the foreign exchange derivative contracts.

The requested deferral account is beneficial to FEI and its customers. It allows FEI to mitigate the impact on its external financial statements arising from undertaking the hedging of the USD denominated payments during the Project execution. By doing so, it facilitates the use of foreign exchange forward contracts that will provide certainty to customers on the exchange rate used for the US dollar portion of the contract.

FEI will report on the use of this deferral account as part of the Project progress reports filed with the BCUC.

6.5 RATE IMPACT

The TLSE Project will have incremental delivery rate impacts from 2022 to 2027. The causes of the delivery rate impacts in each year are explained below:

- **2022 to 2024:** Delivery rates will be impacted (reduced) in these years by the amortization of the TLSE Application and Preliminary Stage Development Costs deferral account as discussed in Section 6.4.4 above. The delivery rate credit due to the amortization of the deferral account will be offset by the incremental property tax in 2023 and 2024, increasing based on the percentage completion of the LNG tank construction until the LNG tank is complete in 2026;

- **2025 and 2026:** Delivery rates will be impacted in 2025 and 2026 as the assets for the regasification equipment, auxiliary system, and ground improvements are scheduled to be placed in service in 2024 and 2025, and will be transferred to rate base on January 1 of 2025 and 2026, respectively (refer to Table 6-4 in Section 6.4.2 above);
- **2027:** Delivery rates will be impacted in 2027 as the assets related to the new 3 Bcf LNG tank are scheduled to be placed in service in 2026, and will be transferred to rate base on January 1 of 2027 (refer to Table 6-4 in Section 6.4.2 above).

Table 6-5 below shows the annual delivery rate impact due to the Project in percentage terms compared to FEI's 2021 approved non-bypass revenue requirement[130] and the incremental annual delivery rate impact in percentage terms (year-over-year) from 2022 to 2027.

Table 6-6: Summary of Delivery Rate Impact for the TLSE Project

	2022	2023	2024	2025	2026	2027
Annual Delivery Margin, Incremental to 2021 Approved, Non-Bypass ($ millions)	(0.162)	0.361	1.274	22.909	36.651	79.799
% Increase to 2021 Approved Delivery Margin, Non-bypass	***(0.02%)***	***0.04%***	***0.14%***	***2.60%***	***4.17%***	***9.07%***
Incremental % Delivery Rate Impact (Year-over-Year)	***(0.02%)***	***0.06%***	***0.10%***	***2.46%***	***1.52%***	***4.71%***
Average Annual % Delivery Rate Impact (6 years, 2022 - 2027)	1.47%					
Average Annual Delivery Rate Impact (6 years, 2022 - 2027), $/GJ	0.068					
Cumulative % Delivery Rate Impact (6 years, 2022 - 2027)	9.07%					
Cumulative Delivery Rate Impact (6 years, 2022 - 2027), $/GJ	0.409					

The Project will result in a cumulative delivery rate impact of 9.07 percent compared to FEI's 2021 approved delivery rates when all construction, including the Base Plant demolition, is completed and all capital costs have entered FEI's rate base. The average annual delivery rate impact over the six years from 2022 to 2027 is estimated to be 1.47 percent annually or $0.068 per GJ annually. For a typical FEI residential customer consuming 90 GJ per year, this would equate to an average bill increase of approximately $6.12 per year over the six years. As discussed in Section 6.3, the levelized delivery rate impact is 6.67 percent, which is equivalent to $0.301 per GJ for a typical FEI residential customer over the life of the assets.

[130] As approved by Order G-319-20.

7. ENVIRONMENT AND ARCHAEOLOGY

7.1 INTRODUCTION

Although the Project will be located on a brown-field site in an industrial area, it is important and necessary to assess the environmental and archaeological impacts associated with the Project. Based on the assessments undertaken, and prior to FEI's planned mitigation activities, the Project has the potential to have a moderate environmental impact and a low to moderate archaeological impact. FEI expects to mitigate potential impacts through additional assessments, permitting, and standard protection and mitigation measures.

In this Section, FEI will explain:

- The potential environmental impacts identified by the preliminary environmental assessment and how these impacts can be mitigated through additional assessment, the implementation of standard environmental protection and mitigation measures, and municipal, regional, provincial and federal permitting processes (Section 7.2); and
- The potential archaeological impacts identified by the preliminary archaeological assessment and how these impacts can be mitigated through additional assessment, the implementation of standard best management practices, and standard provincial and Indigenous permitting processes (Section 7.3).

As discussed in Section 5.8.1, the Tilbury Phase 2 LNG Expansion Project, of which the TLSE Project is a component, triggers the requirements for both a Federal Impact Assessment and a Provincial Environmental Assessment. The Tilbury Phase 2 LNG Expansion Project has entered the environmental assessment process administered by the BC Environmental Assessment Office (BC EAO) and the impact assessment process administered by the Impact Assessment Agency of Canada, which is taking place concurrently with this CPCN Application. Accordingly, the Project will undergo a rigorous assessment of its environmental and other impacts, beyond the scope of assessment discussed in this Section. As part of that process, FEI will be undertaking detailed environmental assessment work, including vegetation, fish/fish habitat, and wildlife/wildlife habitat surveys, as well as surface and ground water resource investigations. Ultimately, the environmental assessment process will provide further opportunity to understand Project impacts and assess the suitability of any proposed mitigations.

7.2 ENVIRONMENTAL ASSESSMENT AND MITIGATION PLAN

As described below, FEI undertook a preliminary environmental assessment of the Project. The assessment indicated that the combined risks that the Project presents for the environment, and that the environment could have on the Project's cost, will vary from low to high depending on the biophysical receptor. As described in greater detail below, a low risk rating indicates that the potential effects are likely within environmental/regulatory standards, can be managed using industry mitigation, and require no specific regulatory approvals or the regulatory process and

costs for approvals are predictable. A medium to high risk rating indicates additional assessment is recommended to characterize and manage the potential adverse effects, as well as additional cost and cost uncertainty for the implementation of specialized mitigation measures, or follow-up work is expected.

Overall, FEI expects that the potential environmental impacts from the Project can be mitigated through additional assessments followed by municipal, regional, provincial and federal permitting processes and the implementation of standard environmental protection and mitigation measures.

7.2.1 Environmental Overview Assessment

7.2.1.1 FEI Retained Experts to Conduct an Environmental Overview Assessment

FEI retained Jacobs Consultancy Canada Inc. (Jacobs)[131] to conduct a preliminary environmental assessment of the Project. The results and conclusions from Jacobs' preliminary environmental assessment are outlined in the FortisBC Tilbury LNG Phase 2 Expansion Project Environmental Overview Assessment report (Environmental Overview Assessment or EOA), a copy of which is attached as Appendix O.

The assessment is based on both a desk-top review of available information and an initial field investigation. The assessment was undertaken to identify and describe environmental impacts, meaning both:

- The potential impacts to the biophysical environment from the Project; and
- Risks to the Project's cost associated with mitigating any potential environmental impacts.

The assessment provides a basis for the completion of detailed assessments and preparation of environmental management plans to be completed after BCUC approval of this Application is received and prior to construction.

Ultimately, Jacobs expects that potential environmental impacts from the Project can be mitigated through:

- Additional assessments related to the atmospheric environment and potentially contaminated soils and groundwater;
- Municipal, regional, provincial and federal permitting processes; and
- The implementation of standard environmental protection and mitigation measures.

[131] Jacobs provides a full spectrum of professional services including consulting, technical, scientific and project delivery for government and private sector clients in 40+ countries worldwide.

7.2.1.2 The Environmental Overview Assessment Describes the Existing Site Conditions and Potential Adverse Effects

The EOA describes the existing conditions on the entire Tilbury site and the Project's potential adverse effects on the environment. Where Jacobs has identified potential adverse effects, the EOA also describes the recommended mitigation and follow-up work required.

In preparing the EOA, Jacobs assessed the following comprehensive list of biophysical receptors:

- Surface water;
- Atmospheric environment;
- Contaminated soils and groundwater;
- Fish and fish habitat;
- Vegetation and wetlands; and
- Wildlife and wildlife habitat.

Jacobs also assessed prior and existing land use in addition to the listed biophysical features.

Within the biophysical receptors listed above, the EOA identifies natural features on or near the Tilbury site that could be impacted during construction. These natural features represent specific aspects of the biophysical receptors which may be impacted by the Project and can be summarized into the following categories:

- Watercourses on or near the Tilbury site:
  - Fish bearing Fraser River to the north;
  - Fish bearing Tilbury Slough to the south; and
  - Non-fish bearing drainage ditch on the site.
- Species at risk with the potential to occur on or near the Tilbury site:
  - Mammals – seven (7) species;
  - Birds – thirteen (13) species;
  - Amphibians – two (2) species;
  - Reptiles – one (1) species;
  - Nonvascular plants – nine (9) species; and
  - Vascular plants – four (4) species.

The EOA also identified locations where FEI may potentially encounter soil or groundwater contamination within or near the Tilbury site, which may impact Project construction, costs and timelines. There are eight areas of potential environmental concern (APECs):[132]

- APEC 1 – former sawmill site;
- APEC 2 – foam generator tank;
- APEC 3 – diesel aboveground storage tank;
- APEC 4 – rust staining;
- APEC 5 – on-site sumps;
- APEC 6 – former PCB containing equipment;
- APEC 7 – unknown quality fill; and
- APEC 8 – pile of used rail lines and ties.

Table 4-7 of the EOA (Appendix O) details the APECs, the potential contaminants of concern and the recommendation for each APEC. In particular, Jacobs recommends completing Stage 1 and 2 Preliminary Site Investigations (PSIs) to further understand the potential for contamination. FEI will be undertaking Stage 1 and/or Stage 2 PSIs as the need is triggered by Project activities.

7.2.1.3 The Project is Considered Low Risk for Most Biophysical Receptors, With Additional Risk for Atmospheric Environment and Contaminated Soils and Groundwater

Jacobs defines the risk categories for the biophysical receptors (prior to the implementation of any mitigation) as follows:[133]

- **Negligible** – Potential adverse effects of the Project may not be detectable or are within the range of natural variability or are inconsequential to the function, health, performance, or sustainability of receptor. No mitigation measures, timing constraints, or receptor-specific regulatory approvals requiring cost to the Project are anticipated.
- **Low** – Potential adverse effects of the Project are detectable; however, they are well within environmental or regulatory standards, or both. Additional assessment work is not likely to be recommended to characterize the potential adverse effect. Potential adverse effect can be managed using industry standard mitigation practices during construction and FEI's existing environmental management program for the Tilbury site during operation. No regulated timing constraints or receptor-specific regulatory approvals requiring cost to the Project are anticipated.

[132] Appendix O, pp. 4-13 to 4-15.
[133] Appendix O, pp. 2-6 and 2-7.

- **Medium** – Predicted adverse effects are detectable and may approach, however are still within, the environmental or regulatory standards, or both. Further assessment work is likely to be recommended to characterize the potential adverse effect. Low to moderate additional cost for the implementation of specialized mitigation measures or follow-up work is expected. If regulated timing constraints are applicable during construction, they are limited in duration and can be managed through construction phasing. Receptor-specific regulatory approvals are required to carry out the Project; however, the regulatory process is well-defined and associated costs are predictable.
- **High** – Predicted adverse effects are beyond environmental or regulatory standards, or both. Further assessment work is likely to be recommended to characterize the potential adverse effect. Considerable costs are expected for the implementation of specialized mitigation measures or follow-up work. Regulated timing constraints are applicable during construction and have the potential to result in substantial construction limitations. Receptor-specific regulatory approvals are required to carry out the Project and material conditions are anticipated in Federal, Provincial, and Municipal approvals.

BIOPHYSICAL RECEPTORS WITH LOW RISK

Jacobs determined that the following five biophysical receptors have a pre-mitigation rating of low risk:

- Surface water quality and quantity;
- Fish and fish habitat;
- Vegetation and wetlands;
- Wildlife and wildlife habitat; and
- Land use.

As described above, a low risk rating means that the potential effects for these biophysical receptors are within environmental/regulatory standards, can be mitigated through the implementation of standard best management practices, and require no specific regulatory approvals or the regulatory process and costs for approvals are predictable.

BIOPHYSICAL RECEPTORS WITH ADDITIONAL RISK

Jacobs determined that two biophysical receptors, (1) the atmospheric biophysical receptor and (2) the contaminated soils and groundwater biophysical receptor, have a pre-mitigation rating of medium to high risk.

The atmospheric environment receptor was given a medium to high risk rating because additional assessment is required to predict emissions to determine whether they are within applicable Ambient Air Quality Objectives and to obtain a Metro Vancouver Air Permit.

While impacts to the atmospheric environment associated with this Project are expected to be minimal, the risks associated with Metro Vancouver permitting under the Greater Vancouver Regional District Air Quality Management Bylaw No. 1082, 2008 are considered medium to high. The potential risk associated with the permitting under this bylaw will be further assessed during the detailed engineering phase through air dispersion modelling and working through the Metro Vancouver permitting process.

Jacobs also determined that the contaminated soils and groundwater biophysical receptor has a pre-mitigation risk rating of medium to high because of the eight APECs identified on the Tilbury site. Further assessment (i.e., a Stage 1 and Stage 2 PSI) is required to characterize and manage the potential adverse effects. Pending outcomes of the Stage 1 and Stage 2 PSI, Jacobs expects low to considerable additional costs to implement specialized mitigation measures or conduct follow-up work.

7.2.2 FEI Will Mitigate Identified Impacts and Risks

As previously indicated, the above risk categories for the biophysical receptors all reflect an assessment prior to the implementation of any mitigation. The EOA also identifies ways to minimize the impacts on the above-described natural features by implementing standard best management practices, as outlined in Table 6-1 of the EOA (Appendix O). FEI will follow the best management practices and mitigation measures applicable to the Tilbury site during construction, including but not limited to, the following:

- Developing and implementing an Environmental Management Plan (EMP);
- Conducting environmental monitoring;
- Assessing and monitoring ground and surface water conditions;
- Minimizing vegetation removal;
- Implementing erosion and sediment controls;
- Adhering to bird timing windows;
- Implementing appropriate soil handling procedures;
- Implementing appropriate waste management; and
- Developing spill response procedures.

FEI discusses below how it expects that potential environmental impacts from the Project can be mitigated through additional assessments followed by municipal, regional, provincial and federal permitting processes and standard environmental protection and mitigation measures.

7.2.2.1 FEI Will Conduct Further Assessment Work

FEI will be undertaking detailed environmental assessment work, including vegetation, fish/fish habitat, and wildlife/wildlife habitat surveys, as well as surface and ground water resource

investigations. A major component of this work will involve further analysis of the APECs, including Stage 1 and 2 PSIs, as required. In addition, a cumulative impact assessment will be undertaken with regard to the atmospheric environment for the entire Tilbury site, including air dispersion modelling to facilitate permitting through Metro Vancouver.

7.2.2.2 Detailed Environmental Assessment Work Will Confirm Potential Permitting Requirements

Table 7-1 of the EOA lists the potential permits and approvals that may be required for the Project, including:

- Fisheries and Oceans Canada project review;
- BCOGC Facility Permit;
- BCOGC Waste Discharge Authorization;
- Metro Vancouver Air Quality Permit
- Metro Vancouver Sewer Use Permit; and
- City of Delta building and development permits.

FEI has begun the detailed environmental assessment work to confirm permitting requirements and this will continue in the coming months. This additional assessment work will confirm permitting requirements. All required environmental permits and approvals for the Project will be applied for as required.

7.2.2.3 FEI Will Develop Detailed Plans to Facilitate Mitigation

FEI will develop site-specific mitigation strategies to offset potential negative environmental impacts associated with the Project or from the environment on the Project.

FEI will prepare an Environmental Management Plan as part of the Project tendering process to ensure that contractors are aware of the Project's environmental requirements in addition to FEI's internal environmental standards.

Further, the successful contractor(s) will develop an Environmental Protection Plan specific to the Project prior to commencement of construction on the Project. Environmental monitoring will be undertaken during all sensitive aspects of the work program and the designated environmental monitor will have "stop work authority" in the event that works underway have the potential to impact the natural environment.

7.3 ARCHAEOLOGICAL ASSESSMENT AND MITIGATION PLANS

7.3.1 Archaeology Overview Assessment

7.3.1.1 FEI Retained Experts to Conduct an Archaeological Overview Assessment

As described below, FEI retained Golder Associates Ltd (Golder)[134] to conduct an Archaeology Overview Assessment (AOA) for the Project area.

The results of the work undertaken by Golder are outlined in the FortisBC Tilbury LNG Production and Storage Facility Expansion, Delta, BC Archaeological Overview Assessment report (Archaeology Overview Assessment or AOA), a copy of which is attached as Appendix P.

The AOA is based on both a desk-top review of available information and a preliminary field reconnaissance (PFR). The purpose of the AOA was to develop a comprehensive understanding of the archaeological resource potential of the area and provide guidance on the need for and, if required, the scope of future archaeological assessments (e.g., archaeological impact assessment or "AIA") related to the Project or future works within the AOA area prior to the commencement of ground disturbing activities.

Golder's AOA determined that the likelihood of impact to archaeological resources, prior to undertaking any mitigation steps, is low to moderate but requires further assessment. Golder expects that potential impacts to archaeological resources as a result of the Project can be mitigated through additional assessment, standard provincial and Indigenous permitting processes, and the implementation of standard best management practices.

7.3.1.2 The AOA Examines the Relevant Area, Assesses Archaeological Potential, and Provides Guidance Regarding the Need for Future Assessments

The AOA area included (see Figure 7-1 below):

- The Tilbury property, the dyke and foreshore adjacent to the Fraser River;
- Hopcott Road between Gravesend Reach and Tilbury Slough and the area to the east following the existing pipeline right-of-way; and
- The area south of the FEI property, including Tilbury Road and the northern arm of Tilbury Slough.

[134] Golder is a multi-disciplinary consulting firm that has provided a variety of professional services including archeological, planning, engineering and environmental services since 1960.

Figure 7-1: AOA Assessment Area Outline (in Red)

As part of the AOA, Golder reviewed a range of environmental, geotechnical, archaeological, cultural and historical information. The review did not identify any registered archaeological sites or historic heritage sites within the AOA area. The archaeological potential of the AOA area was assessed considering environmental variables as well as archaeological and ethnographic information. The primary considerations for assessing archaeological potential included the location of registered archaeological sites, proximity to waterways, documented events resulting in the removal of cultural bearing deposits, and results of previous AIAs.

To facilitate the archaeological potential assessment, the AOA area was subdivided into 13 assessment areas. The AOA concluded that 12 of the 13 assessment areas within the AOA area have some amount of archaeological potential based on proximity (within 100 metres) to waterways, including the inferred locations of slough channels that have been infilled. Portions of the assessment areas were identified as not having archaeological potential. These included areas where: (1) previous AIAs had negative results; (2) documented development activities have resulted in the removal of sediment deposits potentially containing cultural materials; or (3) the distance to present and past waterways is greater than 100 metres.

Where archaeological potential was identified within the AOA area, Golder refined their recommendations through an evaluation of archaeological sensitivity. For the purposes of the AOA, archaeological sensitivity referred to the possibility that if archaeological material was present, that it would be located below historic sediment deposits resulting from development activity or natural depositional processes. In these instances, Golder referred to archaeological potential as being "deep". Similarly, Golder classified archaeological sensitivity as "removed" where historic development activities have resulted in the extraction of sediments with potential to contain archaeological material. Golder's archaeological inferences, based on the results of the archaeological sensitivity evaluation, were classified as either "likely" or "unlikely" and where the inference may be based on incomplete or absent data, a "data absent" qualifier was applied.

The results of the archaeological potential assessment are illustrated in Appendix P, Figure 9 and the results of the archaeological sensitivity assessment are illustrated in Appendix P, Figure 10.

A detailed AIA of the Project area that is based on the recommendations of the AOA will be undertaken after BCUC approval of this Application and prior to and during construction of the Project.

7.3.2 FEI Will Mitigate Any Archaeology Impacts

Potential impacts to archaeological resources as a result of the Project can be mitigated through the standard provincial and Indigenous permitting processes and the implementation of standard best management practices.

7.3.2.1 The AOA Provides Guidance Regarding the Need for Future Assessments and Potential Mitigation

Based on the results of the AOA, Golder recommended that, if possible, FEI should avoid ground-disturbing impacts to areas assessed as having archaeological potential. If avoidance is not possible, Golder recommended that an AIA be conducted prior to development activities.

Golder provided specific recommendations for each of the 13 assessment areas. These recommendations can be summarized in four groups (Appendix P, Figure 11):

1. For areas where no archaeological potential was assessed, proceed with an Archaeological Chance Find Management Procedure in place for all works.
2. For areas with potential for deeply buried archaeological sediments, proceed with an Archaeological Chance Find Management Procedure in place for all works and if works extend below 4.0 metres, conduct monitoring.
3. For areas with potential for deeply buried archaeological sediments that have likely been removed or the subsurface data is absent, proceed with an Archaeological Chance Find Management Procedure in place for all works and if works extend below 40 centimetres, conduct AIA and/or monitoring.

4. For areas with surface or near surface potential, conduct an AIA prior to construction.

While the AOA does not provide recommendations specific to any of the Project's alternatives, the recommendations provided for the 13 assessment areas (Appendix P, Figure 11) are applicable, when overlain on the footprints of each of the Project's alternatives, to the development of the scope of future AIA works. As the footprints for each of the Project's alternatives are similar, the scope of future AIA works, in consideration of the AOA recommendations, will depend on the Project's anticipated impacts resulting from ground disturbance activities. These impacts will be finalized during the Project's detailed engineering phase and will be considered by the Project's archaeological consultant when developing the AIA scope.

7.3.2.2 FEI Has Sought, and Will Continue to Seek, Input from Indigenous Communities Regarding Archaeological Work

Notification letters were sent to Indigenous communities identified through a search of the British Columbia Consultative Areas Database as having an interest in the Project area upon the commencement of the AOA. The notification letters outlined the intended work, including the PFR, and presented the communities with the opportunity to provide information for, or comments on, the AOA.

The following communities were notified of the AOA:

- Chemainus (Stz'uminus) First Nation
- Cowichan Tribes
- Halalt First Nation
- Katzie First Nation
- Kwantlen (Seyem' Qwantlen) First Nation
- Lake Cowichan First Nation
- Lyackson First Nation
- Musqueam Indian Band
- Penelakut Tribe
- Semiahmoo First Nation
- Stó:lō
- Squamish Nation
- Tsawwassen First Nation
- Tsleil-Waututh Nation

Per their respective heritage policies, Golder applied for heritage investigation permits from Musqueam Indian Band, Seyem' Qwantlen, Squamish Nation, Stó:lō, and Tsleil-Waututh Nation. The AOA was conducted under the following Indigenous heritage investigation permits:

- Musqueam Indian Band Heritage Investigation Permit MIB-2019-177-AOA
- Seyem' Qwantlen Heritage Investigation Permit SQ 2020-47
- Squamish Nation Archaeological Investigation Permit 19-0183
- Stó:lō Heritage Investigation Permit 2019-252
- Tsleil-Waututh Nation Cultural Investigation Permit 2019-172

The Stó:lō Research and Resource Management Centre also provided a Heritage Database Review. The results of the Stó:lō Heritage Database Review was used to inform the AOA and was included as Appendix B within the AOA report.

An invitation to participate in the PFR was extended to the following Indigenous communities:

- Katzie First Nation
- Kwantlen (Seyem' Qwantlen) First Nation
- Musqueam Indian Band
- Semiahmoo First Nation
- Stó:lō
- Squamish Nation
- Tsawwassen First Nation
- Tsleil-Waututh Nation

During the PFR, the archaeological field crew consisted of one qualified archaeologist and one community member from Katzie First Nation, Seyem' Qwantlen First Nation, and Tsawwassen First Nation.

Prior to future Project-related archaeological assessments (e.g., archaeological impact assessment, monitoring) Indigenous communities will be notified of the work and provided the opportunity to participate in the archaeological assessments.

7.3.2.3 FEI Will Comply With Applicable Heritage Permitting Requirements

The Ministry of Forests, Lands, Natural Resource Operations and Rural Development (FLNRORD) maintains authority to administer some aspects of the *Heritage Conservation Act* (HCA); however, the BCOGC administers others.

All oil and gas development proposed in BC requires that an Archaeological Information Form (AIF) be submitted to the BCOGC. The AIF indicates whether the proposed development will require a further AIA. Major projects that cover substantial areas typically require an AIA. An AIA was conducted on the Tilbury 1A portion of the Tilbury site in 2013. The AIF can be completed prior to finalizing the AIA; however, the approval would be conditional on completion of an AIA.

Where an AIA is recommended, subsurface archaeological tests may proceed following the issuance by the Archaeology Branch (FLNRORD) of an HCA Section 12.2 permit. In the event that an archaeological site is discovered, then a HCA Section 12.4 permit (from BCOGC) may also be required. In addition, any Indigenous heritage investigation permits that are applicable at the time of the AIA will be obtained. Currently the Indigenous communities that have permitting processes in place are Musqueam, Seyem' Qwantlen, Squamish, Stó:lō and Tsleil-Waututh.

7.3.2.4 FEI Will Develop Further Plans Through the AIA Process

Potential impacts to archaeological and historic heritage sites will be further assessed during the Project AIA. Archaeological permits will be obtained prior to conducting the AIA field work, which will be undertaken during the detailed engineering phase of the Project and, if necessary, during the construction phase of the Project. Indigenous communities will be invited to participate in the AIA field work.

The AIA will be conducted where Project-related impacts to areas identified in the AOA as having archaeological potential are unavoidable. FEI anticipates that the majority of AIA work will be completed prior to construction during the detailed engineering phase of the Project. In addition, portions of the AIA may be completed concurrent with construction (e.g., in areas with potentially deep buried resources, areas with access constraints, or areas where ground conditions are not suitable for manual testing).

The objective of the AIA is to:

- Identify archaeological and historic heritage resources within the Project area; and
- If archaeological and heritage resources are present, to evaluate impacts to those resources as a result of the Project and provide recommendations to effectively manage the impacts stemming from the Project.

During the AIA, surface and subsurface inspection will be conducted to identify archaeological and historic heritage resources within the Project area. Subsurface inspection will involve the excavation of hand dug shovel tests and/or machine excavation within the portions of the Project area that the AOA identified as having archaeological potential.

In the event that archaeological or historic heritage resources are identified within the Project area, the AIA's detailed assessment will allow for the development of archaeological or historic heritage site-specific recommendations to mitigate any potential impacts to archaeological and historic heritage sites as a result of Project activities.

The Project's EMP, which will be prepared and included in the Contractor Request for Proposal documents, will also include archaeological specifications. The EMP is also required as a part of the application to the OGC. Further, prior to construction, successful contractors will develop Project-specific Environmental Protection Plans, which will also address the protection of archaeological, historic heritage and cultural resources.

If required, archaeological monitoring will be undertaken in Project areas where archaeological monitoring has been recommended in either the AOA or the AIA. The designated archaeological monitor will have "stop work authority" in the event that works underway have the potential to result in unauthorized impacts to archaeological, historic heritage or cultural resources.

7.4 CONCLUSION

In conclusion, FEI has assessed the environmental and archaeological impacts associated with the Project. Based on the assessments undertaken, and prior to FEI's planned mitigation activities, the Project has the potential to have a moderate environmental impact and a low to moderate archaeological impact. FEI expects to mitigate potential impacts through additional environmental and archaeological assessments, permitting, and standard protection and mitigation measures. The environmental assessment process administered by the BC EAO and the impact assessment process administered by the Impact Assessment Agency of Canada, which is taking place concurrently with this CPCN Application, will provide further opportunity to understand Project impacts and assess the suitability of any proposed mitigations.

8. CONSULTATION

8.1 INTRODUCTION

Consultation and communication with Indigenous groups and stakeholders are integral components of FEI's project development process. FEI has developed an overarching Engagement Plan so as to ensure Indigenous groups and stakeholders are informed and engaged about the Project.

In this Section, FEI will:

- Explain how the overarching Engagement Plan addresses Indigenous engagement and stakeholder consultation regarding the Project;
- Describe how the Engagement Plan synchronizes with FEI's ongoing engagement as a part of the Provincial Environmental Assessment and Federal Impact Assessment processes (Section 8.2);
- Demonstrate how FEI is undertaking, and will continue to undertake, appropriate stakeholder engagement regarding the Project (Section 8.3); and
- Demonstrate how FEI is undertaking, and will continue to undertake, appropriate engagement with Indigenous groups regarding the Project (Section 8.4).

8.2 FEI'S ENGAGEMENT PLAN ENCOMPASSES INDIGENOUS AND PUBLIC ENGAGEMENT

FEI's Engagement Plan is included as Appendix Q-2 to the Application. As described below, the Engagement Plan sets out the general approach to Indigenous engagement, public consultation and communications activities. The Engagement Plan synchronizes with FEI's ongoing engagement as a part of the Provincial Environmental Assessment (EA) and Federal Impact Assessment (IA) processes.

8.2.1 Project Engagement Builds on Past Engagement Work Regarding Tilbury

FEI has been engaging with Indigenous groups, government, the public and other stakeholders on proposed expansions of the Tilbury LNG facility since 2012. As identified in the Engagement Plan, FEI began engagement with Indigenous groups and stakeholders specific to this Project in the fall of 2019.

To support this engagement, FEI sent notification letters to businesses and residents in the area surrounding the Tilbury LNG facility, and sent email notifications to provincial and municipal government officials and industry stakeholders. FEI also participated in meetings with local government, as requested (details found in Table 8-2), and participated in meetings with other groups (detailed further in Section 8.3.7.3). The Tilbury Phase 2 LNG Expansion Project, of

which the TLSE Project is a component, was announced to the broader public on February 27, 2020. FEI customers and the public were notified through a number of channels, including digital media and customer communication channels, as well as public open houses, where FEI presented information and encouraged community feedback. The Company has tracked issues raised and will work with customers and stakeholders to address them.

FEI has also engaged Indigenous groups and leadership on the Project. Governed by its Statement of Indigenous Principles[135], FEI seeks to provide timely and transparent communication regarding projects that are relevant to Indigenous groups in the project vicinity. The Company began engagement with Indigenous groups specific to the Project in 2018 with preliminary discussions focused on outlining the proposed Project and listening to comments or concerns. As the Project has developed, FEI has continued to keep Indigenous groups apprised of key developments and milestones as well as upcoming opportunities to participate in regulatory review processes. FEI's Indigenous engagement activities to date are outlined in greater detail in Section 8.4 below.

8.2.2 FEI's Project Engagement Plan Synchronizes with Environmental and Impact Assessment Processes

FEI is engaged in consultation with the same Indigenous groups and stakeholders under the BC EA and Federal IA processes for concurrent developments at the Project site. The Project Engagement Plan synchronizes these consultation efforts.

As noted above, the Tilbury Phase 2 LNG Expansion Project is also being developed concurrently at the Tilbury site. The Tilbury Phase 2 LNG Expansion Project is a reviewable project under the Provincial *Environmental Assessment Act* (BC EAA) *Reviewable Projects Regulation*, Part 4 and under the Federal *Impact Assessment Act* (IAA) and *Physical Activities Regulations*. The Tilbury Phase 2 LNG Expansion Project has entered the environmental assessment process administered by the BC Environmental Assessment Office (BC EAO) and the impact assessment process administered by the Impact Assessment Agency of Canada (IAAC), which is taking place concurrently with this CPCN Application. FEI notes that the Tilbury Phase 2 LNG Expansion under review by the BC EAO and the IAAC encompasses a larger expansion of the Tilbury site than what FEI is seeking approval of as part of the CPCN, as components of the larger project will not be owned by FEI.

The Project is being administered under the 2018 BC EAA, which includes four public engagement periods, two more than the previous 2002 BC EAA. IAAC requires a similar level of public participation and the agencies are coordinating activities to ensure the requirements of each process are met.

Under the new BC EAA, the BC EAO will seek the consent of Indigenous groups throughout the process. The new process is meant to implement the Province's commitment to the United Nations Declaration on the Rights of Indigenous People (UNDRIP) and advances reconciliation.

[135] "Statement of Indigenous Principles" https://www.fortisbc.com/in-your-community/indigenous-relations/statement-of-indigenous-principles.

FEI is committed to meeting the comprehensive Indigenous engagement and public consultation requirements of these agencies. These engagement requirements, along with the activities proposed as part of the CPCN engagement, will help ensure the interests of Indigenous groups and the public are collected and addressed throughout the development of the Project.

Given the BC EAO and IAAC assessment is occurring concurrently with the CPCN Application, and involves overlapping stakeholders and Indigenous groups, FEI's approach has been to synchronize consultation activities for both the Tilbury Phase 2 LNG Expansion Project and the TLSE Project in order to ensure engagement is robust, efficient and transparent. Combining consultation ensures interested parties are able to provide input through a single medium. This improves accessibility and mitigates against the risks of confusion and consultation fatigue that could result from engaging on each project separately. Further, this approach reduces the overall burden placed on Indigenous groups by removing the duplicative efforts that would otherwise be required to review each project separately.

As part of the assessment process for the Tilbury Phase 2 LNG Expansion Project, FEI submitted an Initial Project Description (Appendix Q-1) and Engagement Plan (Appendix Q-2), which the BC EAO and IAAC accepted on February 27, 2020. This filing initiated the provincial Early Engagement phase and the federal Planning Phase of the assessments. The Engagement Plan was built upon achieving the objectives laid out in Section 8.3.2 below. Planned engagement activities are designed to ensure appropriate consultation for both the Project and concurrent development of the Tilbury site.

The Engagement Plan was updated in early June of 2020 to reflect the impact of the COVID-19 pandemic on the planned engagement activities. For example, in-person engagement activities were not aligned with guidance from public health authorities and were not feasible at the time. As a result, engagement shifted to alternative delivery methods such as virtual open houses.

FEI's Indigenous engagement and public consultation is detailed in the sections that follow.

8.3 FEI IS UNDERTAKING APPROPRIATE PUBLIC CONSULTATION

FEI describes below how the Company is undertaking, and will continue to undertake, appropriate public engagement regarding the Project.

8.3.1 FEI's Communication and Consultation Approach Identifies a Variety of Stakeholders and Encourages Feedback

FEI recognizes the importance of meaningful engagement, strives to develop and maintain strong relationships with all stakeholders, and takes pride in being a good neighbour. This means building relationships to ensure feedback is considered and incorporated into the Project design where possible and that community impacts are minimized.

FEI will continue to maintain and strengthen relationships developed during previous engagement, with a focus on those stakeholders located near the facility, the municipalities of Delta and Richmond, and local residents and businesses.

The Company's public communication and consultation approach is focused on information sharing, encouraging feedback, and responding to questions and concerns raised. FEI strives to ensure all stakeholders are informed about the Project, have access to Project information, and are encouraged to provide input that may be considered as part of the decision-making process.

8.3.2 FEI Has Identified Appropriate Communication and Consultation Objectives

Consistent with FEI's approach on other CPCN projects, FEI identified a number of communication and consultation objectives to drive engagement activities throughout the Project, including:

- Inform stakeholders using plain language to clearly communicate the potential impacts, opportunities and potential solutions associated with the proposed Project;
- Provide timely and relevant updates about the Project to enable Indigenous groups, the public, government, and other stakeholders to provide input during the environmental assessment and regulatory processes;
- Gather feedback from Indigenous groups, the public, government, and other stakeholders on the impact of the Project and on their interests related to the Project. Where possible, refine the Project or develop mitigation measures; and
- Ensure engagement is inclusive and designed to reach the diversity of people within the community. FEI is committed to incorporating the principles of Gender-Based Analysis Plus (GBA+), recognizing that inequalities in communities affect people differently and to mitigate barriers that limit participation and engagement from distinct groups in the community.

8.3.3 FEI Has Identified Key Stakeholders for Consultation

As part of its communication and consultation planning process, FEI identified a number of relevant stakeholders. Information will be shared with each of the following groups throughout the Project (excluding Indigenous groups, which are addressed later in Section 8.4):

1. FEI customers;
2. Residents, businesses and landowners located near the facility or surrounding area;
3. Provincial government bodies, including: the relevant Members of the Legislative Assembly, the Ministry of Transportation & Infrastructure, the Oil & Gas Commission, BC Hydro and the Agricultural Land Commission;

4. Municipal and regional governments including: the Mayors, Councils, City Managers and/or staff in the municipalities of Delta and Richmond; and
5. Industry and local community groups (see Appendix Q-3 for full list) that may have an interest in the Project.

This group of stakeholders is providing FEI with a wide variety of perspectives on the Project.

8.3.4 FEI Has Pro-Actively Identified Various Issues and Interests for Consideration

FEI's existing Tilbury LNG facility has been operating since 1971 and the Tilbury 1A expansion was completed and producing LNG for customers in 2019. Through its history in the community and recent consultation on the previous expansion, the Company has gained an understanding of interests and potential concerns that may be raised about the Project. Below is a summary of the anticipated key issues. Through ongoing public engagement, FEI will continue to identify issues raised and respond to them.

Table 8-1: Initial Key Issues and Interests

Issue	Summary
Rate impacts	Given the expected rate impact, FEI will communicate with customers to raise awareness of the costs and the benefits of the Project.
Potential environmental impacts	FEI expects that a number of environmental groups, local residents and others may scrutinize the Project's potential impact. FEI will engage with the stakeholders to understand, assess, and where necessary mitigate the potential environmental impacts.
Safety of liquefied natural gas infrastructure	Safety is FEI's top priority and the Project team will be prepared to speak to the measures that will be put in place to keep our employees and the public safe.
Resiliency of the gas system	FEI anticipates that a number of groups will be interested in the benefits of adding LNG storage capacity in the region to potentially avoid gas shortages or outages to large numbers of downstream customers when the flow of gas is interrupted.
Community engagement	FEI will be prepared to speak to how it plans to work with the public to identify local concerns and propose mitigations, where necessary.
Business opportunities	Indigenous and local businesses, and municipalities are expected to be interested in ways they could work to supply the Project. FEI will engage to understand how it may support Indigenous and local businesses.

8.3.5 FEI's Consultation Approach Reflects Community, Social and Environmental Considerations

Community, social and environmental considerations have been taken into account, and have guided communication and consultation planning. FEI has considered a number of social and economic factors of the Project and has determined that the Project should have an overall positive socio-economic impact on residents and businesses. Details of the positive socio-economic impacts are discussed in Section 9 of the Application.

The Project is located on the traditional territory of the Coast Salish peoples within the City of Delta on a long-standing brownfield, industrial site owned by FEI. The land is zoned as I7: High Impact Industrial. This zoning designation allows for the manufacturing, processing, finishing, and storage of natural gas. As such, the proposed Project is consistent with the Delta Official Community Plan for the Project Site.

Delta has three urban communities: Ladner, North Delta and Tsawwassen. The closest residential area is about 5 kilometres (km) to the southwest, in Ladner. Land use south of the Project includes agricultural (approximately 50 percent of the land base) and environmentally sensitive areas such as the Burns Bog Ecological Conservancy (25 percent of the land base).

The City of Richmond is the next closest municipality on the north side of the Fraser River. Land use designations in Richmond north of the Project site include industrial, agricultural and mixed employment. There is some residential occupancy in the agricultural and mixed employment areas of Delta and Richmond, with potential for residents in the industrial areas.

Community, social and environmental factors will continue to inform FEI's communication and consultation as the Project nears the construction phase and socio-economic assessments are refined.

8.3.6 FEI Has Already Undertaken Meaningful Communication and Consultation

FEI has actively engaged with a number of key stakeholders over the years to support work at the Tilbury LNG site, as well as specifically with respect to the Project (including by way of the Environmental Assessment Process). These activities are described below.

8.3.6.1 FEI Has Engaged Over Several Years Regarding Development at Tilbury Generally

Since 2012, when development at the Tilbury site came under consideration, FEI has actively engaged with a number of key stakeholders using various approaches.

FEI uses a number of communication channels to share information with the public, including the Company's major projects website TalkingEnergy.ca, a dedicated Project email and phone number, and through social media platforms.

The Company is also actively involved in events in the communities near the Tilbury LNG facility, which provide the public with an opportunity to learn more about the Company and the facility. FEI also participated in open houses in 2015 and 2019 for the Tilbury Marine Jetty Project Environmental Assessment in Delta and Richmond. This provided the public with opportunities to ask questions about the Tilbury LNG facility, and plans for future expansion.

To educate the community about the properties of LNG, FEI works with partners in the community to organize opportunities for the Company to share its knowledge. These events have included live LNG demonstrations for the Delta and Richmond chambers of commerce, panel discussions, and presentations to community, industry and business associations. The Company has also produced education materials such as videos explaining the characteristics of LNG and the safety features of FEI's LNG facilities.

FEI continues to actively engage with local community groups to support their programs and share information about the proposed expansion. The Company also sets up booths at community events in Delta and Richmond to offer opportunities for the public to ask questions, learn more about the Company, establish a point of contact and communications stream, and gather feedback.

8.3.7 Engagement Activities to Date

The following sub-sections describe activities that FEI recently completed that support the Project. In general, FEI has reached a wide cross-section of stakeholders through diverse channels.

8.3.7.1 Public and Residential Customer Consultation to Date

PROJECT WEBPAGE

FEI created an overarching webpage to ensure there is a streamlined online resource for the public to learn more about the Project and concurrent regulatory processes such as the CPCN and EA. The webpage offers an avenue for public feedback and inquiries through an email address and dedicated phone line. The Project webpage includes a rendering of the Project, a Project overview, links to regulatory filings, updates such as milestones and future construction, and a description of community initiatives and involvement. As of the end of November 2020, there have been more than 2,800 unique visitors to the webpage since its launch on February 27, 2020. The webpage is located at: talkingenergy.ca/tilburyphase2.

EMAIL AND PHONE LINE

Providing a direct way for customers and the public to contact FEI regarding the Project is an essential part of ongoing engagement. FEI established an email and phone line in advance of publicly announcing the Project and concurrent regulatory processes to simplify communications with the public. FEI has included this phone number and email in all

communications materials. As of the end of November 2020, FEI has received 15 emails and 10 phone inquiries. A summary of these inquiries and responses is located in Appendix Q-4.

CUSTOMER NOTIFICATIONS

FEI informed residential and commercial customers about the Project in print and digital formats via bill inserts and its Account Online portal. The inserts were mailed to customers with their bill, and emailed to paperless billing customers during the June 2020 billing cycle (Appendix Q-5). An advertisement was also posted in FEI's Account Online billing portal, which is viewed by up to 20,000 customers per month.

LOCAL LANDOWNER NOTIFICATIONS

FEI mailed 667 notification letters (Appendix Q-6) to businesses and residents within a two kilometre radius of the Tilbury LNG facility on May 29, 2020. The letters informed them of the start of the IAAC and BC EAO processes and upcoming BCUC regulatory process, and provided instructions on how they could ask for more information and provide feedback.

VIRTUAL OPEN HOUSES

Public open houses provide an opportunity to engage with the public and customers face-to-face, answer questions and address concerns. Due to the COVID-19 pandemic and restrictions on safe gatherings, these open houses have been held online. As part of environmental assessment requirements, FEI participated in two virtual open houses led by IAAC and the BC EAO on June 18, 2020, 4:00pm-5:30pm and June 23, 2020, 5:30pm-7:00pm. Offering two dates and times gave the Company the opportunity to reach more members of the public and customers and respond to more questions. In addition to using an online platform, FEI also had a dial-in option for those without access to a computer or internet to ensure the open houses were accessible to a broader audience. The open houses included presentations from IAAC, BC EAO and the Project team, followed by a question and answer period.

More than 200 people participated in the sessions and about 80 comments and questions were received (Appendix Q-7).

PAID ADVERTISEMENTS

FEI promoted the virtual open houses through various paid media advertisements including local print and digital advertisements in the communities most affected by the Project (Richmond and Delta). The advertisements were published in English, Punjabi, Simplified Chinese and Traditional Chinese. They were sent to a circulation of at least 570,000 readers in print and approximately 45,000 online. Examples of these advertisements can be found in Appendix Q-8.

8.3.7.2 Government Consultation to Date

FEI has regularly communicated and met in-person with municipal, provincial, and federal governments to provide updates and respond to questions about the Company and the Tilbury LNG facility for several years. Through these meetings, FEI has gained an understanding of community values, and sought recommendations on consultation and engagement.

FEI regularly meets with City of Delta representatives to inform them of Project updates and provide advance notice of Company activities in the community. FEI also engages City of Delta staff, first responders, and other stakeholders in full-scale emergency exercises at the Tilbury LNG facility.

The Company meets with provincial and federal representatives from communities near the Project to share information, understand local values and receive recommendations on community engagement. FEI also meets with provincial agencies including the Ministry of Energy, Mines & Petroleum Resources, the Ministry of Environment and the Ministry of Jobs, Training and Technology to provide updates and answer questions about the Company and the Project.

The table below summarizes the recent meetings, discussions, presentations, and correspondence FEI has completed with provincial and local government stakeholders related to the proposed Tilbury expansion. The table is listed in chronological order.

Table 8-2: Provincial and Local Government Communications Log

Date	Method of Contact	FortisBC Attendees	Local Government	Notes
October 4, 2019	In-Person Meeting	Courtney Hodson, Community Relations Manager	Ian Paton, MLA South Delta; Dylan Kruger, Delta City Councilor & Constituency Assistant	Provided an overview of the Project, and committed to keeping him informed as the Project progresses. No specific feedback about the Project that requires a response was expressed at this time.
December 5, 2019	In-Person Meeting	Todd Smith, Sr. Mgr Business Development & Technical Assessment; Roger Ord, Project Director; Courtney Hodson, Community Relations Manager	Sean McGill, City Manager of Delta; Steven Lan, Director of Engineering; Mel Cheesman, Director of Corporate Services; Mike Brotherston, Manager of Environment	Provided an overview of the Project to senior City staff. They requested to be kept up to date via email through the City Manager. No specific feedback about the Project that requires a response was expressed by the City.

Date	Method of Contact	FortisBC Attendees	Local Government	Notes
February 27, 2020	Email	Courtney Hodson, Community Relations Manager	Federal Provincial Municipal	Sent notification emails to stakeholders (see Appendix Q-3 for recipients). The purpose of the email was to inform them that the BC EAO and IAAC regulatory processes had begun, and provide the timing of the public comment period and related activities (i.e. open houses). Follow-up emails were sent to the same group.
March 20, 2020	Conference Call	Dan Murray, Project Director; Courtney Hodson, Community Relations Manager	Ravi Kahlon, MLA Delta North	Provided MLA Kahlon with an overview of the Project, and committed to keeping him informed as the Project progresses. No specific feedback about the Project that requires a response was expressed at that time. Note: Due to COVID-19, this meeting was changed from an in-person meeting to a conference call.
April 1, 2020	Email	Courtney Hodson, Community Relations Manager	Federal Provincial Municipal	Notified stakeholders via email (Appendix Q-9) that the BC EAO and IAAC had extended and suspended their engagement timelines, respectively.
June 1, 2020	Email	Courtney Hodson, Community Relations Manager	Federal Provincial Municipal	Notified stakeholders via email (Appendix Q-10) that the BC EAO early engagement process had restarted and the public comment period was starting. Also informed them of the upcoming filing of the CPCN Application.
June 22, 2020	Video conference	Ian Finke, Director of LNG Operations; Courtney Hodson, Community Relations Manager	Delta Mayor & Council	Provided a 10-minute presentation (Appendix Q-11) followed by a question and answer period with Delta Mayor and Council. Note: Due to COVID-19, this in-person workshop was rescheduled from March 2020 and adjusted to a video conference.

8.3.7.3 Further Stakeholder Consultation to Date

FEI met with the Executive Director of the Delta Chamber of Commerce on January 6, 2020, and the President of the Richmond Chamber of Commerce on January 20, 2020, where an overview of the Project was provided. Both chambers acknowledged the anticipated economic benefits the Project will bring to local communities. They requested more information about the economic benefits of the Project, and to be kept informed about the Project on a regular basis through email, and meetings and presentations (as appropriate).

Since those meetings took place, FEI also emailed both chambers to inform them of upcoming BC EAO and BCUC-related milestones, such as the virtual open houses, and offered more information and additional presentations. The Delta Chamber of Commerce also submitted a letter of support (Appendix Q-12) to the BC EAO during the public comment.

As a follow-up request, FEI presented to the Richmond Chamber Board of Directors on September 1, 2020, where an overview of the Tilbury Phase 2 LNG Expansion Project was provided. The Board of Directors expressed interest in the areas of LNG and plant safety, FEI's plans for community engagement, and current and future demand for natural gas. FEI was able to address their questions and will continue to work with the Richmond Chamber to answer any additional questions they have as the Project progresses, by email communication and virtual meetings, or in-person meetings when permitted.

FEI also notified additional stakeholders by email of upcoming Project-related milestones, and the stakeholders are listed in Appendix Q-3.

8.3.8 FEI Has Responded to Issues and Concerns Raised by Stakeholders

As of November 30, 2020, FEI has responded to approximately 25 public inquiries received by telephone, email and open houses. A variety of topics were discussed during these interactions, which are detailed further in the table below. Many of the issues and concerns raised during engagement, and as indicated in the table below, are consistent with the anticipated issues previously outlined in Table 8-1.

Table 8-3: Issues and Concerns Raised

Issue	Description of Issue	FEI's Response
Safety	A number of stakeholders have asked about safety and the technology and procedures included in the Project to keep the public and employees safe.	• FEI responded that safety is our number one priority. The Company explained that our existing LNG facilities feature secondary containment, are built to meet the seismic standards of the time, and emergency exercises are regularly held with local first responders. • FEI will ensure the Project meets Canada's high safety standards and that plans will be in place to keep the public and employees safe.

Issue	Description of Issue	FEI's Response
Potential Environmental Impact	The Project's potential impact to the environment during construction and ongoing operation has been an issue raised by a number of stakeholders.	• As part of the EA process, the potential environmental impact of constructing and operating certain Project components such as the proposed LNG storage tank will be assessed to better define the Project's potential impact. • FEI responded to stakeholders that the Project mitigates potential environmental impacts as Tilbury is powered mainly by renewable hydroelectricity, reducing its carbon intensity relative to the average global LNG facility.
Rate impacts	Several customers have asked questions about the potential rate impact of the Project, including during the virtual open houses.	• FEI responded that the Project was in an early stage of development and rate impacts would be shared as part of the CPCN application. • The Company clarified that the capital costs of the entire Tilbury Phase 2 LNG Expansion would not be passed on to customers, as elements outside of the scope of the Project will be unregulated assets.
Community Engagement	Several members of the public expressed concerns about engagement, specifically whether virtual engagement was adequate.	• The Company will continue to engage on the Project, including in-person engagement activities such as open houses, once public health guidelines allow. • Of note, more than 200 people participated in the virtual open houses. Conducting the open houses online made them more accessible than an in-person option.
Business Opportunities	A number of stakeholders expressed interest in the economic opportunities available on the Project, particularly in response to the current economic environment resulting from the COVID-19 public health emergency.	• The Company expressed its commitment to Indigenous and local hiring, citing the previous expansion at Tilbury as an example, which included $60 million in committed local spending, and supported Indigenous training and employment opportunities through 25 work experience/employment training programs provided by Tsawwassen Matcon Joint Venture, majority owned by the Tsawwassen First Nation, and 48 Tsawwassen First Nation students participated in training programs. • A socio-economic impacts assessment has also been completed, and is discussed in Section 9 of the Application.

8.3.9 FEI Will Address or Respond to Outstanding Issues or Concerns

FEI has responded to all phone calls and emails received up until November 30, 2020, and has sought to address concerns where possible. See Appendix Q-4 for a log of all interactions received and responded to as of the time of filing this Application. The Company will continue to respond to all inquiries received related to the Project.

Based on the feedback FEI has received to date, some concerns expressed are related to issues that are outside the scope of the Project, such as increased LNG production and

hydraulic fracturing. Additionally, a number of issues will be addressed through parallel regulatory processes with the BCOGC, BC EAO, and other regulatory bodies.

FEI will continue to consult with the public as the Project progresses, including looking at ways to address or respond to concerns raised. Specifically, the Company will:

- Transparently communicate the Project's expected rate impact to customers through a bill insert;
- Define any potential environmental impacts, consult with the public on the findings and propose mitigations where necessary;
- Develop the Project with safety as a top priority using the best available technology to keep the public and employees safe;
- Implement socio-economic plans to prioritize Indigenous and local hiring and spending; and
- Continue educating the community on the properties of LNG through materials such as videos as well as live LNG demonstrations.

8.3.10 Consultation and Communications Plan Going Forward

Moving forward, consultation on the Project will focus on continuing to create opportunities for stakeholders to learn more, ask questions, and provide feedback. FEI will maintain the positive relationships developed during engagement to date, particularly with those located closest to the Project, and with those who have demonstrated a high level of interest.

FEI will update all communication channels established and used prior to the filing, as described in Section 8.3.7.1. This includes adding a notification of the filing of the CPCN to the Project webpage, including a link to the Application, and initiating an advertising campaign to notify customers in line with regulatory requirements. A link to the Application will also be available at FortisBC.com. FEI will continue to use bill inserts and Account Online Tile advertisements to provide information on the Project directly to customers. Educational materials such as videos and articles will be shared on social media and on FortisBC websites such as TalkingEnergy.ca to help the public understand LNG and learn more about the Project.

The Company will continue to work with the local municipalities, primarily with Delta and Richmond, and other stakeholders to maintain transparency, and will address feedback throughout the process. When feasible, FEI will offer visits to the Project site to stakeholders so that they can better understand LNG facilities and the Project. In addition, FEI will send a follow-up notification letter to the same residents and businesses located within a two kilometre radius of the facility after the Application is filed, inviting them to participate in the regulatory process.

FEI is committed to ensuring the safety of its employees and the public. The Company will explore further opportunities to host live demonstrations to educate stakeholders and help the

public better understand the properties of LNG. FEI will continue to seek participation from municipal staff and local stakeholders in future emergency preparedness exercises.

FEI will also continue to participate in and support events and organizations that are important to local communities, dependent upon current public health guidelines. A continuous local presence will allow FEI to engage with members of the communities on a regular basis, to seek input and to address questions throughout the Project.

The Company anticipates that there will be more open houses in the coming years for the Tilbury Phase 2 LNG Expansion Project. These open houses will allow the Company to continue to understand key issues, consult with the public and propose further mitigations, where necessary. Depending on the level of ongoing response, FEI may lead additional consultation activities such as smaller group sessions to help ensure the public has meaningful opportunities to provide feedback. These additional events would be promoted through advertising.

8.3.11 FEI's Public Consultation Process to Date Has Been Appropriate

FEI believes that the communication and consultation activities to the time of filing the Application have been sufficient, appropriate and reasonable to meet the requirements of the BCUC's CPCN Guidelines. FEI will continue to consult with stakeholders and the public regarding Project timelines, construction, and public safety. FEI will continue consultation prior to and throughout the various Project phases, including the fulfilment of IAAC, BC EAO and BCOGC-related consultation requirements, to help inform local government and stakeholders about Project activities in an effort to minimize impacts.

FEI is dedicated to maintaining and strengthening positive relationships through an open and transparent consultation process with government, natural gas customers and the public throughout the duration of the Project.

8.4 FEI IS ENGAGING WITH INDIGENOUS GROUPS

FEI is committed to building strong working relationships with Indigenous groups guided by the FEI Statement of Indigenous Principles (Appendix R-1). FEI recognizes that the potential impacts of the Project on the title, rights, and interests of affected Indigenous groups must be identified and avoided or mitigated as appropriate. To achieve this, FEI recognizes that its consultation approach will need to be thorough, timely, and meaningful. FEI also endeavors to create project benefits for local Indigenous groups, through capacity building and economic opportunities.

In this section, FEI outlines the Company's approach to identification and early engagement of potentially impacted Indigenous groups, and details the Company's Indigenous engagement plan going forward.

8.4.1 FEI's Engagement Approach Incorporates Multiple Avenues

FEI is consulting with Indigenous groups regarding the Project via direct engagement activities as well as through the regulatory review processes.

Where appropriate, FEI, together with the Crown agencies responsible for Indigenous consultation (i.e., BCOGC, BC EAO, IAAC), will identify methods to avoid or mitigate potential impacts on those Indigenous interests, and where appropriate, discuss and develop options for accommodation.

The Tilbury Phase 2 LNG Expansion Project, of which this Project is a component, is simultaneously subject to review under the *Environmental Assessment Act* and the *Impact Assessment Act*. As part of these review processes, FEI began early engagement with Indigenous groups that have an asserted interest in the Project area. The purpose of early engagement was to provide information about the Project, describe potential impacts and benefits of the Project, to provide opportunities for input on the Project and to gain an understanding of the interests of Indigenous groups and how they may be affected by the proposed work.

8.4.2 FEI Has Identified Indigenous Groups Potentially Affected

A review of the Consultative Areas Database (CAD), provided in Appendix R-2, has identified 17 Indigenous groups whose established or asserted traditional territories overlap with the Project site. FEI opted to use a more inclusive list of 20 Indigenous groups (identified in the Engagement Plan for the Environmental Assessment, which is provided in Appendix Q-2) for consistency with Indigenous group consultation on other projects in the vicinity. Table 8-4 provides a list of the Indigenous groups identified for engagement.

Table 8-4: Indigenous Groups Affected by Project

Indigenous Groups		
Cowichan Tribes	Musqueam Indian Band	Squamish First Nation
Halalt First Nation	Penelakut Tribe	Stó:lö Nation
Katzie First Nation	Seabird Island Band	Stó:lö Tribal Council
Kwantlen First Nation	Semiahmoo First Nation	Stz'uminus First Nation
Lake Cowichan First Nation	Shxw'ōwhámél First Nation	Tsawwassen First Nation
Lyackson First Nation	Skawahlook First Nation	Tsleil-Waututh Nation
Métis Nation British Columbia	Soowahlie First Nation	

8.4.3 Description of Consultation with Indigenous Groups to Date

Preliminary engagement activities occurred from July 2019 to July 2020. During this period, the communities that have engaged in two-way communication with FEI during the preliminary engagement period are (in alphabetical order):

- Cowichan Tribes

- Halalt First Nation
- Katzie First Nation
- Kwantlen First Nation
- Musqueam Indian Band
- Penelakut Tribe
- Seabird Island Band
- Stz'uminus First Nation
- Tsawwassen First Nation
- Tsleil-Waututh Nation

FEI has engaged with all the Indigenous groups listed in Table 8-4 by sharing information, identifying the next steps in the regulatory review, responding to questions, and recording concerns. FEI has engaged in these activities to support the potentially affected Indigenous groups in understanding the proposed Project at an early stage. This engagement included:

- Sending notification letters regarding relevant Project milestones, including application filing, public comment periods and open house dates;
- Sending notification emails with Project materials and opportunities for review and comment. These emails included an explicit offer to meet and discuss any questions or concerns;
- Attending six Project meetings as requested by five Indigenous communities to discuss questions or comments related to the Project; and
- Facilitating a site visit in response to a request by an Indigenous group.

During preliminary engagement activities, FEI became aware that many Indigenous groups have capacity constraints that limit their engagement ability. As a result, some Indigenous groups may not have time for a meeting during the engagement process. To support the engagement of Indigenous groups during the COVID-19 pandemic, FEI has offered to provide technological equipment to support staff members working from home and FEI is willing to assist in providing avenues for remote monitoring where possible, across FEI projects, including this Project.

Based on FEI's ongoing communication with a number of Indigenous groups during this period, the Company is aware that staff are generally working remotely due to office closures. As such, FEI switched correspondence with Indigenous groups to email rather than mail.

As outlined in Section 8.2, there are concurrent regulatory processes underway for the Tilbury Phase 2 LNG Expansion Project and this Project. In order to limit consultation fatigue and recognizing the resource constraints within Indigenous groups, FEI has sought to combine

engagement activities where possible. Rather than solicit feedback from Indigenous groups on each distinct Project component, FEI sought to provide a holistic picture as part of transparent information sharing. Comments received through consultation with Indigenous groups are applied to all applicable aspects of the Project to ensure they are appropriately captured and addressed.

The following log captures FEI's formal correspondence related to the Project with Indigenous groups. The FEI Indigenous Relations team also has a number of informal touch points including recurring conference calls to connect with a number of the Indigenous groups below.

To date, comments received have been related to the broader Tilbury Phase 2 LNG Expansion Project, and have not been specific to the TLSE Project. The one exception was a question regarding decommissioning of the existing infrastructure and related permitting requirements. The overarching themes are detailed in the following section. References to the "project" in the table below refer to the broader Tilbury Phase 2 LNG Expansion Project except where specifically noted.

Table 8-5: Log of Consultation with Indigenous Groups to Date

Date	Method of Contact	Indigenous Group	Notes
July 2, 2019	Email	• Cowichan Tribes • Halalt First Nation • Lake Cowichan First Nation • Lyackson First Nation • Katzie First Nation • Kwantlen First Nation • Musqueam Indian Band • Penelakut Tribe • Seabird Island Band • Semiahmoo First Nation • Soowahlie First Nation* • Skowkale First Nation* • Stó:lö Nation* • Stó:lö Tribal Council* • Stz'uminus First Nation • Shxw'ōwhámél First Nation • Squamish First Nation • Tsawwassen First Nation • Tsleil-Waututh Nation	Introductory email sent to each Indigenous group notifying them of the project and requesting a meeting.

Date	Method of Contact	Indigenous Group	Notes
July 12, 2019	Email	• Cowichan Tribes • Halalt First Nation • Lake Cowichan First Nation • Lyackson First Nation • Katzie First Nation • Kwantlen First Nation • Musqueam Indian Band • Penelakut Tribe • Seabird Island Band • Semiahmoo First Nation • Soowahlie First Nation* • Skowkale First Nation* • Stó:lö Nation* • Stó:lö Tribal Council* • Stz'uminus First Nation • Shxw'ōwhámél First Nation • Squamish First Nation • Tsawwassen First Nation • Tsleil-Waututh Nation	Draft project description was provided to Indigenous groups to provide additional details and an offer to meet and discuss preliminary comments or concerns.
July 17, 2019	Meeting	• Cowichan Nation Alliance: – Cowichan Tribes – Stz'uminus First Nation – Halalt First Nation – Penelakut Tribe	Meeting at Cowichan Tribes office in Duncan to discuss the project and address initial questions or concerns.
July 19, 2019	Meeting	• Tsawwassen First Nation	Meeting at Tsawwassen First Nation to discuss the project and address initial questions or concerns.
July 29, 2019	Email	• Cowichan Tribes	Cowichan Tribes provided initial comments on the project via the draft project description.
July 30, 2019	Letter	• Musqueam Indian Band	Musqueam provided a letter indicating interest in participating in consultation.
July 31, 2019	Email	• Halalt First Nation	Halalt First Nation provided initial comments on the project via the draft project description.
August 8, 2019	Meeting	• Kwantlen First Nation	Meeting at Kwantlen First Nation to discuss Initial Project Description (IPD) and address questions or concerns.
August 8, 2019	Email	• Seabird Island Band	Seabird Island Band responded to the initial email introducing the project and indicated that they have no input at this time.

Date	Method of Contact	Indigenous Group	Notes
August 14, 2019	Letter	• Tsleil-Waututh Nation	Tsleil-Waututh Nation sent a letter outlining expectations around consultation and accommodation for the project.
August 27, 2019	Meeting	• Musqueam Indian Band	Met with Rights and Title Manager at Musqueam, provided a copy of the draft project description.
September 16, 2019	Email	• Musqueam Indian Band • Cowichan Tribes • Halalt First Nation • Stz'uminus First Nation • Penelakut First Nation • Lyackson First Nation • Katzie First Nation • Kwantlen First Nation • Tsawwassen First Nation • Tsleil-Waututh Nation	FEI provided revised project description by email to the Indigenous groups that had provided comments or responded and indicated an interest in being engaged on the project.
September 24, 2019	Site visit	• Kwantlen First Nation	Project team conducted project site visit with the Kwantlen First Nation to discuss the project.
October 2, 2019	Email	• Tsawwassen First Nation	Tsawwassen is interested in providing comments on the project; however, there are capacity constraints for internal review. Request FEI address any forthcoming comments at a later date. FEI confirmed it would do so.
November 28, 2019	Meeting	• Tsleil-Waututh Nation	Initial meeting with Tsleil-Waututh Nation leads for the project.
January 31, 2020	Call	• Tsleil-Waututh Nation	Call to provide status update on the IPD.
February 14, 2020	Email	• Cowichan Tribes • Halalt First Nation • Lake Cowichan First Nation • Lyackson First Nation • Katzie First Nation • Kwantlen First Nation • Musqueam Indian Band • Penelakut Tribe • Seabird Island Band • Semiahmoo First Nation • Soowahlie First Nation* • Skowkale First Nation* • Stó:lö Nation* • Stó:lö Tribal Council*	FEI sent notification of intent to formally submit the IPD as part of the BC Environmental Assessment process.

Date	Method of Contact	Indigenous Group	Notes
		• Stz'uminus First Nation • Shxw'ōwhámél First Nation • Squamish First Nation • Tsawwassen First Nation • Tsleil-Waututh Nation	
February 19, 2020	Email	• Katzie First Nation	FEI provided a summary of engagement with Katzie First Nation for the project at Katzie's request.
March 26, 2020	Meeting	• Musqueam Indian Band	Online conference meeting held with FEI project team and Musqueam departments including referrals, archeology, environmental stewardship, intergovernmental affairs, and fisheries. The meeting provided an overview of the project.
June 1, 2020	Letter	• Cowichan Tribes • Halalt First Nation • Lake Cowichan First Nation • Lyackson First Nation • Katzie First Nation • Kwantlen First Nation • Musqueam Indian Band • Penelakut Tribe • Seabird Island Band • Semiahmoo First Nation • Soowahlie First Nation* • Skowkale First Nation* • Stó:lö Nation* • Stó:lö Tribal Council* • Stz'uminus First Nation • Shxw'ōwhámél First Nation • Squamish First Nation • Tsawwassen First Nation • Tsleil-Waututh Nation	FEI provided an update on the project and outlined FEI's intention to submit a CPCN application for the TLSE Project with the BCUC. The letter also outlined FEI's approach to applying for both a CPCN and an Environmental Assessment Certificate (Appendix R-3). A letter was provided to Indigenous groups via email as many offices were closed due to the COVID-19 pandemic and subsequent lockdown. FEI felt email would have the most success in reaching the Indigenous groups.

8.4.4 Issues and Concerns Raised Focused on Three Themes

Concerns raised by Indigenous groups during FEI's engagement can be broadly characterized as relating to three themes, outlined in the following table.

Table 8-6: Issues and Concerns Raised

Issue	Description of Issue	FEI's Response
Business Opportunities	Some Indigenous groups have specified interest in potential involvement on the business side of the Project. In particular, a number of communities have expressed a desire to participate in archaeological assessments and in bidding opportunities for construction.	• FEI is updating its tender documents to set out required engagement with Indigenous and local businesses for work on Company projects, including those at the Tilbury LNG facility. Indigenous and local business inclusion will form part of the evaluation criteria for proposals. • FEI also held meetings with business development leads within local Indigenous groups to provide information on the types of opportunities available, to communicate timelines, and to request lists of any Indigenous businesses associated with those respective communities. FEI intends to connect Indigenous businesses directly to prime contractors to facilitate further Indigenous participation on the Project through business-to-business networking sessions. • Longer term, FEI is working toward a workforce development strategy to support the preparation, inclusion, and attachment of Indigenous and other local members of the labour force to Project employment opportunities.
Potential Environmental Impacts	Project decommissioning, demolition, and end-of-life abandonment. FEI responded to question seeking to clarify whether the "old" tank will be demolished or abandoned in place.	• FEI noted that the decommissioning of the "old" Tilbury plant would result in its removal, as opposed to abandonment of the plant in-place. FEI also noted that these activities are subject to review and approval from the BCUC, BCOGC and BC EAO.
	FEI heard that the cumulative effects of increased development on and near Tilbury Island, especially as it relates to greenhouse gas emissions and increased shipping on the Fraser River, are a key area of concerns for Indigenous groups.	• Emissions and air quality issues will be addressed in the BC Environmental Assessment.
	Marine shipping and in-stream impacts were raised as a concern with Project construction and ongoing operation.	• The Project may result in shipping impacts during construction as a result of transportation of equipment modules via the Fraser River, mooring at the temporary construction jetty and offloading at site. These will be addressed in detail via the BC Environmental Assessment.
Economic viability	Some communities have asked about the economic viability of the Project given the fluctuating price of LNG in light of COVID-19.	• FEI noted that the Project plays an important role in system resiliency for the Lower Mainland. Increased storage capacity can maintain the natural gas system in the event of an outage similar to that seen in October 2018.

Concerns raised related to impacts from increased shipping on the Fraser River are limited to the potential delivery of heavy modules for the Project. The full scope of these impacts will be assessed in detail as part of the Environmental Assessment processes. A number of Indigenous groups have expressed interest in continued dialogue throughout the Project, as well as interest in contracting opportunities during Project construction. Follow-up meetings will be scheduled with these communities as additional information around contracting and procurement becomes available.

Concerns and interests that require additional, site-specific information that is not available at an early Project stage will be communicated to those communities as it becomes available. FEI will continue to engage with those Indigenous groups who wish to receive further information as the Project develops through milestone updates and meetings. These activities are detailed in the following section.

8.4.5 FEI Will Continue to Engage with Indigenous Groups

As the Project is developed, FEI will continue to engage with Indigenous groups in a number of ways:

- FEI will maintain contact with those Indigenous groups that have been engaging with the Company and connecting with new communities as needed;
- FEI will provide all potentially affected Indigenous groups with a notification of the filing of the CPCN;
- The Company will continue to work with the Indigenous groups that have expressed interest in the Project to better understand their concerns and work together to address them. This will include email communication, virtual or in-person meetings, and/or site tours, depending on the status of the COVID-19 pandemic and preference of communities;
- FEI will also continue to participate in and support events that are important to local Indigenous groups, dependent upon current public health guidelines. Ongoing involvement will allow FEI to build strong relationships within the community and provide an additional mechanism to address questions and receive comments;
- The Company will support other community engagement activities, which could include live demonstrations to educate community members regarding the properties of LNG;
- FEI will continue to engage Indigenous groups through the BC Environmental Assessment and Canada's Impact Assessment process to gather and incorporate Project feedback, address concerns, and provide information on upcoming business opportunities. These regulatory processes will address some of the preliminary concerns raised by Indigenous groups including greenhouse gas emissions and air quality;
- During the BCOGC permitting process for this Project, more detailed Project information will be available to Indigenous groups for review and comment. This process will include

up-to-date shape files, maps, and environmental management plans. FEI will support the BCOGC consultation process by responding to technical questions and attending meetings where appropriate. The BCOGC process will encompass the comments raised by Indigenous groups around tank demolition; and

- Finally, FEI anticipates that there will be extensive engagement with Indigenous groups in the coming years for the Project through the concurrent regulatory processes underway with the BC EAO and IAAC, and the future BCOGC process. This includes Indigenous participation in planning of the Environmental Assessment, contribution of Indigenous knowledge into the Assessment materials, and the potential for elements of Indigenous-led assessment.

8.4.6 FEI's Indigenous Engagement Process to Date Has Been Appropriate

FEI's Statement of Indigenous Principles states the importance of clear and open communication with Indigenous groups. FEI believes that its engagement process for the Project reflects these principles. Through early engagement activities, FEI has established key points of contact, preferred methods of communication, and an early understanding of potential interests from Indigenous groups. As the Project develops, FEI will continue to work through these channels to resolve outstanding questions and address comments and concerns.

8.5 CONCLUSION

FEI has consulted and sought feedback from Indigenous groups, the public, and other stakeholders regarding the Project. FEI's Engagement Plan for the Project builds on consultation regarding proposed expansions of the Tilbury LNG facility dating back to 2012. FEI developed its overarching Engagement Plan to ensure Indigenous groups and stakeholders are informed and engaged about the Project holistically and to allow for synchronized consultative activities with the parallel Provincial EA and Federal IA processes, which will involve significant engagement. To date, FEI has identified and responded to concerns raised by stakeholders, and FEI's consultation and engagement has been sufficient. FEI will continue to engage with all identified Indigenous groups and stakeholders to address outstanding concerns throughout the lifecycle of the Project.

9. PROVINCIAL GOVERNMENT ENERGY OBJECTIVES AND POLICY CONSIDERATIONS

9.1 INTRODUCTION

Section 46(3.1) of the UCA states that in considering whether to issue a CPCN, the BCUC must consider:

(a) the applicable of British Columbia's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any, and

(c) the extent to which the application for the certificate is consistent with the applicable requirements under sections 6 and 19 of the Clean Energy Act (CEA).

Sections 6 and 19 of the CEA, as referred to in (c) above, do not apply to FEI. FEI addresses the other two requirements below. The discussion demonstrates that the Project is consistent with British Columbia's energy objectives and FEI's resource plan in a number of respects. These factors support the approval of the Project.

9.2 BRITISH COLUMBIA'S ENERGY OBJECTIVES

British Columbia's energy objectives are defined in section 2 of the CEA. Based on the results of the socio-economic evaluation described below, the Project will support the British Columbia energy objective in section 2(k) of the CEA "to encourage economic development and the creation and retention of jobs" in two ways: through construction and through reducing the risk of a supply disruption.

9.2.1 Positive Impacts of Construction on Economic Development and Employment

Positive impacts of the Project will include the creation of additional employment within the Project scope, the procurement of local goods and the use of local services. There is also potential for new employment and contracting opportunities that will contribute to the local economy, which is particularly important given the economic uncertainty created by the COVID-19 pandemic.

FEI will work with Indigenous and local leaders and organizations to develop the local workforce, support local businesses, and connect them to Project opportunities. Throughout the Project, FEI will endeavor to track the following: Project investment in local Indigenous communities and municipalities; local employment opportunities; number of Indigenous and other local members of the workforce employed on the Project; contract value awarded to

Indigenous and other local businesses; and other community investment activities. This information will be valuable as FEI strives to maximize local benefits throughout the Project.

In summary, FEI will continue to work with Indigenous groups and stakeholders to promote the Project's positive socio-economic opportunities. FEI recognizes the potential benefits to Indigenous and other local businesses and believes that the Project has the ability to provide an economic stimulus to the region based on its assessment and FEI's experience with previous projects of a similar scope.

9.2.2 Uninterrupted Flow of Natural Gas is Important for Economic Development

The British Columbia energy objective related to retention of jobs is also served by reducing the potential for a loss or a disruption of gas supply. A loss or disruption of gas supply would impact many hundreds of thousands of natural gas customers who use gas in their homes and businesses, plus those who indirectly rely on natural gas for access to goods or services. The PwC Report in Confidential Appendix B provides additional analysis of the potential implications for customers, the utility and society of a loss or disruption of gas supply. As PwC describes, the economic impacts of a loss or disruption of gas supply may result in permanent business closures and loss of jobs.[136]

9.3 TLSE PROJECT IS CONSISTENT WITH FEI'S LONG TERM RESOURCE PLAN

FEI's most recent Long Term Gas Resource Plan (LTGRP) was filed on December 14, 2017 (2017 LTGRP) and was accepted by the BCUC on February 25, 2019[137]. Several sections of the 2017 LTGRP discuss the use and importance of FEI's on-system LNG storage facilities in serving customer demand reliably through annual demand cycles and during emergency situations. These discussions show that, although the detailed analysis and Tilbury development plan set out in this Application was not completed at the time of the 2017 LTGRP submission, the continued use and potential expansion of the Tilbury LNG Facility is a key component of FEI's long range planning.

In Section 5 of the 2017 LTGRP, FEI describes how the Company's supply portfolio utilizes both the Tilbury LNG and the Mt. Hayes LNG facilities to provide secure and reliable gas supply for core customers, citing the need for flexible resources that can be deployed on short notice to meet changes in load requirements.[138] In particular:

- Section 5.1.3 of the 2017 LTGRP cites the recall of Mist storage resources as one of the factors impacting long-term supply planning.

[136] Confidential Appendix B, PwC Report, page 11.
[137] Decision and Order G-39-19.
[138] 2017 LTGRP, Section 5.3, pages 137-138 including Figure 5.3.

- Section 5.3.3 of the 2017 LTGRP explains how on-system resources like the Tilbury LNG facility are critical in creating a diverse pool of resources to help mitigate locational supply disruptions and price risk.
- Section 5.5.2 of the 2017 LTGRP identifies the Tilbury LNG facility as a key resource in balancing load in cold or extreme weather conditions, or providing gas during emergency conditions. This section also describes how the high level of deliverability from Tilbury helps manage price volatility at the Huntingdon-Sumas Marketplace.
- Section 5.5.3 of the 2017 LTGRP highlights the importance of FEI's on-system LNG resources in providing diversity in gas supply resources and mitigating locational supply disruptions and price risk, improving the Company's ability to reduce locational basis risk.
- Section 5 of the 2017 LTGRP concludes by stating that FEI will "continue to examine potential opportunities on FEI's own transmission and storage systems"[139] to address ongoing regional supply developments that impact the Company's ability to maintain secure, cost-effective supply sources and infrastructure over the long-term. The TLSE Project is a direct result of that ongoing vigilance in regional security of supply issues.

Section 6 of the 2017 LTGRP discusses infrastructure needs on FEI's own systems to address both growth in system capacity requirements and sustainment to ensure unrestrained delivery of natural gas during periods of peak demand and in emergency situations. FEI takes an integrated approach to assessing infrastructure needs, considering long term capacity and sustainment plans, potential new, large increases in industrial load and growing CNG and LNG demand.[140] FEI describes how on-system LNG resources are used with other types of resources to improve system security and reliability.[141] The 2017 LTGRP recommends that FEI identify system reinforcements required to maintain system reliability and resilience for core customers as LNG expansion or other large industrial loads are added on the CTS system.[142]

As part of the Long Term Vision for FEI, Section 8.7 of the 2017 LTGRP summarizes the drivers impacting the need for on-system resources. These include the impact that demand over time will have on system capacity and system sustainment requirements for the continued delivery of safe, secure and cost-effective supply. A final driver impacting resource needs is the extent to which the planning environment might change and the nature of such changes.[143] New information available to FEI since the 2017 LTGRP was filed includes ongoing regional developments in gas supply and information related to the October 2018 T-South Incident.

Finally, the 2017 LTGRP Action Plan sets out the following action items that support the TLSE Project:

[139] 2017 LTGRP, Section 5.6, page 148.
[140] 2017 LTGRP, Section 6.1, page 149.
[141] 2017 LTGRP, Section 6.2.1.1, page 152.
[142] 2017 LTGRP, Section 6.5, page 187-188.
[143] 2017 LTGRP, Section 8.7, page 215.

- Action Item 1 states that "…*FEI's research and investigations will seek to uncover any potential challenges as well as identify opportunities to improve on the secure, reliable and cost effective energy services that the Company provides to its customers.*"[144] The benefit of expanding FEI's on-system storage to address regional supply security, improve supply flexibility and improve the resiliency of the CTS has been identified through such investigations.
- Action Item 5 states that FEI will "*Plan for and prepare CPCN applications for near-term system requirements identified in Section 6 to support safe, reliable and cost effective gas delivery to FEI's customers.*"[145] Although the TLSE Project was identified as a high priority project after submission of the 2017 LTGRP, informed in part by FEI's experience with the Enbridge pipeline rupture in 2018, the basis on which it has been identified and the intent of the Company to pursue these types of applications is clearly set out in the 2017 LTGRP.

9.4 CONCLUSION

In summary, the Project is consistent with British Columbia's energy objectives and FEI's long-term gas resource plan in a number of respects. These factors support the approval of the Project.

[144] 2017 LTGRP, Section 9, page 217.
[145] 2017 LTGRP, Section 9, page 218.

10. CONCLUSION

The TLSE Project is in the public interest. FEI recognizes that the Project represents a large investment in FEI's system; however, the benefits are significant. The Project will significantly improve the resiliency to FEI's system, to the benefit of FEI's customers and British Columbians generally. The T-South Incident underscored the potential for a disruption of gas supply to FEI's system, and demonstrated the unique value of additional storage and regasification resources at Tilbury as insurance against such incidents occurring in the future.

FEI defined its Minimum Resiliency Planning Objective with reference to FEI's experience with the T-South Incident. The objective is truly a "minimum" objective, recognizing that the circumstances in 2018 could easily have resulted in a longer "no-flow" disruption or additional obstacles to obtaining support under mutual aid agreements.

Although a 2 Bcf tank with 800 MMcf/day of regasification capacity would meet the Minimum Resiliency Planning Objective, it would leave little margin for FEI to manage any subsequent supply or demand events that can and do occur more commonly. A new 3 Bcf tank and 800 MMcf/day of regasification capacity is the preferred alternative. The incremental cost of a larger tank is small relative to the total Project cost, as a result of economies of scale, while the incremental benefits of the larger tank are large. It provides the greatest functionality to withstand a 3-day "no-flow" event as well as subsequent gas supply, demand and operational events that occur. A larger tank also provides greater ability to accommodate future load growth. Finally, the larger tank size provides access to greater ancillary benefits, mitigating the potential loss of valuable storage resources, improving the security of supply, enhancing FEI's ability to perform daily load balancing, increasing operational flexibility to maintain its pipelines, as well as providing opportunities to capture cost savings should an expansion of both regional pipelines and a further expansion at Tilbury occur in the future.

FEI will construct the Project with appropriate Indigenous and stakeholder involvement and attention to environmental and other regulatory requirements.

The Company requests that the BCUC approve the Project as set out in the Application.

Appendix A

GUIDEHOUSE REPORT ON NATURAL GAS SYSTEM RESILIENCY

(REDACTED VERSION)

System Resiliency: A Critical Requirement of Natural Gas Systems

Provided to:

Fasken

Fasken, Martineau DuMoulin LLP
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Contents

Introduction and Summary of Opinion

This report was prepared by Guidehouse for Fasken, Martineau DuMoulin LLP (Fasken) to address questions related to the proposed FortisBC Energy Inc. (FEI) Tilbury LNG Tank expansion.

Fasken engaged Guidehouse to provide its opinion on the following set of questions:

1. What does resiliency mean in the context of a natural gas market, supply, and delivery system, and why is it important?
2. How is the resiliency of FEI's distribution system affected by the characteristics of the natural gas value chain, including midstream pipeline capacity and availability of storage (both off-system and on-system) and the composition of the load/customer base?
3. In the case of FEI, to what extent is on-system storage either an alternative to, or complementary to, other resiliency measures such as midstream pipeline infrastructure, off-system storage, or interruptible service and or other demand control measures?
4. What considerations should go into determining the optimal amount of on-system storage for FEI?

For the purposes of this report, Guidehouse defines resiliency as the ability of the energy delivery system to respond to system failures or unforeseen events that impact the operations of the system, such as storms. It is Guidehouse's opinion that the North American gas delivery system is highly resilient due to the large network of interconnected natural gas transmission lines that span the continent and provide capacity to enable natural gas production to reach demand centres.

It is the perspective of Guidehouse that natural gas system resiliency, the ability to withstand an unforeseen system disruption, is a critical component of gas system planning.

The FEI system is heavily dependent on the Enbridge BC pipeline for a majority of its natural gas supply and is vulnerable to single point of failure events along this [redacted]

The Tilbury Tank expansion is designed to strengthen FEI's responsiveness to a system disruption and provide greater resiliency.

From a risk management perspective, based on the evidence reviewed, Guidehouse finds that the Tilbury Tank expansion project offers a prudent, necessary and effective means for FEI to strengthen the resiliency of the FEI distribution system and reduce the risk of an uncontrolled shutdown.

However, we note that some individual natural gas utilities that do not have access to multiple transmission pipelines and rely on a single pipeline for the majority of their natural gas supply have less redundancy[1], which is a key component of a resilient system.

For these utilities, the approach to strengthening resiliency requires consideration of available physical assets balanced against the reasonableness of the cost, i.e., impact to the rate payer.

The FEI gas distribution system is heavily dependent on gas deliveries from the Enbridge T-South Pipeline (Enbridge BC Pipeline), which consists of two looped gas transmission

[1] Redundancy is generally defined as deploying infrastructure that exceeds the needs of "normal" supply and demand conditions, which provides resiliency in times of "abnormal" conditions.

pipelines operating as a single system. A major disruption to this midstream pipeline[2] , similar to the Enbridge incident of October 2018, where an explosion led to region-wide natural gas shortages, can lead to adverse outcomes. One is the risk of a significant loss of pressure that can result in an uncontrolled shutdown, which would have extraordinary repercussions on the integrity of the gas utility distribution system. The second is that this would leave thousands of British Columbia homes and businesses without energy for extended periods. The interruption or loss of energy distribution is not only a serious public health and safety risk; it can have long-term negative impacts on economic activity, energy distribution rates, public confidence, and utility reputation. Energy supply disruption can also have severe social impacts, particularly on vulnerable groups of customers and social service providers such as healthcare, childcare, educational activities, etc., that are indispensable for the proper functioning of a province. In addition, a significant amount of time and resources are required to restore service.

Resiliency in the form of on-system storage provides a form of insurance that can mitigate the potential consequences of an unforeseen and significant pipeline disruption upstream of the FEI system. Resiliency for the FEI system can be strengthened by the proposed Tilbury Tank expansion. The benefits include the ability to provide natural gas and pressure support in response to a significant disruption on an upstream pipeline and allow for a sufficient period of time to determine the magnitude and impact of the disruption, for repairs to be made to the upstream pipeline, and conduct, if necessary, a controlled shutdown of the system in order to prevent a total system collapse.[3]

A. Qualifications

Craig Sabine

Craig Sabine is a Director in the Global Energy Practice at Guidehouse, leads the firm's Utilities and Energy Companies segment in Canada and is past Chair of Guidehouse's regulatory transformation initiative. Craig is a strategic partner and trusted advisor to Canadian utilities, energy sector organizations, the financial services sector and large energy consumers on strategic planning, investment decision making, risk management and other organizational challenges.

Working with executive management teams, Craig focuses on the strategic market opportunities and regulatory challenges within and across the energy value chain and has supported regulatory filings related to system planning, cost allocation, affiliates, working capital and rate design.

Craig is a recognized leader in the analysis of energy markets in Canada, including expertise in provincial regulatory and policy development. Notable impactful assignments have afforded Craig the opportunity to assess the gas supply risk management program of SaskPower, review the full cost risk in the Bruce Power refurbishment agreement, provide expert testimony regarding Manitoba Hydro's $25 billion capital investment plan and build an internal compliance program (ICP) for TransAlta related to NERC compliance.

[2] Midstream pipelines involve the transportation of gas from upstream exploration and production centres to downstream demand centres.
[3] Controlled shutdown refers to a process of systematically informing customers of a disruption in service and closing certain distribution segments in an orderly response to mitigate the effects of pressure loss and prevent a total system collapse.

Paul Moran

Paul Moran is Associate Director in the Energy, Sustainability and Infrastructure practice at Guidehouse, and is responsible for leading engagements for clients in the energy sector including electric and gas utilities, power generators, pipeline and midstream companies, gas storage operators, and LNG export project developers in addition to private equity and infrastructure funds.

Paul is an accomplished electric and gas utility professional with extensive background in the power and gas sectors including electric transmission and distribution, natural gas pipelines and distribution in addition to emerging energy technology, including Smart Grid technology assessments and evaluations.

His 17 years of energy industry experience include providing subject matter expertise related to corporate strategic planning, power and natural gas market analysis and forecasting, business process improvement, organizational design and change management.

B. Duty of Independence

Guidehouse confirms awareness of its duty of independence. Our findings in this report are provided on an objective basis and are based on our experience, which is comprised of direct experience in the natural gas industry and providing strategic advisory services to clients in the natural gas and electric utility sector, and our review of documents provided by FEI, when requested by Guidehouse.

C. Issues

As summarized in the introduction, Guidehouse has been tasked with providing its opinion on the following four major questions:

1. What does resiliency mean in the context of a natural gas market, supply, and delivery system and why is it important?
2. How is the resiliency of FEI's distribution system affected by the characteristics of the natural gas value chain, including midstream pipeline capacity and availability of storage (both off-system and on-system) and the composition of the load/customer base?
3. In the case of FEI, to what extent is on-system storage either an alternative to, or complementary to, other resiliency measures such as midstream pipeline infrastructure, off-system storage, or interruptible service and or other demand control measures?
4. What considerations should go into determining the optimal amount of on-system storage for FEI?

D. Discussion

1. The Meaning of Resiliency in the Context of the Natural Gas Market

In this section, Guidehouse describes the workings of the natural gas system from production to delivery and summarizes the sources of resiliency across the natural gas value chain. A high-level overview of the key findings of this section are:

1. Resiliency and reliability are contrasted, where the latter represents the ability to provide natural gas service on a consistent basis, and the former represents the ability of the natural gas system to prevent, withstand and recover from unforeseen events.

2. Different elements of the natural gas value chain (natural gas production and delivery, i.e. transmission, distribution and storage) provide resiliency and reliability in and of themselves as well as support resiliency and reliability to the overall system.
3. Natural gas production has increased in recent years decreasing supply risk and increasing resiliency and reliability of the system.
4. From the perspective of the natural gas utility, resiliency can be achieved by contracting for access to physical infrastructure, subject to geographic location as well as the contractibility of infrastructure.
5. In the event of a significant system disruption, resiliency is strengthened through redundancy, i.e., by diversity of supply, transport and storage in addition to on-system resources.
6. On-system storage provides an effective resource to respond to upstream supply disruptions by giving the utility time to adapt and enter into a controlled shutdown. On-system storage also provides upstream pressure support and many other resiliency benefits.
7. Utilities across North America have sought and gained regulatory approval for investments related to improving system resiliency.

1.1. Resiliency in the Natural Gas Market

In the context of natural gas pipeline transport and distribution systems, resiliency and reliability are two discrete concepts. Natural gas utility companies plan for and target outcomes of resiliency and reliability in their systems. This study will focus on resiliency as a key value and as an asset provided by the natural gas system. Reliability will also be defined to ensure that the two different services, that must both be provided to customers, are well understood as standalone concepts.

- Reliability is the ability of the energy delivery system to provide customers with an expected natural gas service on a consistent basis.
- Resiliency is the ability to prevent, withstand and recover from system failures or unforeseen events such as damage and/or operational disruption that impact the operations of the system.

As the cornerstone of this report, resiliency comes from the ability of the natural gas system to offer services, backed by physical assets, that enable market participants to prevent, withstand and recover from man-made or natural events that interrupt the flow of gas. The natural gas utility is charged with the responsibility to manage these risk of system disruptions on behalf of end-users by constructing a portfolio of natural gas transportation, on and off-system storage resources and supply contracts that will enable it to address unforeseen events.

Infrastructure combined with contractual assets are the backbone of reliability. Achieving the backbone requires appropriate system sizing coupled with commercial agreements and experienced operators. When all of this is taken together, it increases the probability of achieving the expected reliability of gas delivery.

In a similar fashion, resiliency is achieved by selectively building system redundancy via commercial agreements with tangible upstream physical assets and on-system physical assets to respond to unexpected physical events. Resiliency embedded in the system enables the system to manage and recover from unexpected events more effectively and expeditiously.

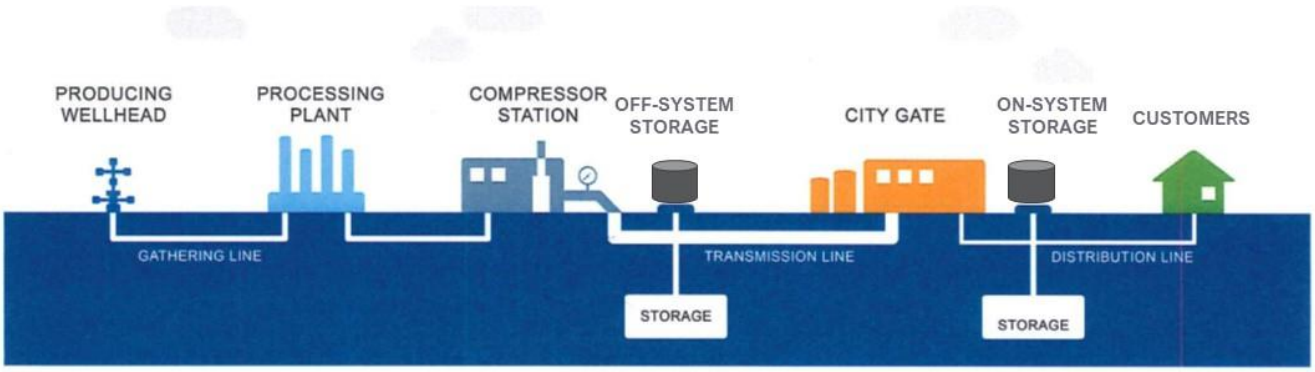
In this section, Guidehouse examines the natural gas value chain from exploration & production through to distribution to end users, and explains what resiliency is and how it contrasts to reliability. Guidehouse demonstrates why resiliency is important and discusses how resiliency is provided. Although the focus is on the natural gas energy delivery system, Guidehouse will also describe how the gas delivery system complements the electric energy system and how the two value chains are dependent upon each other. Items to be addressed include:

- The Function of Each Component of the Natural Gas Value Chain
- The Role of Industry Participants Across the Natural Gas Value Chain
- Natural Gas Regulation
- The Need for and Benefits of Resiliency
- How Resiliency Can Be Achieved

1.2. Natural Gas Value Chain

The natural gas energy delivery value chain is a complex system that involves the exploration and production of natural gas, pipeline transportation to demand centres and final distribution to end users. Across the value chain, physical assets are key contributors to ensuring that customers have reliable access to natural gas, and resiliency must be a consideration at each phase. ***Figure 1*** below provides a representation of the major components of the natural gas value chain.

Figure 1. Natural Gas Physical Infrastructure Value Chain



<u>Natural Gas Production</u>

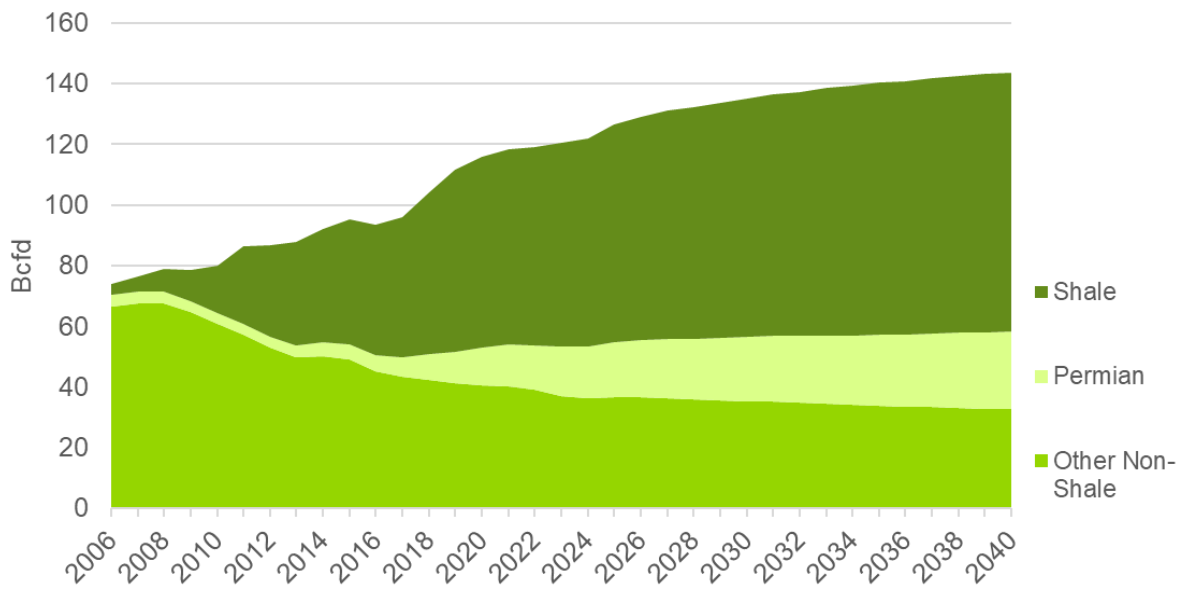
Exploration and Production (E&P) companies explore, drill and extract natural gas from geologic formations, frequently in tandem with oil extraction. Adequate supply is a component of resiliency and it is estimated that Canada and the U.S have a total of approximately 3,600 trillion cubic feet (Tcf) of recoverable reserves of natural gas.[4] This is approximate to 100 years of consumption at current levels.

In North America, natural gas is produced in multiple locations. From British Columbia and Alberta in Canada to Texas, Pennsylvania and Ohio in the U.S., and multiple provinces and states in between. The geographic diversity of the sources of natural gas production enhances the reliability and resiliency of gas supply in North America. ***Figure 2*** below shows

[4] https://www.nrcan.gc.ca/science-data/data-analysis/energy-data-analysis/energy-facts/natural-gas-facts/20067

North American natural gas production from 2006 (historical) to 2040 (Guidehouse projection).[5]

Figure 2. North American Natural Gas Production

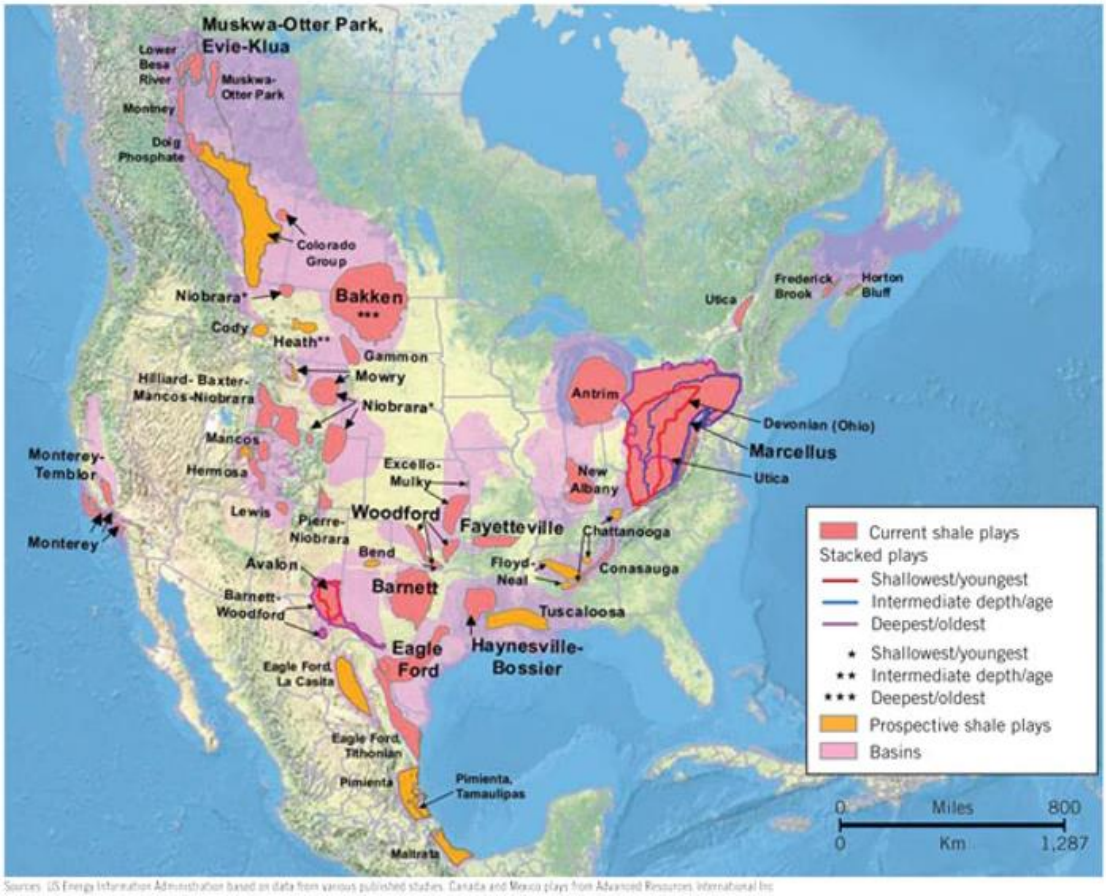


In the mid-2000s, North American E&P companies figured out how to produce natural gas from geologic formations that had previously been too challenging and expensive to extract.

Hence, during the past decade the majority of new production has been sourced from shale plays utilizing these technologies. However, the production from an individual shale well declines very quickly and requires sustained drilling of new wells to support a steady or growing rate of production. While gas production changes over time in response to market conditions, as shown in ***Figure 2***, in general daily production volumes are relatively consistent and do not vary considerably in response to daily or seasonal changes in demand. ***Figure 3*** below provides a map of the major North American shale plays.

[5] Guidehouse North American Natural Gas Outlook

Figure 3. North American Shale Plays and Formations



Natural gas in North American is abundant; however, Guidehouse notes that infrastructure is required to provide adequate deliverability of natural gas supply and ensure resiliency. The next section discusses the components of the natural gas delivery value chain, how they contribute to resiliency, in addition to their limitations in providing resiliency to a natural gas utility.

Resiliency Features of Natural Gas Exploration and Production	
Natural gas is abundant	North American has sufficient supply to provide natural gas for approximately 100 years.
Steady production	Well production is ratable and despite news headlines[6] producers are loath to shut in wells. Shutting in wells can cause formation damage and disrupt future production. Therefore, there is little ability in production to vary output to meet the ebbs and flows of demand. It is noted, however, that, over time, production will increase/decrease in response to economic signals.
Disadvantages / Limitations	Abundant supply requires infrastructure to ensure delivery to market and changes in sources of production require reconfiguration and expansion of existing infrastructure to ensure deliverability. Infrastructure also requires land development and environmental permits / approvals, which can increase the difficulty of developing infrastructure.

[6] https://www.eia.gov/todayinenergy/detail.php?id=44396

Natural Gas Delivery

Gas flowing from wellhead to burner tip, and generally from higher to lower pressure is the fundamental principle of the natural gas delivery system. The amount of pressure in a pipeline is measured in pounds per square inch (PSI) or kilopascals (kPa). Prior to consumption, natural gas must be gathered from the wellhead, treated to remove impurities, transported from producing areas to market demand centers and distributed to end-users. In addition, because natural gas demand is highly seasonal, natural gas production must also be stored during periods of low demand to ensure adequacy of supply to meet peak demand. The following section describes each component of the natural gas delivery system and how each contributes to resiliency.

Gathering Systems

Once produced and extracted at the well, natural gas is transported via gathering pipelines to processing facilities for treatment. Natural gas is composed almost entirely of methane but does contain small amounts of other hydrocarbon gases such as ethane, propane, butane, pentane and non-hydrocarbon impurities. These other hydrocarbons and impurities must be removed through a complex industrial process designed to clean raw natural gas by separating impurities and various non-methane hydrocarbons and fluids to produce what is known as pipeline quality natural gas.

Processing plants also can remove small quantities of propane and butane. These gases are used for chemical feedstocks and other applications.

A gathering system may need one or more field compressors to move the gas into midstream pipelines or the processing plants. A compressor is a machine driven by an internal combustion engine or electric motor that creates pressure to "push" the gas through the lines. Most compressors in the natural gas delivery system use a small amount of natural gas from their own lines as fuel. The reliance on natural gas for compression, rather than electricity, contributes to the resiliency of supply across the natural gas gathering system as this reduces dependency on the power system to deliver electricity to compression stations. Using natural gas to fuel compressors results in higher emissions than using electricity, provided that the electricity is supplied from lower carbon resources. Operators must weigh the resiliency benefits of using natural gas as compressor fuel versus low-emitting electricity, which is dependent on the resiliency of the electricity system.

From the perspective of the natural gas utility, relying on a pipeline that is served by a single processing plant for the majority of the supply, results in reduced resiliency in the event that the processing plant experiences a disruption.

The Transmission System

From the gathering system, the natural gas moves into the transmission system for long-haul transportation to market centres. In Canada there are more than 840,000 kilometers (km) of transmission, gathering and distribution pipelines, including 117,000 km of large-diameter transmission lines, with most provinces having significant pipeline infrastructure.[7] Of this amount, about 73,000 km are federally regulated pipelines, which are primarily transmission

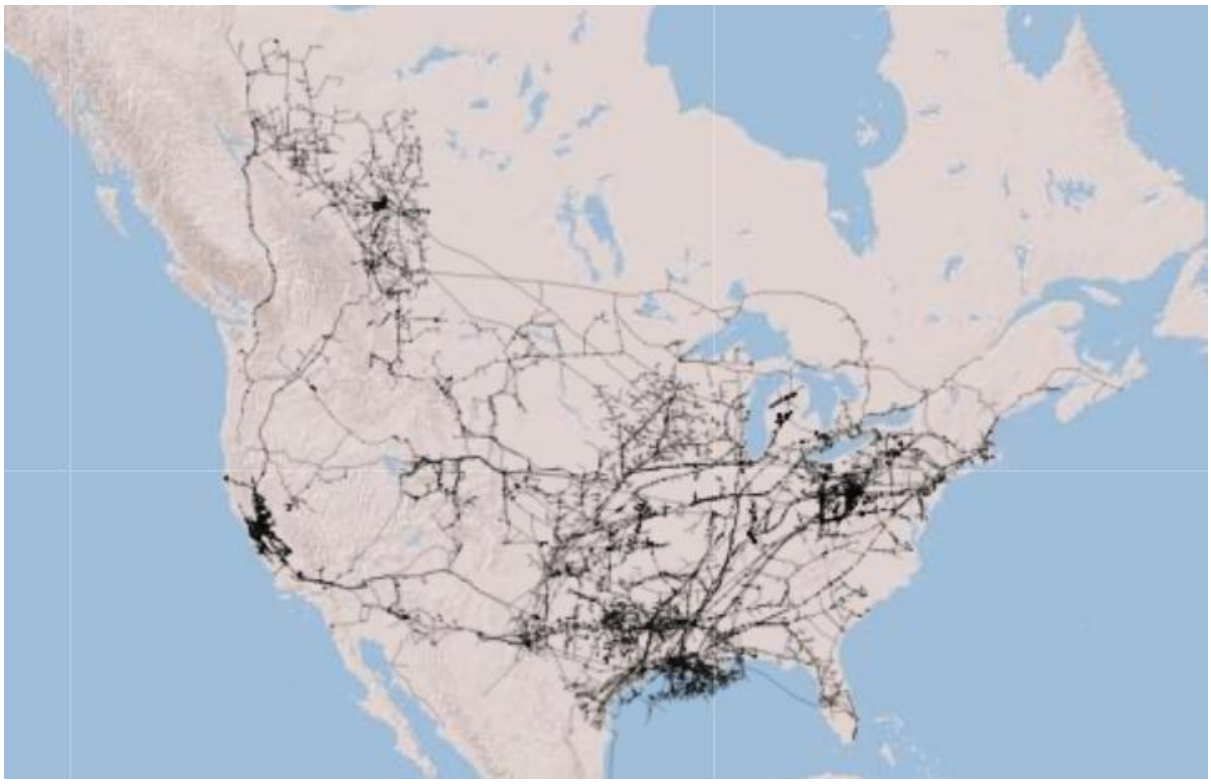
[7] https://www.nrcan.gc.ca/our-natural-resources/energy-sources-distribution/clean-fossil-fuels/pipelines/pipelines-across-canada/18856

pipelines. In the U.S. there are 4.8 MM kilometers of transmission pipeline.[8] In addition to being mainly underground, the North American pipeline system is vast and interconnected, allowing for multiple pathways to reroute natural gas deliveries from production centres to demand centres in the event of a disruption.

These high-pressure transmission lines for natural gas can be compared to the North American inter-provincial and interstate highway system for automobiles. They move large amounts of natural gas thousands of kilometers from the producing regions to local distribution companies (LDCs) such as FEI and industrial customers and some power generators who are served via transmission lines. ***Figure 4*** below provides a high-level overview of the North American natural gas transmission system.

As can be seen in ***Figure 4***, some regions in North America feature more access to the transmission system than others. For example, Western Canada and the U.S. Pacific Northwest are supplied by fewer pipelines as compared to the U.S. Upper Midwest and the U.S. Gulf Coast. From the perspective of resiliency, a natural gas utility or geographic region with more access to multiple transmission pipelines will have greater potential to achieve higher system redundancy and supply diversity, provided it is able to enter into transportation and supply contracts.

Figure 4. North American Natural Gas Transmission System



The pressure of gas in each section of line typically ranges from 200 PSI to 1,500 PSI, depending on the type of area in which the pipeline is operating. Many major interstate pipelines are "looped", i.e. there are two or more lines running parallel to each other in the same right of way. This provides maximum capacity during periods of peak demand and operational flexibility.

[8] https://www.eia.gov/energyexplained/natural-gas/natural-gas-pipelines.php

Gas pipeline operators are responsible for maintaining operational control of the flow of gas on their systems. Operational control is a key contributor to the resiliency of the transmission system because it enables pipeline operators to adjust flow rates and pressure based on operating conditions as well as become aware of and respond to equipment malfunctions and releases.

Linepack

A property of natural gas called compressibility allows for operators to “pack” a pipeline with gas molecules. The amount of gas in the pipe is called the “linepack”. Linepack helps to minimize supply disruptions in the short-term and deliveries to be maintained for a short period of time in the event of an outage or other emergency. Additionally, linepack provides stabilization of the system as demand can fluctuate based upon hourly changes in weather and or usage.

A 50-mile (80km) section of 42-inch (107 cm) transmission line operating at about 1,000 pounds of pressure contains about 200 million cubic feet of gas, which is enough to power a kitchen range for more than 2,000 years. However, when considering the peak design day demand in FEI’s service territory, approximately 871 million cubic feet per day, this translates into about 5.5 hours of supply.

By raising and lowering the pressure on any pipeline segment, a pipeline company can use the segment to store gas during periods when there is less demand at the end of the pipeline. The linepack can be controlled by raising or lowering the pressure in the pipe. By lowering the pressure, the gas will slow down, and companies can effectually store natural gas in the pipeline when demand has decreased. Likewise, they can speed up the delivery by increasing the pressure in the compressor stations. Using linepack in this way allows pipeline operators to handle hourly fluctuations in demand very efficiently.

In addition, pipeline midstream companies and inter-connection pipelines (i.e. LDC or other midstream pipeline companies) have agreements in place called Operational Balancing Agreements (OBAs) in which parties agree to specified procedures for balancing between nominated levels of service and actual quantities transferred between the two pipelines.

Because the amount of linepack available for intra-day flexibility is directly correlated to the amount of demand and the amount of gas in the pipeline segment, linepack has limited capability to serve resiliency in the event of a prolonged supply disruption.

Resiliency Features of Natural Gas Delivery	
Looped systems	Provide increased resiliency of the delivery system by augmenting the amount of delivery capacity of a single string of pipeline.
Linepack	Consists of gas compressed and stored in natural gas pipelines, which allows the system to meet rapid, intraday changes in demand even if upstream supply is insufficient, thus increasing the resiliency of the delivery system.
Operational Control	Allows for system monitoring and operational control of the transmission delivery system, enabling real-time control and improved resiliency.

Resiliency Features of Natural Gas Delivery	
Disadvantages/Limitations	The resiliency features of the transmission system are designed to provide the capacity to respond to disruptions and recover quickly. However, it is noted that the key driver to resiliency for a natural gas utility is system redundancy and the lack of available transportation in a region provides less options to secure additional transportation and supply diversity.

Compressor Stations

Compressor stations are located along each pipeline to boost the pressure that is lost through the friction of the natural gas moving through the steel pipe. Many compressor stations are completely automated, so the equipment can be started or stopped from a pipeline's central control room. The control room can also remotely operate shut-off valves along the transmission system. The operators of the system keep detailed operating data on each compressor station, and continuously adjust the mix of engines that are running to maximize efficiency and safety.

Natural gas moves through the transmission system at up to 48 km/h, so it can take several days for gas to move from the source of production to the point of delivery. Along the way, there are many interconnections with other pipelines and other utility systems, which offers system operators a great deal of flexibility in moving gas.

It is not uncommon for compressor stations to have redundancy; i.e., additional compression capacity installed on site to ensure adequacy in the event of a mechanical failure.

Resiliency Features of Compressor Stations	
Compressor Stations	Provide for control over the flows of natural gas through the delivery system, allowing operators to effectively meet demand. Redundant compression capacity provides resiliency in the event of a mechanical failure.
Disadvantages/Limitations	Compression stations fueled by natural gas are self-sufficient, while those that run on electricity require back-up power to have the same level of resiliency as gas-fired compression.

Natural Gas Storage

Storage of natural gas is an integral component of the natural gas delivery system and enables the delivery of natural gas to consumers and end-users throughout the year with reliable service. From the perspective of the natural gas utility, off-system storage refers to storage that is not directly tied to the natural gas utility's distribution system, but that is accessible via the transmission system. Most, but not all off-system storage is underground; however, there are examples of above-ground off-system storage. Storage provides a physical location to store natural gas. Because natural gas production remains relatively constant year-round, storage enables the gas provider to adjust to daily and seasonal fluctuations in demand.

Underground storage facilities can be developed from depleted gas reservoirs, aquifers, or salt caverns and are connected to one or more transmission pipelines; whereas above ground storage can be provided through liquefied natural gas (LNG) or compressed natural gas (CNG).

Natural gas storage plays a critical role in ensuring the reliability and resiliency of the natural gas system in several ways. The first is that storage plays a role in balancing production with demand. For example, there are significant seasonal variations in demand because natural gas consumption is highest during the wintertime and lowest during mild-weather months in markets that rely heavily on natural gas for space heating during periods of cold weather. For example, approximately 20% of the natural gas consumed in the United States during the winter is supplied by underground storage[9]. Natural gas storage enables supply to match demand on any given day throughout the year.

From the perspective of resiliency, natural gas storage not only provides a supply buffer but also provides a utility vital time to respond to unplanned supply constraints in the pipeline and distribution network. As result, utilities may be afforded sufficient time to avoid an uncontrolled shutdown.

Some pipeline companies that also offer storage services may provide a service called park and loan that enables shippers to borrow/lend gas. These services are typically utilized to balance the daily or intra-day markets.

Resiliency Features of Storage	
Balancing Production and Demand	Allows operators to store excess gas when demand is low and withdraw natural gas to meet high demand.
Unplanned Outages	Allows operators time to respond to upstream disruptions or abnormally high periods of demand and avoid potential uncontrolled shutdowns.
Disadvantages / Limitations	Off-system natural gas storage is dependent on the transmission system for delivery to the natural gas system and provides less resiliency to an LDC than on-system storage.

City Gate Stations

When the natural gas in a transmission pipeline reaches a local gas utility, it normally passes through a "gate station". Utilities frequently have gate stations receiving gas at many different locations and from several different pipelines. Gate stations serve three purposes. First, they reduce the pressure in the line from transmission levels (200 to 1,500 PSI) to distribution levels, which range from ¼ PSI to 200 PSI. It is at this point that an important safety element is introduced. As methane is odorless, an odorant is added to provide the distinctive sour scent associated with natural gas, so that consumers can smell even small quantities of gas. Finally, the gate station measures the flow rate of the gas to determine the amount being received by the utility versus nominated (i.e. from OBAs). It is noted that the FEI natural gas distribution system has features of both a transmission system and a distribution system. From a commercial perspective, the FEI system primarily operates as a distribution system, but it does operate some high-pressure pipelines to facilitate transportation of natural gas at high volumes and high pressure across the system.

The Distribution System

From the gate station, natural gas moves into distribution lines or "mains" that range from 2 inches to more than 24 inches in diameter (5 cm – 61 cm). Within each distribution system, there are sections that operate at different pressures, with regulators controlling the

[9] https://www.aga.org/globalassets/underground_n_g_storage_brochure_final.pdf

pressure. Some regulators are remotely controlled by the utility to change pressures in parts of the system to optimize efficiency. Generally, the closer natural gas gets to a customer, the smaller the pipe diameter is and the lower the pressure is.

The gas utility's central control centre continuously monitors flow rates and pressures at various points in its system. The operators must ensure that the gas reaches each customer with sufficient flow rate and pressure to fuel equipment and appliances. They also ensure that the pressures stay below the maximum pressure for the monitored sections within the system.

As gas flows through the system, regulators control the flow from higher to lower pressures. If a regulator senses that the pressure has dropped below a set point, it will open to allow more gas to flow. Conversely, when pressure rises above a set point, the regulator will close to maintain a constant pressure. As an added safety measure, relief valves are installed on pipelines to vent gas to the atmosphere where necessary.

Many distribution systems also feature on-system storage. This is typically above ground and includes small-scale LNG or compressed natural gas (CNG) storage that enables the distribution company to meet short-term requirements for increased gas demand due to unplanned weather conditions. These facilities are frequently called “peak shaving facilities” as they enable the LDC to reduce (shave) the amount of natural gas needed from external suppliers through on-system resources.

Distribution systems have limited linepack due to the reduced pressures and volumes of the gas on a distribution system compared to a transmission system.

In addition to on-system storage, some LDCs also utilize mobile pipeline solutions. These non-pipeline solutions are frequently LNG or CNG tanker trucks that can deliver needed supply directly to an injection point on the distribution system in the event of significant peak demand or a planned or unplanned service disruption.

Distribution mains are typically interconnected in multiple grid patterns with strategically located shut-off valves. These valves minimize the need for customer disruption to service during maintenance operations and emergencies and provide the redundancy, along with on-system storage or mobile pipeline solutions, needed to ensure reliable and resilient delivery of natural gas.

Absent on-system storage, the resilience of the distribution system is a function of upstream resiliency, i.e., the network of transmission pipelines and natural gas storage that serve the natural gas utility or region.

	Resiliency Features of Gas Distribution
On-System Storage	Enables the gas distribution utility to operate and control a supply reserve to respond to peaking requirements and emergency situations.
Grid Pattern/Valve Shut-Offs	Enable the gas utility to minimize service disruption in response to planned or unplanned outages.
Disadvantages/ Limitations	On-system storage and grid pattern/valve shutdowns provide a means to forestall a catastrophic system failure that may arise due to an upstream pipeline failure, especially in periods of peak demand, but do not provide the same duration of redundancy as a transmission pipeline.

Customer Delivery

Natural gas runs from the main into a home or business in what's called a service line. Typically, the natural gas utility is responsible for maintaining and operating gas pipeline and facilities up to the residential gas meter. All equipment and gas supply lines downstream of the residential meter are the responsibility of the customer.

When the gas reaches a customer's meter, it passes through another pressure regulator to reduce its pressure to under ¼ PSI, if necessary. Some service lines carry gas that is already at very low pressure. This is the normal pressure for natural gas within a household piping system and is less than the pressure created by a child blowing bubbles through a straw in a glass of milk. When a gas furnace or stove is turned on, the gas pressure is slightly higher than the air pressure, so the gas flows out of the burner and ignites in its familiar blue flame.

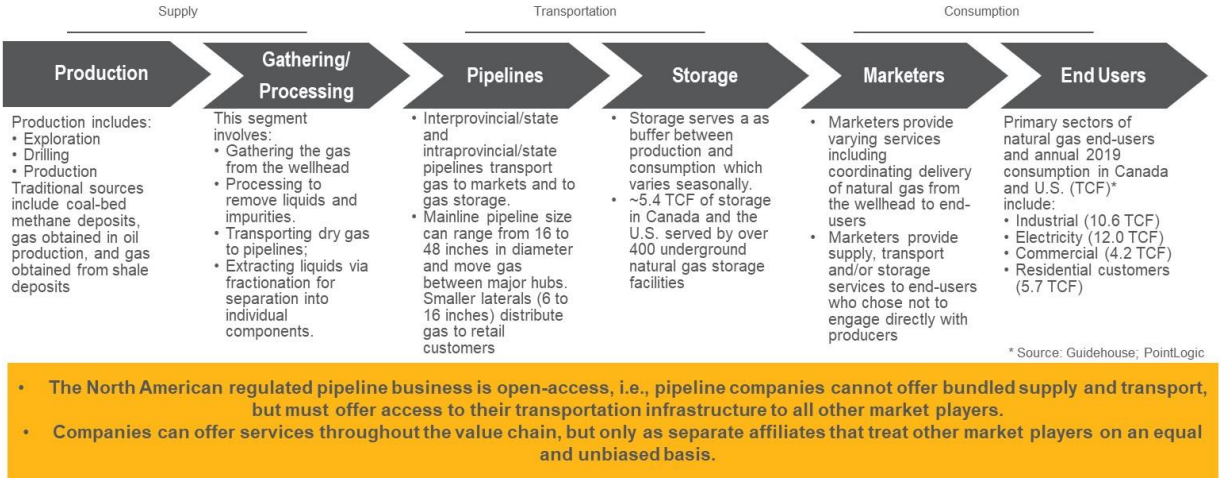
In the event that customer demand exceeds the ability of the natural gas utility to provide supply, the gas utility may curtail certain interruptible customers. Examples of circumstances that could cause such an event include pressure problems, physical disruption upstream or on the distribution system, a supply limitation, or increased demand (e.g., a cold weather-driven event). Given the obligation to serve, the natural gas utility does not curtail firm demand customers who cannot tolerate disruption to the service, unless it is an emergency or other circumstance identified in tariff provisions. The utility may make voluntary arrangements with certain customers who have the ability to either curtail their consumption and/or switch to an alternative fuel (e.g., switch to oil) and calls on these customers to curtail usage. One drawback to this is that the utility may not have enough non-firm customers to make a meaningful impact on demand when voluntarily curtailed. In addition, it may take a significant amount of time to get interruptible customers to reduce their usage.

Resiliency Features of Customer Delivery	
Curtailment	Enables the gas distribution utility to curtail certain customers to manage supply disruptions throughout the year.
Disadvantages/ Limitations	Similar to grid pattern/valve shutoffs, curtailment provides a means to avoid an uncontrolled shutdown, but does not provide system redundancy. Curtailment also takes a significant amount of time.

1.3. Role of Industry Participants Across the Value Chain

This section discusses the roles of industry participants across the industry value chain with an emphasis on the services that industry participants provide to support resiliency. ***Figure 5*** below provides a high-level representation of the primary roles of industry participants across the major components of the natural gas value chain.

Figure 5. Role of Industry Parties Across the Supply-to-Market Value Chain



In the U.S. and Canada, commodity and transportation are unbundled, that is, the delivery of natural gas on pipelines is separated from the commodity. The gas distribution company or large end-user must secure commodity, transportation and storage from industry participants. Pipeline and storage companies are not permitted to offer bundled commodity and transportation.

Types of Pipeline and Storage Services

In this section, we describe the types of commercial structures available to a natural gas utility and other end-users to enter into contractual arrangements for transportation and storage services to provide for reliable delivery of natural gas supply. In terms of resiliency, these commercial arrangements can be called upon to provide responsiveness to an unforeseen event. However, Guidehouse notes that if the underlying physical asset is not operational due to a disruption, the contractual arrangements do not provide, in and of themselves, resiliency.

Pipeline and storage operators typically offer several different types of transportation and storage service.

- Firm pipeline and storage transportation capacity:
  - Direct agreement between the asset and a customer for a year or more, relying on primary receipt and delivery points. Shippers with firm transportation service generally receive priority to ship for the contracted quantity.
- Interruptible pipeline and storage transportation service:
  - Offered under schedules or contracts on an as-available basis.
  - This service can be interrupted on a short notice for a specified number of days or hours during times of peak demand or in the event of system emergencies. In exchange for interruptible service, customers pay lower prices.
- Secondary market for firm transportation rights enables shippers to sell their pipeline or storage capacity to third parties through the capacity release program:
  - Released capacity offers market participants the opportunity to buy and sell from each other as well as from the asset.

- "No-notice service" enables firm shippers to receive a varying amount up to their firm entitlements on a daily basis without penalty:
    - No-notice service is particularly valuable during periods of high demand when transportation capacity may be completely used for shippers who must serve their load without knowing their exact load level each day. No-notice service is generally priced at a premium to firm transportation service. This service is generally provided by pipeline operators that have underground natural gas storage.
- Park and Loan (PAL) enables lending and borrowing gas on a short-term basis to/from the pipeline:
    - Short-term, intra-month storage needs can be met by pipeline and storage operators who offer a service to natural gas users, or by owners of the storage contracts. As described in Section 1.2, pipeline linepack can be utilized to offer PAL services. Excess supply can be "parked" temporarily during periods of reduced demand for delivery to the user at a future date. Users can also borrow molecules during peak demand periods, which are reinjected at a later date. Note: this service is not offered by the Enbridge BC pipeline.

Natural Gas Supply Market

Similar to how pipeline and storage services provide a means to enter into commercial arrangements to use transportation and storage infrastructure, commercial arrangements provide the means to contract for natural gas supply. Guidehouse notes that from the perspective of resiliency, the inherent value of a natural gas supply contract to provide commodity in the event of a system disruption rests upon the functionality of the delivery asset.

The commodity market for natural gas is deregulated in Canada and the U.S. Producers establish a price for their natural gas and end-users enter in purchase agreements. Natural gas can be procured on a long-term basis, seasonally or daily.

The price for natural gas is typically established by sellers and buyers for delivery at a specific point on the transmission system. Hubs, i.e., geographic locations where two or more pipelines interconnect, offer market participants a physical location to establish a price for natural gas supply.

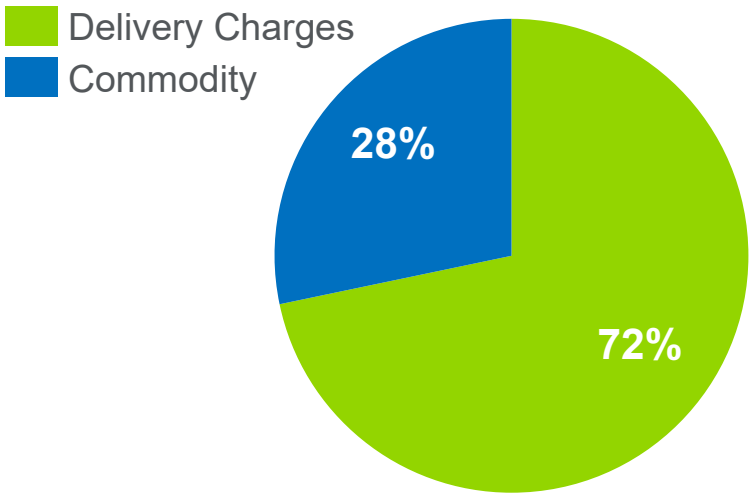
In addition, a financial market for natural gas futures exists where producers and end-users can enter into financial arrangements to manage price risk.

Taken as a whole, the markets for natural gas supply, transportation and storage, offer industry participants several means to enter into commercial agreements to contract for supply and transportation services to provide resiliency.

As shown in ***Figure 6*** below, the delivery charges for a FEI residential customer [10] comprise approximately 72% of a residential customer's bill, with the commodity costs, including transportation, storage and cost of gas comprising approximately 28% of the bill.

[10] https://www.fortisbc.com/accounts-billing/billing-rates/understanding-your-bill-natural-gas/how-to-read-your-gas-bill

Figure 6. FEI Residential Natural Gas Bill Breakdown (as of July 1, 2020)



1.4. Natural Gas Market Regulation

As described above, the natural gas industry offers market participants the opportunity to enter into commercial agreements to contract for services (i.e., transportation, storage and natural gas supply services) that are provided and supported by the physical infrastructure, (i.e., pipelines, storage facilities and natural gas production) to develop a portfolio of transportation, storage and natural gas supply services that will enable the gas LDC to support its own unique reliability and resiliency services.

The services and business operations provided by natural gas market participants are regulated by different Federal, Provincial or State agencies to ensure open access.

The market for interprovincial or interstate pipeline and storage capacity is regulated in Canada by the Canada Energy Regulator (CER) and in the U.S. by the Federal Energy Regulatory Commission (FERC). These agencies regulate the rates, terms and conditions of service of natural gas transportation in interstate commerce. FERC's ratemaking decisions are subject to the Natural Gas Act, which specifies that rates, terms and conditions must be "just and reasonable," and not unduly discriminatory. The CER is subject to the Canadian Energy Regulator Act, and Canadian Oil and Gas Operations Act, among others. Tariffs are established by these agencies that enable the pipeline operator to earn a regulated rate of return by providing non-discriminatory access to shippers through published tolls, or transportation rates. Intra-provincial or Intrastate transportation or storage of natural gas generally is regulated by provincial or state agencies following similar principles.

The key principle underlying regulation of the transmission and storage market is open access. Pipeline and storage companies cannot offer bundled supply and transport but must offer access to their transportation infrastructure to all other market players. Companies can offer services throughout the value chain, but only as separate affiliates that treat other market players on an equal and unbiased basis. Regulation also plays a critical role in guiding pipeline expansions or development of new infrastructure. Unlike the power sector, if existing capacity is fully committed under firm contracts, interstate and interprovincial pipelines are not required to expand their facilities to provide transportation service. However, a pipeline company must receive regulatory approval to construct/expand a pipeline by demonstrating that the pipeline is in the public convenience and necessity. This is typically accomplished by demonstrating market need in the form of shipper (customer)

precedent agreements. Pipeline and off-system storage construction/expansion is therefore a function not just of market need, but also of a customer's demand, creditworthiness, size, and willingness to commit to long-term transportation agreements. A customer's expected utilization of a new pipeline/storage asset or asset expansion is also an important factor in determining economic viability of a project. A natural gas utility is more willing to commit to long-term transportation and/or off-system agreements if it expects to utilize the pipeline year-round. It should be noted that expansion of off-system storage follows a similar process for new infrastructure as well as storage expansions.

Regulation of most LDCs is the mandate of provincial or state regulatory agencies. LDCs are typically granted a franchise to serve a specific geography. Similar to midstream pipeline companies, the rates of an LDC are regulated to ensure two key objectives, including:

1. Allow a Fair Return: Establishment of rates that permit the pipeline operator a reasonable opportunity to recover its costs and provide a profit to investors.
2. Reasonableness: Rates must be reasonable and fair to the LDC's customers. The LDC operator needs enough revenue to ensure it can meet its safety, environmental and other legal obligations.

In British Columbia, the public utility must provide service, according to Section 38 of the Utilities Commission Act, as follows:

> *38: A public utility must (a) provide, and (b) maintain its property and equipment in a condition to enable it to provide, a service to the public that the commission considers is in all respects adequate, safe, efficient, just and reasonable.*[11]

It is important to note that gas commodity costs are passed through to the LDC's customers at cost, without a markup. The LDC is allowed to earn a profit through the delivery of natural gas to its customers based upon the capital invested to provide these services.

Some LDCs, including FEI, permit their customers to secure their gas commodity through a third-party supplier or marketer, but contract with the LDC for transportation.

From the perspective of regulation of resiliency, Guidehouse concludes that natural gas industry participants do not have a direct regulatory mandate to provide a specific level of resiliency. Instead, industry participants enter in contractual arrangements for commodity supply, transportation and storage services that contain specific, legally binding specifications for a certain level of service which feature the resiliency benefits described earlier in this report. In addition, LDCs typically have a regulatory-imposed obligation to serve their customers. This requirement means that LDCs must plan and procure sufficient upstream pipeline and storage capacity and commodity supply in such as manner as to be able to adequately serve their customers at a reasonable cost.

In terms of guiding system planning for resiliency, cost reasonableness is an important element that drives natural gas utility decision-making. As described in Section 1.1 resiliency is the ability of the energy delivery system to respond to system failures or unforeseen events that impact the operations of the system, such as explosions, landslides or other natural phenomena. A natural gas utility typically has two options to secure and/or strengthen its system resiliency to upstream natural gas supply. The first is to secure additional pipeline access and the second is to secure additional access to storage, either off-system or on-system. Natural gas utilities typically utilize a blend of both options.

[11] https://www.canlii.org/en/bc/laws/stat/rsbc-1996-c-473/latest/rsbc-1996-c-473.html#Part_3_Regulation_of_Public_Utilities_33447

Securing additional pipeline capacity is a function of either contracting for existing pipeline availability or participating in the development and construction of new pipelines or existing pipeline expansions. This is similar for access to storage. From the perspective of a natural gas utility, there is a key difference between contracting for capacity upstream versus developing onsite storage. This is that access to upstream assets is achieved through contractual agreements with operations controlled by the asset operator, whereas onsite storage is operated by the natural gas utility. Depending on the resiliency need, developing additional transportation or storage capacity may provide system redundancy and increased resiliency. These assets may be under-utilized for a period of time, creating a risk that these costs to customers could be viewed as unreasonable. However, weighed against the consideration is the potentially significant socio-economic consequences of a loss of service.

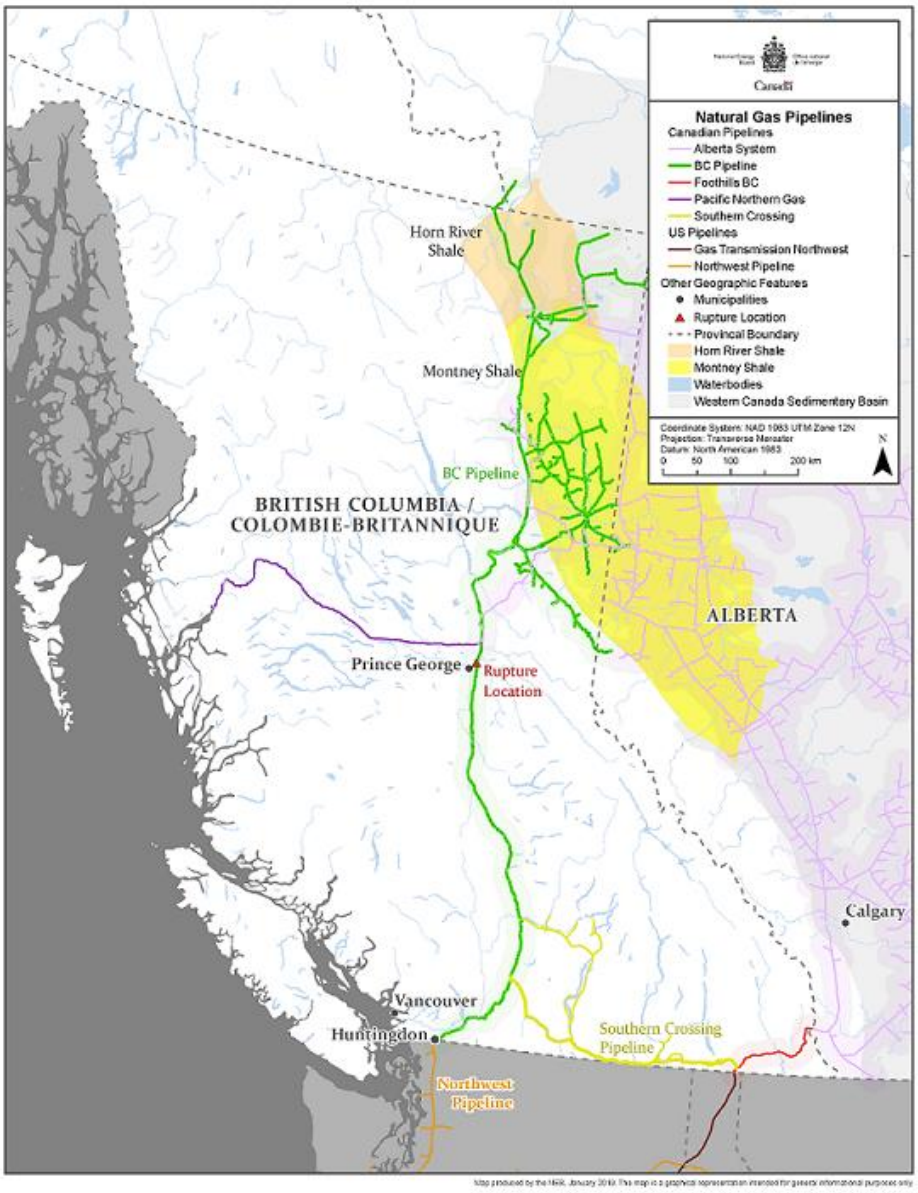
1.5. Need for and Benefits of Resiliency in BC

The October 2018 pipeline disruption on the Enbridge T-South pipeline highlights the current state of resiliency of the natural gas system in BC and the need for further action to ensure strengthened resiliency to manage future events. The Enbridge BC Pipeline system experienced a rupture at a point on the pipeline near Prince George, BC, as illustrated in ***Figure 7*** below.

Enbridge's 2.9-Bcf/day BC Pipeline system[12] (aka Westcoast Energy Pipeline, or WEP); comprises two parallel mainlines, a 36-inch-diameter (91 cm) pipe and 30-inch-diameter (76 cm) pipe, that move Alberta and BC gas supply from northeastern British Columbia south, serving the FEI service territory in addition to providing a 1.3-Bcf/day interconnection at the Huntingdon, BC/Sumas, WA, border crossing point. Here the Enbridge system interconnects with the Northwest Pipeline (NWPL). From there, the gas is delivered to local distribution companies, gas-fired power generation plants, gas storage facilities, as well as for petroleum refining, primarily in Washington State but also in Oregon and Idaho.

[12] https://www.enbridge.com/~/media/12016B2E981A419D97C19039E552E797.ashx

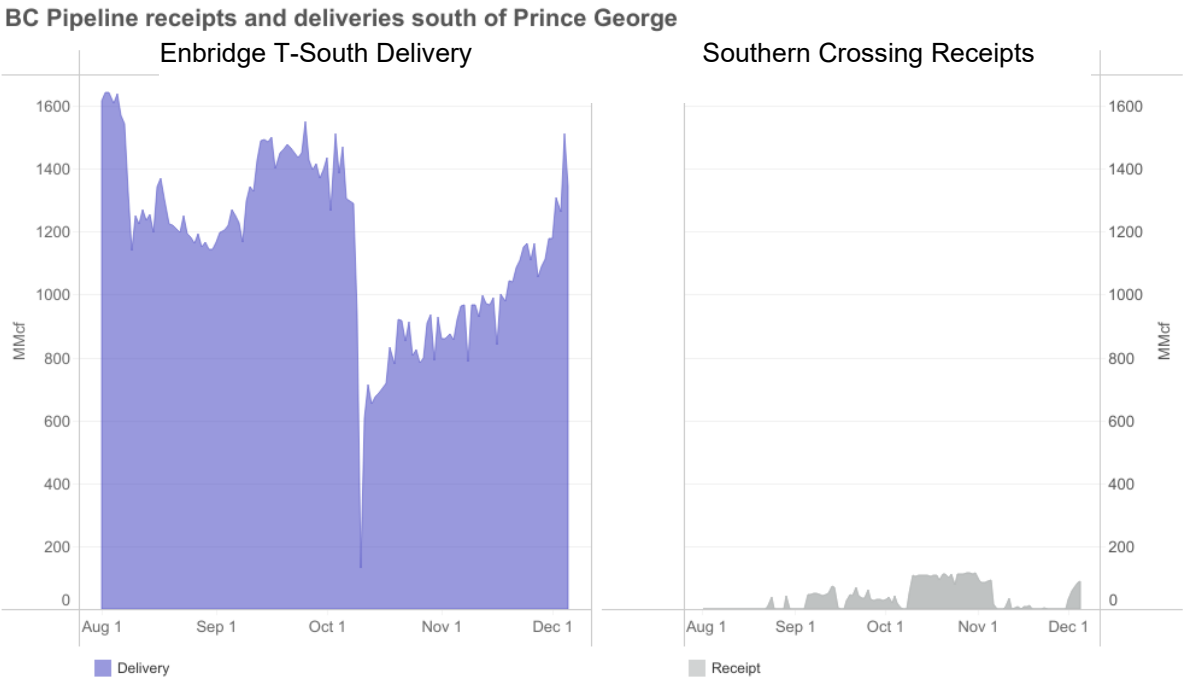
Figure 7. Map of Enbridge BC Pipeline System



The Enbridge system delivers approximately [redacted] of FEI's natural gas needs and the disruption caused a significant disruption of natural gas deliveries. Following the explosion on the T-South pipeline, natural gas deliveries fell 90% from 1.29 billion cubic feet (Bcf) on Oct. 8 to 129 million cubic feet (MMcf) on Oct. 10, as shown below on the left hand side of ***Figure 8***.

Figure 8. BC Pipeline Receipts and Deliveries South of Prince George

(August 2018 – December 2018)



To compensate for the loss of gas from the BC pipeline, FEI sourced and moved more natural gas along its Southern Crossing Pipeline. Gas flows on Southern Crossing approximately doubled (as shown on the right hand side of ***Figure 8***), however, the volumes were too small to replace the significant loss in natural gas supplies following the rupture.

The Southern Crossing pipeline carries natural gas into southern British Columbia from Nova Gas Transmission Limited's (NGTL) Alberta System and can transport about 100MMcf per day of natural gas that can move onto the Enbridge BC system at Kingsvale. Along with utilizing the Southern Crossing pipeline, FortisBC dispatched trucks carrying compressed natural gas into the Lower Mainland during December.[13]

1.6. Delivering Resiliency for an "End of Pipe" LDC

Throughout the natural gas value chain, from production to distribution, resiliency is enabled by the physical characteristics of the natural gas delivery system. The North American natural gas energy delivery system, taken as a whole, is highly resilient, but that is not necessarily the case for particular LDCs within it.

Several factors contribute to North America's system resilience. The natural gas transportation network is composed of an extensive network of interconnected pipelines that offer multiple pathways for rerouting deliveries in the unlikely event of a physical disruption. In addition, pipeline capacity is often increased by installing two or more parallel pipelines in the same right-of-way (called pipeline loops), making it possible to shut off one loop while keeping the other in service. In the event of one or more compressor failures, natural gas pipelines can usually continue to operate at pressures necessary to maintain deliveries to

[13] https://energi.media/british-columbia/neb-impacts-of-enbridges-bc-pipeline-rupture-on-natural-gas-flows/

pipeline customers, at least outside the affected segment. Line pack in the pipelines can be used, if necessary, to provide operational flexibility, typically during the day. As noted above, because of the inherent characteristics of natural gas and the interconnected pipeline system, operators can control and redirect the flow around an outage in one segment. The existence of geographically dispersed production and storage, and its location on different parts of the pipeline and distribution system, also provides flexibility for operators to maintain service in the event of a disruption on parts of the transportation and distribution system.

While the overall resiliency of the North American natural gas system is quite strong, resiliency poses certain unique challenges for a gas LDC. The ability to leverage the natural gas network of interconnected pipelines is largely a function of two factors:

1. The availability of uncontracted capacity on upstream pipelines and storage
2. The physical location of the LDC service territory in relation to the pipelines and storage facilities

Some LDCs are located where access to greater connectivity can be established, such as those that are located in the middle of network systems. Redundancy can more easily be arranged through commercial terms in these situations. However, for LDCs characterized as “end-of-pipe” utilities, there are often greater challenges associated with achieving multiple connections and access to physical resiliency. In these cases, where resiliency is identified as an issue, investments must be made to both enhance connectivity where possible and develop on-system storage options.

On-system storage and expanded pipeline access are not mutually exclusive but are complementary. New pipelines are typically viewed as an effective asset to manage long duration supply issues, increase diversity of supply and strengthen system resiliency. This is because having multiple supply and transportation options provides a natural gas utility with more inherent system resiliency than a natural gas utility that relies on a single pipeline for the majority of its supply. Targeted on-system investments, such as on-system storage, help create system flexibility within the LDC, and aid in improving redundancy and resiliency when upstream pipeline infrastructure is not available. On-system storage is seen as a more effective asset for managing shorter-duration supply issues. For these reasons, gas LDCs often utilize on-system assets to establish resiliency, including LNG/CNG storage tanks and mobile solutions.

1.7. Complementary Energy Systems

FortisBC operates over 50,000 kilometres of natural gas transmission and distribution pipelines in British Columbia. BC’s electricity system is comprised of over 86,000 kilometres of electric transmission and distribution lines, administered primarily by BC Hydro, and FortisBC. Combined, these two systems make up a complementary energy system that is able to meet demand throughout the year for over 1 million natural gas and 2 million electricity customers.

Electricity meets approximately 20% of total BC end use energy demand and is used to power end-uses in all sectors. Natural gas meets approximately 33% of BC end use demand and plays an important role in maintaining the resiliency of the overall energy system by fuelling the majority of space and water heating in the province.[14] The ability of natural gas to be stored and delivered when needed enables natural gas utilities to respond to large swings in energy demand, particularly in the cold winter months. If the electricity system were to

[14] *Guidehouse – Energy Vision 2050, Canada Energy Regulator – Canada’s Energy Future 2019*

meet this space and water heating demand, otherwise met by natural gas, on the coldest day of the winter, it is estimated that 18,000 MW of incremental generation, transmission and distribution capacity would be required. This represents a 60% increase to the current peak electricity load.[15] This highlights the importance of both systems and their complementarity as a unified energy system in BC.

1.8. Industry Examples of the Need for Resiliency

In this section, Guidehouse summarizes its review of infrastructure investments pursued by utilities and regulators in response to concerns about system resiliency and reliability.

1. New Jersey Natural Gas has gained approval to invest in multiple infrastructure projects, including pipelines, system reinforcement and liquefaction and storage facilities, in response to supply shortages due to significant adverse weather conditions in recent years.
2. Dominion Energy Utah has gained approval for an LNG facility designed to mitigate supply disruptions due to expected weather impacts in coming years.

Both case studies include overviews of the significant regulatory processes that the utilities participated in, as well as summaries for the justification for the type of facility and characteristics needed.

Summary of Resilience Measures in New Jersey in Response to Hurricane Sandy and other Extreme Weather Events

Overview

New Jersey Natural Gas (NJNG) gained regulatory approval for multiple infrastructure projects designed to improve the resiliency of the state's natural gas system. These infrastructure improvements were originally proposed to cost $102.5 million and include:

- The PennEast Pipeline Project (PennEast)
- New Jersey Reinvestment in System Enhancement (NJ RISE)
- Liquefaction Project
- Southern Reliability Link (SRL)

The primary reason for the aforementioned infrastructure projects were five major storms that hit New Jersey in 2011 and 2012:

- Hurricane Irene – August 2011
- A powerful snowstorm – October 2011
- A derecho windstorm – June 2012
- Superstorm Sandy – October 2012
- A nor'easter (storm along the East coast of North America) – November 2012

These storms caused major issues for energy supply in the state, leading the New Jersey Board of Public Utilities (BPU) to start a Storm Mitigation Proceeding to investigate ways for

[15] *Ibid*

New Jersey to protect and support its utility infrastructure to better-withstand extreme events in the future.[16]

A summary of the regulatory process, and the resiliency and reliability benefits of each of these projects is provided in the following sections.

PennEast Pipeline Project

In response to major weather events, New Jersey Natural Gas (NJNG) identified the need to increase the number of natural gas supply points for the state's natural gas system. The PennEast Pipeline project is a proposed 115-mile (185 km) pipeline from Luzerne County, Pennsylvania to Mercer County, New Jersey.[17] This pipeline is planned to diversify the natural gas supply for New Jersey and help the state restructure its gas supply portfolio.

As part of its original application, the developers identified the purpose and need for the Pipeline, as it provides the following benefits:

1. Additional supply flexibility, diversity and reliability;
2. liquid points for trading in locally produced gas from the Marcellus Shale and the Utica Shale;
3. direct access to premium markets in the northeast and mid-Atlantic regions;
4. the ability to capture pricing differentials between the various interconnected market pipelines;
5. enhanced natural gas transportation system reliability to the region with modern, state-of-the art facilities, and
6. firm access to currently the most affordable long-lived natural gas reserves.

PennEast has faced some adversity in getting regulatory approval in New Jersey. As of early 2020, the project has been held up while developers pursue permits under the National Historic Preservation Act, and the Clean Water Act.[18] This project has met much pushback at the federal level, with dozens of requests for intervention in the FERC proceeding.[19]

New Jersey Reinvestment in System Enhancement (NJ RISE)

NJ RISE represents a five-year infrastructure initiative by NJNG to invest over $100 million in storm hardening and mitigation projects, in order to increase the state natural gas system's resilience to extreme weather events. These projects include:[20]

- Sea Bright Reinforcement, North Seaside Reinforcement, South Seaside Reinforcement and Long Beach Island Reinforcement – these projects include the installation of approximately 27,500 feet of secondary distribution mains in New Jersey
- Ship Bottom Station Reinforcement – reconstruction of a distribution regulatory station

[16] https://www.bpu.state.nj.us/bpu/pdf/announcements/2014/OrderGrantingParticipationNJRISE.pdf
[17] http://files.dep.state.pa.us/ProgramIntegration/PA%20Pipeline%20Portal/PennEast/December2018/E13-185%20-%20Carbon%20County/L_Environmental%20Assessment/L-1_Module%201_Project%20Summary/L1_Module%201_Carbon_2018_12_19.pdf
[18] https://www.lehighvalleylive.com/news/2020/01/stymied-in-nj-penneast-proposes-building-gas-pipeline-only-into-lehigh-valley-for-now.html
[19] FERC Docket # CP20-47
[20] https://www.njng.com/about/january-2017-NJ-RISE-update.aspx

- Installation of Excess Flow Valves in Storm Affected Areas – installation of approximately 30,000 excess flow valves in coastal communities

NJ RISE was approved by the BPU in 2014, and many of the aforementioned projects are underway or completed. As part of the application process, NJNG had to demonstrate that "NJ RISE will improve the durability, redundancy, stability and integrity of NJNG's gas distribution infrastructure, making it better able to withstand the impacts of major storm events, avoiding customer outages and enabling a faster response to customer outages that may occur."[21] NJNG also provided witness testimony in its application for the program and responded to comments from intervenors.

Liquefaction Project

NJNG completed a Liquefaction Project in 2016 that allowed the company to convert natural gas to LNG and store the LNG at the company's existing tanks in Howell and Stafford, New Jersey. The project cost $36.5 million and was approved for rate recovery in 2016.[22] The two LNG plants have an aggregate estimated maximum deliverability of approximately 170 MMcf/day and 1 Bcf of total storage.

In 2019, NJNG applied to reconfigure its LNG assets to connect the Howell LNG facility directly to its natural gas transmission system. The stated intention of this project was to enhance system reliability and improve the Howell LNG facility's ability to provide peak-shaving supply and pressure support during periods of high natural gas demand, curtailments of pipelines or downtime due to maintenance and inspection.[23]

Southern Reliability Link (SRL)

The SRL is a planned 30-mile (48 km) pipeline designed to connect the southern part of NJNG's distribution territory to the Texas Eastern Pipeline. The purpose of this project is to increase the redundancy, reliability and resiliency of NJNG's natural gas system.[24]

The BPU and NJNG carried out a thorough regulatory review process for the project, which included multiple public hearings, technical conferences and open houses. The public voiced opposition to the project related to the safety and proximity of the pipeline to homes. Organizations also voiced opposition to the project stating that NJNG did not provide enough justification for the pipeline, and that ecological disruptions were not thoroughly investigated. Some members of the public voiced their support of the project, including a local labour union. In addition to commentary received at the various public forums, the BPU received over 1,000 written comments from the public.

NJNG defended the project, and highlighted that, at the time, greater than 85% of NJNG's supply came from a single pipeline. The BPU ultimately approved the project with a number of stipulations intended to address concerns raised throughout the regulatory process by the BPU and by the public.[25]

[21] https://www.njng.com/regulatory/pdf/gr13090828-njng-nj-rise-filing-9-3-2013.pdf
[22] http://investor.njresources.com/static-files/14a4896d-872a-45b1-9899-9d676093172a
[23] https://www.njng.com/regulatory/pdf/NJNG%20IIP%20Petition.pdf
[24] https://www.njng.com/about/southern-reliability-link/
[25] https://www.bpu.state.nj.us/bpu/pdf/boardorders/2016/20160127/1-27-16-6B.pdf

Dominion Energy Utah for Approval of a Voluntary Resource Decision to Construct a Liquefied Natural Gas ("LNG") Facility[26]

Overview

Dominion was approved to build an LNG facility in Utah to maintain service in cases of supply disruptions. The LNG storage facility is planned to be built on Dominion's system near its demand centre along the Wasatch Front. This project is planned to include an LNG facility with liquefaction/ vaporization capabilities. This facility is designed to provide up to 150 million cubic feet (MMcf)/day of deliverability. The project costs are redacted from public documents, but Dominion estimated the LNG facility will result in an annual bill impact for customers of $18.44 or 2.97%[27].

Dominion carried out an open request for proposals (RFP) process for alternatives to the LNG facility. Although much of the information on the alternatives is redacted, a high-level overview of the alternative projects and submitting organizations is below:[28]

- Magnum Energy Midstream – Proposal was related to Salt Cavern storage
  - Dominion's justification for not selecting this project was that, although salt cavern storage is a proven reliable method of storing natural gas, Magnum is not currently serving any natural gas storage customers, so its reliability is unknown.
- Prometheus Energy
  - Documents were highly redacted and did not indicate what this project was. Dominion ruled out this project due to cost
- United Energy Partners
  - Dominion ruled out this option because the service provided by the facility would be subject to all of the risks associated with delivery on a long-distance interstate pipeline, including landslides, flooding, earthquakes, human error, upstream facility design inadequacies and maintenance, attacks, and third-party damage.

The Dominion-owned LNG facility was the chosen option by Dominion. Dominion carried out a historical shortfall analysis to determine the required size of its facility. The company showed that it had recently met a shortfall of 100 MMcf/day. Due to growing demand in the region, Dominion determined that 150 MMcf/day for eight days of services (totalling 1.2 Bcf) was required. An expert witness testifying on behalf of the Division of Public Utilities agreed with Dominion's recommendation and found its analysis reasonable.[29]

Original Application and Dominion Testimony[30]

Five individuals from Dominion and one individual from a consulting engineering firm provided testimony in support of the LNG project, summarized below:

[26] https://psc.utah.gov/2019/04/17/docket-no-19-057-13/
[27] https://pscdocs.utah.gov/gas/19docs/1905713/307951RedactAppVIntryReqforApprvlRsrcDec4-30-2019.pdf
[28] https://pscdocs.utah.gov/gas/19docs/1905713/308009RedactDirTestSchwarzenbachDEU4-30-2019.pdf
[29] https://pscdocs.utah.gov/gas/19docs/1905713/308009RedactDirTestSchwarzenbachDEU4-30-2019.pdf
[30] https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9790072

- The need for the project was highlighted by discussing examples in other jurisdictions where extreme weather has led to service disruptions for many customers (e.g. Arizona and New Mexico 2011)[31]
- The RFP process was summarized, and each of the projects were discussed including the reason for exclusion (typically on cost or inherent risk of projects)[32]
- A detailed summary of the weather events that would cause a service disruption was provided. Specifically, an expert witness stated that a major disruption would occur if the temperature reached 3 degrees Fahrenheit or lower in Salt Lake. This is expected to happen every 16 years. Temperatures get colder more often in other regions in jurisdiction
- A summary of the impacts of service disruption[33]
    - 130k to 650k customers without service
    - Up to 51 days of disruption
    - Between $10,450,000 and $104,600,000 to fix

Summary Intervenor Testimony

The commission received a significant amount of testimony from intervenors refuting aspects of the process. At a high level, the following issues were raised by intervenors:

- The RFP Process was not robust, and favoured Dominion
- The support for the "need" for the project was disputed
- The cost of the project relative to the risk was not supported

Dominion Response and Final Order

Dominion has had to rebut all of these claims in six subsequent testimonies. Following this rebuttal, the commission approved the application under the following requirements:[34]

- The facility must be designated a materially strategic resource, which includes legal covenants governing the sale of the asset.
- Any increase to approved costs must be brought before the commission for approval.

2. FEI Distribution System and Resiliency

This section summarizes how the resiliency of FEI's distribution system is affected by the characteristics of the natural gas value chain, including ability to achieve diversity of supply and transportation/storage capacity via existing infrastructure, midstream pipeline capacity and availability of storage (both off-system and on-system) and the composition of the load/customer base.

The resiliency of the FEI distribution system is highly dependent on several factors, including:

1. The sources of natural gas supply that serve the province and the FEI system.
2. The natural gas pipeline and storage infrastructure serving the region.
3. The physical layout of the FEI distribution system.
4. The amount and location of FEI's on-system storage.
5. The profile of FEI's customers' demand, especially the seasonality of demand.

[31] https://pscdocs.utah.gov/gas/19docs/1905713/307989DirTestFaustDEU4-30-2019.pdf
[32] https://pscdocs.utah.gov/gas/19docs/1905713/308009RedactDirTestSchwarzenbachDEU4-30-2019.pdf
[33] https://pscdocs.utah.gov/gas/19docs/1905713/308015RedactDirTestPlattDEU4-30-2019.pdf
[34] https://pscdocs.utah.gov/gas/19docs/1905713/3104961905713o10-25-2019.pdf

In this section, Guidehouse has found that:

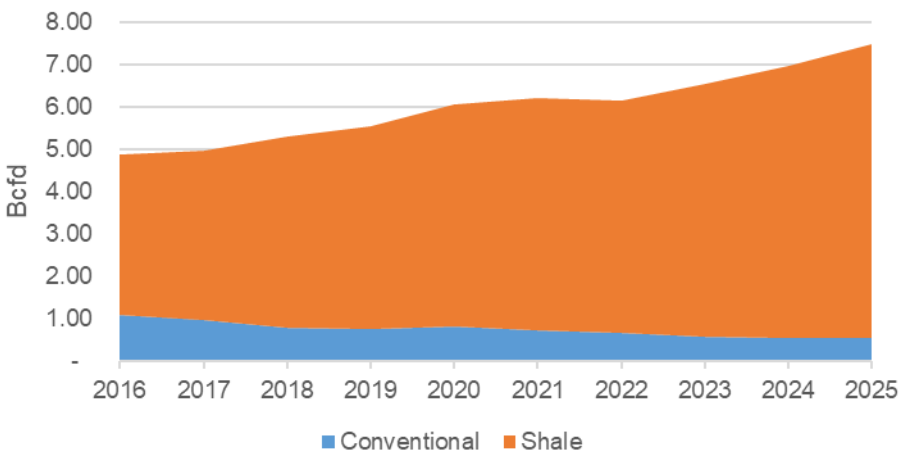
1. BC has significant natural gas resources, especially since the growth of shale gas.
2. BC's pipeline infrastructure covers long distances and connects supply resources in the North, and in Alberta, to load centres throughout the province.
3. FEI is critically dependent on the existing transportation and storage infrastructure in BC, especially the Enbridge BC pipeline, and the province of BC has a relatively low amount of interconnectedness compared to other regions of North America.
4. Pipeline utilzation in the Pacific Northwest has reached 100% in recent years, resulting in large gas price spikes. Demand growth is expected to increase, putting further pressure on regional infrastructure.
5. There is limited on-system storage in the FEI service territory. The utility has contractual relationships with storage assets in the Pacific Northwest, but has no operational control over these assets.

2.1. BC Sources of Supply

British Columbia has multiple sources of natural gas, including conventional and shale, which provide sufficient natural gas for the province and for export. This lowers the amount of supply risk that the province faces from a purely technical availability viewpoint.

British Columbia produces approximately 6 Bcf/day of natural gas per year, accounting for approximately 30% of total Canadian natural gas production, as shown in ***Figure 9*** below.

Figure 9. Forecasted Natural Gas Production in British Columbia (2016-2025) [35]



Natural gas is produced in the north-eastern part of BC, predominantly from the Montney Formation that extends from northeast BC and into Alberta. BC's gas production doubled between 2006 and 2018, primarily in the Montney formation. Other significant gas resources are in the Horn River Basin and Liard Basin.

[35] Guidehouse North American Natural Gas Outlook – Winter 2020

2.2. BC Natural Gas Pipeline Infrastructure

In general, natural gas produced in BC is either:

- delivered to demand centres in BC on pipelines operated by Enbridge's BC Pipeline (also referred to as Westcoast), FortisBC, or Pacific Northern Gas (PNG); as shown in ***Figure 10***;
- or exported eastwards towards Alberta and beyond on TC Energy's (formerly TransCanada) Nova Gas Transmission Limited (NGTL) System or Alliance Pipeline;
- or exported to the south and beyond to the U.S. Pacific Northwest at Huntingdon, where Enbridge's BC Pipeline connects with Williams' Northwest Pipeline, or at Kingsgate where the Foothills pipeline connects with Gas Transmission Northwest (GTN). Gas produced in BC may also be exported to the U.S. Midwest through Alberta and beyond via Alliance Pipeline or the NGTL System, as shown in ***Figure 11***

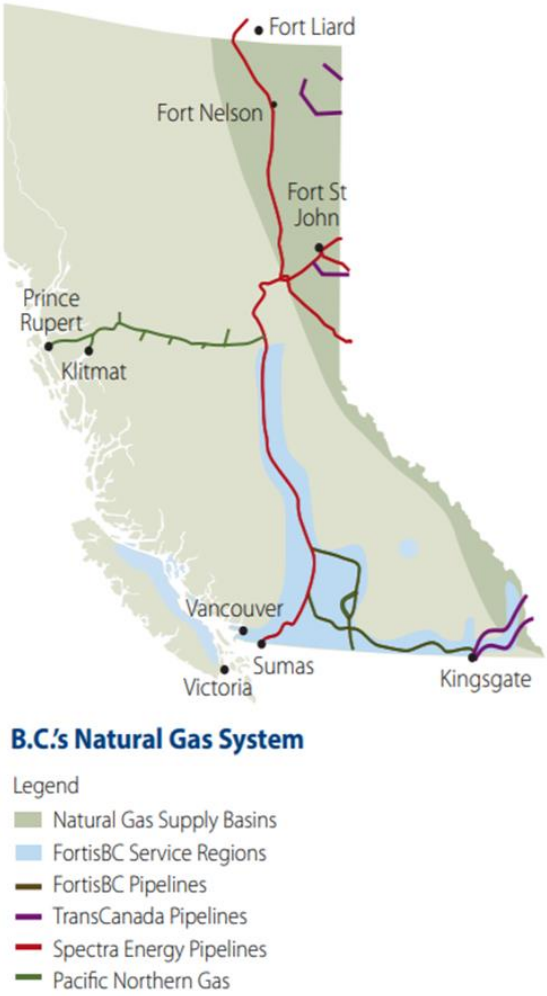
Figure 10. British Columbia Natural Gas Infrastructure

The primary natural gas pipeline in BC is the Enbridge BC Pipeline. This 2,858 kilometre (1,776 miles) long pipeline commences in Fort Nelson, in northeast BC and from Gordondale near the BC - Alberta border, south to the Canada - United States border at Huntingdon/Sumas.

The BC Pipeline can move 2.9 billion cubic feet of natural gas a day (Bcf/day).[36] The northern section of the BC Pipeline (Transmission North, or T-North) is designed to move gas production sourced from third-party processing plants in the Western Canadian Sedimentary Basin, Montney and Horn River resource areas.

The southern section of the BC Pipeline (Transmission South, or T-South) delivers gas supply from the T-North system to downstream markets within BC, including FEI, and the U.S. Pacific Northwest.

The BC Pipeline transports about 55% of the natural gas produced in British Columbia. It serves markets throughout BC and the Lower Mainland, and it supplies about 50% of natural gas demand in the U.S. states of Washington, Oregon and Idaho via a 1.3 Bcf/day interconnect at the Huntington/Sumas border-crossing point. From there, the gas is delivered into Williams's Northwest Pipeline (NWPL), which then flows to local distribution companies, gas-fired power generation plants and gas storage facilities, as well as to petroleum refineries, primarily in Washington state but also some in Oregon



[36] https://www.enbridge.com/~/media/Enb/Documents/Factsheets/BC%20Pipeline%20Factsheet.pdf?la=en

and Idaho. Outside of high seasonal demand in the winter, gas produced in BC can flow further south in the summertime.

The Pacific Northern Gas pipeline serves customers of Pacific Northern Gas in west-central British Columbia.

The FortisBC Pipeline (Southern Crossing) delivers natural gas from Alberta via an interconnection with TC Energy's NGTL system near Kingsgate. The 312-kilometer line extends from Yahk in the East Kootenay and Oliver in the South Okanagan. Compared to the Enbridge BC Pipeline, the Southern Crossing pipeline has a capacity of 0.285 Bcf/day into southern BC from TC Energy's NGTL Alberta System and can transport about 100 MMcf/day of natural gas westbound onto the WEI system at Kingsvale.

2.3. Regional Natural Gas Distribution

There are two natural gas distribution utilities in BC. Pacific Northern Gas (PNG) and FortisBC. PNG serves approximately 42,000 customers in the corridor between Summit Lake and Prince Rupert, and in the Fort St. John and Dawson Creek area. FortisBC distributes gas to approximately 1.2 million customers in 135 communities on over 2,800 km of pipelines. FortisBC and PNG are regulated by the British Columbia Utilities Commission (BCUC).

Figure 11. Map of NW Canada and US PNW Natural Gas Infrastructure

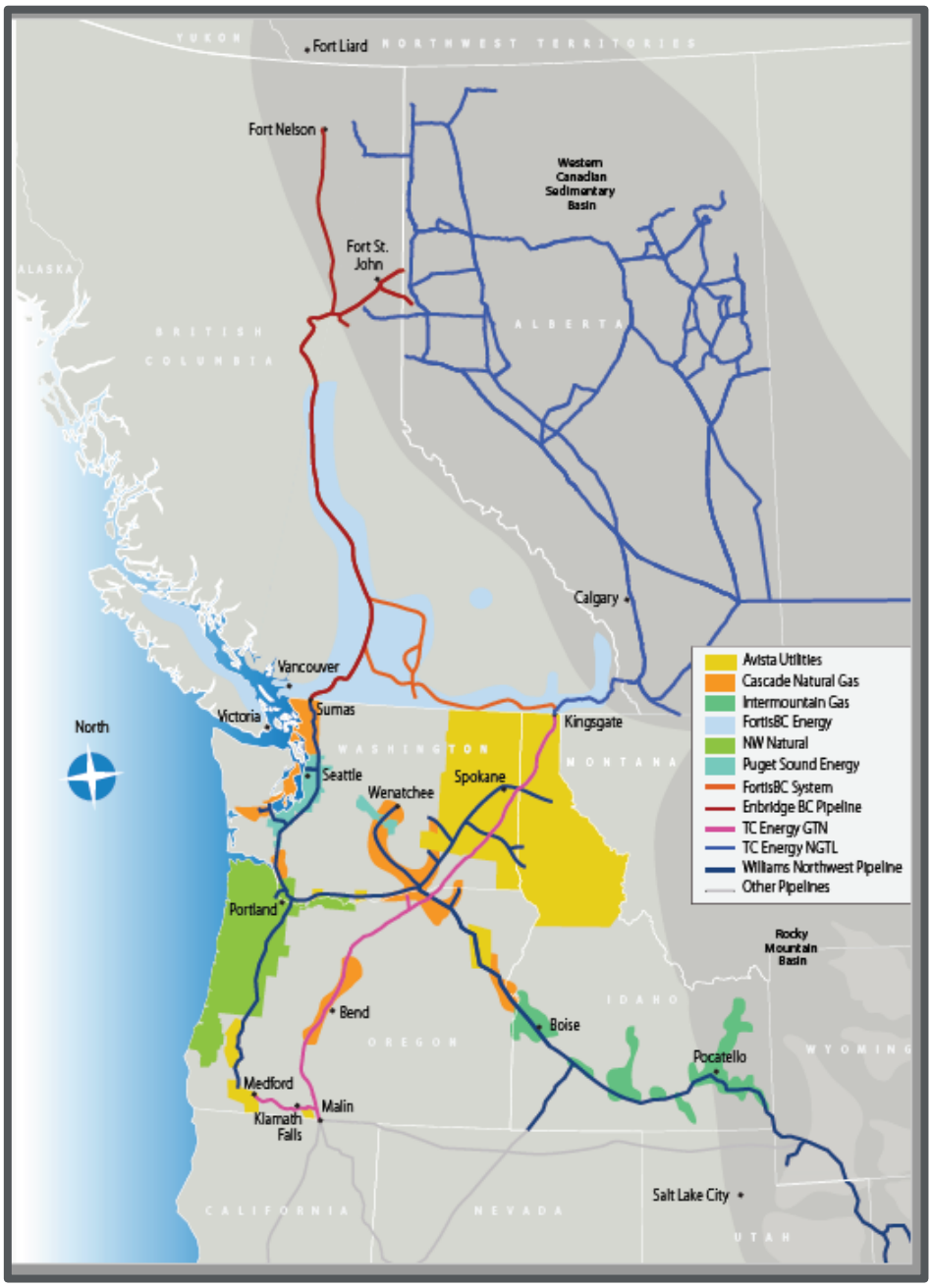


Figure 12 below shows the 2-year historical, and 1-year forecast, pipeline capacity utilization in the Pacific Northwest. Pipeline utilization reached 100% in January 2017. The higher the pipeline utilization rate, the less able the system is to respond to unplanned outages. The high pipeline utilization in the PNW is one of the factors that led to the Sumas trading point

between Canada and Washington experiencing the highest natural gas spot prices of anywhere in the US in the prior five years, at $161.33 per MMBtu (USD) in March of 2019.[37] This utilization is tied to weather along the I-5 corridor.

Figure 12. B.C. and U.S. Pacific Northwest Regional Pipeline Capacity Utilization

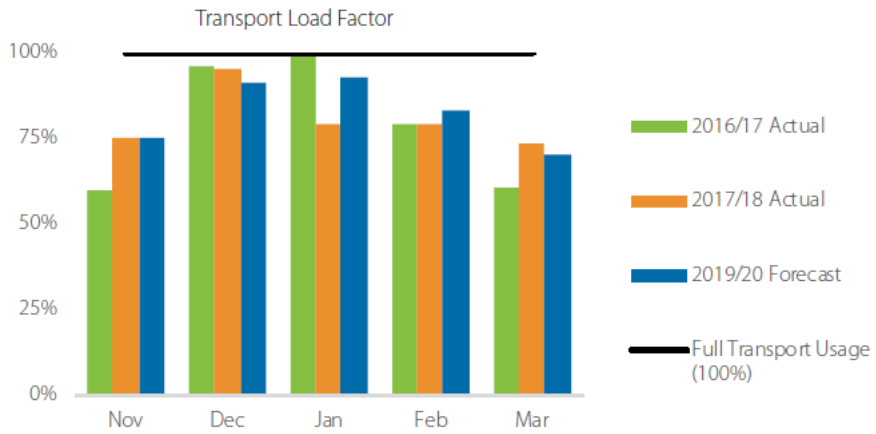


Figure 13 below shows the natural gas supply and demand balance in B.C and the U.S. Pacific Northwest. Pipeline capacity is high enough to meet demand for an average day in January, throughout most of the forecast. Both underground storage and peak LNG are required to meet peak day demand. In the later years of the forecast, the supply-side resources are insufficient to meet peak day demand for the region.

Figure 13. Peak and Average Day Supply/Demand Balance[38]

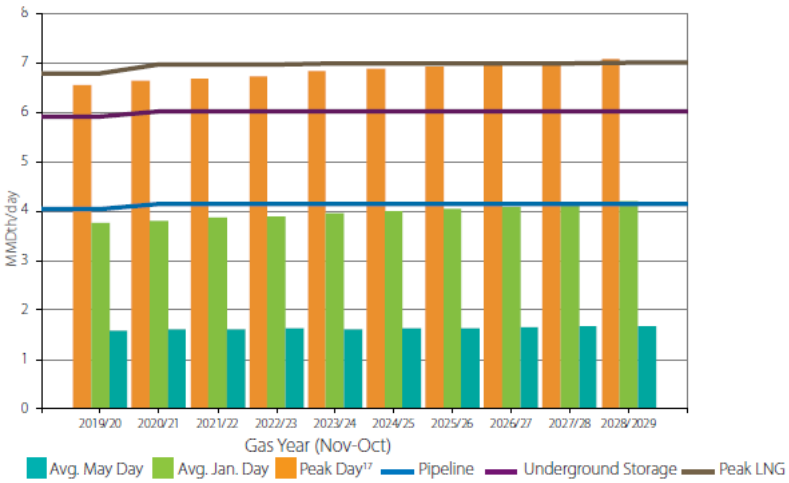


Figure 14 below illustrates the supply/demand balance for the FEI Annual Contracting Plan that services Rate Schedules 1 to 7 (Core rates). For the 2021/22-year, average winter day demand is approximately 2.7 times greater than the average summer day, which demonstrates the seasonality of core demand. Moreover, pipeline capacity serves about 70% of the peak demand, while market area storage and on-system LNG serve about 30% of the peak. This showcases the importance of underground market-based storage and LNG on-system storage to serve peak demand.

[37] https://www.eia.gov/todayinenergy/detail.php?id=38932
[38] 2020 Pacific Northwest Gas Market Outlook, NWGA

Figure 14. FEI Peak and Average Day Supply Demand Balance

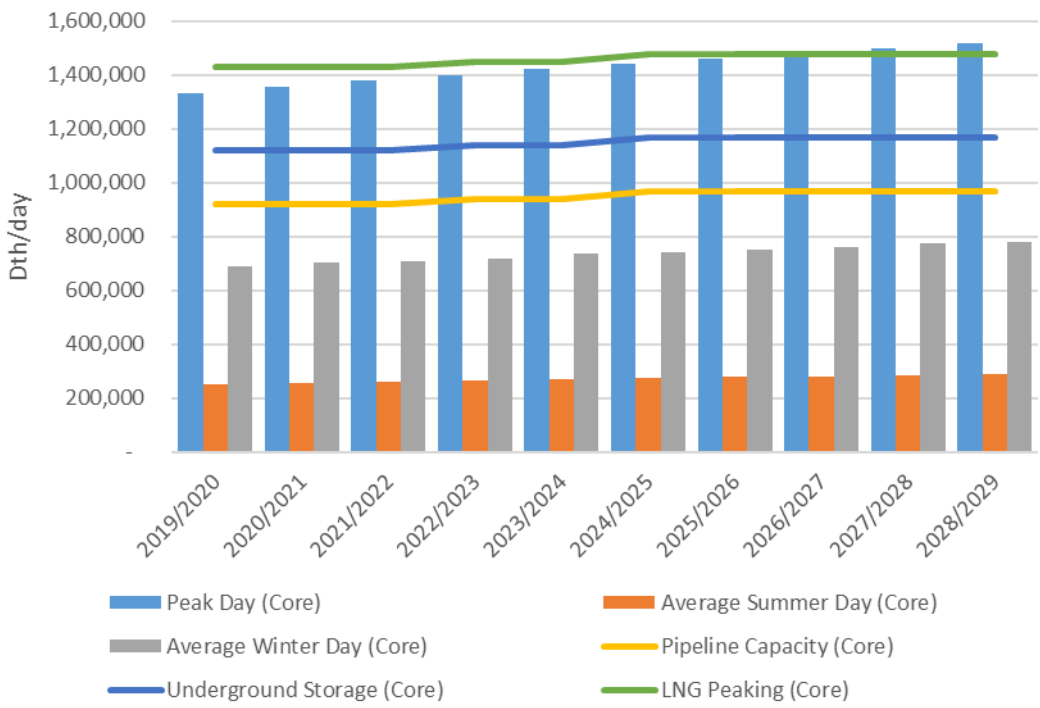
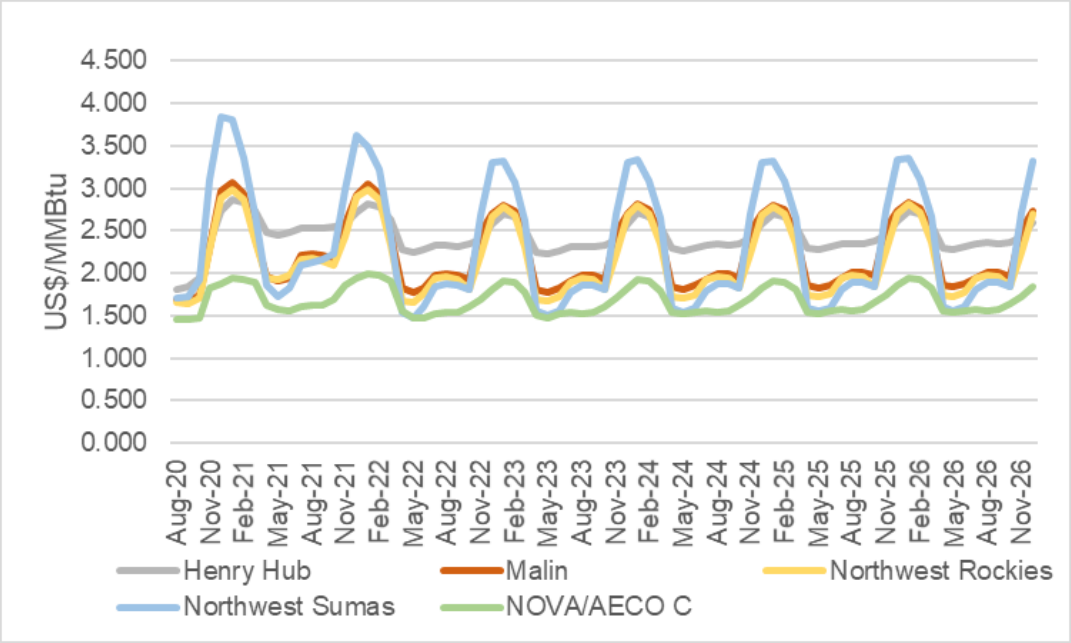


Figure 15 below shows the regional natural gas forward prices at the major trading hubs where BC and the U.S. Pacific Northwest source natural gas - AECO and Sumas for natural gas originating in Alberta and British Columbia, and Northwest Rockies for gas produced in the U.S. Rocky Mountain states of Colorado, Utah and Wyoming. Northwest Sumas is the trading hub for deliveries into Northwest Pipeline from the BC Enbridge pipeline at the Sumas, Wash./Huntington, British Columbia, interconnection at the US/Canadian border. AECO represents the trading hub production in Alberta. Malin is the trading hub located at the California Oregon border. The Henry Hub is a trading hub in Louisiana and represents the North American benchmark prices.

The price of natural gas coming from the supply areas upon which the Pacific Northwest relies is typically lower than the North American benchmark at the Henry Hub. Of note, however, is that winter prices at Northwest Sumas are considerably higher than regional prices. High prices typically reflect limited supply and/or heightened demand. In this example, supply is abundant in the region, but regional infrastructure constraints are resulting in higher winter prices at Northwest Sumas, compared to other regional hubs. This reflects the high utilization of the infrastructure in the region to meet winter demand.

Figure 15. Regional Natural Gas Forward Prices



2.4. Regional Gas Storage Infrastructure

As mentioned in Section 1.2, natural gas storage plays a vital role in ensuring resiliency across the regional natural gas system and for FEI.

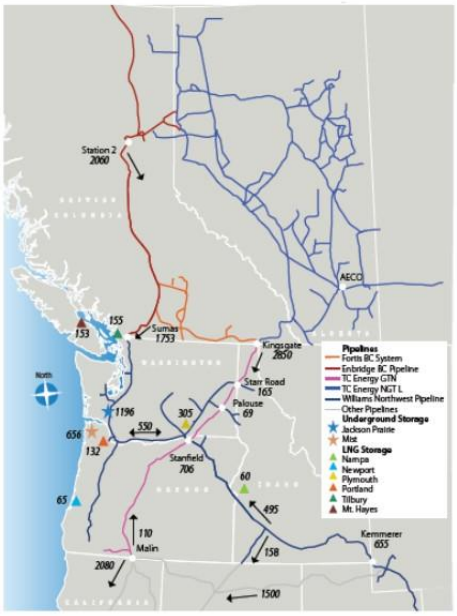
Underground natural gas storage facilities in Canada are located in five provinces: Alberta, BC, Ontario, Quebec, and Saskatchewan. The combined capacity of all underground storage facilities in Canada is 949 Bcf. The majority of this capacity (548 Bcf) is located in Alberta, followed by Ontario with 248 Bcf. BC has the single largest facility, the FortisBC Aitken Creek facility in Fort St. John, with 95 Bcf.

FEI utilizes underground natural gas storage in Alberta and the Aitken Creek facility but requires pipeline capacity to move the gas to FEI city gates. In addition to these facilities, there are two underground storage facilities in the United States (Jackson Prairie in Washington and Mist in Oregon) that can serve BC by displacement.[39] There are also nine above ground LNG storage, i.e., peak storage, facilities in the region, including two in BC, Tilbury and Mt. Hayes, as shown in ***Figure 16*** below.

[39] In this instance, gas stored in Jackson Prairie and Mist is not physically delivered to FEI's system. Rather, the contractual arrangement allows for gas stored in these two assets to displace load in the PNW, so an equivalent level of gas can be imported from the NWPL.

Figure 16. Regional Natural Gas Storage Infrastructure

Regional Natural Gas Infrastructure and Capacities (MDth/day)



Regional Storage Facilities

Facility	Owner	Type	Capacity+ (MDth)	Max Withdrawal ++(MDth/day)
Jackson Prairie, WA	Avista, PSE, NW Pipeline	Underground	25,448	1,196
Mist, OR+++	NW Natural	Underground*	19,172	656
	Underground Subtotal		**44,620**	**1,852**
Plymouth, WA	NW Pipeline	Peak (LNG)	2,388	305
Tilbury, BC	FortisBC Energy	Peak (LNG)	1,634	155
Mt. Hayes, BC	FortisBC Energy	Peak (LNG)	1,530	153
Portland, OR	NW Natural	Peak (LNG)	504	132
Newport, OR	NW Natural	Peak (LNG)	980	65
Nampa, ID	Intermountain Gas	Peak (LNG)	588	60
Tacoma LNG	PSE	Peak (LNG)**	538	85
Swarr Station	PSE	Peak (LPG)***	128	30
Gig Harbor, WA	PSE	Peak (LNG)	16	3
	Peak Storage Subtotal		**8,306**	**988**
TOTAL STORAGE			**52,926**	**2,840**

\+ Working gas capacity; gas that can be used to serve the market.
++ Start of season or full rate; underground storage withdrawal rates decline as working gas volumes decline.
+++ Mist capacity and deliverability include the North Mist Expansion in service May 2019.
** Tacoma LNG will come into partial service in 2021, full service by 2023.
*** LPG: Liquid Propane Gas and Air mixture. Offline for upgrades. Returns to service in 2023.

NOTES: Storage facilities are an essential component of the region's delivery system, providing flexibility to serve demand when the weather gets cold. For shorter duration events, underground storage is a more cost-effective solution than building pipelines to serve seasonal, cold weather loads. Above ground storage, usually LNG, is designed to serve the last measure of demand on the very coldest days of the year.

[16]The source of all charts and tables in this section is NWGA.

2.5. Implications for FEI

The resiliency of the FEI distribution is highly dependent on five critical factors, including

1. The sources of natural gas supply that serve the province and the FEI system
2. The natural gas pipeline and storage infrastructure serving the region
3. The physical layout of the FEI distribution system
4. The amount and location of FEI on-system storage
5. The profile of FEI's customers' demand, especially the seasonality of demand

Due to the location of its service territory, serving the major population centres in the southern portion of BC, FEI is critically dependent on the regional pipeline infrastructure for natural gas supply. This dependence translates to heavy reliance on the Enbridge BC system. Unlike the broader natural gas delivery system in North America that is extremely resilient due to the interconnectivity of multiple natural gas pipelines and storage, the FEI distribution system lacks the benefit of interconnections with multiple pipelines to its city gate stations. For this reason, the FEI distribution system is not characterized by the same level of resiliency as the broader North American natural gas system, due primarily to its reliance on the single pipeline Enbridge BC system for the majority of its access to BC natural gas production. In addition, FEI does not have the benefit of connecting to other pipeline infrastructure to connect other sources of supply in the region to the FEI service territory. As discussed in Section 1.4, capacity utilization is an important factor in determining economic feasibility of new pipelines or expansions. One explanation for why the region has limited

pipeline infrastructure is that, without placing additional emphasis on resiliency, there is not sufficient load factor[40] to justify the economics of additional pipelines.

To compound the situation, demand growth in the Pacific Northwest is among the fastest in the US, due primarily to migration into the region to serve the growing technology industry.[41] The demand growth in these states could lead to regional impacts to the BC system, as FEI is currently dependent on downstream storage in Washington State (Jackson Prairie) and Oregon (Mist). This, when combined with high capacity utilization in the region during periods of peak demand, is likely to result in a growing risk of not being able to respond to a supply interruption in BC.

The lack of diversity of upstream pipeline options for supply poses a risk to the resiliency of the FEI distribution system. In addition to this strong reliance on a single natural gas transmission pipeline for the majority of its gas supply, the FEI system is also dependent on the Enbridge BC pipeline for access to the Aitken Creek underground storage facility in Fort St. John, BC and the underground storage facilities in Alberta. In addition, FEI is dependent on the Northwest Pipeline (NWPL) for access to the Jackson Prairie and Mist storage facilities, which contractually provides gas to FEI via displacement. As shown in ***Figure 16***, this reliance on pipelines where FEI does not have operational control means that the resiliency of the FEI system is highly dependent on the on the operating conditions of pipeline and natural gas utilities that are beyond the control of FEI.

Operating conditions on both the Enbridge BC Pipeline and NWPL systems can limit the ability of FEI to access supply and balancing accounts on the Enbridge BC pipeline system, as well as limit FEI's access to storage from the Jackson Prairie and Mist storage facilities. In addition, FEI does not have renewal rights with NW Natural Gas, the owner and operator of the Mist storage facility. This poses a risk for FEI, as their contract with the storage facility may not be renewed. Reliance on the Enbridge BC pipeline places the FEI system at the risk of a failure on the Enbridge system, as evidenced by the October 2018 incident.

3. Evaluation of On-System Storage and Alternatives

In the case of FEI, to what extent is on-system storage either an alternative to, or complementary to, other resiliency measures such as midstream pipeline infrastructure, off-system storage, or interruptible service and or other demand control measures?

In evaluating on-system storage and its alternatives, Guidehouse has found that:

1. On-system storage is a primary asset that can help FEI respond to short-term supply disruptions.
2. Alternatives, including line pack, third party contractual arrangements and industrial curtailment have limitations in terms of responsiveness to short-term supply disruptions relative to on-system storage.
3. Storage assets are efficient for short duration supply disruptions and peak shaving applications, while pipelines are more efficient for longer deliverability applications.
4. On-system storage and pipelines are complimentary assets.

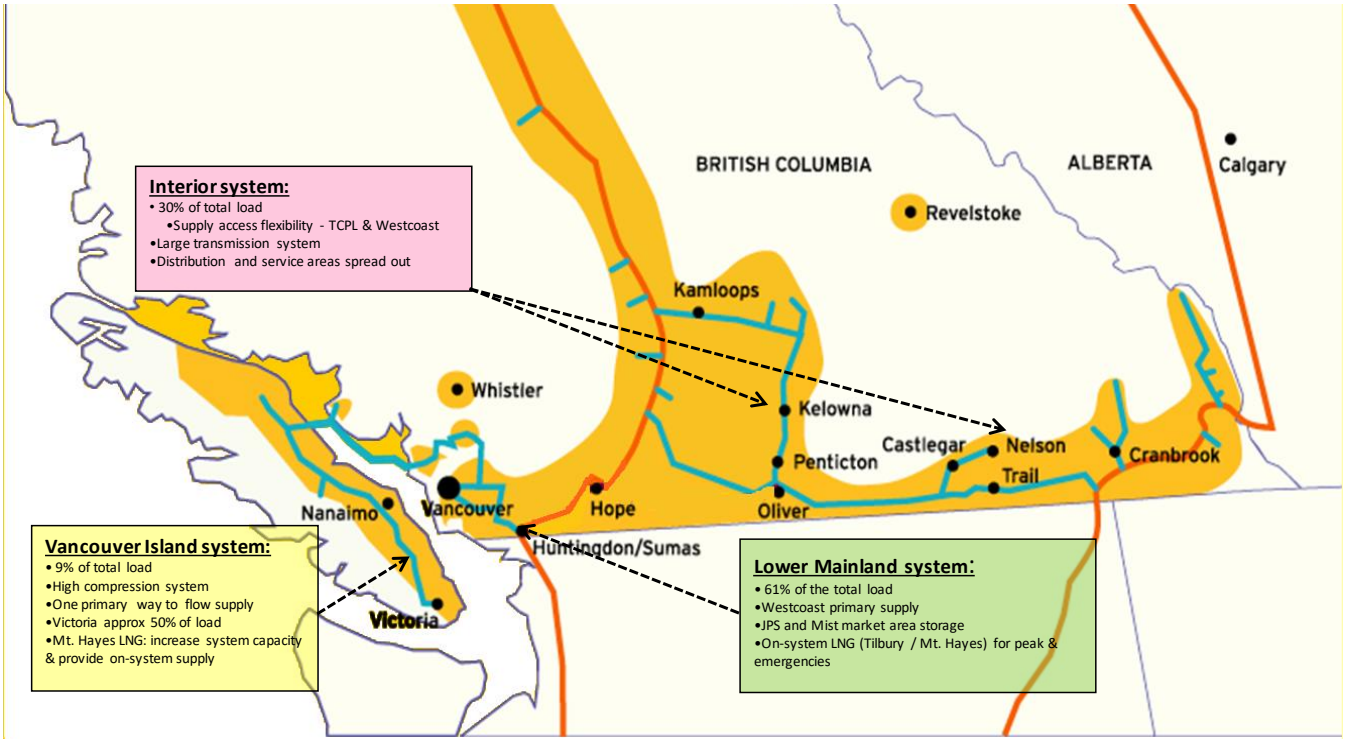
[40] Load factor: The ratio of average load to peak load during a specific period of time, expressed as a percent. It indicates the average utilization of a pipeline system relative to total system capacity.
[41] 2020 Pacific Northwest Gas Market Outlook, NWGA

3.1. Overview of the FEI Distribution System

FEI serves approximately 1.2 million natural gas customers throughout BC focusing on three geographically diverse sections within the FEI service territory. Guidehouse observes that the FEI distribution system is comprised of multiple, formerly independent systems that were combined to form FortisBC Energy. Each of these systems have their own unique operating characteristics and gas supply receipt points. The FEI systems are described below and shown in ***Figure 17*** below.

1. **Interior system** – This system serves over 278,984 customers and gas supply is provided by several different resources including connections with TransCanada Energy pipeline at East Kootenay Exchange (EKE) and Enbridge BC pipeline at Savona and Kingsvale, with the pipelines at EKE and Kingsvale being bi-directional. Average winter demand is 259TJ/D with a peak demand of 441TJ/D.
2. **Lower Mainland (LML) or Coastal Transmission System** – This system is served solely by the Enbridge BC pipeline at Huntingdon. The LML makes up the largest load centre on the FEI BC system, with roughly 626,726 gas customers with average winter demand of 560TJ/D and peak demand of 1,098 TJ/D. The LML is home to the Tilbury LNG Tank which provides 1-3 days of on-system storage.
3. **Vancouver Island, (VI)** – This system provides service to approximately 130,770 customers. Gas supply is served by gas flowing through the LML system and compressed where the VI pipeline begins. VI could, if necessary, block itself off from the LML system and maintain its gas customers by utilizing the Mt Hayes LNG facility. This facility has vaporization and storage to support the island for roughly 10 days. Average winter demand is 82 TJ/D and peak demand of approximately 160 TJ/D.

Figure 17. Overview of FEI Distribution System



3.2. Consideration of Alternatives to On-System Storage

There are, in theory, several alternatives to serve FEI's resiliency requirements. These include:

- Contracting for additional pipeline and underground storage capacity
- Third-party commercial agreements for transportation and/or storage services
- Utilizing line-pack
- Industrial curtailment and demand response measures
- On-system above ground storage

In this section, Guidehouse examines the applicability, efficacy/responsiveness, and operational control of these potential alternatives and describe why on-system storage is an appropriate solution to serve FEI's resiliency requirements.

Long-Haul Pipeline Capacity

The holding of long-haul natural gas transportation is mission critical for managing the duration of the winter heating season which lasts approximately 151 days. The utility of a long-haul pipeline is enhanced by contracting for underground natural gas storage (UGS) to provide for additional gas supplies during the winter peak periods. Long-haul transportation assets, supported by commercial agreements, are vital for serving average winter loads for the duration of the winter heating season. However, as discussed in Section 1.7, given FEI's geographic position and options for connectivity to third party pipelines and underground storage, contracting for additional capacity on the Enbridge BC System will actually contribute to exacerbating FEI's dependence on the Enbridge BC system and increase, rather than decrease, the single point of failure risk presented by the Enbridge BC system. In addition, the growing demand within FEI's service territory coupled with the growing demand along the I-5 corridor places a premium on firm winter capacity. An expansion of the Enbridge BC pipeline would result in underutilized capacity during these summer months, without the benefits of additional resiliency for FEI customers. Lastly, due to the toll structure on the Enbridge BC pipeline, any expansion of this pipeline would result in an increase in the tolls for existing shippers, including FEI.

As discussed in Section 1.4, an additional dilemma facing expanded pipeline development in the region relates to securing additional customers to participate in new pipeline projects or pipeline expansions. Given the high cost of pipeline construction, pipeline projects require scale and most often need multiple customers to enter into long-term transportation agreements to support the economics. In addition, the U.S. FERC requires a demonstration of market need, i.e., precedent transportation agreements, before it will issue a certificate of public convenience and necessity to authorize pipeline construction. In Canada, interprovincial pipeline proposals receive similar consideration by the CER while intra-provincial pipeline projects in British Columbia are reviewed by the BC Oil and Gas Commission and the BCUC. Regional pipeline construction in BC and the U.S. PNW region will only happen if large industrial projects that require natural gas come to fruition.

Third-Party Commercial Agreements

Contracting for additional commercial supply, transport and storage services from third parties is the second option. However, there are limited opportunities available for FEI to do this. This option also leaves FEI exposed to physical disruption that would prevent FEI from

capitalizing on those contractual resources. In contractual arrangements, FEI does not have operational control and therefore cannot rely on contracted assets in all situations, especially in situations of regional disruption of gas supply. Since FEI would be relying on the same physical infrastructure it currently utilizes, this option would not strengthen resiliency for FEI.

Third party commercial agreements are structured to provide a range of services, from baseload commodity supply to complex peaking and balancing arrangements. These commercial arrangements rely on third parties arranging for physical gas supply, as well as potentially contracting for physical assets such as storage or pipeline capacity to perform under the agreement. These physical supply contracts are designed to provide natural gas into existing FEI firm transportation contracts or on a delivered 365-day basis.

FEI has deployed several strategies to build a portfolio of gas supply, transportation and storage contracts utilizing third-party services. FEI also has direct contracts for underground natural gas storage to aide in ensuring gas will be available on the coldest of days, as described in Section 2.4. This supply allows FEI to fill in where flowing gas does not reach the main line for a plethora of reasons, including well freeze offs, field level compression issues, potential ruptures and normal commodity supply to manage the peak of the heating season. These storage contracts provide resiliency to the third-party commercial arrangements. It is important to note, however, that two of these facilities, are located over 1,100 kilometres from the FEI service territory, adjacent to the gas producing regions in BC and Alberta and accessed by the Enbridge BC pipeline. FEI's ability to access gas in this field area storage is reliant on the Enbridge BC pipeline being operational to ensure delivery of the supplies held within the storage facility. This reliance translates into compounding single point failure for FEI and its customer base.

In addition, supply from production area storage will take approximately 20 hours to reach the FEI service territory and is more applicable to be used for predictable events such as extreme weather conditions, using day-ahead weather forecasting. FEI has also contracted for market area storage through commercial agreements allowing access to Jackson Prairie (JPS) and Mist storage. These services are effectuated through a back-haul arrangement, which also rely on the Enbridge BC and NWPL systems to be fully operational.

Additional stress on the regional storage comes in the form of continued growth of the I-5 corridor. As wintertime demand increases along the I-5 corridor, FEI's reliance on Mist and JPS is becoming increasingly strained. Increasing load factors at the storage facilities place additional stress on the aging infrastructure at those facilities. JPS had significant compressor issues during the winter of 2019, due to age and increased load factors on the compressor units. Northwest Natural (NWN) has said in its 2018 IRP that the aging compression at Mist must be upgraded due to increased demand. The existing aging compression infrastructure is requiring increasing maintenance, increasing operating cost and still is susceptible to increased delivery failure. The IRP was a premonition, as Mist suffered compressor failure issues in the winter of 2019. FEI has no renewal rights for Mist, such that NWN has the right to recall the Mist capacity at the end of the contract held by FEI. When combining the growth of NWN's service territory, increased utilization of Mist by NWN and the reliability issues at Mist, it is highly likely that NWN will recall that capacity at the end of FEI's current contracts. In this case, and in the event of a future disruption, like the Enbridge incident, this storage capacity will be unavailable to FEI.

Line Pack

Although line pack can be relied on by long-haul transmission system operators as a flexible

resource to accommodate shorter duration disruption events, it is typically not considered a planning asset by natural gas utilities.[redacted]

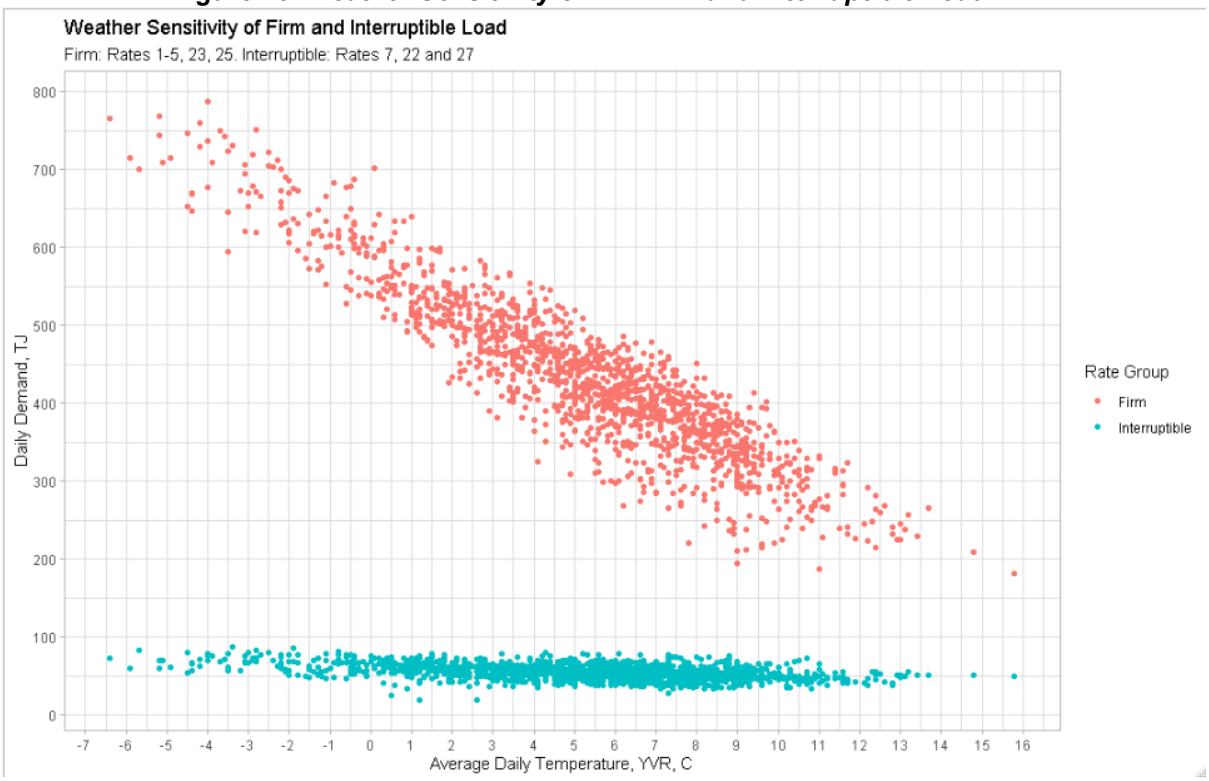
Industrial Curtailment

Curtailment is the interruption of service due to operational or weather-related system constraints, and it's implemented at FEI's discretion. Only industrial customers on an interruptible natural gas transportation rate (Rate Schedules 7, 27, and 22) are subject to curtailment. With a minimum of two hours' notice, customers on interruptible transportation rates can be required to stop using natural gas and switch to an alternate energy source.

One weakness of the industrial curtailment option is that it does not offer an absolute resiliency option, i.e., the ability to reduce a segment of demand to provide natural gas supply and pressure support for the balance of the customers. Under emergency conditions, including a prolonged supply disruption during a period of peak usage, curtailment does not provide supply; it only serves to temporarily shed load. In addition, advanced metering infrastructure (AMI) that provides FEI with the ability to execute a remote shutdown would be required to enable increased flexibility to manage curtailment rather than being forced to curtail the entire grid or carry out community-level curtailment.

An additional weakness of industrial curtailment for FEI is due to the different weather sensitivity of demand of firm vs. interruptible customers. ***Figure 18*** below plots ten years of winter (November through March) daily demand data for both the firm and interruptible rate LML groups vs. average daily temperatures recorded at Vancouver International Airport (YVR). The chart shows the weather sensitivity experienced by firm rate class customers and the relative weather-insensitivity of interruptible customers (IT). It also shows that the IT component of the load is relatively small on colder days relative to the firm load or total load. The implication of this is that amount of curtailable load on a peak day will be a smaller percentage of total load and therefore a less effective tool to mitigate a significant supply disruption. So, on colder days, there is less time for FEI to implement a curtailment of its customers and have a meaningful impact to prolong system life. As mentioned above, Advance Metering Infrastructure (AMI) with remote shutoff capabilities, once in place, could serve to support a controlled curtailment under emergency conditions.

Figure 18. Weather Sensitivity of FEI Firm and Interruptible Load



On-System Storage

On-system storage, such as the proposed Tilbury LNG Tank expansion, does not share the same limiting characteristics as the alternative options. By virtue of being on-system, LNG storage tanks provide enhanced responsiveness and offer greater operational control downstream of the city gate than long-haul transportation, distant off-system storage, line pack or industrial curtailment. Furthermore, on-system storage is the ideal option to provide gas supply and pressure support in the event of an upstream system failure such as the October 2018 outage on the Enbridge BC system. On-system storage does, however, have limited ability to address long durations of load.

The current Tilbury Tank has four purposes:

1. Providing gas supply to meet peak day requirements.
2. Providing emergency supply to support system demand when pipeline or storage delivery capacity falls short of contracted capacity and demand is higher than supply. The reduced capacity could be due to routine or emergency maintenance, or delivery pipeline failure resulting in partial or complete shutdown leading to no-flow of natural gas to the load centres.
3. Providing pressure support for the FEI system.
4. Provide operational flexibility to manage FEI outages or maintenance while helping FEI manage obligations.

The current storage capacity of the Tilbury LNG tank is 1.6 Bcf, consisting of 0.6 Bcf in the legacy facility and 1.0 Bcf at the new Tilbury 1A. FEI considers 0.6 Bcf to be available for planning purposes for resiliency, since the Tilbury 1A facility is planned as a resource for LNG customers. Operationally, the Tilbury 1A facility could provide support in a supply emergency.

The vaporization capability provided by the legacy facility is 150 MMcf/d, provided by the legacy facility. This vaporization capacity corresponds to approximately 17% of the peak design load of 871 MMcf/d. The Tilbury Tank expansion can and will provide storage and delivery capabilities within the FEI distribution system thus providing security from a single point failure of any assets along the Enbridge BC system. Once constructed, the expanded Tilbury LNG Tank will be superior in its ability to provide instantaneous pressure support and deliverability. [redacted] This compares favourably to Tilbury's existing ability to serve 17% of load and will allow FEI to prevent a complete shutdown. Table 1 below compares the characteristics of the legacy Tilbury tank and the proposed expansion.

Table 1. Characteristics of Legacy Tilbury Tank and Proposed Expansion

Characteristic	Legacy Tilbury	Tilbury Tank Expansion
Storage Capacity	0.6 Bcf (planning view)	3.0 Bcf
Vaporization Capacity	150 MMcf/day	800 MMcf/day
Proportion of Design Day Peak Demand	17%	[redacted]

The FEI system is susceptible to a single point of upstream natural gas transmission failure as demonstrated in the incident of October 2018. [redacted] In addition, Guidehouse observes that it would require significant time for FEI to ascertain the supply/demand on its system and develop the appropriate response, i.e., curtailment of customers, in order to mitigate long-term impacts, including catastrophic operational and economic failure. On-system storage would allow FEI to more effectively implement a controlled shutdown that minimizes the impact to at-risk customers if a major interruption event occurred.

It is for these reasons that on-system storage provides an effective means to address the impact of a failure on the Enbridge BC pipeline by giving FEI time to serve customers while remedying the situation with the appropriate operational control, redundancy and emergency response capabilities.

3.3. On-System Storage Complements the Resilience Provided by Upstream Pipeline Expansion

Guidehouse observes that on-system storage, in and of itself, is not sufficient to support FEI's resiliency requirements to mitigate the risk of a prolonged outage. On-system storage provides supply and pressure for a period of time, then liquefaction is required to replenish the stock. To mitigate longer duration outages the system should be supplemented by additional supply sources to provide insurance against more serious and prolonged interruptions.

Expanded pipeline capacity that provides alternative supply to FEI's current access to upstream supply from the Enbridge BC pipeline should be evaluated in the future to ensure adequate long-term resiliency beyond the duration that can be provided by on-system storage, as highlighted in Section 1.6. However, even with additional pipeline infrastructure, it is important to note on-system storage will continue to be beneficial to provide system resiliency to respond to a no-flow event or significant upstream pipeline disruption.

However, even with expansions of transmission pipeline capacity that increase FEI system redundancy, a total system failure on the Enbridge BC pipeline, i.e., a zero-flow event, would require significant time for FEI to balance the supply/demand on its system and insure delivery to its core firm customers. [redacted], FEI should explore multiple asset configurations to mitigate the material risks like those experienced in October of 2018. Increasing on-system storage provides a reasonable measure for the operational control and responsiveness that is necessary to prevent system failure.

3.4. Additional Benefits of On-System Storage

In addition to providing emergency response capabilities, the Tilbury Tank expansion project also brings auxiliary benefits to FEI and its customers. These benefits include operational flexibility, i.e., the ability to provide services such as pressure support, daily load balancing and peak supply across the entire FEI distribution system. Provided that the new Tilbury Tank expansion is sized to provide emergency responsiveness during a supply curtailment at a time of peak load, the Tilbury Tank expansion will be able to provide additional services during non-peak times throughout the years. In other words, the expansion will avoid the need for future investments in peaking supply assets. Similarly, given the expected retirement of the legacy Tilbury facility, the Tank expansion project will serve to provide the transition necessary to enhance resiliency in the near term as FEI explores other assets that can efficiently and economically serve its rate payers. Due to the location of Tilbury, pipeline gas can be used to service Interior BC while Tilbury back-feeds the LML. As a result, the storage at Tilbury can serve a large proportion of the FEI service territory.

4. Considerations for Optimal Amount of On-System Storage

There are important considerations to determine the optimal amount of on-system storage for the proposed Tilbury Tank expansion. In the context of resiliency on the FEI system, Guidehouse provides its opinion on the key factors that require deliberation to determine optimal size of the proposed Tilbury Tank expansion.

Guidehouse observes that on-system storage provides redundancy and responsive flexibility in the form of reserve supply. A supply reserve is necessary to provide additional supply during episodes of peak demand; to provide intra-day operational flexibility including pressure support and to provide emergency response capabilities.

[redacted] The Tank expansion is intended to provide a resiliency in the form of reserve supply and pressure support. In other

words, the Tilbury Tank expansion project may be viewed as a form of insurance to keep the FEI system operating when low probability and high impact upstream system disruptions occur.

4.1. On-System Storage Provides Insurance by Mitigating the Risk of a Supply Disruption

As noted in Section 3.1, the Tilbury Tank expansion project will serve a specific purpose and is designed to enable FEI to respond to an unforeseen supply disruption with the appropriate operational control, redundancy and emergency response capabilities necessary to prevent a system collapse. As a component of system redundancy in the form of reserve supply, the Tilbury Tank expansion project can be viewed as insurance that mitigates the risk of a significant supply disruption.

The critical factors to consider when purchasing insurance include defining the risk, both in terms of the probability of the risk and the consequences of the risk and identifying prudent means to manage the risk. In other words, it is important to understand the likelihood, i.e., the probability of a major system disruption, and the significance, i.e. the potential cost and socio-economic implications of a major system disruption. Another critical consideration in managing risk is the cost to mitigate the risk, e.g. the cost of building infrastructure, or the cost of insurance.

Guidehouse observes that generally accepted definitions of risk include:

- The impact of uncertainty on objectives (ISO 31000)[42]; and
- The possibility that an event will occur and adversely affect the achievement of objectives (COSO ERM)[43]

Furthermore, Guidehouse observes that generally accepted definitions of risk management include "A process … [to] manage risk to be within [the entity's] risk appetite, to provide reasonable assurance regarding the achievement of entity objectives." (COSO ERM)[44], i.e., risk management efficiency is achieved by managing risk to the tolerable level, cost-effectively. It should be noted that the least cost option may not be the most cost-effective option when considering all outcomes of an investment.

Section 3.2 of this paper demonstrates that on-system storage provides an effective means to address the risk of a failure on the Enbridge BC pipeline by enabling FEI to respond to such a situation with the appropriate operational control, redundancy and emergency actions and capabilities. In keeping with the abovementioned principles that define risk and effective risk management, Guidehouse concludes that on-system storage is the most effective means of risk management for FEI to mitigate the risk of an upstream supply disruption.

We next consider the factors that should influence the amount of on-system storage for the proposed Tilbury Tank expansion.

4.2. Key Factors that Influence the Necessary Amount of Storage and Vaporization

[42] https://www.iso.org/iso-31000-risk-management.html
[43] https://www.coso.org/Pages/erm.aspx
[44] https://www.coso.org/Documents/COSO-ERM-Executive-Summary.pdf

Guidehouse notes that the duration of supply deemed necessary by FEI to support the natural gas distribution system in the event of an upstream supply disruption is a critical factor for consideration. This duration is provided by two features of the proposed Tilbury Tank expansion, including:

1. The size of the tank.
2. The amount of vaporization, i.e., the daily quantity of supply that the Tilbury Tank can deliver.

Duration defines the capability of FEI to respond to an upstream supply disruption and needs to be considered in the context of the purpose of the Tilbury Tank expansion. The project is designed to strengthen the resiliency of the FEI gas distribution system. Resiliency is the ability to prevent, withstand, and quickly recover from system damage and/or operational disruption.

A supply disruption can have a significant impact on the daily lives of FEI's customers, as their ability to cook, heat their homes and have access to hot water will be interrupted in the event of a disruption. In addition, a supply disruption can have extraordinary repercussions on the integrity of the gas utility distribution system, as the loss of supply can lead to a decline in pressure that can lead to a collapse of the gas distribution system.

Avoidance and mitigation of these consequences requires FEI to be able to respond with the appropriate level of resiliency. As defined in Section 1.1, resiliency is achieved through the following set of capabilities:

- Preparation: The ability to prepare for and prevent initial system disruption.
- Withstanding: The ability to withstand, mitigate, and manage system disruption.
- Recovery: The ability to quickly recover normal operations and repair system damage.

Determining the appropriate level of duration requires consideration of a set of interdependent, critical defining factors including FEI-specific system characteristics, constraints and requirements. These critical defining factors inform decision-making on the minimum amount of storage and vaporization of the Tilbury Tank that is required to strengthen the resiliency of the FEI system.

Table 2 below provides a framework that defines these critical defining factors and describes how they relate to and influence the ability to prepare, withstand and recover from a system disruption. This framework can be used to evaluate the reasonableness of FEI's approach to determining the recommended minimum size of the Tilbury Tank. More detailed descriptions of each capability are provided after Table 2.

Table 2. Framework for Determining Necessary Storage and Vaporization

Capability	Attributes	Critical Defining Factors
Preparation	The ability to prepare for and prevent initial system disruption	• The anticipated time required to conduct a planned shutdown, i.e., an orderly curtailment of customers to reduce the amount of work and time required to restore service.
Withstanding	The ability to withstand, mitigate, and manage system disruption	• The amount of load on the system at the time of disruption • The amount of load needed to be retained in the event of a supply disruption in order to prevent a collapse of the system, i.e., hydraulic failure.
Recovery	The ability to quickly recover normal operations and	• The time of year, i.e., a disruption in the beginning of winter may exhaust the stored gas, requiring time to refill and limits the ability to respond to subsequent disruptions. A disruption in the summer will have a different impact

Capability	Attributes	Critical Defining Factors
	repair system damage	• The anticipated time, level of effort and expense required to restore a supply disruption.

Preparation

The time required to conduct a planned shutdown defines how FEI would prepare for a significant disruption and prevent a collapse of the system. In the event of an unforeseen supply interruption, it will take several hours to discern the location and magnitude of the disruption. Additional time is required to plan and execute an appropriate curtailment response to prevent a system collapse. For example, additional time will also afford FEI the ability to: communicate with regional utilities to coordinate a response, notify interruptible customers and provide sufficient time to make their own preparations, mobilize alternative forms of short term fuel supply (e.g. mobile LNG), mobilize FEI workforce to prepare for curtailment of customers and emergency response, etc.

Withstanding

The minimum size should also be correlated to the estimated amount of time FEI would require emergency back-up supply in the event of a significant upstream supply disruption, and the relative access to other equivalent options to manage the system. It should also factor in the anticipated time to restore supply.

FEI estimates that the most probable duration of total gas delivery outage in the LML is at least three days. FEI arrived at this estimate by evaluating the October 2018 Enbridge outage duration and response, weather, terrain variability factors, and time required for FEI operational teams to manage a controlled curtailment. The amount of load on the system and the time of year of the disruption are also key considerations when determining the minimum size of the tank, as these will impact how much gas is needed, and how much flexibility FEI has to refill the tank. FEI developed its recommendations for the storage size and vaporization requirements through consideration of the estimated design peak for 2019/2020. 600 MMcfd would serve [redacted] This analysis indicates that approximately 800 MMcf/day of vaporization would be able to support about [redacted] of the system load during a no-flow scenario to the LML at the design peak of 2019/2020. In addition, this solution would also serve approximately 100% of the customers under the 2019/2020 normal winter load scenario.

Recovery

The time, level effort and expense that would be incurred to restore the gas distribution system define the required level of capabilities needed for recovery. As mentioned above, a supply disruption can have extraordinary repercussions on the integrity of the gas utility distribution system and can require significant work to restore service. This can include an initial visit to each individual customer to shut off gas valves, work to repair any equipment damage, purge the gas lines, and test for integrity, and a second visit to each individual customer to relight each appliance or manufacturing process and piece of machinery. This process is tedious, expensive and time-consuming and must be conducted with the safety of customers as the primary concern. In the event of a widespread outage, once the repairs to the system are complete, the process of customer relighting may significantly extend the duration of the outage for some customers. A general rule of thumb used in the gas industry is that one trained service technician can relight up to four residential customers per hour.[45]

[45] https://publications.anl.gov/anlpubs/2003/02/45798.pdf

Key factors that would influence the amount of time, level of effort and expense required to restore the system include:

1. Extent of system collapse.
2. Ability of the utility to mobilize its workforce to execute the emergency response plan (availability of personnel with proper safety and procedure training and vehicle access).
3. Ability to execute on mutual aid agreements with adjacent utilities to secure additional resources.
4. Travel distance between customers.
5. Ability to access the customer premise.

Beyond the critical defining factors that inform the minimum duration requirement necessary to strengthen the resiliency of the FEI system, Guidehouse observes that it is important to note that ancillary benefits of various risk management options should also be considered. As identified in Section 3.4, the Tilbury Tank will be able to provide additional services during non-peak times throughout the year and assist in avoiding the need for future investments in peaking supply assets.

4.3. Industry Approaches for Determining Duration

There is no single industry standard approach to determine duration, i.e., the amount of natural gas required for a resiliency reserve. A standard calculation is challenged for several reasons, including:

- Access to Existing Infrastructure: Gas supply redundancy varies across different natural gas utilities and is a function of access, both physical and contractual, to existing pipeline and underground storage infrastructure.
- Demand Profile: Design day and peak load requirements are a function of a natural gas utility's customer count, profile and seasonality of demand.

Implications of this include that if a utility has more diversity of supply (i.e., is less dependent on a single pipeline for the majority of its supply) its resiliency reserve will be less than a utility that is highly dependent on a single pipeline. This explains why no two natural gas utilities will have the same reserve resiliency requirements.

Neighbouring natural gas utilities in the U.S. PNW region have significant redundancy assets and collectively have a much greater resiliency reserve compared to what the proposed Tilbury Tank expansion will provide to FEI. As an example, the U.S. states of Washington, Oregon, Idaho each are less reliant on a single pipeline compared to FEI. Furthermore, underground storage and on-system storage can provide up to approximately 50% of the region's peak demand for up to approximately 19 days.[46] This is a much larger inherent reserve margin than is being considered by FEI, which is much more dependent on a single pipeline than its neighbouring natural gas utilities. Although resiliency reserve requirements differ on a case-by-case basis, we do note that the approach taken by FEI is similar to that of other utilities in determining the resiliency reserve requirement.

As described above, this approach consists of determining load requirements and estimating the amount of supply buffer (daily requirement and number of days) required to prevent a system collapse. We observe that other utilities have applied a similar methodology.

[46] https://www.nwga.org/wp-content/uploads/2020/03/NWGA_2020OutlookWEB_REV2.pdf

As summarized in Section 1.8, Dominion Energy Utah gained approval from the utility commission for an LNG facility for reliability purposes. Dominion used historical weather and supply limitation analysis to show that shortfalls of 100 million cubic feet (MMcf) were possible in the company's service territory. After determining that demand is expected to grow in the region, Dominion concluded that 150 MMcf for eight days of services (totalling 1.2 Bcf square feet of supply) was required for this facility.

Dominion's project was also supported by several economic analyses, including one carried out by a third party, the Kem C. Gardner Policy Institute. The study analysed the impact of severe a natural gas system outage due to cold weather, under high and low scenarios. The study expects such an event would result in approximately 390,000 to 650,000 natural gas customers in Dominion's Utah service territory without natural gas, some up to a period of 28 days. The overall impact to gross state product ranges from $1.45 billion to $2.38 billion in the low and high scenario respectively.[47] Dominion's own analysis shows that restoring service to 650,000 customers would cost the utility between $10.45 million and $104.60 million.

Another example of an LNG facility that gained regulatory approval in another jurisdiction is the Northeast Energy Center in Massachusetts. National Grid (NGrid), the natural gas utility in the region, identified a need for the facility, primarily due to the fact that NGrid received all of its LNG solely from GDF Suez. National Grid has over 6 million Dth of LNG storage capacity in the region and, at the time, GDF Suez was the only organization able to provide enough LNG to fill this capacity. This posed two problems for NGrid, there was upstream risk that GDF Suez would not be able to provide all of the necessary LNG for NGrid to fill its tanks, and GDF Suez's prices were recently taken out from under FERC control.

To respond to these potential supply issues, NGrid proposed a number of solutions, including the contracting with the Northeast Energy Center, a natural gas liquefaction, storage and truck loading facility for up to 12,240 Dth of LNG per day. The NE Energy Center was designed to be connected to a pipeline owned by the Tennessee Natural Gas Pipeline Company, LLC ("TGP"), which would diversify the supply options for the region.

The capacity of the NE Energy Center was set based on NGrid's 2013 Supply Plan, which included long term forecasts under normal weather circumstances and design day / design year circumstances. Supply shortfalls were identified through this process leading to the contracting with NE Energy Center and contracting / development of other supply resources.[48]

In the context of buying insurance, Guidehouse concludes that FEI has fittingly applied the appropriate risk management approach and chosen an effective and prudent solution in the form of the duration of supply that the proposed Tilbury Tank expansion will provide. Moreover, the approach undertaken by FEI to determine its resiliency reserve requirements is similar to the approach of other natural gas utilities.

E. Conclusion

Our examination of the four questions has uncovered key findings and conclusions that illustrate the need for increased resiliency in the LML natural gas system and the benefits of the Tilbury Tank expansion project. The socio-economic implications of not taking action to mitigate the risks, like those experienced in October 2018, are significant. Due to the lack of additional transportation infrastructure in the region, FEI has limited alternatives to achieve greater diversity of supply and transportation. From a risk management perspective, the

[47] https://pscdocs.utah.gov/gas/19docs/1905713/308019DEUEx4.04%e2%80%934-30-2019.pdf
[48] https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9218304

proposed Tilbury Tank expansion provides a prudent, necessary and effective means of mitigating the risk of a disruption on the Enbridge BC system, especially during a period of peak demand.

There is an important distinction between resiliency and reliability, where reliability relates to the ability for a gas system to provide service day after day, and resiliency relates to the ability for a gas system to manage and respond to unforeseen circumstances that may disrupt supply or put upward pressure on demand. Six key considerations highlight the needs for and benefits of increasing resiliency:

1. Fundamentally, it is necessary for the natural gas system to be resilient to unexpected, low probability and high-risk impact events. The system must have characteristics that enable operators to manage threats and recover from disruptions quickly so that continuity of service can be maintained for customers when other physical and commercial resources that enable service are challenged.

2. System resiliency is as important to natural gas delivery as is reliability. Given an LDC's obligation to serve, a gas utility must seek to strengthen its resiliency while balancing the need for operational control, redundancy and emergency response capabilities, at a reasonable cost to ratepayers.

3. There are key features throughout the integrated natural gas value chain that allow for system resiliency, including a networked long-haul transportation system that connects natural gas production and underground storage, with distribution systems that deliver to end-users.

4. The province of BC is highly dependent on a single midstream pipeline for natural gas supply and has minimal on- and off-system storage, resulting in a system that does not have an abundance of inherent resiliency.

5. A balanced portfolio of capabilities, i.e. the ability to maintain system pressure and provide customers with supply, that factor into resiliency is required to optimize for any given natural gas LDC.

6. There are certain aspects of system resiliency to the natural gas utility, its customers and to the communities it serves, that only on-system storage can provide. These include, emergency responsiveness, i.e., the ability to continue to provide reliable service in the event of a significant upstream pipeline disruption, the ability to prevent collapse of the system due to a drop in hydraulic pressure, and rapid response capability after a failure to avoid system collapse.

The unique features of the systems that support the FEI gas distribution network result in challenges for FEI system operators to maintain system resiliency. Currently, the FEI system is not supported by a balanced infrastructure profile, including on-system and off-system

options that result in robust resiliency, as shown by the Oct 2018 pipeline disruption that very nearly led to an uncontrolled shutdown of the FEI distribution network.

Several planning and investment options working together will result in enhanced resiliency for natural gas distributors. Core on-system storage enables several days of resiliency against a major upstream disruption. In the case of FEI, new on-system storage is essential to deliver increased resiliency to prevent a catastrophic failure. Guidehouse observes that increased diversity of supply and transport sources into the FEI system will contribute to additional redundancy that will also contribute to strengthening resiliency.

There are many examples from other jurisdictions that face similar resiliency challenges and who have responded by investing in storage, pipelines and LNG peak shaving facilities, among other options. Regulators and other stakeholders have supported these measures to insure against unintended socio-economic consequences. The natural gas utility has carried out analysis and provided its opinion on optimal sizing and siting, while reviewing cost-reasonableness.

As discussed in Section 4 of this report, the rapid depressurization that would most likely occur in the event of an upstream supply disruption and the time and cost to restore service underscores the need for the insurance provided by on-system storage to provide supply and/or enable FEI to segment its system and execute a controlled shutdown.

On-system storage is one contributing option to drive system resiliency. However, robust and resilient systems require a diversity of options that create redundancy, as well as supportive and synergistic products and services that will deliver essential disruption-management and service continuity for customers who rely on natural gas services to support comfort at home and economic activity in the province of BC.

On-system storage and expanded pipeline access are not mutually exclusive but are complementary. Expanded pipeline access will increase system redundancy and contribute to long-term system resiliency, while on-system storage is the only option that will provide emergency response capabilities, by providing supply and pressure support to prevent hydraulic failure behind the city gate.

Based on our review of FEI's planning activities, our understanding of the North American and regional natural gas market, and on the FEI experience in operating its system, Guidehouse concludes that the Tilbury Tank expansion project offers the necessary means to strengthen the resiliency of the FEI natural gas distribution system.

F. Appendix A – Guidehouse CV's

The CVs of Guidehouse team responsible for the report are included below

Craig Sabine
Director
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Professional Summary

Craig Sabine is a Director in the Global Energy Practice at Guidehouse, leads the firm's Utilities and Energy companies segment in Canada and is past Chair of Guidehouse's regulatory transformation initiative. Craig is a strategic partner and trusted advisor to Canadian utilities, energy sector organizations, the financial services sector and large energy consumers on strategic planning, investment decision making, risk management and other organizational challenges

Working with executive management teams, Craig focuses on the strategic market opportunities and regulatory challenges within and across the energy value chain and has supported regulatory filings related to system planning, cost allocation, affiliates, working capital and rate design.

Craig is a recognized leader in the analysis of energy markets in Canada, including expertise in provincial regulatory and policy development. Notable impactful assignments have afforded Craig the opportunity to assess the gas supply risk management program of SaskPower, review the full cost risk in the Bruce Power refurbishment agreement, provide expert testimony regarding Manitoba Hydro's $25 billion capital investment plan and build an internal compliance program (ICP) for TransAlta related to NERC compliance.

Prior to Guidehouse Craig was a Senior Manager and Eastern Region Lead of MNP LLP's energy practice and a Manager at ICF Marbek.

Craig earned his MBA from the Queen's Smith School of Business and his BES in Environment and Resources from the University of Waterloo.

Areas of Expertise

- Portfolio assessment and business planning
- Enterprise Risk
- Cost Allocation and affiliates
- Regulatory economics
- Integrated planning
- Policy design
- Organizational development
- Generation procurement and divestiture
- Processes and Efficiency

Professional Experience

Energy and Utilities – Risk and Regulatory

- Ontario Energy Board, Enbridge Gas Supply Plan Review – Craig recently led development of a report on behalf of the OEB to review Enbridge's natural gas supply plan and determine its alignment to the regulatory goals and principles of the Board and the prudence of its portfolio decision making approach. Guidehouse found that storage procurement process is required to be enhanced to provide market fairness for ratepayers.

- SaskPower Gas Supply Risk Management Program Review – Craig led a team to examine SaskPower's gas supply and hedging platform and recommend opportunities for improvement leveraging a more flexibility probability-focused approach to hedge gas supply. With gas consumption increasing in the province, this was a very important assignment.
- Northpoint Energy Gas Hedging Process Review – Craig recently participated with a SWOT team to review, enhance and implement an improved set of parameters and procedures to ensure robust risk protection in gas purchasing at Northpoint Energy, who supplies SaskPower with natural gas needs and services.
- Hydro One Cost Allocation and Rate Harmonization. In 2019, Craig co-led a project to determine the appropriate cost allocation methodology to harmonize rates across legacy Hydro One and acquired customer bases, needed to proceed through a re-basing COS application. The filing is currently under review by the Ontario Energy Board.
- Ontario Energy Board Gas LDC Cap and Trade Regulatory Framework – Craig recently served as the special advisor to the OEB as the Ontario Government developed its Cap and Trade program. Supporting development of the cap and trade regulatory framework, Craig was responsible for assisting the OEB to develop an aligned regulatory framework for natural gas utilities who will be covered entities and ensure that the OEB's jurisdiction supports the utilities' compliance with the program at reasonable and prudent costs for rate payers.
- Enbridge Shared Services Allocation Model - Craig participated on a team who assessed the shared services cost model of one of Ontario's largest natural gas distribution utilities, whose parent company provides shared services support in a number of operational functions. To approve the natural gas rates charged to Ontario consumers, Enbridge Gas Distribution must have its shared services cost allocation approved by the OEB after third party assessment. The analysis included benchmarking the shared costs of several functions to other cost of service and ratemaking submissions of gas and electric utilities
- Kinder Morgan General Rate Application – Craig has worked closely with an internal team of operations, project management and finance experts at a major Canadian pipelines company to prepare the rate base for their 2013 rates application to the National Energy Board. Craig is managing all aspects of development and verification of the rate base and capital project accounts to develop one of three key sections of the GRA cost of service.
- Hydro One Transmission Total Cost Benchmarking. Craig participated with a team in 2018/19, combining Guidehouse and First Quartile Consulting to benchmark the total cost and work practices of Hydro One Networks' transmission operations. The team collected cost and practice data from utilities across North America, conducted interviews with Hydro One Networks staff, and provided recommendations to improve overall performance. The report was filed with the regulator.
- SaskPower, Large Customer Tx Connection Process Risk Review – Craig led an optimization assignment for SaskPower to review and determine enhancements to the customer connection process for commercial and industrial connections. The review included examining the policies and process, risk management strategy and controls used to prepare for and invest in connecting new large customer loads and upstream system investments. The work included a current state assessment, identification of risks and gaps and jurisdictional scan for common and best practice in customer connection requirements.

- Hydro Ottawa, Regulatory Compliance Review – Craig is currently leading a project assess the client's current regulatory compliance program against industry best practices and the principles of process improvement in order to develop a recommendation and roadmap for implementation an optimized program and set of policies. The engagement involves stakeholder facilitation, regulatory research and analysis and process mapping.
- OEB Regulatory Reporting Review and Enhancement – Craig managed the first stage of a change initiative at the OEB, to review and perform and gap analysis of the processes, procedures and systems in place at the Board to execute its reporting and entity performance management needs. In support of the new Renewed Regulatory Framework and scorecard performance management approach, the OEB is ensuring its data and reporting structures are aligned with industry best practice to realize the full potential of information coming into its systems
- OPA Process Audit and Re-design - Craig recently supported the OPA in efforts to reconstruct the review and assurance process of regulated price plan (RPP) claims submitted by Ontario electricity distributors as part of their settlement activities. Craig provided technical expertise on two field audits of the settlement claims and has been managing the development of a compliance and risk-based oriented certification program to replace annual audit.
- OEB Internal Controls Review – Craig participated as subject matter expert and reviewer on an assignment to evaluate the design and compliance of internal controls within the OEB's procurement, finance and IT departments. Subsequently the MNP evaluated and recommended on the need for and design of an internal audit function within the organization.
- IESO (formerly OPA) – Audits of Bruce Power Refurbishment Implementation Agreement – Craig managed three separate audits on behalf of the OPA over their long-term contract with Bruce Power – the Bruce Power Refurbishment Implementation Agreement (BPRIA). The audits provide assurance opinion over the costs associated with Units 1 and 2 refurbishment project, the O&M costs to date and the total fuel costs. These audits totaled over $5.6 billion in shared investment between Bruce Power and the Province of Ontario and will support accountability improvement over future contracts to supply Ontario electricity from the Bruce Nuclear Station

NERC Standards Compliance – Reliability Standards

- ATCO NERC Audit - Craig and an expert team completed a gap analysis of ATCO's procedures to comply with AESO reliability standards, which are largely based upon NERC standards. ATCO will complete an audit with the AESO to achieve compliance with 9 GOP reliability standards and provided recommendations for improvement of evidence packaging, format and adherence to each requirement and sub-requirement. Craig, led management of the project, supported assessment of the standards and reviewed the resulting gap analysis report.
- TransAlta NERC Compliance - Mr. Sabine worked with a team of reliability, compliance and NERC standards experts to support TransAlta's development of corporate internal compliance program that will enable the firm to build and support evidence of compliance with NERC and provincial reliability standards programs, in all of its operating jurisdictions. The project will position TransAlta as a premier Canadian utility in the reliability space and ensure internally consistent procedures are met within day to day operations and compliance efforts.

- AESO NERC Audit - For Alberta's electricity system operator, Craig's NERC team completed a mock audit process in conjunction with the internal audit of the AESO's reliability standards compliance program. The gap analysis portion assessed the AESO's level of compliance with NERC reliability standards with the project lead, while supporting the preparation of SMEs for an upcoming WECC audit, to which the AESO is responsible for bulk electricity system reliability compliance. Craig participated in mock auditing activities and managed the administration and scheduling of the project.
- EnCana NERC and CIP Compliance – Craig was assigned to verify compliance with NERC reliability standards, EnCana commissioned a team of consultants led by Craig to assess the firm's position leading into an AESO post self-certification compliance audit. The expert compliance and data quality team assessed CIP-001, EOP-004, PRC-001, PRC-004, TOP-005 and related requirements for EnCana's Cavalier Cogen facility using a gap analysis tool.
- Hydro One CIP Mock Audit - This assignment, for Ontario's largest electricity transmitter, focused on preparing the firm for compliance with the critical infrastructure protection and IT security related requirements of the NERC Reliability Standards. A team consisting of electricity systems and IT infrastructure experts performed mock audit activities with a variety of SMEs from across Hydro One to assess the readiness of the firm for audit, the level of rigor available in the firm's evidence and the internal compliance procedures that are in place to adhere to the NERC and IESO standards.

Energy and Utilities – Strategy and Regulatory

- ATCO Electric, Regulatory Reform Strategy – As advisor to ATCO's management team, Craig has been developing regulatory strategies to support ATCO's transformation objectives as pressures continue to mount for utility businesses reform and innovation. Particularly, Craig has helped to identify technologies, business models and rate structures that could support ATCO investment in grid modernization, distributed energy and non-wires alternatives and platform initiatives.
- Ontario Energy Board, Gas Markets Advisory – Craig continues to support the OEB to assess North American natural gas markets, supply, storage and transportation, a role he has been fulfilling in some form since 2010. Facilitating market price outlooks, updated quarterly, Craig supports the processes to review utility natural gas supply plans, QRAM filings and other strategic and policy initiatives.
- SaskPower Integrated Planning Process Support – Craig and a Guidehouse team are currently supporting SaskPower through a complete improvement program of their supply planning process. Modelled after integrated resource planning (IRP), Guidehouse has conducted workshops and interviews to better understand the departmental inputs and touch points to analyze and report a 20-year future strategy for the SaskPower's resources. The assignment involves full support, process design and training to conduct an IRP for the first time and moving away from a 20-year supply option-only planning approach.
- Gazifere Corporate IRM Review - Craig supported the Gatineau and Outaouais region natural gas utility review its last five-year IRM period and recommend changes to take before the regulator that may improve the value and success of IRM for rate payers and shareholders. The assignment includes an economic and demographic assessment to understand the driving forces of IRM performance given the current structure and set of performance factors.

- ENMAX Billing and Customer Care Costs Allocation Approach – Recently, Craig led the development of an assignment to review, benchmark and optimize the procedure with which ENMAX allocates the costs of its Encompass, the organization's affiliate billing and customer care company. With several non-regulated customers and the utility EPC, Encompass incurs costs to serve all affiliate and contracted entities. Craig's team discovered several allocation factors that could be changed and compliant with Alberta's affiliates transactions regulations, while saving shareholders over $1.7 million in annual cost.
- Gazifere Corporate Cost Allocation Model – Craig was engaged to provide the Gatineau based subsidiary of Enbridge with a review of their current cost allocation methodology and determine next steps to develop an amended model reflective of regulatory best practices. Craig managed the assignment and constructed a full suite budgeting model to allocation corporate costs from Enbridge Inc. and EGD to Gazifere, considering the regulatory principles of prudence, cost-benefit and fair market value. Craig provided expert testimony before the Regie de Energie.
- ENMAX Affiliates Transactions Program Review – Craig recently testified during ENMAX's 2015 rates application before the AUC. Craig managed the third-party review and fair market value assessment of ENMAX's 2011 and 2012 affiliate transactions in support of the firm's cost of service rate filing and forward approach for determining affiliate transactions. The goal of the assignment was to provide assurance of compliance with the AUC's Affiliates Code of Conduct and to provide opinion on the fair market value of affiliate transactions between ENMAX and for-profit entities. Craig provided IR support and testimony before an AUC panel.
- Manitoba Public Utilities Board Expert Witness - Craig acted as an independent expert on behalf of the Manitoba PUB, evaluating the costs and benefits of Manitoba Hydro's current capital development strategy. Craig and a team of other experts provided key insight and analysis to the PUB to evaluate the potential benefits of the preferred plan and set of alternatives in the Needs for and Alternatives to process that will ultimately provide recommendations for approvals of the Keeyask and Conawapa large hydro projects, their risk adjusted net present value to the rate payers of Manitoba and an assessment of the key risks that must be considered to support the 20 year capital plan. Craig provided expert testimony before the Board in 2014.
- ENMAX Fibre Optics Business Valuation – In support of the potential for regulatory hearings associated with the sale of a non-regulated business, Craig managed the development of a valuation of fibre optics assets for a Canadian utility. The assignment developed a full model of equipment, construction, labour and operating costs associated with an urban fibre optic network.

Work History

Director, Guidehouse, 2015 – present

Senior Manager, MNP LLP, 2012 – 2015

Manager, ICF International, 2003 – 2012

Environment Canada, 2002 – 2003

Testimony Experience

Gazifere 2017 COS. April, 2016

Coffin and Lowry v. Atlantic Power Corporation. March, 2015

ENMAX General Rate Application Hearing, AUC. July, 2014

Manitoba Hydro NFAT Hearing, MPUB. April, 2014

Natural Gas Markets Review Consultative Hearing, OEB. 2010/14

Education

2012 M.B.A. Executive Program, Queen's School of Business, Kingston, ON, Canada

2004 B.E.S. Environmental and Resource Studies. Minor, Biology University of Waterloo, ON, Canada

Paul Moran
Associate Director

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Professional Summary

Paul Moran is Associate Director in the Energy practice and is responsible for leading engagements for clients in the energy sector including electric and gas utilities, power generators, and pipeline and midstream companies.

Paul is an accomplished electric and gas utility professional with extensive background in the power and gas sectors including electric transmission and distribution, natural gas pipelines and distribution in addition to emerging energy technology. His 17 years of energy industry experience include providing subject matter expertise related to corporate strategic planning, risk management, business process improvement, organizational design and change management.

He has led several client engagements focused on facilitating the development of strategic plans for public and investor-owned utilities in addition to strategic and business planning for specific business units and emerging technology evaluations such as renewable resources and electric vehicles in support of utility-sponsored new business ventures. He has also managed broader projects to design and implement ERM programs as part of a utility's strategic plan development.

Prior to joining Navigant, Paul served as the Director of Strategic Planning for CenterPoint Energy where his responsibilities included coordinating the strategic planning process and annual ERM review.

Professional Experience

Integrated Resource Planning and Natural Gas Supply Planning

- For a large US Midwestern gas and electric utility, developed a long-term integrated resource plan which included a risk assessment to consider critical uncertainties including fuel prices, energy demand, technological changes in generation, including coal, natural gas, wind and solar, capital costs for new generation units, and wind output. In evaluating the various portfolio options, the analysis examined the tradeoffs between cost, risk, and environmental stewardship.

- For a major US gas distribution company, assisted in the design, implementation and monitoring of demand-side management programs reduce natural gas consumption by improving the energy efficiency of buildings, space heating systems, water heating, and other gas appliances. Programs included conservation improvement programs designed at providing residential and commercial building developers and end-users with incentives to deploy more efficient heating systems and appliances.

- Managed a cross-functional team to evaluate a software system replacement for gas supply, transportation, trading and risk management including documentation of business and technical requirements, vendor selection, user acceptance training, change management, process redesign and system implementation.

Professional Experience

Electric and Natural Gas Market Analysis and Forecasting

- Performed multiple assessments of North American electric and natural gas markets and developed long-term forecasts of supply and demand, electricity and natural gas prices to examine the impacts of market trends, i.e., coal retirements, clean power plan, renewable integration and transmission and pipeline expansions, on power and gas market markets using proprietary models in addition to the GPCM® natural gas forecasting model and PROMOD electricity market modeling software.

- Performed multiple assessments of natural gas markets and developed long-term forecasts of supply and demand, gas prices and pipeline utilization using proprietary models in addition to the GPCM® natural gas forecasting model.

- Assessed market fundamentals and economics of emerging supply basins to evaluate the competitive position of producer reserves in addition to developing growth and acquisition strategies for producers, pipelines and midstream/storage companies.

- Provided an analysis of key regulatory developments and power market and natural gas market trends including projections of production, demand and natural gas prices and basis for a gas storage operator in Texas.

- Conducted several strategic market assessment and valuations of major interstate natural gas pipelines in support of acquisitions. Developed models to evaluate multiple supply and demand scenarios, forecast pipeline flows and project re-contracting volumes and rates to assess the competitive position and projected performance of the pipelines.

- Prepared a competitive assessment of LNG and steam coal procurement options in support of a fuel supply strategy for a power plant developer in Chile.

- Developed a natural gas fuel supply and transportation strategy to source U.S. natural gas production for a power project in Mexico.

- Advised in the screening, valuation and detailed due diligence of several LNG export facilities and natural gas midstream assets, throughout the U.S. on behalf of equity investors and lenders.

- Managed a study to evaluate a comprehensive, long-term natural gas and transportation strategy for a U.S. based developer of two U.S. Gulf Coast LNG export facilities. Assessed natural gas market fundamentals and developed a long-term price forecast. Prepared and delivered recommendations to the executive management of the Company.

- Performed strategic advisory services for a client interested in developing small-scale LNG liquefaction terminals in the U.S. Responsibilities included development of a model to analyze the investment strategy under different supply growth scenarios and capital constraints.

Professional Experience

Regulatory and Compliance

- Prepared and delivered expert witness testimony in support of gas pipeline business risk and tariff design before several regulatory commissions, including the Ontario Energy Board.

- Developed a comprehensive review of the natural gas hedging program for a large electric utility in Canada. The scope of the review was to validate the program objectives and review the long-term approach in the context of changing natural gas market fundamentals. In addition, the review identified opportunities for improvement and recommendations on enhancements to strengthen the hedging program.

- Managed a comprehensive review and assessment of a large electric utility's current regulatory compliance program and processes across operations, engineering, finance, risk management, customer service and regulatory reporting. Developed recommendations to improve and enhance the effectiveness of the program and implemented a multi-stage program to facilitate improved regulatory reporting and strengthen alignment between the regulatory affairs group and the business units

- Conducted an independent review of a 3rd Party audit of a large electric utility's fuel adjustment mechanism that was commissioned by the public utility commission. Reviewed certain assertions related to organization, staffing and controls, and provided insights and perspective related to the organization and staffing of the fuel purchasing and risk management functions. In addition, provided expert witness testimony and evidence related to the report.

- For a large, multi-year Advanced Metering and Smart Grid deployment, developed and managed a program to ensure compliance with regulatory reporting to U.S. Federal agencies and State public utility commissions.

- Developed and implemented a regulatory compliance program for a U.S. electric retailer to ensure timely and accurate preparation of regulatory filings and compliance with requirements.

- Managed financial analysis, review and development of regulatory filings and rate cases for a U.S. electric transmission and distribution and gas distribution company.

- Prepared strategic reviews of gas procurement supply plans, commodity hedging programs and risk management strategies for gas utilities and electric power generators in addition to designing gas hedging programs for market participants.

Professional Experience

Strategic Planning

- Developed a robust financial planning tool for a non-regulated subsidiary of a Fortune 1000 U.S. energy company to forecast market capitalization, earnings, credit rating and debt capacity to evaluate the impact on major strategic acquisition and development initiatives and changes in market conditions on its financial position. Conducted workshops with members of the company's senior management team to facilitate all aspects of the strategic planning process.

- Led client strategic planning engagements for IPPs, electric and gas utilities, midstream and pipeline companies and provided subject matter expertise for client engagements related to Corporate Strategic and Business Plans, generation resource plans, business process improvement, organizational design, change management and performance monitoring.

- Developed and led the annual strategic planning process for a large Fortune 500 energy company across its pipeline, field services, natural gas distribution and electric business units. Facilitated senior executive strategic planning workshops on scenario analysis, market outlook, enterprise risk management and competitive intelligence.

- Evaluated potential mergers, acquisitions and divestitures of pipelines, storage assets, gas trading books, electric utilities and gas distribution companies and conducted asset valuation, due diligence and financial analysis to support business cases. Delivered recommendations to senior executive management.

- Designed and implemented a performance measurement and risk management process to measure and track key performance indicators to improve operating results and enhance financial performance.

- Facilitated the development of corporate and business unit strategies designed to enable a Fortune 500 utility to achieve its earnings and growth targets as part of its annual strategic planning process.

New Business Development and Market Assessments

- Developed business strategy for creation and execution of a $20 million tax equity fund to participate in solar ventures. Negotiated lease terms with host sites. Negotiated strategic alliance with EPC contractor.

- For a large electric and gas utility, led the evaluation and business case development for a new service offering to provide residential home appliance repair and warranty services.

- Managed the evaluation of an entry into the retail electricity market including economic evaluation, market analysis, business case development and market-entry strategy which was approved by executive management and the Board of Directors.

- Led the business case development for an Advanced Meter Reading/Smart Grid deployment totaling over $1 billion in capital expenditures, including capital budgeting, forecasting and financial analysis.

Work History

Associate Director, Navigant	2015 – Present
Principal, Wood Mackenzie	2013 – 2015
Director, Pace Global	2011 – 2013
Director of Strategic Planning, CenterPoint Energy	2006 – 2011
Lead Analyst, CenterPoint Energy	2003 – 2006

Education

B.A., Political Science	Providence College
MBA, Strategy & Finance	Indiana University

G. Appendix B – Guidehouse Engagement Letter

FASKEN

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May 28, 2020
File No.: 240148.00966

Via Email
Privileged and Confidential

Navigant Consulting Ltd.
First Canadian Place | 100 King Street West |
Suite 4950 | P.O. Box 64 | Toronto, ON
M5X 1B1 | Canada

Attention: Craig Sabine

Dear Sirs/Mesdames

Re: FortisBC Energy Inc. ("FEI") - Tilbury Tank Resiliency CPCN (the "Regulatory Proceeding")

As you are aware, we act on behalf of FEI in the above referenced Regulatory Proceeding. This letter of instruction confirms your engagement for the provision of an independent expert report to be introduced into evidence in that Regulatory Proceeding. It outlines the issues to be addressed and provides some general guidance as to the format of your report.

Apart from our instructions below as to the issues to be addressed and the format of your report, the contents of your report are entirely for you in the exercise of your independent professional judgment. We are retaining you to provide independent expert evidence for the above captioned Regulatory Proceeding, not as an advocate for our client. The integrity of your conclusions is dependent upon your objectivity.

Matters on Which Your Opinion is Requested

We request that your report set out your independent objective opinion with respect to the following questions:

1. What does resiliency mean in the context of a natural gas market, supply and delivery system and why is it important?

2. How is the resiliency of FEI's distribution system affected by the characteristics of the natural gas value chain, including midstream pipeline capacity and availability of storage (both off-system and on-system), and the composition of the load/customer base?

3. In the case of FEI, to what extent is on-system storage either an alternative to, or complementary to, other resiliency measures such as midstream pipeline infrastructure, off-system storage, or interruptible service and or other demand control measures?

4. What considerations should go into determining the optimal amount of on-system storage for FEI?

In order to facilitate your analysis and the preparation of your report, FEI will make available information that you request. You can assume, for the purposes of your analysis, that any information provided by FEI is accurate.

Overview of the Structure of Your Report

We request that your independent expert report be set out generally consistent with the following structure.

A. Introduction and Summary of Opinion

Your introduction should

- reference the nature of your engagement as an independent expert as per this letter,
- identify the questions posed to you, and
- set forth, in a summary fashion, your independent objective opinions on each question.

B. Qualifications

Please state, in a summary fashion, the professional qualifications, technical education, training and experience of those individuals who are responsible for the content. Explain how the authors' expertise relates to the subject matter of your opinions. Detailed *curricula vitae* should be attached as an appendix.

C. Duty of Independence

We confirm that you have a duty to assist the regulator and are not to be an advocate for any party ("Duty of Independence"). In this section of your report, please certify the following:

- You are aware of your Duty of Independence,
- You have prepared your report in accordance with the Duty of Independence, and
- If called to give oral or written testimony, you will give that testimony in conformity with the Duty of Independence.

D. Issues

This section should set out the issues as posed in this letter.

E. Discussion

Under this heading, you should set out in full your independent objective opinions in the same order that the issues are presented. You should provide the reasons for your opinions including reference to pertinent facts or assumptions, any research you conducted that led you to form the opinion, and any applicable technical or other documents, standards, guidelines, etc.

F. Conclusion

You may provide a conclusion if you wish.

Appendices

Please include this letter, and the *curricula vitae* of those people responsible for the content of your report, as appendices to your report. If additional instructions are required, then supplementary letters of instruction from us should also be attached to your report. You may attach other documents or schedules that elaborate on, or are integral to your analysis.

In conclusion, if you have any questions with respect to the nature and scope of your engagement, please contact the writer at your soonest convenience.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

Matthew T. Ghikas
Personal Law Corporation

MTG/lh

cc Doug Slater
Director, Regulatory Affairs
FortisBC Energy Inc.

Appendix B

PRICEWATERHOUSE COOPERS – THE CASE FOR IMPROVED SYSTEM RESILIENCY

(REDACTED VERSION)

~~CONFIDENTIAL~~

www.pwc.com/ca

FortisBC

The case for improved system resiliency

June, 2020

pwc

Strictly private and confidential

Contents

1. Introduction and context

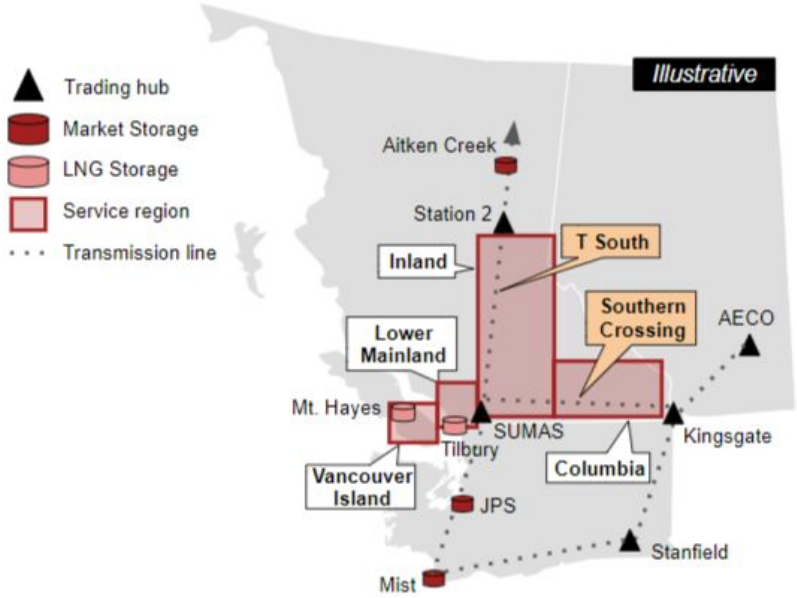
1.1 Study background

Over the past decade, British Columbia (BC) has faced four natural gas pipeline incidents, including the Enbridge Alaska Highway pipeline fire in February 2009, the Enbridge valve enclosure fire in June 2012, and the Enbridge Nig Creek rupture in June 2012. The fourth incident took place most recently, on October 9th, 2018, when the Enbridge T-south pipeline ruptured near Prince George, BC. As a result, almost 700,000 BC customers were asked to reduce their usage by turning down thermostats, minimizing the use of hot water, or using alternative energy sources. Fortunately, a second pipeline in the same right of way was not damaged, and a major shutdown was avoided. The event was significant enough, combined with the backdrop of three other incidents over the past decade and even more across Canada and the NW United States (refer to appendix), that concerns were raised regarding the ability to meet energy demands of the province and the subsequent economic, social and environmental implications in the event of a prolonged disruption. PwC was retained by FortisBC Energy Inc. to study these impacts and implications.

Currently, the majority of natural gas supply originates from inside BC (Montney Basin) and is supplemented with supply from Alberta or the US, as required. Estimates suggest that there are ~150 years of reserves in the Montney Basin, indicating that there is abundant supply. Demand for natural gas is forecasted to grow at an average annual rate of 0.3% to 2040[1], driven primarily by population increases and new industry. In addition, “step-change” drivers (e.g. new LNG, new industry) could be expected to create additional demand pressure on the system over time and increased switching from interruptible to firm supply contracts may contribute to false confidence in system resiliency.

BC’s natural gas transmission and distribution (T&D) infrastructure both enables and constrains the transport of natural gas to local consumers. FortisBC Energy Inc’s (FEI) network of T&D infrastructure supplies over 1,000,000 customers across four major service regions - Vancouver Island, Lower Mainland, Inland, and Columbia. In 2018, FEI’s customers consumed ~210PJ of Natural Gas, representing just over 50% of the province's demand, making the FEI system a critical part of the province's energy infrastructure[2].

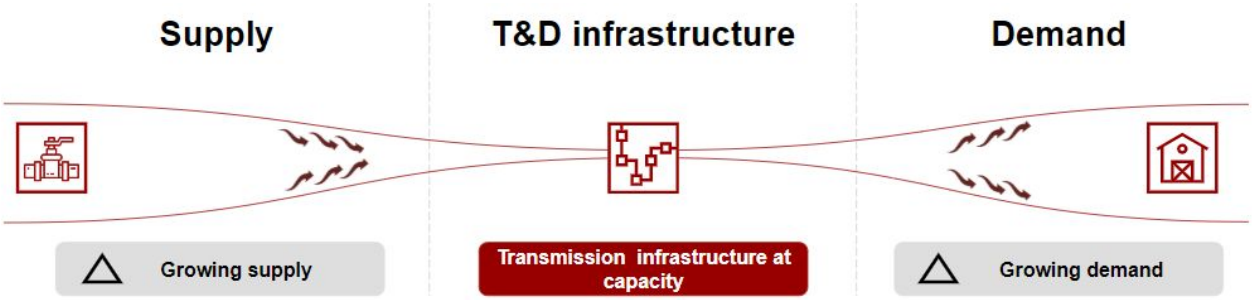
Figure: Natural gas system overview



[1] NEB

[2] NEB and Fortis Consumer Data. Province’s demand reflects primary demand, inclusive of non-marketed natural gas.

However, overall system capacity is strained under both current and forecasted demand conditions and has become the bottleneck between supply and demand in BC. The situation is complicated with a high dependence on two major pipelines (i.e., T-South, Southern Crossing) supplying [redacted] of all natural gas to FEIs system and commercial arrangements with US suppliers for short term, peak demand that may be at risk during a major disruption.



1.2 Study objectives and limitations

The objective of this study is to conduct a holistic assessment of the economic, social, and environmental impacts that could arise in the event of a disruption to natural gas supply. The intent is that the study will provide the province and the energy industry with data to help weigh the costs and benefits of different infrastructure investments to enhance system resiliency in the province.

2. Approach

This section summarizes our approach to assessing the risks and impacts of a potential natural gas supply disruption event in BC. Overall, our approach involved four steps which are each described in more detail below:

1. **Scenario development:** creating three scenarios pertaining to the conditions of a natural gas disruption;
2. **Primary data collection:** using interviews with stakeholders who may be affected by the disruptions to understand how they may be impacted;
3. **Economic and fiscal impact modelling:** using input-output method to quantitatively estimate the impact of each scenario on the economy; and
4. **Wider impact assessment:** qualitative assessment of the social and environmental impacts of each scenario.

Our assessment was guided by the PwC Total Impact Measurement & Management (TIMM) framework, shown below. TIMM is a holistic framework covering social, environmental, fiscal and economic dimensions that is underpinned by a common set of valuation approaches that PwC apply globally.

Figure: TIMM framework

Economic: contributions to economic growth and development (including jobs created);

Social: impacts on wellbeing of individuals and communities;

Environmental: changes to the environment as a result of bringing products and services to market; and

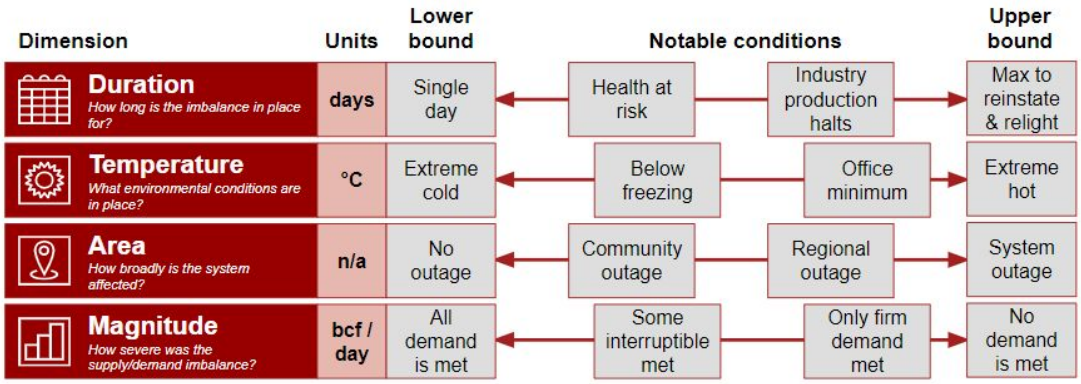
Tax: taxes borne and collected which are used to develop a thriving society

2.1 Scenario development

In order to assess the potential impact that a natural gas disruption could have on BC, we developed three scenarios for evaluation. The scenarios are hypothetical events used to evaluate potential impacts of supply disruption and were designed to be both realistic (i.e. a mix of less extreme to more extreme scenarios, but ensuring that all are real possibilities), while also considering an exhaustive range of parameters (see below). In analyzing the impacts of these scenarios, we did not consider possible causes, likelihood or readiness to respond.

In order to develop the scenarios, we identified four key dimensions that would drive scenario impact, including 1) the duration of the disruption, 2) the temperature and environmental conditions at the time of the hypothesized event, 3) the geographic area impacted by the disruption, and 4) the magnitude of the supply / demand imbalance. Once these were defined, we developed the upper and lower bound variable ranges for each dimension. These bounds were defined based on our research, which included working with FEI to define the appropriate scenario parameters, with input about system and stakeholder constraints from stakeholder interviews. This enabled us to identify actual conditions that reflect critical threshold values that would drive scenario impact. For example, OH&S has a minimum office temperature requirement of 16C, and employees should not be present in the office if the temperature is below this threshold.

Figure: Framework for defining scenarios



The notable conditions were defined intentionally, based on the insights from interviews and research on system and stakeholder constraints. These helped to ensure that scenarios developed were realistic and reflected real thresholds that lead to material changes to economic, social or environmental impact between scenarios. The rational is described below:

Table: Scenario development notable conditions

Dimension	Lower impact notable condition	Higher impact notable condition
Duration	**Health at risk** - 4 days, time that health risks emerge in lower temperatures	**Industry production halts** - 6 weeks, industry consumer can operate before production stops
Temperature	**Below freezing** - in an enclosed non-heated space, pipes burst, leading to property damage	**Office minimum** - OH&S office minimum of 16C for no work
Area	**Community outage** - smaller than a region, implies little to no industrial customers	**Regional outage** - outage impacts entire energy FortisBC operating region
Magnitude	**Some interruptible met** - some contracts for interruptible service are still met	**Only firm demand met** - No interruptible contracts are met, but all firm demand met

The result of this framework is the three scenarios defined below. Each scenario considers bounds and notable conditions and the relevant thresholds to develop the three scenarios:

[redacted]

[redacted]

2.2 Primary data collection

Interviews were used to understand how a natural gas supply disruption would affect key sectors of the BC economy. A total of 40 interviews were conducted with stakeholders, as detailed in the table below, including 22 interviews with gas consumers and government actors. The key interview questions included: experience of past natural gas disruptions (notably the Enbridge event), the impact of an outage on operations, mitigation processes in place (e.g. backup systems), costs incurred due to the disruption, and social and environmental implications. Several FEI departments were also interviewed to learn about the company's network operations, capacity levers and constraints.

Consumer interviews were selected to provide coverage of those sectors which are heavy natural gas users and represent a significant share of the BC economy. Combined, the consumer interviews covered sectors representing over 70% of the FEI system gas consumption. Within FortisBC, 18 interviews were conducted across a number of departments with a mix of executive leadership and senior management.

Table: Stakeholders interviewed by group, and number of interviews by group (in brackets)

Industrial consumers (9)	Commercial consumers (4)	Institutional consumers (9)	Fortis (18)
Pulp & paper	Offices / real estate	Vancouver Island Health Authority	FortisBC Energy Inc., FortisBC various departments, including:
Wood products	Hotel and food services	School District (Education)	Security Emergency Management and Facilities
Coal mining	Finance	BC Institute of Technology	Resource Development
Greenhouses	BC Chamber of Commerce	Two (2) municipal public services	Energy Supply and Gas Control
Cement		Municipal Waste Management	Integrated Resource Planning
Food production		BC Provincial Government	System Capacity Planning
Utilities		BC Institute of Technology	Public Sector & Commercial Accounts, Industrial Accounts
Animal production		BGIS Facility Management	Communications, Gov. Relations
Air transportation			Budgeting and Strategic Initiatives

2.3 Economic and fiscal impact modelling

Using the information obtained in these interviews a series of output shocks for each sector under the different gas outage scenarios was developed. To give one example, in the event of a total loss of gas supply, [redacted] which was estimated using the interview inputs along with the scenarios' parameters (which define the duration of the shock and geographical coverage) and economic data from Statistics BC and Statistics Canada. These direct output shocks by industry were then used in the assessment of wider economic impacts across the BC economy using Statistics Canada input-output multipliers to measure indirect and induced impacts. As defined below, indirect effects occur due to changes in supply chain spending [redacted] Induced effects measure the knock-on effects of employee spending, including those affected by indirect effects [redacted]

The economic footprint was therefore estimated at the direct, indirect and induced levels:

- **Direct impacts** result from direct output effects on the sector.
- **Indirect impacts** arise from the activities of the firms providing inputs to the sector suppliers (i.e. their supply chain)
- **Induced impacts** are the result of consumer spending by employees of the businesses stimulated by direct and indirect expenditures.
- **The total economic footprint** equals the sum of the direct, indirect, and induced economic impacts.

2.4 Wider impact assessment

The environmental impacts considered pertain to changes to the environment as a result of the natural gas disruption and the industries' responses. These impacts include changes in water and land use, waste disposal, water pollution and the greenhouse gas (GHG) emissions. Social impacts relate to changes in wellbeing of individuals and communities, including health and safety, education, livelihoods and community cohesion.

Interview findings were used to determine which social and environmental impacts would be most likely to occur and to assess their materiality. All wider impacts except GHG emissions were assessed in a qualitative manner. The potential for

increased carbon dioxide emissions was quantitatively estimated based on input from interviewees who, in the event of a gas outage, said they would shift to more polluting backup fuels such as diesel. To estimate the dollar impact of the GHG emissions, we assumed that the industrial customers maintain the same energy overall consumption but 100% of the shortfall is made up of diesel, and applied the social cost of carbon of $138CAD per/ ton of CO2 emissions based PwC meta-study of academic and government estimates[3].

2.5 Key limitations to the approach

The overall approach is subject to some limitations, including:

Sample size of primary research: There are tens of thousands of business gas customers, but the interview approach means only a small number of them can be sampled. To address this, we recognize the margin for error in results by providing a range of outcomes to reflect uncertainty and building conservatism into the estimates (as noted under sectoral coverage point below). Further primary research could be conducted in the future to increase the sample size of the research.

Sectoral coverage: Interviews have not covered every available sector (sample interviews covered over 70% of total consumption and over 50% of total provincial GDP), therefore the impacts of some sectors are not measured and no direct impact was modelled in sectors not covered by interviews. This builds additional conservativism into the estimates. Instead, proprietary multipliers (developed in collaboration with Stats Canada) were used to calculate indirect impacts on those sectors.

Refer to **Appendix** of this report for a complete list of limitations and assumptions.

3 Social cost of carbon $138CAD per/ ton of CO2 is based on an estimate current as of August 2019. Note the GHG reduction associated with reduced economic output was not quantified.

3. Key findings

3.1 Results by scenario

This section discusses the economic, social and environmental impacts associated with each scenario. The economic results illustrate the potential impact to BC's GDP in the event of a natural gas disruption. The social and environmental results are qualitative, with the exception of the impact of GHG emissions arising from substitution to backup fuels which were also quantified.

[redacted]

As summarized in the Figure above, the economic impact estimates vary substantially between the three scenarios. These variations are largely driven by the following scenario assumptions:

[redacted]

[redacted]

3.2 Breakdown of economic results

The following table shows the economic impacts by scenario and stakeholder group.

[redacted]

[redacted]

3.3 Key social and environmental impacts

The key social and environmental impacts identified in the study relate to greenhouse gas (GHG) emissions, education, health and livelihood.

An impact on GHGs would arise due to switching from natural gas to more polluting back-up fuels, including coal, wood and diesel, which may result in greater emissions. It was estimated that this could lead to between [redacted]

[4] As stated in the approach section, any reduction in GHG emissions associated with the decline in GDP was not quantified.

[redacted]

[redacted]

[redacted]

[redacted]

3.4 The implications of COVID-19

The analysis described in this report, including all primary research, was completed prior to the emergence of the COVID-19 pandemic and as a result does not incorporate any updated economic forecasts in the modelling or assumptions. Several considerations for how COVID-19 may affect the findings are set out below:

- **The economic cycle:** In the short term, economic forecasts have weakened, and it is expected that the economy will shrink in 2020. For example, the Conference Board of Canada now forecasts the real GDP in B.C. to decline by 3.8 per cent (a reduction of ~$9.6B, [redacted] this year, whilst pre-COVID-19 provincial GDP growth rate estimates were above 1 percent.[6] In the medium to long term, the economy is likely to return to previous trends and therefore this factor would only have a material impact to the estimates of economic loss if the gas outage event occurs in the short term.

- [redacted]

- [redacted]

[redacted]

[6] The Conference Board of Canada: Provincial Outlook Summary. May 27, 2020

- **Mitigation strategies put in place in response to COVID-19:** The enforced shutdown of workplaces under COVID-19 has several similarities to the effects modelled in the gas outage scenarios where some premises are assumed to close if temperatures cannot be maintained. As a result of COVID-19 many businesses have already invested in technologies to improve the efficiency of working from home and shifted business models to focus on on-line sales and deliveries. It is expected that some of the shift of working from home will become permanent. These factors may reduce the magnitude of the economic impacts estimated in [redacted] as firms are better able to mitigate the closure of premises.

- **Onshoring trends** - Onshoring is the return of manufacturing to developed countries. This phenomenon has been fueled in recent years by automation, increased labour costs in developing countries, increased trade wars, concern about intellectual property misappropriation and the increased demand for customization. It is expected that COVID 19 will accelerate onshoring with support from developed countries looking to secure supply chains and reduce dependence on China. Onshoring in North America will rely to some extent on the availability of inexpensive natural gas and is expected to increase the demand for natural gas in the future. This will tend to exacerbate the impact of the three scenarios depicted in this report.

Appendices

Appendix

Limitations

Input-output modelling: An Input-Output (IO) is used to assess indirect and induced economic impacts. These models represent the flow of money in an economy, primarily through the connection between industries. They show the extent to which different industries are buying and selling to one another in a particular geographic region. IO modelling is commonly used to determine the economic impact caused by an exogenous shock to the economy, in this case a fall in output driven by a disruption to the gas supply.

The input-output modelling approach is subject to several common limitations:

- **Constant returns to scale and fixed input ratios:** The same quantity and mix of inputs is needed per unit of output, regardless of the level of production. In other words, if output increases by 10%, input requirements will also increase by 10% across each input category.
- **Downstream supply shortages are not automatically modelled:** I-O multipliers assume there are no restrictions from availability of raw materials or employees.
- **The model is static:** No price forecasts or price variations are built into I-O multipliers.

Use of Primary research: PwC has relied on the information provided by the interviewees to estimate the direct impact on businesses of natural gas supply disruptions. A key assumption in the analysis is that the results obtained from these interviews were inferred across an entire sector of the economy. Whilst every attempt was made to interview representative organizations, this approach does imply there is a significant uncertainty over the direct impact estimates and as such these are presented as ranges. Where no businesses were interviewed in a given economic sector, it is assumed that there is no direct impact. This approach built in conservatism to the direct impact estimates.

Data limitations: PwC has relied upon the completeness, accuracy, and fair presentation of all information and data obtained from the various sources set out in our report, which were not audited or otherwise verified. The findings in this report are conditional upon such completeness, accuracy, and fair presentation, which have not been verified independently by PwC. Accordingly, we provide no opinion, attestation or other form of assurance with respect to the results of this study.

Receipt of new data or facts: PwC reserves the right at its discretion to withdraw or revise this report should we receive additional data or be made aware of facts existing at the date of the report that were not known to us when we prepared this report. The findings are as of August 2019 and PwC is under no obligation to advise any person of any change or matter brought to its attention after such date, which would affect our findings.

This report and related analysis must be considered as a whole: Selecting only portions of the analysis or the factors considered by us, without considering all factors and analysis together, could create a misleading view of our findings. The preparation of our analysis is a complex process and is not necessarily susceptible to partial analysis or summary description. Any attempt to do so could lead to undue emphasis on any particular factor or analysis.

We note that significant deviations from the above listed major assumptions may result in a significant change to our analysis.

[redacted]

[redacted]

Overview of major natural gas disruption events

Table: British Columbia natural gas disruption events (2009 - 2019)

Date	Location	Description
Oct 9, 2018	Prince George, BC	Enbridge T-South rupture
Jun 28, 2012	Buick, BC	Enbridge Nig Creek rupture
Jun 23, 2012	Fort St. John, BC	Enbridge valve enclosure fire
Feb 20, 2009	Wonowon, BC	Enbridge Alaska Highway pipeline sending barrel rupture

Table: Rest of Canada natural gas disruption events (2009 - 2019)

Date	Location	Description
Jan 25, 2014	Otterbourne, MB	TC Canadian Mainline rupture
Oct 17, 2013	Fort McMurray, AB	TC NOVA rupture
Feb 19, 2011	Beardmore, ON	TC Line 100 explosion and fire
Sep 26, 2009	Marten River, ON	TC Line 100 rupture
Sep 12, 2009	Englehart, ON	TC Line 2 rupture and fire

Table: Northwest US (WA, OR, ID, MT) regional natural gas disruption events (2009 - 2019)

Date	Location	Description
Mar 9, 2016	Seattle, WA	Puget Sound Energy distribution line rupture
Mar 31, 2014	Plymouth, WA	Williams Plymouth LNG facility explosion and fire

Diane Roy
Vice President, Regulatory Affairs

Gas Regulatory Affairs Correspondence
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~~CONFIDENTIAL~~

August 31, 2020

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Marija Tresoglavic, Acting Commission Secretary

Dear Ms. Tresoglavic:

Re: FortisBC Energy Inc. (FEI)

2020/2021 Annual Contracting Plan (2020/21 ACP) – British Columbia Utilities Commission (BCUC) Letter L-31-20 Compliance Filing - ~~CONFIDENTIAL~~

FEI files the attached report for review by the BCUC in compliance with Letter L-31-20, dated June 5, 2020, which directed FEI as follows:

> FEI to file, as a compliance document, an assessment of risks to gas supply resiliency, including both **commodity and capacity considerations**, in the near-term (1 year) and mid-term (5 years) and a discussion of alternatives available to mitigate these risks. This document should discuss potential contracts, investments, capital expenditures and strategies under consideration to address the risk of resiliency. FEI is to make this compliance filing to the BCUC by July 15, 2020.

At FEI's request, the BCUC changed the due date for this compliance filing to August 31, 2020.

In the attached report, FEI describes its plans to address resiliency in the short, medium and long terms. This includes descriptions of FEI's Tilbury expansion and automatic metering infrastructure (AMI) projects, for which FEI will be filing CPCN applications in the fall of 2020. In these CPCN applications, FEI will provide more detailed information on the projects, and many of the topics addressed in this compliance filing. Therefore, to avoid duplication of

questions and answers, FEI respectfully requests that information requests on the information in this compliance report be deferred to its upcoming CPCN applications.

Consistent with the treatment of FEI's Annual Contracting Plans, FEI is filing this compliance report on a confidential basis pursuant to section 71(5) of the *Utilities Commission Act*, section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-15-19, and section 6.0 of the BCUC's Rules for Natural Gas Energy Supply Contracts. FEI requests that the BCUC exercise its discretion to allow the Compliance Filing to remain confidential. The compliance report contains confidential, commercially sensitive information related to FEI's natural gas resource portfolio and future portfolio strategies to enhancing system resiliency. FEI procures its natural gas resources in a competitive market and it is customary for for competing gas purchasers to keep their gas supply procurement strategies confidential.

If further information about this submission is required, please contact Jordan Cumming, Energy Supply Planning Coordinator at (778) 578-3856.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

1. INTRODUCTION AND OVERVIEW

FEI files this report (Compliance Report) in compliance with BCUC Order L-31-20, which accepted FEI's 2020/21 Annual Contracting Plan (ACP). In Order L-31-20, the BCUC requested that FEI file an assessment of risks to gas supply resiliency, as follows:

> FEI to file, as a compliance document, an assessment of risks to gas supply resiliency, including both **commodity and capacity considerations**, in the near-term (1 year) and mid-term (5 years) and a discussion of alternatives available to mitigate these risks. This document should discuss potential contracts, investments, capital expenditures and strategies under consideration to address the risk of resiliency. FEI is to make this compliance filing to the BCUC by July 15, 2020[1].

FEI has provided safe and reliable natural gas service in the province for many years. To provide reliable service, FEI has maintained the integrity of its assets, and ensured the adequacy and security of its supply. FEI has also completed projects over the years that have significantly enhanced resiliency, such as the Southern Crossing Pipeline (SCP) and Mt. Hayes LNG facility. FEI's system exhibits a high level of reliability and has to date proven resilient to system failures and unforeseen events in the region. While FEI has long regarded resiliency as an important system attribute, the 2018 rupture of the Westcoast Energy Inc. (Westcoast)[2] T-South pipeline system (extending from northeastern B.C. to the Lower Mainland)[3] underscored the benefits that would come from new investments in system resiliency.

Broadly speaking, gas system resiliency depends on a combination of pipeline diversity, ample storage and the ability to manage load. FEI has assessed the various options in conjunction with external experts, and has concluded that FEI's system resiliency is best enhanced through a portfolio of measures. Just as FEI's ACP combines assets with distinct attributes to meet the shape of FEI's load profile, a portfolio approach to resiliency incorporate enhancements with distinct attributes that together provide a cost effective approach to resiliency. In the medium term, FEI's expansion of LNG storage and vapourization capacity at Tilbury, and Advanced Metering Infrastructure (AMI) project, will add key components to FEI's portfolio approach to resiliency while providing other benefits for customers. In the longer term, FEI will be looking at possible regional pipeline expansions to fill out its portfolio by increasing the diversity of regional pipelines, and also serve load growth.

Attached as Appendix A is an independent report by Guidehouse Inc. - formerly Navigant - (Guidehouse), entitled, "System Resiliency: A Critical Requirement of Natural Gas Systems" (Guidehouse Report). The Guidehouse Report was commissioned for inclusion in an upcoming CPCN application for new on-system LNG at Tilbury, but is included in this Compliance Report

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[1] The due date for this Compliance Report was subsequently changed to August 31, 2020.
[2] Westcoast is a subsidiary of Enbridge Inc.
[3] See section 3.2.2 below for a description of the T-South system.

due to its relevance to the subject of resiliency. The Guidehouse Report includes a comprehensive discussion of the resiliency of natural gas systems, from the wellhead to the customer meter set. The Guidehouse Report supports FEI's portfolio approach to enhancing system resiliency.

As already alluded to above, this Compliance Report anticipates a number of matters that FEI will be addressing in two CPCN applications it plans to file in the fall of 2020 related to additional on-system LNG storage[4] at Tilbury, and the broad deployment of AMI. Much of the material in this Compliance Report represents a summary of information being developed for those applications, since they will examine need and alternatives in detail. To the extent that the BCUC wishes to ask information requests on this material, FEI respectfully suggests that the upcoming CPCN proceedings would be the most efficient processes in which to do so. To facilitate this, FEI will include this Compliance Report as an appendix to its upcoming Tilbury and AMI CPCN applications.

In this Compliance Report FEI makes the following points:

- System integrity, reliability and resiliency are related but distinct concepts. Gas system resiliency depends on a combination of diverse pipelines, ample storage and load management. (Section 2)
- While FEI's system and the surrounding regional systems incorporate resiliency, e.g. through on-system and off-system storage and pipeline looping, it would be beneficial for FEI to make new investments to enhance system resiliency. (Section 3)
- Key enhancements to system resiliency that could be in service within 3 to 5 years include expansions of on-system LNG storage at Tilbury and AMI for FEI's residential and commercial customers. (Section 4)
- There are four possible pipeline expansions in the region that could be implemented in the longer term, but FEI prefers expansions to the SCP from a resiliency standpoint. (Section 5)
- A portfolio approach that employs a mix of pipeline diversity and expanded on-system storage will be the most cost-effective way to enhance resiliency. (Section 6)

2. WHAT IS SYSTEM RESILENCY?

Resiliency refers to the ability to prevent, withstand and recover from system failures or unforeseen events. In the following section, FEI will discuss how:

[4] FEI uses the term on-system LNG storage to refer to the combination of storage and vapourization (the latter providing the ability to convert the stored LNG back into gas for injection into the transmission and distribution system.

- resiliency differs from reliability and integrity and why all three attributes are necessary features of an energy system (Section 2.1);
- gas systems exhibit much higher levels of reliability than electric systems, but failures do occur (Section 2.2); and
- gas system resiliency depends on a combination of diverse pipelines, ample storage and load management (Section 2.3)

2.1 *RESILIENCY DIFFERS FROM RELIABILITY AND INTEGRITY – ALL ARE NECESSARY FEATURES OF AN ENERGY SYSTEM*

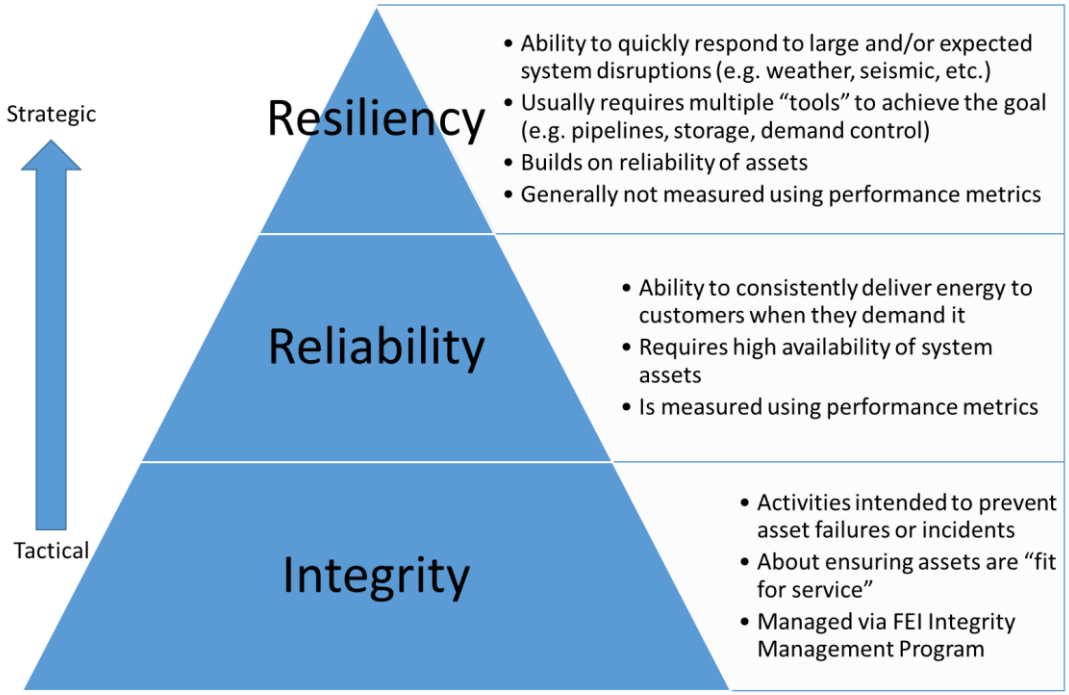
In the context of energy networks, the terms reliability and resiliency are sometimes used interchangeably, but they are not synonymous. Reliability and resiliency, as well as system integrity, are all desirable attributes of service to customers. In this section, FEI defines these concepts and illustrates how they relate to each other.

2.1.1 Integrity, Reliability, and Resiliency as Building Blocks of Customer Service

Figure 2-1 below depicts the concepts of resiliency, reliability and integrity as building blocks of customer service. As discussed in the figure and in the paragraphs that follow:

- **Integrity** (Section 2.1.2) is ongoing on a day-to-day basis, as it is focused on detecting and mitigating ongoing threats to system assets; it is more “tactical” in nature.
- **Reliability** (Section 2.1.3) is built upon or includes system integrity, and tends to be more of a strategic consideration (e.g., securing contracted assets for each gas year and infrastructure capital planning).
- **Resiliency** (Section 2.1.4) is a higher-level strategic consideration that typically requires longer-term planning and solutions. It is concerned with the capability of the system to withstand an unforeseen event, such as an upstream pipeline failure. Resiliency depends on having an appropriate combination of physical assets that can provide (a) continuity of supply to withstand the disruption or buy time to shut down the system in a controlled manner, and (b) the means to quickly and effectively shed enough load to stabilize the system before hydraulic collapse of the entire system occurs.

Figure 2-1: Hierarchical Relationship between Integrity, Reliability and Resiliency



2.1.2 Defining Integrity: Having System Components Meet Design Specifications Throughout Lifecycle

The **integrity** of system assets is the foundation of the reliability and resiliency of the natural gas system. In the context of gas transmission and delivery, integrity refers to the ability of individual system elements to meet their original design specifications, and to fulfil their intended purpose or application. The concept of integrity applies throughout the entire lifecycle of gas system assets including planning, design, procurement, fabrication, construction, commissioning, operations, maintenance, and retirement.

At FEI, integrity of gas system assets is tracked through its Integrity Management Program (IMP). The IMP is a comprehensive management system with the stated goal of striving for zero incidents of significant consequences. An incident of significant consequence can be generally defined as an event involving the functionality of a gas system asset which materially impacts safety, the environment or continuity of service to a large number of customers.

In the context of reliability and resiliency, the focus of integrity management on avoiding service disruption is key. Integrity management is concerned with avoiding incidents such as leaks and ruptures that would undermine the ability of the assets to deliver service. Thus, FEI's IMP uses tools and technology to detect and mitigate threats to system assets, such as corrosion, third party damage, and external forces such as landslides, floods, and seismic events. Consistent with industry practice, FEI is continually seeking improved methods to address these threats. By reducing the likelihood of these threats materializing, integrity management ensures that it is highly likely that the gas assets will be available to serve customers. As discussed below,

ensuring the ongoing fitness for service of FEI's gas assets is foundational to delivering safe and reliable service.

2.1.3 Defining Reliability: Adequacy and Security of Supply Throughout the Year

Reliability refers to designing and operating a system to ensure it meets the expected customer demand at all times, and is a combination of two concepts: **adequacy** and **security**. Adequacy refers to the ability to ensure a sufficient supply of energy, whereas security refers to the ability to consistently deliver that supply to customers.

- From the perspective of **adequacy**, maintaining reliability requires utility operators to have sufficient resources to balance their energy supply capacity with customer demand throughout the year. This is necessary to ensure adequate energy supply even during peak demand periods, while also being able to deal with the expected variability in customer demand at other times. To assist with this balance, energy can be stored directly (e.g., natural gas can be compressed, liquefied, or stored underground), or as a different form (e.g., in the electricity context, water held behind a hydroelectric dam).

- The **security** aspect of reliability is a combination of the concepts of integrity and redundancy. As discussed above, integrity is concerned (among other things) with preventing disruptions to service. Due to the nature of the assets and the success of integrity management in the natural gas industry, disruptions to natural gas service are relatively rare. In the electric industry, where the integrity of electric assets is more difficult to maintain, and disruptions are thus more frequent, redundancy is a mandatory requirement for reliable systems. While no mandatory redundancy requirements have been developed in the natural gas industry, gas assets such as storage and pipeline systems do incorporate a level of redundancy in their design and operation.

A feature of reliability is that it is measured using performance metrics that evaluate the availability of service to customers. In the electric industry, the common measures of reliability include the System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI), both of which are included in FortisBC Inc.'s service quality indicators. In the natural gas industry, because unplanned interruptions to service are relatively rare, metrics related to integrity are a proxy for reliability. Thus, FEI's reliability of service quality indicators include reporting on pipeline incidents and leaks. Section 2.2 below discusses further the reliability of gas systems in comparison to electrical systems, emphasizing that unplanned gas supply interruptions are low probability but potentially high consequence events.

2.1.4 Defining Resiliency: The Ability to Manage Through and Recover from Unexpected Events

Resiliency refers to the ability to prevent, withstand and recover from system failures or unforeseen events. Resiliency is directly linked to the concept of reliability in the sense that a system cannot be resilient without first having reliable components. However, resiliency also encompasses concepts such as preparing for, operating through, and recovering from significant disruptions, no matter the cause.

Section 1.1 of the Guidehouse Report differentiates resiliency from reliability in this way:[5]

> In the context of natural gas pipeline transport and distribution systems, resiliency and reliability are two discrete concepts. Natural gas utility companies plan for and target outcomes of resiliency and reliability in their systems. …
>
> - Reliability is the ability of the energy delivery system to provide customers with an expected natural gas service on a consistent basis.
> - Resiliency is the ability to prevent, withstand and recover from system failures or unforeseen events such as damage and/or operational disruption that impact the operations of the system.
>
> As the cornerstone of this report, resiliency comes from the ability of the natural gas system to offer services, backed by physical assets, that enable market participants to prevent, withstand and recover from man-made or natural events that interrupt the flow of gas. The natural gas utility is charged with the responsibility to manage these risk of system disruptions on behalf of end-users by constructing a portfolio of natural gas transportation, on and off-system storage resources and supply contracts that will enable it to address unforeseen events.
>
> Infrastructure combined with contractual assets are the backbone of reliability. Achieving the backbone requires appropriate system sizing coupled with commercial agreements and experienced operators. When all of this is taken together, it increases the probability of achieving the expected reliability of gas delivery.
>
> In a similar fashion, resiliency is achieved by selectively building system redundancy via commercial agreements with tangible upstream physical assets and on-system physical assets to respond to unexpected physical events. Resiliency embedded in the system enables the system to manage and recover from unexpected events more effectively and expeditiously.

As noted by Guidehouse above, building system redundancy is a key way to improve resiliency. This type of redundancy may not increase reliability metrics in any given year, but will enable

[5] Guidehouse Report (August 2020). "System Resiliency: A Critical Requirement of Natural Gas System." Appendix A - Page 6

the utility to withstand system failures and unforeseen events and prevent disruptions to gas supply when such events occur.

Resiliency, as the ability to prevent, withstand, and recover from system failures or unforeseen events, is critical for natural gas systems because the consequences of a lack of resiliency can be significant. Specifically, insufficient resiliency poses a risk of an **uncontrolled shutdown** of the distribution system (also called **hydraulic collapse**). An uncontrolled shutdown or hydraulic collapse occurs when parts or all of the gas distribution system are naturally lost due to a collapse of system pressure and gas supply. An uncontrolled shutdown is a serious scenario both in terms of service disruptions to customers as well as the potential for safety concerns:

- When the pressure in a portion of the gas system collapses in an uncontrolled manner, FEI is unable to directly determine which customers are receiving sufficient pressure to operate their appliances or equipment safely. These pressure variations can vary both in time (as the event progresses) and location (from area to area or even street to street). This uncertainty greatly complicates the ability of FEI to localize, manage and respond to the supply deficiency.

- From a safety perspective, the uncontrolled drop in gas pressure can also introduce the possibility of air being drawn into the gas distribution grid. This is a potentially hazardous situation as the gas-air mixture can result in fire or explosion risks. Entrained air can also blow out the flames in customer appliances or equipment resulting in mis-operation and possible gas odour calls. Consequently, any air within the gas distribution pipes must be carefully purged by technicians attending each customer premise prior to relighting any appliances. This purge and regasification process could take days to months, depending on both the scale of outages and access to qualified resources.

Given these significant consequences, a key aspect of resiliency is being able to manage through extreme events in a way that avoids uncontrolled shutdowns, including, if necessary, a **controlled shutdown** and restoration of the system. For example, a system exhibits resiliency if there is sufficient on-system resources (LNG storage and vapourization[6]) to bridge the period of upstream supply disruption. If sufficient on-system LNG resources are not available to bridge the entire period of disruption, they still provide a level of resiliency by providing time for the utility to implement a controlled shutdown of the system. A controlled shutdown is a planned and safe depressurization of a part of the gas system using strategic control points, including stations and valves. It is far better from the perspective of customers, the utility, and society generally, if the utility has time to implement a controlled shutdown. In a controlled shutdown, FEI is aware of which areas and customers are no longer supplied with natural gas, which allows for safe regasification and relights of customer appliances. While a controlled shutdown is considered a measure “of last resort", it provides valuable flexibility to the operator when all

[6] Vapourization capacity determines the rate at which the LNG in the tank can be regasified, and thus determines the extent to which on-system LNG can serve daily requirements. A higher rate of vapourization means that a larger percentage of the daily load can be met. The volume of the tank is linked to how many days over which that percentage of daily load can be served.

supply options are exhausted and improves customer service by minimizing the scale and duration of any necessary outages.

In summary, the concept of resiliency includes the ability to withstand unforeseen events and prevent a shutdown of any kind. This can be achieved, for example, through on-system storage to manage short-term events, and redundancy in pipeline capacity to withstand longer-term disruptions. Resiliency, however, also includes the ability of the utility to manage through an extreme event via a controlled shut down and restoration of the system in a manner that minimizes service disruption. This type of resiliency can be enhanced through features of AMI that permit remote shut-down and other technologies to increase load control. In short, a resilient system is one that has multiple tools available to 'weather the storm' without an uncontrolled shutdown and minimize service disruption.

2.2 GAS SYSTEMS EXHIBIT A MUCH HIGHER LEVEL OF RELIABILITY THAN ELECTRIC SYSTEMS, BUT FAILURES DO OCCUR

In general, gas transmission and distribution systems experience significantly fewer outages than electric networks.[7] However, when gas customer outages do occur, they tend to be longer in duration (due to the need for purging and appliance relighting, as described above). Resiliency investments for the natural gas system are consequently focussed on addressing low probability events. But events can and do occur, and they can give rise to significant consequences.

The vast majority of electric transmission infrastructure in North America is via overhead power lines, which are more exposed to disruptive events including lightning, wind, ice, trees and third-party contacts. Consequently, electric powerlines have considerably higher outage rates than underground gas lines.

Based on industry experience, on average, a typical 80 km overhead electric transmission circuit is expected to experience one unplanned outage event per year[8]. Since circuit outages are an expected occurrence in electric networks, asset redundancy is commonly employed to ensure compliance with minimum standards of reliability. Indeed, the BC Mandatory Reliability Standards require that the bulk electric system be planned and operated to withstand an unexpected outage of the single most critical system element, coincident with the forecast

[7] Industry surveys and studies conducted by the US Gas Technology Institute have demonstrated gas customer average reliability/availability levels (due to unplanned causes) of 0.9999978. (Gas Technology Institute, Topical Report (July 19, 2018) "Assessment of Natural Gas and Electric Distribution Service Reliability," p. 10.) This is consistent with service availability levels of the Canadian Gas Association when comparing outage incidents. In contrast, the comparable average availability for most electric customers in BC is approximately 0.99959.

[8] North American Electric Reliability Corporation. "Outage Metrics, 2019 WECC AC Circuit." Total Circuit Outage Frequency of 1.97 per 100 mi·yr (for 200-299kV circuits).

system peak load, while not experiencing any firm customer outages[9]. This is referred to as the *N*-1 reliability criterion and is based on North American industry standards. These industry standards were developed and mandated following two major Northeast blackouts, one in 1965 and one in 2003. In other words, the cost of this necessary system redundancy is broadly accepted by electric operators and regulators in order to ensure adequate levels of customer service.

In contrast, large-diameter, high-pressure pipelines may operate for long periods without experiencing any unplanned outage events. As such, regional gas transmission systems are typically designed and operated to transport a contracted quantity of gas, as opposed to being explicitly planned to achieve an expected level of reliability. To FEI's knowledge, there are no specified regulatory requirements for gas system reliability anywhere in North America equivalent to the electric utility *N*-1 criterion. However, in interconnected gas networks with numerous supply points interspersed with multiple delivery points, a reliable network is a consequential outcome. Thus, in many areas of North America, the redundancy afforded by multiple gas supplies, storage, and transportation paths results in an inherently resilient system.

The rates of reliability would suggest that, on average, a typical natural gas customer in BC would expect 69 seconds of service outage per year, compared to almost four hours per year for a typical electric customer in BC (even with the high standards of redundancy on the electric system).[10] In practice, the vast majority of FEI's customers have never experienced a single natural gas outage, other than for planned reasons such as a meter exchange.

Gas pipeline failures are thus relatively rare occurrences; however, they can be high consequence events. If a rupture followed by ignition occurs, the result may be significant property damage, or harm to individuals in the vicinity of the failure. Further, if there is insufficient pipeline redundancy in the region, the reduced transportation capacity can potentially lead to gas shortages or outages to large numbers of downstream customers. This was demonstrated during the T-South pipeline system rupture in October 2018. Within BC, this gas supply disruption is the closest analogy to the Northeast electric blackouts of 1965 and 2003.

The ability of a natural gas system to withstand and recover from extreme or prolonged events is becoming increasingly relevant. Much of the infrastructure in the region is aging, which increases the risk of failures due to time-dependent threats. It is also possible that disruptive events, such as wildfires, landslides, and floods, are becoming more frequent and severe, which increases the risk of damage to the pipeline infrastructure.

In summary, it is common for electric networks to experience frequent, but relatively low-consequence outage events. In contrast, gas systems typically exhibit low-probability, but

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[9] BCUC Order Number R-27-18 (June 28, 2018). "British Columbia Hydro and Power Authority Mandatory Reliability Standard TPL-001-4 Assessment Report." P. 8, Attachment D.

[10] Gas Technology Institute, Topical Report (July 19, 2018), "Assessment of Natural Gas and Electric Distribution Service Reliability." Online: https://www.gti.energy/wp-content/uploads/2018/11/Assessment-of-Natural-Gas-Electric-Distribution-Service-Reliability-TopicalReport-Jul2018.pdf

potentially high consequence failures. This is a fundamental underpinning for the options currently being evaluated by FEI to increase resiliency, which will be discussed in Section 4 and 5 of this Compliance Report.

2.3 *GAS SYSTEM RESILIENCY DEPENDS ON A COMBINATION OF DIVERSE PIPELINES, AMPLE STORAGE AND LOAD MANAGEMENT*

Broadly speaking, and leaving aside adequacy of supply, there are three elements that contribute to natural gas system resiliency:

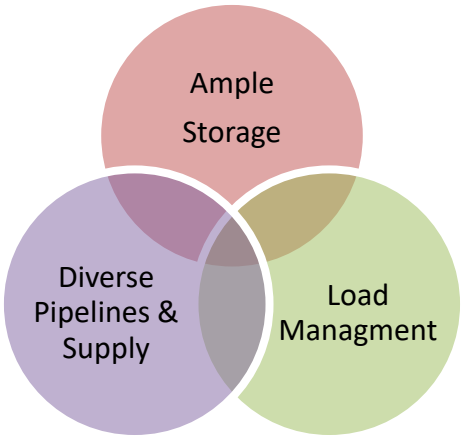
1. **Diverse Pipelines and Supply:** Pipelines can continuously transport a significant amount of gas supply to the market centres on a daily basis, and therefore address customers' baseload and seasonal demand requirements. Having access to multiple regional pipelines, preferably separated geographically, to serve the distribution system improves a utility's ability to dependably collect and deliver gas supply to consumers.

2. **Ample Storage:** Access to storage, preferably located on a utility's own system, allows a utility to manage expected or unexpected changes in supply for a period of time. It can bridge a shortfall in supply entering the utility system, or provide time to shed load or implement a controlled shutdown of portions of the system to avoid hydraulic collapse. The two common storage mediums are underground and LNG. Underground storage uses natural geological formations to hold supply in gaseous form, and (in FEI's case where underground storage is off-system) requires a functioning regional pipeline to transport stored natural gas to the utility distribution system. LNG needs to be accompanied by adequate vapourization to convert the LNG back to gas for delivery to customers. On-system LNG storage has the benefit of being able to inject supply close to the load centres, and is not reliant on functioning regional pipeline infrastructure.

3. **Load Management:** The ability to manage load during a period of supply constraint allows an operator to shed load in a controlled shutdown, while ensuring the constrained supply of gas is maintained for the maximum number of customers. Until recently, the only options for gas load curtailment were through broad public appeals to reduce consumption, or direct curtailment requests to large volume and/or interruptible customers. The former has no certainty of customer compliance, while the latter may not be sufficient to prevent a system collapse. Neither may be timely enough during a rapid-onset supply disruption. Even measures directly in the control of the utility (e.g. closing valves or shutting-in stations supplying entire communities), may not be sufficiently responsive. Newer technology (for example, the deployment of AMI with remote-shutoff valves) instead allows the utility operator to quickly, accurately, and directly target any required customer load shedding. Relying on load management inherently means disrupting service to customers, and is ideally used in conjunction with other supply-based solutions.

FEI views resiliency as a combination of the above three elements, as depicted in Figure 2-2.

Figure 2-2: Key Elements of a Resilient Gas System



Since each of the three elements adds resiliency in distinct, but complementary ways, the resiliency of FEI's system is optimized through an appropriate combination of all three. For instance, on-system LNG storage can provide the immediate response capabilities to ensure survival of FEI's system during a critical supply emergency. Diversifying regional pipeline infrastructure would help FEI withstand a longer-term interruption or constraint on the T-South system. Load management (potentially facilitated by technology upgrades like AMI) will enable FEI to avoid an uncontrolled shutdown in extreme events, and initiate a controlled shutdown and restoration if necessary.

3. FEI'S CURRENT STATE OF SYSTEM RESILIENCY

FEI's system, and infrastructure in the region, currently incorporates features that provide resiliency, including all three elements identified in Figure 2-2 above. FEI's own transmission system, including the Vancouver Island Transmission System (VITS), and the Coastal Transmission System (CTS), incorporates some pipeline redundancy, providing a degree of resiliency. In terms of the regional infrastructure, FEI's Southern Crossing Pipeline provides some resiliency to FEI's interior system from a different network of pipelines for example. While the T-South system is located on a single right of way, it incorporates pipeline loops and two lines operated together as a system. The Mt. Hayes LNG facility also provides a material amount of on-system support, particularly to the Vancouver Island system, and the Tilbury LNG facilities (the legacy LNG facility at Tilbury (Tilbury Base Plant) and Tilbury 1A) and off-system regional storage facilities provide some resiliency benefits. FEI also has the ability to manage load by enlisting customer support and manually shutting-in customers or segments of the system. However, all three resiliency elements – pipeline, storage, and load management – could be enhanced. FEI has determined that it makes sense to pursue resiliency enhancements in all areas.

This Section will discuss how:

- FEI's own transmission system incorporates some pipeline redundancy (Section 3.1);
- Existing on-system storage and regional pipeline resources could be expanded or diversified to enhance resiliency (Section 3.2);
- The limited regional pipeline infrastructure, and FEI's resulting heavy dependence on the T-South system, elevates risk of supply disruption relative to areas of North America served by a web of pipelines (Section 3.3); and
- FEI's current supply portfolio incorporates strategies to mitigate a portion of risk to gas supply resiliency in the 1 to 3 year term (Section 3.4).

3.1 *FEI'S TRANSMISSION SYSTEM INCORPORATES PIPELINE REDUNDANCY*

FEI's own transmission system has a degree of resiliency due to the redundancy incorporated into its design. This redundancy has been incorporated as the need arose for additional system capacity to supply customers during peak load periods.

Over the years, FEI has looped various segments of the transmission system to increase capacity. For example, FEI added an NPS[11] 42 pipeline in parallel with existing NPS 18 and NPS 30 pipelines in 1977 and 1992, and looped the existing NPS 20 and NPS 24 pipelines with an NPS 36 pipeline during the Coastal Transmission System upgrade project in 2017. While each of these projects were undertaken to increase the available capacity at peak times, a secondary benefit is that they also allow one of the parallel pipeline sections to be removed from service during lighter-load periods, if required for maintenance, inspection, or repair.

Similarly, in the application for the Fraser River South Arm Crossing Upgrade project[12], the BCUC supported the need to replace two existing, seismically-vulnerable NPS 20 and NPS 24 pipelines with two new pipelines. In its determination, the BCUC noted that this solution was not the "least-cost" alternative (for example, as compared to replacement with a single pipeline), but agreed it was the most cost-effective alternative and would securely address the seismic, erosion, and dike settlement risks of the project.

Further, in the Lower Mainland Intermediate Pressure System Upgrade project[13], the integrity-driven need to replace an NPS 20 pipeline between Coquitlam and Vancouver also presented the unique, one-time opportunity to increase the pipe size to NPS 30 and consequently enhance capacity and hence the resiliency of supply to customers in the Vancouver, Burnaby, and North Shore areas. Once again, the BCUC agreed that the increased flexibility and resiliency benefits justified the added project costs associated with the pipe size increase.

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[11] Nominal Pipe Size diameter, in inches.

[12] Certificate of Public Convenience and Necessity for the Upgrade of the Transmission Pipeline Crossing of the South Arm of the Fraser River granted by the BCUC via Order C-2-09, dated March 12, 2009.

[13] Certificate of Public Convenience and Necessity for the Lower Mainland Intermediate Pressure System Upgrade granted by the BCUC via Order C-11-15, dated October 16, 2015.

These projects demonstrate how FEI considers the requirement to maintain or enhance system resiliency where it can be achieved cost-effectively. FEI will continue with this practice as it plans and upgrades its transmission system.

3.2 *RESILIENCY CAN BE IMPROVED BY EXPANDING ON-SYSTEM LNG AND NEW REGIONAL PIPELINE INFRASTRUCTURE*

FEI's resiliency needs are influenced by its physical location within the broader regional pipeline system, as well as customer load and composition. FEI's system is positioned in a regional pipeline corridor with limited network connectivity, making FEI dependent on the T-South system. FEI also serves a significant load with an overall low load factor[14], making regional pipeline additions more difficult to justify from the perspective of an efficient supply portfolio alone. Expansions to on-system LNG storage would help enhance the resiliency of FEI's system by providing the immediate response capabilities to ensure survival of the system during a critical supply emergency, and dovetails well with FEI's efficient supply portfolio and load profile. The addition of new regional pipeline infrastructure, preferably constructed in a corridor different from the T-South system, would help ensure that some supply is available during an event that involves a sustained loss of pipeline capacity.

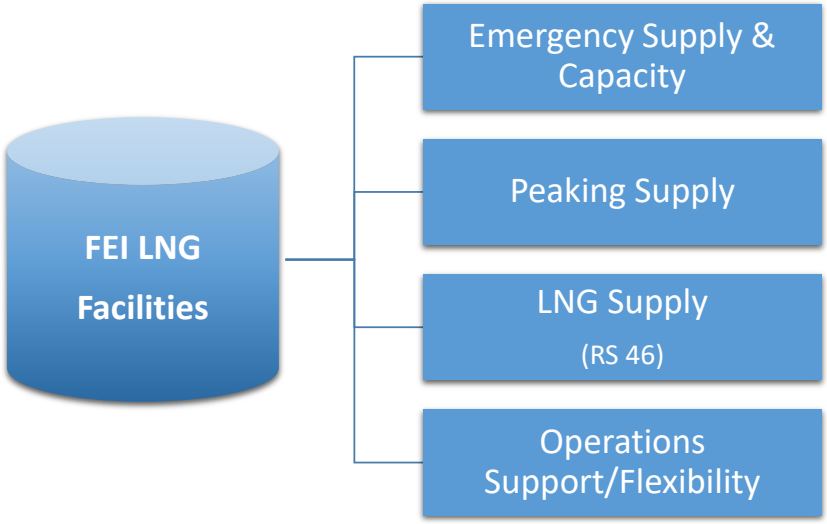
3.2.1 Existing On-System Storage In the Region

As indicated in Figure 2-2, ample storage is one of three key elements of a resilient gas system. This section describes FEI's existing on-system LNG infrastructure, which is comprised of the Tilbury and Mt. Hayes LNG facilities, and explains why expanding the Tilbury LNG storage and vapourization is desirable to enhance resiliency.

From a planning perspective, FEI's LNG facilities provide a number of beneficial purposes as shown in Figure 3-1 below.

[14] Load factor is a measure of the customer utilization of pipeline assets. It is equal to the customers' average demand divided by their peak day demand.

Figure 3-1: Multiple Roles of FEI's LNG Facilities



These roles are explained in further detail below:

- **Emergency Supply and Capacity** refers to the use of LNG to offset a supply shortfall and/or to provide additional capacity (via increasing pressure on the system) during a gas supply emergency;
- **Peaking Supply** refers to the use of LNG to provide supply during peak demand events due to cold weather. Similar to the above, LNG can provide additional capacity (by increasing pressure on the system) during a peaking event;
- **LNG Supply** refers to the use of LNG as a fuel source for transportation or remote energy use, such as FEI Rate Schedule (RS) 46 customers; and
- **Operations Support / Flexibility** refers to the use of LNG to support maintenance activities that may require specific flow conditions (i.e. in-line inspection) or temporary reductions in capacity.

FEI's on-system LNG inventory is managed on an integrated basis to provide these customer benefits. As part of its planning, FEI considers how much inventory may be needed for each function to ensure adequate resources are available to manage these events when they do occur.

The Tilbury Base Plant was designed and built between 1969 and 1971 and has operated since commissioning with an excellent safety and reliability record. The facility was built to provide peaking supply, while also providing an important on-system capacity resource. The Tilbury Base Plant is strategically located providing on-system storage and gas supply support in the Lower Mainland load centre and as such, it provides benefits related to security of supply,

reliability and flexibility to serve loads within FEI's system. These are important benefits when mitigating temporary operational issues associated with FEI's pipeline infrastructure.

While the Tilbury Base Plant provides natural gas supply for short durations when demand during cold weather events exceeds contracted supply, it is not able to support the Lower Mainland demand in the event of a significant disruption in gas supply flowing to the Lower Mainland. The vapourization capacity at the Tilbury Base Plant (150 million cubic feet per day (MMcf/day)) is sufficient to serve 17 percent of the peak day requirements of FEI's RS 1 to 7 customers and RS 23 and 25 customers (i.e., Firm Rate Schedule customers) in the Lower Mainland based on the 2019/2020 load forecast.

The Mt. Hayes LNG facility also provides natural gas supply for short durations during cold weather events, but also provides a significant resiliency benefit to customers on Vancouver Island. This facility (which is much newer than the Tilbury Base Plant) is capable of serving the peak day load on Vancouver Island for approximately 10 days without relying on transmission support from the Lower Mainland. On low demand days on Vancouver Island, it is possible to physically flow gas from the Mt. Hayes LNG facility to the Lower Mainland by reverse flowing the VITS. However, this capability diminishes as Vancouver Island demand increases and is effectively zero during cold winter load periods. As such, the Mt. Hayes LNG facility could not also support the Lower Mainland to any significant extent.

[redacted]

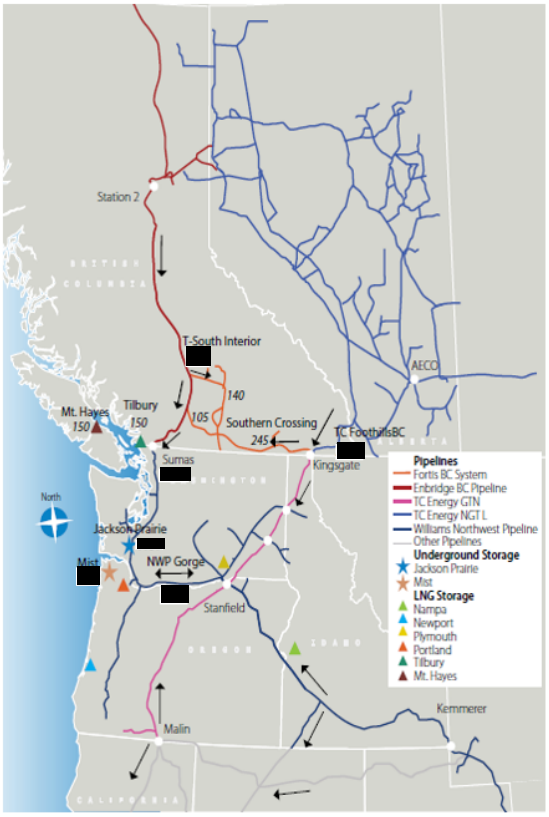
3.2.2 Existing Regional Pipeline Infrastructure

As described below, there are inherent limitations in the resiliency of regional pipeline infrastructure. There are also market and other constraints that have impeded the development of new infrastructure that would enhance resiliency in the region.

3.2.2.1 There Is Limited Pipeline Interconnectivity in the Region

The Westcoast T-South and TC Energy (collectively, Nova Gas Transmission, Foothills BC and Gas Transmission Northwest) transmission systems serving FEI and the broader Pacific Northwest Region are predominantly in north-south corridors with limited interconnectivity between them as shown in Figure 3-2 below.

Figure 3-2: Regional Gas Infrastructure



Source of Regional Gas Infrastructure Map: Northwest Gas Association

Pipeline	Daily Deliverability[1] (MMcf/day)
Enbridge T-South (Huntingdon Delivery Area)[2]	[redacted]
Enbridge T-South (BC Interior)	
FortisBC ITS (Oliver North)	140
FortisBC SCP (Oliver to Kingsvale)	105
FortisBC SCP (Yahk to Oliver)	245
TC FoothillsBC	[redacted]
NWP Gorge	

Market Area Storage	Daily Deliverability (MMcf/day)	Storage Capacity (Bcf)
Jackson Prairie (JPS)	[redacted]	25
Mist		19

On System Storage	Daily Deliverability (MMcf/day)	Storage Capacity (Bcf)
Mt. Hayes LNG	150	1.5
Tilbury LNG	150	1.6

1. Daily deliverability is the maximum amount of gas that can flow on the pipeline or the maximum amount of gas that can be withdrawn out of storage. It is important to note that the daily deliverability out of the market area storage is assuming storage inventories are full. These resources do have withdrawal rates decline as working gas volumes decline.

2. Including 105 MMcf/day T-South Kingsvale to Huntingdon capacity.

The T-South system consists of two looped gas transmission pipelines operating as a single system. The T-South system connects production fields in northeast BC with the Lower Mainland (Huntingdon) and Williams Northwest Pipeline (NWP) at Sumas, Washington. The T-South system flows north to south and runs approximately 916 km between Station 2 and Huntingdon. The two pipelines comprising the system are tied together by common headers and compression stations and hence are operated as a single pipeline.

U.S. utilities along the Interstate 5 (I-5) Corridor also receive gas supply from the T-South system but their dependency is somewhat mitigated by pipeline diversity, and off-system storage. An east to west interconnecting pipeline in the Columbia River Gorge corridor provides 534 MMcf/day of interconnecting capacity between the two north-south pipeline systems in the U.S. Moreover, facilities at Mist and Jackson Prairie (JPS) provide approximately 44 billion cubic feet (BCF) of on-system storage and up to 1,798 MMcf/day of capacity to the I-5 corridor load centres.

In contrast, FEI has limited connectivity between the two north-south pipeline systems in BC, as Figure 3-2 illustrates above. FEI sources a small portion of supply from the TC Energy system in southeast BC, which is transported east to west through FEI's SCP to serve the various communities in the Interior of BC. Approximately 105 MMcf/day of east to west connectivity from SCP can also be utilized to provide gas supply to customers in the Lower Mainland, via

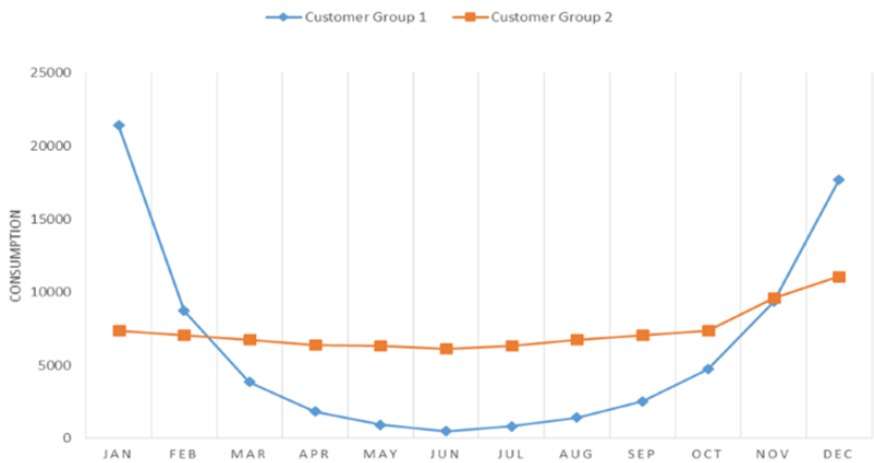
FEI's interconnect with the T-South system at Kingsvale. However, 105 MMcf/d represents [redacted] of the total Lower Mainland design day demand for 2019/2020. The SCP pipeline system also has limited capacity at this time, and also relies on a segment of the T-South system (Kingsvale to Huntingdon) to deliver gas to the Lower Mainland. This places a constraint on how much FEI is able to diversify its sourcing of gas supply away from northeast BC, so as to reduce its significant reliance on Westcoast's T-North[15] and T-South systems.

3.2.2.2 Regional Pipeline Development Reflects Regional Load Profile

As discussed below, the current limitations on system resiliency in regional pipeline infrastructure can be attributed to the region's load profile and composition of end users, as well as the high costs associated with pipeline additions/expansions.

There are two distinct types of customer profiles, one that is comprised of residential and commercial customers which is heat sensitive, and the other comprised of industrial customers which is relatively flat throughout the calendar year. These load profiles are illustrated in Figure 3-3 below.

Figure 3-3: Customer Load Profiles



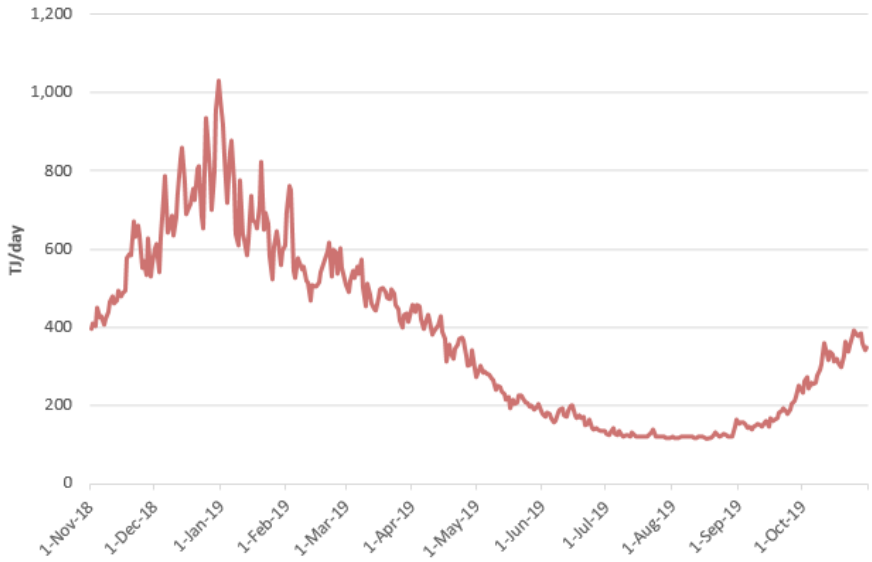
Customer Group 1	Rate Schedule	Customer (#)	Load Factor	Usage Per Customer
Residential	1	934,667	32%	86
Commercial	2	88,318	31%	332
	3	6,333	38%	3,612
	23	1,511	37%	5,056
Customer Group 2	**Rate Schedule**	**Customer (#)**	**Load Factor**	**Usage Per Customer**
Industrial	5	355	46%	14,792
	25	475	56%	26,686

# of customer and customer usage as per 2019 FEI Annual Report

[15] FEI contracts T-North Capacity to transport gas supply to and from the Aitken Creek storage facility. Aitken Creek is currently connected to the T-North section of the WEI pipeline system, which is supplied from several major gas processing plants.

As Figure 3-3 shows, the load profile of residential and commercial customers (Customer Group 1) is significantly higher in the winter months than in the summer months, and therefore has a low load factor. In contrast, industrial customers (Customer Group 2) exhibit a load profile that is less heat sensitive. Given that the majority of FEI's customers are residential and commercial, the load requirements for all service regions are significantly higher during the winter compared to the summer, as Figure 3-4 illustrates below. This annual load profile is consistent with other utilities along the I-5 corridor.

Figure 3-4: FEI's 2018/19 Core Customer[16] Load Profile (Actuals)



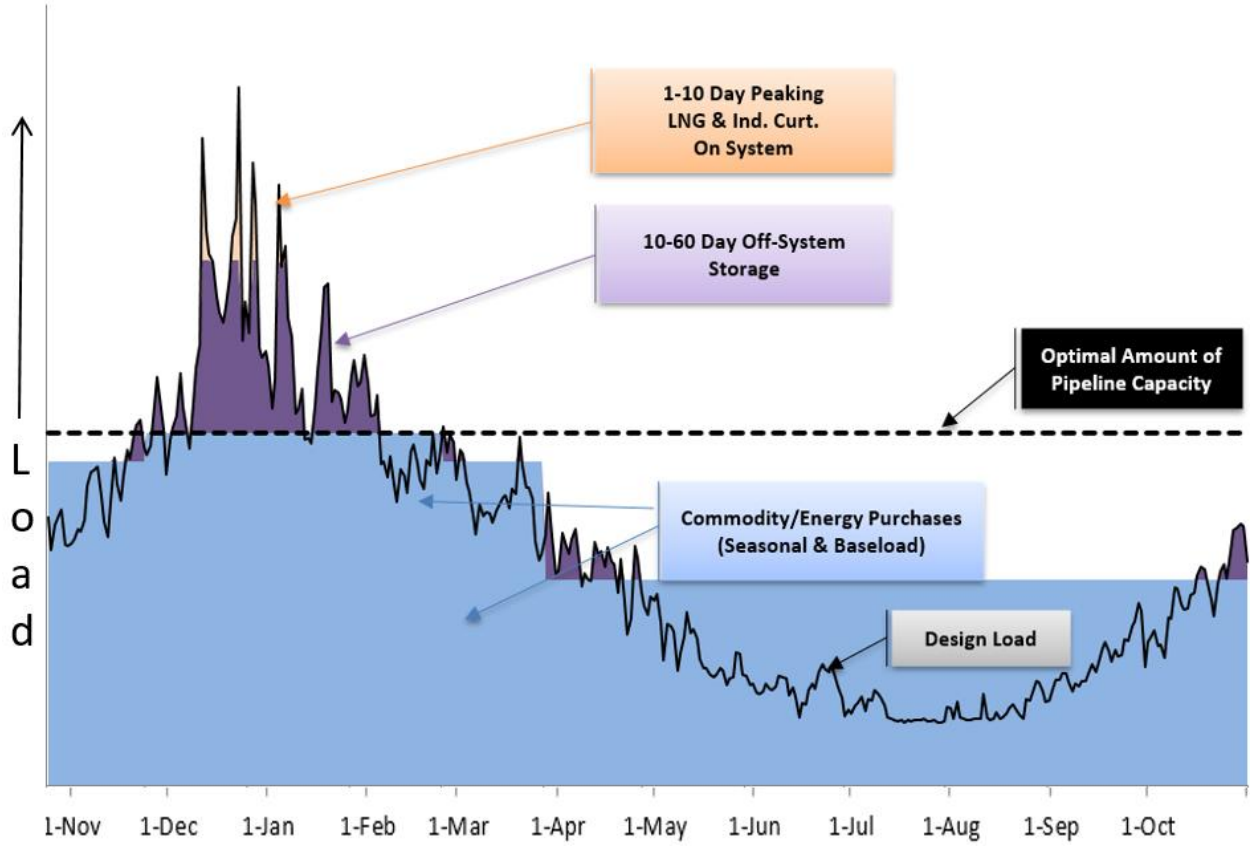
The region's infrastructure (regional pipeline, off-system storage, and on-system storage) has been built over time to match this type of load profile with a focus on cost efficiency. Shaping resources to match the load profile is generally the primary factor in regional gas infrastructure development given the high reliability of pipeline resources as discussed in Section 2 above.

FEI optimizes its supply portfolio annually based on the available infrastructure in the region, and this portfolio is described in FEI's Annual Contracting Plan filed with the BCUC. FEI's portfolio is designed to deliver enough gas supply into its distribution system to meet its Core load's design peak day, as well as the winter and annual load requirements for the upcoming gas year (November to October). In general terms, the optimal supply portfolio (Figure 3-5 below) includes

- pipeline capacity to meet annual and seasonal demand;
- off-system storage resources to meet colder periods (10-60 days); and
- LNG storage to meet peak demand (1-10 days).

[16] Core Customers are defined as Rate Schedule (RS) 1 to 7 and RS 46 customers.

Figure 3-5: FEI's 2018/19 Core Customer Load Profile (Actuals)



Given the low load factor during the summer for FEI's customers and the region as a whole, pipeline capacity is generally underutilized throughout the months between April and October. This is a contributing factor as to why pipeline expansions to meet customer load growth have been limited over the past several decades. The last pipeline expansion built to serve regional demand was the SCP, in 2000.

3.2.2.3 Regional Pipeline Infrastructure Development Limited by High Cost

The high costs associated with underwriting regional pipeline capacity is another reason why there has been limited new pipeline infrastructure in the region over the past several decades. To underwrite the cost of the new pipeline infrastructure generally requires broad regional support, backed by firm transportation contracts. On this point, Guidehouse states:[17]

> Given the high cost of pipeline construction, pipeline projects require scale and most often need multiple customers to enter into long-term transportation agreements to support the economics. In addition, the U.S. FERC requires a

[17] Guidehouse Report (August 2020). "System Resiliency: A Critical Requirement of Natural Gas System." Appendix A - Page 40.

> demonstration of market need, i.e., precedent transportation agreements, before it will issue a certificate of public convenience and necessity to authorize pipeline construction. In Canada, interprovincial pipeline proposals receive similar consideration by the [Canadian Energy Regulator] CER while intra-provincial pipeline projects in British Columbia are reviewed by the BC Oil and Gas Commission and the BCUC. Regional pipeline construction in BC and the U.S. PNW region will only happen if large industrial projects that require natural gas come to fruition.

Historically, the regional market and regulatory model have not supported the construction of pipelines to add redundancy for reliability and/or resiliency. Rather, it has led to assets being constructed to meet the size and shape of the load in the region.

Furthermore, while the cost and regulatory requirements mean that regional cooperation is required for major pipeline infrastructure, it has historically been a challenge for regional shippers, such as utilities along the I-5 corridor, to agree on what the region requires to meet future load growth. This challenge, along with the difficulties in justifying the high cost of pipelines that are not utilized 365 days a year, has inhibited pipeline development in the region.

As a result of these challenges, the region has relied on lower cost smaller scale expansions, specifically, through storage assets such as off-system storage (Jackson Prairie and Mist) or on-system utility infrastructure (i.e., FEI's Mt. Hayes LNG Facility). However, regional gas demand has continued to grow since the last pipeline expansion (the SCP in 2000), and so additional pipeline infrastructure may now be appropriate from a demand perspective, which could also benefit system resiliency.[18] Section 3.4.3.2 of this Compliance Report discusses in greater detail how the forward market prices at Sumas/Huntingdon are signaling to the market that additional infrastructure is required.

3.3 *RISK OF SUPPLY DISRUPTION DUE TO RELIANCE ON T-SOUTH*

FEI is, for the reasons described above, dependent on the T-South system for approximately [redacted] of the gas entering its system. As discussed below, the T-South rupture in 2018 underscored that FEI's current need to rely on a single pipeline system for most of its supply creates a challenge for FEI's system resiliency. It leaves FEI and its customers at risk of experiencing significant consequences resulting from a supply disruption.

3.3.1 2018 T-South Incident Underscored the Risks of Supply Interruption

On October 9, 2018, an NPS 36 natural gas pipeline forming part of the T-South system ruptured near Prince George, BC (the T-South Incident). The NPS 36 pipeline that ruptured

[18] Westcoast is currently constructing a small scale expansion on its T-South system (~100 MMcf/day of incremental capacity) and is planned to be placed in-service in 2021.

shared the right-of-way with a second NPS 30 Westcoast pipeline. While only the NPS 36 pipeline had ruptured, the natural gas in that pipeline had ignited and Westcoast shutdown the adjacent NPS 30 pipeline as a precaution and monitored it to evaluate its condition. Given FEI's reliance on the T-South system, as discussed in the previous section, this incident was a test of FEI's system resiliency.

The following subsections will discuss the T-South Incident in three phases.

1. The first phase refers to the events that occurred in the 48 hours immediately following the rupture of the NPS 36 pipeline where gas supply on the T-South system was restricted to zero.

2. The second phase refers to the period following the first phase where gas supply remained constrained, as Westcoast reinstated the NPS 30 pipeline at a reduced capacity and the ruptured NPS 36 pipeline remained out of service and undergoing repairs.

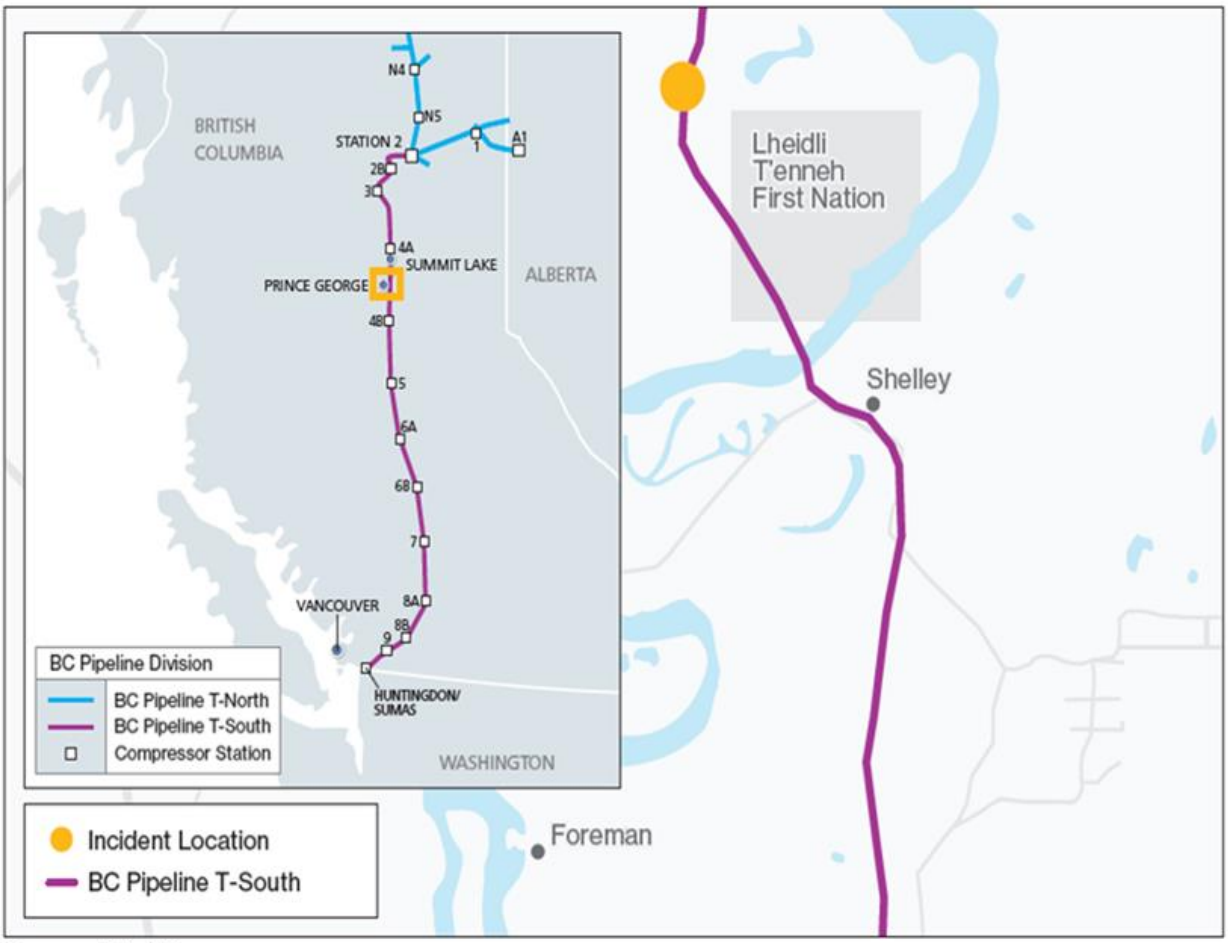
3. The third phase refers to the 56 week period following the second phase, where the NPS 36 was returned to service, however, capacity restrictions remained in place on the T-South system, until Westcoast lifted its *force majeure* on December 2, 2019.

3.3.1.1 Phase 1 of the T-South Incident (October 9, 2018 to October 11, 2018)

The T-South Incident resulted in a complete loss of gas supply from the T-South system. On October 10, 2018, Westcoast declared *force majeure*, effective as of October 9, 2018. Westcoast's *force majeure* notice indicated that service was interrupted as a result of the rupture of the NPS 36 pipeline, and that flow was restricted to zero on all delivery points on the T-South system between Compressor Station 4B and Huntingdon, as shown in Figure 3-6 below.[19]

[19] The rupture occurred between Compressor Stations 4A and 4B. Huntingdon is located south of Compressor Station 4B, and it is where the FEI Lower Mainland system connects to the T-South system.

Figure 3-6: Location of Westcoast's Rupture on its T-South System



Source: Enbridge

FEI's system was at risk of hydraulic collapse for a period of approximately 48 hours, which was avoided due to the following circumstances:

1. The time of year (i.e. not in winter load period);
2. Warmer than normal weather immediately following the incident, resulting in lower than normal demand;
3. FEI's Mt. Hayes LNG on-system storage facility was able to supply all the demand for the Vancouver Island system while also providing some supply to the Lower Mainland (by physically reversing flow as compared to normal operations);[20]

[20] Tilbury LNG – this facility was on standby during the event and was reserved for use as a last resort due to its limited capacity. Given the increased storage capacity at Mt. Hayes, FEI would send out LNG from Mt. Hayes first over Tilbury.

4. SCP was able to supply the Kootenay and the southern/central Okanagan and part of the northern Interior. SCP also delivered a quantity of supply at Kingsvale on the T-South system;

5. The level of mutual aid[21] response from parties in the US, in particular NWP. The mutual aid response by the US entities enabled the curtailment of natural gas based power plants on the NWP system as well as imports of supply at Huntingdon. US utilities were supported, in part, by access to a higher capacity (as compared to FEI's SCP) east to west pipeline through the Columbia River Gorge to supplement the loss of T-South supply. The Mist and JPS storage facilities with a total capacity of 43 BCF also provided supply into the region; and

6. Curtailment of FEI's interruptible and large industrial customers following the event.

3.3.1.2 Phase 2 of the T-South Incident – T-South Capacity at ~50 Percent until November 1, 2018

The zero supply period in Phase 1 ended on October 11, 2018 when Westcoast returned the NPS 30 pipeline to service, ramping the NPS 30 pipeline up to 80 per cent of its 60 day high pressure prior to the incident as permitted by the National Energy Board (NEB) order (restoring overall T-South capacity to approximately 50 percent of firm capacity).

The total capacity of the T-South system during this period was constrained with only one of two pipes in service and at a reduced capacity. Warm weather throughout Phase 2, and a positive response from FEI residential and commercial customers to requests for conservation, resulted in lower than normal demand. This mitigated the gas supply risk during the supply constraint. Phase 2 concluded with the repair and return to service of the ruptured NPS 36 pipeline on November 1, 2018, at a reduced capacity.

3.3.1.3 T-South Incident Phase 3 – T-South Capacity Restrictions In Place until December 2, 2019

The third major development of the T-South Incident occurred when Westcoast notified all of its shippers that the T-South system would be back in service at a reduced pressure of 80 percent of its normal operating pressure.[22] A return to full maximum operating pressure took approximately 14 months. During this period, the NEB allowed Westcoast to increase the restricted operating pressure of the NPS 36 pipeline from 80 percent to 85 percent, and then to 88 percent of the previous 60 day high pressure by pipeline segment. Westcoast restored the T-South system to full capacity on December 2, 2019.

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[21] This is referring to the Northwest Mutual Assistance Agreement, which is comprises of 18-member organizations that utilize, operate or control natural gas transportation and/or storage facilities in the Pacific Northwest. The support provided is on a best effort basis by the parties who all have a vested interest in maintaining a secure, reliable regional natural gas system.

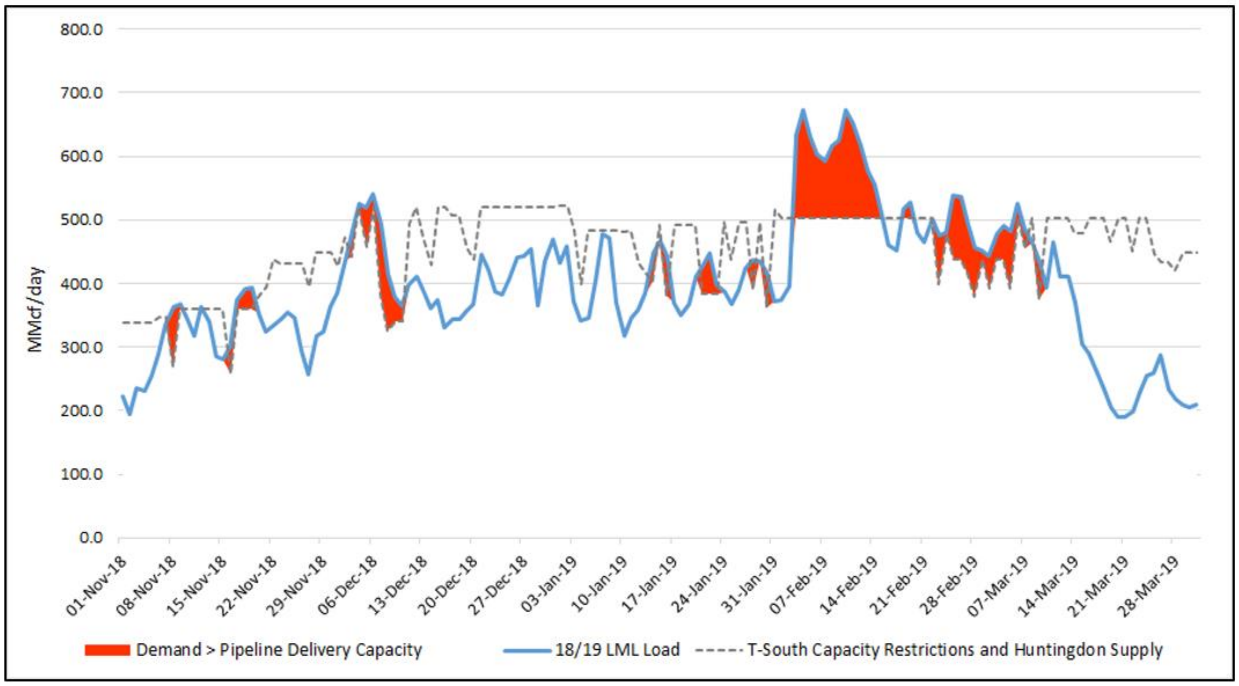
[22] Enbridge Critical Notice No. 50939 (October 18, 2018) "BC Pipeline Operational Upset – Transmission South Update." The Notice advised shippers that Enbridge estimated that the NPS 36 would be back in service at a reduced operating pressure of 80% of normal operating pressure by mid-November 2018. .

Given that the T-South to Huntingdon pipeline segment is normally fully utilized during the winter by customers along the I-5 corridor, the risk of a gas supply shortage persisted throughout the 2018/2019 winter, not just for FEI and its customers, but for the region as a whole.

FEI mitigated some of this risk prior to the 2018/19 winter season by securing 120 TJ/day of Huntingdon supply to replace the lost physical supply that was contracted by FEI to flow on the T-South system. The Huntingdon supply, which FEI was indirectly buying from shippers that had contracted T-South capacity, was the only available short-term supply option. This additional supply was critical for FEI to handle the load requirements during the 2018/19 winter season.

Figure 3-7 below illustrates FEI's actual winter load requirements (Lower Mainland, Whistler, and Vancouver Island) compared to the combination of T-South capacity available to FEI on a daily basis as well as the additional Huntingdon supply noted above.

Figure 3-7: FEI's T-South Capacity Restrictions vs Mainland Winter Load (Actuals)[23]



In addition to purchasing the Huntingdon supply prior to the winter season, FEI took an appropriately conservative approach to handling its off-system storage resources throughout the winter. This was done by refilling the Mist and JPS resources throughout the winter when capacity became available or when the load decreased. This kept FEI's contracted inventory

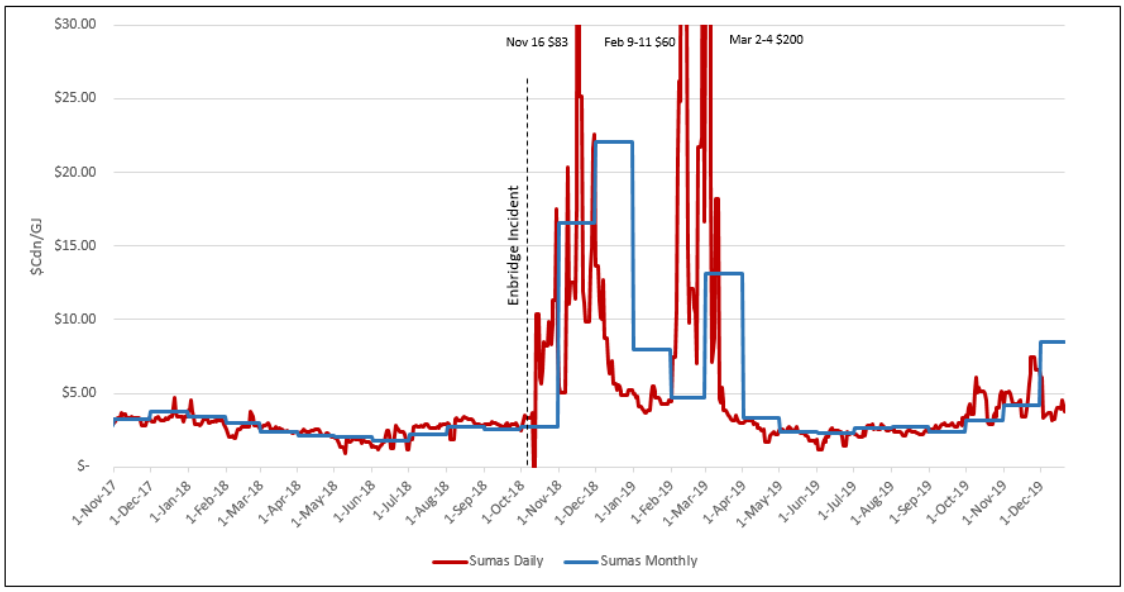
[23] FEI's T-South capacity includes the 428 MMcf/day of T-South to Huntingdon Delivery Area and 50 MMcf/day of Kingsvale to Huntingdon. The winter load profile does not include the Interior region because it was less severely impacted by the T-South operational constraints, given the availability of supply across FEI's Southern Crossing Pipeline.

levels high, which allowed FEI to have high deliverability when it was required.[24] The value of this approach was affirmed during the record cold weather the region experienced during February and early March (see Figure 3-7 above). These periods are represented in Figure 3-7 above by the red shaded portions where the blue line is above the dashed grey line, which was a period of several weeks.

3.3.2 Lessons and Outcomes of the T-South Incident

While FEI and the utilities along the I-5 corridor were able to manage through the T-South Incident, the incident resulted in higher gas supply costs for all market participants. As Figure 3-8 below shows, the commodity prices at the Sumas/Huntingdon market in winter 2018/19 were higher compared to the previous winter 2017/18, and volatile including the highest daily settlement price on record between March 2 and 4, 2019 ($200 per gigajoule). The Sumas/Huntingdon market price was a key factor in reducing demand at various times during the T-South restrictions, especially during the winter season. The high Sumas/Huntingdon prices resulted in customers, including natural gas power generators along the I-5 corridor, using alternative fuel sources where possible.

Figure 3-8: Sumas Daily and Monthly Settlement Prices



The T-South Incident prompted FEI to re-examine the resiliency of its system, and the region as a whole, and demonstrated that:

- Additional regional pipeline infrastructure, if alternative pipeline routes can be developed, could add resiliency by reducing FEI's reliance on the T-South system;

[24] JPS and Mist have withdrawal rates decline as working gas volumes decline.

- FEI should evaluate the potential to construct more on-system LNG storage and vaporization resources, which is a tool that can be used to prevent impacts to customers in the immediate impacts of a severe supply constraint or a "no flow"[25] event; and

- New tools to facilitate load shedding in a controlled and flexible fashion, a benefit associated with AMI, would complement on-system LNG to mitigate the impacts of an outage on customers and society.

FEI is currently evaluating these requirements and CPCN applications for a Tilbury expansion and AMI will soon be filed; however, these projects will take several years to implement. The next section discusses FEI's strategies to increase its gas supply resiliency until new infrastructure is placed in service.

3.4 *FEI'S CURRENT SUPPLY PORTFOLIO INCORPORATES STRATEGIES TO ENHANCE GAS SUPPLY RESILIENCY IN THE NEAR TERM (1-3 YEARS)*

In the 2019/20 ACP, FEI increased resiliency within the portfolio by holding contingency resources on T-South and by taking back capacity on SCP.[26] However, FEI's options are limited in the short term given that resources in the region are fully contracted as shown in Table 3-1 below, and constrained during the winter. Further, the majority of Huntingdon/Sumas supply is physically delivered via the T-South system, therefore this option does not enhance resiliency in FEI's portfolio. While the measures FEI has taken are appropriate to address immediate needs in the next few years, the infrastructure investments contemplated in this Compliance Filing represent a long-term solution.

[25] "No Flow" – defined as an emergency event that restricts the physical delivery of natural gas to a certain service area or load center.

[26] These strategies have been addressed in FEI's 2019/20 ACP and 2020/21 ACP which have both been accepted by the BCUC via Letter L-40-19 and Letter L-31-20, respectively.

Table 3-1: Existing Pipeline and Storage Resources in the Region

Pipeline	Daily Deliverability[1] (MMcf/day)	Total Winter Supply (Bcf)	Contract Status
Enbridge T-South (Huntingdon Delivery)	1702	257	Fully Contracted
Enbridge T-South (Interior Delivery)	224	34	Fully Contracted
FortisBC SCP (Oliver North)	140	21	Fully Contracted
FortisBC SCP (Kingsvale)[2]	105	16	Fully Contracted
TCPL (FoothillsBC)	2930	442	Fully Contracted
NWP Gorge	534	81	Fully Contracted
Market Area Storage	**Daily Deliverability (MMcf/day)**	**Storage Capacity (Bcf)**	
Jackson Prairie (JPS)	1161	25	Fully Contracted
Mist	637	19	Fully Contracted
On System Storage	**Daily Deliverability (MMcf/day)**	**Storage Capacity (Bcf)**	
Mt. Hayes LNG	150	1.5	Fully Utilized on Peak Day
Tilbury LNG	150	1.6	Fully Utilized on Peak Day

1. Daily deliverability is the maximum amount of gas that can flow on the pipeline or the maximum amount of gas that can be withdrawn out of storage. It is important to note that the daily deliverability out of the market area storage is assuming storage inventories are full. These resources do have withdrawal rates decline as working gas volumes decline.

2. The 105 MMcf/day is included in the 1,702 MMcf/day Huntingdon Deliveries (i.e. Kingsvale to Huntingdon).

3.4.1 FEI Has Increased Contingency Resources Including Excess Capacity on T-South

In the past, FEI contracted pipeline capacity on third party pipelines based on the winter design load requirements of its Core customers. Going forward, given market conditions, FEI plans to maintain contingency resources within the ACP portfolio. In FEI's ACP, contingency resources are resources (supply, LNG, and/or pipeline infrastructure) above the current load forecast for Core customers. Each year, FEI will determine a pipeline planning margin for contingency resources based on market conditions (i.e., supply risks, fully or de-contracted regional resources, and/or potential return of transportation service customers to FEI's bundled service). In the 2020/21 ACP, FEI has retained approximately 15 percent of excess capacity on the T-South system as a contingency resource based on the T-South Incident and the NEB orders.[27] This does not mean that an incident on the T-South system in the future would result in a similar

[27] The daily capacity approved by WEI changed over time as the T-South Incident unfolded and the NEB amended its operating pressure restrictions. On October 10, 2018, the NEB allowed Westcoast to return the NPS 30 pipeline at a restricted operating pressure of 80 percent of its previous 60-day high pressure (National Energy Board, Order NB-001-2018). On October 23, 2018, the NEB specified additional measures including the operation of the NPS 36 pipeline with a restricted operation pressure of 80 percent of its previous 60-day high pressure (National Energy Board, Order NB-001-2018, Amendment No.1) On November 16, 2018 an amendment was issued by the NEB to allow Westcoast to increase the restricted operating pressure of the NPS 36 pipeline from 80 percent to 85 percent of its previous 60-day high pressure (National Energy Board, Order NB-001-2018, Amendment No. 2) On December 24, 2018, another amendment was issued by the NEB restricting the operating pressure of the NPS 36 pipeline to 88 percent of the previous 60 day high pressure (National Energy Board, Order NB-001-2018, Amendment No. 3). See also the Pipeline Transportation Safety Investigation P18H0088 report.

order from the Canada Energy Regulator (CER). There is a possibility that a scenario could arise where the CER imposes more severe operating pressure restrictions such that supply is restricted even greater than 85 percent of firm capacity for a period of time. However, the 15 percent planning margin is FEI's best estimate of what is needed to ensure that it has the firm resources required to meet the design load forecast of its Core customers, in the event of a future supply restriction.

These contingency resources provide some resiliency benefits, particularly if there is reduced capacity on the T-South system, similar to phase three of the T-South Incident. However, it does not insulate FEI from a shut down of T-South or other event that would restrict supply on T-South greater than 15 percent (i.e., phase one and two of the T-South Incident). In order to provide additional resiliency against such events, additional infrastructure would be required.

3.4.2 FEI Has Increased Diversity of Supply by Taking Back SCP Capacity

As previously discussed, the region relies heavily on gas from northeast BC that flows on Westcoast's T-North and T-South systems. FEI uses those systems to service the Lower Mainland and a portion of the Interior customers. The only pipeline available for FEI to diversify its supply portfolio in terms of supply hubs is SCP.

Currently, SCP provides 105 MMcf/day of incremental supply to the Huntingdon market via contracted capacity on SCP and Westcoast's Kingsvale to Huntingdon. Out of the 105 MMcf/day, 47 MMcf/day is currently contracted to NW Natural until October 31, 2020. Given that this contract was expiring and it was the only opportunity for FEI to diversify its supply, FEI has taken back the SCP capacity contracted to NW Natural effective November 1, 2020.

3.4.3 Huntingdon/Sumas Supply Is the Only Alternative and it Is Much Less Desirable

The only available alternative to the considerations discussed in Section 3.4.1 and 3.4.2 would be to purchase additional Huntingdon/Sumas supply as a contingency resource instead of holding excess pipeline capacity. This would reduce FEI's exposure to pipeline tolling costs, but would be undesirable given the factors discussed below.

3.4.3.1 Huntingdon/Sumas Market is a Challenging Price Environment

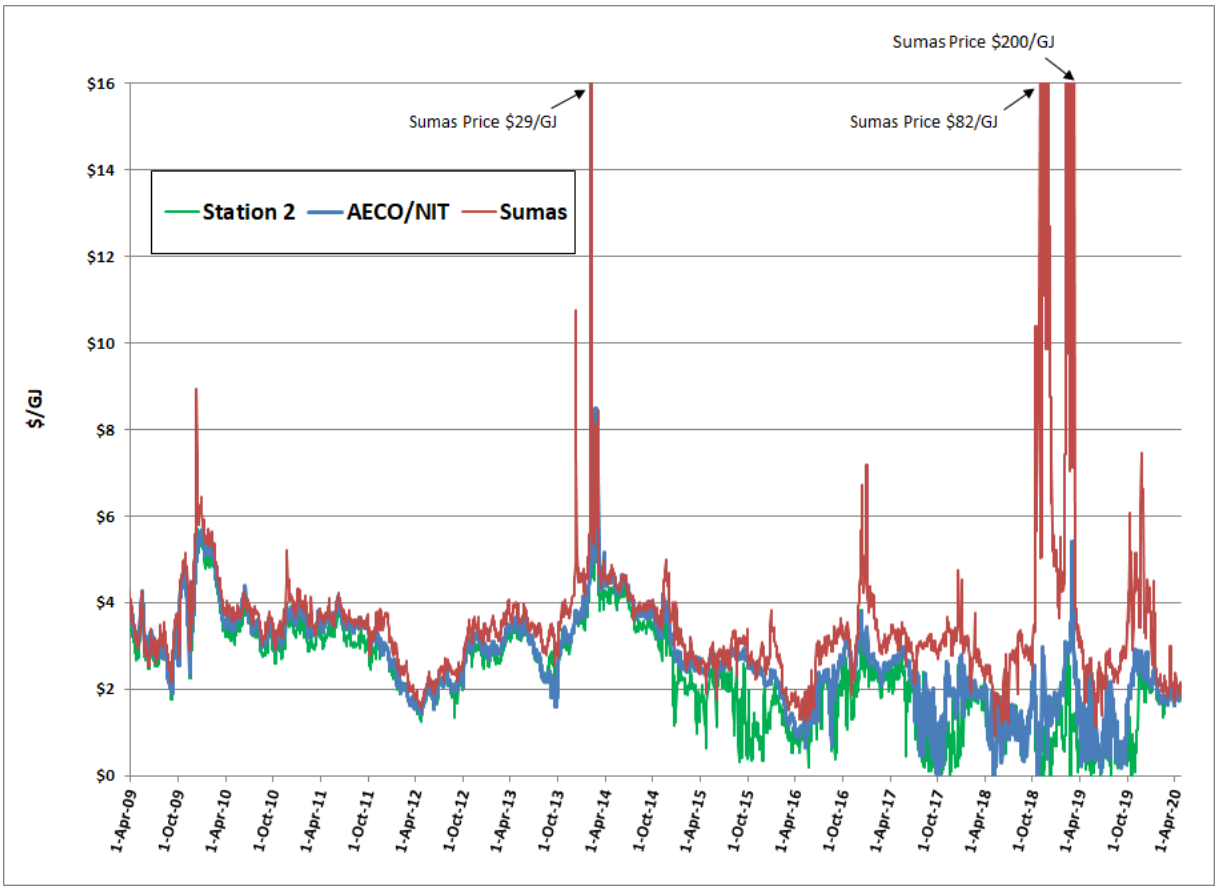
Despite the abundance of low-cost gas supply produced in the western Canadian shale gas basins and delivered to the AECO/NIT and Station 2 market hubs[28], constrained pipeline infrastructure to the Huntingdon/Sumas market results in extreme price volatility and Sumas price spikes.

[28] AECO/NIT is located in Alberta and is widely used as the Canadian benchmark for natural gas prices, while Station 2 is a Westcoast trading point located in northeast BC. The low cost gas supply produced in Western Canada and delivered to AECO/NIT and Station 2 is discussed in Appendix B of the 2020/21 ACP.

Periods of pricing volatility usually occur when increased demand in the PNW region exceeds the delivery capacity of pipelines into the region, which causes Sumas prices to increase significantly above other market prices. Any significant supply disruption can also cause price spikes and sustained elevated prices, as occurred during all three phases of the T-South Incident.

Figure 3-9 below illustrates this volatility, including but not limited to periods of supply disruption. It shows historical AECO/NIT, Sumas, and Station 2 daily spot prices over the last eleven years.

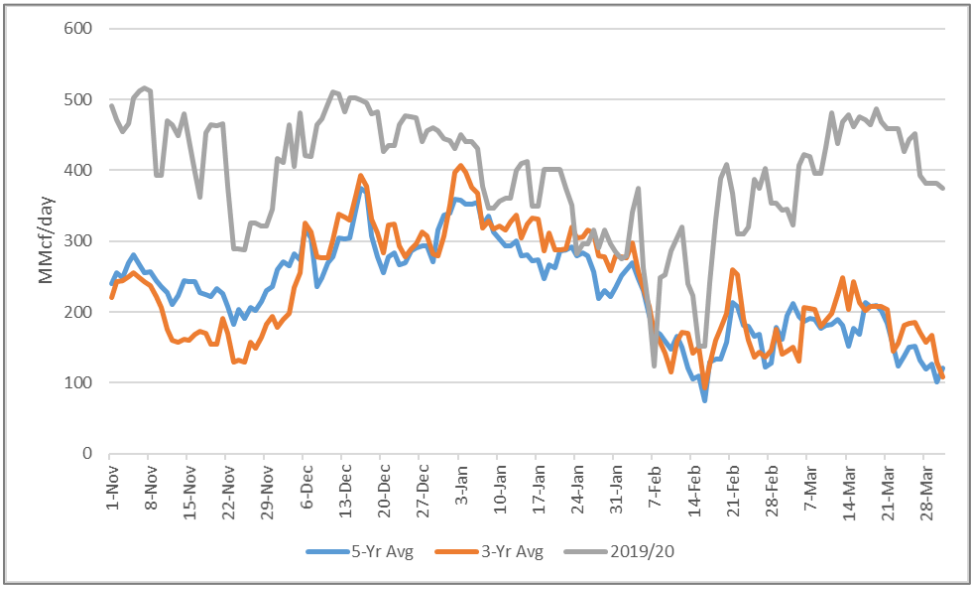
Figure 3-9: Historical Daily Market Spot Prices



As Figure 3-9 above shows, the largest price spike occurred in winter 2018/19. Restricted gas flows due to the T-South Incident and cold weather caused prices to spike above $80 per gigajoule (GJ) in November 2018. The combination of continuing T-South capacity restrictions, cold winter weather and low storage levels and storage operational issues in the PNW in February 2019 caused Sumas daily prices to spike to record levels of $200 per GJ. Sumas market prices were at higher than normal levels for most of the 2018/19 winter period. Prior to the T-South Incident, the largest price spikes in 2013/14, 2016/17, and 2017/18 were due to high winter demand. The most recent price spikes occurred in November of winter 2019/20 due to colder weather and increased demand from power generation.

Prior to the T-South Incident, the pricing volatility generally corresponded with colder than normal weather in the PNW region, which resulted in demand exceeding the delivery capacity at Huntingdon. This typically caused commercial and industrial users to use an alternative fuel if possible. However, there is another growing risk to the Huntingdon/Sumas market that results from an increase in the reliance on natural gas based power generation in the region. As shown in Figure 3-10 below, for the 2019/20 winter period, natural gas based power generation on the NWP system averaged approximately 400 MMcf/day, which is only 100 MMcf/day below its maximum availability. The volume was also approximately 165 MMcf/day higher than the 3-year and 5-year averages.

Figure 3-10: Natural Gas for Power Generation on Northwest Pipeline

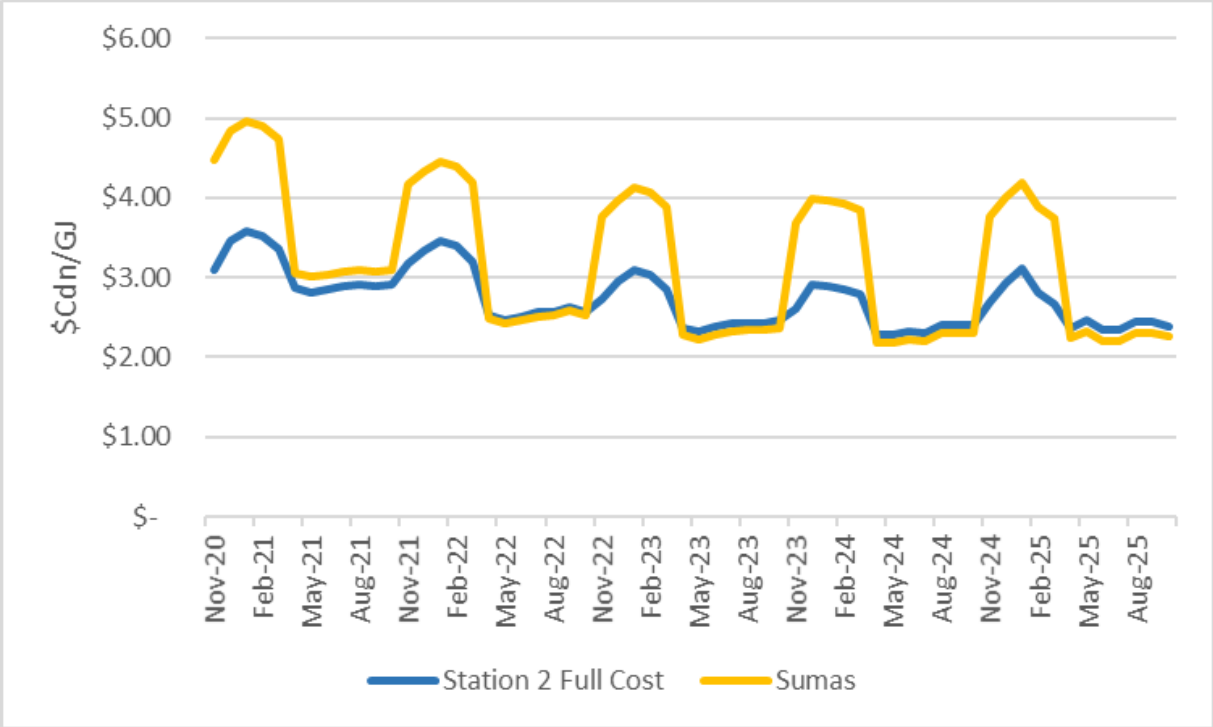


The increase in gas demand for power plants in the region is due in large part to the coal retirements across western North America now and in the future. Government and environmental policies aimed at reducing Greenhouse gas (GHG) emissions to meet environmental objectives and targets are pushing for renewable resources including hydro, solar and wind to offset the loss of supply from the coal plants. However, these renewable resources are not firm. When they are not available, the natural gas power plants are needed, which further increases Sumas price volatility.

3.4.3.2 Forward Prices Reflect Supply Risks and Volatility

FEI believes the Huntingdon/Sumas market will continue to have significant supply risks and pricing volatility going forward until a new pipeline and/or storage resource is added to the region. As Figure 3-11 shows, the forward market prices are providing a good indication to the market that absent any additional resources in the region, the Sumas price will continue to be higher in the winter than the Station 2 price plus the fixed transportation costs to get to the Sumas/Huntingdon market.

Figure 3-11: Station 2 Full Cost and Sumas Forward Price Comparison[29]



This Sumas price disconnection risk is not expected to diminish in the future given the current transportation infrastructure, winter demand in the region, and the potential for greater power generation and industrial demand. In the next few years, additional demand for gas at Huntingdon may come from major industrial projects such as Woodfibre LNG, methanol production plants and more gas-fired plants to replace coal plants for power generation in the PNW. Compounding the issue is that some of these industrial projects have already secured firm transportation capacity on the T-South system for a portion, if not all, of their demand requirements.

These developments will pose future risk to any customer that relies on supply at the Huntingdon market. Although FEI's Core customers do not currently rely on Huntingdon supply, a significant number of customers in the transportation service model do, given that they do not have the credit and/or financial capabilities to secure long-term pipeline capacity on third party pipelines. This was shown recently when 42 percent (over 900 transportation service customers) provided notice to FEI of their intention to move to FEI's bundled service for the 2019/20 gas year, due in large part to the Sumas pricing volatility they experienced during the 2018/19 winter. This type of movement poses risks to FEI, including not being able to secure enough incremental resources in the region to serve more customers moving to the bundled service. FEI may also have to return to the Huntingdon market in the near future to serve new

[29] Forward Sumas and Station 2 prices as of August 27, 2020. Station 2 full cost includes Station 2 forward monthly price, T-South fuel, Westcoast 2020 interim tolls, motor fuel and carbon tax.

load growth. Additional infrastructure in the region would likely help to reduce price volatility at Huntingdon and therefore would be beneficial to FEI and its customers.

3.4.3.3 Huntingdon/Sumas Supply Consideration Going Forward

All of the developments discussed in Section 3.4.3 validate FEI's approach to holding excess pipeline capacity on third party pipelines rather than purchasing Huntingdon supply as a contingency resource. Based on current market conditions, the additional costs to pay tolls and variable charges to third party pipelines to gain direct access to supply is more prudent than the alternative of purchasing supply at the delivered market (Huntingdon/Sumas). However, in the absence of additional infrastructure in the region, FEI may require this supply in the future depending on Core load growth and contingency resource requirements. Consequently, FEI expects increasing costs to secure the resources needed to serve increasing demand. Therefore, FEI would be interested in pipeline infrastructure to serve demand load growth and to enhance system resiliency.

4. PROJECTS TO ENHANCE SYSTEM RESILIENCY IN THE MEDIUM TERM (3 TO 5 YEARS)

In this section, FEI discusses the work it is currently undertaking to enhance system resiliency. This work aims to address two out of the three elements of system resiliency identified in Section 2.3 above - Ample Storage and Load Management - in the medium term (3 to 5 years). This section is organized as follows:

- **Section 4.1 – Tilbury LNG Storage Expansion** – This section discusses an upcoming CPCN Application to expand the Tilbury LNG facilities with additional storage and vaporization capabilities. Within this section, FEI will highlight at a high level the benefits and approximate costs associated with this project, and discuss some potential alternatives considered.

- **Section 4.2 – Advanced Metering Infrastructure** – This section discusses another upcoming application to the BCUC to install new gas meters with shutoff valves that can be controlled remotely for the vast majority of customers. FEI will highlight the benefits and approximate costs associated with this project, and discuss some potential alternatives considered.

4.1 *TILBURY LNG STORAGE EXPANSION PROJECT*

FEI is currently working on a CPCN Application to expand Tilbury LNG with additional storage and vaporization capabilities, while also replacing FEI's 50-year old Tilbury Base Plant. The proposed Tilbury LNG Storage Expansion (TLSE) Project will continue to serve supply requirements in the way Tilbury has done for the past 50 years, but also significantly improve

FEI's ability to withstand and manage through a significant supply emergency like phase 1 of the T-South Incident.[30]

4.1.1 Project Need: Serve A Larger Portion of Daily Load from On-System Storage for the Expected Duration of a Pipeline Disruption

The Tilbury Base Plant provides peaking supply for FEI's Core customers as well as emergency supply to the system as a whole. However, it was designed in the late 1960s primarily as a winter peaking facility. The Tilbury Base Plant's capability to provide emergency supply is limited, providing only a fraction of the gas (approximately 17 percent) required to serve the peak demand of Firm Rate Schedule customers in the Lower Mainland.[31] [redacted] The analysis to be detailed in the upcoming CPCN Application demonstrates the significant benefits that will come with increasing the storage and vapourization capacity at Tilbury.

4.1.2 Project Description

The TLSE Project will be constructed on the existing Tilbury site, and consist of a new storage tank and a regasification package. FEI is still finalizing the cost estimates for the TLSE Project, and is still refining scope to optimize costs and benefits. The preferred option is expected to include

- up to 3 BCF of storage; and
- between 600 to 800 MMcf/day of vaporization capacity.

4.1.3 The Project Will Deliver Significant Benefits

The TLSE Project will significantly increase the resiliency of FEI's natural gas delivery system in the event of a critical disruption of regional pipeline supply by:

- Allowing FEI to continue to serve a much larger portion of the daily system in the event of a supply emergency, including during winter periods; and
- Providing sufficient storage to meet that larger portion of the daily system load for a longer period of time (i.e., 3 to 5 days), having regard to a reasonable estimate of the time during which supply to FEI's system could be disrupted. This would allow additional

[30] Diversifying regional pipeline infrastructure would help FEI withstand a longer-term interruption (i.e., phase 2 and 3 of the T-South Incident).

[31] The vaporization capacity is the amount of supply that can be sent out from the facility into FEI transmission system over a 24-hour period at maximum rates.

time for FEI to make any necessary operational decisions so that, if needed, FEI could execute a controlled shutdown.

Although the main purpose of the project is to increase resiliency, there are also valuable ancillary benefits provided by the TLSE Project:

- Replace aging Tilbury Base Plant – The Tilbury Base Plant is now 50 years old, and the new facility will be designed according to modern industry standards;
- Improved Security of Supply – As FEI's customer demand grows, the requirements for peaking supply increases. Contracting sufficient peaking resources could be challenging and costly. With the growing constraint in regional infrastructure and onset of renewable energy, on-system storage creates optionality to mitigate risk and reduce dependence on third party storage services;
- Enhanced Daily Balancing – Additional vaporization and storage capacity would allow FEI to deliver a large amount of supply within a short period. This would provide FEI with additional operational flexibility to manage daily balancing; and
- Increased Operational Flexibility and Efficiency – Send out from Tilbury could be used to facilitate maintenance on FEI's transmission pipelines, increasing the system availability window for FEI to perform maintenance activities.

4.1.4 FEI Has Considered, But Ruled Out Alternatives to Development at Tilbury

FEI evaluated multiple alternatives to address the need for greater resiliency via on-system storage. These alternatives included on-system underground storage options, acquiring a new site for aboveground storage, and a new LNG storage tank on the existing Tilbury site. Ultimately, FEI determined that the only feasible means of adding resiliency to manage through short duration supply emergencies is through the addition of a new LNG storage tank and vapourization capacity on the existing Tilbury site. The Tilbury CPCN Application will provide comprehensive analysis regarding the alternatives to development at Tilbury that were screened out based on feasibility and ability to deliver the desired resiliency, as well as the range of sizing of the storage and vapourization components that FEI has considered.

4.1.5 Timeline and Cost

FEI anticipates filing an application for approval of the proposed TLSE project in fall 2020, with a BCUC decision in 2021. If approved, and following the issuance of an environmental assessment certificate, FEI anticipates beginning construction in 2022, with final project completion anticipated in 2025.

FEI has not yet completed its estimating and scoping of the Project, but based on the work done to date FEI believes that the Project could cost in the range between $700 and $900 million. A

portion of that cost could be viewed as representing the cost of removing and replace the legacy Tilbury Base Plant, with the remainder representing an investment in system resiliency. FEI's CPCN Application will provide a robust cost estimate. FEI will also discuss the drivers of scoping decisions, and any trade-offs that come with them.

4.2 *ADVANCED METERING INFRASTRUCTURE*

FEI is currently working on an application to the BCUC for the implementation of an Advanced Metering Infrastructure (AMI) network. The purpose of this project is to implement an AMI network that will deliver improved information about natural gas consumption and pipeline conditions to FEI and its customers. While the project is necessary due to the diminishing viability of procuring cost-effective manual meter reading services, an additional benefit of AMI is that it will improve FEI's ability to manage load on the system in the event of an emergency - one of the three key elements of a resilient system.

4.2.1 Project Description

The AMI Project will result in the replacement of approximately one million existing residential and commercial customer meters with advanced meters and the associated infrastructure to support delivery of hourly metering information from the advanced meters at customer premises back to FEI. The AMI Project will also involve the installation of communicating sensors on pipeline assets. The AMI network will be capable of collecting natural gas consumption and other information from all customer meters and will have additional capacity for collection of information on infrastructure and pipeline assets. Additionally, AMI will allow customers to access their hourly consumption information through a secure and private online customer information portal.

The AMI project will also complete installation of the remaining approximately 700,000 by-pass valves to avoid future interruption of gas service for meter-set maintenance activities at each premise and will replace gas regulators that are near end of life.

4.2.2 AMI Project Will Improve Resiliency

The AMI Project is primarily driven by the need to address the declining viability of manual meter reading. However, from a resiliency standpoint, the AMI system would significantly improve FEI's ability to manage system load during an extended loss of supply.

- ***Declining viability of manual meter reading*** - FEI currently contracts a third party vendor, Olameter Inc. (Olameter), to provide manual meter reading services. Olameter has provided these services to FEI since January of 2012, employing 150 meter readers to read approximately one million meters per month. The current contract with Olameter expires December 31, 2020.

The trend toward automation of meter reading within the utility industry in North America, and particularly within British Columbia, has made securing a competitive third party manual meter reading contract increasingly difficult. An automated meter reading solution would insulate FEI from the challenges of securing a manual meter reading services at a reasonable cost in the long term.

- **Enhancing system resiliency** - In the event of an extended loss of natural gas supply, AMI will provide FEI with more granular information regarding the demand on its system and the remoted shut-off valve in the AMI meter will enable FEI to strategically shut off gas to selected customers based on their gas usage and need, and not due to their proximity to an isolated section of pipeline. AMI will also help FEI to keep the natural gas system pressurized, thereby reducing recovery time for customers that experience service interruption.

4.2.3 Project Timeline and Estimated Costs

FEI anticipates filing an application for approval of the proposed AMI project in September of 2020, with a BCUC decision in 2021. If approved, and following a BCUC decision to proceed with the project, FEI will begin AMI network installation in 2022 through to the second quarter of 2023. AMI meter installation will begin in 2023, with final project completion anticipated in 2026.

FEI estimates the AMI Project will add an estimated additional $100 million in capital to the estimated $525 million FEI plans to spend continuing today's normal meter program over the next 26 years. The implementation of the AMI project would advance the majority of those capital expenditures prior to the end of 2025, but will result in reduced future sustainment capital and operating expenses. The expected rate impact of the AMI project is an initial small rate increase followed by future rate decreases.

5. LONG TERM CONSIDERATIONS – REGIONAL PIPELINE INFRASTRUCTURE (5 YEARS OR GREATER)

In this section, FEI discusses options to augment the resiliency of the system by addressing the final element a resilient system – pipeline diversity – which necessarily involves a longer timeline (5+ years). Pipeline operators, including FEI, are exploring infrastructure options that will facilitate load growth opportunities and provide much needed gas supply resiliency to the region. These discussions may trigger an "Open Season" process, which is when pipeline companies introduce a project and gauge customer interest to underwrite the project by making commitments through contracts for capacity on the new pipeline. Although any new pipeline infrastructure will provide benefits to the region as a whole, some projects will be a better fit for FEI than others from a resiliency perspective, depending on the proposed pipeline route.

The section is organized as follows:

- **Section 5.1 – Regional Pipeline Infrastructure Options –** This section provides at a high level, the potential pipeline infrastructure options in the region.
- **Section 5.2 – FEI's Portfolio Approach to Developing Regional Pipeline Resiliency** – This section discusses how FEI could optimize its portfolio if an open season is announced for a new pipeline in a different corridor from the T-South system. This will include an analysis on the optimal amount of pipeline capacity to be contracted based on resiliency considerations, and the potential portfolio costs using tolling scenarios.

In reading this section, it should be recognized that the resiliency benefits from any future pipeline development would complement, rather than replace, the benefits afforded by expanding FEI's on-system storage and vapourization. Section 6 below outlines how pipeline and on-system LNG investments each dovetail with different components of an efficient supply portfolio as identified in FEI's ACPs.

5.1 *FOUR POSSIBILITIES EXIST FOR FUTURE REGIONAL PIPELINE DEVELOPMENT*

There are currently no open seasons for regional pipeline infrastructure. However, based on FEI's past evaluations of opportunities and the existing infrastructure in the region, there are generally four possibilities for future pipeline expansion:

- An expansion to the T-South system;
- SCP Expansion to Huntingdon;
- SCP Expansion to Kingsvale (i.e., interconnecting with the T-South system); and
- An expansion to Northwest Pipeline's (NWP) Gorge capacity.

The following figure shows where the four possible expansions are located in the region and their pipeline routes. Each of these would help facilitate load growth as well as reduce the gap between the Sumas/Huntingdon forward market prices and the Station 2 prices plus fixed transportation costs to get to the Sumas/Huntingdon market. The following subsection will discuss which expansions would benefit FEI from a resiliency perspective.

Figure 5-1: Potential Regional Pipeline Infrastructure Expansions

5.1.1 Expansion of T-South: Significant Cost Comes With Limited Resiliency Benefit

The last open season for an expansion of the T-South system that Westcoast conducted was in April 2017, which offered shippers to contract for 190 MMcf/day of T-South to Huntingdon Delivery capacity. Out of the 190 MMcf/day, 90 MMcf/day was existing capacity on T-South that had been made available on an interruptible basis and an additional 100 MMcf/day was new firm year-round capacity. This small-scale expansion will be completed mainly by major compression upgrades along the T-South pipeline system route. While the project was planned to be in-service by late 2020, this has been delayed by one year following the work needed to restore T-South after the pipeline rupture.

Any further expansion of T-South would require sections to be looped with large diameter pipe. These expansions are expected to be highly capital intensive resulting in significant toll increases for all shippers depending on the amount of new capacity that is developed. As the T-South expansion would increase the capacity of the existing T-South system within the same corridor, it would add limited resiliency to FEI's service region than a pipeline in a different corridor.

5.1.2 An Expansion of Gorge capacity on Northwest Pipeline: Negligible Benefits in Event of Supply Disruption on T-South

Another possibility for future pipeline development is an expansion of the Gorge capacity on the NWP system, which would increase the physical capacity to bring supply westbound from Stanfield. This would allow gas to flow north into the Seattle and Tacoma region and decrease demand at Huntingdon/Sumas. While this project has merit and would provide increased physical supply into the region, it would not be FEI's preferred choice for a new pipeline into the region. This is because, under normal conditions, FEI would need to rely on displacement or notional deliveries to receive the gas on the FEI system. Given that the displacement process is dependent on physical gas flow on T-South to Huntingdon, FEI could not rely on this pipeline expansion during a supply emergency situation. Therefore, this project would have very limited benefits to FEI under a no flow event from the T-South system.

5.1.3 SCP Expansion to Kingsvale: Resiliency Benefit Is Significant but Less than SCP Expansion to Huntingdon

SCP is the only available opportunity for FEI to diversify away from its dependence on the T-South system. As such, FEI has previously evaluated an SCP expansion to Kingsvale to provide a potential solution to deliver incremental gas supply to Huntingdon.

This project would consist primarily of a 161 km, NPS 24 or greater pipeline expansion from Oliver to Kingsvale, BC, extending the existing SCP. It is estimated that the incremental volume to Huntingdon could increase by approximately 300-400 MMcf/day via Westcoast's T-South Kingsvale to Huntingdon capacity. Given that this consideration would provide FEI greater access to Alberta supply via the AECO/NIT market, TC Energy's NOVA and FoothillsBC pipeline systems would also likely require an expansion.

An expansion of SCP to Kingsvale, with some of FEI's required supply being shifted from T-South to SCP, would mitigate a significant portion of FEI's reliance on the T-South system. However, it would not provide redundancy for the section of T-South between Kingsvale and Huntingdon, since all of the gas from SCP would have to travel on that segment to reach the load centre in the Lower Mainland. This expansion would provide the region with increased pipeline diversity, security of supply and various other gas supply benefits which are included in Table 5-1.

5.1.4 SCP Expansion to Huntingdon Provides Greatest resiliency Benefit Among Pipeline Options

An SCP Expansion to Huntingdon would be FEI's preferred choice of pipeline development from a resiliency standpoint, given that this solution would entail an entirely different path from the T-South system. This project would involve an expansion of SCP through construction of additional compressor stations and a new pipeline connecting SCP near Oliver, BC to the Sumas/Huntingdon market. This project would amplify the resiliency benefits of the SCP expansion to Kingsvale, as discussed in Table 5-1.

5.1.5 Summary of Potential Pipeline Expansions in the Region

The pros and cons of each of the potential pipeline expansions discussed above are set out in Table 5-1 below. This table highlights why, among the potential pipeline expansions, Option 4 (SCP Expansion to Huntingdon) is preferred from a resiliency standpoint.

Table 5-1: Potential Regional Pipeline Expansion (Summary Table)

	Option 1 T-South Expansion	Option 2 NWP Gorge Expansion	Option 3 SCP Expansion to Kingsvale	Option 4 SCP Expansion to Huntingdon
Description	Major expansion of Westcoast's T-South to Huntingdon pipeline segment; Approx. 350 to 550 MMcf/day	Increase pipeline capacity to bring supply westbound from Stanfield; Approx. 85 to 175 MMcf/day	SCP pipeline expansion from Oliver to Kingsvale; This would also involve a T-South upgrade from Kingsvale to Huntingdon and TC Energy's NOVA and FoothillsBC pipeline expansion; Approx 250 - 350 MMcf/day	SCP pipeline expansion from Oliver to Huntingdon; This would also involve an expansion on TC Energy's NOVA and FoothillsBC pipeline system; Approx. 350 to 550 MMcf/day
Pros	Facilitate new load growth at the lowest cost (compared to Option 3 and 4); Mitigates a significant amount of Sumas price volatility for cold weather events (depending on the pipeline size and industrial projects coming only).	Facilitates new load growth (US Pacific Northwest region only)	Mitigates a significant portion of FEI's exposure to T-South; Greater access to different supply source (AECO/NIT); Mitigates a significant amount of Sumas price volatility for cold weather events; Shorter new pipeline segment than Option 4.	Provides greatest resiliency benefit among pipeline options because it provides a direct path to the Lower Mainland Greater access to different supply source (AECO/NIT); Mitigates a significant amount of Sumas price volatility for cold weather events and supply disruption
Cons	FEI remains similarly reliant on single pipeline system Tolls for all existing T-South shippers will increase; Supply disruption could cause Sumas pricing volatility	Location of expansion results in very limited resiliency benefits and does not address a disruption of supply on the T-South system.	Higher unit cost (compared to Option 1) to improve resiliency Doesn't provide resiliency for the T-South section between Kingsvale and Huntingdon; Supply disruption between Kingsvale and Huntingdon could cause Sumas pricing volatility; Uncertainty over market support (i.e., if tolling cost is higher than other options)	Higher unit cost (compared to Option 1) to improve resiliency Uncertainty over tolling cost (wide ranges provided); Uncertainty over market support (i.e., if tolling cost is higher than other options)

5.2 *NEW PIPELINE INFRASTRUCTURE WOULD FIT WITH FEI'S EFFICIENT SUPPLY PORTFOLIO*

As discussed in Section 3.2, FEI has determined the optimal amount of firm pipeline capacity to serve its load requirements in the context of its ACP. FEI's approach to acquiring capacity on

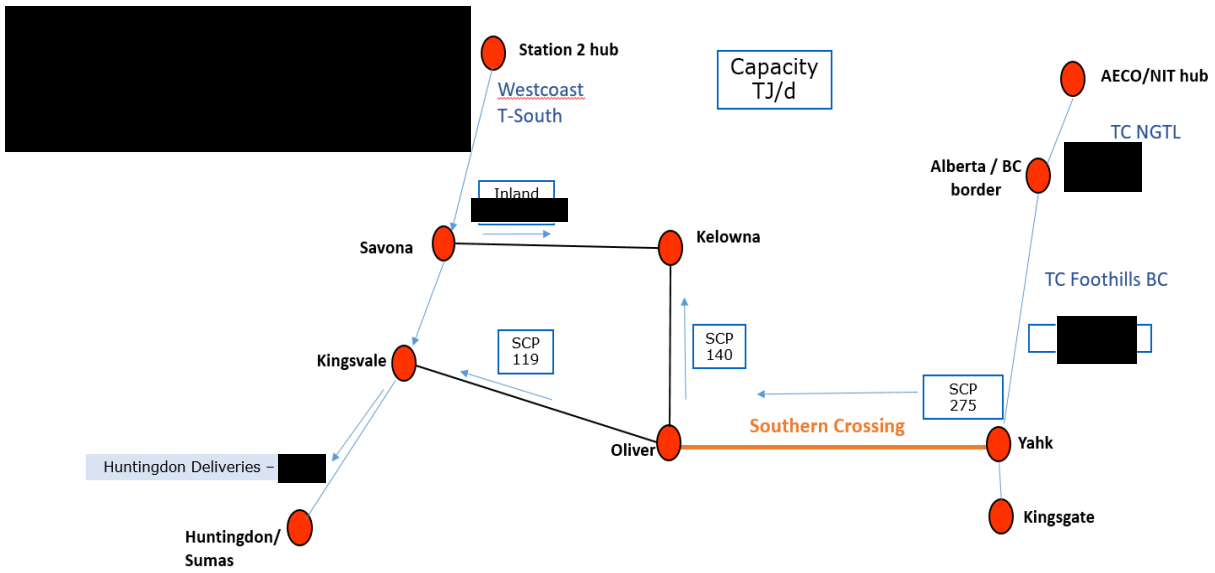
any future new pipeline infrastructure would ideally complement the efficient supply portfolio identified in FEI's Annual Contracting Plans at that time.

[redacted]

[redacted]

[redacted]

[redacted]



[redacted]

11

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[redacted]

6. FEI'S PORTFOLIO APPROACH TO RESILIENCY

As discussed in Section 2.3, the resiliency of FEI's gas system is derived from a combination of diverse pipelines and supply, storage and load management. Sections 3 to 5 have described the improvements that can be made to each of these elements. This Section will discuss why FEI believes employing a mix of pipeline redundancy and expanded peaking resources (i.e., on-system LNG storage) will be the most cost-effective way to enhance resiliency, while also creating flexibility within FEI's ACP.[32]

In the following section, FEI will:

- discuss the merits of a portfolio approach to resiliency with enhancements to pipeline redundancy and peaking resources (Section 6.1); and
- explain how alternatives to this portfolio approach would be at a higher cost and may not be feasible (Section 6.2).

[32] AMI is a demand side tool and will not be involved in the optimization of FEI's ACP portfolio.

6.1 *A PORTFOLIO APPROACH WITH ENHANCEMENTS TO PIPELINE REDUNDANCY AND PEAKING RESOURCES IS OPTIMAL*

The principles that FEI follows to optimize its ACP, as discussed in Section 3.2.2.2, should also apply to system resiliency investments. This approach incorporates resiliency measures based on both short-term and long-term planning considerations, while also having regard to the cost effectiveness of the portfolio.

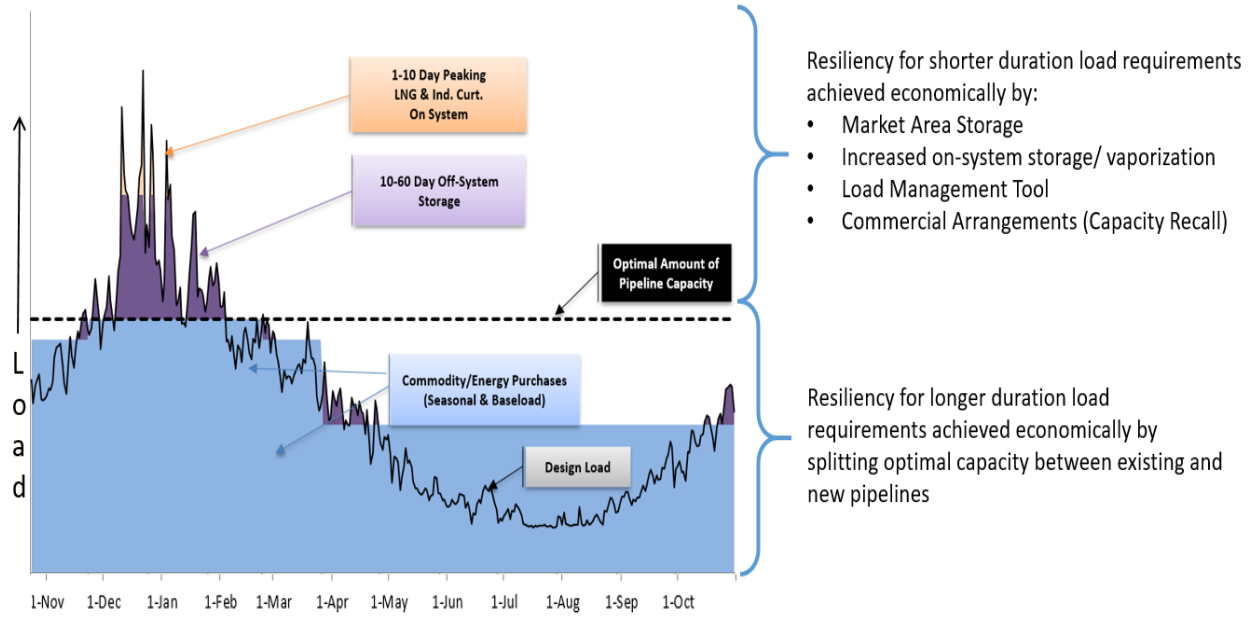
A fundamental principle of constructing a portfolio of gas supply resources is to match the resource characteristics to the characteristics of demand. For example:

- on-system LNG storage resources provide short duration supply to cover winter peak demand driven by weather conditions;
- off-system underground storage, depending on its location and characteristics, provides short to medium duration seasonal supply; and
- pipelines are the most efficient resource for supplying gas over long durations.

The same principle can apply to enhancing system resiliency. On-system LNG storage is the most effective way to respond immediately to a critical emergency to ensure survival of FEI's system, as in phase 1 of the T-South Incident. FEI's ability to rely on on-system resources in the event of a supply disruption does not depend on the physical or contractual availability of alternate pipeline capacity upstream of FEI's system. However, on-system LNG has limitations in addressing long-term capacity shortfalls or duration issues, as were experienced during phase 2 and 3 of the T-South Incident. A pipeline solution (preferably in a different corridor from the T-South system) would further mitigate the risk of a prolonged reduction in gas supply.

Figure 6-1 below depicts how redundant pipeline capacity can be used efficiently, in combination with expanded peaking resources like on-system LNG storage, to build resiliency.

Figure 6-1: Resiliency Measures Should Reflect Optimal ACP Supply Portfolio



Having a mix of resiliency investments is cost effective and provides greater flexibility compared to alternatives, which will be discussed in the following section. Table 6-1 below adds to the hypothetical scenario discussed in Section 5.2, by including the estimated cost of service for additional on system storage through an expansion at Tilbury.

[redacted]

As Table 6-1 illustrates, a reasonable portfolio that could enhance resiliency as well as other gas supply benefits could cost an estimated [redacted] over the existing annual portfolio costs. As discussed in Section 5.2, these resources would not only provide increased resiliency, but also help serve load growth in the region.

6.2 *RELYING ON ONLY PIPELINE OR ON-SYSTEM STORAGE WOULD COST MORE THAN THE PORTFOLIO APPROACH AND MAY NOT BE FEASIBLE*

FEI evaluated whether it makes sense to pursue one of pipeline or on-system LNG solutions exclusively, instead of a portfolio of measures. As discussed below, FEI's evaluation indicates that looking to only one measure to address all resiliency needs is either too costly or not feasible.

6.2.1 Doubling the Amount of Pipeline Capacity FEI Holds Using a New Pipeline

The portfolio approach described above involves splitting the optimal amount of pipeline capacity between two pipelines, such that a disruption on one pipeline would still leave access to supply. In theory, a different approach could be to forego an expansion of on-system LNG and contract the optimal amount of pipeline capacity on both pipelines, [redacted] Redundancy to this extent would mitigate a significant amount of risk during the winter if one of the regional pipelines was shut down due to an emergency situation. However, FEI would incur significantly higher annual costs compared to the portfolio approach, and it would still not eliminate the need for on-system storage.

Table 6-2 below provides an illustration of the potential costs associated with an optimal portfolio of pipeline capacity and on-system LNG storage, versus redundant pipeline capacity. The cost estimates are based on simplifying assumptions and should be viewed as conceptual only. Nevertheless, the analysis illustrates the point that purchasing redundant pipeline capacity to this extent would be more costly than a portfolio approach.

[redacted]

In addition to the higher expected costs, there are several other considerations that favour a portfolio approach that includes on-system LNG storage, including:

- **FEI exercises greater control over on-system LNG development**. As discussed in Section 3.2.2, given the high costs of pipeline projects, underwriting new pipeline infrastructure may require multiple customers. Tilbury is also a single "brown-field" site, as opposed to linear infrastructure that can give rise to different development considerations and involve more stakeholders.
- **Uncertainty whether FEI would be able to contract for the required amount of new regional pipeline capacity**. Table 6-2 above assumes that FEI would be able to contract for a significant amount of capacity on a new pipeline. A standard open season includes a process where the bids for capacity are submitted confidentially. Therefore, other participants could outbid FEI, which could result in FEI holding less than the desired amount of contracted capacity.
- **FEI's portfolio will still require on-system LNG and off-system storage**. If one pipeline is shutdown due to an emergency, FEI will still require storage resources to handle the load requirements of its customers above the optimal amount of pipeline capacity, e.g. to supply peak load. Therefore, FEI would still need to address the aging Tilbury Base Plant, which the cost analysis in Table 6-2 does not take into account.

6.2.2 Enhancing System Resiliency Using Only On-System or Underground Storage Resources

FEI also considered relying exclusively on storage to provide redundancy for the gas supply normally provided by pipelines through the winter period. This included evaluating on-system underground storage options, acquiring a new site for aboveground storage, and a new LNG storage tank(s) on the existing Tilbury site. Ultimately, FEI determined that the only feasible means of enhancing resiliency via storage is through the addition of a new LNG storage tank and vapourization capacity on the existing Tilbury site. However, that site would not accommodate the amount of storage needed to enable the exclusive reliance on storage for resiliency. [redacted]

[redacted]

In its assessment of the resiliency needs of FEI's system, Guidehouse also concludes that on-system storage is not sufficient by itself to meet FEI's requirements. The Guidehouse Report states:[33]

> Guidehouse observes that on-system storage, in and of itself, is not sufficient to support FEI's resiliency requirements to mitigate the risk of a prolonged outage. On-system storage provides supply and pressure for a period of time, then liquefaction is required to replenish the stock. To mitigate longer duration outages the system should be supplemented by additional supply sources to provide insurance against more serious and prolonged interruptions.
>
> Expanded pipeline capacity that provides alternative supply to FEI's current access to upstream supply from the Enbridge BC pipeline should be evaluated in the future to ensure adequate long-term resiliency beyond the duration that can be provided by on-system storage, as highlighted in Section 1.6 [of the Guidehouse Report]. However, even with additional pipeline infrastructure, it is important to note on-system storage will continue to be beneficial to provide system resiliency to respond to a no-flow event or significant upstream pipeline disruption.
>
> However, even with expansions of transmission pipeline capacity that increase FEI system redundancy, a total system failure on the Enbridge BC pipeline, i.e., a zero-flow event, would require significant time for FEI to balance the supply/demand on its system and insure delivery to its core firm customers. [redacted] FEI should explore multiple asset configurations to mitigate the material risks like those experienced in October of 2018. Increasing

[33] Guidehouse Report (August 2020). "System Resiliency: A Critical Requirement of Natural Gas System." Appendix A - Page 44-45

> on-system storage provides a reasonable measure for the operational control and responsiveness that is necessary to prevent system failure.

As explained by Guidehouse above, on-system storage and pipeline diversity each have attributes that are needed to enhance FEI's system resiliency. For this reason, as well as the cost analysis provided above, a portfolio approach is the most cost-effective way to enhance resiliency of supply to FEI's customers.

7. CONCLUSION

In this Compliance Report, FEI has explained that the resiliency of the gas system depends on a combination of diverse pipelines and supply, ample storage, and load management. FEI continues to provide safe and reliable natural gas service in the province and has taken steps within its ACP to increase that resiliency. However, the resiliency of the system can be improved. It is appropriate to make further investments that will not only address resiliency, but also bring other benefits for customers. The optimal means of doing that involves enhancing load management capabilities, expanding on-system LNG, and exploring regional pipeline options. A portfolio approach to resiliency underlies and supports FEI's upcoming AMI and TLSE Project CPCN applications as well as FEI's interest in any open seasons for capacity on new regional pipelines in the future.

Appendix A
GUIDEHOUSE REPORT

(Refer to Appendix A to the TLSE CPCN Application)

Appendix D

CONSULTANT CREDENTIALS

View Attachment panel for documents

Appendix E

LNG STORAGE TANK TECHNICAL WRITE-UP AND ESTIMATES

FILED CONFIDENTIALLY

Appendix E-1

3 BCF LNG TANK TECHNICAL WRITE-UP

FILED CONFIDENTIALLY

Appendix E-2

2 BCF LNG TANK TECHNICAL WRITE-UP

FILED CONFIDENTIALLY

Appendix E-3

LNG TANK BASIS OF ESTIMATE REPORT

FILED CONFIDENTIALLY

Appendix F

REGASIFICATION PACKAGE BASIS OF ESTIMATE AND PROCESS FLOW DIAGRAMS

FILED CONFIDENTIALLY

Appendix F-1

BASIS OF ESTIMATE AND COST ESTIMATE

FILED CONFIDENTIALLY

Appendix F-2

PROCESS FLOW DIAGRAMS

FILED CONFIDENTIALLY

Appendix G

GROUND IMPROVEMENT AND EARLY WORKS BASIS OF ESTIMATE AND COST ESTIMATE

FILED CONFIDENTIALLY

Appendix G-1

BASIS OF ESTIMATE AND COST ESTIMATE (3 BcF)

FILED CONFIDENTIALLY

Appendix G-2

BASIS OF ESTIMATE AND COST ESTIMATE (2 BcF)

FILED CONFIDENTIALLY

Appendix H

AUXILIARY SYSTEMS BASIS OF ESTIMATE AND COST ESTIMATE

FILED CONFIDENTIALLY

Appendix I

BASE PLANT DEMOLITION BASIS OF ESTIMATE

FILED CONFIDENTIALLY

Appendix I-1

BASIS OF ESTIMATE

FILED CONFIDENTIALLY

Appendix I-2

COST ESTIMATE

FILED CONFIDENTIALLY

Appendix J

FEI BASE COST ESTIMATE

FILED CONFIDENTIALLY

Appendix J-1

BASIS OF ESTIMATE

FILED CONFIDENTIALLY

Appendix J-2

COST ESTIMATE (3 BCF)

FILED CONFIDENTIALLY

Appendix J-3

COST ESTIMATE (2 BCF)

FILED CONFIDENTIALLY

Appendix J-4

TOTAL BASE COST ESTIMATE SUMMARY (3 BCF)

FILED CONFIDENTIALLY

Appendix J-5

TOTAL BASE COST ESTIMATE SUMMARY (2 BCF)

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Appendix K

RISK ANALYSIS REPORTS

FILED CONFIDENTIALLY

Appendix K-1

PROJECT RISK ASSESSMENT REPORT

FILED CONFIDENTIALLY

Appendix K-2

VALIDATION ESTIMATING CONTINGENCY REPORT

FILED CONFIDENTIALLY

Appendix K-3

VAILDATION ESTIMATING ESCALATION REPORT

FILED CONFIDENTIALLY

Appendix L

DETAILED PROJECT SCHEDULE

FILED CONFIDENTIALLY

Appendix M

FINANCIAL SCHEDULES

FILED CONFIDENTIALLY

Appendix M-1

FINANCIAL SCHEDULES (3 BCF)

FILED CONFIDENTIALLY

Appendix M-2

FINANCIAL SCHEDULES (2 BCF)

FILED CONFIDENTIALLY

Appendix N

PARTNERS IN PERFORMANCE (PIP) ESTIMATE OF O&M COSTS

FILED CONFIDENTIALLY

Appendix O

ENVIRONMENTAL OVERVIEW ASSESSMENT REPORT

Jacobs

FortisBC Tilbury LNG Storage Expansion Project

Environmental Overview Assessment

Rev. 2

June 2020

FortisBC Energy Inc.

FortisBC Tilbury LNG Storage Expansion Project

Project No:	CE764600
Document Title:	Environmental Overview Assessment
Document No.:	FES0319201042VBC
Revision:	Rev. 2
Date:	June 2020
Client Name:	FortisBC Energy Inc.
Project Manager:	Megan Barnes, Jacobs Consultancy Canada Inc.

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Document history and status

Revision	Date	Description	Author	Reviewed	Approved
1	June 2020	Full Report	Multiple Authors	TL	LK
2	June 2020	Full Report	Multiple Authors	MB	LK

Executive Summary

FortisBC Energy Inc. (FortisBC) is expanding the existing liquefied natural gas (LNG) facility at 7651 Hopcott Road, on Tilbury Island in the City of Delta (Delta), British Columbia (BC) (the Tilbury site). To expand the current facility, FortisBC is required to apply to the British Columbia Utilities Commission (BCUC) for a Certificate of Public Convenience and Necessity (CPCN). Part of this process requires FortisBC to explore feasible alternatives and compare costs associated with potential construction by conducting an Environmental Overview Assessment (EOA), FortisBC has retained Jacobs Consultancy Canada Inc. (Jacobs) to conduct the EOA for the proposed Tilbury LNG Storage Expansion Project (the Project).

The proposed Project comprises of up to 142,400 cubic metres (approximately 3.3 petajoules) of LNG storage. The Project will receive natural gas at the Tilbury site through established pipeline systems. It will connect to FortisBC's existing LNG facilities to provide resiliency of natural gas service to customers in the lower mainland.

Three proposed expansion alternatives have been reviewed in this EOA:

- Alternative 1. Demolish and remove existing 0.6 billion cubic foot (Bcf) tank and associated plant and replace with a 2 Bcf tank including interconnecting pipe and vaporization.
- Alternative 2. Demolish and remove existing 0.6 Bcf tank and associated plant and replace with a 3 Bcf tank including interconnecting pipe and vaporization.
- Alternative 3. Demolish associated plant, keep existing tank, and build a 1.5 Bcf tank including interconnecting pipe and vaporization.

This report describes the existing conditions on the entire Tilbury site and describes the potential adverse effects to the biophysical environment from the Project based on each alternative. Where potential adverse effects are predicted, this EOA describes, at a high-level, the recommended mitigation and follow-up work in order to inform Project costs. This EOA provides an assessment of the risks to the Project for each of the three alternatives as well as potential mitigation measures.

The EOA provides an overview of the main environmental receptor for the Project for each alternative, included in the executive summary is a table summarizing the constraints and sensitivities of each environmental receptor.

- Surface Water
- Atmospheric Environment
- Contaminated Soils and Groundwater
- Fish and Fish Habitat
- Vegetation and Wetlands
- Wildlife and Wildlife Habitat

Land use was also reviewed, and a brief history of the Tilbury site has been provided along with a characterization of neighbouring land use designations and Fraser River users.

For the purposes of this report, risks to the Project are considered in the form of additional costs (such as, activities requiring further follow-up work or mitigation), timing constraints (such as, species-specific timing windows) or both (such as, permits or approvals). Risks to the environment are considered in the form of potential effects to the environmental receptors relative to applicable environmental or regulatory standards and that may require mitigation or follow-up activities. Risk categories range from Negligible, Low, Medium, and High.

This EOA concludes that each of the three Project alternatives, have the same potential effects, mitigation / follow-up actions and overall risk rating for all environmental receptors. The combined risk to the environment and the Project assessed in this EOA vary from low to high depending on environmental receptor.

Five environmental receptors including, surface water quality and quantity, fish and fish habitat, vegetation and wetlands, wildlife and wildlife habitat, and land use were determined to have low risk ratings. A low risk rating was determined because the potential effects are likely within environmental/regulatory standards, can be managed using industry mitigation and require no specific regulatory approvals or the regulatory process and costs for approvals are predictable.

The atmospheric environment receptor was determined to have a medium to high risk rating. A medium to high risk rating was determined because additional assessment is recommended to predict emissions to determine whether emissions are within applicable Ambient Air Quality Objectives and to obtain a Metro Vancouver Air Permit. Pending the outcomes of further emissions modeling, additional cost for the implementation of specialized mitigation measures or follow-up work are expected.

The contaminated soils and groundwater environmental receptor were determined to have a medium to high risk rating. A medium to high risk rating was determined because there are eight APECs identified on the Tilbury site and further assessment (i.e., a Stage 1 and Stage 2 PSI) is recommended to characterize and manage the potential adverse effects. Pending outcomes of the Stage 1 and Stage 2 PSI, low to considerable additional cost for the implementation of specialized mitigation measures or follow-up work are expected.

Table ES-1 Summary of Constraints, Sensitivities, and Risk by Environmental Receptor

Environmental Receptor	Summary of Constraints or Sensitivities	Project Risk
Surface Water Quality and Quantity	▪ Two waterbodies border the Tilbury site, including the Fraser River (northern boundary) and the Tilbury Slough (southern boundary) ▪ Site drainage with connectivity to Tilbury Slough; however, no connectivity to Fraser River except surface runoff from dike	Low
Atmospheric Environment	▪ Emissions during Project operation will require amendment of current Metro Vancouver Air Emissions Permit ▪ Potential risks to atmospheric environment due to operational emissions to and accidents and malfunctions	Medium to High
Contaminated Soils and Groundwater	▪ Seven APECs identified on-site, and one off-site, potential to encounter previously contaminated soils and/or groundwater at identified areas of environmental concern. Recommendation to conduct Stage 1 and 2 Preliminary Site Investigations.	Medium to High
Fish and Fish Habitat	▪ No specific fish and fish habitat constraints were identified within the Tilbury site; however, sensitivities include fish habitat and potential occurrence of species at risk in adjacent watercourses (Fraser River and Tilbury Slough) ▪ Manage for erosion and mobilization of deleterious substances to downstream habitats, and introduction or spread of invasive species through aquatic pathways	Low
Vegetation and Wetlands	▪ No specific vegetation constraints were identified within the Tilbury site, however potential sensitivities include: occurrence of species at risk near the Tilbury site, introduction of invasive species and clearing mature/native vegetation on-site.	Low
Wildlife and Wildlife Habitat	▪ No specific wildlife or wildlife features were identified within the Tilbury site; however, potential sensitivities include: occurrence of species at risk near the Tilbury site, potential for amphibians in drainage ditches on-site, potential for migratory bird nests on-site, potential disturbance of marine mammals and foraging birds. ▪ Risks to wildlife and wildlife habitat resulting from accidents and malfunctions	Low
Land Use	▪ Project site is located in Special Industrial zone and adjacent to operating industrial facilities	Low

Contents

Appendixes

Tables

Figures

Acronyms and Abbreviations

µg/m^3	microgram(s) per cubic metre
AEC	area(s) of environmental concern
AIA	Archaeological Impact Assessment
AIF	Archaeological Information Form
AOA	Archaeological Overview Assessment
APEC	area(s) of potential environmental concern
AST	aboveground storage tank
AQO	air quality objectives
AW	Freshwater Aquatic Life (use)
BC	British Columbia
BC AAQO	British Columbia Ambient Air Quality Objective
BC CDC	British Columbia Conservation Data Centre
BC *CSR*	British Columbia *Contaminated Sites Regulation*
BC EAO	British Columbia Environmental Assessment Office
BC ENV	British Columbia Ministry of Environment and Climate Change Strategy
BC MFLNRORD	British Columbia Ministry of Forests, Lands, Natural Resource Operations and Rural Development
BC *OGAA*	British Columbia *Oil and Gas Activities Act*
BC OGC	British Columbia Oil and Gas Commission
Bcf	billion cubic feet
BCUC	British Columbia Utilities Commission
BEC	Biogeoclimatic Ecosystem Classification
BTEX	benzene, toluene, ethylbenzene, and xylene
CAAQS	Canada Ambient Air Quality Standard
CCME	Canadian Council of Ministers of the Environment
CDF	Coastal Douglas-fir
CDFmm	Moist Maritime Coastal Douglas-fir subzone
cm	centimetre(s)
CO	carbon dioxide
CofC	Certificate of Compliance
COSEWIC	Committee on the Status of Endangered Wildlife in Canada
CPCN	Certificate of Public Convenience and Necessity
Delta	City of Delta
DFO	Fisheries and Oceans Canada

DSI	Detailed Site Investigation
EA	Environmental Assessment
ECCC	Environment and Climate Change Canada
EMA	*Environmental Management Act*
EMP	Environmental Management Plan
EOA	Environmental Overview Assessment
ESA	Environmental Site Assessment
ESC	erosion and sediment control
FortisBC	FortisBC Energy Inc.
GHG	greenhouse gas
HADD	harmful alteration, disruption, or destruction
HCA	*Heritage Conservation Act*
HEPH	heavy extractable petroleum hydrocarbon
IA	Impact Assessment
IBA	Important Bird Area
IL	Industrial Land (use)
km	kilometre(s)
kV	kiloVolt(s)
LEPH	light extractable petroleum hydrocarbon
LNG	liquefied natural gas
MBCA	*Migratory Birds Convention Act*
NO_2	nitrogen dioxide
m	metre(s)
m^3	cubic metre(s)
m^3/s	cubic metre(s) per second
MVAAQO	Metro Vancouver Ambient Air Quality Objective
NWA	National Wildlife Area
O_3	ozone
OCP	Official Community Plan
OGMA	Old Growth Management Area
PAH	polycyclic aromatic hydrocarbon
PCB	polychlorinated biphenyl
PCOC	potential contaminant of concern
PCP	pentachlorophenol
PFOA	perfluorooctanoic acid

PFOS	perfluorooctane sulphonate
PJ	petajoule(s)
$PM_{2.5}$	fine particulate matter
ppb	part(s) per billion
Project	Tilbury LNG Storage Expansion Project
PSI	Preliminary Site Investigation
QEP	Qualified Environmental Professional
Richmond	City of Richmond
RL	Residential Land (use)
SARA	*Species at Risk Act*
Site Registry	British Columbia Ministry of Environment and Climate Change Strategy Online Site Registry
SO_2	sulphur dioxide
Tilbury site	liquefied natural gas facility at 7651 Hopcott Road, on Tilbury Island in the City of Delta, British Columbia
tpd	tonnes per day
UBC	University of British Columbia
UST	underground storage tank
UWR	Ungulate Winter Range
VOC	volatile organic compound
VPH	volatile petroleum hydrocarbon
WHA	Wildlife Habitat Area
WMA	Wildlife Management Area

1. Introduction

FortisBC Energy Inc. (FortisBC) is applying to the British Columbia Utilities Commission (BCUC) for a Certificate of Public Convenience and Necessity (CPCN) to expand its existing liquefied natural gas (LNG) facility at 7651 Hopcott Road, on Tilbury Island in the City of Delta (Delta), British Columbia (BC) (Figure 1-1) (the Tilbury site).

The Tilbury LNG Storage Expansion Project (the Project) comprises of an expansion to increase the supply for all of FortisBC's 1.1 million natural gas customers in BC. The Project will receive natural gas at the Tilbury site through established pipeline systems, it will connect to FortisBC's existing LNG facilities to provide resiliency of natural gas service to customers in the lower mainland.

The existing Tilbury site includes the original production and storage facility in operation since 1971, a Phase 1A production and storage expansion in operation since 2019 (Phase 1A), and ancillaries including power supply, gas supply, and both natural gas and LNG distribution facilities to serve public utility customers.

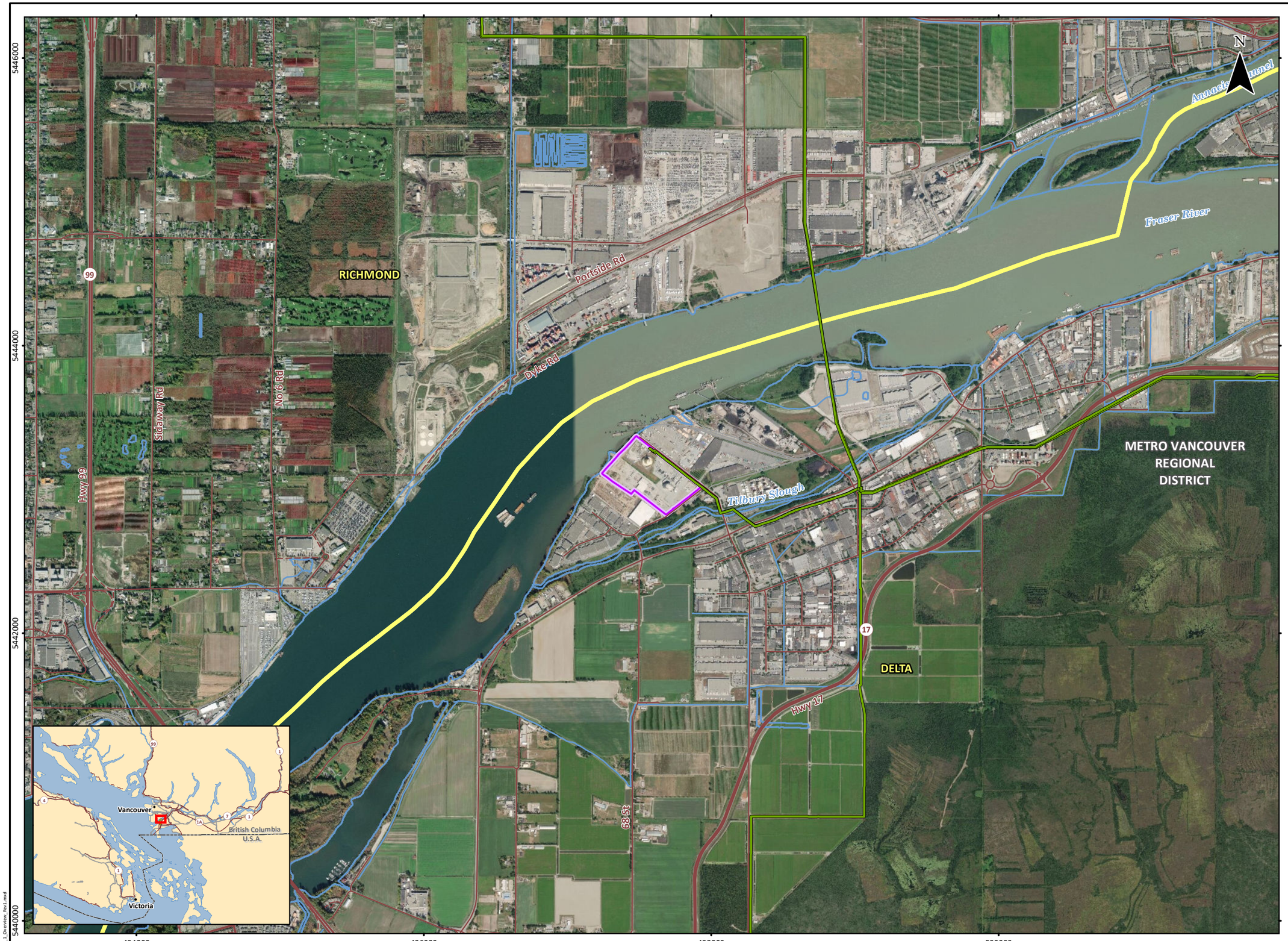
FortisBC retained Jacobs Consultancy Canada Inc. (Jacobs) to conduct an Environmental Overview Assessment (EOA) in support of the CPCN Application.

This objectives of this EOA are to describe the existing conditions on the entire Tilbury site, to define and describe the potential adverse effects to the biophysical environment from the Project, and to identify feasible Project alternatives. Where potential adverse effects are predicted, this EOA describes, at a high-level, the recommended mitigation and follow-up work in order to inform Project costs. This EOA provides an assessment of the risks to the environment and to the Project for the following three alternatives.

Three proposed expansion alternatives have been reviewed in this EOA:

- Alternative 1. Demolish and remove existing 0.6 billion cubic foot (Bcf) tank and associated plant and replace with a 2 Bcf tank including interconnecting pipe and vaporization.
- Alternative 2. Demolish and remove existing 0.6 Bcf tank and associated plant and replace with a 3 Bcf tank including interconnecting pipe and vaporization.
- Alternative 3. Demolish associated plant, keep existing tank, and build a 1.5 Bcf tank including interconnecting pipe and vaporization.

The results of the EOA will inform further detailed assessments and the preparation of Environmental Management Plans (EMPs) to be completed following the approval of this CPCN Application by the BCUC and prior to the start of Project construction.



FORTIS BC™

June 2020

FIGURE 1-1

OVERVIEW

PAGE 1 OF 1

TILBURY PHASE 2
LNG EXPANSION PROJECT

Proposed Project Components

- Project Area

Base Data

- FortisBC Existing Tranmission Line
- Highway
- Road
- Resource Road
- Railway
- Watercourse
- Municipality
- Waterbody

SCALE: 1:25,000

0 200 400 600 800 1,000 m

(All Locations Approximate)

JACOBS

Project Number CE742500

UTM Zone 10 North. NAD 1983.
Existing FortisBC Pipeline: FortisBC 2012; Transportation: BC FLNRORD 2012; Regional Districts & Municipalities: BC FLNRORD. 2017; Political Boundaries: ESRI 2005, USNIMA 2000; Hydrology: BC FLNRORD 2011; Imagery Service Layer Credits: Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AeroGRID, IGN, and the GIS User Community.

Although there is no reason to believe that there are any errors associated with the data used to generate this product or in the product itself, users of these data are advised that errors in the data may be present.

Mapped By: DJN | Checked By: CMR

Fig1_1_Overview_Rev1.mxd

2. Methodology

The content of this EOA is intended to meet the BCUC CPCN Application Guidelines (BCUC 2015). As such, the EOA provides an overview of the following biophysical receptors.

- Surface Water Quality and Quantity
- Atmospheric Environment
- Fish and Fish Habitat
- Vegetation and Wetlands
- Wildlife and Wildlife Habitat
- Species at Risk (discussed as part of the above biological categories)
- Contaminated Soils and Groundwater

Land use was also reviewed, and a brief history of the Tilbury site has been provided along with a characterization of neighbouring land use designations and Fraser River users.

2.1 Overview of Existing Conditions

The description of existing conditions is based on a combination of desktop review of publicly available information, previous relevant studies completed for the Tilbury site, and a preliminary reconnaissance Tilbury site visit conducted on October 22, 2019.

2.1.1 Study Area

The review of existing conditions was completed within a defined Study Area that is specific to each environmental receptor and based on the potential zones of interaction between the receptor and the Project. Study areas for each environmental receptor are listed in Table 2-1.

Table 2-1. Environmental Receptor Study Areas

Environmental Receptor	Description
Surface Water Quality and Quantity	The Study Area included the property boundary of the Tilbury site and the area extending 100 m from the property boundary.
Atmospheric Environment	The Study Area included the property boundary of the Tilbury site and the area extending 10 km from the property boundary or as identified by required modelling.
Contaminated Soils and Groundwater	The Study Area included the property boundary of the Tilbury site and the area extending 250 m from the property boundary.
Fish and Fish Habitat, Including Species at Risk	The Study Area included the property boundary of the Tilbury site and the area extending 100 m from the property boundary.
Vegetation and Wetlands, Including Species at Risk	The Study Area included the property boundary of the Tilbury site and the area extending 100 m from the property boundary.
Wildlife and Wildlife Habitat, Including Species at Risk	The Study Area included the property boundary of the Tilbury site and the area extending 1 km from the property boundary.
Land Use	The Study Area included the property boundary of the Tilbury site and the area extending 100 m from the property boundary.

Notes:

km = kilometre(s)

m = metre(s)

2.1.2 Information and Data Sources

2.1.2.1 Surface Water Quality and Quantity

The following information sources were reviewed to obtain information on the existing water quality and quantity conditions within the Study Area.

- iMapBC Provincial database (Government of BC 2020)
- Real-Time Hydrometric Data for Fraser River at Port Mann Pumping Station (08MH126) (ECCC 2020a)
- Freshwater Quality Monitoring and Surveillance - Online Data for Fraser River (Main Arm) at Gravesend Reach - Buoy (BC08MH0453) (ECCC 2020b)
- Water quality study for Pattullo Bridge replacement (Hatfield Consultants 2018)
- Fraser River water quality objectives (Swain et al. 1998)

In addition to environmental reports, Jacobs reviewed as-constructed drawings of the dike and stormwater drainage system. These documents were reviewed to gain a better understanding of the current drainage systems in the Tilbury site and any potential connectivity to nearby waterways. These records consisted of:

- Aplin & Martin:
  - As-Constructed Drawings: Lot Consolidation at 6939 Tilbury Road, On-site Civil Records
  - As-Constructed Drawings: Dike Improvements for Lot Consolidation at 6939 Tilbury Road

A Tilbury site reconnaissance was also conducted on October 22, 2019, to identify any watercourses or drainages in the Study Area and to consider connectivity to adjacent watercourses.

2.1.2.2 Atmospheric Environment

The following information sources were reviewed to obtain information on the existing conditions within the Study Area.

To characterize air quality in the area of the Tilbury site, hourly data was downloaded from the Government of British Columbia, BC Ministry of Environment and Climate Change Strategy (BC ENV) Air Data Archive website for the year 2018 (most recent reporting year at time of writing). The hourly data were used to determine maximum, and percentile concentrations, as appropriate, to estimate local air quality (BC ENV 2019c).

2.1.2.3 Contaminated Soils and Groundwater

The following information sources were reviewed to obtain information on the existing conditions within the Study Area. For this EOA, it is limited to the following:

1) Previous environmental reports completed for the Tilbury site.
2) Historical aerial photographs.
3) BC Ministry of the Environment and Climate Change Strategy Online Site Registry (Site Registry).

Previous Environmental Reports

Jacobs reviewed available environmental reports to assess historical information to determine current and historical activities and the Tilbury site's environmental conditions. Jacobs reviewed the reports detailed in Table 2-2 provided by FortisBC that pertain to the Tilbury site.

Table 2-2. Previous Environmental Reports

No.	Report Title	Year
1	Phase I Environmental Site Assessment (ESA), Tilbury Island, SRK – Robinson Inc.	1991
2	Environmental Property Review, LNG Plant Hopcott Road, PGX Organix Ltd.	1998
3	Phase I ESA, BC Gas Property Hopcott Road, Delta, PGX Organix Ltd	1998
4	Soil and Groundwater Remediation of the Underground Storage Tank Area, 7515 Hopcott Road, NEXT Environmental	1998
5	Phase I ESA, 7150 Tilbury Road, Golder	2008
6	Summary Letter, Phase II ESA, 7150 Tilbury Road, Golder	2008
7	Phase II ESA, 7150 Tilbury Road, Golder	2008
8	Geotechnical Assessment, 7150 Tilbury Road, Delta, Golder	2008
9	Woodwaste Review, Delta Hardwoods Sawmill, 7515 Hopcott Road, Golder	2009
10	Supplementary Phase II ESA, 7150 Tilbury Road, Golder	2009
11	Stage 1 and 2 Preliminary Site Investigation (PSI), 7150 Tilbury Road, Golder	2010
12	Supplemental Investigation and Confirmation of Remediation, 7150 Tilbury Road, Golder	2010
13	Summary of Site Conditions, 7150 Tilbury Road	2010
14	Addendum to Submission for a Certificate of Compliance (CofC), 7150 Tilbury Road, Golder	2010
15	CofC, 7150 Tilbury Road, BC ENV	2010
16	Overview of Geo-environmental Conditions at 6939 Tilbury Road, Golder	2012
17	Site profile, 7651 Hopcott Road, FortisBC	2013
18	Limited Phase I ESA, 7525 and 7651 Hopcott Road, Terra Environmental	2013
19	Soil Removal Permit Release, 7525 and 7651 Hopcott Road, BC ENV	2014
20	Results of Stockpile Testing, Tilbury, Delta, BC, Golder	2014
21	Results of Soil Sample Analyses – Hopcott Road excavation, Delta, Golder	2015

Notes:

CofC = Certificate of Compliance
ESA = Environmental Site Assessment
PSI = Preliminary Site Investigation

Historical Aerial Photographs

Aerial photographs, going back to before the Tilbury site's disturbance, were obtained from the University of British Columbia (UBC) and reviewed for the Tilbury site. Aerial photographs provide visual evidence of Tilbury site occupancy, operational activities, and general details. They capture a view of the Tilbury site and the surrounding areas at a given time, allowing comparison of historical Tilbury site conditions on a temporal scale; however, the accuracy of the aerial photograph interpretation is directly affected by the aerial photograph resolution and scale. The aerial photographs were reviewed to determine historical land use and the presence of structures, land improvements, areas of soil disturbance, or adjacent land uses that could have affected the Tilbury site's environmental conditions. The Tilbury site's history was also reviewed using current and historical aerial and street view photography available in Google Earth. Aerial photographs are provided in Appendix A.

British Columbia Ministry of Environment and Climate Change Strategy Site Registry

The BC ENV maintains the Site Registry, a database of properties which have had environmental information submitted to the BC ENV and which have had a formal site identification number assigned. Based on information provided to BC ENV, since 1988, the Site Registry documents the milestones in the investigation and remediation process of a property. Some properties in the Site Registry are contaminated; others are being investigated and may or may not require remediation; and, others have been remediated. A search of the Site Registry was completed for the Tilbury site and adjacent properties within a 500-m radius (a minimum search radius of 250 m is required) using iMapBC on the DataBC website and through the BC Online search requests.

Site Inspection and Interviews

The site visit of the Tilbury site and adjacent land was conducted by Jacobs' personnel on October 22, 2019. Interviews with Tilbury site personnel were conducted during the inspection. The site visit consisted of a walkthrough of the Tilbury site's original production and storage facility, and publicly accessible off-site areas while documenting items of interest and Areas of Potential Environmental Concern (APECs): potentially contaminating operations (such as, auto repair, manufacturing, gas stations, industrial operations, and so forth), evidence of underground storage tanks (USTs) or aboveground storage tanks (ASTs), waste dumping or landfilling, previous environmental investigations (for example, groundwater monitoring wells), and storage of hazardous materials. The results of the Tilbury site visit were cross-referenced with the information gathered during the desktop assessment to determine which areas constitute APECs.

2.1.2.4 Fish and Fish Habitat

The following information sources were reviewed to obtain information on the existing conditions within the Study Area.

- Previous environmental reports completed for the Tilbury site
- BC CDC iMap (BC CDC 2020a)
- BC Species and Ecosystem Explorer (BC CDC 2020b)
- HabitatWizard (BC ENV 2020) and iMapBC (Government of BC 2020)
- Aquatic Species at Risk Database (DFO 2019a)
- Species at Risk Public Registry (ECCC 2020c)

A search for potential watercourses and fish presence was conducted using online mapping databases, including HabitatWizard (BC ENV 2020), BC Conservation Data Centre (BC CDC) iMap (BC CDC 2020a) and iMapBC (Government of BC 2020). Fish inventory data and conservation status were reviewed using BC Species and Ecosystem Explorer (BC CDC 2020b) and Aquatic Species at Risk Database (DFO 2019a).

Jacobs reviewed the Tilbury site historical environmental reports for information on previous conditions and construction activities. The environmental reports assessed included the following:

- Summary of Site Conditions, 7150 Tilbury Road (BC MOE 2010)
- Environmental review for the proposed FortisBC Energy Inc. Tilbury 2 Project Phase 1A (TERA Environmental Consultants 2013)
- Environmental review for the proposed FortisBC Energy Inc. Tilbury 2 Project Phase 1A – Dike Improvements (TERA Environmental Consultants 2014)
- Bird Nest Survey – Tilbury Island Dike Upgrade Project (CH2M 2018)

A Tilbury site reconnaissance was conducted on October 22, 2019, to identify any watercourses or drainages in the Study Area and to assess these features for fish habitat potential. This cursory aquatic assessment focused on basic considerations of fish habitat potential, including barriers to access and general habitat conditions (such as, flow, substrate, and structure).

2.1.2.5 Vegetation and Wetlands

The following information sources were reviewed to obtain information on the existing conditions within the Study Area.

A desktop background review of plant species and ecological communities at risk with the potential to occur within the Study Area was completed. Information and data were collected through a desktop review of publicly available datasets (DataBC, iMapBC, BC CDC, Species at Risk Public Registry). The following information sources were reviewed to obtain information on the existing conditions within the Study Area:

- Biogeoclimatic Ecosystem Classification (BEC) zones and subzones (BC CDC 2020a);
- Approved Old Growth Management Areas (OGMAs) (BC MFLNRORD 2019a,b);
- Federally identified Critical Habitat for plant species at risk (ECCC 2019a);
- Known occurrences of plant species and ecosystem communities at risk (BC CDC 2020a); and
- Known locations of invasive plants (BC CDC 2020a).

To determine the potential presence of plant species and ecological communities at risk to occur within the Study Area, a query of BC CDC Ecosystem Explorer was conducted to identify plant species and ecological communities at risk that are known to occur within the BEC subzone that the Study Area is located within. A search for known occurrences of plant species and ecological communities at risk and species with Federally-designated Critical Habitat was also conducted within the Study Area. This list of species was further refined based on the range and habitat suitability of each species (Appendix D).

A site reconnaissance was conducted to collect information on native vegetation community assemblages within the Study Area, identify and locate potential plant species and ecological communities at risk, as well as document observed invasive plant populations. This information helped to refine the list of species and ecological communities potentially present within the Study Area.

2.1.2.6 Wildlife and Wildlife Habitat

The following information sources were reviewed to obtain information on the existing conditions within the Study Area.

A desktop background review of wildlife species at risk with the potential to occur within the Study Area was completed. Information and data were collected through a desktop review of publicly available datasets (DataBC, iMapBC, HabitatWizard, BC CDC, Species at Risk Public Registry). The following information sources were reviewed to obtain information on the existing conditions within the Study Area:

- Provincially identified wildlife areas (such as, Wildlife Habitat Areas [WHAs], Wildlife Management Areas [WMAs], and Ungulate Winter Ranges [UWRs]) (BC MFLNRORD 2019c,d,e,f; BC MFLNRORD 2020)
- Federally identified Critical Habitat for wildlife species at risk (ECCC 2019a);
- Known occurrences of wildlife species at risk (BC CDC 2020a);
- BC Parks, Ecological Reserves, and Protected Areas (BC ENV 2019e);
- BC Breeding Bird Atlas (BC Breeding Bird Atlas 2020);
- The Birds of North America (BNA 2020); and

- Various wildlife habitat area designations, including critical waterfowl habitat areas (Hayes et al. 1993), Important Bird Areas (IBAs) (IBA Canada 2020), Western Hemisphere Shorebird Reserves (WHSRN 2020), Ramsar wetlands (Bureau of the Convention on Wetlands 2014), and World Biosphere Reserves (UNESCO 2012).

To determine the potential presence of wildlife species at risk to occur within the Study Area, a query of BC CDC Ecosystem Explorer was conducted to identify wildlife species at risk that are known to occur within the BEC subzone that the Study Area is located within. A search for known occurrences of wildlife species at risk and species with Federally-designated Critical Habitat was also conducted within the Study Area. This list of species was further refined based on the range and habitat suitability of each species (Appendix D)

Reconnaissance was conducted to collect information on wildlife species at risk and wildlife habitat features (that is, raptor or heron nests, bird colonies, mineral licks, wallows, dens, burrows, wildlife, trees, and amphibian breeding areas). Activity, behavior, and species abundance, where evident and relevant, was also noted. This information helped to refine the list of species potentially present within the Study Area.

2.1.2.7 Land Use

Land use was reviewed to provide a brief history of the Tilbury site and characterization of neighbouring land use designations and Fraser River users. The following sources were referenced to obtain information on the existing conditions within the Study Area:

- City of Delta Official Community Plan (OCP) (Delta 2019)
- City of Richmond (Richmond) OCP (Richmond 2019)
- FortisBC existing knowledge on the history of the Tilbury site
- Legal Plot Plan (Appendix E)

2.2 Identification of Potential Effects of the Project

An effect is considered any response by an environmental receptor to a project's impact. The potential effects were identified when Project activities resulted in a direct or indirect impact to environmental receptors within the study areas and where considerations of environmental values may present a risk to the Project.

2.2.1 Risk Determination

For the purposes of this report, risks to the Project are considered in the form of additional costs (such as, activities requiring further follow-up work or mitigation), timing constraints (such as, species-specific timing windows) or both (such as, permits or approvals). Risks to the environment are considered in the form of potential effects to the environmental receptors relative to applicable environmental or regulatory standards and that may require mitigation or follow-up activities. Risk categories are described as follows.

- **Negligible** – Potential adverse effects of the Project may not be detectable or are within the range of natural variability or are inconsequential to the function, health, performance, or sustainability of receptor. No mitigation measures, timing constraints, or receptor-specific regulatory approvals requiring cost to the Project are anticipated.
- **Low** – Potential adverse effects of the Project are detectable; however, they are well within environmental or regulatory standards, or both. Additional assessment work is not likely to be recommended to characterize the potential adverse effect. Potential adverse effect can be managed using industry standard mitigation practices during construction and FortisBC's existing environmental management program for the Tilbury site during operation. No regulated timing constraints or receptor-specific regulatory approvals requiring cost to the Project are anticipated.

- **Medium** – Predicted adverse effects are detectable and may approach, however are still within, the environmental or regulatory standards, or both. Further assessment work is likely to be recommended to characterize the potential adverse effect. Low to moderate additional cost for the implementation of specialized mitigation measures or follow-up work are expected. If regulated timing constraints are applicable during construction, they are limited in duration and can be managed through construction phasing. Receptor-specific regulatory approvals are required to carry out the Project; however, the regulatory process is well-defined and associated costs are predictable.
- **High** – Predicted adverse effects are beyond environmental or regulatory standards, or both. Further assessment work is likely to be recommended to characterize the potential adverse effect. Considerable costs are expected for the implementation of specialized mitigation measures or follow- up work. Regulated timing constraints are applicable during construction and have the potential to result in substantial construction limitations. Receptor-specific regulatory approvals are required to carry out the Project and material conditions are anticipated in Federal, Provincial, and Municipal approvals.

2.2.2 Mitigation Measures

To reduce the potential adverse effects during Project construction and operation, general mitigation measures have been identified based upon FortisBC's management standards and procedures, current industry-accepted standards, understanding of regulatory requirements, and the professional experience and judgement of the Project team.

The mitigation measures and follow-up activities provided are not exhaustive and are limited to those activities and measures that are anticipated to represent a cost to the Project.

3. Regulatory Overview

This section provides an overview of the environmental legislation, regulations, and bylaws that apply to the Project. A list of environmental permits and approvals that are expected to be required for the Project is provided in (Section 7).

British Columbia *Environmental Assessment Act*

Aspects of the Project will contribute to triggering a Provincial Environmental Assessment (EA) pursuant to the BC *Environmental Assessment Act* as it exceeds the trigger for assessment as follows:

> *"Modification of an existing facility if (b) the modification results in an increase in the capability of the facility to store an energy resource, other than electricity, by a quantity that can yield by combustion ≥3 PJ of energy or, for liquefied natural gas, increase by ≥136 000 m^3" (BC ENV 2019f)*

The Project includes adding storage of up to 3.3 PJ which would increase the total storage at the Tilbury site to 5.1 petajoules (PJ) with the existing base plant Tilbury tank remaining which exceeds the 3 PJ threshold.

FortisBC submitted their Initial Project Description on February 27, 2020 to the BC Environmental Assessment Office (BC EAO) and initiated the BC EAO's assessment process under the BC *Environmental Assessment Act*. The description of the Project will be further refined through the BC EAO process and for the submission of the Detailed Project Description later in 2020.

Federal *Impact Assessment Act*

The Project will also be subject to the Federal Impact Assessment (IA) process under the Canadian *Impact Assessment Act*. Section 38(d) of The *Physical Activities Regulation* includes;

> ***38*** *The expansion of one of the following:* ***(d)*** *an existing facility for the liquefaction, storage or regasification of liquefied natural gas, if the expansion would result in an increase in the liquefied natural gas processing or storage capacity of 50% or more and a total liquefied natural gas processing capacity of 3 000 t/day or more or a total liquefied natural gas storage capacity of 136 000 m^3 or more, as the case may be." (Government of Canada 2019a)*

The Project includes adding LNG storage of up to 142,400cubic metres (m^3) (3.3 PJ) for a total facility LNG storage of up to 216,900 m^3 (5.1PJ). The Project represents an increase in LNG storage capacity of more than 50 percent and total LNG storage capacity of more than 136,000 m^3. Therefore, the Project would be considered a physical activity pursuant to the *Regulations Designating Physical Activities* and is thereby reviewable under the Federal *Impact Assessment Act*.

On March 5, 2020 the BC EAO requested substitution pursuant to the *Impact Assessment Act* in accordance with the Impact Assessment Cooperation Agreement between Canada and British Columbia.

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Federal and Provincial Environmental Assessment Process

Given that both the Federal and Provincial EA processes are triggered, FortisBC has submitted a request on March 5, 2020 that the Province request the Federal Minister of Environment to approve the substitution of the BC EA process for the Federal IA process. If substitution is approved for the proposed Project, it is expected that the BC EAO will conduct the EA/IA in accordance with the conditions set out in the Substitution Decision, and at

the end of the assessment process, the BC EAO will provide its report to both the Provincial and Federal Ministers for their consideration.

3.1 Other Federal Legislation

The Project is on the Fraser River but avoids instream work, precluding the need for review by Transport Canada or the Vancouver Fraser Port Authority. Federal legislation that may be applicable to the Project is discussed in this section.

3.1.1 *Canada Wildlife Act*, R.S.C., 2020, c.W-9

The *Canada Wildlife Act* (Government of Canada 2020) protects migratory birds, wildlife, and habitat in National Wildlife Areas (NWAs). Regulations (R.S, 2020, c. W-9, S.1 and 1995, c.23, s2F) under the *Canada Wildlife Act* prohibit hunting, fishing, farming, recreational activities, industrial activities, domestic animals, disturbing soil, damaging plants, or dumping waste in NWAs without appropriate permits.

3.1.2 *Fisheries Act*

On June 21, 2019, Bill C-68 received royal assent, which included amendments to the *Fisheries Act* (DFO 2019b). Amendments include: protection for all fish and fish habitats, not just those related to a commercial, aboriginal or recreational fishery; restoration of the prohibition against 'harmful alteration, disruption or destruction (HADD) of fish habitat'; prohibition of activities, other than fishing, that cause 'the death of fish'; and consideration of the cumulative effects of development activities on fish and fish habitat. Provisions within the *Fisheries Act* officially came into force on August 28, 2019. Guidance and policy to meet the new fish and fish habitat protection provisions are still being released, with only two interim Codes of Practice available at the time of writing.

The self-assessment process under the previous *Fisheries Act* is obsolete with changes to review processes. However, assessment by a Qualified Environmental Professional (QEP) is still helpful to determine which projects require review by DFO. A Request for Review by DFO is required for works that may cause the death of fish or HADD of fish habitat, and for activities not covered by a Code of Practice or associated with DFO's Measures to Protect Fish and Fish Habitat. After reviewing the Request for Review, DFO will determine if an authorization under the *Fisheries Act* is required.

3.1.3 *Migratory Birds Convention Act*, S.C. 1994, c. 22

The *Migratory Birds Convention Act* (*MBCA*) protects and prescribes for the management of migratory birds and their habitat in Canada (Government of Canada 1994). Environment and Climate Change Canada (ECCC) administers the *MBCA* through the Canadian Wildlife Service. The *MBCA* prohibits "the killing, capturing, injuring, taking or disturbing of migratory birds or the damaging, destroying, removing or disturbing of nests." Under the Migratory Birds Regulations, no person shall "disturb, destroy or take a nest, egg, nest shelter, eider duck shelter or duck box of a migratory bird" (Government of Canada 1994).

3.1.4 *Species at Risk Act*, S.C. 2020 c. 29

The *Species at Risk Act* (*SARA*) protects species listed on Schedule 1 as Extirpated, Endangered, and Threatened, and affords species listed as Special Concern the benefits of management planning (Government of Canada 2020). The Federal Cabinet determines species included on Schedule 1 and are based on recommendations by the Committee on the Status of Endangered Wildlife in Canada (COSEWIC) and consultation with government, Indigenous groups, and the public. *SARA* applies to Federal lands; however, the Act also applies to other lands when Provincial protection is deemed inadequate by the Federal Minister of the Environment. *SARA* also applies to all lands in Canada for Schedule 1 bird species cited in the *MBCA*.

Species that were designated At Risk by COSEWIC before the creation of *SARA* must be reassessed according to the new criteria of the Act before they can be added to Schedule 1. These species are listed on Schedules 2 and 3 and are not yet officially protected under *SARA*.

3.2 Other Provincial Legislation

The Project falls under many different Provincial bodies most notably the British Columbia Oil and Gas Commission (BC OGC) which acts as a single window regulatory agency for oil and gas activities in BC. The Project will require consulting with the BC OGC to determine which Provincial regulatory requirements and approval are required.

3.2.1 *Environmental Management Act*, SBC 2003, c. 53

The *Environmental Management Act* (EMA) regulates industrial and Municipal waste discharge, pollution, hazardous waste, and contaminated site remediation. The *EMA* provides the authority for introducing wastes into the environment, while protecting public health and the environment. The *EMA* enables the use of permits, regulations, and Codes of Practice to authorize discharges to the environment and enforcement options (such as, administrative penalties, orders, and fines to encourage compliance). Guidelines and objectives for water quality are developed under the *EMA*.

The *EMA* and the *Waste Discharge Regulation* are the principal pieces of legislation for air emissions and wastewater discharges (such as hydrostatic testing releases) in BC. These regulations set conditions on how certain classes of activities (such as, a type of industry or business) may be conducted. The *EMA* Oil and Gas Waste Regulation regulates contaminants (water, emissions) generated from certain oil and gas activities in the commissioning and operating phases.

Another applicable regulation to this Project under the *EMA* is the BC *Contaminated Sites Regulation* (BC *CSR*), including amendments up to BC *Regulation 13/2019* as of January 24, 2019 (BC ENV 2019b). The particular effect on permits by this legislation is as follows:

1) **Application for Municipal Permit that Disturbs the Soil:** The BC *CSR* will require, by mid-2020, that every Municipality that issues a permit involving soil disturbance (such as, subdivision, change of use, development, building permits or Soil Removal Permit) that a Site Profile or Site Disclosure Statement be submitted to the Municipality.
2) **Site Profile or Site Disclosure Statement for Properties with Schedule 2 Activities:** If there are, or have been, any industrial activities on the land that are listed in the BC CSR Schedule 2, the Municipal permit process is “frozen”, and the Site Disclosure Statement is forwarded to the BC ENV.
3) **Stage 1 and 2 Preliminary Site Investigations:** The BC ENV will require further environmental investigation on the property, the minimum being a Stage 1 PSI or a Stage 1 and 2 PSIs if APECs are identified. Reports of these investigations are forwarded to BC ENV. Generally, there are three potential outcomes of the Stage 1 and 2 PSI outlined as follows.
    a) **No Contamination Outcome:** If there is no indication of contamination on the property by the environmental reports, the BC ENV will signal to the Municipality that the permit process can continue.
    b) **Contamination Identified, Limited to Property – Soft Release of Permit:** If there are indications of contamination on the property and it is not migrating off the property, a release of the permit can be achieved if the proponent confirms that the contamination will be further investigated and remediated according to BC CSR standards and the BC ENV technical guidance documents.
    c) **Contamination Identified – High Risk and/or Migrating – Full Investigation and Legal Instrument Required:** If there are indications of contamination that are considered high risk and/or there is potential for the contamination to be migrating off the property, the BC ENV will likely require further

environmental investigations through to the issuance of a legal instrument such as a CofC or Approval in Principle. When this instrument is procured, then the BC ENV will indicate to the Municipality that the permit process can resume.

If the outcome of the Stage 1 and 2 PSI is option (b) or (c), further environmental investigations are required as outlined as follows.

- Detailed Site Investigation (DSI) that delineates the extent of identified contamination
- Confirmation of remediation including a report that is completed after the remediation of the contamination
- Possible risk assessment of residual contaminated environmental media that is left after remediation efforts have been completed
- Application for a CofC or Approval in Principle (also optional for the no contamination outcome)
- An example of overall process and timing of the permit freeze and release process as it might apply to the Project is shown in Figure 3-1.

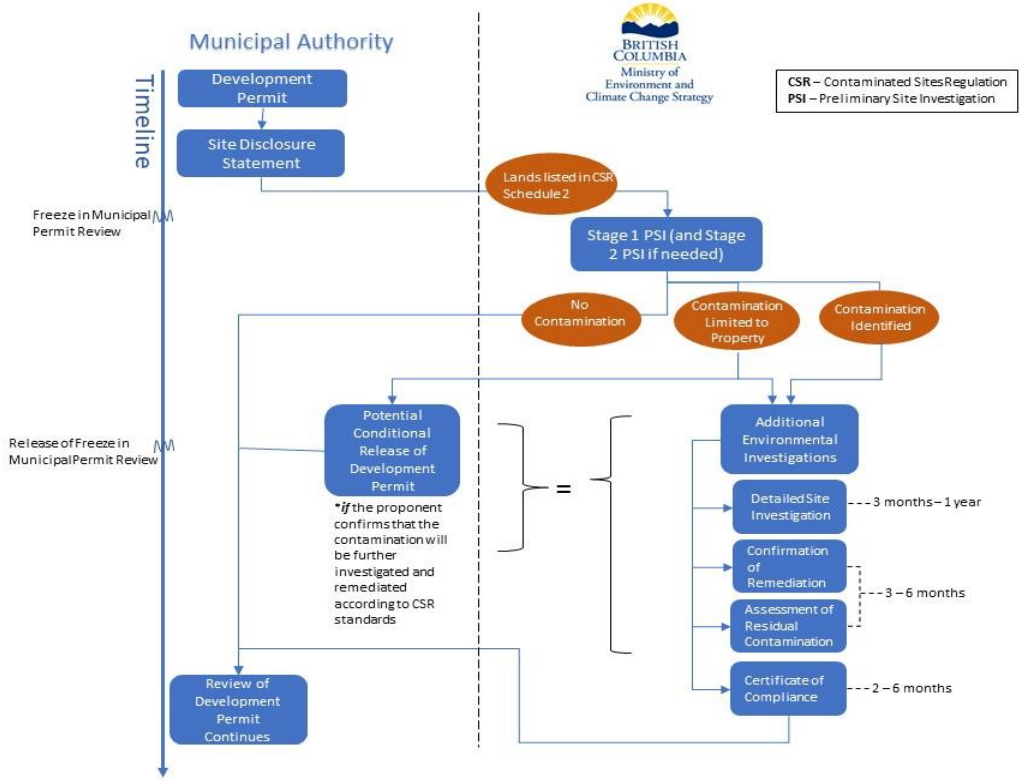


Figure 3-1. Example of BC *Contaminated Sites Regulation* Process and Timing Diagram

3.2.2 British Columbia *Wildlife Act*, RSBC 1996, c. 488

The BC *Wildlife Act* (Government of BC 1996a) protects wildlife and wildlife habitat in BC by identifying and designating WMAs, defining human interactions with wildlife, and regulating hunting, trapping, and angling. The BC *Wildlife Act* protects most native vertebrates from direct harm or harassment, regulates hunting, trapping and sport fishing, and protects nesting birds and active nests that are occupied by a bird or its egg(s). The nests of some bird species are afforded specific consideration under Section 34b of the BC *Wildlife Act* regardless of whether they are occupied. These protected nests, as relevant to this Project, include those used seasonally by

peregrine falcon, burrowing owl, Bald eagle, osprey, and great blue heron. A general BC *Wildlife Act* Permit is required for any trapping or handling of live wildlife (that is, salvages), including species at risk.

3.2.3 British Columbia *Oil and Gas Activities Act*, RSBC 2008

The BC *Oil and Gas Activities Act (OGAA)* (Government of BC 2008) regulates oil and gas and related activities in BC. This includes oil wells, facilities, pipelines, refineries, processing plants, and roads. These activities are regulated through permits, authorizations, orders, and regulations. Oil and gas activities for the Project include natural gas receiving, processing, liquefaction, and LNG storage.

A Facility Permit, or amendment, is required for construction and operation of the Project. This requires site-specific environmental baseline fieldwork, detailed engineering information, and consultation with Indigenous groups and public stakeholders.

An Archaeological Information Form (AIF) is required to determine whether the proposed development needs a further Archaeological Impact Assessment (AIA). An AIA was conducted on the Phase 1A portion of the Tilbury site in 2013. If a Heritage Investigation Permit and/or a Heritage Site Alteration Permit is required, engagement with potentially affected Indigenous groups will need to be conducted.

3.2.4 British Columbia *Water Sustainability Act*, RSBC 2014

The BC *Water Sustainability Act* manages instream works and the diversion and use of water in the Province (Government of Canada 2014). Key regulations include water rights and licensing requirements for industrial use, protection of aquatic ecosystems, fees for surface and groundwater use and groundwater protection, including requirements for well construction and maintenance. BC OGC administers the *Water Sustainability Act* for oil and gas projects, reviewing applications for changes in and about a stream (Section 11) and water use (Sections 9 and 10). Changes in and about a stream or extraction of water from natural sources are not anticipated to be required for the Project.

3.2.5 British Columbia *Weed Control Act*, RSBC 1996, c.487

The BC *Weed Control Act* (Government of BC 1996b) aims to control the spread of designated Noxious plants on all Provincial Crown and private land. There is an obligation under the Act for the land occupier to control these designated Noxious plants. The Act requires all land occupiers to avoid establishment and dispersal of Noxious weeds as defined by the Act.

3.3 Regional Bylaws

The Project and its surroundings are located within Delta which is part of the Metro Vancouver area. As most of the bylaws triggered by the Project are under Delta's jurisdiction, there are only two areas where the Regional (Metro Vancouver) bylaws would apply. One if the Project were to dispose of waste water (such as, hydrostatic test water), into the sanitary sewer as this is controlled at Municipal and Regional levels with Sanitary Sewer Bylaws. Two, the Project will be subject to the requirements of the Metro Vancouver air quality permitting process under the Air Quality Management Bylaw and the Non-Road Diesel Engine Emission Regulation Bylaws.

3.4 Municipal Bylaws

Delta Municipal Bylaws include Development Permits Areas, Noise Control, Building, Highways, and Tree Removal. Refer to the Preliminary List of Additional Permits and Approvals for the Proposed Expansion in Table 3-1 for information on specific permits.

3.5 Permit Summary

Table 3-1. Preliminary List of Permits and Approvals for the Proposed Expansion

Approval	Agency	Legislation/ Regulation	Application Considerations
Request for Review and *Fisheries Act* Authorization	DFO	*Fisheries Act*	A Request for Review by DFO is required if Project activities may result in HADD of fish habitat or the death of fish. An assessment under the *Fisheries Act* will be completed by a QEP to determine the need for DFO review, focusing on potential impacts to adjacent/downstream watercourses that provide fish habitat.
Federal IA	Impact Assessment Agency of Canada	*Canadian Impact Assessment Act*	The Project is subject to the Federal IA process under the Canadian *Impact Assessment Act*. Section 38(d) of the *Physical Activities Regulation*.
Provincial Environmental Assessment	BC EAO	*British Columbia Environmental Assessment Act*	The Project will trigger a Provincial EA pursuant to the BC *Environmental Assessment Act* as it exceeds the trigger for assessment.
Facility Permit or Amendment	BC OGC/ BC ENV	*OGAA/EMA*	An amendment to the existing Facility Permit or New Facility Permit is required for the construction and operation of the expansion. The amendments could be completed in phases to align with the construction phases. Requires site-specific environmental baseline fieldwork, detailed engineering information, and consultation with Indigenous groups and public stakeholders prior to EA Application submission.
AIF	BC OGC and BC MFLNRORD	*OGAA*	All oil and gas development proposed in BC requires an AIF be submitted to the BC OGC. The AIF indicates whether the proposed development will require a further AIA. Major projects that cover substantial areas typically require an AIA. An AIA was conducted on the Phase 1A portion of the Tilbury site in 2013. The AIF can be completed prior to finalizing the AIA; however, the approval would be conditional on completion of an AIA.
Waste Discharge Authorization	BC OGC	*OGAA*	Disposal of waste water into to the aquatic environment will require an Authorization. Air emissions from the new facility may require approvals. This will be applied for as part of the Facility Permit Amendment Application to the BC OGC.
Heritage Inspection Permit	BC MFLNRORD	*HCA* (subsection 12.2)	An AOA would be completed for the proposed expansion. The AOA would determine if further archaeological assessment (such as, an AIA), is required. An AIA would require a Heritage Inspection Permit. Engagement with potentially affected Indigenous groups will be required during the preparation and review of the Application.
Heritage Site Alteration Permit	BC OGC	*HCA* (subsection 12.4)	A Heritage Site Alteration Permit will be required to alter (meaning to change in any manner) an archaeological site. Typically follows a Heritage Inspection / Investigation Permit. An AIF must be completed in advance. Engagement with potentially affected Indigenous groups will be required during the preparation and review of the Application.
Indigenous Group Heritage Permits	Various Indigenous Groups	*Indigenous policies*	Several Indigenous groups will issue permits for archaeological work conducted in their territory.

Table 3-1. Preliminary List of Permits and Approvals for the Proposed Expansion

Approval	Agency	Legislation/ Regulation	Application Considerations
General Permit Applications	BC MFLNRORD	*Wildlife Act*	A permit is required for amphibian salvage, wildlife sundry, fish research at watercourse crossing, and fish salvage.
Sewer Use Permit	Metro Vancouver	*Bylaw 299*	A permit is required to discharge hydrostatic test and other construction waste water (excluding contaminated water) to the sanitary sewer system.
Air Quality Permit	Metro Vancouver	*Bylaw 1082*	A permit is required for anticipated airborne emissions from the Project.
Non-Road Diesel Engine Registration	Metro Vancouver	*Bylaw 1161*	Non-road diesel engines (construction equipment) used on-site must meet requirements of the bylaw.
Building Permit	Delta	*Local Government Act*	A Permit is required for new structures on the Tilbury site.
Development Permit	Delta	*Local Government Act*	Form and Character and Environmental Protections Development Permits may be required for the changes to the Tilbury site. Consultation is required with Delta to confirm Development Permit requirements.
Demolition Permit	Delta	*Local Government Act*	A permit is required for the demolition of existing structures.
Provincial Identification Number	BC ENV	*Hazardous Waste Regulation*	Any person, partnership, or company in BC that produces, stores, treats, recycles or discharges more than a prescribed quantity of hazardous waste must register with the Ministry Director within 30 days by completing a registration form and applying for a Provincial Identification Number
Tree Cutting Permit	Delta	*Bylaw 7415*	A permit is required for removal of any tree in the City of Delta with a diameter of 20 cm or greater measured at 1.4 m above its base.
Soil Removal and Deposit Permit	Delta/BC ENV	*Bylaw 7221/EMA/* BC *CSR*	A permit is required for deposit or removal of any soil in the City of Delta
Highway Use Permit	Delta	Bylaw 6922	A permit is required for using the City of Delta highways and contributing to the wear and tear.

Notes:
AOA = Archaeological Overview Assessment
BC MFLNRORD = British Columbia Ministry of Forests, Lands, Natural Resource Operations and Rural Development
cm = centimetre(s)
HCA = Heritage Conservation Act

3.6 Other Governance

3.6.1 Contaminated Sites

Provincially, the BC ENV provides Protocols, Procedures, and Guidance (technical, administrative, and external) documents that outline the general framework for completing contaminated sites environmental investigations in BC. Of the information available, two are relevant to describing the overall requirements that should be addressed during the investigation of contaminated sites. The following two Provincial guidance documents were considered during the preparation of this EOA:

1) Technical Guidance 10 on Contaminated Sites – Guidance for a Stage 1 Preliminary Site Investigation (BC MOE 2016a). This outlines the activities for completing a Stage 1 PSI and provides a checklist of specific items.
2) Technical Guidance 11 on Contaminated Sites – Guidance for a Stage 2 Preliminary Site Investigation and Detailed Site Investigation. (BC MOE 2016b) This outlines the required activities that need to be conducted to complete such investigations and also includes a checklist of specific items.

Federally, the Canadian Standards Association document entitled Standard Z768-01 (R2016) – Phase I Environmental Site Assessment outlines the methods for completing Phase I ESA investigations (CSA 2016).

3.6.2 British Columbia Oil and Gas Commission

The Oil and Gas Activity Application Manual (BC OGC 2019) is a comprehensive document on the oil and gas permit application explaining the process a facility must take for completing their applications. This document is not a regulatory requirement but a guidebook on permitting with the BC OGC.

The following BC OGC document was also reviewed and considered in the preparation of this EOA:

- Environmental Protection and Management Guideline, Version 2.7 (BC OGC 2018)

3.6.3 Water Quality and Fisheries

The following guidance documents were reviewed and considered in the preparation of this EOA:

- Approved Water Quality Guidelines for Aquatic Life, Wildlife and Agriculture – Summary Report (BC ENV 2019d)
- British Columbia Working Water Quality Guidelines for Aquatic Life, Wildlife and Agriculture – Summary Report (BC MOE 2017)
- City of Delta – Drinking Water Quality Report (Delta 2018a)
- City of Delta – Protection and Conservation of Streams, Rivers & Oceans (Delta 2020)
- Environmental Protection and Management Guideline, Version 2.7 (BC OGC 2018)
- Projects Near Water: Measures to Protect Fish and Fish Habitat (DFO 2019c)

3.6.4 Vegetation and Wildlife

The following guidance documents were reviewed and considered in the preparation of this EOA:

- *Oil and Gas Activities Act* General Regulation (Government of BC 2010)
- Accounts and Measures for Managing Identified Wildlife (BC MWLAP 2004)
- Develop with Care 2014 (BC MOE 2014a)

- Guidelines for Raptor Conservation during Urban and Rural Land Development in British Columbia (BC MOE 2013)
- Guidelines for Amphibian and Reptile Conservation during Urban and Rural Land Development in British Columbia (BC MOE 2014b)
- Guidelines for Evaluating, Avoiding and Mitigating Impacts of Major Development Projects on Wildlife in British Columbia (Harper et al. 2001)
- Best Management Practices for Amphibian and Reptile Salvages in British Columbia (BC MFLNRO 2016)
- Best Practices for Managing Invasive Plants on Oil and Gas Operations (PRRD and ISCBC 2013)
- Best Management Practices Guidelines for Pacific Water Shrew (Craig et. al. 2010)
- Noxious Weed Destruction Bylaw (Delta 1930)
- Delta's Birds & Biodiversity Conservation Strategy (Delta 2018b)
- Strategic Directions for Biodiversity Conservation in the Metro Vancouver Region (Metro Vancouver 2008)

3.6.5 Atmospheric Environment

Air quality objectives (AQOs) are limits on the acceptable presence of contaminants in the atmosphere. These are established by government agencies to protect human health and the environment. The Federal, Provincial, and Municipal governments have set AQOs and standards that are applicable to the Project. These AQOs and standards are used to guide air management decisions.

Federal

- Canada Ambient Air Quality Standards (CAAQS) from Canadian Council of Ministers of the Environment (CCME) are the driver for air quality management across Canada (CCME 2019).
- The CAAQS for fine particulate matter ($PM_{2.5}$) and ozone (O_3) were endorsed by the Minister of Environment in 2012 and by CCME and supersede Canada-wide Standards for Particulate Matter and Ozone (Canada Gazette 2013). CAAQS for sulphur dioxide (SO_2) were endorsed by the CCME in 2016.

Provincial

- British Columbia Ambient Air Quality Objectives (BC AAQOs) are listed in the BC Ambient Air Quality Objectives Information Sheet (BC ENV 2018).

Municipal

- Municipal air quality objectives for the Project Study Area are listed in the Metro Vancouver Ambient Air Quality Objectives (MVAAQOs) (Metro Vancouver 2020).

3.6.6 Land Use

The following guidance documents were reviewed and considered in the preparation of the Land Use section of this EOA:

- City of Delta OCP (Delta 2019) was reviewed to identify Municipal zoning, environmentally sensitive areas, agricultural land reserves, and residential areas in proximity to the Tilbury site.
- Richmond OCP (Richmond 2019) was reviewed to identify zoning and land use designations on the north side of the Fraser River directly across from the Tilbury site.

4. Overview of Existing Conditions

The following sections describe the existing biophysical environments within the defined Study Areas specific to each environmental receptor (Section 2). This description of existing conditions is based on a combination of desktop review of publicly available information, previous relevant studies completed for the Tilbury site, and a preliminary reconnaissance visit conducted on October 22, 2019.

4.1 Surface Water Quality and Quantity

The Study Area includes the Fraser River and Tilbury Slough, though no instream works are planned for either watercourse. The Tilbury site is on generally flat terrain that drains southeast through open and closed (culverted) drainage ditches. No watercourses or natural drainages were identified within the property boundaries during the Tilbury site reconnaissance on October 22, 2019, and none were identified through an online database query (Government of BC 2019). The drainage ditches join at the south end of the Tilbury site before entering a culvert and flowing into Tilbury Slough, which is a side channel of the Fraser River that is located approximately 100 m southeast of the property boundary. The north property boundary extends to within approximately 15 m of the Fraser River's southeastern shore, but generally aligns with the dike. The dike prevents stormwater runoff entering the Fraser River from the site. Figure 4-1 provides an overview of surface water features and associated riparian habitat within the Study Area.

The Fraser River basin drains a total of 21 million hectares (Rivershed Society of BC 2020) through the Fraser Plateau and into the Fraser Valley, eventually discharging to the Strait of Georgia. The Fraser River is tidally-influenced at the Tilbury site, and seasonally influenced by the salt water wedge which extends as far upstream as Annacis Island during low discharge periods (Ages and Woollard 1976). Tides from the Strait of Georgia result in water level fluctuations upwards of 2 m during lower flow periods in the Study Area. The Fraser River near the Project has been heavily developed along the shorelines, with bank protection and training structures decreasing sedimentation (and dredging requirements) in the reach (FREMP 2006).

ECCC maintains a hydrometric station on the Fraser River near Douglas Island, approximately 19 km upstream of the Project (ECCC 2020a). This station (08MH126) has been operational since 1965, providing flow data between 1965 to 1972 and 1983 to 1992. Low flow in the Fraser River occurs during the winter season and prior to spring melt. Lowest flows typically occur in January, with a mean discharge of 1,780 cubic metres per second (m^3/s). The highest flows occur during spring freshet, with a mean discharge in June of 8,590 m^3/s.

Table 4-1. Historical Streamflow (m^3/s) Summary for Fraser River at Port Mann Pumping Station (Station Number 08MH126) between 1965 to 1972 and 1983 to 1992

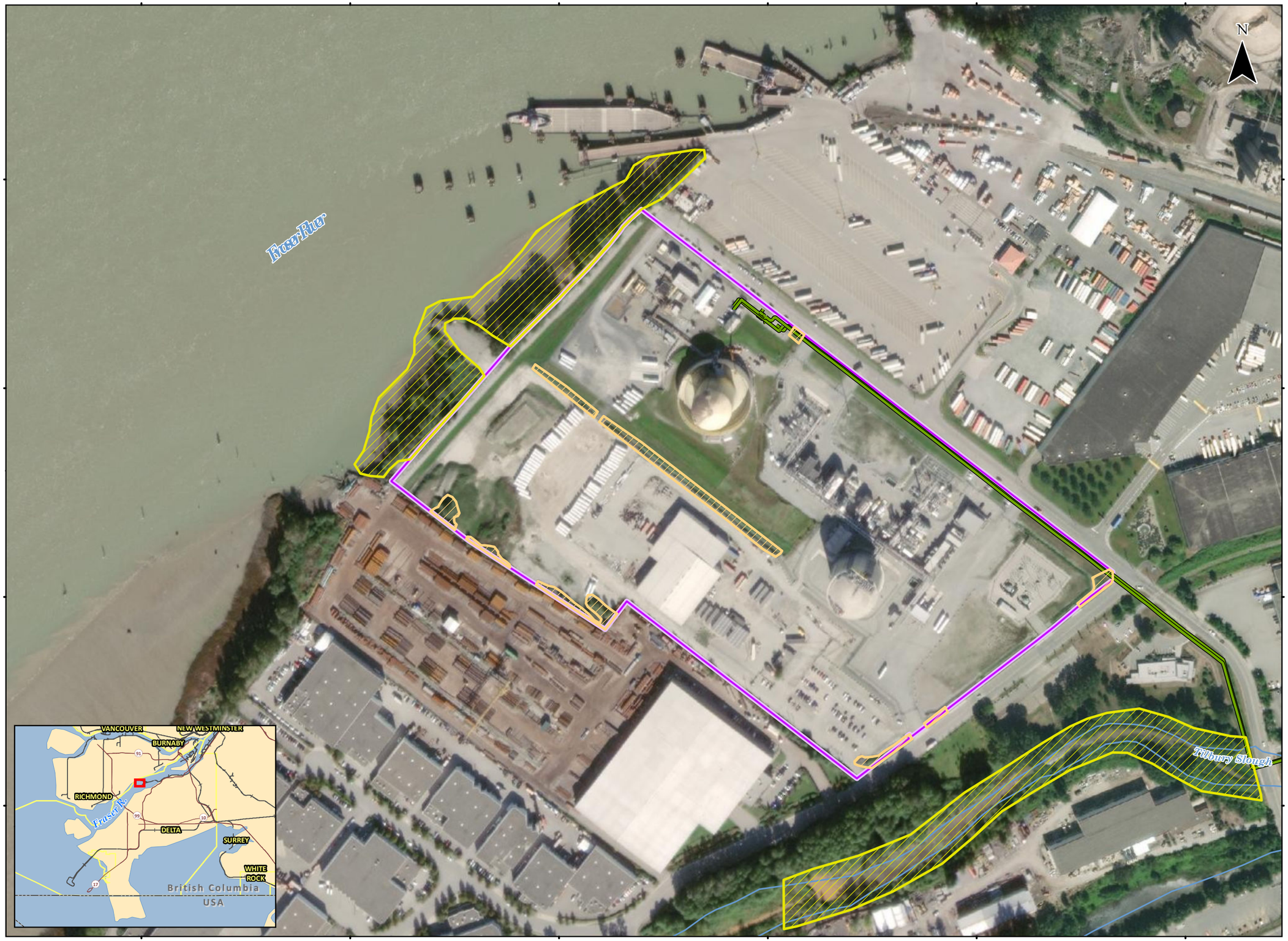
	January	February	March	April	May	June	July	August	September	October	November	December
Mean monthly discharge	1,780	1,820	1,880	2,850	5,790	8,590	6,580	4,210	2,850	2,550	2,690	1,870
Maximum monthly discharge	2,510	3,090	3,110	3,530	7,310	11,900	9,010	5,340	3,860	3,730	4,610	2,800
Minimum monthly discharge	1,030	1,110	1,080	1,600	3,550	6,920	4,740	2,930	2,190	1,460	1,660	1,280

Source: ECCC 2020a

Swain et al. (1998) has established water quality objectives for the Lower Fraser River, including the reach between New Westminster and Roberts Banks which encompasses the Study Area. For this reach, water quality objectives were based on considerations of protection of sensitive aquatic life, livestock watering, secondary-contact recreation, and irrigation (Swain et al. 1998). Provincial standards, including BC ENV approved (BC ENV 2019d) and working (BC MOE 2017) guidelines, are also generally applied to the Fraser River for the purpose of evaluating aquatic ecosystem health, human health, and potential impacts from existing and proposed developments and discharges.

BC ENV collects water quality data in the lower reach of the Fraser River at several monitoring stations to assess water quality, understand trends and emerging issues, and inform water quality guidelines and regulatory decisions. Measured parameters vary between stations, but generally consist of nutrients, metals, major ions, and other physical-chemical variables (such as, dissolved oxygen and pH). A water quality monitoring buoy (Fraser River at Gravesend Reach - Buoy [BC08MH0453]) is located across the river from Tilbury Island and adjacent to the Study Area (ECCC 2020b). A water and sediment quality study completed for the Pattullo Bridge replacement on behalf of the Ministry of Transportation and Infrastructure's examined water quality data from this station between August 2008 and November 2106 (Hatfield Consultants 2018). Exceedances in Provincial guidelines were identified for alkalinity, dissolved aluminum, and total cadmium, chromium, cobalt, copper, selenium, silver, and iron, and exceedances in Fraser River water quality objectives for E. Coli and Enterococcus (Hatfield Consultants 2018).

Fish and fish habitat values were not identified on the Tilbury site; however, the site drainage ditches are sensitive areas due to the risk of erosion and sedimentation during construction, with potential of introducing deleterious substance to downstream fish habitats.



FORTIS BC™

June 2020

FIGURE 4-1

ENVIRONMENTALLY SENSITIVE AREAS

TILBURY PHASE 2 LNG EXPANSION PROJECT

Environmentally Sensitive Area

- Riparian Habitat
- Drainage Ditch

Proposed Project Components

- Site Plan

Base Data

- Existing FortisBC Natural Gas Pipeline
- Road
- Railway
- Waterbody

SCALE: 1:3,500

0 50 100 150 m

(All Locations Approximate)

JACOBS®

Project Number CE742500

UTM Zone 10 North. NAD 1983.
Proposed Marine Jetty: Ausenco March 2019; Expected Powerline and Substation: FortisBC Sept 2018; Existing Pipeline: FortisBC 2012; Transportation: BC FLNRORD 2012; Regional Districts & Municipalities: BC FLNRORD. 2017; Political Boundaries: ESRI 2005, USNIMA 2000; Hydrology: BC FLNRORD 2011; Imagery Service Layer Credits: Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AeroGRID, IGN, and the GIS User Community.

Although there is no reason to believe that there are any errors associated with the data used to generate this product or in the product itself, users of these data are advised that errors in the data may be present.

Mapped By: SL | Checked By: DS

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4.2 Atmospheric Environment

Data from the Lower Fraser valley ambient air quality monitors were obtained for the Richmond South Station for the year 2018. The monitor is located 5.4 km east of the Tilbury site and is representative of the Tilbury site. These data were the most recent and representative available at the time of EOA preparation but may not capture effects of recent buildout at the facility.

The monitored design values vary for each contaminant and averaging period. The method of determining the monitored design value is shown in Table 4-2. The applicable AQOs are also shown in Table 4-2 and include values from Municipal, Provincial, and Federal regulations (that is, the MVAAQO, BC AAQO, and the CAAQS). The proposed 2025 AQ standards are presented in the footnotes to Table 4-2.

The monitored values show air quality in the region is below all applicable AQOs and standards with the exception of 24-hour average $PM_{2.5}$ (measured as 29.2 micrograms per cubic metre [µg/m^3]), which is marginally above the CAAQS and BC AAQO. The maximum 24-hour concentration measured was 123.2 µg/m^3.

It should be noted that Metro Vancouver considers methane as a non-photoreactive VOC and there are set reporting requirements associated with its discharge in air (planned and unplanned). There are no set criteria associated with methane for Metro Vancouver.

Table 4-2. Summary of 2018 Monitored Concentrations for Richmond South Station and Applicable Air Quality Objectives

Contaminant	Avg. Period	µg/m^3	ppb	Maximum[a]	Design Value (Richmond South Station)	Criterion	Design Value Calculation[b]
NO_2	1- hour	188	100	50.2 ppb	38.4 ppb	BC AAQO	98th percentile of maximum 1-hour concentrations
		200	106	--	--	MVAAQO	Maximum
		113	60	--	--	CAAQS	--
		79	42			2025 CAAQS[c]	3-year avg of annual 98th percentile of maximum daily concentrations
	Annual	60	32	--	11.2 ppb	BC AAQO	Average of 1-hour values
		32	17	--	--	CAAQS	--
		40	21	--	--	MVAAQO	Maximum
		23	12	--	--	2025 CAAQS	--
O_3	1-hour	161	82	--	79.2 ppb	MVAAQO	Maximum
	8-hour	128	65	--	--	MVAAQO	Maximum

Table 4-2. Summary of 2018 Monitored Concentrations for Richmond South Station and Applicable Air Quality Objectives

Contaminant	Avg. Period	µg/m³	ppb	Maximum[a]	Design Value (Richmond South Station)	Criterion	Design Value Calculation[b]
		123	63	48 ppb	44.7 ppb	CAAQS	4th highest daily maximum 8-hour rolling average concentration
			60	--	--	2025 CAAQS	--
$PM_{2.5}$	24-hour	25	--	123.2 µg/m³	29.2 µg/m³	BC AAQO and MVAAQO	98th percentile of 24-hour averages
		27	--	--	--	2020 CAAQS	98th percentile of annual 24-hour average concentrations
	Annual	8 (6[d])	--	--	7.3 µg/m³	BC AAQO and MVAAQO	Average of 24-hour values
		8.8	--	--	--	2020 CAAQS	--
SO_2	1-hour	196	75	6.1 ppb	3 ppb	Interim AQO	99th percentile of daily maximum 1-hour averages
		183	70	--	--	CAAQS and MVAAQO	--
		170	65	--	--	2025 CAAQS	99th percentile of daily maximum 1-hour averages
	Annual	13	5	--	0.3 ppb	CAAQS and MVAAQO	--
		10.5	4	--	--	2025 CAAQS	--
CO	1-hour	14,300	13,000	1,930 ppb	--	BC AAQO (Reference)[e]	Maximum
	8-hour	5,500	5,000	1,030 ppb	--	BC AAQO (Reference)[e]	Maximum
	1-hour	30,000	26,200	--	--	MVAAQO	Maximum
	8-hour	10,000	8,700	--	--	MVAAQO	Maximum

Table 4-2. Summary of 2018 Monitored Concentrations for Richmond South Station and Applicable Air Quality Objectives

Contaminant	Avg. Period	µg/m³	ppb	Maximum[a]	Design Value (Richmond South Station)	Criterion	Design Value Calculation[b]

[a] Maximum is the highest concentration for each contaminant and averaging period from the 2018 data set,

b Metro Vancouver objectives are "not to be exceeded" for all averaging periods and contaminants.

c Currently, there is uncertainty as to how Metro Vancouver will apply this air quality objective for areas already exceeding or close to the criteria.

d Metro Vancouver's annual $PM_{2.5}$ planning goal of 6 µg/m^3 is a longer-term aspirational target to support continuous improvements.

e The 1-hour and 8-hour CO objectives from BC AAQO are pollution control objectives were rescinded in 2006, however the ambient air quality objectives continue to be used for reference purposes.

References: BC ENV 2018, 2019c; CCME 2019; Metro Vancouver 2020.

Notes:

CO = carbon dioxide
NO_2 = Nitrogen dioxide
ppb = parts per billion

4.3 Contaminated Soils and Groundwater

The desktop portion of the review was limited to the following: a review of environmental reports provided by FortisBC, a review of historical aerial photos, a review of the Site Registry and a site visit was completed. The desktop review findings are summarized in the following tables: Tables 4-2, 4-3, and 4-4 and the Tilbury site visit and interview findings are summarized in Table 4-5.

Table 4-3. Limited Desktop Review Findings – Previous Environmental Report Review

Findings	
Previous Environmental Reports	FortisBC provided Jacobs with previous environmental reports available for the Tilbury site, as listed in subsection 2.1.2.3. The following is a review summary as it pertains to investigated areas of the Tilbury site and land to the south. ▪ **Western half of the Tilbury site**: This part of the Tilbury site was historically occupied by a sawmill (circa 1974). Prior to 1974, the land was used for agricultural purposes. The area was subject to numerous environmental investigations dating from 1991 to 2010 when a CofC was obtained. Civic addresses listed on these reports are 7150 Tilbury Road, 7515 Tilbury Road, and 6939 Tilbury Road. Environmental investigations included Phase I and II ESAs, UST removals, supplemental investigations, and soil and groundwater remediations. Overall, a total of nine APECs was identified and investigated in this area, five of which were carried forward as Areas of Environmental Concern and were subsequently delineated and remediated to meet the BC *CSR* IL use and AW standards. The CofC was issued to certify that the area was remediated to meet the numeric-based BC *CSR* standards for soil and water. The following parameters were remediated in soil to meet BC *CSR* IL standards: LEPHs, HEPHs, PAHs, VPHs, PCP, cresol, xylene, copper, and chromium. The following parameters were remediated in groundwater to meet the BC *CSR* AW standards: LEPH, non-chlorinated phenols (total), naphthalene, arsenic, and copper. Foreshore was not included on the CofC. ▪ **Eastern half of the Tilbury site**: This part of the Tilbury site was historically occupied by an LNG facility on its northern half (circa 1974) (historical civic address 7651 Hopcott Road). Prior to 1974, the land was used for agricultural purposes. An environmental property review report was completed in 1998 and a Limited Phase I ESA was completed in 2013. Both documents identified no APECs for the Study Area and no further investigation was warranted at the time. A Soil Removal and Deposit Permit was issued for this area in 2014. The permit required a PSI and subsequently a legal instrument to investigate or remediate all environmental media in this area. The permit also indicated that a site profile was not required for the southern half of this area with a historic civic address of 7525 Hopcott Road, as there were no historical commercial or industrial uses of this property listed in Schedule 2. Approximately 2,330 m^3 of stockpiled soil from 7525 Hopcott Road and north of 7651 Hopcott Road was excavated in 2014 and classified as meeting BC *CSR* RL use quality based on LEPH/HEPH, PAH, metals, and phenols laboratory analytical results. ▪ **Hopcott Road**: Soil sampling was completed in 2015 to investigate hydrocarbon odour reported during road widening works. Samples were analyzed for metals, extractable petroleum hydrocarbons, PAHs, VPH, BTEX, and PCBs. No exceedances of Parkland, RL, Commercial Land, or IL use BC *CSR* standards were noted.

Notes:
AW = Freshwater Aquatic Life
BTEX = benzene, toluene, ethylbenzene, and xylenes
HEPH = heavy extractable petroleum hydrocarbon
IL = Industrial Land (use)
LEPH = light extractable petroleum hydrocarbon
PAH = polycyclic aromatic hydrocarbon
PCB = polychlorinated biphenyl
PCP = pentachlorophenol
RL = Residential Land (use)
VPH = volatile petroleum hydrocarbon

Table 4-4. Limited Desktop Review Findings – Aerial Photographs[a]

Year	Aerial Photo Number/ID	Observations and Comments
1938 (UBC GIC 1938)	A 5938:17	The site appears cleared and used for agricultural purposes. The neighbouring land to the north, south, east, and west also appears used as agricultural. The Fraser River is located north of the Tilbury site. River Road is visible south of the Tilbury site.
1949 (UBC GIC 1949)	BC 783:71	The Tilbury site and surrounding area appear similar to the 1938 aerial photograph.
1951 (UBC GIC 1951)	570-R1-49	River dike is visible along the Fraser River. The Tilbury site and surrounding area appear similar to the previous aerial photographs.
1955 (UBC GIC 1955)	BC1672:72	The Tilbury site and surrounding area appear similar to the previous aerial photographs.
1963 (UBC GIC 1963)	BC5064:126	The Tilbury site and surrounding area appear similar to the previous aerial photographs. A rail line is visible to the northeast of the site running from a dock on the Fraser River to the southeast.
1969 (UBC GIC 1969)	BC5319-167	The Tilbury site and surrounding area appear similar to the previous aerial photographs. Hopcott Road is visible east of the Tilbury site.
1974 (UBC GIC 1974)	BC5588 -227	The northern part of the western half of the Tilbury site appears to be used as a sawmill. Several large structures associated with the sawmill are visible on the photograph and, what appears to be, lumber and logs are visible across this area and encroaching onto the lot to the west. A large dock is visible to the north of these structures. Access road connects the sawmill with the Tilbury Road south of the Tilbury site. The northern part of the eastern half of the Tilbury site appears to be cleared and filled. A large tank is also visible in this area of the Tilbury site. Several structures and associated parking and loading areas are located north of the tank. Industrial development is visible on the northeast end of the Hopcott Road at the start of the rail line running to the southeast. The remaining areas of the Tilbury site and surrounding land continue to be used for agricultural purposes similar to the previous aerial photographs.
1979 (UBC GIC 1979)	30BC79006-016	Additional buildings and associated parking are visible on the eastern half of the Tilbury site. The western half of the Tilbury site remains similar to the previous photograph with logs visible in the Fraser River. Clearing and fill deposition is visible on the lot south-west from the Tilbury site. A rail spur is visible south of the Tilbury Road. The remaining surrounding land use appears similar to the previous aerial photographs.
1984 (UBC GIC 1994)	15BC84013-141	The southern part of the western half of the Tilbury site appears to be used for storage, likely lumber. Additional structure, including tanks' secondary containment wall, have been developed on the eastern half of the Tilbury site. Further clearing or fill deposition is visible on the land west and east of the Tilbury site. The remaining surrounding land use appears similar to the previous aerial photographs.
1989 (UBC GIC 1989)	DAS89068-172	The Tilbury site appears similar to the previous aerial photograph. The remaining surrounding area appears similar to the previous aerial photograph.

Table 4-4. Limited Desktop Review Findings – Aerial Photographs[a]

Year	Aerial Photo Number/ID	Observations and Comments
1994 (UBC GIC 1994)	FFC Vancouver 94-98	The western half of the Tilbury site appears to be cleared of previous smaller structures and a new larger structure is now visible in the centre of this area. The eastern half of the Tilbury site appears similar to the previous aerial photograph. The industrial development northeast from the Tilbury site has been decommissioned and the site is cleared of structures. The remaining surrounding area appears similar to the previous aerial photograph.
1999 (UBC GIC 1999)	SRS 6064 - 08	The Tilbury site appears similar to the previous aerial photograph. The area east of the site across the Hopcott Road has been developed again and a large industrial complex is visible to the southeast. Industrial development is visible south of the Tilbury Sough. The remaining surrounding area appears similar to the previous aerial photograph.
2004 (UBC GIC 2004)	SRS 6912 - 235	Additional structures are visible on the western half of the Tilbury site. The remainder of the Tilbury site appears similar to the previous aerial photograph. Industrial development is visible further to the west of the Tilbury site. The remaining surrounding area appears similar to the previous aerial photograph.
2009 (UBC GIC 2009)	SRS 7964- 386	Clearing is visible in the southern part of the eastern half of the Tilbury site. The remainder of the Tilbury site appears similar to the previous aerial photograph. The remaining surrounding area appears similar to the previous aerial photograph.
2016 (UBC GIC 2016)	N/A	Additional structures and a large tank are visible in the southern part of the eastern half of the Tilbury site. Smaller structures are no longer visible on the western half of the Tilbury site. The remainder of the Tilbury site appears similar to the previous aerial photograph. Industrial development is visible immediately west of the Tilbury site. The remaining surrounding area appears similar to the previous aerial photograph.

[a] Copies of aerial photos are presented in Appendix A

The wide area BC Site Registry search results and Detailed and Synopsis Site Registry reports are presented in Appendix B and are summarized in Table 4-5. Jacobs' search of the BC Site Registry and iMap (through the environmental remediation sites layer) (Government of BC 2019a) identified a total of five registered sites within a 500-m search radius of the Tilbury site. The Tilbury site's legal parcel itself was listed under Site ID 5557 (6845, 6939, 7150 Tilbury Road, Delta, BC) and Site ID 16202 (7651 Hopcott Road, Delta, BC).

In addition, Site ID 6314 coordinates were outside of the 500-m search radius, but based on the description and iMap search results, pertains to the northeast side of Hopcott Road, and is therefore discussed herein.

Table 4-5. Limited Desktop Review Findings – BC Site Registry Search

BC Site Registry ID	Address	Location	Description
5557 (APEC 1)	6845, 6939, 7150 Tilbury Road (Formerly 7515 Hopcott Road)	On legal parcel associated with the Tilbury site footprint.	▪ A CofC was issued by the BC ENV in June 2010 for a portion of the former 7515 Hopcott Road (7150 Hopcott Road). The foreshore portion of the lot was not part of this Certificate. ▪ Final determination of contaminated site - site not contaminated, was issued in Jan 2008 for PID: 016-198-492 on the recommendation of an approved professional (Reidar Zapf-Gilje) under Protocol 6 of the BC *CSR*. ▪ Associated Sites: The southeast roadway (the lot south of Tilbury Road - Site 5037) was subdivided to allow for a roadway dedication. The rest of the property (Site 5557) is the mill site.
16202 (APEC 2 to APEC 5)	7651 Hopcott Road	On legal parcel associated with the Tilbury site footprint	▪ Land use was listed as: natural gas processing. ▪ The site profile questionnaire entered in January 2014 answered yes to PCB-containing electrical transformers or capacitors either at grade, attached aboveground to poles, located within buildings, or stored. However, the location of these were not provided. The site profile also indicated the following Schedule 2 activity: F3 - Natural Gas Processing. ▪ Further investigation in the form of a PSI was required by the Ministry.
5037	Tilbury Road through 7515 Hopcott Road	South of the Tilbury Site across the Tilbury Road	▪ Final determination of contaminated site - site not contaminated, was issued in November 2000. ▪ Associated Sites: The site was subdivided from Site ID: 5557 to allow for a roadway dedication. ▪ The current status of the site, as of January 2003, is Inactive – No Further Action.
6973	7700 Hopcott Road		▪ No Site Profile has been submitted for this site.
6314	7510 Hopcott Road	Northeast Side of Hopcott Road	▪ The property owner listed was Hopcott Warehouses Ltd. A PSI and environmental remediation were completed in May 2000 and February 2002, respectively, to determine and remediate source of drinking water contamination (toluene and ethylbenzene) in municipally supplied drinking water. ▪ The current status of the site, as of June 2002, is Inactive – No Further Action. ▪ No Site Profile has been submitted for this site.

4.3.1 Site Visit and Interviews

The Tilbury site and adjacent land visit was conducted by Jacobs' personnel on October 22, 2019. Leslie Kristoff and Edmond Leung with FortisBC were present. The Tilbury site includes the following areas:

- The original production and storage facility
- The Phase 1A production and storage expansion
- The former sawmill site

The site visit consisted of a walkthrough of the original production and storage facility only with observation of the remainder of the Tilbury site and neighbouring land from the publicly accessible off-site areas.

The findings of the site visit are summarized in Table 4-6.

Table 4-6. Site Visit and Interviews

Findings	
Original Production and Storage Facility	The original production and storage facility is located on the northeast part of the Tilbury site and, according to the FortisBC representatives, has been in operation since the 1970s. The area is approximately 70 percent covered with gravel with the remaining areas occupied by on-site structures and concrete surfaces. A double walled LNG tank with secondary containment is located in this area. The LNG tank was constructed on untreated timber pilings used at the time of construction to densify the area (E. Leung pers comm. 2019). A foam generator tank (**APEC 2**) is located immediately south of the LNG tank. The foam generator tank is connected to the LNG tank and uses Ansul Jet – X expansion foam for fire protection (E. Leung pers comm. 2019). Any foam generated during fire protection testing is disposed into the LNG tank's secondary containment and from there, pumped via a PVC pipe into a ditch west of the LNG tank (**APEC 2**). Ansul Jet-X Safety Data Sheets (SDS) are included as Appendix F. A number of ASTs were noted during the site visit. One generator back-up diesel AST (**APEC 3**) on a concrete base was located in the northeast corner. The diesel AST was installed in the mid-1990s (E. Leung pers comm. 2019). One AST containing mercaptan, a gas odorant chemical, was located north of the LNG tank. Four ASTs containing coolants (butane, propane, ethane) were located in the northern part. One area of rust covered gravel approximately 5 m in diameter was noted in the northeast part of the Tilbury site (**APEC 4**). Rust is collected during flushing of cooler pipes used to aid a cooling process (E. Leung pers comm. 2019). The cooling water is sourced from a water well located northwest from the LNG tank and discharged into the ground - eventually reaching the perimeter ditch located along the eastern part of the Tilbury site. A concrete base LNG loading area was located west of the LNG tank. A machine shop building, used for storage, is located east of the LNG tank along with the transformers and switchgear used for power supply to this part of the Tilbury site (APEC 6). No items of environmental concern were noted for the shop building during this site visit. According to FortisBC representatives, no sumps are located in this part of the Tilbury site.
Phase 1A Production and Storage Expansion	The Phase 1A production and storage expansion area includes a new LNG tank and ancillaries including power supply, gas supply, and both natural gas and LNG distribution facilities, in operation since 2019. Three large sumps collecting any discharge and rainwater are located in this part of the Tilbury site (E. Leung pers comm. 2019). Sump water may be connected to the perimeter ditches for discharge (**APEC 5**). A 69 kV to 13 kV substation is located in the southeast corner with transformers located southeast of the new LNG tank. The substation and transformers were built in 2018.
Former Sawmill Site	A pile of geotechnical preload is located on the northern part of this area close to the Fraser River. A warehouse, previously used by the former sawmill (**APEC 1**), is now being used for storage of spare parts, pipes, and valves (E. Leung pers comm. 2019). The remainder of this area is used for parking of vehicles and LNG Tankers.
Neighbouring Properties	The Tilbury site is located in an industrial area with the following industrial operations in its vicinity: ▪ East across the Hopcott Road: Seaspan Ferries Corporation at 7700 Hopcott Road, Delta, and a Multi-tenant industrial building at 7510 Hopcott Road, Delta (Cloverleaf Seafood Inc., SCI Logistics, Fountain Tire Distribution Centre, and Canadian Alliance Terminals). No items of environmental concern were noted during the site visit. ▪ South across the Tilbury Road: Delta Community Animal Shelter at 7505 Hopcott Road, Delta. Asphalt patch and backfill was noted south of the Tilbury Road which corresponds with the former rail spur visible south of the Tilbury Road in the 1979 aerial photo. Due to its hydraulically inferred downgradient location from the Tilbury site this was not considered an APEC. ▪ West: Varsteel Ltd at 6845 Tilbury Road, Delta. No items of environmental concern were noted during the site visit. ▪ North: Fraser River. A pile of old rail lines and ties (**APEC 8**) was located in the northwest corner of the Tilbury site on the Fraser River dike. A strong creosote like odour was noted in the vicinity of this pile.

Note:
kV = kiloVolt(s)

4.3.2 Interpretation of Findings (APECs and PCOCs)

The following eight APECs and their associated potential contaminants of concern (PCOCs) were identified for the Tilbury site. The recommendations for further work are presented in the far-right column. The location of the APECs are shown on Figure 4-2.

Table 4-7. Area of Potential Environmental Concern Summary

APEC	Rationale	PCOC			Recommendations
		Soil	Groundwater	Vapour	
On-Site					
APEC 1 Former Sawmill	The sawmill historically occupied the western half of the Tilbury site. Aerial images identified logs and structures in this area as far back as circa 1974. Lumber and logs visible across this area and encroaching onto the lot to the west. A CofC was obtained for the western portion of the Tilbury site only in 2010. The following parameters were remediated in soil to meet BC *CSR* IL standards: LEPH, HEPH, PAHs, VPHs, pentachlorophenol, cresol, xylene, copper, and chromium. The following parameters were remediated in groundwater to meet the BC *CSR* AW standards: LEPH, non-chlorinated phenols (total), naphthalene, arsenic, and copper. Given the year the CofC was obtained and subsequent updates to the BC *CSR*, there is potential that residual contamination and/or additional PCOCs remain in the underlying soil and groundwater.	LEPH, HEPH, VPH, PAHs, VOCs, BTEX, chlorinated and non-chlorinated phenols, and metals.	Water-soluble tannins, fatty acids, wood resin acids (terpenes), LEPH, HEPH, VPH, PAHs, VOCs, BTEX, chlorinated and non-chlorinated phenols, and metals	VPH, PAHs, VOCs, BTEX	Review of historical analytical results and compare to current BC *CSR* standards. Stage 2 PSI as required.
APEC 2 Foam Generator Tank	The foam generator tank is located immediately south of the LNG tank. The foam generator tank uses Ansul Jet X expansion foam for fire protection. Any foam generated during fire protection testing is disposed into the LNG tank's secondary containment and from there, pumped via a PVC pipe into a ditch west of the LNG tank. Given duration of use of the foam generator tank (over 30 years) and the fact that the foam is left to infiltrate into the on-site ditch, potential exists for PCOCs to migrate into the on-site soil and groundwater.	PFOS and PFOA	PFOA	n/a	Review of Ansul Jet X expansion foam chemical composition . Stage 2 PSIs as required.
APEC 3 Diesel AST	One generator back-up diesel AST on a concrete base was located in the northern corner of the Tilbury site. The diesel AST has been in-use since the mid-1990s. Given duration of use of the diesel AST (over 30 years), potential exists for PCOCs to migrate into the on-site soil and groundwater.	LEPH, HEPH, VPH, PAHs	LEPH, HEPH, VPH, PAHs	VPH, PAHs	Stage 1 and 2 PSIs

Table 4-7. Area of Potential Environmental Concern Summary

APEC	Rationale	PCOC			Recommendations
		Soil	Groundwater	Vapour	
APEC 4 Rust Staining	Rust covered gravel, approximately 5 m in diameter, was noted in the northeast part of the Tilbury site. Rust is collected during flushing of cooler pipes used to aid a cooling process in the LNG plant. The cooling water is sourced from a water well located northwest from the LNG tank and discharged into the ground - eventually reaching the perimeter ditch located along the eastern part of the Tilbury site. Given the duration of use of the cooler system (nearly 50 years) and rust staining on the gravel surface, potential exists for PCOCs to be present in on-site soil and groundwater.	metals	metals	n/a	Stage 1 and 2 PSIs
APEC 5 On-Site Sumps	Three large sumps are located in the eastern part of the Tilbury site. The sumps are collecting rainwater and any discharge from power, natural gas, and LNG distribution facilities that have been in operation since 2019. The sump water is further discharged into eastern perimeter ditch. Given the potential for the sumps to create preferential pathways to environmental receptors, potential exists for long term impacts to soil, groundwater, and surface water quality at the Tilbury site.	LEPH, HEPH, PAHs, metals, PCBs	LEPH, HEPH, PAHs, metals, PCBs	PAHs	Stage 1 and 2 PSIs
APEC 6 PCB-Containing Equipment	A site profile submitted in 2013 for the portion of the Tilbury site occupied by the original production and storage facility indicated PCB-containing equipment existed on-site at that time. The transformers and switchgear used for power supply to this part of the site is located in the northern corner of the Tilbury site. Due to the long duration of use of these equipment (nearly 50 years) potential exists for soil and groundwater impacts at the Tilbury site.	PCBs, metals	PCB, metals	n/a	Stage 1 and 2 PSIs
APEC 7 Unknown Quality Fill	In the aerial photo from 1974, the northern part of the eastern half of the Tilbury site appears to be cleared and filled. Given this timing of the fill deposition, potential exists for the low-quality fill to be present on this part of the Tilbury site. Given the duration this potentially low-quality fill is present, potential for soil and groundwater quality impacts exist at the Tilbury site.	LEPH, HEPH, PAHs, metals	LEPH, HEPH, PAHs, and metals	PAHs	Stage 1 and 2 PSIs

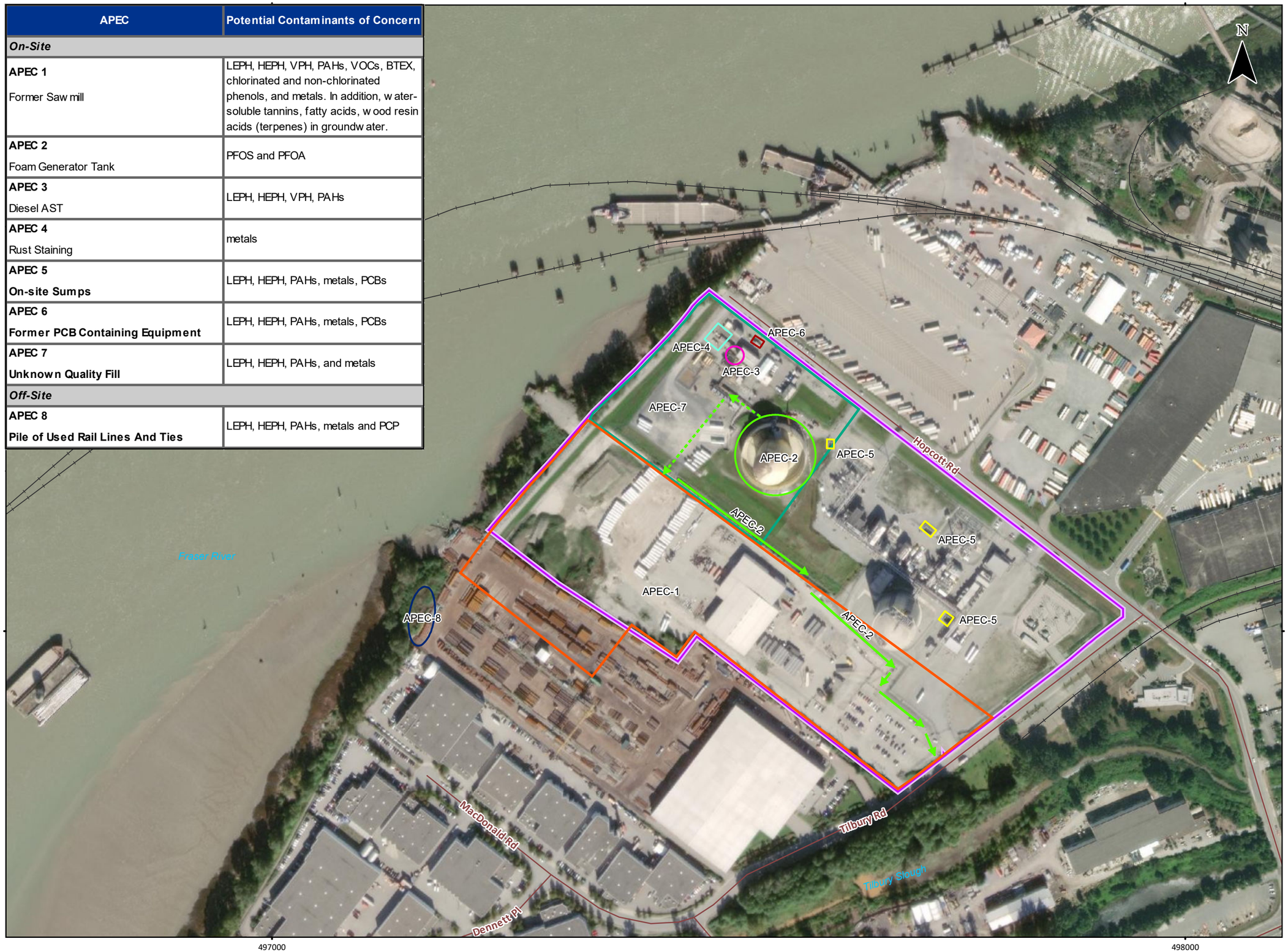
Table 4-7. Area of Potential Environmental Concern Summary

APEC	Rationale	PCOC			Recommendations
		Soil	Groundwater	Vapour	
Off-Site					
APEC 8 Pile of Used Rail Lines and Ties	During the site visit, a pile of old rail lines and ties was located in the northwest corner of the Tilbury site on the Fraser River dike. A strong creosote like odour was noted in the vicinity of this pile. The location from which these came from remains unknown. However, a rail spur was visible on aerial photos, from circa 1979 to circa 1999, south of the Tilbury site across the Tilbury Road. According to the environmental reports reviewed, this area south of the Tilbury Road was part of the larger historical sawmill site and the possibility exists that, once decommissioned in 1999, rail spur parts were stored on the current location. Given the possible long duration of stockpiling there exists the potential for PCOCs to have migrated onto the Tilbury site footprint.	LEPH, HEPH, PAHs, metals, and PCPs	LEPH, HEPH, PAHs, metals, and PCP	PAHs	Stage 1 and 2 PSIs

Notes:

BTEX = benzene, toluene, ethylbenzene, and xylene
HEPH = Heavy Extractable Petroleum Hydrocarbons
LEPH = Light Extractable Petroleum Hydrocarbons
PAH = Polycyclic aromatic hydrocarbons
PCB = Polychlorinated biphenyl
PCP = Pentachlorophenol
PFOS = Perfluorooctane sulphonate
PFOA = Perfluorooctanoic acid
VOCs = Volatile Organic Compound

APEC	Potential Contaminants of Concern
On-Site	
APEC 1 Former Saw mill	LEPH, HEPH, VPH, PAHs, VOCs, BTEX, chlorinated and non-chlorinated phenols, and metals. In addition, w ater-soluble tannins, fatty acids, w ood resin acids (terpenes) in groundw ater.
APEC 2 Foam Generator Tank	PFOS and PFOA
APEC 3 Diesel AST	LEPH, HEPH, VPH, PAHs
APEC 4 Rust Staining	metals
APEC 5 **On-site Sumps**	LEPH, HEPH, PAHs, metals, PCBs
APEC 6 **Former PCB Containing Equipment**	LEPH, HEPH, PAHs, metals, PCBs
APEC 7 **Unknown Quality Fill**	LEPH, HEPH, PAHs, and metals
Off-Site	
APEC 8 **Pile of Used Rail Lines And Ties**	LEPH, HEPH, PAHs, metals and PCP



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June 2020

FIGURE 4-2

AREAS OF POTENTIAL ENVIRONMENTAL CONCERN

TILBURY EOA
TILBURY EXPANSION CPCN

Project Area

Areas of Potential Environmental Concern

- APEC-1
- APEC-2 Underground Piping
- APEC-2 Ditch
- APEC-2
- APEC-3
- APEC-4
- APEC-5
- APEC-6
- APEC-7
- APEC-8

Base Data

- Road
- Railway
- Property Boundary

Notes:
1. APEC: Area of Potential Environmental Concern
2, Light extractable petroleum hydrocarbons (LEPH), heavy extractable petroleum hydrocarbons (HEPH), volatile petroleum hydrocarbons (VPH), polycyclic aromatic hydrocarbons (PAHs), volatile organic compounds (VOCs), benzene, toluene, ethylbenzene and xylenes (BTEX)
3. pentachlorophenol (PCP)
Perfluorooctane sulfonate (PFOS
Perfluorooctanoic acid (PFOA)
polychlorinated biphenyl (PCB)

SCALE: 1:4,000

0 30 60 90 120 150 m

(All Locations Approximate)

Jacobs

Project Number CE764600

UTM Zone 10 North. NAD 1983.
Transportation: BC FLNRORD 2012; BCGov 2019; Political Boundaries: ESRI 2005, USNIMA 2000; Imagery Service Layer Credits: Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AeroGRID, IGN, and the GIS User Community.

Although there is no reason to believe that there are any errors associated with the data used to generate this product or in the product itself, users of these data are advised that errors in the data may be present.

Mapped By: SL | Checked By: JS

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4.4 Fish and Fish Habitat

4.4.1 Watercourses in the Study Area

No watercourses or natural drainages were identified within the property boundaries during the Tilbury site reconnaissance on October 22, 2019, and none were identified through online database queries (BC CDC 2020b). Watercourses outside of the property boundary but within the Study Area include the Fraser River and Tilbury Slough, a small side channel of the Fraser River. The north property boundary extends to within approximately 15 m of the Fraser River's southeastern shore, but generally aligns with the dike and avoids interacting with riparian vegetation. The non-vegetated dike prevents seepage of stormwater from the site into the Fraser River. The south end of the property is approximately 100 m north of Tilbury Slough. Drainage from the Tilbury site flows south and into Tilbury Slough via a culvert.

No connection of drainage between the Tilbury site and Tilbury Slough was identified as part of a previous environmental review (TERA Environmental Consultants 2013); however, subsequent site developments provide drainage connectivity to the slough and introduce the potential for impacts to fish and fish habitat in downstream environments.

4.4.2 Fish and Fish Habitat Potential on the Tilbury Site

There are a series of drainage ditches located on the property that serve to drain surface water from the Tilbury site. Site drainage enters Tilbury Slough via a culvert located at the southwest end of the property. All on-site ditches are constructed with concrete, coarse materials, and only a section at the corner of Hopcott and Tilbury Roads was observed to have fine substrates and grasses. A ditch in the centre of the property (perpendicular to the north perimeter border) had approximately 250 m of standing water but would likely be dry during summer months. A silt fence and boulder pile to the south of the wetted area is acting as a semi-permeable barrier, preventing fish access from the slough but allowing drainage towards the slough. None of the ditches within the property boundary were determined to have fish habitat potential.

Due to the lack of fish habitat on the Tilbury site, principal areas of focus for fish and fish habitat include potential interactions with fish and fish habitat in Fraser River to the north and Tilbury Slough to the south.

4.4.3 Fish and Fish Habitat in the Study Area

The Fraser River estuary is known to support 78 different species of fish, including seven salmon species, several Provincially Red- and Blue-listed species, and Federal species at risk (such as, White Sturgeon [Lower Fraser River Population] [*Acipenser transmontanus*]). This population of sturgeon was assessed as Threatened by COSEWIC in Canada in 2012 and is Red-listed in BC (BC CDC 2020b). White Sturgeon spawn in the Fraser River; however, their spawning habitats are expected to be located further upstream of the Tilbury site in less depositional environments. However, the shoreline habitats near the Tilbury site, and certain habitats in Tilbury Slough, may provide important rearing habitats for juvenile White Sturgeon.

Important migratory habitats for Eulachon (*Thaleichthys pacificus*) are expected to be present in the Fraser River adjacent to the Tilbury site and inside the Study Area. Eulachon is a small anadromous schooling species of fish that provides a food source for other fishes (for example, White Sturgeon) and marine mammals. Eulachon is Blue-listed (Special Concern) in BC and is considered Endangered by COSEWIC (BC CDC 2020b). Eulachon populations are under consideration for listing on Schedule 1 of the *SARA* (Government of Canada 2020).

Salmonids of conservation concern that occur near the Tilbury site include species of trout and char and all five species of Pacific salmon. Westslope Cutthroat Trout (*Oncorhynchus clarki lewisi*) is designated as Special Concern under the *SARA* and Bull Trout (Salvelinus confluentus) are under consideration for *SARA* listing (DFO

2019a). These species, in addition to Coastal Cutthroat Trout (*Oncorhynchus clarkia clarkia*), are Blue-listed in BC (BC CDC 2020b).

Several populations of Sockeye Salmon (*Oncorhynchus nerka*) are listed by COSEWIC as Endangered, including the Cultus Lake population in 2002/2003 and seven more populations recognized in 2017 (ECCC 2019a). COSEWIC in 2017 also listed two sockeye populations as Threatened and five as Special Concern. These populations of Pacific salmon migrate past the Tilbury site in the Fraser River, including spawning adults and out-migrating smolts. A small proportion of sockeye are "river-type" and may use the Lower Fraser River for rearing, rather than using lakes (Johannes et al. 2011).

The Thompson and Chilcotin River Steelhead (*Oncorhynchus mykiss*) populations in BC were classified in 2018 by COSEWIC as Endangered and recommended for emergency listing under the *SARA* (ECCC 2019a). These populations may migrate past the Tilbury site during adult and juvenile stages.

Vegetated river banks are present along the Fraser River behind the dike, with most of the shoreline being red-coded for high fish habitat productivity by the Fraser River Estuary Management Program (FREMP 2006). Both banks of Tilbury Slough were also red-coded by the Fraser River Estuary Management Program along its entire length. The shoreline habitats adjacent to the Tilbury site (in the Fraser River and Tilbury Slough) are expected to provide important rearing habitats for a number of salmonid species, particularly in areas with tidal marsh vegetation and riparian cover. No fish capture points were found for salmonids in the Tilbury Slough; however, such off-channel habitats are often used by rearing salmonids.

The only documented fish captures in Tilbury Slough were approximately 1.4 km east of the south property perimeter and included Threespine Stickleback (*Gasterosteus aculeatus)* and Brassy Minnow (*Hybognathus hankinsoni*) (BC ENV 2019a). The Brassy Minnow (Pacific Group) is Blue-listed in BC (BC CDC 2019b).

4.5 Vegetation and Wetlands

The Tilbury site is situated in the Coastal Douglas-fir (CDF) biogeoclimatic zone, although it is transitional to the Coastal Western Hemlock zone. The CDF biogeoclimatic zone has warm dry summers and mild wet winters while the Coastal Western Hemlock zone is slightly cooler and wetter (Delong et al. 1991). The Moist Maritime Coastal Douglas-fir subzone (CDFmm) is the only subzone or variant to occur within CDF and is found on southeast Vancouver Island, the Gulf Islands, and the adjacent mainland coast (Green and Klinka 2007).

The Tilbury site is in an industrial area on the banks of the Fraser River. It was previously cleared of natural forest and has been heavily disturbed. The northeast and southeast perimeters are bounded by existing paved roads with little to no vegetation within the Tilbury site. The southwest perimeter abuts against the adjacent property and has a narrow band of primarily non-native vegetation. The northern boundary of the Tilbury site abuts a non-vegetated dike constructed for flood control. A band of riparian vegetation up to approximately 45-m-wide extends from the dike toward the Fraser River. The riparian area has mixed deciduous forest cover dominated by red alder (*Alnus rubra*) and black cottonwood (*Populus trichocarpa*), with a shrub layer consisting mostly of Himalayan blackberry (R*ubus armeniacus*) and red osier dogwood (*Cornus sericea*).

Tilbury Slough is located within the Vegetation Study Area (Table 2-1), to the southeast of the Tilbury site and is dominated by common cattail (*Typha latifolia*), grasses (*Poaceae* spp.), rushes (*Juncus* spp.), and sedges (*Carex* spp.). A mixed coniferous/deciduous forested area is located between Tilbury Road and the slough, with a shrub understory dominated by Himalayan blackberry. The forested area is between 15-m-wide and 60-m-wide, with the remainder consisting of exposed soil, gravel, and shrub cover.

Drainage ditches run along the edges of the Tilbury site. Riparian vegetation associated with the ditch system is a combination of natural and introduced species such as Himalayan blackberry that are common on disturbed and

riparian sites. Where the ditch is not draining, standing water has accumulated and a riparian plant community exists.

Within the City of Delta, 34 ecological communities at risk occur within the CDFmm (BC CDC 2019a). Within the ecosystem types that occur within or adjacent to the Tilbury site, 29 of these ecological communities at risk may occur at the Tilbury site (such as, terrestrial upland, estuary, and wetland ecosystem types) (Appendix C). None of these at risk ecological communities have known occurrences within or adjacent to the Tilbury site (BC CDC 2019a). Their occurrence is considered highly unlikely as the Tilbury site is disturbed and ecological communities at risk require relatively undisturbed conditions for their development.

Nine non-vascular and four vascular plant species at risk have the potential to occur within the Study Area (BC CDC 2019a) (Appendix D). Vancouver Island beggarticks (*Bidens amplissima*) (*SARA* Schedule 1, Special Concern, BC Blue-listed), has a known occurrence adjacent to the Study Area, approximately 250 m southwest of the southwestern boundary of the Tilbury site.

In addition, though not within the Study Area, six Critical Habitat polygons for streambank lupine (*Lupinus rivularis*) (*SARA* Schedule 1, Endangered, BC Red-listed), occur within approximately 11 km. The nearest of these is located about 1.2 km east of the Tilbury site along a tributary to, and partially overlapping, Tilbury Slough (BC CDC 2019a).

Suitable habitat for Vancouver Island beggarticks and streambank lupine may occur within Tilbury Slough or in the riparian area of the Fraser River. Both species are known to occur within the tidal zones of the Fraser River and are commonly found along the shoreline of marshes, wet meadows, bogs, ditches, stream banks, and lake margins at low elevations (SCCP 2020). Expansion construction will be primarily in the upland areas away from the river and is not anticipated to impact riparian vegetation,

No Federally-designated Critical Habitat for plant species occurs within the Study Area. No invasive vegetation was identified in the Study Area during the desktop search (BC CDC 2019a); however Himalayan blackberry is abundant on the south side of Tilbury Road and north of the site along the shore of the Fraser River. This species is not designated as Provincially or Regional Noxious under the BC *Weed Control Act*.

4.6 Wildlife and Wildlife Habitat

Within the Wildlife Study Area, wildlife use is primarily limited to a small band of trees north of the Tilbury site along the Fraser River and south of the Tilbury site in the forested and riparian area on the banks of Tilbury Slough. Several trees along the north of the property have been documented to contain periodic stick nests for breeding birds and Bald eagle (*Haliaeetus leucocephalus*). The drainage ditches that run along the edges of the property sites are not fish-bearing; however, they could provide some moderately suitable amphibian habitat. Wildlife species common to the Delta area (such as, coyote and songbirds) are common in the Study Area; however, the area has limited value for wildlife in its present condition as it is a heavily disturbed industrial site. The Study Area may provide suitable habitat for several reptile species (such as, garter snakes). No stick nests were identified within the Wildlife Study Area during the site reconnaissance.

Tilbury Slough is located directly south of the Tilbury site, within the Study Area. The shoreline along Tilbury Slough is comprised of a mixture of intertidal marsh, riparian shrub, and deciduous forest, which has been altered in some areas by industrial development. The slough is flushed by tidal action, with salt water intrusions; the higher tides inundate the surrounding riparian habitat (Nassichuk et al. 1984). During low tides, upper portions of the slough are completely drained.

There are no OGMAs (legal or non-legal) in the Study Area (BC MFLNRORD 2019a,b). The Study Area does not overlap any Critical Habitat for Federally-listed species at risk, Provincial WHAs (Approved or Proposed),

Provincial WMAs, UWRs, Provincial or Federal parks, ecological reserves, or protected areas (ECCC 2019a; BC MFLNRORD 2019c,d,e,f; BC MFLNRORD 2020; BC ENV 2019e).

The Tilbury site is adjacent to IBA BC 017 that supports at least 50 species of shorebird, as well as a variety of raptors and waterfowl. Patches of forest within the IBA provide important nesting and roosting habitat for Great Blue Herons and raptors, including Bald Eagles, while agricultural fields within the IBA provide foraging habitat for overwintering and migratory birds (IBA Canada 2020).

Within the Study Area, 23 Provincially- or Federally-listed wildlife species have the potential to occur. (Appendix D). This list includes all Provincially- or Federally-listed wildlife species that may occur within the Metro Vancouver Regional District according to the BC CDC (20209a) but excludes those species with no available suitable habitat within the Study Area, as well as all invertebrate species. The resulting list includes 7 mammals, 13 birds, 2 amphibians, and 1 reptile (Appendix D).

Little brown myotis (*Myotis lucifugus*) was emergency listed as Endangered on Schedule 1 of *SARA* in 2014. This species is known to roost in a variety of habitats, including old buildings, large decaying trees, and rock crevices/caves. They prefer older forest stands and tall, large-diameter trees, which are not present in the younger forest stands along the shoreline to the north of the Tilbury site or along Tilbury Slough. There are a few older buildings on-site that could potentially provide roosting habitat for little brown myotis; however, suitability is low due to the disturbed nature of the Tilbury site.

There is a recorded known occurrence of a barn owl nest site within the Tilbury Slough, directly south of the Tilbury site (BC CDC 2020a). Suitable habitat for barn owl nesting (large tree cavities, caves, or underutilized buildings) does not occur on the Tilbury site. Although it is possible that the 13 identified bird species at risk use the site for dispersal, feeding, hunting, cover, and roosting, it is unlikely that they use it for breeding or nesting as the Tilbury site is a heavily disturbed industrial site with low habitat potential.

Seven southern red-backed voles, *occidentalis* subspecies (*Myodes gapperi occidentalis*) (Provincially Red-listed, not Federally-listed) were trapped approximately 2 km from the Tilbury site in 1999 (BC CDC 2014b). The occurrence was located in pine woodland habitat with dense salal (*Gaultheria shallon*) understory but it was noted that mixed deciduous forest with a similar understory would also provide suitable habitat (Fraker et al. 1999).

There is Critical Habitat defined for the Pacific water shrew (*Sorex bendirii*) approximately 1.5 km east of the Tilbury site along Fraser Perimeter Road (BC CDC 2020a). Tilbury Slough provides potentially suitable habitat for the species, but it is anticipated that the tidally-influenced brackish waters of the slough are likely too saline for their occurrence. Available information identifies freshwater habitat and adjacent riparian areas as suitable habitat for the species (Craig et al. 2010; Environment Canada 2014). Information on tolerance to brackish water was not found but one occurrence of a similar species, Vancouver Island water shrew (*Sorex palustrix brooksi*) was recorded in slow-moving brackish water (Craig 2004). The absence of contiguous aquatic or riparian habitat between the Critical Habitat polygon and the slough and relatively poor-quality habitat within and around the brackish slough suggests that occurrence of the species within the Tilbury site is unlikely.

Marine mammals that may be present within the Wildlife Study Area include harbour seals (*Phoca vitulina*) (not *SARA*-listed, BC Yellow-listed), Steller sea lion (*Eumetopias jubatus*) (*SARA* Schedule 1 – Special Concern, BC Blue-listed) and California sea lion (*Zalophus californianus*) (not *SARA*-listed, BC Yellow-listed) (BC CDC 2020b). The harbour seal is widely distributed and may occur within or adjacent to the Tilbury site, while the Stellar sea lion is unlikely to be present. Sea lions congregate in the Fraser estuary during the Eulachon run; rafts of greater than 100 California sea lions have been observed as far as 50 km upstream of the mouth (likely upstream of the Tilbury site) (Bigg 1985).

Construction of the proposed expansion is not expected to substantially change habitat for potential species at risk in the area due to the previously disturbed nature of the Tilbury site. The main habitat value for wildlife occurs in conjunction with the perimeter drainage ditch and the riparian areas along the Fraser River, which are not anticipated to be impacted by the Project.

Construction activity would likely temporarily displace small mammals, marine mammals, and birds from using nearby adjacent areas during the construction phase; however, alternative habitat is available in the surrounding area. The resulting potential effect is considered to be minimal.

Operation of the LNG facility would pose little threat to wildlife populations in the Study Area. Increased traffic along nearby roads and activity in and around the Tilbury site footprint may temporarily discourage use by small mammals and birds during periods of activity. However, these species can habituate to routine human activities and adverse effects on wildlife use of nearby areas are expected to be minimal.

4.7 Land Use

The land use of the Tilbury site includes the property boundary and the area extending 100 m from the property boundary. The Tilbury site is located within the Municipal boundary of Delta within the Tilbury Industrial Park on the southern shoreline of the south arm of the Fraser River (Figure 1-1). The legal description of the Tilbury site is Lot 1 District Lot 135 Group 2 New Westminster District Plan EPP28232 Except Plan EPP 36476. PID: 029-263-301 (Appendix E).

FortisBC currently operates an existing LNG facility, occupying the northern portion of the 7651 Hopcott property (closest to the Fraser River). Coordinates of the approximate centre of the Tilbury site are 49 08’28”N and 123 01’ 57”W and elevation is approximately 1 metre above sea level.

The Tilbury site has been used for natural gas processing and storage for nearly 50 years. The existing FortisBC LNG facility includes the original production and storage facility that has been in operation since 1971 (base plant), a Phase 1A production and storage expansion in operation since 2019 (Phase 1A), and ancillaries including power supply, gas supply, and both natural gas and LNG distribution facilities to serve public utility customers. Parts of the Project are expected to occur within the footprint of the existing 50-year-old liquefaction and storage plant.

As described in the Delta OCP, the proposed expansion occupies an area intended for IL use (Delta 2019). The FortisBC property where the proposed expansion will be located is designated as I7 (Special Industrial) which allows for the manufacturing, processing, finishing, and storage of natural gas. As such, the proposed expansion is consistent with the OCP for the Tilbury site. FortisBC plans to use the temporary construction jetty along the Fraser River adjacent to the property in cooperation with any waterlot leaseholders.

Neighbouring properties are used for industrial purposes with lands zoned for agricultural use and environmentally sensitive areas located immediately south of the industrial area (Delta 2019). The nearest resident is approximately 700 m to the southwest of the Tilbury site with the closest residential neighbourhood located approximately 5 km away in Ladner.

Richmond is the next closest municipality on the north side of the Fraser River. Land use designations in Richmond directly north of the Tilbury site include industrial, agricultural, and mixed employment (Richmond 2019). There is some residential occupancy in the agricultural and mixed employment areas of both Delta and Richmond, with potential for residents in the industrial zones.

Public access to the Tilbury site is limited, although there is public use of the dike to the north of the property along the Fraser River. Parks in the area include the Deas Island Park under Metro Vancouver and Burns Bog Ecological Conservancy Area. The proposed expansion is located on private property owned by FortisBC and there is no land based recreational access to the Tilbury site.

The Fraser River is an important transportation route and is home to numerous industrial facilities and cargo terminals that handle logs, steel, machinery, and general industrial cargo. The Fraser River is also used for commercial and recreational purposes including boating, fishing, tourism, and marine transportation among other activities.

5. Project Alternatives

This EOA provides an assessment of the Project alternatives as described in Table 5-1.

Table 5-1. Description of Project Options

Project Option	Tank Size	Send Out Components	Decommissioning
Alternative 1	New 2 Bcf Tank	Send out components (vaporizers, auxiliaries, piping) to support new tank, metering station	Decommission old tank
Alternative 2	New 3 Bcf Tank	Send out components (vaporizers, auxiliaries, piping) to support new tank, metering station	Decommission old tank
Alternative 3	New 1.5 Bcf Tank	Send out components (vaporizers, auxiliaries, piping) to support new tank, metering station	No decommissioning of old tank

The Project will advance in three general stages: pre-construction, construction, and decommissioning. The general activities associated with these stages are outlined in Table 5-2.

Table 5-2. Project Activities for each Project Alternative

Project Activities	Description
Alternative 1	
Pre-construction	▪ Ground improvement under new tank (stone columns, soil removal, gravel import) ▪ Redirecting on-site drainage
Construction	▪ Civil works for pouring foundations for new tank and piping ▪ Delivery and installation of equipment ▪ Commissioning of piping and vessels
Decommissioning	▪ Decommission existing 0.6 Bcf tank and associated plant ▪ Disposal of hazardous and non-hazardous waste ▪ Reinstating drainage
Alternative 2	
Pre-construction	▪ Ground improvement under new tank (stone columns, soil removal, gravel import) ▪ Redirecting on-site drainage
Construction	▪ Civil works for pouring foundations for new tank and piping ▪ Delivery and installation of equipment ▪ Commissioning of piping and vessels
Decommissioning	▪ Decommission existing 0.6 Bcf tank and associated plant ▪ Disposal of hazardous and non-hazardous waste ▪ Reinstating drainage
Alternative 3	
Pre-construction	▪ Ground improvement under new tank (stone columns, soil removal, gravel import) ▪ Redirecting on-site drainage
Construction	▪ Civil works for pouring foundations for new tank and piping ▪ Delivery and installation of equipment ▪ Commissioning of piping and vessels
Decommissioning	▪ No decommissioning of old facility

6. Potential Effects, Mitigation and Risks

A summary of the potential effects to environmental receptors and associated risk determination is provided in Table 6-1. The mitigation measures and follow-up activities provided are not exhaustive and are limited to those activities and measures anticipated to represent a cost to the Project. Risks to the Project are considered in the form of additional costs, timing constraints or both. Risks to the environment are considered in the form of potential effects to the environmental receptors relative to applicable environmental or regulatory standards and that may require mitigation or follow-up activities. Each risk rating was assigned based on the methodology presented in subsection 2.2.1.

Table 6-1. Potential Effects, Mitigation and Risks of the Project and Project Alternatives

Environmental Receptor	Project Alternative 1				Project Alternative 2				Project Alternative 3			
	Summary of Constraints or Sensitivities	Potential Effects	Risk Rating[a]	Mitigation/Follow-up Activities	Summary of Constraints or Sensitivities	Potential Effects	Project Risk[a]	Mitigation/ Follow-up Activities	Summary of Constraints or Sensitivities	Potential Effects	Project Risk[a]	Mitigation/ Follow-up Activities
Surface Water Quality and Quantity	▪ Two waterbodies border the Project site, including the Fraser River (northern boundary) and the Tilbury Slough (southern boundary) ▪ Site surface drainages with connectivity to Tilbury Slough; no connectivity to the Fraser River except from potential dike runoff	▪ Introduction of deleterious substances into drainage ditches and adjacent and downstream watercourses (such as, sediment, construction debris)	Low • Potential effect likely well within environmental/regulatory standards • Potential effect can be managed using industry standard mitigation • No regulated timing constraints or receptor-specific regulatory approvals requiring cost to the Project are anticipated.	▪ Develop and implement an EMP and conduct environmental monitoring as directed by a QEP ▪ Implement sediment and erosion control measures to prevent sediment from entering drainage ditches and adjacent watercourses ▪ Isolate surface drainage ditches if flowing during construction to manage potential downstream water quality issues ▪ Manage stormwater runoff and grey water produced during construction	▪ Same as Project Alternative 1				▪ Same as Project Alternative 1			
Atmospheric Environment	▪ Emissions during Project operation will require amendment of current Metro Vancouver Air Emissions Permit ▪ Potential risks to atmospheric environment due to operational emissions to and accidents and malfunctions	▪ Project Operations will result in NOx emissions (vaporization process) and fugitive VOC and GHG emissions from tank operation ▪ Increase in dust levels due to soil, gravel, and other material handling ▪ Increase in noise levels due to construction and related activities ▪ Increase in concentrations of gaseous combustion products, from on-site and transport ▪ Potential for elevated hazardous air pollutants due to welding fumes ▪ Facility component leak, failure, or accidental release	Medium - High • Additional assessment recommended to predict emissions and obtain Metro Vancouver Air Permit and determine whether predicted emissions impacts are within applicable Ambient Air Quality Objectives • Additional cost for the implementation of specialized mitigation measures or follow-up work are expected. The regulatory process is well-defined and associated costs are predictable.	▪ Develop and implement and EMP that addresses mitigation of dust levels, mitigation of noise levels, and where possible minimization of combustion products and welding fumes. ▪ Avoid overnight construction and related activities to reduce possible noise impacts. ▪ Develop Accident Response protocols as part of the EMP.	▪ Same as Project Alternative 1				▪ Same as Project Alternative 1 ▪ Alternative 3 would include the continued operation of the existing tank and therefore the existing VOC and GHG emissions will continue. The potential effects, risk rating and mitigation/ follow-up activities remain the same as those described for Alternative 1.			

Table 6-1. Potential Effects, Mitigation and Risks of the Project and Project Alternatives

Environmental Receptor	Project Alternative 1				Project Alternative 2				Project Alternative 3			
	Summary of Constraints or Sensitivities	Potential Effects	Risk Rating[a]	Mitigation/Follow-up Activities	Summary of Constraints or Sensitivities	Potential Effects	Project Risk[a]	Mitigation/ Follow-up Activities	Summary of Constraints or Sensitivities	Potential Effects	Project Risk[a]	Mitigation/ Follow-up Activities
Contaminated Soils and Groundwater	Eight APECs. See Table 4-6. Area of Potential Environmental Concern Summary for details: ▪ APEC 1 Former Sawmill ▪ APEC 2 Foam Generator Tank ▪ APEC 3 Diesel AST ▪ APEC 4 Rust Staining ▪ APEC 5 On-Site Sumps ▪ APEC 6 Former PCB-containing Equipment ▪ APEC 7 Unknown Quality Fill ▪ APEC 8 Pile of Used Rail Lines and Ties	▪ Potential to encounter previously contaminated soils and/or groundwater at identified APECs.	Medium to High • Additional assessment recommended for identified APECs (Stage 1 and Stage 2 PSI) • Pending outcomes of the Stage 1 and Stage 2 PSI, low to considerable additional cost for the implementation of specialized mitigation measures or follow-up work are expected • Regulatory approvals are required to carry out the Project; however, the regulatory process is well-defined and associated costs are predictable.	▪ Finalize Stage 1 PSI ▪ Work with BC ENV to unfreeze any permits that may be caught under the Site Profile-Site Disclosure Statement Process ▪ Complete Stage 2 PSI work on all APECs for soil and groundwater to determine if contamination exists and to provide additional information for quantifying expected volumes of contaminated soils and/or groundwater: ▪ Preparation of a Soil Management Plan so that movement of soils during construction is already mapped out to reduce construction delays ▪ Liaise with BC ENV to discuss potential obligations and timing of remediation requirements.	▪ Same as Project Alternative 1				▪ Same as Project Alternative 1			
Fish and Fish Habitat	▪ No specific fish and fish habitat constraints were identified within the Tilbury site, however sensitivities inside the Study Area include: ▪ Fish habitat and potential for the occurrence of species at risk in adjacent watercourses (Fraser River and Tilbury Slough) ▪ Potential for erosion and sedimentation events and introduction of deleterious substances to downstream fish habitats ▪ Potential for the introduction or spread of invasive aquatic species ▪ Risks to fish and fish habitat values resulting from construction accidents and malfunctions adjacent to the north and south boundaries of the Tilbury site	▪ Introduction of deleterious substances into adjacent or downstream fish habitats (such as, sediment, construction debris) ▪ Introduction or proliferation of invasive aquatic species potentially found within site drainage ditches	Low • Potential effect likely well within environmental/regulatory standards • Potential effect can be managed using industry standard mitigation • No regulated timing constraints or receptor-specific regulatory approvals requiring cost to the Project are anticipated.	▪ Develop and implement an EMP and conduct environmental monitoring as directed by a QEP ▪ Implement sediment and erosion control measures to prevent mobilization of sediment into adjacent or downstream fish habitats ▪ Isolate surface drainage ditches if flowing during construction to manage potential downstream water quality issues ▪ Manage stormwater runoff and grey water produced during construction	▪ See Project Alternative 1				▪ See Project Alternative 1			

Table 6-1. Potential Effects, Mitigation and Risks of the Project and Project Alternatives

Environmental Receptor	Project Alternative 1				Project Alternative 2				Project Alternative 3			
	Summary of Constraints or Sensitivities	Potential Effects	Risk Rating[a]	Mitigation/Follow-up Activities	Summary of Constraints or Sensitivities	Potential Effects	Project Risk[a]	Mitigation/ Follow-up Activities	Summary of Constraints or Sensitivities	Potential Effects	Project Risk[a]	Mitigation/ Follow-up Activities
Vegetation and Wetlands	▪ No specific vegetation constraints were identified within the Tilbury site, but potential sensitivities include: ▪ Potential for occurrence of species at risk within perimeter drainage ditches ▪ Potential for the introduction or facilitated spread of invasive species ▪ Risks to vegetation resulting from accidents and malfunctions	▪ Harm to occurrences of species at risk Introduction or facilitated spread of invasive species ▪ Alteration of Tilbury Slough habitat resulting from upstream erosion or sedimentation entering the perimeter ditch	Low • Potential effect likely well within environmental/regulatory standards • Potential effect can be managed using industry standard mitigation • No regulated timing constraints or receptor-specific regulatory approvals requiring cost to the Project are anticipated.	▪ Develop and implement EMP addressing mitigation measures for clearing, invasive species, pre-construction surveys, contingencies for identification of species at risk, and ESC measures ▪ Complete pre-construction surveys for plant species at risk by a QEP and implement mitigation measures where necessary Implement invasive species mitigation to limit the risk of spread of invasive species to, from and among construction areas ▪ Develop and implement effect ESC mitigation measures	▪ See Project Alternative 1				▪ See Project Alternative 1			
Wildlife and Wildlife Habitat	▪ No specific wildlife or wildlife features were identified within the Tilbury site, but potential sensitivities include: ▪ Potential for occurrence of species at risk within perimeter drainage ditches ▪ Potential for amphibians in perimeter drainage ditches Potential for migratory bird nests in forested areas surrounding the Tilbury site ▪ Potential for disturbance of marine mammals and foraging or roosting birds ▪ Potential for alteration of aquatic habitat as a result of erosion or sedimentation ▪ Risks to wildlife and wildlife habitat resulting from accidents and malfunctions	▪ Direct injury or mortality of amphibians or species at risk resulting from equipment operations Temporary disturbance and displacement of wildlife as a results of construction activities ▪ Alteration of aquatic habitat resulting from erosion or sedimentation	Low • Potential effect likely well within environmental/regulatory standards • Potential effect can be managed using industry standard mitigation • No regulated timing constraints or receptor-specific regulatory approvals requiring cost to the Project are anticipated.	▪ Develop and implement an EMP that includes mitigation measures for pre-construction surveys, contingencies for identification of species at risk, ESC measures and measures to minimize disturbance to wildlife ▪ Conduct environmental monitoring of the implementation of sediment and erosion controls and measures to reduce disturbance to wildlife species, where warranted ▪ Where practical, plan construction activities within the least-risk timing windows for applicable species ▪ Schedule work within the perimeter drainage ditches outside the amphibian sensitive timing windows to the extent practical, which are species-specific, but generally early spring (egg-laying and fall breeding season). If construction works within the ditch cannot avoid sensitive life stages for amphibians, QEP will conduct an amphibian salvage prior to construction.	▪ See Project Alternative 1				▪ See Project Alternative 1			

Table 6-1. Potential Effects, Mitigation and Risks of the Project and Project Alternatives

Environmental Receptor	Project Alternative 1				Project Alternative 2				Project Alternative 3			
	Summary of Constraints or Sensitivities	Potential Effects	Risk Rating[a]	Mitigation/Follow-up Activities	Summary of Constraints or Sensitivities	Potential Effects	Project Risk[a]	Mitigation/ Follow-up Activities	Summary of Constraints or Sensitivities	Potential Effects	Project Risk[a]	Mitigation/ Follow-up Activities
Land Use	▪ Project site is located in Special Industrial zone and adjacent to operating industrial facilities	▪ Potential challenges to construction access and timing related to use of local roads	Low • Potential effect can be managed using industry standard mitigation • Regulatory approvals are required to carry out the Project; however, the regulatory process is well-defined and associated costs are predictable.	▪ Engage with nearby operators to coordinate access	▪ See Project Alternative 1				▪ See Project Alternative 1			

[a] Risk rating were assigned based on methodology presented in subsection 2.2.1.

Notes:

AEC = area(s) of environmental concern
GHG = greenhouse gas

7. Regulatory Approvals and Timelines

Based on the results of the EOA, several environmental permits and approvals are anticipated to be required prior to proceeding with Project construction. A list of permits and approvals that will likely need to be obtained is provided in Table 7-1 along with the estimated timeframe for issuance. Table 7-1 also identifies the permit and approvals applicable to each Project option.

Table 7-1. Potential Environmental Permits and Approvals for Project Options

Issuing Agency	Permit/Approval Name	Review Timeframe	Applicable to Project Alternative 1?	Applicable to Project Alternative 2?	Applicable to Project Alternative 3?
Contaminated Sites Approved Professionals Society	Review of the BC ENV CofC application	2 weeks, (3 months if selected for the random 1:8 selected for an audit)	yes	yes	yes
BC ENV	CofC	6 weeks to 3 months	yes	yes	yes
BC MFLNRORD	*Wildlife Act* General Permit Application	2 to 3 months Required for amphibian salvage. Application preparation is approximately 1 month.	unlikely	unlikely	unlikely
DFO	Assessment to determine requirement of DFO review	1 month	yes	yes	yes
	Request for Review	3 months	unlikely	unlikely	unlikely
BC OGC	Facility Permit or Amendment	7 to 8 months	yes	yes	yes
	Waste Discharge Authorization	8 months	yes	yes	yes
	AIF and AIA (not technically permits)	6 months (requires consultation)	yes	yes	yes
	Heritage Site Alteration Permit (subsection 12.4)	1 to 4 months	unlikely	unlikely	unlikely
Indigenous Groups	Indigenous group permits for archaeological work	1 month	yes	yes	yes
BC MFLNRORD	Heritage Inspection Permit (subsection 12.2)	6 to 8 months	yes	yes	yes
Metro Vancouver	Sanitary Sewer Use Permit	4 months	yes	yes	yes
	Air Emissions Permit	12 to 18 months	yes	yes	yes
Delta	Building Permit	1 to 4 months	yes	yes	yes
	Tree Cutting Permit		unlikely	unlikely	unlikely
	Development Permit		yes	yes	yes
	Demolition Permit		yes	yes	no
	Soil Removal and Deposit Permit	1 month	yes	yes	yes
	Highway Use Permit	1 month	yes	yes	yes

8. Conclusion

8.1 Summary and Overall Risk Rating

Environmental constraints and potential environmental impacts related to the Project will be further assessed and documented during the detailed engineering phase of the Project. The detailed design phase will include assessment of land use, site contamination, vegetation, fish and wildlife and their habitat, and surface/ground water resources.

For the purposes of this report, risks to the Project are considered in the form of additional costs (such as, activities requiring further follow-up work or mitigation), timing constraints (such as, species-specific timing windows) or both (such as, permits or approvals). Risks to the environment are considered in the form of potential effects to the environmental receptors relative to applicable environmental or regulatory standards and that may require mitigation or follow-up activities. Risk categories are described in Section 2.2.1.

This EOA concludes that each of the three Project alternatives, have the same potential effects, mitigation / follow-up actions and overall risk rating for all environmental receptors. The combined risk to the environment and the Project assessed in this EOA vary from low to high depending on environmental receptor.

Five environmental receptors including, surface water quality and quantity, fish and fish habitat, vegetation and wetlands, wildlife and wildlife habitat, and land use were determined to have low risk ratings. A low risk rating was determined because the potential effects are likely within environmental/regulatory standards, can be managed using industry mitigation and require no specific regulatory approvals or the regulatory process and costs for approvals are predictable.

The atmospheric environment receptor was determined to have a medium to high risk rating. A medium to high risk rating was determined because additional assessment is recommended to predict emissions to determine whether emissions are within applicable Ambient Air Quality Objectives and to obtain a Metro Vancouver Air Permit. Pending the outcomes of further emissions modeling, additional cost for the implementation of specialized mitigation measures or follow-up work are expected

The contaminated soils and groundwater environmental receptor were determined to have a medium to high risk rating. A medium to high risk rating was determined because there are eight APECs identified on the Tilbury site and further assessment (i.e., a Stage 1 and Stage 2 PSI) is recommended to characterize and manage the potential adverse effects. Pending outcomes of the Stage 1 and Stage 2 PSI, low to considerable additional cost for the implementation of specialized mitigation measures or follow-up work are expected.

Table 8-1 provides a summary of the constraints or sensitives for each environmental receptor and the associated risk rating.

Table 8-1. Summary of Constraints, Sensitivities and Risk by Environmental Receptor

Environmental Receptor	Summary of Constraints or Sensitivities	Risk Rating
Surface Water Quality and Quantity	▪ Two waterbodies border the Tilbury site, including the Fraser River (northern boundary) and the Tilbury Slough (southern boundary) ▪ Site drainage with connectivity to Tilbury Slough; however, no connectivity to Fraser River except surface runoff from dike	Low

Table 8-1. Summary of Constraints, Sensitivities and Risk by Environmental Receptor

Environmental Receptor	Summary of Constraints or Sensitivities	Risk Rating
Atmospheric Environment	▪ Emissions during Project operation will require amendment of current Metro Vancouver Air Emissions Permit ▪ Potential risks to atmospheric environment due to accidents and malfunctions	Medium to High
Contaminated Soils and Groundwater	▪ Seven APECs identified on-site, and one off-site, potential to encounter previously contaminated soils and/or groundwater at identified AECs. Recommendation to conduct Stage 1 and 2 PSIs.	Medium to High
Fish and Fish Habitat	▪ No specific fish and fish habitat constraints were identified within the Tilbury site; however, sensitivities include fish habitat and potential occurrence of species at risk in adjacent watercourses (Fraser River and Tilbury Slough) ▪ Manage for erosion and mobilization of deleterious substances to downstream habitats, and introduction or spread of invasive species through aquatic pathways	Low
Vegetation and Wetlands	▪ No specific vegetation constraints were identified within the Tilbury site, however potential sensitivities include: occurrence of species at risk near Tilbury site, introduction of invasive species and clearing mature/native vegetation near on-site.	Low
Wildlife and Wildlife Habitat	▪ No specific wildlife or wildlife features were identified within the Tilbury site; however, potential sensitivities include: occurrence of species at risk near Tilbury site, potential for amphibians in drainage ditches on-site, potential for migratory bird nests on-site, potential disturbance of marine mammals and foraging birds. ▪ Risks to wildlife and wildlife habitat resulting from accidents and malfunctions.	Low
Land Use	▪ Project site is located in Special Industrial zone and adjacent to operating industrial facilities	Low

*Refer to Table 6-1 for a detailed list of mitigation measures and Section 2.2.1 for risk rating definitions.

9. References

9.1 Personal Communications

Jacobs wishes to acknowledge those people identified in the Personal Communications for their assistance in supplying information and comments incorporated into this report.

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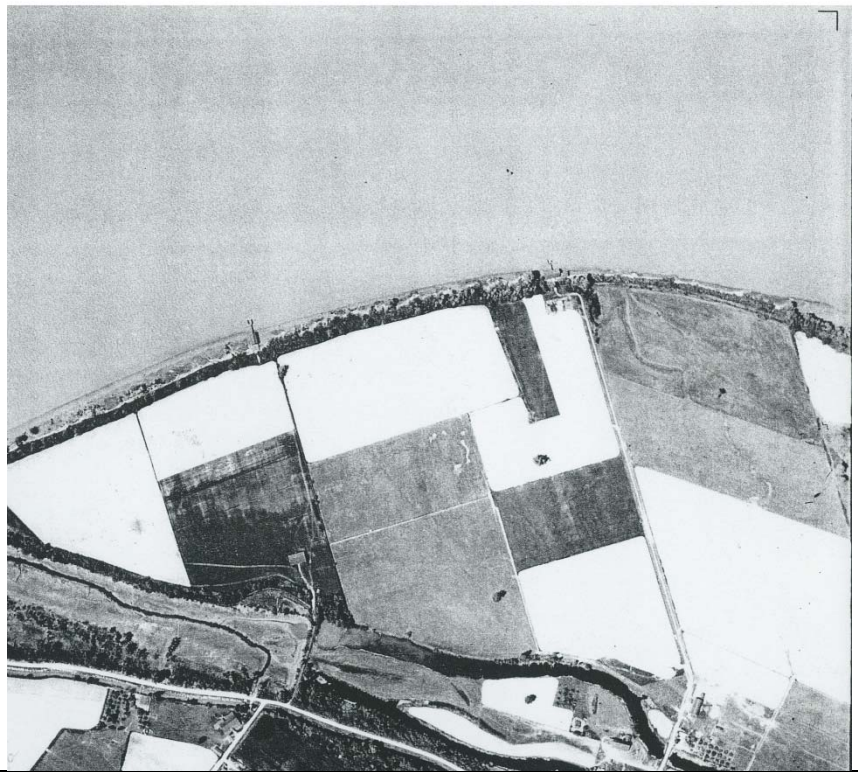
Appendix A
Aerial Photos

Contents



Aerial Photograph A-1. 1938, Desktop Review, Tilbury Site (University of British Columbia [UBC] Geographic Information Centre [GIC] 1938).

Aerial Photograph A-2. 1949, Desktop Review, Tilbury Site (UBC GIC 1949).

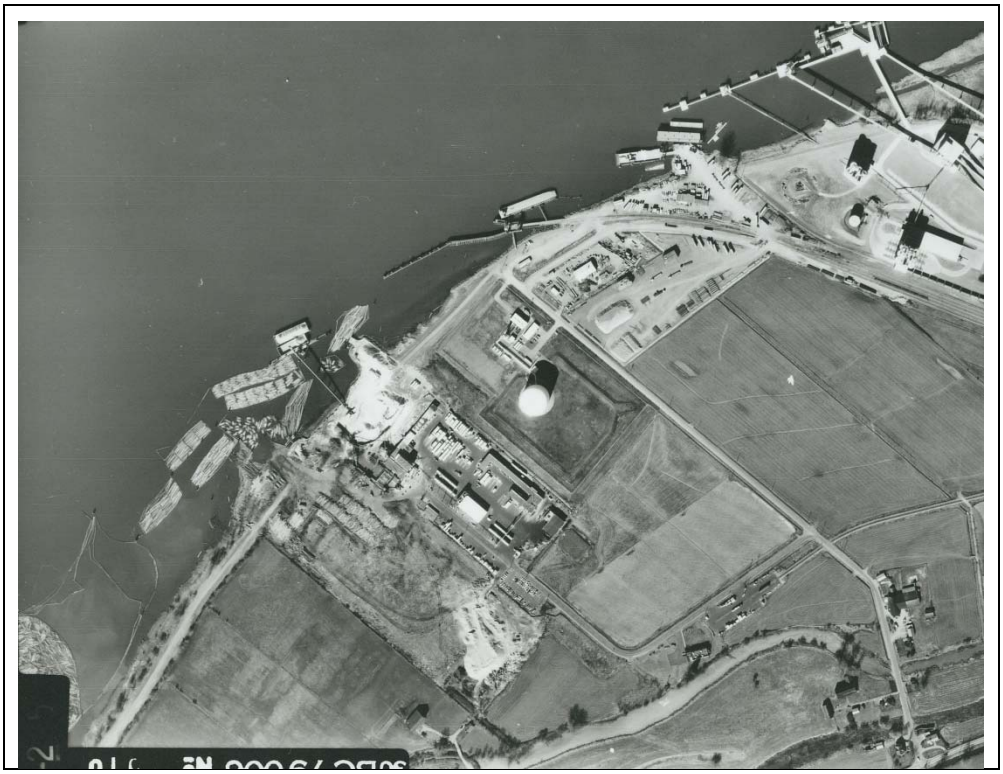
Aerial Photograph A-3. 1951, Desktop Review, Tilbury Site (UBC GIC 1951).

Aerial Photograph A-4. 1954, Desktop Review, Tilbury Site (UBC GIC 1954).

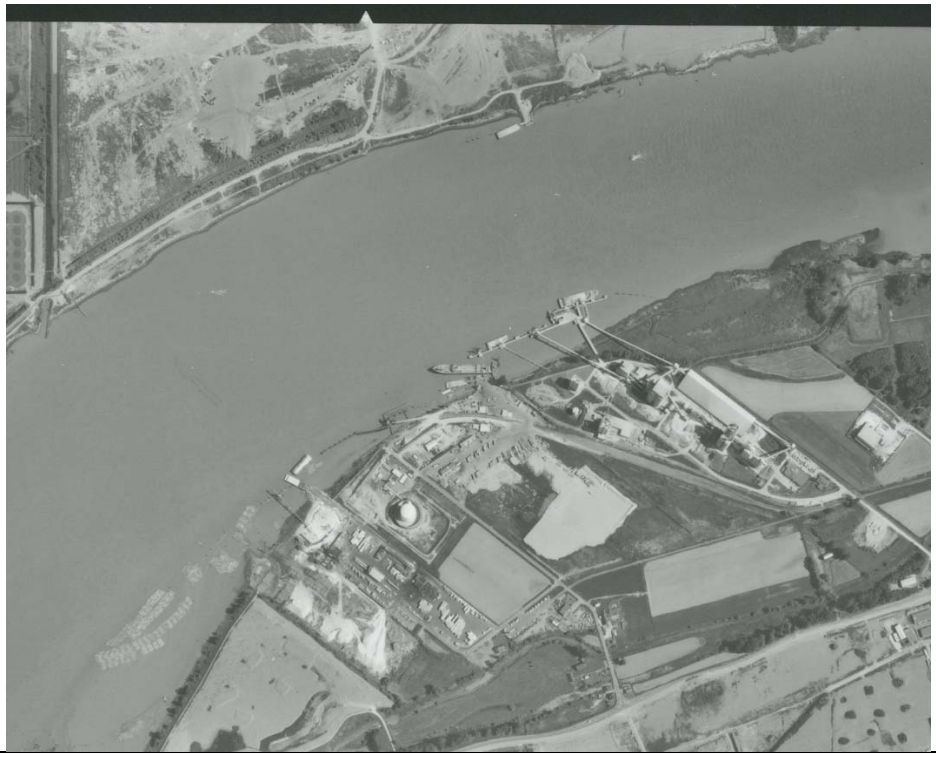
Aerial Photograph A-5. 1963, Desktop Review, Tilbury Site (UBC GIC 1963).

Aerial Photograph A-6. 1969, Desktop Review, Tilbury Site (UBC GIC 1969).

Aerial Photograph A-7.1974, Desktop Review, Tilbury Site (UBC GIC 1974).



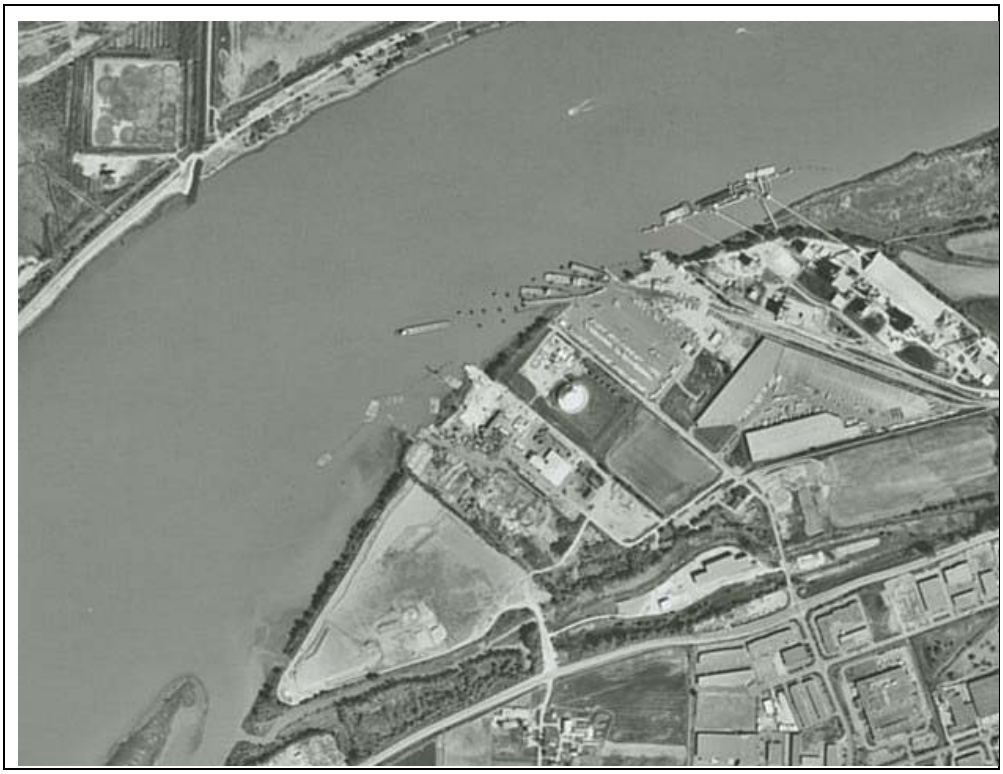
Aerial Photograph A-8. 1979, Desktop Review, Tilbury Site (UBC GIC 1979).



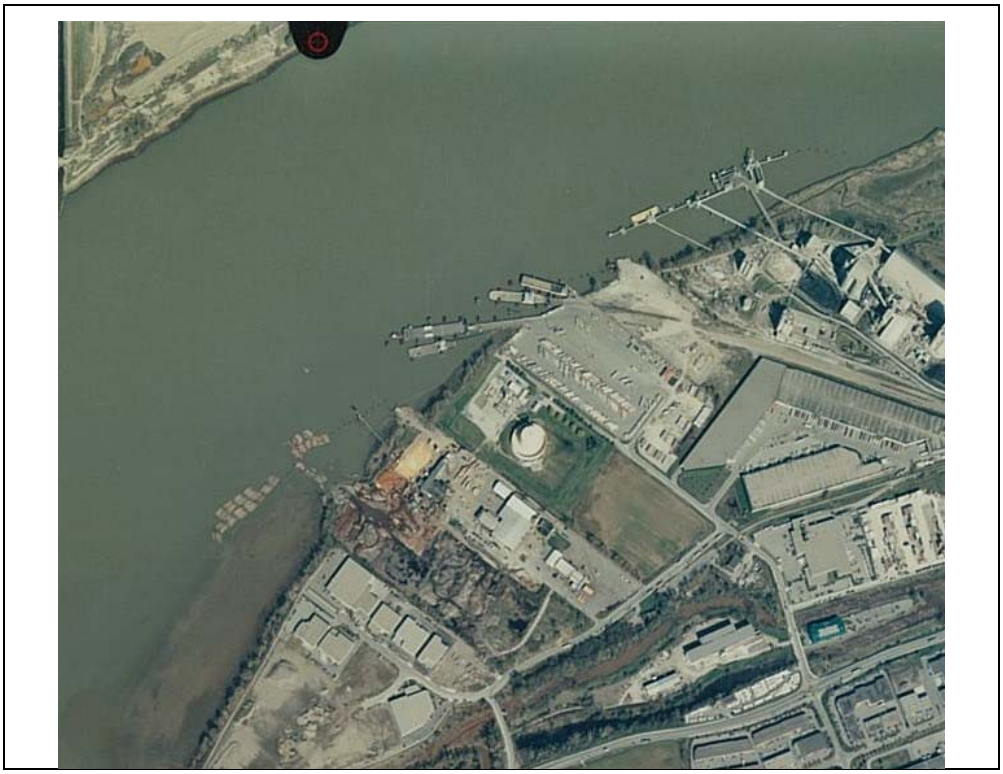
Aerial Photograph A-9. 1984, Desktop Review, Tilbury Site (UBC GIC 1984).

Aerial Photograph A-10. 1989, Desktop Review, Tilbury Site (UBC GIC 1989).

Aerial Photograph A-11. 1994, Desktop Review, Tilbury Site (UBC GIC 1994).



Aerial Photograph A-12. 1999, Desktop Review, Tilbury Site (UBC GIC 1999).

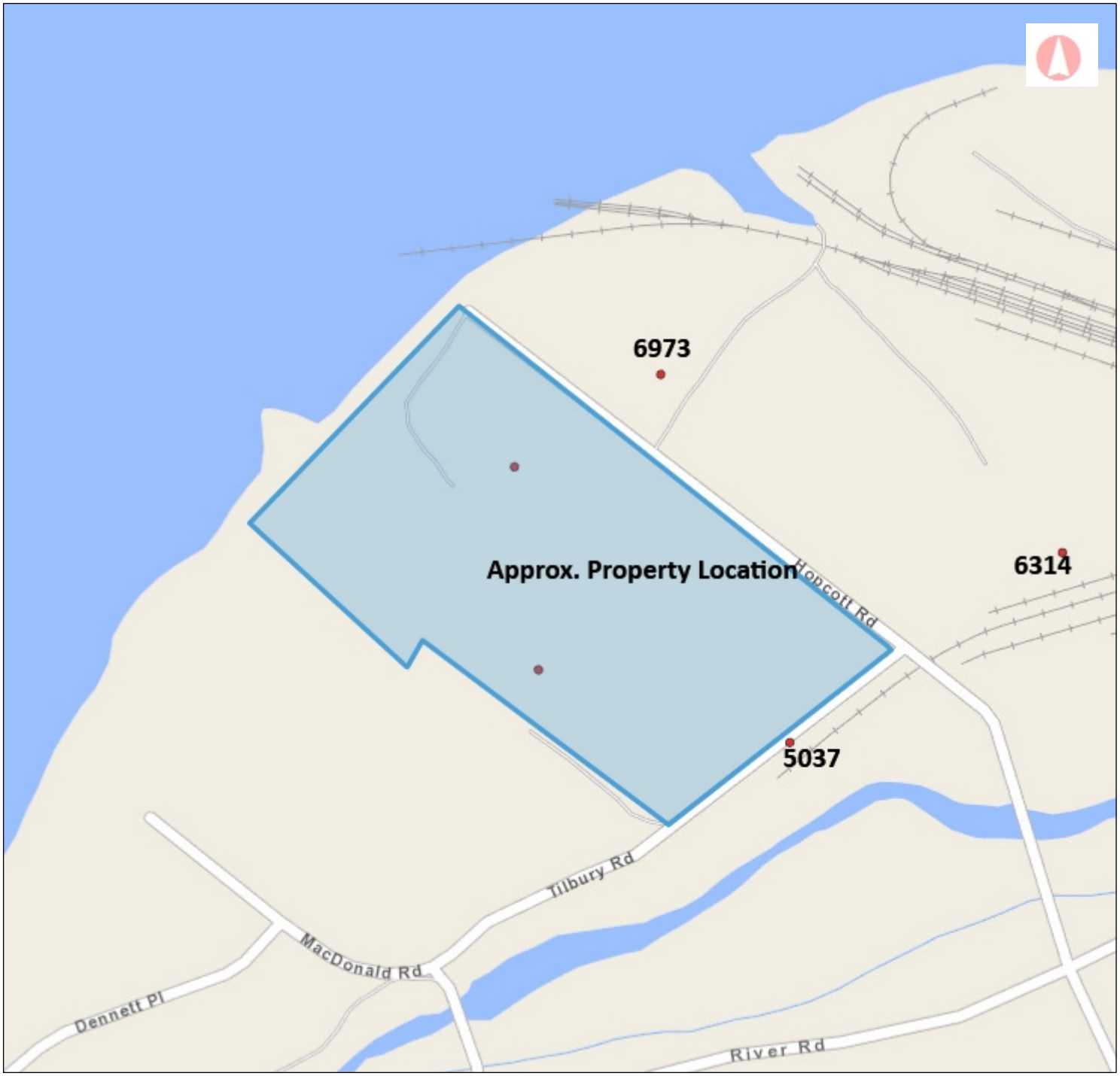


Aerial Photograph A-13. 2004, Desktop Review, Tilbury Site (UBC GIC 2004).

Aerial Photograph A-13. 2009, Desktop Review, Tilbury Site (UBC GIC 2009).

Aerial Photograph A-13. 2016, Desktop Review, Tilbury Site (UBC GIC 2016).

Appendix B
Site Registry Records



BRITISH COLUMBIA

iMapBC - Site Registry

Legend

- Environmental Remediation

0 0.18 0.37 km

1: 9,028

Copyright/Disclaimer

Datum: NAD83
Projection: WGS_1984_Web_Mercator_Auxiliary_Sphere

Key Map of British Columbia

```
As Of: OCT 20, 2019          BC Online: Site Registry                  19/10/22
                     For: PG45409  CH2M HILL CANADA LIMITED            09:26:01
Folio: CE764600.A.CS.E                                                Page    1
   2 records selected for PID 029263301

   Site Id        Lastupd  Address / City
   0005557        12DEC03  6845, 6939, 7150 TILBURY ROAD
                           DELTA
   0016202        14JAN20  7651 HOPCOTT ROAD
                           DELTA
```

```
 As of: OCT 20, 2019       BC Online: Site Registry                    19-10-22
                      For: PG45409  CH2M HILL CANADA LIMITED           09:26:30
 Folio: CE764600.A.CS.E                                                Page   1
                                 Detail Report
SITE LOCATION
       Site ID:       5557                            Latitude:  49d 08m 23.2s
 Victoria File: 26250-20/5557                        Longitude: 123d 01m 59.8s
 Regional File: 26250-20/5557
        Region: SURREY, LOWER MAINLAND

 Site Address: 6845, 6939, 7150 TILBURY ROAD
               FORMERLY 7515 HOPCOTT ROAD
         City: DELTA                           Prov/State: BC
  Postal Code: V4G 1B7

 Registered: DEC 18, 1998  Updated: DEC 03, 2012  Detail Removed: NOV 27, 2012

 Notations:  11   Participants:  22    Associated Sites:   1
 Documents:  13 Susp. Land Use:   3 Parcel Descriptions:   6

Location Description: LOCATION DERIVED REFERENCING RECTIFIED NAD 83
 ORTHOPHOTOGRAPHY.  LAT/LONG VERIFIED USING GOOGLE EARTH ON 2009-04-23.

Record Status: NOT ASSIGNED
 Fee category: UNRANKED

 = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = =
NOTATIONS

  Notation Type: CERTIFICATE OF COMPLIANCE ISSUED USING NUMERICAL STANDARDS
 Notation Class: ENVIRONMENTAL MANAGEMENT ACT: GENERAL
      Initiated: JUN 14, 2010                       Approved: JUN 14, 2010

 Ministry Contact: LOCKHART, DAVE

 Notation Participants                              Notation Roles
 WEYERHAEUSER COMPANY LIMITED                       RECEIVED BY
 WALTON, DOUG G                                     ISSUED BY
 HAMILTON, GARY                                     APPROVED PROFESSIONAL

 Note: THIS CERTIFICATE COVERS A PORTION OF LOT 2, THE PORTION OF LOT 2 BELOW
 TILBURY ROAD HAS NOT BEEN INVESTIGATED.
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
```

Notation Type: CERTIFICATE OF COMPLIANCE REQUESTED
Notation Class: ENVIRONMENTAL MANAGEMENT ACT: GENERAL
Initiated: MAY 28, 2010 Approved: MAY 28, 2010

Ministry Contact: HEWLETT, LUCY

Notation Participants	Notation Roles
WEYERHAEUSER COMPANY LIMITED	REQUESTED BY
GOLDER ASSOCIATES LTD.	APPROVED PROFESSIONAL

- -

Notation Type: NOTICE OF INDEPENDENT REMEDIATION COMPLETION SUBMITTED
Notation Class: ENVIRONMENTAL MANAGEMENT ACT: GENERAL
Initiated: FEB 04, 2010 Approved: FEB 04, 2010

NOTATIONS

Ministry Contact: SAMWAYS, JENNIFER

Notation Participants	Notation Roles
GOLDER ASSOCIATES LTD (BURNABY, 500 - 4260 STILL CREEK DRIVE, BOB DEVLIN)	SUBMITTED BY

Note: COMPLETE: 2010-01-26

- -

Notation Type: NOTICE OF INDEPENDENT REMEDIATION INITIATION SUBMITTED
Notation Class: ENVIRONMENTAL MANAGEMENT ACT: GENERAL
Initiated: FEB 04, 2010 Approved: FEB 04, 2010

Ministry Contact: SAMWAYS, JENNIFER

Notation Participants	Notation Roles
GOLDER ASSOCIATES LTD (BURNABY, 500 - 4260 STILL CREEK DRIVE, BOB DEVLIN)	SUBMITTED BY

Note: START: 2010-01-18

- -
Notation Type: SITE PROFILE REVIEWED - FURTHER INVESTIGATION REQUIRED BY THE MINISTRY
Notation Class: ENVIRONMENTAL MANAGEMENT ACT: GENERAL
Initiated: APR 03, 2009 Approved:

Ministry Contact: HANEMAYER, VINCENT (SURREY) C

Note: RELEASE REQUEST RECEIVED FOR DEMOLITION PERMIT ON 2009-03-30. RELEASE WAS GRANTED FOR PID 016-198-506 BECAUSE IN THE OPINION OF THE DIRECTOR THE SITE DOES NOT POSE A SIGNIFICANT RISK. RELEASE REQUEST RECEIVED FOR SOIL REMOVAL PERMIT ON 2009-04-22. RELEASE WAS GRANTED BECAUSE IN THE OPINION OF THE DIRECTOR THE SITE DOES NOT POSE A SIGNIFICANT RISK. INVESTIGATION REQUIRED PRIOR TO ANY FUTURE PERMITS ON SITE.

Required Actions: DETAILED SITE INVESTIGATION REQUIRED.
- -
Notation Type: NOTICE OF INDEPENDENT REMEDIATION COMPLETION SUBMITTED
Notation Class: ENVIRONMENTAL MANAGEMENT ACT: GENERAL
Initiated: APR 02, 2009 Approved: APR 02, 2009

Ministry Contact: ROSSER, CRAIG L

Notation Participants	Notation Roles
GOLDER ASSOCIATES LTD (BURNABY, 500 - 4260 STILL CREEK DRIVE, BOB DEVLIN)	SUBMITTED BY

Note: COMPLETE: 2009-06-30
- -
Notation Type: NOTICE OF INDEPENDENT REMEDIATION INITIATION SUBMITTED
Notation Class: ENVIRONMENTAL MANAGEMENT ACT: GENERAL

NOTATIONS

Initiated: APR 02, 2009 Approved: APR 02, 2009

Ministry Contact: ROSSER, CRAIG L

Notation Participants	Notation Roles
GOLDER ASSOCIATES LTD (BURNABY, 500 - 4260 STILL CREEK DRIVE, BOB DEVLIN)	SUBMITTED BY

Note: START: 2009-04-27

- -

Notation Type: SITE PROFILE RECEIVED
Notation Class: ENVIRONMENTAL MANAGEMENT ACT: GENERAL
Initiated: APR 02, 2009 Approved:

Ministry Contact: HANEMAYER, VINCENT (SURREY) C

Notation Participants	Notation Roles
WEYERHAEUSER COMPANY LIMITED	SITE PROFILE SUBMITTED BY

Note: MORE INFORMATION REQUIRED PRIOR TO ISSUANCE OF RELEASE REQUEST DECISION. PROPERLY COMPLETED SITE PROFILE SUBMITTED FOR PID 016-198-506 ONLY (7150 TILBURY ROAD) ON 2009-04-02.

- -

Notation Type: FINAL DETERMINATION OF CONTAMINATED SITE ISSUED - SITE NOT CONTAMINATED
Notation Class: ENVIRONMENTAL MANAGEMENT ACT: GENERAL
Initiated: JAN 09, 2008 Approved: JAN 09, 2008

Ministry Contact: LOCKHART, DAVE

Notation Participants	Notation Roles
DOUBLE DOT INVESTMENT GROUP LTD.	RECEIVED BY
WALTON, DOUG G	ISSUED BY
ZAPF-GILJE, REIDAR	APPROVED PROFESSIONAL

Note: ISSUED ON THE RECOMMENDATION OF AN APPROVED PROFESSIONAL (REIDAR ZAPF-GILJE) UNDER PROTOCOL 6 OF THE CONTAMINATED SITES REGULATION THIS NOTICE WAS GIVEN FOR PID: 016-198-492

- -

Notation Type: PRELIMINARY DETERMINATION OF CONTAMINATED SITE ISSUED - SITE NOT CONTAMINATED
Notation Class: ENVIRONMENTAL MANAGEMENT ACT: GENERAL
Initiated: NOV 29, 2007 Approved: NOV 29, 2007

Ministry Contact: WALTON, DOUG G

Notation Participants	Notation Roles
DOUBLE DOT INVESTMENT GROUP LTD.	RECEIVED BY
WALTON, DOUG G	ISSUED BY

```
 ZAPF-GILJE, REIDAR                                   APPROVED PROFESSIONAL











 As of: OCT 20, 2019       BC Online: Site Registry                 19-10-22
                      For: PG45409  CH2M HILL CANADA LIMITED         09:26:30
 Folio: CE764600.A.CS.E                                             Page   4
NOTATIONS


 Note: ISSUED ON THE RECOMMENDATION OF AN APPROVED PROFESSIONAL (REIDAR
 ZAPF-GILJE) UNDER PROTOCOL 6 OF THE CONTAMINATED SITES REGULATION THIS NOTICE
 WAS GIVEN FOR PID: 016-198-492 ONLY AND DOES NOT COVER THE OTHER PARCELS
 LISTED
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Notation Type: NOTICE OF INDEPENDENT REMEDIATION INITIATION SUBMITTED (WMA
                 28(2))
 Notation Class: WASTE MANAGEMENT ACT: CONTAMINATED SITES NOTATIONS
      Initiated: JUN 29, 1998                         Approved: JUL 23, 1998

 Ministry Contact: MCCAMMON, ALAN (SURREY) W

 Notation Participants                                Notation Roles
 NEXT ENVIRONMENTAL INC (BURNABY)                     SUBMITTED BY
 COAST MOUNTAIN HARDWOOD INC. (DELTA)                 REQUESTED BY
 MCCAMMON, ALAN (SURREY) W                            RECEIVED BY

 Note: INDEPENDENT REMEDIATION PURSUANT TO SECTION 57 OF THE CONTAMINATED
 SITES REGULATION.  DECOMMISSIONED 4 TANKS.
 = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = =
SITE PARTICIPANTS

   Participant: COAST MOUNTAIN HARDWOOD INC. (DELTA)
       Role(s): PROPERTY OWNER
    Start Date: JUN 29, 1998                            End Date:
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
   Participant: DOUBLE DOT INVESTMENT GROUP LTD.
       Role(s): PROPERTY OWNER
    Start Date: NOV 29, 2007                            End Date:
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
   Participant: GOLDER ASSOCIATES LTD ( BURNABY, 500 - 4260 STILL CREEK
```

DRIVE, BOB DEVLIN)
Role(s): ENVIRONMENTAL CONSULTANT/CONTRACTOR
Start Date: APR 02, 2009 End Date:
- -
Participant: GOLDER ASSOCIATES LTD (BURNABY)
Role(s): ENVIRONMENTAL CONSULTANT/CONTRACTOR
Start Date: FEB 01, 2010 End Date:
- -
Participant: GOLDER ASSOCIATES LTD.
Role(s): ENVIRONMENTAL CONSULTANT/CONTRACTOR
Start Date: APR 23, 2010 End Date:
- -
Participant: HAMILTON, GARY
Role(s): ENVIRONMENTAL CONSULTANT/CONTRACTOR
Start Date: JUN 11, 2010 End Date:
- -
Participant: HANEMAYER, VINCENT (SURREY) C
Role(s): MAIN MINISTRY CONTACT
Start Date: APR 02, 2009 End Date:

SITE PARTICIPANTS

- -
Participant: HEWLETT, LUCY
Role(s): ALTERNATE MINISTRY CONTACT
Start Date: MAY 28, 2010 End Date:
- -
Participant: LEVELTON CONSULTANTS LTD.
Role(s): ENVIRONMENTAL CONSULTANT/CONTRACTOR
Start Date: AUG 14, 2006 End Date:
- -
Participant: LOCKHART, DAVE
Role(s): ALTERNATE MINISTRY CONTACT
Start Date: JAN 08, 2008 End Date:
- -
Participant: MCCAMMON, ALAN (SURREY) W

```
      Role(s): MAIN MINISTRY CONTACT
   Start Date: JUN 29, 1998                          End Date: MAR 01, 2009
- - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Participant: NEXT ENVIRONMENTAL INC (BURNABY)
      Role(s): ENVIRONMENTAL CONSULTANT/CONTRACTOR
   Start Date: JUN 29, 1998                          End Date:
- - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Participant: NEXT ENVIRONMENTAL INC.
      Role(s): ENVIRONMENTAL CONSULTANT/CONTRACTOR
   Start Date: NOV 19, 1998                          End Date:
- - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Participant: ROSSER, CRAIG L
      Role(s): ALTERNATE MINISTRY CONTACT
   Start Date: APR 02, 2009                          End Date:
- - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Participant: SAMWAYS, JENNIFER
      Role(s): ALTERNATE MINISTRY CONTACT
   Start Date: FEB 04, 2010                          End Date:
- - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Participant: SRK-ROBINSON INC (NORTH VANCOUVER)
      Role(s): ENVIRONMENTAL CONSULTANT/CONTRACTOR
   Start Date: NOV 01, 1991                          End Date:
- - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Participant: WALTON, DOUG G
      Role(s): ALTERNATE MINISTRY CONTACT
   Start Date: NOV 29, 2007                          End Date:
- - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Participant: WEYERHAEUSER COMPANY LIMITED
      Role(s): PROPERTY OWNER
   Start Date: MAY 28, 2010                          End Date:
- - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Participant: WEYERHAEUSER COMPANY LIMITED
      Role(s): SITE PROFILE CONTACT
   Start Date: APR 02, 2009                          End Date:
- - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Participant: WEYERHAEUSER COMPANY LIMITED
      Role(s): PROPERTY OWNER
```

SITE PARTICIPANTS

SITE PROFILE COMPLETOR
SITE PROFILE CONTACT
Start Date: APR 02, 2009 End Date:
- -
Participant: WEYERHAEUSER COMPANY LIMITED
Role(s): PROPERTY OWNER
Start Date: APR 02, 2009 End Date:
- -
Participant: ZAPF-GILJE, REIDAR
Role(s): ENVIRONMENTAL CONSULTANT/CONTRACTOR
Start Date: NOV 18, 2007 End Date:
= =

DOCUMENTS

Title: ADDENDUM TO SUBMISSION FOR A CERTIFICATE OF COMPLIANCE, 7150 TILBURY ROAD, DELTA, BC - MOE SITE ID 5557
Authored: MAY 13, 2010 Submitted: MAY 28, 2010
Participants Role
GOLDER ASSOCIATES LTD. AUTHOR
- -
Title: SUMMARY OF SITE CONDITION
Authored: APR 23, 2010 Submitted: MAY 28, 2010
Participants Role
GOLDER ASSOCIATES LTD. AUTHOR
- -
Title: SUPPLEMENTAL INVESTIGATION AND CONFIRMATION OF REMEDIATION WEYERHAEUSER DELTA HARDWOODS SITE, 7150 TILBURY ROAD, DELTA, BC
Authored: FEB 03, 2010 Submitted: MAY 28, 2010
Participants Role
GOLDER ASSOCIATES LTD (BURNABY) AUTHOR
- -
Title: DETAILED SITE INVESTIGATION AND CONFIRMATION OF REMEDIATION WEYERHAEUSER DELTA HARDWOODS SITE, 7150 TILBURY ROAD, DELTA, BC
Authored: FEB 03, 2010 Submitted: MAY 28, 2010
Participants Role
GOLDER ASSOCIATES LTD (BURNABY) AUTHOR
- -
Title: STAGE 1 AND 2 PRELIMINARY SITE INVESTIGATION WEYERHAEUSER DELTA HARDWOODS SITE, 7150 TILBURY ROAD, DELTA, BC
Authored: FEB 01, 2010 Submitted: MAY 28, 2010
Participants Role
GOLDER ASSOCIATES LTD (BURNABY) AUTHOR
- -
Title: recommendation provided under Section 15 (5) of the Contaminated

Sites Regulation
Authored: NOV 18, 2007 Submitted: NOV 18, 2007
Participants Role
ZAPF-GILJE, REIDAR AUTHOR
- -
Title: Roster Review - 6845 Tilbury Road, Delta, BC
Authored: NOV 07, 2007 Submitted: NOV 07, 2007

DOCUMENTS

Participants Role
LEVELTON CONSULTANTS LTD. AUTHOR
- -
Title: Roster Review - 6845 Tilbury Road, Delta, BC
Authored: OCT 11, 2007 Submitted: OCT 11, 2007
Participants Role
LEVELTON CONSULTANTS LTD. AUTHOR
- -
Title: STAGE 2 PRELIMINARY SITE INVESTIGATION - 6845 TILBURY ROAD, DELTA, BC
Authored: OCT 05, 2007 Submitted: OCT 05, 2007
Participants Role
LEVELTON CONSULTANTS LTD. AUTHOR
- -
Title: Roster Review - 6845 Tilbury Road, Delta, BC
Authored: SEP 14, 2007 Submitted: SEP 14, 2007
Participants Role
LEVELTON CONSULTANTS LTD. AUTHOR
- -
Title: STAGE 1 PRELIMINARY SITE INVESTIGATION - 6845 TILBURY ROAD, DELTA, BC
Authored: AUG 14, 2006 Submitted: AUG 14, 2006
Participants Role
LEVELTON CONSULTANTS LTD. AUTHOR
- -
Title: SOIL AND GROUNDWATER REMEDIATION OF THE UNDERGROUND STORAGE TANK AREA, 7515 HOPCOTT ROAD, DELTA, BC
Authored: NOV 19, 1998 Submitted: MAY 28, 2010

Participants Role
NEXT ENVIRONMENTAL INC. AUTHOR
- -
Title: PHASE 1 ENVIRONMENTAL PROPERTY ASSESSMENT TILBURY ISLAND, DELTA, BC
Authored: NOV 01, 1991 Submitted: MAY 28, 2010
Participants Role
SRK-ROBINSON INC (NORTH VANCOUVER) AUTHOR
= =
ASSOCIATED SITES

Site id: 5037 Date: NOV 30, 1998
Notes: THE SOUTHEAST ROADWAY (SITE 5037) IS BEING SUBDIVIDED TO ALLOW FOR A ROADWAY DEDICATION. A SITE PROFILE WAS RECEIVED FROM THE CORP. OF DELTA FOR THIS SITE. THE REST OF THE PROPERTY (SITE 5557) IS THE MILL SITE. A NOTICE OF IR WAS RECEIVED 06/29/98.
= =
SUSPECTED LAND USE

Description: APPLIANCE/EQUIP OR ENGINE REPAIR/RECONDITION/CLEANING/SALVAG
Notes: INSERTED FOR SITE PROFILE DATED 2009-03-10(described on Site Profile dated 09-03-10)
- -
Description: BULK COMMODITY STORAGE OR SHIPPING (EG. COAL)
Notes: INSERTED FOR SITE PROFILE DATED 2009-03-10(described on Site Profile dated 09-03-10)

SUSPECTED LAND USE

- -
Description: SAWMILLS
Notes: INSERTED FOR SITE PROFILE DATED 2009-03-10(described on Site Profile dated 09-03-10)
= =
PARCEL DESCRIPTIONS

Date Added: JAN 02, 2008 Crown Land PIN#:

LTO PID#: 016198492 Crown Land File#:
Land Desc: LOT 1 DISTRICT LOT 135 GROUP 2 NEW WESTMINSTER DISTRICT PLAN 85922EXCEPT PLANS LMP40044 AND EPP9594

- -

Date Added: DEC 04, 1998 Crown Land PIN#:
LTO PID#: 016198506 Crown Land File#:
Land Desc: LOT 2 EXCEPT; PART DEDICATED ROAD ON PLAN LMP42736DISTRICT LOT 135 GROUP 2 NEW WESTMINSTER DISTRICT PLAN 85922

- -

Date Added: JAN 26, 2012 Crown Land PIN#:
LTO PID#: 028749910 Crown Land File#:
Land Desc: ALL THAT PORTION OF LOT 1 DISTRICT LOT 135 GROUP 2 NEW WESTMINSTER DISTRICT PLAN 85922 EXCEPT PLAN LMP40044 INCLUDED WITHIN LOT A PLAN EPP9594

- -

Date Added: JAN 26, 2012 Crown Land PIN#:
LTO PID#: 028750055 Crown Land File#:
Land Desc: LOT A DISTRICT LOT 135 GROUP 2 NEW WESTMINSTER DISTRICT PLAN EPP9594

- -

Date Added: JAN 26, 2012 Crown Land PIN#:
LTO PID#: 028750063 Crown Land File#:
Land Desc: LOT B DISTRICT LOT 135 GROUP 2 NEW WESTMINSTER DISTRICT PLAN EPP9594

- -

Date Added: JUN 11, 2014 Crown Land PIN#:
LTO PID#: 029263301 Crown Land File#:
Land Desc: LOT 1 DISTRICT LOT 135 GROUP 2 NEW WESTMINSTER DISTRICT PLAN EPP28232 EXCEPT PLAN EPP36476

= =

CURRENT SITE PROFILE INFORMATION (Sec. III to X)
Site Profile Completion Date: MAR 10, 2009

Local Authority Received: MAR 17, 2009

Ministry Regional Manager Received: APR 02, 2009 Decision: APR 03, 2009
Decision: INVESTIGATION REQUIRED

Site Registrar Received: Entry Date:

III COMMERCIAL AND INDUSTRIAL PURPOSES OR ACTIVITIES ON SITE
Schedule 2
Reference Description

```
 As of: OCT 20, 2019       BC Online: Site Registry                    19-10-22
                      For: PG45409  CH2M HILL CANADA LIMITED           09:26:30
 Folio: CE764600.A.CS.E                                                Page   9
         E1        APPLIANCE/EQUIP OR ENGINE REPAIR/RECONDITION/CLEANING/SALVAG
         G3        BULK COMMODITY STORAGE OR SHIPPING (EG. COAL)
         I9        SAWMILLS

AREAS OF POTENTIAL CONCERN
 Petroleum, solvent or other polluting substance spills to the environment
    greater than 100 litres?.................................................NO
 Residue left after removal of piled materials such as chemicals, coal,
    ore, smelter slag, air quality control system baghouse dust?............NO
 Discarded barrels, drums or tanks?.......................................NO
 Contamination resulting from migration of substances from other
    properties?..............................................................NO

FILL MATERIALS
 Fill dirt, soil, gravel, sand or like materials from a contaminated site
    or from a source used for any of the activiities listed under Schedule
    2?.......................................................................NO
 Discarded or waste granular materials such as sand blasting grit, asphalt
    paving or roofing material, spent foundry casting sands, mine ore,
    waste rock or float?.....................................................NO
 Dredged sediments, or sediments and debris materials originating from
    locations adjacent to foreshore industrial activities, or municipal
    sanitary or stormwater discharges?.......................................NO

WASTE DISPOSAL
 Materials such as household garbage, mixed municipal refuse, or demolition
    debris?..................................................................NO
 Waste or byproducts such as tank bottoms, residues, sludge, or
    flocculation precipitates from industrial processes or wastewater
    treatment?...............................................................NO
 Waste products from smelting or mining activities, such as smelter slag,
    mine tailings, or cull materials from coal processing?...................NO
 Waste products from natural gas and oil well drilling activities, such as
    drilling fluids and muds?................................................NO
 Waste products from photographic developing or finishing laboratories;
    asphalt tar manufacturing; boilers, incinerators or other thermal
    facilities (eg. ash); appliance, small equipment or engine repair or
    salvage; dry cleaning operations (eg. solvents); or automobile and
    truck parts cleaning or repair?..........................................NO
 Materials such as household garbage, mixed municipal refuse, or demolition
```

debris?.....NO
Waste or byproducts such as tank bottoms, residues, sludge, or flocculation precipitates from industrial processes or wastewater treatment?.....NO
Waste products from smelting or mining activities, such as smelter slag, mine tailings, or cull materials from coal processing?.....NO
Waste products from natural gas and oil well drilling activities, such as drilling fluids and muds?.....NO
Waste products from photographic developing or finishing laboratories; asphalt tar manufacturing; boilers, incinerators or other thermal facilities (eg. ash); appliance, small equipment or engine repair or salvage; dry cleaning operations (eg. solvents); for from the cleaning or repair of parts of boats, ships, barges, automobiles or trucks,

including sandblasting grit or paint scrapings?.....NO

TANKS OR CONTAINERS USED OR STORED
Underground fuel or chemical storage tanks?.....YES
Above ground fuel or chemical storage tanks?.....YES
Underground fuel or chemical storage tanks other than storage tanks for compressed gases?.....NO
Above ground fuel or chemical storage tanks other than storage tanks for compressed gases?.....NO

SPECIAL (HAZARDOUS) WASTES OR SUBSTANCES
PCB-containing electrical transformers or capacitors either at grade, attached above ground to poles, located within buildings, or stored?....YES
Waste asbestos or asbestos containing materials such as pipe wrapping, blown-in insulation or panelling buried?.....NO
Paints, solvents, mineral spirits or waste pest control products or pest control product containers stored in volumes greater than 205 litres?...NO
PCB-containing electrical transformers or capacitors either at grade, attached above ground to poles, located within buildings, or stored?....NO
Waste asbestos or asbestos containing materials such as pipe wrapping, blown-in insulation or panelling buried?.....NO
Paints, solvents, mineral spirits or waste pest control products or pest

control product containers stored in volumes greater than 205 litres?...NO

LEGAL OR REGULATORY ACTIONS OR CONSTRAINTS

Government orders or other notifications pertaining to environmental conditions or quality of soil, water, groundwater or other environmental media?.....NO

Liens to recover costs, restrictive covenants on land use, or other charges or encumbrances, stemming from contaminants or wastes remaining onsite or from other environmental conditions?.....NO

Government notifications relating to past or recurring environmental violations at the site or any facility located on the site?.....NO

X ADDITIONAL COMMENTS AND EXPLANATIONS

End of Detail Report

```
 As of: OCT 20, 2019       BC Online: Site Registry                    19-10-22
                      For: PG45409  CH2M HILL CANADA LIMITED           09:26:30
 Folio: CE764600.A.CS.E                                                Page   1
                                 Detail Report
SITE LOCATION
       Site ID:      16202                              Latitude:  49d 08m 30.0s
 Victoria File: 26250-20/16202                         Longitude: 123d 02m 01.0s
 Regional File:
        Region: SURREY, LOWER MAINLAND

 Site Address: 7651 HOPCOTT ROAD
         City: DELTA                            Prov/State: BC
  Postal Code: V4G 1B7

 Registered: JAN 07, 2014  Updated: JAN 20, 2014  Detail Removed: JAN 14, 2014

 Notations:   2   Participants:   3    Associated Sites:   0
 Documents:   0 Susp. Land Use:   1 Parcel Descriptions:   2

Location Description: LAT/LONG VERIFIED USING GOOGLE EARTH ON JANUARY 2, 2014.

Record Status: NOT ASSIGNED
 Fee category: NOT APPLICABLE

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NOTATIONS

  Notation Type: SITE PROFILE REVIEWED - FURTHER INVESTIGATION REQUIRED BY THE
                 MINISTRY
 Notation Class: ENVIRONMENTAL MANAGEMENT ACT: GENERAL
      Initiated: JAN 02, 2014                        Approved:

 Ministry Contact: LARSEN, KELLI

 Required Actions: PRELIMINARY SITE INVESTIGATION
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Notation Type: SITE PROFILE RECEIVED
 Notation Class: ENVIRONMENTAL MANAGEMENT ACT: GENERAL
      Initiated: DEC 23, 2013                        Approved:

 Ministry Contact: LARSEN, KELLI

 Notation Participants                               Notation Roles
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 FORTIS BC ENERGY INC.                                   SITE PROFILE SUBMITTED
                                                         BY
 = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = =
SITE PARTICIPANTS

   Participant: FORTIS BC ENERGY INC.
       Role(s): PROPERTY OWNER
    Start Date: DEC 23, 2013                           End Date:
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
   Participant: FORTIS BC ENERGY INC.
       Role(s): SITE PROFILE COMPLETOR
                SITE PROFILE CONTACT
    Start Date: DEC 23, 2013                           End Date:









 As of: OCT 20, 2019       BC Online: Site Registry                    19-10-22
                     For: PG45409  CH2M HILL CANADA LIMITED            09:26:30
 Folio: CE764600.A.CS.E                                                Page   2
SITE PARTICIPANTS

 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
   Participant: LARSEN, KELLI
       Role(s): MAIN MINISTRY CONTACT
    Start Date: DEC 23, 2013                           End Date:
 = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = =
SUSPECTED LAND USE

 Description: NATURAL GAS PROCESSING
       Notes: INSERTED FOR SITE PROFILE DATED 2013-01-25(described on Site
              Profile dated 13-01-25)
 = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = =
PARCEL DESCRIPTIONS

  Date Added: JAN 25, 2013                    Crown Land PIN#:
    LTO PID#: 005938856                      Crown Land File#:
   Land Desc: LOT 12 DISTRICT LOT 135 GROUP 2 NEW WESTMINSTER DISTRICT PLAN
              45616
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Date Added: JUN 11, 2014                    Crown Land PIN#:
    LTO PID#: 029263301                      Crown Land File#:
```

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   Land Desc: LOT 1  DISTRICT LOT 135  GROUP 2  NEW WESTMINSTER DISTRICT  PLAN
              EPP28232  EXCEPT PLAN EPP36476
 = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = =
CURRENT SITE PROFILE INFORMATION (Sec. III to X)
                                     Site Profile Completion Date: JAN 25, 2013

Local Authority         Received: DEC 20, 2013

Ministry Regional Manager Received: DEC 23, 2013        Decision: JAN 02, 2014
   Decision: INVESTIGATION REQUIRED

Site Registrar       Received:                         Entry Date:

III  COMMERCIAL AND INDUSTRIAL PURPOSES OR ACTIVITIES ON SITE
       Schedule 2
    Reference            Description
         F3        NATURAL GAS PROCESSING

AREAS OF POTENTIAL CONCERN
 Petroleum, solvent or other polluting substance spills to the environment
    greater than 100 litres?................................................NO
 Residue left after removal of piled materials such as chemicals, coal,
    ore, smelter slag, air quality control system baghouse dust?............NO
 Discarded barrels, drums or tanks?.........................................NO
 Contamination resulting from migration of substances from other
    properties?.............................................................NO

FILL MATERIALS
 Fill dirt, soil, gravel, sand or like materials from a contaminated site
    or from a source used for any of the activiities listed under Schedule
    2?......................................................................NO








 As of: OCT 20, 2019       BC Online: Site Registry                 19-10-22
                      For: PG45409  CH2M HILL CANADA LIMITED         09:26:30
 Folio: CE764600.A.CS.E                                              Page   3
 Discarded or waste granular materials such as sand blasting grit, asphalt
    paving or roofing material, spent foundry casting sands, mine ore,
    waste rock or float?....................................................NO
 Dredged sediments, or sediments and debris materials originating from
```

locations adjacent to foreshore industrial activities, or municipal sanitary or stormwater discharges?.....NO

WASTE DISPOSAL (QUESTIONS AS OF JANUARY 1 2009)
Materials such as household garbage, mixed municipal refuse, or demolition debris?.....NO
Waste or byproducts such as tank bottoms, residues, sludge, or flocculation precipitates from industrial processes or wastewater treatment?.....NO
Waste products from smelting or mining activities, such as smelter slag, mine tailings, or cull materials from coal processing?.....NO
Waste products from natural gas and oil well drilling activities, such as drilling fluids and muds?.....NO
Waste products from photographic developing or finishing laboratories; asphalt tar manufacturing; boilers, incinerators or other thermal facilities (eg. ash); appliance, small equipment or engine repair or salvage; dry cleaning operations (eg. solvents); for from the cleaning or repair of parts of boats, ships, barges, automobiles or trucks, including sandblasting grit or paint scrapings?.....NO

TANKS OR CONTAINERS USED OR STORED, OTHER THAN TANKS USED FOR RESIDENTIAL HEATING FUEL
Underground fuel or chemical storage tanks other than storage tanks for compressed gases?.....NO
Above ground fuel or chemical storage tanks other than storage tanks for compressed gases?.....NO

HAZARDOUS WASTES OR HAZARDOUS SUBSTANCES
PCB-containing electrical transformers or capacitors either at grade, attached above ground to poles, located within buildings, or stored?....YES
Waste asbestos or asbestos containing materials such as pipe wrapping, blown-in insulation or panelling buried?.....NO
Paints, solvents, mineral spirits or waste pest control products or pest control product containers stored in volumes greater than 205 litres?...NO

LEGAL OR REGULATORY ACTIONS OR CONSTRAINTS
Government orders or other notifications pertaining to environmental conditions or quality of soil, water, groundwater or other environmental media?.....NO
Liens to recover costs, restrictive covenants on land use, or other charges or encumbrances, stemming from contaminants or wastes remaining onsite or from other environmental conditions?.....NO
Government notifications relating to past or recurring environmental violations at the site or any facility located on the site?.....NO

X ADDITIONAL COMMENTS AND EXPLANATIONS

End of Detail Report

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As Of: OCT 20, 2019          BC Online: Site Registry                  19/10/22
                     For: PG45409  CH2M HILL CANADA LIMITED            09:36:33
Folio: CE764600.A.CS.E                                                 Page    1
   4 records selected for 0.5 km from latitude 49  deg, 08 min, 26   sec
     and Longitude 123 deg, 02 min, 00   sec
   Site Id        Lastupd  Address / City
   0005037        03JAN27  TILBURY ROAD THROUGH 7515 HOPCOTT ROAD
                           DELTA
   0005557        12DEC03  6845, 6939, 7150 TILBURY ROAD
                           DELTA
   0006973        19JUN07  7700 HOPCOTT ROAD
                           DELTA
   0016202        14JAN20  7651 HOPCOTT ROAD
                           DELTA
```

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 As of: OCT 20, 2019       BC Online: Site Registry                    19-10-22
                      For: PG45409  CH2M HILL CANADA LIMITED           09:38:21
 Folio: CE764600.A.CS.E                                                Page   1
                                Synopsis Report
SITE LOCATION
       Site ID:       5037                            Latitude:  49d 08m 20.8s
 Victoria File:                                      Longitude: 123d 01m 46.9s
 Regional File: 26250-20/5037
        Region: SURREY, LOWER MAINLAND

  Common Name:
 Site Address: TILBURY ROAD THROUGH 7515 HOPCOTT ROAD
         City: DELTA                          Prov/State: BC
  Postal Code: V4G 1B7

 Registered: OCT 02, 1998  Updated: JAN 27, 2003  Detail Removed: JAN 23, 2003

 Notations:   8   Participants:   9    Associated Sites:   1
 Documents:   3 Susp. Land Use:   1 Parcel Descriptions:   1

Location Description: SITE CREATED BY SITE PROFILE, ENTERED 1998-04-28.
 LOCATION DERIVED BY BC ENVIRONMENT REFERENCING RECTIFIED NAD 83
 ORTHOPHOTOGRAPHY.

       Status: NOT ASSIGNED
 Fee category: NOT APPLICABLE

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CURRENT SITE PROFILE INFORMATION (Sec. III to X)
                                     Site Profile Completion Date: APR 02, 1998

Local Authority         Received: APR 14, 1998

Ministry Regional Manager Received: APR 22, 1998         Decision: MAY 28, 1998
   Decision: INVESTIGATION REQUIRED

Site Registrar       Received:                          Entry Date:

III  COMMERCIAL AND INDUSTRIAL PURPOSES OR ACTIVITIES ON SITE
       Schedule 2
       Reference            Description
         I7        WOOD TREATMENT (ANTISAPSTAIN OR PRESERVATION)
```

AREAS OF POTENTIAL CONCERN

Petroleum, solvent or other polluting substance spills to the environment greater than 100 litres?.....NO

Residue left after removal of piled materials such as chemicals, coal, ore, smelter slag, air quality control system baghouse dust?.....NO

Discarded barrels, drums or tanks?.....NO

FILL MATERIALS

Fill dirt, soil, gravel, sand or like materials from a contaminated site or from a source used for any of the activiities listed under Schedule 2?.....NO

Discarded or waste granular materials such as sand blasting grit, asphalt paving or roofing material, spent foundry casting sands, mine ore,

waste rock or float?.....NO

Dredged sediments, or sediments and debris materials originating from locations adjacent to foreshore industrial activities, or municipal sanitary or stormwater discharges?.....YES

WASTE DISPOSAL

Materials such as household garbage, mixed municipal refuse, or demolition debris?.....NO

Waste or byproducts such as tank bottoms, residues, sludge, or flocculation precipitates from industrial processes or wastewater treatment?.....NO

Waste products from smelting or mining activities, such as smelter slag, mine tailings, or cull materials from coal processing?.....NO

Waste products from natural gas and oil well drilling activities, such as drilling fluids and muds?.....NO

Waste products from photographic developing or finishing laboratories; asphalt tar manufacturing; boilers, incinerators or other thermal facilities (eg. ash); appliance, small equipment or engine repair or salvage; dry cleaning operations (eg. solvents); or automobile and truck parts cleaning or repair?.....NO

TANKS OR CONTAINERS USED OR STORED

Underground fuel or chemical storage tanks?.....YES
Above ground fuel or chemical storage tanks?.....YES

SPECIAL (HAZARDOUS) WASTES OR SUBSTANCES

PCB-containing electrical transformers or capacitors either at grade, attached above ground to poles, located within buildings, or stored?....YES
Waste asbestos or asbestos containing materials such as pipe wrapping, blown-in insulation or panelling buried?.....NO
Paints, solvents, mineral spirits or waste pest control products or pest control product containers stored in volumes greater than 205 litres?...NO

LEGAL OR REGULATORY ACTIONS OR CONSTRAINTS

Government orders or other notifications pertaining to environmental conditions or quality of soil, water, groundwater or other environmental media?.....NO
Liens to recover costs, restrictive covenants on land use, or other charges or encumbrances, stemming from contaminants or wastes remaining onsite or from other environmental conditions?.....NO
Government notifications relating to past or recurring environmental violations at the site or any facility located on the site?.....NO

X ADDITIONAL COMMENTS AND EXPLANATIONS

End of Synopsis Report

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 As of: OCT 13, 2013       BC Online: Site Registry                    13-10-16
                      For: PD69911  TERA ENVIRONMENTAL CONSULTANTS     11:46:33
 Folio:                                                                Page   1
                                 Detail Report
SITE LOCATION
       Site ID:       5037                            Latitude:  49d 08m 20.8s
 Victoria File:                                      Longitude: 123d 01m 46.9s
 Regional File: 26250-20/5037
        Region: SURREY, LOWER MAINLAND

 Site Address: TILBURY ROAD THROUGH 7515 HOPCOTT ROAD
         City: DELTA                           Prov/State: BC
  Postal Code: V4G 1B7

 Registered: OCT 02, 1998  Updated: JAN 27, 2003  Detail Removed: JAN 23, 2003

 Notations:  10   Participants:   9    Associated Sites:   1
 Documents:   3 Susp. Land Use:   1 Parcel Descriptions:   1

Location Description: SITE CREATED BY SITE PROFILE, ENTERED 1998-04-28.
 LOCATION DERIVED BY BC ENVIRONMENT REFERENCING RECTIFIED NAD 83
 ORTHOPHOTOGRAPHY.

Record Status: INACTIVE - NO FURTHER ACTION
 Fee category: NOT APPLICABLE

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NOTATIONS

  Notation Type: FINAL DETERMINATION (WMA 26.4(2)(D)OR(3))
 Notation Class: WASTE MANAGEMENT ACT: CONTAMINATED SITES NOTATIONS
      Initiated: NOV 21, 2000                        Approved: NOV 21, 2000

 Ministry Contact: HANEMAYER, VINCENT (SURREY) C

 Notation Participants                               Notation Roles
 WEYERHAEUSER CANADA LTD (VANCOUVER)                 RECEIVED BY
 MCCAMMON, ALAN (SURREY) W                           ISSUED BY

 Note: SITE DETERMINED NOT TO BE CONTAMINATED
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Notation Type: PRELIMINARY DETERMINATION (WMA 26.4(2)(A))
 Notation Class: WASTE MANAGEMENT ACT: CONTAMINATED SITES NOTATIONS
      Initiated: OCT 16, 2000                        Approved: OCT 16, 2000

 Ministry Contact: HANEMAYER, VINCENT (SURREY) C

 Notation Participants                               Notation Roles
 WEYERHAEUSER CANADA LTD (VANCOUVER)                 RECEIVED BY
 MCCAMMON, ALAN (SURREY) W                           ISSUED BY

 Note: SITE DETERMINED NOT TO BE CONTAMINATED

 Required Actions: FINAL DETERMINATION DUE NOVEMBER 15, 2000
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Notation Type: REQUEST FOR DETERMINATION
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NOTATIONS

Notation Class: WASTE MANAGEMENT ACT: CONTAMINATED SITES NOTATIONS
Initiated: SEP 06, 2000 Approved: SEP 06, 2000

Ministry Contact: HANEMAYER, VINCENT (SURREY) C

Notation Participants	Notation Roles
WEYERHAEUSER CANADA LTD (VANCOUVER)	REQUESTED BY
HANEMAYER, VINCENT (SURREY) C	RECEIVED BY

- -

Notation Type: APPROVAL IN PRINCIPLE ISSUED
Notation Class: WASTE MANAGEMENT ACT: CONTAMINATED SITES NOTATIONS
Initiated: DEC 07, 1998 Approved: DEC 07, 1998

Ministry Contact: HANEMAYER, VINCENT (SURREY) C

Notation Participants	Notation Roles
BEEDIE GROUP (BURNABY)	RECEIVED BY
MCCAMMON, ALAN (SURREY) W	ISSUED BY

Note: APPROVAL IN PRINCIPLE ISSUED FOR COMMERCIAL LAND USE.

Required Actions: - RISK ASSESSMENT DOCUMENTATION RESPECTING MANGANESE CONCENTRATIONS IN GROUNDWATER SHALL BE SUBMITTED TO THE MINISTRY WITHIN TWO YEARS OF THE DATE OF ISSUANCE OF THIS APPROVAL OR MANGANESE IN GROUNDWATER MAY BE ADDRESSED BY OTHER MINISTRY APPROVED METHODS.

- -

Notation Type: APPROVAL IN PRINCIPLE REQUESTED
Notation Class: WASTE MANAGEMENT ACT: CONTAMINATED SITES NOTATIONS
Initiated: NOV 12, 1998 Approved: NOV 12, 1998

Ministry Contact: HANEMAYER, VINCENT (SURREY) C

Notation Participants	Notation Roles
NEXT ENVIRONMENTAL INC (BURNABY)	SUBMITTED BY
BEEDIE GROUP (BURNABY)	REQUESTED BY

- -

Notation Type: PRELIMINARY SITE INVESTIGATION REPORT: EXTERNAL REVIEW REQUESTED
Notation Class: WASTE MANAGEMENT ACT: CONTAMINATED SITES NOTATIONS
Initiated: SEP 30, 1998 Approved: SEP 30, 1998

Ministry Contact: HANEMAYER, VINCENT (SURREY) C

Notation Participants	Notation Roles
NEXT ENVIRONMENTAL INC (BURNABY)	SUBMITTED BY
BEEDIE GROUP (BURNABY)	REQUESTED BY

Note: STAGE 1 & STAGE 2 REPORTS SUBMITTED ON BEHALF OF THE BEEDIE GROUP & ADDRESS CONTAMINANT ISSUES ON ROADWAY RIGHT OF WAY THROUGH THE SOUTHERN PORTION OF THE PROPERTY.

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- - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -




As of: OCT 13, 2013       BC Online: Site Registry                   13-10-16
                       For: PD69911  TERA ENVIRONMENTAL CONSULTANTS     11:46:33
 Folio:                                                              Page    3
NOTATIONS

  Notation Type: SITE PROFILE REVIEWED - FURTHER INVESTIGATION REQUIRED BY THE
                 MINISTRY
 Notation Class: ENVIRONMENTAL MANAGEMENT ACT: GENERAL
      Initiated: MAY 28, 1998                        Approved:

 Ministry Contact: POPE, DOUGLAS
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Notation Type: SITE PROFILE - FURTHER INVESTIGATION REQUIRED BY THE MINISTRY
 Notation Class: WASTE MANAGEMENT ACT: CONTAMINATED SITES NOTATIONS
      Initiated: MAY 28, 1998                        Approved:

 Ministry Contact: POPE, DOUGLAS
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Notation Type: SITE PROFILE RECEIVED
 Notation Class: ENVIRONMENTAL MANAGEMENT ACT: GENERAL
      Initiated: APR 22, 1998                        Approved:

 Ministry Contact: POPE, DOUGLAS

 Notation Participants                               Notation Roles
 COAST MOUNTAIN HARDWOOD INC. (DELTA)                SITE PROFILE SUBMITTED
                                                     BY
 COAST MOUNTAIN HARDWOOD INC. (DELTA)                SITE PROFILE SUBMITTED
                                                     BY
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Notation Type: SITE PROFILE RECEIVED
 Notation Class: WASTE MANAGEMENT ACT: CONTAMINATED SITES NOTATIONS
      Initiated: APR 22, 1998                        Approved:

 Ministry Contact: POPE, DOUGLAS

 Notation Participants                               Notation Roles
 COAST MOUNTAIN HARDWOOD INC. (DELTA)                SITE PROFILE SUBMITTED
                                                     BY
 COAST MOUNTAIN HARDWOOD INC. (DELTA)                SITE PROFILE SUBMITTED
                                                     BY
 = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = =
SITE PARTICIPANTS

   Participant: BEEDIE GROUP (BURNABY)
       Role(s): POTENTIALLY AFFECTED PARTY
    Start Date: SEP 28, 1998                           End Date:
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
   Participant: COAST MOUNTAIN HARDWOOD INC. (DELTA)
       Role(s): FORMER PROPERTY OWNER
                SITE PROFILE COMPLETOR
                SITE PROFILE CONTACT
```

```
   Start Date: APR 22, 1998                          End Date:
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Participant: HANEMAYER, VINCENT (SURREY) C
      Role(s): MAIN MINISTRY CONTACT




As of: OCT 13, 2013       BC Online: Site Registry                    13-10-16
                     For: PD69911  TERA ENVIRONMENTAL CONSULTANTS     11:46:33
Folio:                                                                Page   4
SITE PARTICIPANTS

   Start Date: AUG 06, 1998                          End Date:
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Participant: MCCAMMON, ALAN (SURREY) W
      Role(s): ALTERNATE MINISTRY CONTACT
   Start Date: DEC 07, 1998                          End Date:
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Participant: NEXT ENVIRONMENTAL INC (BURNABY)
      Role(s): ENVIRONMENTAL CONSULTANT/CONTRACTOR
   Start Date: JUL 31, 1998                          End Date:
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Participant: POPE, DOUGLAS
      Role(s): MAIN MINISTRY CONTACT
   Start Date: APR 22, 1998                          End Date: AUG 06, 1998
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Participant: SCOTT, CAM C
      Role(s): ALTERNATE MINISTRY CONTACT
   Start Date: JUN 29, 1998                          End Date: AUG 31, 1998
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Participant: SEACOR ENVIRONMENTAL ENGINEERING INC (RICHMOND)
      Role(s): ENVIRONMENTAL CONSULTANT/CONTRACTOR
               EXTERNAL SITE ACTIVITY REVIEWER
   Start Date: JUL 31, 1998                          End Date:
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Participant: WEYERHAEUSER CANADA LTD (VANCOUVER)
      Role(s): FORMER PROPERTY OWNER
   Start Date: SEP 06, 2000                          End Date:
 = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = =
DOCUMENTS

 Title: REMEDIAL PLAN FOR PROPOSED ROAD DEDICATION AT 7515 HOPCOTT ROAD,
        DELTA, BC
             Authored: NOV 09, 1998             Submitted: NOV 10, 1998
 Participants                                     Role
 NEXT ENVIRONMENTAL INC (BURNABY)                 AUTHOR
 BEEDIE GROUP (BURNABY)                           COMMISSIONER
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
 Title: ENVIRONMENTAL STAGE 2 PRELIMINARY SITE INVESTIGATIONOF THE FUTURE
        ROAD AT 7515 HOPCOTT ROAD, DELTA, BC
             Authored: SEP 28, 1998             Submitted: OCT 02, 1998
 Participants                                     Role
 NEXT ENVIRONMENTAL INC (BURNABY)                 AUTHOR
 BEEDIE GROUP (BURNABY)                           COMMISSIONER
 SEACOR ENVIRONMENTAL ENGINEERING INC (RICHMOND)  EXTERNAL REVIEWER
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
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Title: ENVIRONMENTAL STAGE 1 PRELIMINARY SITE INVESTIGATION OF THE FUTURE
       ROAD AT 7515 HOPCOTT ROAD, DELTA, BC
             Authored: JUL 31, 1998                Submitted: AUG 05, 1998
Participants                                        Role
NEXT ENVIRONMENTAL INC (BURNABY)                    AUTHOR
COAST MOUNTAIN HARDWOOD INC. (DELTA)                COMMISSIONER
SEACOR ENVIRONMENTAL ENGINEERING INC (RICHMOND)     EXTERNAL REVIEWER




As of: OCT 13, 2013       BC Online: Site Registry                   13-10-16
                     For: PD69911  TERA ENVIRONMENTAL CONSULTANTS    11:46:33
Folio:                                                               Page    5
= = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = =
ASSOCIATED SITES

     Site id:       5557                              Date: NOV 30, 1998
       Notes: THE SOUTHEAST ROADWAY (SITE 5037) IS BEING SUBDIVIDED TO ALLOW
              FOR A ROADWAY DEDICATION.  A SITE PROFILE WAS RECEIVED FROM THE
              CORP. OF DELTA FOR THIS SITE.  THE REST OF THE PROPERTY (SITE
              5557) IS THE MILL SITE. A NOTICE OF IR WAS RECEIVED 06/29/98.
= = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = =
SUSPECTED LAND USE

 Description: WOOD TREATMENT (ANTISAPSTAIN OR PRESERVATION)
       Notes: INSERTED FOR SITE PROFILE DATED 1998-04-02(described on Site
              Profile dated 98-04-02)
= = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = =
PARCEL DESCRIPTIONS

  Date Added: DEC 02, 1998                Crown Land PIN#:
     LTO PID#:                           Crown Land File#: N/A5037
   Land Desc: ROAD ALLOWANCE THROUGH LOT 2 DISTRICT LOT 135 GROUP 2 NEW
              WESTMINSTER DISTRICT PLAN 85922
= = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = =
CURRENT SITE PROFILE INFORMATION (Sec. III to X)
                              Site Profile Completion Date: APR 02, 1998

Local Authority         Received: APR 14, 1998

Ministry Regional Manager Received: APR 22, 1998        Decision: MAY 28, 1998
   Decision: INVESTIGATION REQUIRED

Site Registrar       Received:                        Entry Date:

III  COMMERCIAL AND INDUSTRIAL PURPOSES OR ACTIVITIES ON SITE
       Schedule 2
    Reference            Description
         I7        WOOD TREATMENT (ANTISAPSTAIN OR PRESERVATION)

AREAS OF POTENTIAL CONCERN
 Petroleum, solvent or other polluting substance spills to the environment
    greater than 100 litres?............................................NO
 Residue left after removal of piled materials such as chemicals, coal,
    ore, smelter slag, air quality control system baghouse dust?...........NO
 Discarded barrels, drums or tanks?........................................NO
```

FILL MATERIALS
Fill dirt, soil, gravel, sand or like materials from a contaminated site or from a source used for any of the activiities listed under Schedule 2?.....NO
Discarded or waste granular materials such as sand blasting grit, asphalt paving or roofing material, spent foundry casting sands, mine ore, waste rock or float?.....NO
Dredged sediments, or sediments and debris materials originating from locations adjacent to foreshore industrial activities, or municipal

sanitary or stormwater discharges?.....YES

WASTE DISPOSAL
Materials such as household garbage, mixed municipal refuse, or demolition debris?.....NO
Waste or byproducts such as tank bottoms, residues, sludge, or flocculation precipitates from industrial processes or wastewater treatment?.....NO
Waste products from smelting or mining activities, such as smelter slag, mine tailings, or cull materials from coal processing?.....NO
Waste products from natural gas and oil well drilling activities, such as drilling fluids and muds?.....NO
Waste products from photographic developing or finishing laboratories; asphalt tar manufacturing; boilers, incinerators or other thermal facilities (eg. ash); appliance, small equipment or engine repair or salvage; dry cleaning operations (eg. solvents); or automobile and truck parts cleaning or repair?.....NO

TANKS OR CONTAINERS USED OR STORED
Underground fuel or chemical storage tanks?.....YES
Above ground fuel or chemical storage tanks?.....YES

SPECIAL (HAZARDOUS) WASTES OR SUBSTANCES
PCB-containing electrical transformers or capacitors either at grade, attached above ground to poles, located within buildings, or stored?....YES
Waste asbestos or asbestos containing materials such as pipe wrapping, blown-in insulation or panelling buried?.....NO
Paints, solvents, mineral spirits or waste pest control products or pest control product containers stored in volumes greater than 205 litres?...NO

LEGAL OR REGULATORY ACTIONS OR CONSTRAINTS
Government orders or other notifications pertaining to environmental conditions or quality of soil, water, groundwater or other environmental media?.....NO
Liens to recover costs, restrictive covenants on land use, or other charges or encumbrances, stemming from contaminants or wastes remaining onsite or from other environmental conditions?.....NO
Government notifications relating to past or recurring environmental violations at the site or any facility located on the site?.....NO

X ADDITIONAL COMMENTS AND EXPLANATIONS

End of Detail Report

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 As of: OCT 20, 2019       BC Online: Site Registry                    19-10-22
                      For: PG45409  CH2M HILL CANADA LIMITED           09:59:28
 Folio: CE764600.A.CS.E                                                Page   1
                                Synopsis Report
SITE LOCATION
       Site ID:       6314                            Latitude:  49d 08m 27.1s
 Victoria File:                                      Longitude: 123d 01m 32.9s
 Regional File: 26250-20/6314
        Region: SURREY, LOWER MAINLAND

  Common Name:
 Site Address: 7510 HOPCOTT ROAD
         City: DELTA                           Prov/State: BC
  Postal Code:

 Registered: NOV 25, 1999  Updated: JUL 04, 2002  Detail Removed: JUN 24, 2002

 Notations:   6   Participants:  10    Associated Sites:   0
 Documents:   2 Susp. Land Use:   0 Parcel Descriptions:   0

Location Description: NE SIDE OF HOPCOTT RD, TILBURY ISLAND.  LAT/LONG
 CONFIRMED USING GOAT BY MINISTRY STAFF.

       Status: NOT ASSIGNED
 Fee category: UNRANKED

No Site Profile has been submitted for this site

                             End of Synopsis Report
```

```
 As of: OCT 13, 2013       BC Online: Site Registry                    13-10-16
                     For: PD69911  TERA ENVIRONMENTAL CONSULTANTS      11:46:33
 Folio:                                                                Page   1
                                Detail Report
SITE LOCATION
       Site ID:       6314                            Latitude:  49d 08m 27.1s
 Victoria File:                                      Longitude: 123d 01m 32.9s
 Regional File: 26250-20/6314
        Region: SURREY, LOWER MAINLAND

 Site Address: 7510 HOPCOTT ROAD
         City: DELTA                           Prov/State: BC
  Postal Code:

 Registered: NOV 25, 1999  Updated: JUL 04, 2002  Detail Removed: JUN 24, 2002

 Notations:   6   Participants:  10    Associated Sites:   0
 Documents:   2 Susp. Land Use:   0 Parcel Descriptions:   0

Location Description: NE SIDE OF HOPCOTT RD, TILBURY ISLAND.  LAT/LONG
 CONFIRMED USING GOAT BY MINISTRY STAFF.

Record Status: INACTIVE - NO FURTHER ACTION
 Fee category: UNRANKED

 = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = = =
NOTATIONS

  Notation Type: NOTICE OF INDEPENDENT REMEDIATION COMPLETION SUBMITTED (WMA
                 28(2))
 Notation Class: WASTE MANAGEMENT ACT: CONTAMINATED SITES NOTATIONS
      Initiated: FEB 11, 2002                        Approved: MAY 21, 2002

 Ministry Contact: SUNDHER, AVTAR

 Notation Participants                               Notation Roles
 MORGUARD INVESTMENTS LTD.                           SUBMITTED BY
 CORPORATION OF DELTA (DELTA, B.C.)                  RECEIVED BY
 HOPCOTT WAREHOUSES LTD. (VANCOUVER)                 RECEIVED BY
 SOUTH FRASER HEALTH REGION                          RECEIVED BY
 GOLDER ASSOCIATES LTD (BURNABY)                     ISSUED BY

 Note: REMEDIATION CONFIRMATION REPORT SUBMITTED.

 Required Actions: 2002-05-21 - LETTER SENT ACKNOWLEDGING COMPLETION OF
 INDEPENDENT REMEDIATION RELATED TO DRINKING WATER CONTAMINATION. MINISTRY HAS
 NO FURTHER QUESTIONS AT THIS TIME.
 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
  Notation Type: NOTICE OF INDEPENDENT REMEDIATION INITIATION SUBMITTED (WMA
                 28(2))
 Notation Class: WASTE MANAGEMENT ACT: CONTAMINATED SITES NOTATIONS
      Initiated: JUL 26, 2001                        Approved: JUL 26, 2001

 Ministry Contact: MCCAMMON, ALAN (SURREY) W

 Notation Participants                               Notation Roles
```

NOTATIONS

GOLDER ASSOCIATES LTD (BURNABY) SUBMITTED BY

- -

Notation Type: SITE INVESTIGATION REPORT SUBMITTED
Notation Class: ADMINISTRATIVE
Initiated: JUN 12, 2000 Approved: JUN 12, 2000

Ministry Contact: SUNDHER, AVTAR

Notation Participants	Notation Roles
MORGUARD INVESTMENTS LTD.	SUBMITTED BY
CORPORATION OF DELTA (DELTA, B.C.)	RECEIVED BY
SOUTH FRASER HEALTH REGION	RECEIVED BY

Note: PRELIMINARY SITE INVESTIGATION REPORT. DRAFT REPORT SUBMITTED MAY 30, 2000.

- -

Notation Type: SITE INVESTIGATION REQUESTED
Notation Class: ADMINISTRATIVE
Initiated: DEC 22, 1999 Approved: DEC 22, 1999

Ministry Contact: SUNDHER, AVTAR

Notation Participants	Notation Roles
CORPORATION OF DELTA (DELTA, B.C.)	RECEIVED BY
HOPCOTT WAREHOUSES LTD. (VANCOUVER)	RECEIVED BY
MORGUARD INVESTMENTS LTD.	RECEIVED BY
SOUTH FRASER HEALTH REGION	RECEIVED BY
COLLIERS MACAULAY NICOLLS INC. (SURREY)	RECEIVED BY

Note: SECOND REQUEST FOR SITE INVESTIGATION. INADEQUATE RESPONSE TO PREVIOUS REQUEST. DRAFT SITE INVESTIGATION ORDER ATTACHED.

Required Actions: 2000-03-06 - LETTER STATING REQUIREMENTS FOR MINISTRY NOT ISSUING DRAFT SITE INVESTIGATION ORDER DATED DEC 22, 1999. PROPERTY OWNER AGREED TO UNDERTAKE REQUESTED INVESTIGATION.

- -

Notation Type: SITE INVESTIGATION REQUESTED
Notation Class: ADMINISTRATIVE
Initiated: DEC 17, 1998 Approved: DEC 17, 1998

Ministry Contact: SUNDHER, AVTAR

Notation Participants	Notation Roles
COLLIERS MACAULAY NICOLLS INC. (SURREY)	RECEIVED BY
SOUTH FRASER HEALTH REGION	RECEIVED BY
CORPORATION OF DELTA (DELTA, B.C.)	RECEIVED BY

Note: REQUEST FOR SITE INVESTIGATION TO DETERMINE SOURCE OF DRINKING WATER CONTAMINATION (TOLUENE, ETHYLBENZENE AND TOLUENE) IN MUNICIPALLY SUPPLIED DRINKING WATER LINE.

- -

NOTATIONS

Notation Type: INSPECTION / VISIT
Notation Class: ADMINISTRATIVE
Initiated: NOV 05, 1998 Approved: NOV 05, 1998

Ministry Contact: SUNDHER, AVTAR

Notation Participants	Notation Roles
SOUTH FRASER HEALTH REGION	REFERRED BY
CORPORATION OF DELTA (DELTA, B.C.)	REFERRED BY

Note: MINISTRY VISIT WITH CORPORATION OF DELTA & SOUTH FRASER HEALTH REGION TO INVESTIGATE COMPLAINT OF ODOUR IN FACILITY TAP WATER.

= =

SITE PARTICIPANTS

Participant: COLLIERS MACAULAY NICOLLS INC. (SURREY)
Role(s): PROPERTY INTEREST HOLDER
Start Date: DEC 17, 1998 End Date:
Notes: PROPERTY MANAGEMENT COMPANY

- -

Participant: CORPORATION OF DELTA (DELTA, B.C.)
Role(s): MUNICIPAL/REGIONAL CONTACT
Start Date: NOV 05, 1998 End Date:

- -

Participant: EVS ENVIRONMENT CONSULTANTS (NORTH VANCOUVER, B.C.)
Role(s): ENVIRONMENTAL CONSULTANT/CONTRACTOR
Start Date: OCT 01, 1998 End Date:

- -

Participant: GOLDER ASSOCIATES LTD (BURNABY)
Role(s): ENVIRONMENTAL CONSULTANT/CONTRACTOR
Start Date: AUG 24, 2000 End Date:

- -

Participant: HILDEBRAND, JANE MARIE
Role(s): ALTERNATE MINISTRY CONTACT
Start Date: DEC 17, 1998 End Date: MAR 31, 2003

- -

Participant: HOPCOTT WAREHOUSES LTD. (VANCOUVER)
Role(s): PROPERTY OWNER
Start Date: DEC 22, 1999 End Date:

- -

Participant: MCCAMMON, ALAN (SURREY) W
Role(s): ALTERNATE MINISTRY CONTACT
Start Date: MAR 06, 2000 End Date:

- -

Participant: MORGUARD INVESTMENTS LTD.
Role(s): PROPERTY INTEREST HOLDER
Start Date: JAN 17, 1999 End Date:

- -

Participant: SOUTH FRASER HEALTH REGION
Role(s): MUNICIPAL/REGIONAL CONTACT
Start Date: SEP 01, 1998 End Date:

SITE PARTICIPANTS

- -

Participant: SUNDHER, AVTAR
Role(s): MAIN MINISTRY CONTACT
Start Date: NOV 05, 1998 End Date:

= =

DOCUMENTS

Title: ENVIRONMENTAL REMEDIATION AT 7510 HOPCOTT ROAD, DELTA, BC
Authored: FEB 06, 2002 Submitted: FEB 11, 2002

Participants	Role
GOLDER ASSOCIATES LTD (BURNABY)	AUTHOR
MORGUARD INVESTMENTS LTD.	COMMISSIONER

Notes: REMEDIATION RELATED TO IDENTIFIED SOURCE OF DRINKING WATER CONTAMINATION. ISOLATED POCKET OF CONTAMINATION AROUND PORTION OF PVC DRINKING WATER LINE

- -

Title: PRELIMINARY SITE INVESTIGATION FOR 7510 HOPCOTT ROAD, DELTA, BC
Authored: MAY 01, 2000 Submitted: MAY 30, 2000

Participants	Role
EVS ENVIRONMENT CONSULTANTS (NORTH VANCOUVER, B.C.)	AUTHOR
MORGUARD INVESTMENTS LTD.	COMMISSIONER

Notes: PRELIMINARY SITE INVESTIGATION TO DETERMINE SOURCE OF CONTAMINATION OF MUNCIPALLY SUPPLIED DRINKING WATER.

No activities were reported for this site

End of Detail Report

```
 As of: OCT 20, 2019       BC Online: Site Registry                    19-10-22
                      For: PG45409  CH2M HILL CANADA LIMITED           09:38:21
 Folio: CE764600.A.CS.E                                                Page   1
                                Synopsis Report
SITE LOCATION
       Site ID:       6973                            Latitude:  49d 08m 33.1s
 Victoria File:                                      Longitude: 123d 01m 53.5s
 Regional File: 26250-20/6973
        Region: SURREY, LOWER MAINLAND

  Common Name:
 Site Address: 7700 HOPCOTT ROAD
         City: DELTA                           Prov/State: BC
  Postal Code:

 Registered: OCT 20, 2000  Updated: JUN 07, 2019  Detail Removed: JUN 07, 2019

 Notations:   2   Participants:   6    Associated Sites:   0
 Documents:   0 Susp. Land Use:   0 Parcel Descriptions:   1

Location Description: LOCATION CONFIRMED USING PARCELMAP BC ON 7 JUNE, 2019

       Status: NOT ASSIGNED
 Fee category: UNRANKED

No Site Profile has been submitted for this site

                              End of Synopsis Report
```

Appendix C
Ecological Communities at Risk with Potential to Occur Within the Study Area

Table C-1. Ecological Communities at Risk with Potential to Occur Within the Study Area

Common Name	Scientific Name	Provincial Designations[a]	Ecosystem Group
common cattail Marsh	*Typha latifolia* Marsh	Blue	Wetland Realm - Mineral Wetland Group: Marsh Wetland Class (Wm)
American glasswort – sea-milkwort	*Sarcocornia pacifica - Lysimachia maritima*	Red	Estuarine Realm: Estuarine Marsh Class (Em)
beaked ditch-grass Herbaceous Vegetation	*Ruppia maritima* Herbaceous Vegetation	Red	Estuarine Realm: Estuarine Marsh Class (Em)
black cottonwood - red alder/salmonberry	*Populus trichocarpa - Alnus rubra/Rubus spectabilis*	Blue	Terrestrial Realm - Flood Group (F): Middle Bench Flood Class (Fm); Terrestrial Realm - Forest: Broadleaf - moist/wet
buckbean - slender sedge	*Menyanthes trifoliata - Carex lasiocarpa*	Blue	Wetland Realm - Peatland Group: Fen Wetland Class (Wf)
common spike-rush Herbaceous Vegetation	*Eleocharis palustris* Herbaceous Vegetation	Blue	Wetland Realm - Mineral Wetland Group: Marsh Wetland Class (Wm)
Douglas-fir - arbutus	*Pseudotsuga menziesii - Arbutus menziesii*	Red	Terrestrial Realm - Forest: Coniferous - dry
Douglas-fir/dull Oregon-grape	*Pseudotsuga menziesii/Berberis nervosa*	Red	Terrestrial Realm - Forest: Coniferous - mesic
grand fir/dull Oregon-grape	*Abies grandis/Berberis nervosa*	Red	Terrestrial Realm - Forest: Coniferous - mesic
grand fir/three-leaved foamflower	*Abies grandis/Tiarella trifoliata*	Red	Terrestrial Realm - Forest: Coniferous - moist/wet
hard-stemmed bulrush Deep Marsh	*Schoenoplectus acutus* Deep Marsh	Blue	Wetland Realm - Mineral Wetland Group: Marsh Wetland Class (Wm)
Labrador-tea/western bog-laurel/peat-mosses	*Rhododendron groenlandicum/Kalmia microphylla/Sphagnum* spp.	Blue	Wetland Realm - Peatland Group: Bog Wetland Class (Wb)
lodgepole pine/peat-mosses CDFmm	*Pinus contorta/Sphagnum* spp. CDFmm	Red	Wetland Realm - Peatland Group: Bog Wetland Class (Wb)
Lyngbye's sedge herbaceous vegetation	*Carex lyngbyei* Herbaceous Vegetation	Red	Estuarine Realm: Estuarine Marsh Class (Em)
red alder/salmonberry/ common horsetail	*Alnus rubra/Rubus spectabilis/ Equisetum arvense*	Blue	Terrestrial Realm - Flood Group (F): Low Bench Flood Class (Fl)
red alder/skunk cabbage	*Alnus rubra/Lysichiton americanus*	Red	Wetland Realm - Mineral Wetland Group: Swamp Wetland Class (Ws)
red alder/slough sedge (black cottonwood)	*Alnus rubra/Carex obnupta [Populus trichocarpa]*	Red	Wetland Realm - Mineral Wetland Group: Swamp Wetland Class (Ws)
seacoast bulrush Alkali Marsh	*Bolboschoenus maritimus var. paludosus Alkali Marsh*	Red	Wetland Realm - Mineral Wetland Group: Marsh Wetland Class (Wm)
seashore saltgrass - Pacific swampfire	*Distichlis spicata - Sarcocornia pacifica*	Red	Estuarine Realm: Estuarine Marsh Class (Em)

Table C-1. Ecological Communities at Risk with Potential to Occur Within the Study Area

Common Name	Scientific Name	Provincial Designations[a]	Ecosystem Group
Sitka willow - Pacific willow/ skunk cabbage	*Salix sitchensis - Salix lasiandra var. lasiandra/Lysichiton americanus*	Red	Wetland Realm - Mineral Wetland Group: Swamp Wetland Class (Ws)
slender sedge - white beak-rush	*Carex lasiocarpa - Rhynchospora alba*	Red	Wetland Realm - Peatland Group: Fen Wetland Class (Wf)
sweet gale/Sitka sedge	*Myrica gale/Carex sitchensis*	Red	Wetland Realm - Peatland Group: Fen Wetland Class (Wf)
three-way sedge	*Dulichium arundinaceum* Herbaceous Vegetation	Red	Wetland Realm - Mineral Wetland Group: Marsh Wetland Class (Wm)
western redcedar - Douglas-fir/Oregon beaked-moss	*Thuja plicata - Pseudotsuga menziesii/Eurhynchium oreganum*	Red	Terrestrial Realm - Forest: Coniferous - moist/wet
western redcedar - Sitka spruce/skunk cabbage	*Thuja plicata - Picea sitchensis/Lysichiton americanus*	Blue	Terrestrial Realm - Forest: Coniferous - moist/wet; Wetland Realm - Mineral Wetland Group: Swamp Wetland Class (Ws)
western redcedar/common snowberry	*Thuja plicata/Symphoricarpos albus*	Red	Terrestrial Realm - Flood Group (F): Highbench Flood; Terrestrial Realm - Forest: Mixed - moist/wet
western redcedar/Indian-plum	*Thuja plicata/Oemleria cerasiformis*	Red	Terrestrial Realm - Forest: Coniferous - moist/wet
western redcedar/sword fern - skunk cabbage	*Thuja plicata/Polystichum munitum - Lysichiton americanus*	Blue	Terrestrial Realm - Forest: Coniferous - moist/wet; Wetland Realm - Mineral Wetland Group: Swamp Wetland Class (Ws)
western redcedar/vanilla-leaf	*Thuja plicata/Achlys triphylla*	Red	Terrestrial Realm - Forest: Coniferous - moist/wet

Sources: BC CDC

[a] BC Provincial List (BC CDC 2019b). This table only includes Red and Blue-listed species or Federally-listed species.

Red List: Includes any indigenous species and subspecies that is Extirpated, Endangered, or Threatened in BC. Species may be legally designated as Extirpated, Endangered, or Threatened under the BC *Wildlife Act*.

Blue List: Includes any indigenous species and subspecies considered to be of special concern in BC. Elements are of special concern because of characteristics that make them particularly sensitive to human activities or natural events.

Notes:

BC = British Columbia
BC CDC = British Columbia Conservation Data Centre

Appendix D
Wildlife and Plant Species at Risk with Potential to Occur Within the Study Area

Table D-1. Wildlife and Plant Species at Risk with Potential to Occur Within the Study Area

Common Name	Scientific Name	Habitat	Provincial Designations[a]	Federal Designations
Mammals				
Little brown myotis	*Myotis lucifugus*	Roosts in buildings, large decaying trees, and rock crevices/caves. Forages in a variety of habitats, especially wetlands.	--	Endangered[b,c]
Long-tailed weasel, *altifrontalis* subspecies	*Mustela frenata altifrontalis*	Utilize a variety of habitats at all elevations, including coniferous and deciduous forests, riparian shrublands, and agricultural clearings. Burrow in hollow trees, stumps, logs, rock or debris piles, haystacks, farm machinery, outbuildings.	Red	--
Olympic shrew	*Sorex rohweri*	Associated with riparian zones in and around streams and wetlands. Also utilizes grass or shrub communities in close proximity to forest cover.	Red	--
Pacific water shrew	*Sorex bendirii*	Moist riparian habitats with high canopy, shrub, and woody debris cover.	Red	Endangered[b,c]
Southern red-backed vole, *occidentalis* subspecies	*Myodes gapperi occidentalis*	Typically found in old growth communities, but also utilizes coniferous or mixed forests, bogs and swamps, and old-field or grass dominated communities. Nests under tree roots, logs, or brush piles.	Red	--
Townsend's big-eared bat	*Corynorhinus townsendii*	Cultivated valleys bordered by open deciduous forests, brush, or coniferous forests.	Blue	--
Trowbridge's Shrew	*Sorex trowbridgii*	Restricted to low elevation forests and wetlands of the Fraser Lowlands. Prefers upland areas away from water where litter and soils are drier and easier to forage in. Also utilizes grassland or disturbed areas.	Blue	--
Birds				
American bittern	*Botaurus lentiginosus*	Freshwater sloughs, marshes, swamps, and shallow lakes.	Blue	--
Band-tailed pigeon	*Patagioenas fasciata*	Edges and openings of mature coniferous, mixed, and deciduous forests, city yards and parks, wooded groves and openings with abundant berry producing shrubs.	Blue	Special Concern[b,c]
Barn Owl	*Tyto alba*	Live in grasslands, deserts, marshes, agricultural fields, strips of forest, woodlots, ranchlands, brushy fields, and suburbs and cities. They nest in tree cavities, caves, and in buildings.	Red	Threatened[b,c]
Bank swallow	*Riparia riparia*	Open areas, often near water. Nesting near the top of steep banks associated with inland water, gravel pits, and road embankments. Nesting in the same area in successive years is common.	--	Threatened[b,c]

Table D-1. Wildlife and Plant Species at Risk with Potential to Occur Within the Study Area

Common Name	Scientific Name	Habitat	Provincial Designations[a]	Federal Designations
Barn swallow	*Hirundo rustica*	Open areas near water. Often nest in overhangs of manufactured structures (such as, barns and bridges), cliffs, or caves.	Blue	Threatened[b,c]
Common nighthawk	*Chordeiles minor*	Open forest and forest clearings (such as, logged or burned areas, natural woodland clearings), grasslands, lakeshores, rock outcrops, and flat gravel roads. Typically nest in areas where the ground is devoid of vegetation.	--	Threatened[b] Special Concern[c]
Great blue heron, *fannini* subspecies	*Ardea herodias fannini*	Nest on large, mossy limbs in the canopy of large conifers in old growth forest within 50 km of the ocean.	Blue	Special Concern[b,c]
Green heron	*Butorides virescens*	Wooded wetlands, ponds and streams, sloughs, estuaries, tidal channels, and other waterbodies with sufficient protective cover	Blue	--
Olive-sided flycatcher	*Contopus cooperi*	Forests and woodlands burned areas with standing dead trees, subalpine coniferous forest, and mixed coniferous-deciduous forest, especially near wetland areas.	Blue	Threatened[b] Special Concern[c]
Purple martin	*Progne subis*	Nests in artificial nest boxes in marine waters, forages over wetlands, estuaries, open fields, ponds, and forested habitat	Blue	--
Rough-legged hawk	*Buteo lagopus*	Cliffs, conifer forests, cropland, hedgerow, grassland, riparian areas	Blue	--
Short-eared owl	*Asio flammeus*	Rangelands, grasslands, estuaries, marshes, ponds, near open water, dry marshes, farmlands, low Arctic tundra, brushy fields, and forest clearings.	Blue	Special Concern[b,c]
Western screech-owl, *kennicottii* subspecies	*Megascops kennicottii kennicottii*	Mature lowland coniferous and mixed forest, shrub forest	Blue	Threatened[b,c]
Amphibians				
Northern red-legged frog	*Rana aurora*	Permanent or ephemeral streams, ponds and marshes with abundant emergent vegetation, moist forest.	Blue	Special Concern[b,c]
Western toad	*Anaxyrus boreas*	Forested areas, wet shrublands, avalanche slopes, meadows, clear-cuts, streamsides and shallow pond edges, often with dense shrub cover.	--	Special Concern[b,c]
Turtles				
Painted Turtle - Pacific Coast Population	*Chrysemys picta* pop. 1	Wetlands, lakes, ponds, and adjacent riparian areas.	Red	Threatened[b] Endangered[c]

Table D-1. Wildlife and Plant Species at Risk with Potential to Occur Within the Study Area

Common Name	Scientific Name	Habitat	Provincial Designations[a]	Federal Designations
Vascular Plants				
Henderson's checker-mallow	*Sidalcea hendersonii*	Meadows, wet places, tidal flats. Flowering from June to August.	Blue	--
Streambank lupine	*Lupinus rivularis*	Open lowlands, mudflats. Flowering from late May to October.	Red	Endangered[b,c]
Two-edged water-starwort	*Callitriche heterophylla var. heterophylla*	Shallow ponds and shorelines. Fruiting in September.	Blue	--
Vancouver Island beggarticks	*Bidens amplissima*	Low elevation, wet, open habitat. Flowering in late summer.	Blue	Special Concern[b,c]
Non-Vascular Plants				
California Alsia Moss	*Alsia californica*	Trees near coastal environments.	Blue	--
Cedar Moss	*Brachythecium holzingeri*	Wet habitats on humus at moderate elevations.	Blue	--
Naked Flag Moss	*Discelium nudum*	Clay or silt soil on banks at low to moderate elevations.	Red	--
Pocket moss	*Fissidens ventricosus*	Rocks submerged in rapidly running streams. Occasionally on wet rocks beside streams.	Blue	--
Hygroamblystegium moss	*Hygroamblystegium fluviatile*	Unknown	Blue	--
Hidden Urn Moss	*Physcomitrium immersum*	Wet soil in disturbed floodplains or mudflats near streams at moderate to high elevations.	Red	--
Common bladder-moss	*Physcomitrium pyriforme*	Unknown	Blue	--
Platyhypnidium moss	*Platyhypnidium riparioides*	Submerged or semi-submerged on rocks, tree roots and wood in streams, ditches, canals, and ponds.	Blue	--
Delicate earth-moss	*Pseudephemerum nitidum*	Grows on the edge of fields	Blue	--

Table D-1. Wildlife and Plant Species at Risk with Potential to Occur Within the Study Area

Common Name	Scientific Name	Habitat	Provincial Designations[a]	Federal Designations

Sources: BC CDC, COSEWIC

[a] BC Provincial List (BC CDC 2019b). This table only includes Red- and Blue-listed species or Federally-listed species.

Red List: Includes any indigenous species and subspecies that is Extirpated, Endangered, or Threatened in BC. Species may be legally designated as Extirpated, Endangered, or Threatened under the BC *Wildlife Act*.

Blue List: Includes any indigenous species and subspecies considered to be of special concern in BC. Elements are of special concern because of characteristics that make them particularly sensitive to human activities or natural events.

[b] *SARA*. The Act establishes Schedule 1 as the list of species to be protected on all Federal lands in Canada. The Act also applies to all lands in Canada for Schedule 1 bird species cited in the *Migratory Birds Convention Act*. This table only includes designations of Endangered, Threatened, or Special Concern.

Endangered: A species that is facing imminent extirpation or extinction.

Threatened: A species that is likely to become an Endangered species if nothing is done to reverse the factors leading to its extirpation or extinction.

Special Concern: A species that may become a Threatened or an Endangered species due to a combination of biological characteristics and identified threats.

[c] COSEWIC 2019. Table only includes designations of Endangered, Threatened, and Special Concern.

Endangered: A species facing imminent extirpation or extinction.

Threatened: A species likely to become Endangered if nothing is done to reverse the factors leading to its extirpation or extinction.

Special Concern: A species that may become Threatened or Endangered due to a combination of biological characteristics and identified threats.

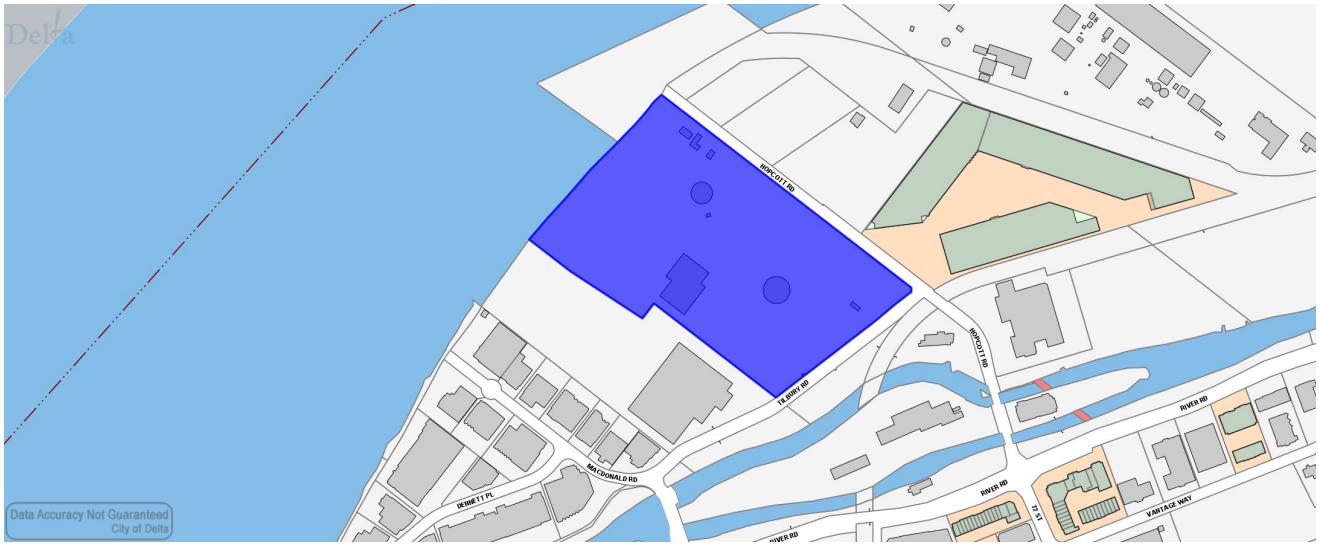
Notes:

Status designations that are not applicable are denoted by "--" (such as, designations of species that have not been assessed or that are not considered to have special conservation status).

BC = British Columbia
BC CDC = British Columbia Conservation Data Centre
COSEWIC = Committee on the Status of Endangered Wildlife in Canada
SARA = *Species at Risk Act*

Appendix E
Legal Plot Plan

DeltaMap Report: Tuesday October 22, 2019



Layer: Standard Parcels

GID:	**1191876**
PID Number:	**029-263-301**
Roll Number:	**346250010**
Address:	**7651 HOPCOTT RD**
Lot Number:	**REM 1**
Legal Plan:	**EPP28232**
Approx. Area (m2):	**179446.7**
LDESC:	**LT 1 DL 135 GP 2 NWD PL EPP28232 EX PL EPP36476**
REVISED:	**May 14, 2014**

REFERENCE PLAN OF LOT A, PLAN EPP 9594, LOT 12, PLAN 45616, AND LOT 14, PLAN 45616, EXCEPT PART IN PLAN LMP 40041, ALL OF DISTRICT LOT 135, GROUP 2, NEW WESTMINSTER DISTRICT

EPP 28232

PURSUANT TO SECTION 100(1)(b) OF THE LAND TITLE ACT

B.C.G.S. 92G.015

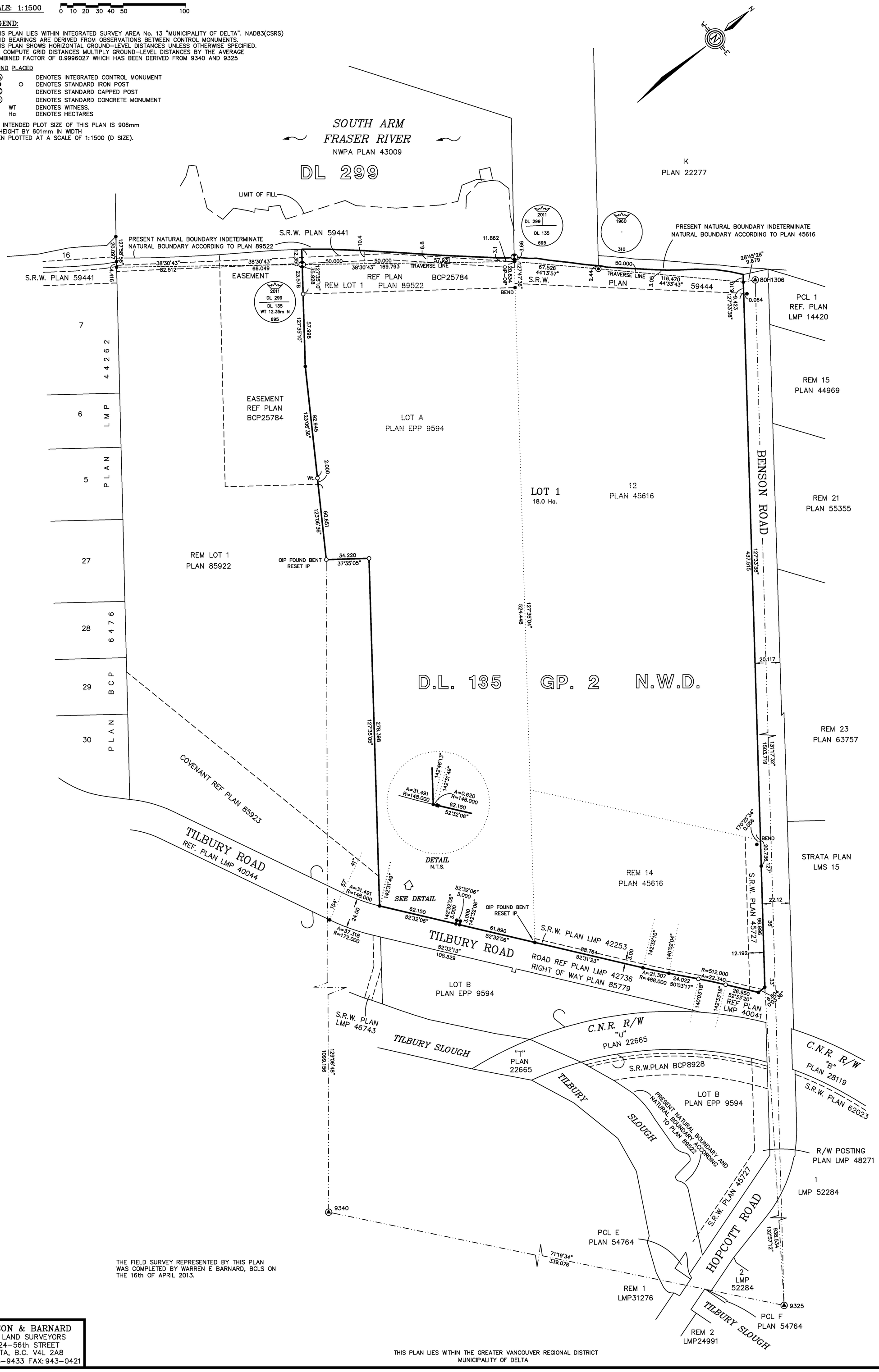
SCALE: 1:1500 0 10 20 30 40 50 100

LEGEND:

- THIS PLAN LIES WITHIN INTEGRATED SURVEY AREA No. 13 "MUNICIPALITY OF DELTA". NAD83(CSRS)
- GRID BEARINGS ARE DERIVED FROM OBSERVATIONS BETWEEN CONTROL MONUMENTS.
- THIS PLAN SHOWS HORIZONTAL GROUND-LEVEL DISTANCES UNLESS OTHERWISE SPECIFIED.
- TO COMPUTE GRID DISTANCES MULTIPLY GROUND-LEVEL DISTANCES BY THE AVERAGE COMBINED FACTOR OF 0.9996027 WHICH HAS BEEN DERIVED FROM 9340 AND 9325

FOUND	PLACED	
▲		DENOTES INTEGRATED CONTROL MONUMENT
●	O	DENOTES STANDARD IRON POST
⊗		DENOTES STANDARD CAPPED POST
⊙		DENOTES STANDARD CONCRETE MONUMENT
	WT	DENOTES WITNESS.
	Ha	DENOTES HECTARES

THE INTENDED PLOT SIZE OF THIS PLAN IS 906mm IN HEIGHT BY 601mm IN WIDTH WHEN PLOTTED AT A SCALE OF 1:1500 (D SIZE).



THE FIELD SURVEY REPRESENTED BY THIS PLAN WAS COMPLETED BY WARREN E BARNARD, BCLS ON THE 16th OF APRIL 2013.

WATSON & BARNARD
B.C. LAND SURVEYORS
1524-56th STREET
DELTA, B.C. V4L 2A8
TEL.: 943-9433 FAX: 943-0421

THIS PLAN LIES WITHIN THE GREATER VANCOUVER REGIONAL DISTRICT
MUNICIPALITY OF DELTA

FILE: 23295RP
PLOT: 2013/04/22
MAP: K-7(S)

DLINK\DWG2013\23295RP.dwg M1500 SIGMA2/JOBS2011/23295.DWG 028-750-055 (LOT A) 005-938-856 (LOT 12) 005-938-899 (LOT 14)

EPP36476

REFERENCE PLAN OF A PORTION OF LOT 1, DISTRICT LOT 135, GROUP 2, NEW WESTMINSTER DISTRICT, PLAN EPP28232

PURSUANT TO SECTION 107 OF THE LAND TITLE ACT

B.C.G.S. 92G.015

SCALE: 1:750 (10 5 0 10 20 30 40 50)

LEGEND:

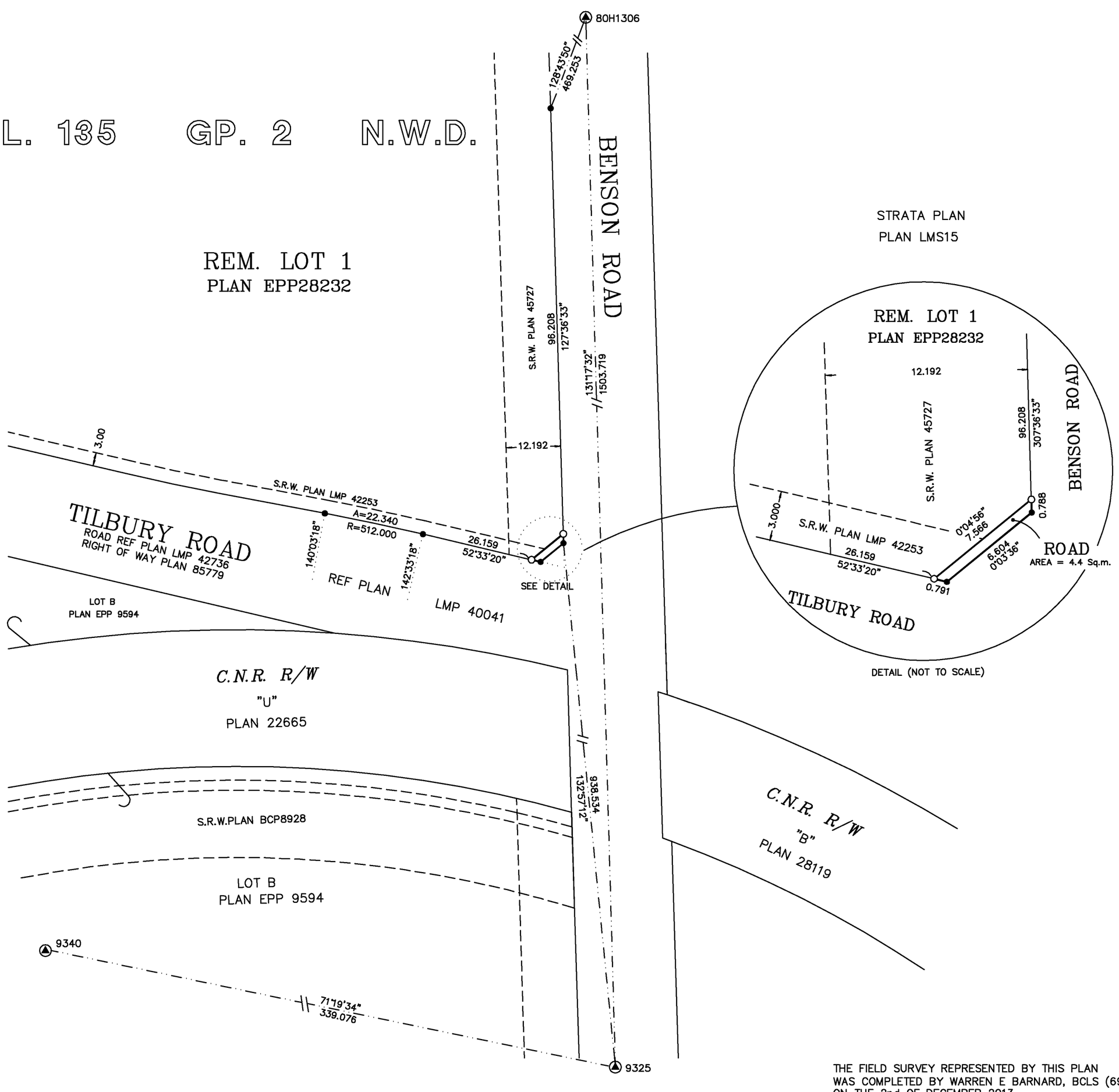
- THIS PLAN LIES WITHIN INTEGRATED SURVEY AREA No. 13 "MUNICIPALITY OF DELTA". NAD83(CSRS)
- GRID BEARINGS ARE DERIVED FROM OBSERVATIONS BETWEEN CONTROL MONUMENTS.
- THIS PLAN SHOWS HORIZONTAL GROUND-LEVEL DISTANCES UNLESS OTHERWISE SPECIFIED.
- TO COMPUTE GRID DISTANCES MULTIPLY GROUND-LEVEL DISTANCES BY THE AVERAGE COMBINED FACTOR OF 0.9996027 WHICH HAS BEEN DERIVED FROM 9325 AND 9340

FOUND	PLACED	
▲		DENOTES INTEGRATED CONTROL MONUMENT
●	○	DENOTES STANDARD IRON POST
⊗		DENOTES STANDARD CAPPED POST
⊙		DENOTES STANDARD CONCRETE MONUMENT
WT		DENOTES WITNESS.
Sq.m.		DENOTES SQUARE METRES

THE INTENDED PLOT SIZE OF THIS PLAN IS 906mm IN HEIGHT BY 601mm IN WIDTH WHEN PLOTTED AT A SCALE OF 1:1500 (D SIZE).

ROAD DEDICATION AREA = 4.4 Sq.m.

THIS PLAN LIES WITHIN THE JURISDICTION OF THE APPROVING OFFICER FOR THE MUNICIPALITY OF DELTA



THE FIELD SURVEY REPRESENTED BY THIS PLAN WAS COMPLETED BY WARREN E BARNARD, BCLS (695) ON THE 2nd OF DECEMBER 2013.

DLINK\DWG2013\23295RP2.dwg M500 SIGMA2/JOBS2011/23295.DWG

WATSON & BARNARD
B.C. LAND SURVEYORS
1524-56th STREET
DELTA, B.C. V4L 2A8
TEL.: 943-9433 FAX: 943-0421

THIS PLAN LIES WITHIN THE GREATER VANCOUVER REGIONAL DISTRICT
MUNICIPALITY OF DELTA

FILE: 23295RP2
PLOT: 2013/12/10
MAP: K-7(S)

PARCEL IDENTIFIER (PID): 029-263-301

SHORT LEGAL DESCRIPTION:S/EPP28232/////1
MARG:REM
TAXATION AUTHORITY:
1 Delta, The City of

FULL LEGAL DESCRIPTION: CURRENT
LOT 1 DISTRICT LOT 135 GROUP 2 NEW WESTMINSTER DISTRICT PLAN EPP28232
EXCEPT PLAN EPP36476

MISCELLANEOUS NOTES:

ASSOCIATED PLAN NUMBERS:
CONSOLIDATION PLAN EPP28232
ROAD PLAN EPP36476
STATUTORY RIGHT OF WAY PLAN EPP36477

AFB/IFB: MN: N PE: 0 SL: 1 TI: 1

Appendix P

ARCHAEOLOGICAL OVERVIEW ASSESSMENT REPORT

REPORT

FortisBC Tilbury LNG Production and Storage Facility Expansion, Delta, BC

Archaeological Overview Assessment

Submitted to:

Christopher Wylie
1975 Springfield Road #100
Kelowna, BC
V1Y 7V7

Submitted by:

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19134134-017-R-Rev0

26 May 2020

Prepared under Musqueam Heritage Research/Investigation Permit MIB-2019-177-AOA,
Seyem' Qwantlen Heritage Investigation Permit SQ 2020-47,
Squamish Nation Archaeological Investigation Permit 19-0183,
Stó:lō Heritage Investigation Permit 2019-252, and
Tsleil-Waututh Nation Cultural Heritage Investigation Permit 2019-172

Distribution List

1 Copy FortisBC

1 Copy Archaeology Branch

1 Copy Cowichan Tribes

1 Copy Halalt First Nation

1 Copy Katzie First Nation

1 Copy Kwantlen First Nation

1 Copy Lake Cowichan First Nation

1 Copy Lyackson First Nation

1 Copy Musqueam Indian Band

1 Copy Penelakut Tribe

1 Copy Semiahmoo First Nation

1 Copy Squamish Nation

1 Copy Stó:lō Research and Resource Management Centre

1 Copy Stz'uminus First Nation

1 Copy Tsawwassen First Nation

1 Copy Tsleil-Waututh Nation

1 Copy Golder Associates

Executive Summary

At the request of FortisBC Energy Inc., Golder Associates Ltd. was retained to undertake an archaeological overview assessment of the FortisBC Tilbury LNG Production and Storage Facility Expansion (the Study) on Tilbury Island, Delta, BC (the Study area).

The Study is being undertaken to develop a comprehensive understanding of the archaeological resource potential of the Study area and will be used to guide the need for further archaeological studies in relation to future FortisBC Energy Inc. planned works. The archaeological overview assessment may also be used by FortisBC Energy Inc. in support of a Certificate of Public Convenience and Necessity application to the British Columbia Utilities Commission.

The objectives of the archaeological overview assessment were to:

- Identify known heritage sites within the Study area, to the degree possible, using existing records.
- Evaluate archaeological potential within the Study area.
- Assess the need for more detailed archaeological investigations, if warranted.
- Provide archaeological recommendations for the Project.

For purposes of the archaeological overview assessment, the Study area has been divided into 13 assessment areas, designated A – M, representing proposed or possible development areas. In addition to the Project site, or properties owned by FortisBC Energy Inc., assessment areas include: the dyke and foreshore adjacent to the Fraser River; Hopcott Road between Gravesend Reach and Tilbury Slough and the area to the east following the existing pipeline right-of-way; and, the area south of the FortisBC Energy Inc. property including Tilbury Road and the northern arm of Tilbury Slough. The assessments of archaeological potential, archaeological sensitivity, and archaeological recommendations that follow are grouped into the 13 assessment areas.

Archaeological Potential

The primary considerations for assessing archaeological potential in this Study area include:

- Locations of previously documented archaeological sites.
- Proximity (within 100 m) to waterways, including from the inferred locations of slough channels that have since been in-filled.
- Documented subsurface excavations from historical developments or erosion leading to the removal of deposits that may have contained cultural materials, if an archaeological site were present.
- Results of a previous archaeological impact assessment.

Due to proximity to waterways, including the inferred locations of slough channels, archaeological potential has been identified in 12 of 13 assessment areas. There is no archaeological potential identified in assessment area J due to the negative results of the archaeological impact assessment in that area. Areas A, C, G, and H have no potential assessed for large portions of the respective areas due to: distance from a watercourse; the negative results of the archaeological impact assessment; and/or, documented subsurface excavations from previous development. Archaeological potential is summarized by assessment area in the Table concluding this section.

Archaeological Sensitivity

Archaeological sensitivity in this Study addresses the possibility for archaeological material, if present, to have survived **Deep** beneath subsequent deposits that were the result of historical land-altering occurrences, including the placement of fill or sediment accumulation. For the purposes of recommendations provided in this study, "deep" is minimally 40 cm below grade, but may be much deeper. It may further be suggested that archaeological potential has been **Removed** by development activities. Archaeological sensitivity mapping for this Study was generated through review of subsurface tests used to support several geotechnical and other investigations in the Study area. Archaeological inferences drawn from these data, are framed as **Likely**, or **Unlikely**. Where the inference is extrapolated based on data that may be incomplete or absent, the term **Data Absent** is used. Archaeological sensitivity is summarized by assessment area in the Table concluding this section.

Recommendations

Project-related impacts in areas with archaeological potential should be avoided if possible. Some areas of potential present fewer risks than others, in part depending on the type of development proposed. Recommendations for archaeological investigations to mitigate development risks presented below and are summarized by each assessment area in the following Table.

- In the larger portions of assessment areas K, L and M, excluding the roadbeds and areas of prior disturbance such as buried pipelines – conduct an archaeological impact assessment prior to construction.
- In much of the area that has been previously developed (including parts of assessment areas A, B, C, D, F, G, H, Ia, Ib, K and L, and all of area E) the chance of encountering archaeological remains at least in the upper layers of fill is low. A chance find management plan should be implemented prior to ground disturbance to provide workers with the steps to follow should suspected archaeological materials be encountered during construction when an archaeologist is not present. For proposed work extending below 40 cm dbs in this area, work should be preceded by an archaeological impact assessment or monitored concurrently, depending on the type of work (i.e., work such as some geotechnical tests or pile driving would not be monitored due to lack of recovered subsurface material available for examination), and/or recommendations provided as a result of previous archaeological investigations.
- In most of the area offshore of the dyke (area A), due to reported depths of fill or sediments, a chance find management plan should be implemented during work conducted in this area. If the proposed work extends below 4.0 m dbs, monitoring should be conducted (providing material from the depths where archaeological potential is anticipated will be exposed on the surface and available for observation).
- Where no archaeological potential has been assessed due to distance from water, previous subsurface excavations, or previous archaeological investigations (including parts of areas A, B, C, D, F, G, H, Ia and Ib, and all of area J) a chance find management plan should be implemented during work conducted in this area.

Where an archaeological impact assessment is recommended, subsurface archaeological tests may proceed following the issuance by the Archaeology Branch of a *Heritage Conservation Act* Section 12.2 permit. The archaeological impact assessment report will include recommendations for specific heritage resource management during site development once development plans are refined. In the event that an archaeological site is identified, further archaeological work, including monitoring of geotechnical tests or subsurface excavations

for construction may proceed under a Section 12.4 permit issued by the Oil and Gas Commission. The Oil and Gas Commission will also require that an Archaeological Information Form be prepared as part of the permit initiation for the Project, and subsequently updated with results of all archaeological investigations.

Table: Archaeological potential, sensitivity and recommendations.

Assessment Area and Location	Archaeological Potential and Sensitivity	Recommendations
A Dyke and Foreshore	■ Includes areas of deep potential: ▪ Not removed in foreshore, and, ▪ Data absent under stub jetty; and, ■ An area of removed potential under dyke.	■ No further archaeological investigations are recommended in the areas where inferred depth of potential exceeds the practical reach of mechanical testing depths, in areas where excavation would compromise the integrity of the dyke, or where potential is considered removed. A chance find management plan should be implemented during construction in this area. ■ Archaeological monitoring is recommended where Project activities will involve removal of sediments from potentially artifact bearing depths that may be available for archaeological examination.
B Hopcott Road	■ Includes areas of deep potential: ▪ Likely removed, where tested, and ▪ Data absent where tests absent; and, ■ An area of no potential.	■ Subsurface archaeological investigations are recommended prior to, or concurrent with, Project excavations extending below engineered fill in areas with deep archaeological potential to address data absence or confirm inference from geotechnical data that levels with artifact-bearing potential have been removed. ■ No further archaeological investigations are recommended in area of no assessed potential. A chance find management plan should be implemented during construction in this area.
C	■ Includes area of deep potential, likely removed; and, ■ An area of no potential.	■ Subsurface archaeological investigations are recommended prior to Project excavations below reported depths of fill in areas with deep archaeological potential to confirm the inference from geotechnical data that levels with artifact-bearing potential have been removed. ■ No further archaeological investigations are recommended in the area of no assessed potential. A chance find management plan should be implemented during construction in this area.
D South Parcel, M	■ Includes area of deep potential, likely removed; and, ■ An area of no potential.	■ Subsurface archaeological investigations are recommended prior to Project excavations below reported depths of fill in areas with deep archaeological potential to confirm the inference from geotechnical data that levels with artifact-bearing potential have been removed. ■ No further archaeological investigations are recommended in the area of no assessed potential. A chance find management plan should be implemented during construction in this area.
E South Parcel, E	■ Is an area with deep potential, likely removed.	■ Subsurface archaeological investigations are recommended prior to Project excavations below reported depths of fill to confirm the inference from geotechnical data that levels with artifact-bearing potential have been removed.
F North Parcel, W	■ Includes area of deep potential, data absent; and, ■ An area of no potential.	■ Subsurface archaeological investigations are recommended prior to Project excavations below reported depths of fill in area with deep archaeological potential. ■ No further archaeological investigations are recommended in the area of no assessed potential. A chance find management plan should be implemented during construction in this area.

Assessment Area and Location	Archaeological Potential and Sensitivity	Recommendations
G North Parcel, M	■ Includes area of deep potential, likely removed; and, ■ Areas of no potential.	■ Subsurface archaeological investigations recommended prior to Project excavations below reported depths of fill in area with deep archaeological potential to confirm the inference from geotechnical data that levels with artifact-bearing potential have been removed. ■ No further archaeological investigations are recommended in areas of no assessed potential. A chance find management plan should be implemented during construction in this area.
H North Parcel, M	■ Includes area of deep potential, likely removed; and, ■ Areas of no potential.	■ Subsurface archaeological investigations are recommended prior to Project excavations below reported depths of fill in area with deep archaeological potential to confirm the inference from geotechnical data that levels with artifact-bearing potential have been removed. ■ No further archaeological investigations are recommended in areas of no assessed potential. A chance find management plan should be implemented during construction in this area.
Ia North Parcel, M	■ Includes small area of no assessed potential; and, ■ An area of deep potential, likely removed.	■ No further archaeological investigations are recommended in the area of no assessed potential. A chance find management plan should be implemented during construction in this area. ■ Subsurface archaeological investigations are recommended prior to Project excavations below reported depths of fill in the area with deep archaeological potential to confirm the inference from geotechnical data that levels with artifact-bearing potential have been removed.
Ib North Parcel, E	■ Includes large area of no assessed potential; and, ■ A small area of deep potential, likely removed.	■ No further archaeological investigations are recommended in the area of no assessed potential. A chance find management plan should be implemented during construction in this area. ■ Subsurface archaeological investigations are recommended prior to Project excavations below reported depths of fill in the area with deep archaeological potential to confirm the inference from geotechnical data that levels with artifact-bearing potential have been removed.
J North Parcel, SE	■ Is an area with no assessed potential.	■ No further archaeological investigations are recommended. A chance find management plan should be implemented during construction in this area.
K Tilbury Road/ Slough W	■ Includes an area of archaeological potential; and, ■ An area of deep potential, data absent (Tilbury Road).	■ Subsurface archaeological investigations are recommended in area with archaeological potential. ■ Subsurface archaeological investigations are recommended prior to, or concurrent with, Project excavations below reported depths of fill in area with deep archaeological potential.
L Tilbury Road/ Slough M	■ Includes an area of archaeological potential; and, ■ An area of deep potential, data absent (Tilbury Road).	■ Subsurface archaeological investigations are recommended in area with archaeological potential. ■ Subsurface archaeological investigations are recommended prior to, or concurrent with, Project excavations below reported depths of fill in area with deep archaeological potential.
M Tilbury Slough E	■ Is area with archaeological potential.	■ Subsurface archaeological investigations are recommended, if proposed excavations are outside footprint of existing pipeline.

Credits

Project Director	Andrew (Andy) Mason, MA, RPCA
Project Manager	Charles Moore, MA, RPCA
Archaeological Field Supervisor	Charles Moore
Archaeological Field Assistants	Jodie Swartz, Katzie First Nation Lindsey Yates, Kwantlen First Nation. Melinda Cassidy, Tsawwassen First Nation
GIS Analyst	Jonathan Pokotylo, BSc, Adv Dipl Tech GIS
Report Authors	Charles Moore
Senior Technical Review	Andy Mason

Table of Contents

TABLES

FIGURES

APPENDICES

APPENDIX A
Select Photographs

APPENDIX B
Stó:lō Research and Resource Management Centre Database Search Review

Abbreviations and Acronyms

AOA Archaeological Overview Assessment

AIA Archaeological Impact Assessment

AIF Archaeological Information Form

BP Before Present

CAD Consultative Area Database

CFMP Chance Find Management Plan

CD Chart Datum, or hydrographic datum, with “0” elevation representing lower low tide.

CHR Community Heritage Registers

CMT Culturally Modified Tree

dbs Depth Below Surface

FCR Fire Cracked Rock

FLNRORD Forests, Lands, Natural Resource Operations and Rural Development

GIS Geographic Information System

HCA *Heritage Conservation Act*

LGA *Local Government Act*

LNG Liquefied Natural Gas

MASL Metres Above Sea Level

mtpa Million Tons per Annum (typical measure of LNG facility capacity)

NAD North American Datum

OGC Oil and Gas Commission (British Columbia)

PHR Provincial Heritage Register

UTM Universal Transverse Mercator

1.0 INTRODUCTION

At the request of FortisBC Energy Inc. (FortisBC), Golder Associates Ltd. (Golder) was retained to undertake an archaeological overview assessment (AOA) of the FortisBC Tilbury Liquid Natural Gas (LNG) Production and Storage Facility Expansion (the Study) on Tilbury Island, Delta, BC (the Study area, Figure 1).

The Study is being undertaken to develop a comprehensive understanding of the archaeological resource potential of the Study area and will be used to guide the need for further archaeological studies within the Study area in relation to future FortisBC planned works. The AOA may also be used by FortisBC in support of Certificate of Public Convenience and Necessity (CPCN) applications to the British Columbia Utilities Commission (BCUC), as well as both provincial and federal Environmental Assessment processes. As an LNG project, the planned works will be permitted by the BC Oil and Gas Commission (OGC), and an Archaeological Information Form (AIF) has been submitted to the OGC.

2.0 PROJECT DESCRIPTION

The Tilbury LNG facility was constructed in 1971 with an original storage tank capacity of 28,000 m^3 on the “northern” parcel of land comprising the FortisBC property, or Project site (Figure 2) (Appendix A, Photographs 1 and 2). At present, FortisBC is undertaking two Tilbury LNG facility expansion projects within the Study area, each at different points in their respective life cycles; Tilbury Phase 1 and Tilbury Phase 2 (the Projects). Once completed, the Projects will result in expansion of the capacity of the Tilbury LNG facility.

In 2014, FortisBC began construction of the Tilbury Phase 1 expansion which comprises the Phase 1A facilities, the Phase 1B facilities, and the Coastal Transmission System (CTS) expansion which includes the upgrade of an approximately 1 – 3 km pipeline between Tilbury Gate Station and Tilbury LNG facility. The Phase 1A facilities became operational in 2019 (Figure 2).

The Tilbury Phase 1B facilities are in the design and engineering stages with an anticipated in-service date of 2023. Once completed, the Phase 1B facilities will provide additional LNG production and distribution facilities connected to the Phase 1A storage tank (existing, with a capacity of 46,000 m^3). Phase 1B will extend the footprint of FortisBC facilities into the “southern” parcel of land in the Project site (Figure 2).

The CTS expansion will result in seismic integrity and increased gas send-out capacity upgrades to the pipeline between the Tilbury Gate Station and the Tilbury LNG facility.

In February 2020, the Tilbury Phase 2 Initial Project Description was submitted to the BC Environmental Assessment Office. Development of the Tilbury Phase 2 expansion which comprises construction of a new LNG storage tank (Tilbury Tank 2) and one or more liquefaction trains will be completed over multiple years with an anticipated completion date of 2028. Detailed engineering and construction plans for the Tilbury Phase 2 developments are expected in 2021 or 2022. The proposed Tilbury Tank 2, with the Tilbury Phase 1A tank or Tilbury Tank 1, is intended to provide security of public utility service and resiliency against possible interruptions of natural gas supply to the Region, but will also be sized and designed with capacity to meet the future demands of the LNG export market. The LNG production will be built in phases of one or more ‘liquefaction trains’ to meet market demand. The proposed in-service date for Tilbury Tank 2 is 2024 while the proposed in-service date for the liquefaction trains is 2024-2028. Completion of Tilbury Phase 2 will result in an expansion of facilities of up to 162,000 m^3 of LNG storage and up to 3.5 million tons per annum (mtpa) of liquid natural gas (LNG) liquefaction on Tilbury Island.

The Tilbury Phase 2 facilities may be located in additional areas in both the northern and southern portions of the Project site (Figure 2).

This southern portion of the Project site is also being developed by WesPac Midstream-Vancouver LLC (WesPac), which is proposing to construct a marine jetty with a terrestrial pipe rack to supply LNG to the marine transportation sector and for export. WesPac's project is separate and distinct from the FortisBC Phase 1 and Phase 2 projects. The WesPac project is currently undergoing a combined Federal and Provincial Environmental Assessment, under a substituted Provincial process that is led by the BC Environmental Assessment Office.

Portions of the nearly 50-year old Tilbury LNG facility are approaching end of useful life and may be decommissioned and removed as part of the normal course of the regulated utility business at some point in the future. Decommissioning and removal activities will be considered and coordinated with all other activities on the FortisBC property including operation of Phase 1A LNG facilities expansion as well as design and construction of the Phase 1B and Phase 2.

For purposes of the AOA, the Study area has been divided into 13 assessment areas representing proposed or possible development areas. The Study area also includes areas surrounding the Project site assessment areas include: the dyke and foreshore adjacent to the Fraser River; Hopcott Road between Gravesend Reach and Tilbury Slough and the area to the east following the existing pipeline right-of-way; and, the area south of the FortisBC property including Tilbury Road and the northern arm of Tilbury Slough. The areas, designated A – M, are illustrated in Figure 2 and listed in Table 1.

Table 1: Assessment areas.

Designation	Assessment Area Location	Possible Development
A	Dyke and Foreshore	N/A
B	Hopcott Road	Pipeline right-of-way, existing and proposed
C	South Parcel, W	Possible build or temporary workspace
D	South Parcel, M	Possible build area
E	South Parcel, E	Possible temporary workspace or parking
F	North Parcel, W	Demolition and possible re-build or temporary workspace
G	North Parcel, M	Demolition and possible re-build area
H	North Parcel, M	Possible build
Ia	North Parcel, E	N/A (recent build)
Ib	North Parcel, M	N/A (recent build)
J	North Parcel, SE	Possible temporary workspace
K	Tilbury Road/Slough W	N/A
L	Tilbury Road/Slough M	N/A
M	Tilbury Slough E	Pipeline right-of-way

2.1 Potential Impacts to Heritage Resources

Project construction-related, land-altering activities have the potential to affect heritage resources. Excavations for roads, foundations, demolition, ditching, clearing, grading, paving, the installation of subsurface utilities, driving piles, landscaping, subsurface geotechnical testing and other ancillary developments all have the potential to affect heritage resources by disturbing cultural deposits and features, damaging artifacts, hindering or increasing access to archaeological deposits, and destroying contextual information that is essential for interpreting site function and age (Davis et al. 2004; Williams and Corfield 2003).

Post-construction remedial and maintenance activities also have the potential to affect buried heritage resources due to compression, altered drainage patterns, and use of agrochemicals which leach into archaeological deposits (Davis et al. 2004).

2.2 Objectives

The objectives of the archaeological overview assessment were to:

- Identify known heritage sites within the Study area, to the degree possible, using existing records.
- Evaluate archaeological potential within the Study area.
- Assess the need for more detailed archaeological investigations, if warranted.
- Provide archaeological recommendations for the Project.

3.0 HERITAGE LEGISLATION AND POLICY

3.1 Heritage Conservation Act

All archaeological sites on provincial Crown or private land that predate AD 1846 are automatically protected under the *Heritage Conservation Act* (HCA). Certain sites, including burials and rock art sites, which have historical or archaeological value, are also protected regardless of age. Heritage wrecks, consisting of the remains of vessels (and aircraft) after two or more years have passed since they sank, crashed, or were abandoned (including being placed in terrestrial environment as part of landfill), are also protected.

Subsurface investigation of an archaeological site or investigation with the intent to locate a site requires a permit under Section 12.2 of the HCA. The Archaeology Branch is the provincial government agency in the Ministry of Forests, Lands, Natural Resource Operations and Rural Development (FLNRORD) responsible for administering the HCA, issuing permits, maintaining a database of recorded archaeological sites, and handling referrals from various development agencies.

Site protection under the HCA does not necessarily negate impact; in some cases, development proceeds after an impact assessment or other mitigation actions. With the exception of impacts occurring under a Section 12.2 permit or Ministerial Order under Section 12.3, any alteration to a known archaeological site must be permitted under Section 12.4 of the HCA. A Section 12.4 permit can be held by the individual responsible for the site alteration and/or co-held by a qualified archaeologist and normally includes data recovery or mitigation requirements such as archaeological construction monitoring or systematic data recovery (i.e., an archaeological excavation).

For developments proceeding under the OGC permitting process, including LNG Projects, the responsibility for issuing Section 12.4 permits lies with the OGC. All applications for HCA permits are forwarded to appropriate First Nations for a 30-day review and to solicit comments regarding the proposed methodology.

3.2 Municipal By-laws

Historical sites that are not protected by the HCA may be protected by municipal by-laws, under the authority of the *Local Government Act*. These sites are usually documented on Community Heritage Registers (CHRs), the Provincial Heritage Register (PHR), and the Canadian Register of Historic Places (CRHPs). A CHR entry generates a degree of recognition for these sites; however, without a site-specific protection mechanism such as a heritage designation by-law, heritage revitalization agreement by-law, or heritage restrictive covenant, inclusion on a CHR, the PHR, and/or the CRHP does not provide automatic protection for these sites.

3.3 First Nations Heritage Policy and Permitting Systems

Many BC First Nations have developed their own heritage policies and permitting systems. Golder and the professional archaeological community largely respect these requirements, although they are not required by the Province to meet regulatory requirements. In general, the scope of these policies reflects a measure of oversight with archaeological research in each respective First Nation's territory so that particular cultural protocols are observed, particularly as they relate to ancestral remains and spiritual locations. While aspects of these policies parallel the HCA, many diverge when it comes to the definition of what constitutes a "heritage resource." Most First Nations heritage policies take a broader view of heritage resources than compared to the HCA (Mason 2011).

4.0 METHODOLOGY

4.1 First Nations Communication and Permitting

Based on a review of the Consultative Areas Database – Public (CAD) maintained by the BC Ministry of Indigenous Relations and Reconciliation, First Nations groups or organizations with interests in the Study area were contacted regarding this AOA. Heritage permits were requested from those First Nations groups and organizations that have a heritage permitting system in place. Invitations were also extended to First Nations to participate in the field visit to the site.

4.2 Background Research

Golder assembled and reviewed readily available information for the Study area pertaining to the local environmental setting, cultural background, historical land use, and previously recorded archaeological and historical sites. The sources of available information that were reviewed include:

- Provincial Heritage Register (PHR), accessed using the Remote Access to Archaeological Data or RAAD application).
- Available archaeological and ethnographic reports.

- Readily available historical and surficial geology maps.
- Historical vegetation mapping.
- Golder's proprietary cultural resources database for Metro Vancouver.
- Heritage resource database review conducted by the Stó:lō Research and Resource Management Centre.
- Golder's proprietary historical shipwreck records and database.
- Historical aerial photographs.
- Available historical geotechnical and geo-environmental subsurface data.

4.3 Field Visit

A preliminary field reconnaissance (PFR) was conducted to visually inspect the ground surface and assess archaeological potential within the Study area. In addition, the reconnaissance sought to identify locations where the likelihood of encountering archaeological sites has been affected by past development-related activities (e.g., where natural soils have been removed or deeply buried by fill material). Field observations were recorded using field notes and photographs.

4.4 Data Analysis

The data analysis for the AOA involved compiling background information to generate archaeological potential and sensitivity mapping for the Study area. Environmental variables (e.g., slope; aspect; vegetation classes; soil types; distance to various water bodies including the ocean, rivers, streams, sloughs, and bogs; and trails) as well as archaeological and ethnographic information (e.g., site deposits, site locations, land use and place names) were considered to determine archaeological site potential, i.e., the likelihood that archaeological sites are, or were at one time, present in the Study area.

The primary considerations for assessing archaeological potential in this Study area include:

- Locations of previously documented archaeological sites.
- Proximity (within 100 m) to watercourses, including from the inferred locations of slough channels that have since been in-filled.
- Documented subsurface excavations from historical developments or erosion leading to the removal of deposits that may have contained cultural materials, if an archaeological site were present.
- Results of a previous archaeological impact assessment.

Archaeological sensitivity in this Study addresses the possibility for archaeological material, if present, to have survived **Deep** beneath subsequent deposits that were the result of historical land-altering occurrences, including the placement of fill or sediment accumulation. For the purposes of this study, "deep" is minimally 40 cm below grade, but may be much deeper. It may further be suggested that archaeological potential has been **Removed** by

development activities. Archaeological sensitivity mapping for this Study was generated through review of subsurface tests used to support several geotechnical and other investigations in the Study area. Archaeological inferences drawn from these data, are framed as **Likely**, or **Unlikely**. Where the inference is extrapolated based on data that may be incomplete or absent, the term **Data Absent** is used.

Assessments of archaeological sensitivity may refine recommendations for further study in specific ways. For instance, mechanical testing would be required if the inferred depth of artifact-bearing deposits is between one and three metres. Archaeological testing may not be practical at greater depths, and archaeological monitoring of development activities may be an alternative. In areas where potential has been assessed as likely removed, based on inferences from non-archaeological data, more limited archaeological investigations may be adequate to confirm the inferences than might be prescribed in the absence of such data.

FortisBC is still in the planning stage for development, so specific development impacts are not considered in the recommendations. If future development plans are limited in depths of impact (e.g., a temporary laydown area or a parking lot) and proposed in areas where archaeological potential is identified only in deep deposits, subsurface archaeological investigations may not be required, and archaeological risk may be appropriately addressed under chance find procedures.

Assessment findings are discussed in Section 5.0, potential and sensitivity assessments are presented respectively in Sections 6.0 and 7.0, and heritage management recommendations are made in Section 8.0.

5.0 RESULTS

The following sections provide the results of First Nations communication and permitting, background information review, and potential assessment for the Study area.

5.1 First Nations Communication and Permitting

Based on information obtained from CAD, the Study area is located within the area of interest of the following groups: Katzie First Nation, Kwantlen First Nation, Musqueam Indian Band, Semiahmoo First Nation, Stó:lō, Squamish Nation, Tsawwassen First Nation, and Tsleil-Waututh Nation. We also understand that the Study area falls within the marine traditional territory of Hul'qumi'num Treaty Group which includes Chemainus (Stz'uminus) First Nation, Cowichan Tribes, Halalt First Nation, Lake Cowichan First Nation; Lyackson First Nation, and Penelakut Tribe.

First Nation groups or organizations with potential interests in the Study area that require heritage investigation permits under their heritage policies include: Kwantlen First Nation (Seyem' Qwantlen), Musqueam Indian Band, Squamish Nation, Stó:lō, and Tsleil-Waututh Nation. The AOA was conducted under Musqueam Indian Band Heritage Investigation Permit MIB-2019-177-AOA, Seyem' Qwantlen Heritage Investigation Permit SQ 2020-47, Squamish Nation Archaeological Investigation Permit 19-0183, Stó:lō Heritage Investigation Permit 2019-252, and Tsleil-Waututh Nation Cultural Heritage Investigation Permit 2019-172. A Heritage Database Review was provided by the Stó:lō Research and Resource Management Centre.

One community member each from Katzie First Nation, Kwantlen First Nation, and Tsawwassen First Nation responded to the invitations and participated in the PFR.

5.2 Physical Environment

The physical and biological environment influences many of the activities that contribute to the character of the region. These variables are interconnected and include physical aspects of the land (e.g., topography or sea level history) and resource availability (e.g., floral and faunal). Linking both are the valuation of landscapes through cultural activities of site selection, travel in the area, and resource utilization and optimization.

5.2.1 Physiography and Surficial Geology

The Study area is situated within the Fraser River delta, a geomorphic formation resulting from sediments accumulating at the mouth of the Fraser River (which is situated within the Georgia Depression) faster than the Strait of Georgia marine processes can disperse them. Sediment depths to the top of the bedrock range from 200 to 1000 metres with an average of 500 metres (Clague et al. 1998).

The Fraser River delta began to form, near present-day New Westminster, approximately 10,500 years BP, when glacial sediments began to accumulate in a palaeobay of the lower Pitt River drainage (Clague 1998; Locher 2006; Figure 4). Through continuous sediment deposition, the delta expanded westward into the Strait of Georgia over the past 8,000 years (Clague et al. 1983). Around 5,000 years BP, sediment deposition ceased in Boundary Bay and commenced in the Strait of Georgia (Clague et al. 1991, 1998; Figure 3). It was also around this time that islands situated in the mid-delta area, including Tilbury, developed and stabilized. Nearly 3,000 years later, the delta's westward growth closed the passage between Boundary Bay and the Strait of Georgia (Jol and Roberts 1988). Since this time, the environment has been much more stable, enabling the maintenance of the overall shape and extent of the delta and the islands it contains (Figure 3).

As is illustrated in Figure 4, the Study area is situated overtop Fraser River sediments. The Fraser River sediments are deltaic and distributary channel fill sediments which overlay and cut estuarine sediments. Specifically, the Project is composed of Fb and Fc sediments, which are described as overbank sandy to silt loam, or silty to silt clay loam, normally up to 2 m thick and overlying deltaic and distributary channel fill (Figure 4). South and east of Tilbury Island the delta gives way to the bog and swamp deposits of Burns Bog (SAb, Figure 4). Similar deposits are observed on the opposite bank of the river where SAb deposits extend from the bank across most of central Lulu Island, specifically with peat, organic silt loam and silty clay loam 0.3 to more than 10 m thick and overlying Fraser River Sediments (Armstrong and Hicock 1976). Note that the adjacent diagonal swath of Fraser River sediments marks a former river channel, named Daniel's Arm, which extended from Annacis Island to the North Arm and was still marked by remnant sloughs, including Daniel's or Bath Slough (Figures 4 and 5), during the historical period. Peat bogs notable on either side of this channel as well as other locations represent some of the older deposits in the delta (Keen 2010).

The soils within the Study area are poorly drained fine to medium sandy and silty deltaic deposits identified as Blundell soil, which has a high organic content (Luttmerding 1981). Considering the poor drainage of these soils and the likely seasonal flooding that occurred within the Project during the precontact period, the islands and shorelines of the delta were probably inhabited or utilized during different parts of the year for different lengths of time to procure a variety of resources. Archaeological remains, if present, would be concentrated on drier elevated ground, likely limited to natural levees.

The historical occupation of the area required the development of dykes, typically building height with fill over natural levees, to protect the land and drainage systems and enable industrial and residential construction, and farming activities. With drainage improvements, the soils on Tilbury Island proved very well suited for growing

agricultural crops (Keen 2010). Dyking was a private enterprise prior to 1894. Following the 1894 flood, the provincial government acknowledged the inadequacy of privately constructed dykes and developed an integrated dyke system (Siemens 1966). Subsequent to another devastating flood in 1948, a more comprehensive system of dykes and flood protection was constructed.

Prior to the 20th century when the delta was constrained by dykes, and dredging occurred regularly to create navigable shipping channels (Barrie 2000), the delta was prone to erosion by continuous channel shifting. The documented lateral and downstream migration of the river channel bends alternately eroded and deposited sediments along the Fraser River banks which would have potentially destroyed evidence of earlier archaeological sites (D. Ham 2005). On the other hand, channel dredging practices and vessel wake during the past century has likely accelerated sediment erosion in areas where lateral migration and erosion of sediments through natural processes had previously been limited (Eldridge 1991). Even where a riverbank is now laterally stable, seasonal changes between freshet and relatively weaker, or low river flows, will cause alternating cycles of erosion and deposition of a sediment mantle of the intertidal and subtidal riverbed (Tetra Tech 2018). Nonetheless, cultural sites may still exist in portions of the riverbank where lateral migration and erosion of sediments has been limited, and archaeological material may be buried deeply in the riverbed or possibly exposed and covered alternately depending on the maximum depth seasonal sediment erosion.

5.2.2 Sea Levels and Delta Development

A review of sea level data for the lower Fraser region suggests that during the height of the Late Wisconsin glaciation, the Study area was covered by up to 2 km of ice, rendering the area uninhabitable during this time (Clague et al. 1983). Approximately 13,000 years ago the ice began to retreat, and the sea began to advance into the isostatically-depressed Fraser basin (Williams and Robert 1988). As the ice sheets continued to recede, the land began to rebound rapidly, resulting in the emergence of the coastal lowlands and the establishment of the Fraser River Delta approximately 11,000 BP (Clague et al. 1983; Williams and Robert 1988).

Between 7,000 and 7,500 years ago, sea levels began to rise again, until approximately 5,500 BP to 5,000 BP, when a period of stability commenced. Clague et al. (1983) suggest that the sea rose to within 2 m of its present level by 5,000 BP, and that sea levels have remained relatively stable over the past 5,000 years, with local fluctuations of no more than 1 m to 2 m.

5.2.3 Rivers, Sloughs and Marine and Riverine Resources

The Fraser River has linked people and resources from the coast to the interior for at least 5,000 years. Before channelling and dyking, the Fraser River would have overflowed its banks every freshet and during periods of heavy precipitation. Such flooding events would have influenced the character of the lowland plant communities available to past populations, and hence the timing and length of occupation period of the groups on the delta. The permanent channels, including sloughs, provided access to the interior “terrestrial” areas, and also provided marine and riverine fish and plant resources.

The Fraser River is one of the largest salmon spawning rivers in the world; all five species of Pacific salmon use it to access spawning beds spanning the Fraser Delta to the interior. Other spawning species found in the river include white sturgeon, eulachon, herring, and trout (BC Ministry of Environment 2020; Ham et al. 1986). Spawning season begins pre-freshet for sturgeon and eulachon; however, the most important migration, both in

terms of numbers and as a human food source, is salmon which historically peak in August and early September. Resident fish species that inhabit the sloughs and tributaries of the Fraser include: starry flounder, suckers, sticklebacks, sculpins, perches, and chub and dace (i.e., minnows) (BC Ministry of Environment 2020; Ham et al. 1986).

In addition to the Fraser River, Tilbury slough runs through the Study area. Early historical maps, such as Aemilius Simpson's of 1827 to Hawkins and Campbell's of 1869 (reproduced in Eldridge 2019), show the slough as an open, relatively wide, channel. The slough channels, with banks or levees that were slightly raised above the surrounding poorly drained land, were preferentially selected as settlement and activity sites during the precontact and historic periods. Archaeological evidence of this may be observed at Crescent Slough, Cohilukthan Slough, Annacis Channel, and Bath slough (section 5.4.1). The quieter waters of sloughs also provided access to plant varieties such as cattails, grasses, rushes, tules, and flags.

During the Fraser River annual salmon runs, massive amounts of fish could be easily caught, dried, smoked and preserved for the winter, or traded. Many Coast Salish oral histories focus on salmon, the origin of the salmon and the powerful salmon spirit peoples (Maud 1978). Fishing for sockeye began in July using trawl and dip nets from canoes, before moving upriver as the season progressed (Suttles 1955, 1990b). In the lower reaches of the Fraser, side channels and sloughs were often used to construct tidal pounds and weirs to catch salmon and sturgeon (Suttles 1990a). Fish meat and many of the bones were consumed; however, fish bones could also be soaked and shaped into utensils and fishing implements (Stewart 1996).

Sea mammals, such as harbour seals, California and northern sea lions, river otters, and the northern fur seal, may have travelled the river as far as the salt water reached (Ham et al. 1986; Northcote 1974). Seal hunting was a common practice for Coast Salish peoples living on the sea and along the Lower Fraser River, and was accomplished by either clubbing on land, or netting or harpooning from a canoe (Suttles 1952).

Edible shellfish available in the estuary include various species of clam and native oysters. Archaeological midden evidence near the Study area also demonstrates extensive shellfish use. Butterclams, native littlenecks, bay mussels, horseclams and basket cockles are some of the most commonly represented species (Croes et al. 2013).

5.2.4 Terrestrial Setting

There are two main biogeoclimatic zones in the Lower Mainland, the Coastal Douglas-fir (CDF) and Coastal Western Hemlock (CWH) zones. Although these biogeoclimatic zones are designations based on modern observations, climate and vegetation have remained similar since 6,600 BP (Mathewes 1973).

In contrast to the dominant coniferous forests of region, the Study area was historically dominated by wetland vegetation, primarily grass with shrubs (North et al. 1979) (Figure 5). The riverbanks on both sides of the Fraser River consisted of alder scrub indicating higher ground. The bank areas along Tilbury Slough were also treed, but here the cover was mixed coniferous forest (wet sites). The grass and shrub were concentrated between the banks of Tilbury Island. The land behind the opposite bank on Lulu Island, in further contrast, consisted of moss with scrub pine.

These grassland and scrub areas were often flooded. First Nations people in the past and today continue to access these wetlands to hunt and to gather plant resources, including wet grass prairie of bunchgrass, rushes, sedges and reeds. Crabapple, cranberries and other berry-bearing plants were also found in these areas, and are common in bogs (Figure 5).

The lowlands were also populated with beaver, river otters, mule deer, smaller mammals and insectivores, as well as various birds of prey. Migrating birds like geese, swans, and widgeons may also have bred in the area (Ham et al. 1986).

5.3 Cultural Background

All of the groups with Aboriginal Interests in or near the Project site are speakers of Coast Salish languages: *Halq'eméylem / Hul'q'umi'num' / hən̓q̓əmin̓əm̓, SENĆOŦEN* and *Sḵwx̱wú7mesh sníchim*. These groups are related culturally and linguistically, and, collectively, their culture is known as Central Coast Salish (Barnett 1955; Hill-Tout 1897; Kennedy and Bouchard 1976; Suttles 1990a). Regardless of the language spoken, Central Coast Salish groups followed similar settlement and subsistence patterns during the precontact and historic periods. The following section provides a brief overview of the historically documented subsistence and settlement approaches of Coast Salish peoples.

Observations of Central Coast Salish groups began in the early 1800s when Simon Fraser first explored the west coast (Lamb 1960), and continued with Charles Hill-Tout (published between 1895 and 1911; Maud 1978), Homer Barnett (1938, 1955; mid-1930s), Wilson Duff (1952a, 1952b, summers of 1949 and 1950), Diamond Jenness, and Wayne Suttles (Jenness 1955; Suttles 1955). Recently, an abundance of *hən̓q̓əmin̓əm̓* cultural information became available with the publication of the Stó:lō Nation historical atlas (K. Carlson 2001). A Database Search Review of traditional use sites (TUS), provided for this Project by the Stó:lō Research and Resource Management Centre, has also been considered (Appendix B). Considered together, these ethnographic data provide insight into how Central Coast Salish peoples interacted with and viewed their surrounding landscape, for fishing, hunting, gathering, and spiritual use, which in turn informs the assessment of heritage resource potential in the Study area.

5.3.1 Ethnographic Patterns of Land and Water Use

First Nations' ecological understanding of resource availability within the natural landscape has been understated as simply gathering of wild resources (Smith 2005). Deur (2005) suggests that human intervention and management is implied because opportunistically gathering crops would not have met the rate of consumption described by ethnographic sources. Archaeological evidence shows First Nations used varying levels of landscape management to intensify local resources, ensuring larger yields and a level of food security that opportunistic hunting and gathering subsistence strategies did not afford (Lepofsky et al. 2005; Smith 2005; Turner 1991, 1999). Tending and cultivation of plants, intertidal land clearing for clam gardens, and landscape burning are examples of food production by First Nations groups in the region. Resource procurement that is localized or that requires cultivation and expenditure of labour beyond harvesting is subject to some form of control or ownership within coastal groups (Turner and Jones 2000; Williams 2006).

5.3.2 Subsistence

Subsistence activities occurred in a seasonal round. Locations for subsistence activities varied according to the resource and season and involved some or all of a group travelling to camps or settlements which were usually also accessible by canoe. Habitation at camps might consist of temporary matt houses or cedar bark huts, but many groups also built permanent house frames that were closed in with transported planks or bark at their summer and autumn fishing sites (Ham et al. 1986:32; Jenness 1955; Suttles 1951).

The summer months were the most important in the subsistence economy due to large, usually predictable runs of spawning salmon in the Fraser River and its approaches, as well as smaller coastal rivers. The summer months also provided plant resources for use in manufacture, medicine and sustenance. According to Suttles (1990b:459) approximately 40 plants were available for consumption in the form of sprouts and stems, bulbs and roots, berries and fruits, or nuts. Berries generally gathered in summer included cranberries, blueberries, and huckleberries, which were particularly abundant in low-lying areas (Duff 1952b; Suttles 1990b).

The fall subsistence and settlement pattern was in many ways, a continuation of the summer pattern as salmon were still plentiful. By late September, however, emphasis on the salmon fishery began to wane as other economic activities, such as hunting and berry-picking, gathered momentum. Most hunting took place in the fall as animals tended to be fat and their young had had the summer to develop. Some hunting forays could last several weeks and in these cases hunters established base camps. Deer, elk, black bear, and beaver were some of the mammal species hunted. Bird species hunted, included ducks, Canada geese, bald eagles, and spruce grouse (Duff 1952b; Suttles 1951). Plant food available in the autumn included wild crab-apples. Wapato, a wild root vegetable, was dug during the fall (Suttles 1955); the bracken fern rhizome was also favoured.

Winter was the season when primary group villages were utilized and was largely a time of ceremonial activity, with less emphasis placed on subsistence activities. Stored foods, such as salmon and dried berries, were consumed (Duff 1952b; Suttles 1955). Hunting and fishing activities were limited to locally available resources such as deer, elk, ducks, and steelhead trout (Ham 1982:33; Jenness 1955:8; Patenaude 1985:62; Suttles 1955). Although most hunting occurred in the fall, bear hunting was common in the winter as they could be easily smoked out of their dens in the winter (Duff 1952b; Suttles 1955).

In the springtime, as stored food resources would have become depleted, plant foods played an important role. The shoots of salmonberry, thimbleberry, the round stalk of the cow-parsnip, and other green shoots were eaten (Duff 1952b). Eulachon enter the coastal rivers during late April until the end of May (Drake and Wilson 1992; Duff 1952b; Suttles 1955). These fish were caught in large numbers and provided an important addition to the spring diet. White sturgeon, a fish species that can weigh as much as 800 kg, were also consumed. By mid-June spawning sockeye would begin to appear and economic activities would again turn to the salmon fishery (Duff 1952b).

5.3.3 Resource Management Practices

First Nations groups on the Northwest Coast participated in the cultivation and intensification of particular plant species that had cultural utility. Plant communities were encouraged using a variety of horticultural methods including selective harvesting, pruning, weeding, soil aeration, transplanting, and habitat expansion. Examples of horticultural methods and their ecological results include selective harvesting which promotes dispersal of propagules and reduces interspecies competition; pruning that stimulates vegetative reproduction leading to increases in flowering and fruiting; and transplanting which promotes growth in new habitats (Turner and Peacock 2005). Turner and Peacock (2005) also refer to tending, weeding and landscape burning to reduce competitive species and increase soil nutrients. Controlled landscape burning was an important aspect of the Northwest Coast subsistence economy and was used for a variety of purposes, from enhancing food resources and game habitat to a technique used in hunting or war (Turner 1991, 1999).

Ethnographic records provide examples of garden plots that were cleared and staked to delineate ownership that was passed on generationally (Suttles 2005). The physical labour expended in developing and tending these

garden plots demonstrates their cultural importance in precontact subsistence (Deur 2005). Physical archaeological evidence of this behavior can include the recovery of digging sticks, plot markers, baskets or identification of processing sites delineated by large concentrations of fire cracked rock and anthropogenic landforms such as ridges and troughs.

Clam gardens and tidal fish traps, in the form of intertidal rock walls, are examples of marine landscape engineering by coastal First Nations. Both of these resource management techniques require the expenditure of labour to construct a low tide rock wall. Potential archaeological evidence for this subsistence strategy may be found in proximity to shorelines and bivalve habitat. Fish traps consisting of stakes and woven cedar strips are more likely to be found in estuarine environment of the Study area (Greene et al. 2015).

The Fraser River sockeye salmon run was harvested in the Fraser River, but could also be intercepted and caught while the fish were approaching the river with reef-netting, a fishing method which both exploited specific natural features of the sea bed and artificially enhanced them. Point Roberts, located directly across Boundary Bay from Crescent Beach was a significant reef net and processing location for sockeye salmon before the First Nations fishery was displaced by the construction of a cannery at the point (Moore and Mason 2012).

5.3.4 First Nations Place Names

Ethnographies and First Nation place names and land use data on culturally valued landscapes, plants and animals, locations and settlements, and subsistence strategies were collected and plotted from a limited review of readily available sources (McHalsie in Carlson 2001; Suttles n.d.). Apart from the river itself (*Stó:lō*), no *Halq'eméylem/Hul'q'umi'num'/Hən̓q̓əmin̓əm̓*, or *SENĆOŦEN* place names and traditional land use values were identified in the Study area, however, some were identified in proximity. These names are important to archaeologists as not only do they demonstrate First Nations use of the Study area, information that has been shared from one generation to the next, in some cases they can give some indication of the range of activities that may have taken place. Both the named locations and the activities they imply are important as they can assist archaeologists with the identification and interpretation of archaeological sites. For instance, in an area known for traditional fishing, expected archaeological site types could include fish weirs, midden sites with post holes both for drying racks and habitation structures, and artifacts often associated with fishing and fish processing in the region, including hand mauls (hammer stones) and ground stone scrapers.

Similarly, named places indicate that these names do not necessarily refer to fixed geographical locations, but instead refer to general areas or activities, including travel routes. The Fraser River including Gravesend Reach and Tilbury Slough in the Study area, was the principal travel route in the Region, providing access by water to and from the Georgia Strait, throughout the various waterways of the Fraser River delta and valley, and east as far as the Fraser Canyon (Spuzzum Creek). The Sto:lo Research and Resource Management Centre TUS Database Result (Appendix B) identifies the river's traditional place name, *Stó:lō*, and is further considered *Sxwōxwiyám* by the Stó:lō, meaning that the river relates to core and integral elements of Stó:lō cultural traditions and identity. The south shore of the Fraser River through the Study area is also identified as a "GIS-Modeled Travel Route" and as such is taken to represent water-borne travel on the river between the "modelled trails" placed along the opposite modern river banks, and therefore in "close proximity" to the Study area (Appendix A).

Variations in the spellings of individual place names are the product of either translations, dialects or languages. A summary of First Nations place names and land use areas recorded in the vicinity of the Study area and in addition to *Stó:lō*, are discussed below in Table 2 and plotted in Figure 6.

Table 2: Coast Salish named locations.

Name	Translation/Description/Comments	Reference
ƛ̓əqtinəs *Kli'ka-te'h-nus* *Klik-a-the-nus* *Tl'uqtinus* *laktinas*	"Long shore, long chest, beach." This was the "terrible large village" observed by the first Hudson's Bay Company traders on the South Arm. On Gravesend Reach, in the vicinity of the north end of the George Massey Tunnel. East of Woodward's Landing on the south shore of Lulu Island. Settlement site, including some year-round. Resource gathering and fishing area: berries, reeds, salmon, sturgeon.	Rozen 1979 McHalsie in K. Carlson 2001 Suttles 2004 Brealey 2010 RAAD
Dl'akti'nes[1]	Woodward's Landing, where Ladner ferry was. Salmon traps in area.	McHalsie in K. Carlson 2001 Nelson (1927) cited in Rozen 1979
Maʔqʷəm *šəšəqəm*	Burns bog. Area for plants and material gathering (blueberries, cranberries, Labrador tea and sphagnum) and hunting.	Andrew Bak (Personal communication 2005) Don Welsh (Personal communication 2004)
pəɬχəneməxʷ *pətxənéməx* *Pelhxenáaw'-mexw*	"Meadow land, prairie, meadow country". An area a little above [upstream from] Ladner. The western end, meadow area, of Deas Island.	Rozen 1979 McHalsie in K. Carlson 2001 Suttles 2004
sxalá'wis	Crescent slough, located southwest of Burns Bog.	Simon Pierre in Duff 1952c
sc̓ələxʷqəṅ *Sc'lúlux'qun* *Sts'elexwken* *Sts'uluhwqun*	"Going upriver to the top end; go upstream; throat." Ladner. Cohilukthan slough, which runs from Tsawwassen through Ladner to the Fraser River. There was a camping site in the Ladner area, on the south bank of the Fraser River south arm.	Rozen 1979 McHalsie in K. Carlson 2001 Suttles 2004
qʷəqʷəʔapəɬp	"Crabapple trees", Site of Glenrose Cannery.	Suttles 2004
səw̓q̓ʷeqsən *sewk'wek'sin*	Camping ground, people live there sometimes (St. Mungo Cannery).	Edward Sparrow Sr. in Rozen 1979 RAAD
xʷmeć̓ənəɬp	The high land from extending from Sunbury down to Mud Bay. Black haw tree (*Crataegus douglasii*).	Suttles 2004

Figure 6 illustrates that no known named locations are situated within the Study area. The named place closest to the Study area is the large documented settlement known as *ƛ̓əqtinəs*, located on opposite bank of the river and usually associated with DgRs-17 (Brealey 2010). Few named places are located along the south bank of the Fraser near the Project site, the closest upstream being *xʷmeć̓ənətp*, located approximately 7 km away and representing an extensive terrestrial resource extraction area; and *pətxəneməxʷ*, or meadow land located often ascribed to Deas Island, but based on the early historical vegetation mapping (see Figure 5) more likely to have been located in the larger, adjacent area between Burns Bog and the river (Figure 6).

[1] This is the same traditional place name as *ƛ̓əqtinəs*, *Kli'ka-te'h-nus*, etc., preceding it in the table, but is placed by McHalsie at Woodward's Landing, about 3.5 km downstream from the location of archaeological site DgRs-17 (see Figure 6).

5.3.5 Historical Land Use and Disturbance

The Fraser River Delta was first observed and recorded by Europeans when Narvaez and Elisa passed the mouths of the river in 1791 (Philips 2003); however, it was not until after 1827, when the Hudson's Bay Company established its first outpost on what is now the coast of British Columbia at Fort Langley, that Europeans began to settle the shores of the Fraser River.

Land was cleared and cultivated to provide food for the traders at Fort Langley, and the earliest settlers of the Fraser Delta were also involved in agricultural pursuits, as well as the salmon fishery and canning industry, and the logging industry along the Lower Fraser River. Settlement in the region increased after it was officially surveyed in 1859 (Philips 2003). Around the same time, paddlewheel steam vessels began to navigate the Fraser River, transporting people and goods between many "landings" located in the Lower Mainland, and connecting with communities on Vancouver Island and the United States (Ross 1979).

Farming in Delta began in Ladner in 1868 with the practice of cultivation subsequently spreading up the river, in parallel with early efforts to dyke the land and protect the fields and farm buildings from flooding, typically beginning with adding fill to raise and lengthen the natural levees. The Tsawwassen Reserve was established in 1878, and Delta and Richmond both became incorporated as municipalities in 1879. Both areas consisted of a number of small, often ethnic communities that developed alongside early agricultural and industrial centres. These communities were not fully integrated and connected within the larger municipalities of Delta and Richmond until road and rail infrastructure improved and communication networks developed in the early to mid-20th century. In what is now the City of Delta, the nearby communities along the river included Annieville (north-east Delta), Sunbury (situated east of Tilbury Island), Burr Landing (on Deas Slough), Ladner Landing, and Port Guichon (Figure 6). The shoreline across from Tilbury Island was simply known as East Richmond (roughly from the western end of Tilbury Island to the western end of Annacis Island) (Ross 1979).

Salmon canneries were also early nodes for transport and residences on the river, albeit primarily seasonal. The first successful salmon cannery on the Fraser River was located at Annieville in 1870, followed by the Deas Island cannery (1871). The Deas Island cannery was the closest to the Study area, just 2 km downstream, while the Ewen cannery on Lion Island was located 3 km upstream (established in 1884) (Keen 2010).

Tilbury Island would have been farmed from the second half of the 19th century, but nothing is readily available in the historical record regarding who the first settlers were and precisely when first early land clearing, dyking and cultivation occurred. In the early 1960's, the island was first industrially developed with the arrival of the rail line and plants such the Dow Chemical facility at the east end of the island and active from 1961 to 1992 (latterly as Chatteron Petrochemical).

In 1971, BC Hydro built the original LNG peakshaving plant adjacent to the rail ferry terminal (run by RivTow and then CP Rail before Seaspan) and in the north eastern corner of the Project site. The southern portion of the Study area was sold by BC Hydro, and was developed in its entirety including the adjacent lot farther west by the Harmac lumber mill. The southern part of the northern portion remained agricultural until Phase 1A was developed (Appendix A Photograph 1). BC Hydro sold its gas division to BC Gas in 1989, and this interest subsequently became FortisBC. The southern portion of the Project site has since been bought back by FortisBC from Varsteel which retains the adjacent property to the west previously owned by the lumber mill (Christopher Wylie, personal communication 2020) (see Figure 2).

5.4 Previous Heritage Studies

Within the Northwest Coast culture area, the Strait of Georgia Region has been the focus of considerable archaeological research undertaken over the past 60+ years (Ames and Maschner 1999; Matson and Coupland 1995). In addition to broader regional studies, multiple assessments carried out in the past in vicinity of the Study area. For the purpose of this assessment, only large-scale studies including the Archaeological Resource Survey, Lower Mainland, BC (Archaeological Sites Advisory Board 1975), the South Fraser Perimeter Road Assessment (Golder 2013), and George Massey Tunnel Heritage Resource Assessment (Golder 2015) are summarized.

The Archaeological Sites Advisory Board (ASAB) conducted the Archaeological Resource Survey, Lower Mainland, BC; a large-scale inventory study intended to identify potential construction impacts in the region under HCA Permit 1975-6 (ASAB 1975). The survey was conducted across 378 locations proposed for development, additionally, all previously recorded sites within site recording units DgRt, DgRs, DgRt, and DgRq were re-assessed along with six sites present within unit DhRt. The inventory resulted in the recording of one newly identified archaeological site. All of the sites assessed during the study had their site type categorized and were assigned priority levels for future work based on their significance and the likelihood that they could be impacted by future development. The banks of the Fraser River in the Lower Mainland were systematically surveyed in 1993, including the south shore of the South Arm of the Fraser River and revisits of previously recorded sites (Eldridge and Mackie 1993).

Between 2001 and 2013, Golder conducted a series of investigations including inventory and impact assessments related to the construction of the South Fraser Perimeter Road (Highway 17), a transportation corridor which passes just over a kilometer south of the Study area (Figure 7). The inventory and impact assessments resulted in the recording of one newly identified archaeological sites within two kilometres of the Study Area, DgRs-83 at the edge of Burns Bog. Two additional sites identified along the road corridor within two kilometres of the Study area, DgRr-39 and DgRs-82, were subsequently listed as legacy sites and not subject to protection. Archaeological site DgRs-54 (Nottingham Farm site) located along the edge of Crescent Slough had its site boundaries considerably expanded as a result of the investigations and subsequent site alteration investigations (see Figure 6) (Golder 2013).

In 2014, Golder undertook a heritage resource overview assessment (HROA) and an archaeological impact assessment (AIA) (conducted under HCA Permit 2014-0201) for the proposed George Massey Tunnel Replacement Project (Golder 2015). The HROA characterised a study area consisting of a 1000 m wide corridor on both sides of, and including the George Massey Tunnel, the replacement bridge footprint, and a series of improvements to Highway 99 between Bridgeport Road and the Canada-U.S. Border (Figure 6). The results of HROA indicated that several areas within the bridge and highway footprint had archaeological potential and it was recommended that an archaeological impact assessment be conducted. Golder's subsequent AIA of the proposed George Massey Tunnel Replacement Project was conducted in 2014 and included survey, manually excavated subsurface tests, and mechanically excavated subsurface tests using a backhoe to identify shallow and deeply buried archaeological deposits. No archaeological sites were identified as a result of the survey or testing conducted as part of the AIA (Golder 2015).

An AIA was conducted within the Project site in 2014 in preparation for the construction of the Phase 1A storage tank (Stantec 2014). The study consisted of 107 machine tests spaced between 10 m and 40 m, that were located in parts of assessment areas H, I and J (see Figure 2). The area was found to be significantly impacted from previous land use and development (although largely limited to agricultural use prior to that date), and no archaeological sites were found during the course of the testing. Based on these results, no further archaeological work was recommended for the "Tilbury 2 Project" (Phase 1A) (Stantec 2014).

5.4.1 Heritage Sites

Heritage sites reviewed in this section include all previously recorded and protected sites located within a five-kilometre radius of the Study area as recorded in the PHR and accessed in the RAAD application (Archaeology Branch 2020). The following sections consider archaeological sites (primarily precontact); heritage wreck sites, and historical sites (primarily built heritage protected through municipal by-laws).

5.4.1.1 Archaeological Sites

Archaeological sites located within five kilometres are illustrated in Figure 6, and listed below in Table 3.

Table 3: Known archaeological sites within five kilometres of Study area.

Archaeological Site	Site Name	Distance from PA	Description / Characteristics	Comments
DgRr-23	n/a	4.4 km upstream	■ Precontact, fish weir, surface lithics. ■ Historic building, surface materials.	■ Located on south bank of South Arm. ■ Ground slate knife recovered. ■ Structure and design of the fishing weir could not be ascertained. ■ Modern milled stakes interspersed with older stakes. ■ Japanese domestic ceramics (possibly 90 years old) recovered.
DgRr-25	Don Island	3.1 km upstream	■ Precontact, surface refuse, fire broken rock. ■ Postcontact, subsurface refuse.	■ Located on north bank of South Arm. ■ Note that presence of Don and Lion Islands (then unnamed) on 1827 Simpson chart indicate long-term stability of mid-estuary. ■ Dense concentration of fire-cracked rock (FCR) spread over 33 m continuous area. ■ Scatter of early 20th century Japanese crockery, glass, and butter clam fragments. ■ Wooden pilings and earthen dyke observed. ■ Don Island was home to a community of Japanese fisher families between 1901 and the beginning of World War II.
DgRr-41	Ewen Cannery / Lion Island	2.7 km upstream	■ Postcontact, building, surface refuse, subsurface refuse.	■ Home to the Ewen Cannery between 1885 and 1930. Remains of the canning complex and Chinese bunkhouse at the eastern end of the island and the Japanese fishing camp at the western end.
DgRs-15	n/a	2.5 km NW (Lulu Island)	■ Plant fibre	■ Basketry fragments found in peat farm. ■ Area may have previously been a slough.
DgRs-17	*Kli'ka-te'h-nus / Tl'ektines / Ƛəqtinəs* / Richmond Dump Site	0.7 km across river	■ Precontact, surface FCR, lithics, fishing weir.	■ Located on north bank of South Arm extending 2.2 km in length. ■ Notes from assessments in 1973 and 2001 suggest that the main portion of this site had been either destroyed by past development activity, or is now covered by approximately 10 feet of sanitary land fill. ■ Miscellaneous stakes, some in rows, observed, clusters, as is FCR along most of intertidal length of site ■ Some stakes are milled. ■ It is understood that additional stakes have been recorded in a recent survey of the site.

Archaeological Site	Site Name	Distance from PA	Description / Characteristics	Comments
DgRs-39	n/a	1.8 km upstream	■ Precontact, fishing weir, surface lithics. ■ Historic, surface refuse.	■ Located on north bank of South Arm ■ Weir stakes aligned with a right-angle bend. Parallel and adjacent to rows of planks and milled lumber stakes on either side of canal outflow at lower intertidal zone, described as “probably historic”.
DgRs-56	Nottingham Farm	2.3 km S (Delta)	■ Precontact, surface faunal, lithics, fire broken rock.	■ Located on Crescent Slough ■ It is understood that in addition to surface finds, basketry and worked wood was found at depth during excavation for sewer pipe (information not yet available in RAAD)
DgRs-83	n/a	1.75 km SE (Delta)	■ Precontact, Surface lithics and fire broken rock	■ At monitored borehole ■ Cultural materials from side of road may have been imported from another location
DgRs-113	Deas Slough Vessel – unidentified	2.8 km SW	■ Postcontact, marine shipwreck.	■ Located in Deas Slough, partially exposed intertidal water. Wooden hull and decks extant with no superstructure. Thought to be a former naval auxiliary vessel, 31 m in length. Abandoned sometime before 1963 based on historical aerial photographs.
DgRs-114	Deas Slough Barge – unidentified	3.75 km SW	■ Postcontact, marine shipwreck.	■ Located along the northwest bank of Deas Slough in shallow intertidal water. Wooden hull of the scow-ended barge, 27 m x 9 m, is largely overgrown. Abandoned after 1963 and before 1974, based on historical aerial photographs.
DhRs-81	Bath Slough	4.6 km NW (Lulu Island)	■ Precontact, Surface lithics	■ Located both sides of Cambie Road over about 650 m distance on banks of former slough. ■ Collected artifacts included hand mauls, ground stone knives, and flaked tools ■ Inferred fishing site with weir, based on recovered hand mauls and ground stone blades, also hunting and harvesting location.
DhRs-82	Gilley Road Bypass Site	4.0 km NNE (Lulu Island)	■ Precontact, subsurface lithics	■ Inferred to be from bank or levee of Bath Slough (no longer extant) ■ Pecked bowl and FCR collected
DhRs-809	n/a	3.5 km NNE (Lulu Island)	■ Precontact, surface lithics	■ One broken point and debitage recovered from surface and plough zone. ■ No results from subsurface testing.

No previously recorded archaeological sites are located in the Study area. Based on known site locations within 5 km of the Study area, there is higher potential for precontact sites to be located along the banks of the river and sloughs. Details of known sites suggest that the activities most likely to be represented in the archaeological record of the area are fishing (weirs) and fish processing.

DgRs-17

The nearest archaeological site is DgRs-17, located on the opposite bank of Gravesend Reach (Figure 8). The river channel is about 800 m wide at the Study area, and DgRs-17 extends a distance of about two kilometres within and along the intertidal part of the riverbed so that it is located at minimum 0.70 km from the Study area, to a downstream maximum of 1.18 km, and an upstream maximum of 1.25 km. The site was registered in 1974 based on historical evidence. Several subsequent archaeological assessments conducted at the site since 1978

have identified the vertical stubs of stakes and clusters of FCR observed in different locations at different times in the intertidal sediments. Morley Eldridge (2019) conducted a study of the site in 2013 which summarized previous research, and attempted to resolve some conflicting assessments. The study included a detailed GIS interpretation of the early historic shoreline location, conducted radiocarbon dating analysis on selected stakes, and subsurface testing of the upland directly north of the site. Eldridge concluded that the shoreline where the site is located has been subject to erosion of between 7 m and 50 m since it was first mapped in detail in 1859, contrary to the assessment that the site may be located well inland from the current shoreline (Eldridge 2019). No archaeological material was encountered in the 48 auger tests of the upland area. Eldridge concluded that most of the FCR observed was Aboriginal in origin, although he notes that even down the length of the site during his survey of the intertidal area there were areas where a drape of sediment covered previously mapped archaeological materials while other areas were exposed. Two of the stakes were dated to around 1800, while others were modern (mid-20th century). Eldridge concludes that “those stakes, fire broken rocks, and other artifacts of aboriginal manufacture …are consistent with village remains dating from before contact into the mid-19th century” (Eldridge 2019).

DgRs-17 is the only archaeological site within a kilometer of the Study area, and therefore is only one considered with individual detail. Other sites within the five-kilometre radius of the Study area are compared below based on location and site type (Figure 6).

Sites Proximate to River and Slough Channels

Of the 10 protected precontact sites located within 5 km of the Study area, only one, DgRs-83, is *not* located on a current riverbank, or current or relict slough bank. Four sites are located along the South Arm. The width of these sites, representing the approximate maximum distance between recorded site boundaries measured perpendicular to the water, range in width as follows: 10 m width at DgRr-23, 45 m width at DgRs-39; 60 m width at DgRs-17; to 100 m width at DgRr-25 (comprising primarily a scatter of FCR, 33 m in length).

DgRs-56 is located along Crescent slough and is up to 100 m in width. Another other three slough sites are associated with the former location of Bath Slough, on Lulu Island: DhRr-82 is a spot location; DhRr-809 has a width of about 60 m; and DhRr-81 has a total width of about 350 metres that is interpreted to represent material from both banks of the former river channel.

Heritage wreck sites DgRs-113 and DgRs-114, also located in a slough (Deas Slough), and are discussed in section 5.4.2 below.

Fish Weir Sites

Four the archaeological sites are associated with possible fishing weirs. Stakes were observed in the banks of the South Arm at sites DgRr-23, DgRs-17 and DgRs-39. All of these sites included milled timbers driven into the riverbed so that some of the stake features are late historical, and the stake alignment at DgRs-39 is considered “likely historical”. The artifact type most associated with building fish weirs is the ground stone hand maul, or hammer stone. An artifact associated with processing fish, (based on ethnographic practices in the region, the fish being processed were likely caught in a nearby weir) is the ground stone knife or blade. Although no weir stakes were found at DhRr-81, the presence of a fish weir is inferred by the hand mauls and ground stone knives found at the site. A ground stone knife was also found at DgRs-39.

Notable is the presence of basketry at the two slough locations DgRs-53 and DgRs-15. Basketry may be associated with fish capture and processing, and is also important in gathering berries. Both of these sites are on a slough, or former slough, and are located one or more kilometres inland.

Site Aspect

The site where fish processing through smoking and drying occurs benefits from a southern exposure. Of the sites located on river, three, DgRr-25, DgRs-17, and DgRs-39, are located on the north bank of the river and have a south-facing aspect. Only DgRr-23 is situated on the same side of the river as the Study area, and shares a north-facing aspect.

5.4.1.2 Heritage Wreck Sites

The PHR was searched to identify all heritage wrecks located within five kilometres of the Study area. Additionally, wrecks observed in historical images and historically reported casualties in and near the Study area were considered. No heritage wrecks are located in the Study area. Two registered heritage wreck sites are located in the intertidal area portion of Deas Slough, between three and four kilometres downstream of the Study area. These two heritage wreck sites illustrate the nature of potential wrecks that might be found abandoned along the South Arm and sloughs. The two heritage wreck sites recorded in this area are mapped as archaeological sites in Figure 6, and detailed in Table 4.

Table 4: Summary of recorded heritage wrecks located nearest to the Study area.

Name, Registry	Estimated Loss Date	Nature of Loss	Place of Loss	Size of Vessel in gross tons	Hull Material	Type of Vessel,
Unknown vessel DgRs-113	c. 1963	Abandoned	Deas Island Slough	> 120 tons	Wood	Naval surplus vessel
Unknown barge DgRs-114	Before 1974	Abandoned	Deas Island Slough	Unknown	Wood	Scow barge

An additional wreck was observed in the historical areal photograph review located in the intertidal riverbed off Tilbury Island about 1.3 kilometres upstream from the Study area (Figure 7). This wreck is a scow-form barge, measuring approximately 7.5 m by 26 m, abandoned in place sometime after 1984 and before 1991, based on the historical areal photograph review (see section 5.5).

Many more wrecking events are reported to have occurred than are typically found and identified on the seabed. Reported locations are often approximate, and it is not always readily apparent if an incident led to a total loss or a partial loss (i.e., where the vessel or aircraft was repaired or salvaged so that it was not left to form a wreck site). On the other hand, many vessels which are abandoned are not reported as casualties (potential wrecks caused by a specific accident or event) and are therefore not easily identified from the historical record.

Over 140 wrecking events were reported in the Fraser River within the past 120 years (Northern Maritime Research 2002). Many of these occurred in the interior of British Columbia, or within the Fraser River Delta, but more than 15 kilometres from the Study area (i.e., between the western end of Lulu Island and Steveston). Table 5 summarizes the available information on the reported lost vessels potentially located in Gravesend Reach (Department of Transport 1981; Mills n.d; Nauticapedia 2020; Northern Maritime Research 2002; Rogers 1973, 1992). It should be noted that no vessel or aircraft losses were reported in this area in recent history (i.e., from 1991 to 2018; Transportation Safety Board of Canada 2020a, 2020b). None of the wrecking events are specifically linked to in or near the Study area, or Tilbury Island.

Table 5: Vessels reported lost in the South Arm of the Fraser River and potentially located in Gravesend Reach or associated sloughs

Name, Registry	Date of Loss Y/M/D	Nature of Loss	Place of Loss	Size of Vessel in gross tons	Hull Material	Type of Vessel, Official Number Year Built (if known)
Cheam, Unknown	1906/??/??	Wrecked	Fraser River (?)	286	Wood	Steam stern-wheeler, 117153, 1905
Noname, Vancouver, B.C.	1911/10/23	Collision with *Iroquois,* foundered	Fraser River (?)	77	Wood	Steam screw, 126081, 1908
Townsend, Vancouver, B.C.	1957/03/14	Collision w/ scow, sank, blown up	Clearing channel for Deas Island Tunnel.	583	Wood	Dredge, 138170, 1904
Pal III, Vancouver, B.C.	1967/02/15	Fire	Deas Island Slough	7.6 (Net ton)	Wood	Unknown, 313784, 1961
Bonnie Prince, New Westminster, B.C.	1972/10/10	Sank	Fraser River	14	Wood	Fishing, 193424, 1951
River Drifter, Vancouver, B.C.	1980/06/07	Fire	Fraser River (?)	Unknown	Unknown	Fishing, 13K19475Li, unknown
Chasca, Vancouver, B.C.	1985/06/10	Fire/explosion	Deas Island Slough, Captain's Cove Marina	3.9	Unknown	Yacht, 13K93445Li, unknown
Race Rock, Vancouver, B.C.	1996/03/17	Fire, abandoned, beached	South Arm Woodward's Landing	47.1	Wood	Seiner, 154434, 1927

5.4.1.3 Historical Sites

The historical sites listed in Table 6 and shown as registered heritage sites in Figure 6 are located within five kilometres of the Study area and consist of built heritage, or sites associated with post-contact activities and registered or recognized federally (n=3), or by the province of British Columbia (n=2), and/or or under municipal by-law, by the Corporation (now City) of Delta (n=4), and the City of Richmond (n=1) (Archaeology Branch 2020).

Table 6: Historical sites within five kilometres of Study area.

Address	Historical Site / Map Identifier	Designating Authority and Year	Constr. Date and Builder	Description / Characteristics
Don Island and Lion Island	DgRr-59 Ewan Cannery and Residences	Recognized Heritage Site Province of British Columbia, 2017	1901	Cannery on Lion Island active to c. 1930. Community of Japanese fishermen and families present on Don Island, c. 1901 to internment during WWII. One of 60 locations recognized by the province in 2017 as representing the significant contributions of Japanese Canadians and Canadians of Japanese descent to the economic, social and cultural development of the province of British Columbia.
6001 River Road	DgRs-20 Burr Villa / Harry Burr House	Designated Heritage Site 1981 Corporation of Delta, 2006 Canadian Register	1905-1906, Fred Land, David Price	Wood frame Queen Anne Revival style residence. Originally built on the corner of 62B Street and River Road near head of Deas Channel Relocated to Deas Island Regional Park in 1982. Historically important within the Crescent Island community. Steamer landing and post office once at the Burr property.
6001 River Road	DgRs-21 Inverholme School	Designated Heritage Site 1983 Corporation of Delta, 2006 Canadian Register	1909, Hector Campbell	Example of the standard one-room design provided by the Provincial Department of Public Works. Separate boys' and girls' entrances. Moved from 72 Street south of Ladner Trunk Road in 1926 adjacent to the Paterson farm. Moved from Paterson farm to Deas Island Regional Park in 1982.
5734 River Road	DgRs-90 Sheldrake Barn	Designated Heritage Site Corporation of Delta, 2008 Canadian Register, 2010	1912	Small side-gabled structure with a shed and hipped roof addition. An early agricultural outbuilding near Green Slough. Built by George Hubert Sheldrake and his wife Jennie Euphemia Sheldrake.
6001 River Road	DgRs-110 Delta Agricultural Exhibition Building / Delta Agricultural Hall	Community Heritage Register Corporation of Delta, 2007	1899	Part of the heritage grouping at Deas Island Regional Park which includes Burr Villa and Inverholme School.
6001 River Road	DgRs-122	Community Heritage Register Corporation of Delta, 2009	1873	Cannery buildings established by black tinsmith John Sullivan Deas are no longer extant. Site marked by cannery boiler, is now within Deas Island Regional Park.
5800 No. 7 Road	DhRs-615 Rathburn house	Community Heritage Register City of Richmond, 2003	1911	2 ½ storey residence with veranda on 3 sides. Typical of 'gable-front' farmhouse common pre-WWI.
5800 No. 7 Road	DhRs-1296 Mahal Cranberry Farm	Recognized Heritage Site Province of British Columbia, 2017		One of 15 locations recognized by the province in 2017 as representing the significant contributions of South Asian Canadians to the economic, social and cultural development of the province of British Columbia.

No historical sites are located in the Study area. The nearest historical sites are the four sites (including three relocated heritage buildings) in Deas Island Regional Park, located just over two kilometres downstream of the Study area (Figure 6).

5.5 Review of Historical Imagery

One of the first detailed charts of the river, made in 1869 by the Boundary Survey, shows an indication of a slough outlet located to the east of the Study area, that may have cut to the northwest across Tilbury Island from Tilbury Slough in prehistory (Hawkin and Campbell sheet 7, reproduced in Eldridge 2019) (Figure 7). Otherwise on this and other early charts, the general configuration of Tilbury Island's north shore is similar to today, although, when it is mapped, the slough is represented as an open and much broader channel.

A comparative visual analysis of historical aerial photographs for the Study area was conducted using photographs obtained from the University of British Columbia, Geographical Information Centre. Photographs for the Study area were examined by sets taken in the following years: 1938, 1949, 1954, 1963, 1979, 1984, 1991, 1997, 2002, and 2009. During the review, importance was placed on identifying changes in surrounding topography and other environmental or cultural features that would influence the presence/absence of archaeological sites and affect the archaeological sensitivity mapping. Cultural features, including industrial development are labelled in Figure 7 based on the dates when first visible in the aerial photograph years listed above.

Tilbury Island facing Gravesend Reach shows extensive erosion of the shoreline between 500 m and 1000 m east (upstream) of the Study area since 1949 (Figure 7). In contrast, there has been a gradual accumulation of sediments along the shoreline downstream of the rail ferry terminal jetties, including at the Study area, along with increased vegetation on the bank north of the dyke.

Potential lost drainage features were identified from differentiated soil or vegetation tones visible across agricultural fields. These were digitized to provide possible relict slough locations presented in Figure 7. The contrasting tones suggesting relict channels were still visible in aerial photography over agricultural fields throughout the region in the 1930s and 1940s, but are not readily apparent in more recent images, even in the reduced areas that remain under cultivation.

The review of historical imagery is presented in Table 7. Observable change is discussed in terms of change to locations identified in Table 7 as follows: *Dykes* of Tilbury Island; *River*, indicating the South Arm channel side of Tilbury Island; *Slough*, for Tilbury Slough and adjacent land; *pipe crossing*, where the existing LNG gas pipe crosses Tilbury Slough and adjacent land; and, *relict sloughs*, visible in fields within the Study area (Table 7).

Table 7: Historical aerial photograph summary for Study area.

Date and Aerial Photograph Number*	Inferred Tide State	Land Use(s) Within Study Area	Comments
1938 A5938:18	Low	Agricultural.	■ *Dykes:* Tilbury Island is dyked, and the dyke is typically covered with small trees or brush. ■ *River:* Small wharf with float and building at head of wharf extends into river just west of end of Hopcott Road; a similar structure exists downstream, where MacDonald Road would extend to. ■ *Slough:* Tilbury Slough closely conforms with current configuration, however, it is dammed at Huston (east end) and MacDonald (west end) roads making the slough effectively a pond in between. A large tree (conifer) on Tilbury slough south of the Project site is present. ■ *Pipe Crossing*: Farmyard, buildings, and orchard located west side of Hopcott Road north of Slough. ■ *Relict Sloughs:* Some shadows apparent in fields, generally NW-SE orientation.
1949 BC785:44 BC783:71, 72	Low	Agricultural.	■ *Dykes:* Tilbury Island dykes have had most of trees removed and the dykes appear to have been recently built up with light-coloured materials (likely newly deposited dredgeate fill and possibly gravel with rip-rap in some areas). ■ *River:* Building gone but wharf still in place at end of Hopcott Road, ■ *Slough:* Sediment plume observed from Tilbury Slough into the South Arm of the Fraser River. Tilbury Slough crossed by beaver dams and small bridge? ■ *Pipe Crossing*: No change. ■ *Relict sloughs:* One large meander and another converging slough are suggested by discolouration in fields of Study area.
1954 BC1672:72 BC1870:23, 24	High	Agricultural.	■ *Dykes:* No change. ■ *River:* Float or boat may be secured to small Hopcroft Road wharf, and other small boats anchored downstream but no path to wharf reflects current use from land. Active sedimentation downstream in the form of a large beach and bar formation. ■ *Slough:* No change. ■ *Pipe Crossing*: No change. ■ *Relict Sloughs:* A slightly different arrangement than previous suggests convergence of relict sloughs.
April 28 1963 BC5064:127	Low	Agricultural and first of industrial use on island. Rail line built to rail ferry terminus with spur to chemical plant at east end of island.	■ *Dykes:* No change. ■ *River:* Small wharf is gone. Rail ferry ramp installed on adjacent property. Jetty constructed to sandbar east of the Study area (associated with newly constructed Dow Chemicals). Sediment bar formation evident in the 1954 imagery is no longer present, likely due to dredging. ■ *Slough*: No change ■ *Pipe Crossing*: Orchard gone. ■ *Relict Sloughs:* Visible.

Date and Aerial Photograph Number*	Inferred Tide State	Land Use(s) Within Study Area	Comments
June 11 1974 BC5588:225-227	High	Agricultural in the southern portion of Study area, while LNG facility including earthen berm around tank and sawmill established on the northern portions.	■ *Dykes:* Where Harmac sawmill located, land raised and/or dyke lowered for ramp to water, and low bank and stub jetty. ■ *River:* Many piles driven around mill and downstream for log boom storage; stub jetty, wood chip conveyor and log ramp built. Another wharf (Lehigh Hansen) built upstream of rail ferry jetty. ■ *Slough:* Road (Tilbury) built north of slough and buildings, one larger and one or two smaller ones likely including pump shed, have been built on north shore of slough in Study area. ■ *Pipe Crossing:* Excavation and location where pipe crosses slough may be visible. ■ *Relict Sloughs:* dark patch visible in middle of eastern part of surviving southern field, corresponds with one previously observed dark area, and generally runs perpendicular to river.
1979 BC79008:168 BC79006:14	Low	Still Agricultural in the southern portion of Study area. No change to industrial configuration in the northern portion of the Study area.	■ *Dykes:* Appears to be new surface along river west of Study area. ■ *River:* Numerous log booms along shore. Reformation of the sediment bar first identified in the 1954 imagery, located downstream of Study area. ■ *Slough:* Rail spur extended into Study area over Hopcott Road north of slough. ■ *Pipe Crossing:* No change. ■ *Relict Sloughs:* Dark patches visible in middle of eastern part of surviving southern field, corresponding with previous observations.
1984 BC84013:141 BC84013:187	High	Industrial. Continued use of sawmill, lumber yard, and jetty in Study area. Sawmill yard has been extended to Tilbury Road. Circular dyke-around gas tank is being installed and berm is being supplemented. West end of Tilbury is now covered in preload.	■ *Dykes:* No change. ■ *River:* Sand bar extending in Study area between jetties out to 30 m or 40 m offshore, visible at relatively high tide. Conversely, there is a decrease in exposed area of the downstream sediment bar present in the 1979 imagery. As a measure of preservation in the absence of demolition the pre-1938 wharf at the foot of MacDonald Road is still visible, and largely intact below deck planking. ■ *Slough:* Larger building north of slough appears unused (overgrowth and no vehicles in lot) ■ *Pipe Crossing:* No change. ■ *Relict Sloughs:* Dark patch in southeastern corner of eastern part of surviving southern field.
September 18 1991 FF9131:56	High	Industrial. Continued use of sawmill, although activity is reduced (based on lack of stacked lumber, partial building demolition, and few booms in water).	■ *Dykes:* No change. ■ *River:* Active sedimentation downstream of Study area, with inferred deposition downstream, while sediment bar upstream of the island-causeway formation at Tilbury Island is absent; the channel here was likely dredged. ■ *Slough:* No change. ■ *Pipe Crossing:* No change. ■ *Relict Sloughs:* Two dark strips clearly visible in colour image in middle and eastern part of surviving southern field, corresponding with previous observations.

Date and Aerial Photograph Number*	Inferred Tide State	Land Use(s) Within Study Area	Comments
September 27 1997 FFC9700:110	High	Industrial. Continued use of sawmill, lumber yard, and jetty with large structure built.	■ *Dykes:* No change. ■ *River:* No change. ■ *Slough:* No change. ■ *Pipe Crossing:* No change. ■ *Relict Sloughs:* No clear delineation in mostly green field.
July 9 2002 SRS6600:355 SRS6600:269	High and low	Industrial. Continued use of sawmill, lumber yard, and jetty in Study area. Tilbury Road has been extended to the properties west of the Study area where construction in preloaded areas has begun. Small structures added and fencing upgraded at FortisBC facility.	■ *Dykes:* No change. ■ *River:* Exposed sediment bar observed downstream of the Study area at low tide. Evidence of further sedimentation in Study area, downstream of rail ferry wharves. Vegetation is now well established over upper part of beach between jetties in Study area ■ *Slough:* No change. ■ *Pipe Crossing:* Farm buildings at Hopcott Road by slough are now gone and replaced with new buildings and parking lots both east and west of Hopcott Road. ■ *Relict Sloughs:* No clear delineation in mostly grey field. ■
April 4 2009 SRS7964:387	High	Industrial. Sawmill in Study area has been replaced with (Varsteel and Dominion) steel plant.	■ *Dykes:* More dyke improvements suggested around new development to west of Study area. ■ *River*: Sediments continuing to build around island-causeway formation upstream of Study area. Wood chip conveyor still standing. ■ *Slough*: Two beaver dams visible. Lot paved by larger building off Tilbury near slough. Pumphouse area now completely overgrown. ■ *Pipe Crossing*: No change. ■ *Relict Sloughs*: No clear delineation in surviving field.

*When exact dates of images are unknown, the year the photograph was taken is provided. It is assumed that all imagery would have been obtained from April to September.

5.6 Review of Subsurface Data Available for Study Area

Golder has been able to review a series of geotechnical and other studies of the subsurface conditions in the Study area (Golder 2009, 2014a, 2014b, 2014c, 2014d, 2015b, 2016, 2018, 2019; Golder and EQE 2009), and a single AIA (Stantec 2014). Aspects of these studies that are relevant to archaeological potential and sensitivity are summarized by assessment area below, and the relevant test locations from these studies are mapped in Figure 8.

The borehole logs sometimes specify that some layers are fill. Based on the archaeological investigations in an area of the Project site that had not yet been subject to industrial development, the top levels of soil are silty clays with grey as well as brownish or orangey colours (Stantec 2014). This level, including the top 30 cm that was identified as plough zone, and to depths of between 50 cm and 100 cm in the area tested by Stantec as potentially artifact-bearing. The level below, described variously clayey silt, sand with some silt, silty sand or sandy silt, but consistently described as grey in colour, and typically extending to four to five metres in depth below the surface is likely sterile. It is worth noting, however, that on occasion, organic layers or “wood seams” were observed at depth in the geotechnical boreholes {i.e., at 7.5 m dbs[2] observed in one test (Golder 2014b)}.

[2] dbs – Depth below surface, or grade, measured at the test location.

Elevations cited below are to geodetic datum, where “0” elevation is roughly equivalent to the highest normal tide. The elevations after the Phase 1A development in the central and eastern parts of the Project site were approximately 0.75 m above the previous elevations of the field, ending at an elevation of approximately 2.0 m. This suggests the depth of fill which appears consistent over the developed ground within the Project site with base elevations typically about 2.0 m at the eastern end of the Project site, rising to between 2.25 m and 2.5 m at the western end, and up to 4.1 m to the crest of the dyke.

The subsurface data are detailed by assessment area below, and summarized in the following Table 8.

Assessment Area A

The dyke in this area has been recently upgraded. Geotechnical investigations with auger holes were conducted before (Golder 2014c, 2018) this upgrade. Approximately 1 m of sand and gravel fill was reported added to the dyke in 1977 (Golder 2014c). Two borehole tests confirmed this thickness between 0.9 m and 1.2 m. Below this layer of relatively recent fill or “crust” was the dyke “core”, consisting of clayey silt to silty clay and also considered fill by the geotechnical engineers, and extending between 3 m and 4 m below the surface. No organic material, such as peat or organic sandy loam which might indicate an original surface, was reported in these layers (Golder 2014c).

Further exploratory dyke investigations included 13 augerholes (Golder 2018). The results of augerhole tests were not interpreted in the report with respect to fill and native soils however, it appears that the subsurface has been highly disturbed by previous development, including outside the dyke footprint, and there is a broad range of minimum fill depths from 0.90 m to 3.6 m including 1.5 depth of wood debris in one borehole (Figure 8).

The dyke upgrade involved the removal of approximately 1 m of material, and the addition of approximately 2 m of fill. At the completion of construction, native soils levels may be calculated at depths of 5 m to 6 m beneath accumulated fill. It is likely that the elevation of this level has also been depressed over time due to compression under the fill. Current surface elevation of the dyke is 4.10 m. Dyke fill was added over a width of approximately 20 m. The dyke upgrade also involved considerable subsurface disturbance, including ground improvement along the length of area A at 8 m width, consisting of stone columns one metre in diameter and driven with 2.7 m spacing and wood piles interspaced (2014c).

Borehole test samples were also extracted from offshore of the Project Site (Golder 2016). The shallowest two of these of these boreholes in the offshore area were located in about 3 m of water depth below chart datum (Figure 8). The upper layer in these tests consisted of silty sand to sandy silt, inferred to be channel fill with a thickness of about 5 m to 7 m at the proposed Wespac bunkering terminal, tapering to nonexistent about 200 m away from riverbank (Golder 2016).

Assessment Area B

In preparation for road widening and resurfacing of Hopcott Road (previously known as Benson Road) along the eastern edge of the Study area, 10 augerhole tests were placed along the road between the dyke and Tilbury Road (Golder 2014a). Measured depths of fill under the road and on the verge (topsoil) were typically between 0.61 m and 0.76 m, but always directly over grey clayey silt or silty sand (Figure 8). The recommendation for road resurfacing, which has been completed, was for a 30 cm sub-excavation, replaced with 50 cm of fill plus asphalt, for a net increase in surface elevation before paving of more than 20 cm.

Assessment Area C

Assessment area C, located on the portion of the former mill site closest to the river was tested in 2009 as part of a study assessing the depths of wood waste throughout the property (Golder 2009). Ten tests were placed in area C with surface elevations of between 2.36 m and 3.41 m as part of this study. Tests in this area revealed that material defined as fill, including wood waste, typically extended to depths of between 1.5 m and 2.0 m, lay directly over grey clayey silt (Figure 8).

Assessment Areas D and E

The central portion of the former mill site, assessment area D (Figure 8), was also assessed for wood waste (Golder 2009). Eight tests were placed in the southwestern part of area D. Material described as fill typically extended to depths of about 1.5 m, to a maximum of 2.0 m, laying directly over grey clayey silt to silty clay (Figure 8).

The area to the southeast of the large structure still standing in the southern parcel (Figure 8) was also tested in 11 test locations for wood waste (Golder 2009). Three of the tests had surface elevations recorded at between 1.84 m and 2.14 m. Fill was identified at between 0.91 m and 3.05 m in depths. Most of the fill was located directly over was grey clayey silt or sand.

The southeastern portion of assessment area D as well as area E was tested with 6 auger holes as part of geotechnical assessment associated with Phase 1 B (Golder 2015b). Surface elevations ranged between 2.11 m to 2.37 m. Fill was identified at depths between 0.97 m and 1.07 m directly over grey sand or silty sand (Figure 8).

There are no known subsurface records of the southern parcel (assessment areas C, D and E) prior to the land being developed as a mill site.

Assessment Areas F and G

Assessment areas F and G represent the area developed around the original LNG storage tank (Appendix A Photographs 1 and 2). Two boreholes were placed as part of a seismic review (Golder and EQE 1996). It was noted that the top soils had been stripped off and vibro-compacted to 100 m diameter around the tank before gravel fill had been brought in. Piles were driven to 16 m depths under the tank and within a 39 m diameter.

Assessment Areas H, I and J

Assessment areas H, I and J represent the eastern part of the northern parcel of land that was undeveloped, except for agricultural use, prior to the Tilbury 1A development. The areas are divided to reflect areas already developed in Phase 1A (assessment areas I), and the areas where development may occur in Phase 1B (assessment areas H and J). Both the AIA (Stantec 2014) and the Geotechnical Interpretive Report conducted for the Front End Engineering Design (Golder 2014b) were conducted in preparation for the Phase 1A work, which included the construction of the Phase 1A storage tank and supporting infrastructure built to date.

The AIA consisted 107 machine tests set primarily in agricultural fields prior to development. In the narrow strip of landscaped area near to and to the south of the original LNG tank, top soils were recorded to depths of between 20 and 60 cm. In the field, the top 30 cm was observed to be plow zone. To between depths between 50 cm and 100 cm dbs, the mottled brown/grey clays were observed overlying grey clay with orange-brown inclusions to below depths tested. It may be noted that a deeper interface between the two clay layers corresponds with the inferred location of the relict slough through the property (see Figure 7).

The surface elevations of auger and bore holes placed in this area are between 1.0 m and 1.45 m (Golder 2014b). This is 60 cm to 120 cm lower than the adjacent formerly agricultural field following its industrial development (assessment areas D and E), suggesting the net level of fill introduced as part of its development (Figure 8). The depths to grey sand or clayey silt ranged between 0.61 m and 5.19 m, however, the average depth was 1.45 m (outliers excluded).

Ground preparation for Phase 1A involved the stripping of the upper approximately 1.0 m of soil, which was replaced by fill raising the surface to a final elevation to approximately 2.0 m. The tank densification footprint was within an 80 m diameter footprint, within a ground improvement area, approximately 100 m square.

Assessment Areas K, L and M

The is no subsurface data available for assessment areas K, L and M.

Table 8: Recorded depths of fill summarized by assessment area.

Assessment Area	Recorded and/or Inferred Depths of Fill Below Surface	Data Source
A	Approx. 3 m to 7 m	(Golder 2014c, 2016, 2018)
B	0.81 m to 0.96 cm	(Golder 2014a)
C	1.5 m to 2.0 m	(Golder 2009)
D & E	0.97 m to 3.05 m	(Golder 2009, 2015b)
F & G	No fill depth data available	(Golder and EQE 1996)
H, I & J	0.61 m to 5.19 m	(Golder 2014b; Stantec 2014)
K.L & M	No subsurface data available	N/A

5.7 Results of Preliminary Field Reconnaissance

The PFR was conducted through the morning and early afternoon of 21 of November 2019 by Charles Moore, accompanied by First Nations assistants, Jodie Swartz (Katzie First Nation), Lindsey Yates (Kwantlen First Nation), and Melinda Cassidy (Tsawwassen First Nation). Chris Wylie (FortisBC) was also in attendance.

Project Site

The Project site was not accessed during the PFR. Representations of the current state of development of the Project site (assessment areas C, D, E, F, G, H, I, and J) are represented in Photographs 1 to 7 (Appendix A). Photographs 6 and 7, taken from the edge of the Project site and assessment areas E, J and I, suggest the level and character of fill introduced to the site as part of the development.

Assessment Area A

The tide on 21 November 2019 reached a low of 0.8 m at 7:12 am according to tidal station 7654, New Westminster, and rose through the day to a high of 3.0 m at 14:05. Assessment area A was the first area visited to take advantage of the intertidal exposure of the riverbank.

Recent dyke upgrades are apparent with the crest of the dyke being surfaced with gravel, with angular boulders armouring the slope on the Fraser River side of the dyke, and landscaping into ditch on the back side of the dyke (Appendix A, Photograph 8). The ditch was mostly shallow and vegetated, but in some areas adjacent to assessment area C a sharper bank was evident (Appendix A, Photograph 9). This was examined and the exposed surface consisted of engineered fill.

Access to the river from the dyke was limited due to heavy growth. Access was achieved on either side of the stub wharf areas (Appendix A, Photographs 10 and 11). The lower intertidal area was silt. This was examined for archaeological features, notably stake stubs that might be associated with a fishing weir; none were observed. A low rip-rap wall extending through the middle and lower intertidal was seen to support accumulated sediments and vegetation from the extreme north end of assessment area A, and into Seaspan property.

Some cut banks were observed in the middle intertidal areas; the exposed matrix consisted of silt with wood waste inclusions under a cap of fibrous root matt. In the upper intertidal were areas of steeper bank, rising with trees and brush to the top of the dyke; these areas were primarily covered with rip rap most of which appeared to pre-date the recent dyke upgrade (Appendix A, Photograph 12). Where sediments were available, these were examined, and found to consist of silt with imbedded quantities of modern debris including what appeared to be wood waste from the mill. Most of the trees (alder or cottonwood) which now grow on the river side of the dyke were not present as recently as1995 (see Appendix A, Photograph 1).

Some large pilings were observed in lower intertidal and subtidal portions of the river. A small cluster of pilings in the upper intertidal are assumed to represent the small wharf observed near the west end of Hopcott Road, observed in historical aerial photographs and known to have been built prior to 1939 (Appendix A, Photograph 12).

No structure was observed in the riverbank or riverbed that suggested the presence of a heritage wreck.

Assessment Area B

Hopcott Road has been recently upgraded. The road verge to the Project site has a sidewalk but is otherwise landscaped with grass (Appendix A, Photograph 14). Where there is a ditch outside the fence line, it is very shallow with no exposures. The part of assessment area B next to the Project site was observed from inside a moving vehicle.

Assessment Area M

Along the south and west side of Hopcott Road between Tilbury Slough and the Project Site is a buried gas pipeline. This route was walked. It is landscaped or paved its entire length into area M. The north side of Tilbury slough was walked beyond the point where the buried pipe crosses the slough. The slough appears to be fresh water and not influenced by tides, and is mostly filled with rushes and reeds. Although the area at its west end is mostly cleared, the vegetation is generally dense. No archaeological material or cultural deposits were observed in the exposures of sediments that were examined (Appendix A, Photographs 14 and 15).

Assessment Area L

Most of assessment area L is occupied by the Delta Community Animal Shelter building and fenced run. The areas around the shelter were partially cleared, part brush and trees, part landscaped, and part paved (where there was formerly a rail siding for the sawmill). Where exposures were available these were examined. The slough is still choked with reeds in this area, if less so than on the other side of Hopcott Road (Appendix A; Photographs 17 – 19). A single large cedar was observed within the alders; this is believed to be the same tree

that was observed in this location near Tilbury Slough in aerial photographs dating back to 1939 (Appendix A; Photographs 20). The tree has not been culturally modified. No archaeological material or cultural deposits were observed in the exposures of sediments examined.

Assessment Area K

Tilbury Road, running through assessment areas K and L is wide and in good condition and was likely upgraded at about the same time as Hopcott Road. Assessment area K includes a large clearing that formerly had a structure thought to be an administration building for the sawmill. This area is level and recently planted with saplings. The treed area in the southern part of area K contains a pump house with a standpipe (Appendix A; Photographs 21). A small concrete foundation, presumably of a previous pump structure, is nearby. A ditch that runs down the line between the Varsteel and FortisBC properties empties into the Slough west of the pumphouse. A beaver dam spanning Tilbury Slough is located just to the east of this outlet. The available exposures in the ditch and along side the slough were examined and found to consist of silt; no cultural material was observed in the sediments.

Some rotten posts were observed, but these were minimally 20 cm in diameter and considered to be historical, mechanically driven piles. No structure was observed in the slough or imbedded in its banks that suggested the presence of a heritage wreck.

6.0 ARCHAEOLOGICAL POTENTIAL ASSESSMENT

Based on the results summarized in section 5.0, the primary considerations for assessing archaeological potential in this Study area include:

- Locations of previously documented archaeological sites.
- Proximity (within 100 m) to watercourses, including from the inferred locations of slough channels that have since been in-filled.
- Documented subsurface excavations from historical developments or erosion leading to the removal of deposits that may have contained cultural materials, if an archaeological site were present.
- Results of a previous AIA.

While no archaeological sites are located within or in close proximity to the Study area, the prevalence of site locations within 5 km that are situated on the banks of the river, or current and former sloughs, underscores the importance of proximity to watercourses. Potential has been removed in areas where deep construction impacts have been documented (Golder and EQE 1996; Golder 2014b, 2014c). The absence of archaeological potential was also established where an AIA was conducted with negative results (Stantec 2014).

Due to proximity to watercourses, including the inferred locations of slough channels, archaeological potential has been identified in 12 of 13 assessment areas. There is no archaeological potential identified in assessment area J due to the negative results of the archaeological impact assessment in that area. Areas A, C, G, and H have no potential assessed for large portions of the respective areas due to: distance from a waterway; the negative results of the archaeological impact assessment; and/or, documented subsurface excavations from previous development. Archaeological potential is illustrated in Figure 9 and summarized by assessment area in Table 9.

7.0 ARCHAEOLOGICAL SENSITIVITY ASSESSMENT

Previous development in the Project site does not necessarily negate archaeological potential but geotechnical and other subsurface data sources provide for inferences regarding the possibility for surviving archaeological material and its depth if present, Archaeological potential was also not negated by field observations in assessment areas K, L and M. Although deep disturbance may be assumed within the footprint of the gas pipe and utilities trenches for existing and historical buildings, and shallow disturbance is obvious in the areas developed with structures, landscaping and pavement. Areas K, L and M are assessed with archaeological potential from the surface or near surface (and deeper) (Figure 10).

In the case of assessment area A on the river side of the dyke, aerial photographs and borehole data suggest that there may be up to seven metres of recent fill material above a buried level with archaeological potential. However, nothing suggests that the archaeological potential at depth has been removed due to dredging or other excavations (Figure 10).

In some areas, while surface disturbance from development may be obvious, there may be insufficient data to infer the depths of native material removed or thickness of imported fill added. These “data absent” areas include under the stub jetty in assessment area A, the original facilities area in assessment area F, the Tilbury Road roadbed through assessment areas K and L, and Hopcott Road from the Tilbury Road intersection and south (Figure 10).

Based on available geotechnical data, it is possible to infer that developments included the stripping of surface material prior to the addition of fill likely led to the removal of the levels of sediment that may be considered potentially artifact bearing. The areas where this assessment has been made include all of assessment area E, and much of assessment areas B, C, D, G and H (Figure 10).

Archaeological sensitivity is summarized in Table 9.

8.0 RECOMMENDATIONS

Project-related impacts in areas with archaeological potential should be avoided if possible. Some areas of potential present fewer risks than others, in part depending on the type of development proposed. Recommendations for archaeological investigations to mitigate development risks in each assessment area where archaeological potential are presented in Table 9.

Figure 11 illustrates the extents of four different areas with specific recommendations:

- In the larger portions of assessment areas K, L and M, excluding the roadbeds and areas of prior disturbance such as buried pipelines – conduct an AIA prior to construction.
- In much of the area that has been previously developed (including parts of assessment areas A, B, C, D, F, G, H, Ia, Ib, K and L, and all of area E) the chance of encountering archaeological remains at least in the upper layers of fill is low. A chance find management plan (CFMP) should be implemented prior to ground disturbance to provide workers with the steps to follow should suspected archaeological materials be encountered during construction when an archaeologist is not present. For proposed work extending below 40 cm dbs in this area, work should be preceded by an AIA or monitored concurrently, depending on the type of work (i.e., work such as some geotechnical tests or pile driving would not be monitored due to lack of recovered subsurface material available for examination), and/or recommendations provided as a result of previous archaeological investigations.

- In most of the area offshore of the dyke (area A), due to reported depths of fill or sediments, a CFMP should be implemented during work conducted in this area. If the proposed work extends below 4.0 m dbs, monitoring should be conducted (providing material from the depths where archaeological potential is anticipated will be exposed on the surface and available for observation).
- Where no archaeological potential has been assessed due to distance from water, previous subsurface excavations, or previous archaeological investigations (including parts of areas A, B, C, D, F, G, H, Ia and Ib, and all of area J) a CFMP should be implemented during work conducted in this area.

Where an AIA is recommended, subsurface archaeological tests may proceed following the issuance by the Archaeology Branch of an HCA section 12.2 permit. The AIA report will include recommendations for specific heritage resource management during site development once development plans are refined. In the event that an archaeological site is identified, further archaeological work, including monitoring of geotechnical tests or subsurface excavations for construction may proceed under a section 12.4 permit issued by the OGC. The OGC will also require that an AIF be prepared as part of the permit initiation for the Project, and subsequently updated with results of all archaeological investigations.

Table 9: Archaeological potential, sensitivity and recommendations.

Assessment Area and Location	Archaeological Sensitivity	Recommendations
A Dyke and Foreshore	■ Includes areas of deep potential: ▪ Not removed in foreshore, and, ▪ Data absent under stub jetty; and, ■ An area of removed potential under dyke.	■ No further archaeological investigations are recommended in the areas where the inferred depth of potential exceeds the practical reach of mechanical testing, in areas where excavation would compromise the integrity of the dyke, or where potential is considered removed. A CFMP should be implemented during construction in this area. ■ Archaeological monitoring is recommended where Project activities will involve removal of sediments from potentially artifact bearing depths that may be available for archaeological examination.
B Hopcott Road	■ Includes areas of deep potential: ▪ Likely removed, where tested, and ▪ Data absent where tests absent; and, ■ An area of no potential.	■ Subsurface archaeological investigations are recommended prior to, or concurrent with, Project excavations extending below engineered fill in areas with deep archaeological potential to address data absence or confirm inference from geotechnical data that levels with artifact-bearing potential have been removed. ■ No further archaeological investigations are recommended in area of no assessed potential. A CFMP should be implemented during construction in this area.
C South Parcel, W	■ Includes area of deep potential, likely removed; and, ■ An area of no potential.	■ Subsurface archaeological investigations are recommended prior to Project excavations below reported depths of fill in areas with deep archaeological potential to confirm the inference from geotechnical data that levels with artifact-bearing potential have been removed. ■ No further archaeological investigations are recommended in the area of no assessed potential. A CFMP should be implemented during construction in this area.

Assessment Area and Location	Archaeological Sensitivity	Recommendations
D South Parcel, W	■ Includes area of deep potential, likely removed; and, ■ An area of no potential.	■ Subsurface archaeological investigations are recommended prior to Project excavations below reported depths of fill in areas with deep archaeological potential to confirm the inference from geotechnical data that levels with artifact-bearing potential have been removed. ■ No further archaeological investigations are recommended in the area of no assessed potential. A CFMP should be implemented during construction in this area.
E South Parcel, E	■ Is an area with deep potential, likely removed.	■ Subsurface archaeological investigations are recommended prior to Project excavations below reported depths of fill to confirm the inference from geotechnical data that levels with artifact-bearing potential have been removed.
F North Parcel, W	■ Includes area of deep potential, data absent; and, ■ An area of no potential.	■ Subsurface archaeological investigations are recommended prior to Project excavations below reported depths of fill in the area with deep archaeological potential. ■ No further archaeological investigations are recommended in the area of no assessed potential. A CFMP should be implemented during construction in this area.
G North Parcel, M	■ Includes area of deep potential, likely removed; and, ■ Areas of no potential.	■ Subsurface archaeological investigations are recommended prior to Project excavations below reported depths of fill in area with deep archaeological potential to confirm the inference from geotechnical data that levels with artifact-bearing potential have been removed. ■ No further archaeological investigations are recommended in areas of no assessed potential. A CFMP should be implemented during construction in this area.
H North Parcel, M	■ Includes area of deep potential, likely removed; and, ■ Areas of no potential.	■ Subsurface archaeological investigations are recommended prior to Project excavations below reported depths of fill in area with deep archaeological potential to confirm the inference from geotechnical data that levels with artifact-bearing potential have been removed. ■ No further archaeological investigations are recommended in areas of no assessed potential. A CFMP should be implemented during construction in this area.
Ia North Parcel, M	■ Includes large area of no assessed potential; and, ■ A small area of deep potential, likely removed.	■ No further archaeological investigations are recommended in the area of no assessed potential. A CFMP should be implemented during construction in this area. ■ Subsurface archaeological investigations are recommended prior to Project excavations below reported depths of fill in the area with deep archaeological potential to confirm the inference from geotechnical data that levels with artifact-bearing potential have been removed.

Assessment Area and Location	Archaeological Sensitivity	Recommendations
Ib North Parcel, E	■ Includes large area of no assessed potential; and, ■ A small area of deep potential, likely removed.	■ No further archaeological investigations are recommended in the area of no assessed potential. A CFMP should be implemented during construction in this area. ■ Subsurface archaeological investigations are recommended prior to Project excavations below reported depths of fill in the area with deep archaeological potential to confirm the inference from geotechnical data that levels with artifact-bearing potential have been removed.
J North Parcel, SE	■ Is an area with no assessed potential.	■ No further archaeological investigations are recommended. A CFMP should be implemented during construction in this area.
K Tilbury Road/ Slough W	■ Includes an area of archaeological potential; and, ■ An area of deep potential, data absent (Tilbury Road).	■ Subsurface archaeological investigations are recommended in the area with archaeological potential. ■ Subsurface archaeological investigations are recommended prior to, or concurrent with, Project excavations below reported depths of fill in area with deep archaeological potential.
L Tilbury Road/ Slough M	■ Includes an area of archaeological potential; and, ■ An area of deep potential, data absent (Tilbury Road).	■ Subsurface archaeological investigations are recommended in the area with archaeological potential. ■ Subsurface archaeological investigations recommended prior to, or concurrent with, Project excavations below reported depths of fill in area with deep archaeological potential.
M Tilbury Slough E	■ Is area with archaeological potential.	■ Subsurface archaeological investigations are recommended, if proposed excavations are outside footprint of existing pipeline.

9.0 CLOSING

This report was prepared for the exclusive use of FortisBC and any use, reliance, or decisions made by third parties on the basis of this report are the sole responsibility of such third parties.

We trust the information in this report is satisfactory for your present needs. Should you require additional information or clarification, please do not hesitate to contact the undersigned at your earliest convenience.

Golder Associates Ltd.

Charles D. Moore, MA, RPCA, RPA
Senior Archaeologist

Andrew R. Mason, MA, RPCA
Principal, Cultural Heritage Specialist

CDM/ARM/lih

https://golderca.sharepoint.com/sites/125155/project files/6 deliverables/issued to client_for wp/19134134-017-r-rev0/19134134-017-r-rev0-fortis_tilbury_aoa 26may_20.docx

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LEGEND

- STUDY AREA
- RECORDED ARCHAEOLOGICAL SITE BOUNDARY (PROVINCE OF BC)
- HISTORIC PLACE - FORMALLY RECOGNIZED (PROVINCE OF BC)
- HISTORIC PLACE - UNPROTECTED NOT RECOGNIZED (PROVINCE OF BC)

0 4,500 9,000

1:225,000 METRES

REFERENCES

1. ARCHAEOLOGICAL AND HERITAGE SITES OBTAINED FROM MINISTRY OF FORESTS, LANDS, NATURAL RESOURCE OPERATIONS AND RURAL DEVELOPMENT (DOWNLOADED 20191202).
2. MAP BASE SOURCE ESRI, NRCAN, GEOBASE. AND THE GIS USER COMMUNITY.
COORDINATE SYSTEM: NAD 1983 UTM ZONE 10N

CLIENT
FORTISBC ENERGY INC.

PROJECT
FORTISBC TILBURY LNG PRODUCTION AND STORAGE FACILITY EXPANSION, DELTA, BC

TITLE
PROJECT LOCATION

CONSULTANT
GOLDER

YYYY-MM-DD	2020-05-26
DESIGNED	CM
PREPARED	JP
REVIEWED	CDM
APPROVED	ARM

PROJECT NO.	PHASE	REV.	FIGURE
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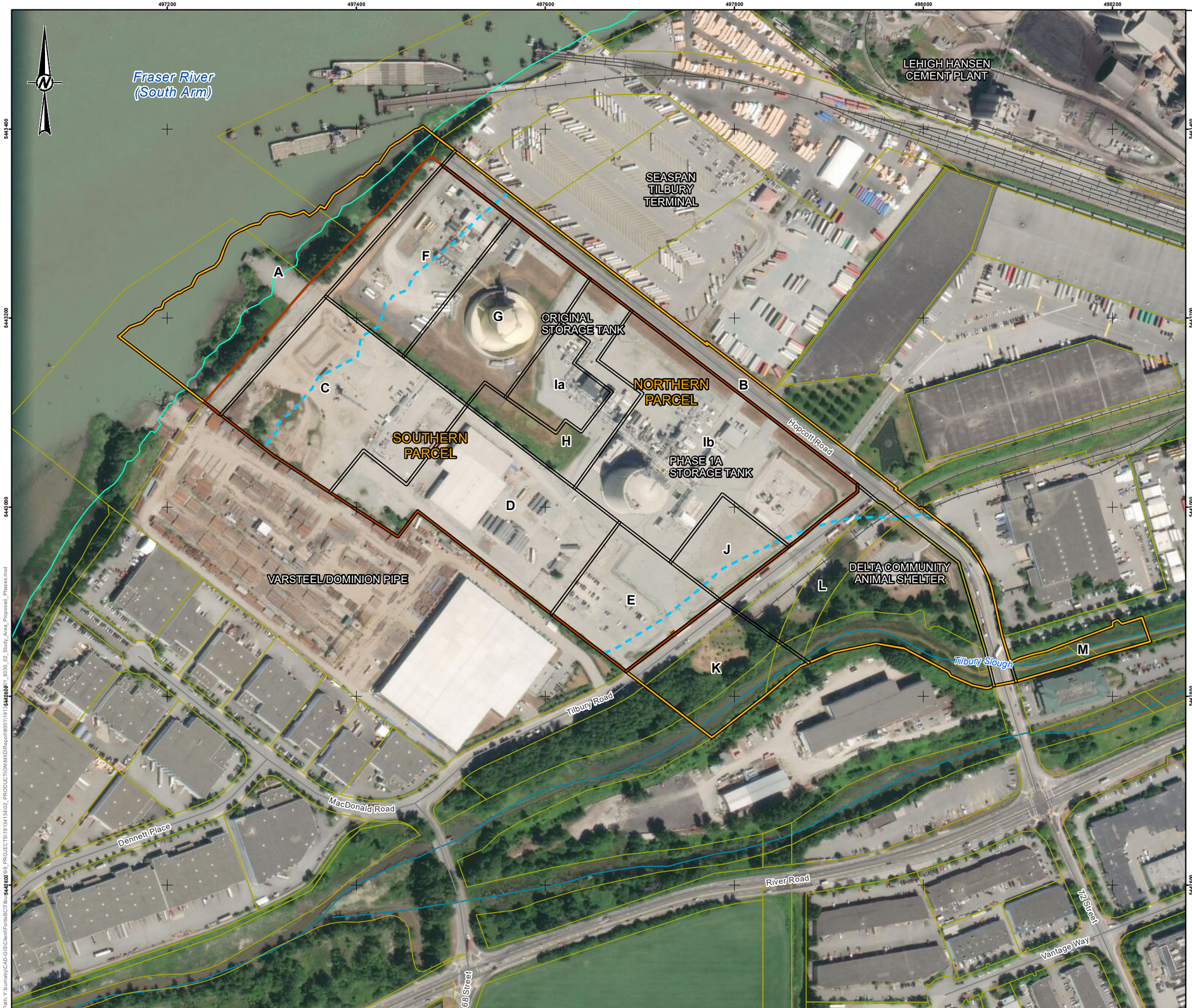

LEGEND

- PROJECT SITE
- ASSESSMENT AREA
  "A" ASSESSMENT AREA DESIGNATION
- STUDY AREA
- CADASTRAL BOUNDARY
- ROAD
- RAILWAY
- HISTORIC SHORELINE c.1949
- WATERCOURSE
- WATER OFFSET - 100m

Designation	Assessment Area Location	Possible Development
A	Dyke and Foreshore	N/A
B	Hopcott Road	Pipeline right-of-way, existing and proposed
C	South Parcel, W	Possible build or temporary workspace
D	South Parcel, M	Possible build area
E	South Parcel, E	Possible temporary workspace or parking
F	North Parcel, W	Demolition and possible re-build or temporary workspace
G	North Parcel, M	Demolition and possible re-build area
H	North Parcel, M	Possible build
Ia	North Parcel, E	N/A (recent build)
Ib	North Parcel, E	N/A (recent build)
J	North Parcel, SE	Possible temporary workspace
K	Tilbury Road/Slough W	N/A
L	Tilbury Road/Slough M	N/A
M	Tilbury Slough E	Pipeline right-of-way

0 80 160
1:4,000 METRES

REFERENCES

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PROJECTION: NAD 1983 UTM ZONE 10

CLIENT
FORTISBC ENERGY INC.

PROJECT
FORTISBC TILBURY LNG PRODUCTION AND STORAGE FACILITY EXPANSION, DELTA, BC

TITLE
STUDY AREA AND ASSESSMENT AREAS

CONSULTANT
GOLDER

YYYY-MM-DD	2020-05-26
PREPARED	CM
DESIGN	JP
REVIEW	CDM
APPROVED	ARM

PROJECT NO.	PHASE	REV.	FIGURE
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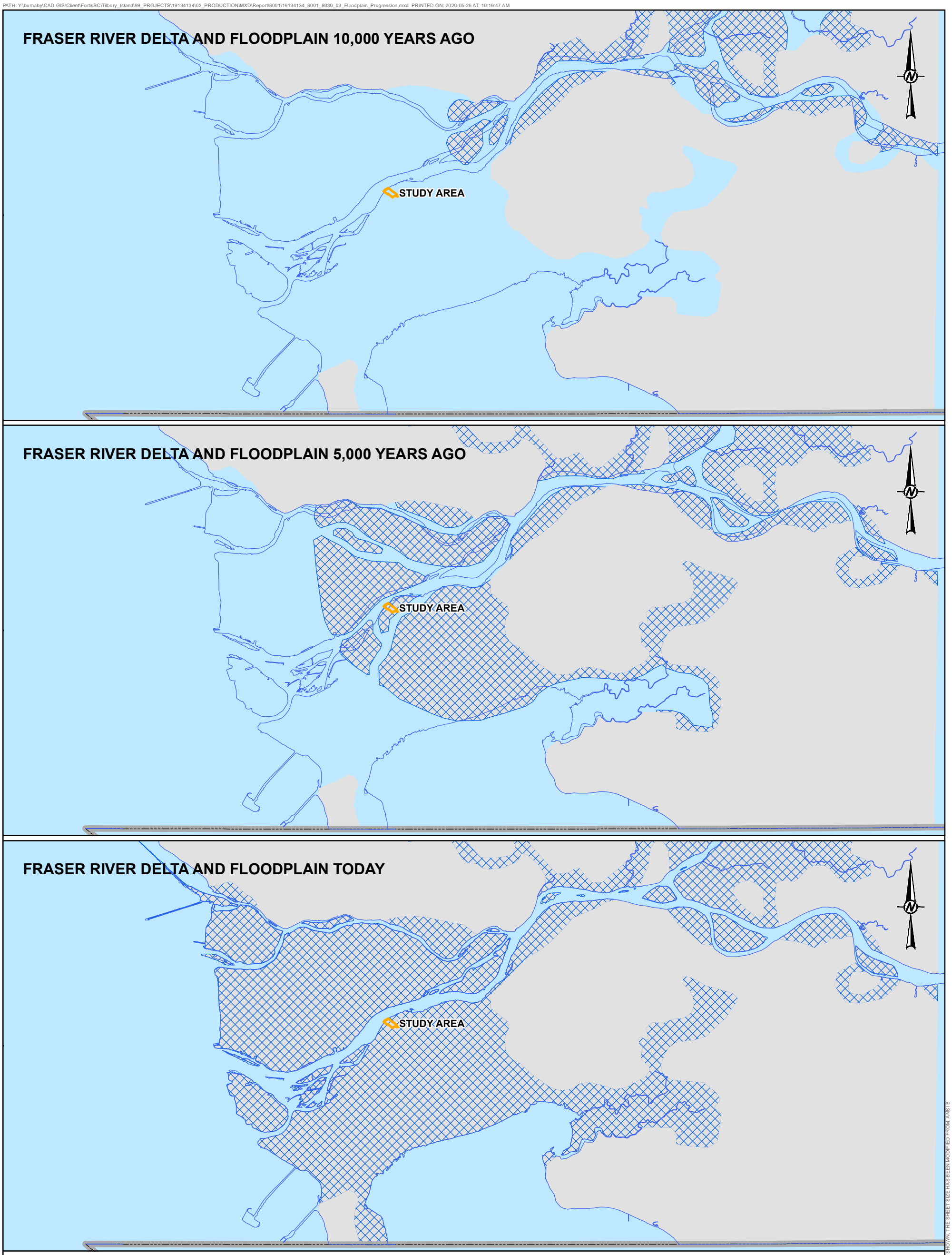

LEGEND

- STUDY AREA
- FRASER RIVER DELTA AND FLOODPLAIN
- LAND
- PRESENT DAY SHORELINE
- CANADA/U.S.A BORDER

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REFERENCE(S)
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2. PRESENT DAY SHORELINE OBTAINED FROM ESRI CANADA.
3. CANADA/U.S.A BORDER OBTAINED FROM GEOBASE®.
DATUM: NAD83 PROJECTION: UTM ZONE 10

CLIENT
FORTISBC ENERGY INC.

PROJECT
FORTISBC TILBURY LNG PRODUCTION AND STORAGE FACILITY EXPANSION, DELTA, BC

TITLE
FLOODPLAIN PROGRESSION

CONSULTANT
GOLDER

YYYY-MM-DD	2020-05-26
DESIGNED	CM
PREPARED	JP
REVIEWED	CDM
APPROVED	ARM

PROJECT NO.	CONTROL	REV.	FIGURE
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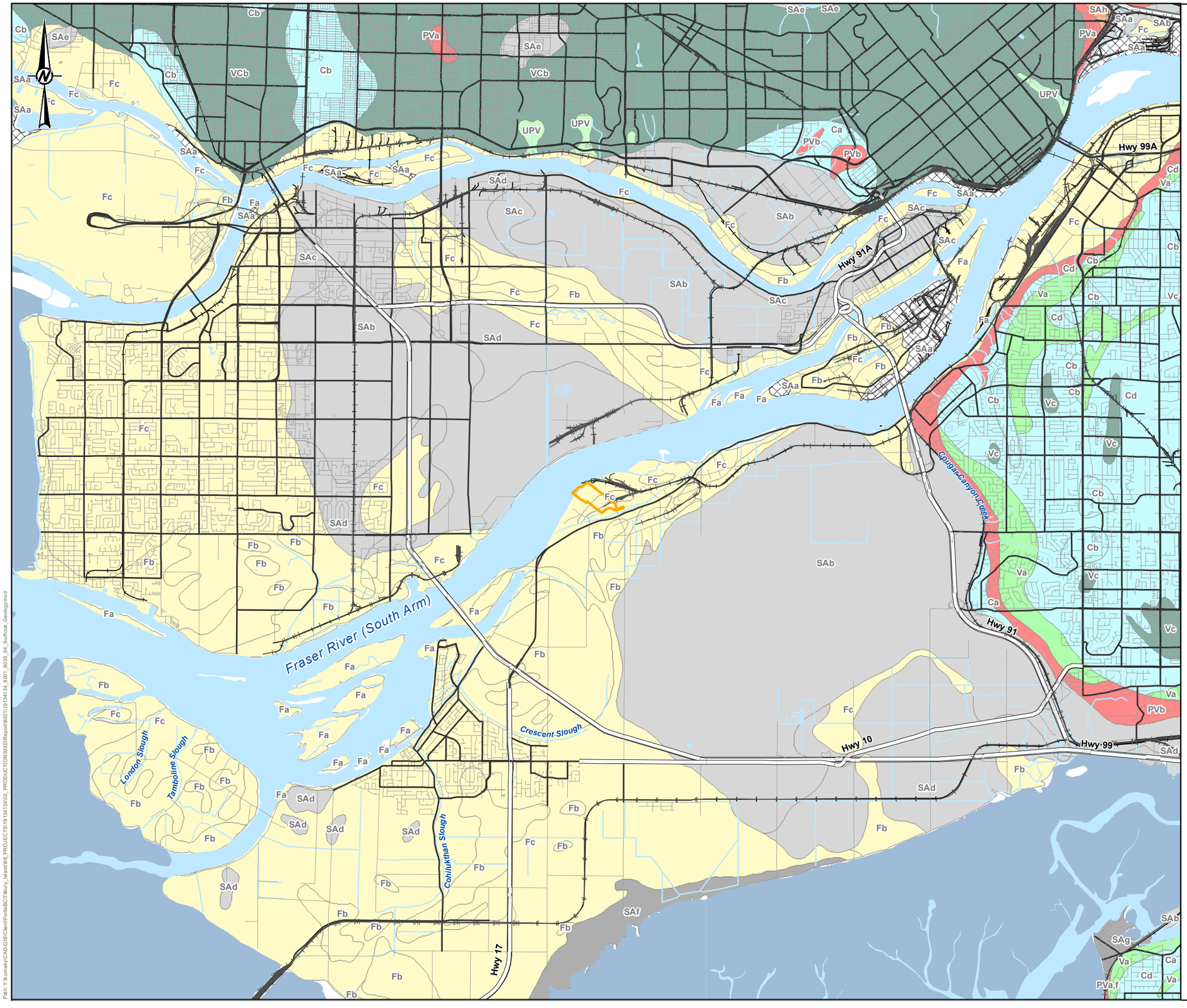

LEGEND

- STUDY AREA
- HIGHWAY
- MAJOR ROAD
- LOCAL ROAD
- RAILWAY
- WATERCOURSE
- INTERTIDAL AREA
- WATERBODY

SURFICIAL GEOLOGY

QUATERNARY

POSTGLACIAL

SALISH SEDIMENTS

Zfill Landfill including sand, gravel, till, crushed stone, and refuse

SAb-e Bog, swamp, and shallow lake deposits: SAb, low, and peat, organic silt loam, and silty clay loam 0.3 to 10+m thick overlying Fraser River Sediments (Fc,d,g,h) or Salish lacustrine deposits (SAq,r); SAc, similar to SAb except that the organic sediments are overlain by up to 1 m of silt loam, silt, and sand (Fraser River overbank deposits); SAd, lowland organic sandy loam to clay loam 15 to 45 cm thick overlying Fraser River Sediments (Fd); SAe, upland peat up to 8+m thick

SAf,g Marine shore sediments (beach deposits): SAf, sand to sandy loam up to 2 m thick overlying estuarine, fossiliferous, fine sand and clayey silt, 10 to 185 m thick (Fe of Lithologic Units and Environments of Deposition); SAg, medium to coarse sand and gravel up to 8 m thick

SAh Stream deposits, includes channel fill, floodplain, and overbank sediments: SAh, lowland stream channel fill and overbank sandy loam, and clay loam; in places contains disseminated organic material; up to 8 m thick

FRASER RIVER SEDIMENTS

Fa-c Deltaic and distributary channel fill sediments overlying and cutting estuarine sediments and overlain in part of the area by overbank sediments: Fa, channel deposits, fine to medium sand and minor silt occurring along present day river channels; Fb, overbank sandy to silt loam up to 2 m thick overlying 15 m or more of Fd; Fc, overbank silty to silt clay loam normally up to 2 m thick overlying 15 m or more of Fd; Fd, deltaic and distributary channel fill (includes tidal flat deposits) sandy to silt loam, 10 to 40 m thick interbedded fine to medium sand and minor silt beds; may also contain organic and fossiliferous material

PLEISTOCENE

CAPILANO SEDIMENTS

Ca,b,d Raised marine, deltaic, and fluvial deposits: Ga, raised marine beach, spit, bar, and lag veneer, poorly sorted sand to gravel (except in bar deposits) normally less than I m thick but up to 8 m thick, mantling older sediments and containing fossil marine shell casts up to 175 m above sea level; Cb, raised beach medium to coarse sand 1 to 5 m thick containing fossil marine shell casts; Cc, raised deltaic and channel fill medium sand to cobble gravel up to 15 m thick deposited by proglacial streams and commonly underlain by silty to silty clay loam; Cd, marine and glaciomarine stony (including till-like deposits) to stoneless silt loam to clay loam with minor sand and silt normally less than 3 m thick but up to 30 m thick, containing marine shells. These deposits thicken from west to east.

VASHON DRIFT ND CAPILANO SEDIMENTS

VCb Glacial drift including: lodgment and minor flow till, lenses and interbeds of substratified glaciofluvial sand to gravel, and lenses and interbeds of glacio-lacustrine laminated stony silt; up to 25 m thick but in most places less than 8 m thick (correlates with Va,b); overlain by glaciomarine and marine deposits similar to Cd normally less than 3 m but in places up to 10 m thick. Marine derived lag gravel normally less than 1 m thick containing marine shell casts has been found mantling till and glaciomarine deposits up to 175 m above sea level; above 175 m till is mantled by bouldery gravel that may be in part ablation till, in part colluvium, and in part marine shore in origin. VCb, bedrock more than 10 m below surface

VASHON DRIFT

Va Till and glaciofluvial deposits: Va, lodgment till with sandy loam matrix, up to 10 m thick, overlain in many places by gravelly ablation till up to 3 m thick. Vashon Till exposed in the northwest part of the map area is drumlinized.

PRE-VASHON DEPOSITS

PVa,b,f Glacial, nonglacial, and glaciomarine sediments PVa, Quadra fluvial channel fill and floodplain deposits, crossbedded sand containing minor silt and gravel lenses and interbeds; PVb, Quadra (?) glaciofluvial deposits, deltaic, and crossbedded sand to gravel (may be in part Vb); PVf, Semiahmoo till, glacio-fluvial, glaciomarine, and glaciolacustrine deposits

UNDIVIDED PRE-VASHON DRIFT

UPV Till, glaciofluvial, glaciolacustrine, fluvial, and organic sediments

0 1,600 3,200

1:80,000 METRES

REFERENCES

1. ROAD, RAILWAY, WATERCOURSE INTERTIDAL AREA, AND WATERBODY DATA OBTAINED FROM GEOGRATIS, © DEPARTMENT OF NATURAL RESOURCES CANADA. ALL RIGHTS RESERVED.
2. SURFICIAL GEOLOGY OBTAINED FROM GEOLOGICAL SURVEY OF
DATUM: NAD83 CSRS PROJECTION: UTM ZONE 10N
PROJECTION: NAD 1983 UTM ZONE 10

CLIENT
FORTISBC ENERGY INC.

PROJECT
FORTISBC TILBURY LNG PRODUCTION AND STORAGE FACILITY EXPANSION, DELTA, BC

TITLE
SURFICIAL GEOLOGY

CONSULTANT
GOLDER

YYYY-MM-DD	2020-05-26
PREPARED	CM
DESIGN	JP
REVIEW	CDM
APPROVED	ARM

PROJECT NO.	PHASE	REV.	FIGURE
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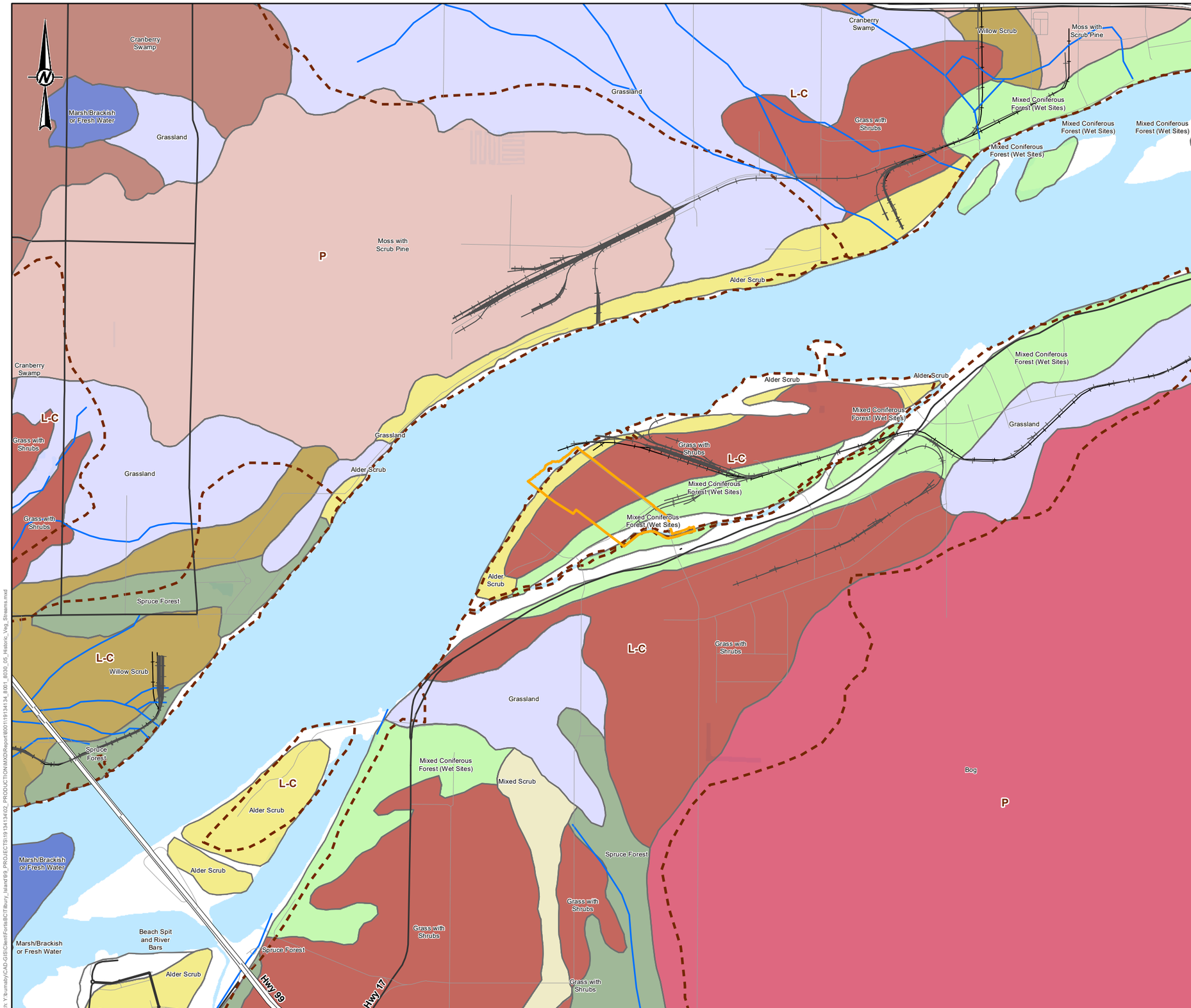

LEGEND

- STUDY AREA
- HIGHWAY
- MAJOR ROAD
- LOCAL ROAD
- RAILWAY
- HISTORICAL STREAM
- WATERBODY
- HISTORICAL SOIL POLYGON

SOIL CODE, SOIL NAME

- L-C, LADNER CLAY
- P, PEAT

HISTORICAL VEGETATION

- HISTORICAL VEGETATION NOT AVAILABLE

CONIFEROUS FOREST

- SPRUCE FOREST
- MIXED CONIFEROUS FOREST (WET SITES)

SCRUB FOREST

- ALDER SCRUB
- WILLOW SCRUB
- MIXED SCRUB

GRASS

- GRASSLAND
- MARSH/BRACKISH OR FRESH WATER

SHRUBS/MOSS

- BOG
- MOSS WITH SCRUB PINE
- CRANBERRY SWAMP
- GRASS WITH SHRUBS

0 500 1,000

1:25,000 METRES

REFERENCES

1. ROAD, RAILWAY, WATERCOURSE INTERTIDAL AREA, AND WATERBODY DATA OBTAINED FROM GEOGRATIS, © DEPARTMENT OF NATURAL RESOURCES CANADA. ALL RIGHTS RESERVED.
2. HISTORICAL VEGETATION DIGITIZED FROM NORTH, DUNN AND TEVERSHAM. 1979. VEGETATION OF THE SOUTHWESTERN FRASER LOWLAND, 1858 TO 1880 (MAP). ENVIRONMENT CANADA.
3. HISTORICAL STREAM DIGITIZED FROM "LOST STREAMS OF THE LOWER MAINLAND (1998)", FISHERIES AND OCEANS CANADA.

DATUM: NAD83 CSRS PROJECTION: UTM ZONE 10N

CLIENT
FORTISBC ENERGY INC.

PROJECT
FORTISBC TILBURY LNG PRODUCTION AND STORAGE FACILITY EXPANSION, DELTA, BC

TITLE
STUDY AREA HISTORICAL VEGETATION AND HISTORICAL STREAM DATA

CONSULTANT

GOLDER

YYYY-MM-DD	2020-05-26
PREPARED	CM
DESIGN	JP
REVIEW	CDM
APPROVED	ARM

PROJECT NO.	PHASE	REV.	FIGURE
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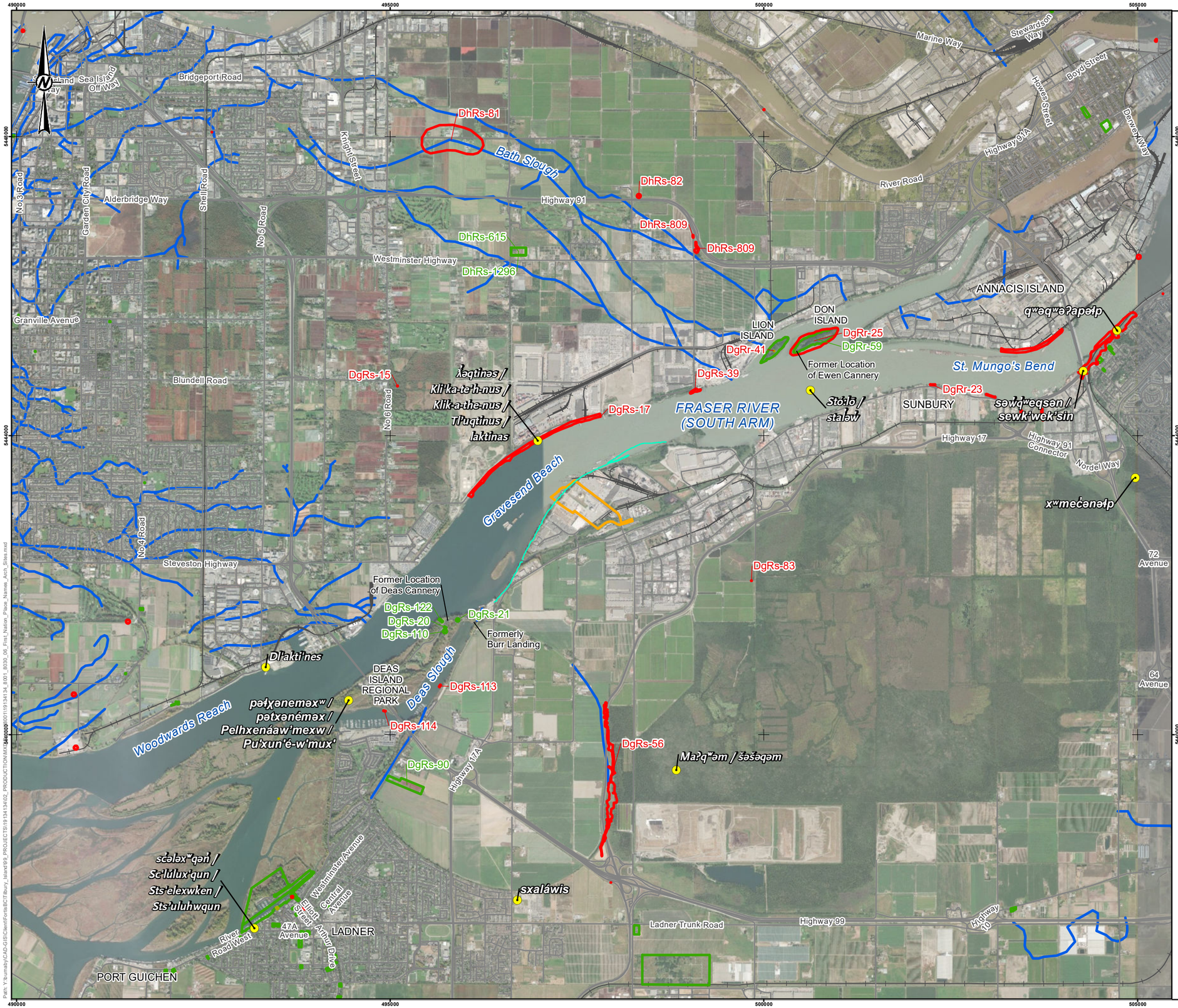

LEGEND

- STUDY AREA
- RECORDED ARCHAEOLOGIAL SITE BOUNDARY
- HISTORIC PLACE - FORMALLY RECOGNIZED
- HISTORIC PLACE - UNPROTECTED NOT RECOGNIZED
- ROAD
- RAILWAY
- HISTORIC SHORELINE c.1949
- HISTORICAL STREAM
- APPROXIMATE LOCATION OF ABORIGINAL PLACE/LAND USE AREA

Name	Translation/Description/Comments	Reference
λəqtinəs Kli'ka-te'h-nus Klik-a-the-nus Tl'uqtinus laktinas	"Long shore, long chest, beach." This was the "terrible large village" observed by the first Hudson's Bay Company traders on the South Arm. On Gravesend Reach, in the vicinity of the north end of the George Massey Tunnel. East of Woodward's Landing on the south shore of Lulu Island. Settlement site, including some year-round. Resource gathering and fishing area: berries, reeds, salmon, sturgeon.	Rozen 1979 McHalsie in K. Carlson 2001 Suttles 2004 Brealey 2010 RAAD
Dl'akti'nes	Woodward's Landing, where Ladner ferry was.	McHalsie in K. Carlson 2001
Maʔqʷəm šəšəqəm	Burns bog. Area for plants and material gathering (blueberries, cranberries, Labrador tea and sphagnum) and hunting.	Andrew Bak (Personal communication 2005) Don Welsh (Personal communication 2004)
pəɬχəneməxʷ pətxənéməx Pelhxenáaw'-mexw	"Meadow land, prairie, meadow country". An area a little above [upstream from] Ladner. The western end, meadow area, of Deas Island.	Rozen 1979 McHalsie in K. Carlson 2001 Suttles 2004
sxalá'wis	Crescent slough, located southwest of Burns Bog	Simon Pierre in Duff 1952c
sc̓əlǝxʷqən̓ Sc'lúlux'qun Sts'elexwken Sts'uluhwqun	"Going upriver to the top end; go upstream; throat." Ladner. Cohilukthan slough, which runs from Tsawwassen through Ladner to the Fraser River. There was a camping site in the Ladner area, on the south bank of the Fraser River south arm.	Rozen 1979 McHalsie in K. Carlson 2001 Suttles 2004
qʷəqʷəʔapəɬp	"Crabapple trees", Site of Glenrose Cannery	Suttles 2004
səw̓q̓ʷeqsən sewk'wek'sin	Camping ground, people live there sometimes (St. Mungo Cannery)	Edward Sparrow Sr. in Rozen 1979 RAAD
xʷmeċənəɬp	The high land from extending from Sunbury down to Mud Bay	Suttles 2004

0 1,000 2,000
1:50,000 METRES

NOTES

1. ONLY ARCHAEOLOGICAL AND HERITAGE SITES WITHIN 5KM OF THE PROJECT AREA ARE LABELLED.

REFERENCES

1. ROADS OBTAINED FROM GEOGRATIS, © DEPARTMENT OF NATURAL RESOURCES CANADA. ALL RIGHTS RESERVED.
2. RECORDED ARCHAEOLOGICAL SITES (DOWNLOADED DECEMBER 12, 2019), RAILWAYS AND WATER FEATURES PUBLISHED BY AND OBTAINED FROM THE MINISTRY OF FORESTS, LANDS, NATURAL RESOURCE OPERATIONS AND RURAL DEVELOPMENT.
3. HISTORICAL STREAM DIGITIZED FROM "LOST STREAMS OF THE LOWER MAINLAND (1998)", FISHERIES AND OCEANS CANADA.
4. HISTORICAL SHORELINE DIGITIZED FROM AERIAL PHOTOS BC783 PHOTOS 68-71. 1949.
5. IMAGERY COPYRIGHT © 20180717 ESRI AND ITS LICENSORS. SOURCE: DIGITALGLOBE,VIVID CANADA WV03. USED UNDER LICENSE, ALL RIGHTS RESERVED.

PROJECTION: NAD 1983 UTM ZONE 10

CLIENT
FORTISBC ENERGY INC.

PROJECT
FORTISBC TILBURY LNG PRODUCTION AND STORAGE FACILITY EXPANSION, DELTA, BC

TITLE
FIRST NATIONS PLACE NAMES AND RECORDED ARCHAEOLOGICAL SITES

CONSULTANT
GOLDER

YYYY-MM-DD	2020-05-26
PREPARED	CM
DESIGN	JP
REVIEW	CDM
APPROVED	ARM

PROJECT NO.	PHASE	REV.	FIGURE
19134134	8001	0	6

LEGEND

- PROJECT AREA
- RECORDED ARCHAEOLOGICAL SITE
- ROAD
- RAILWAY
- WATERCOURSE
- HISTORIC SHORELINE c.1949
- WRECK OBSERVED IN AERIAL PHOTOGRAPHS, PRE-1984

0 200 400
1:10,000 METRES

REFERENCES

1. ROADS OBTAINED FROM GEOGRATIS, © DEPARTMENT OF NATURAL RESOURCES CANADA. ALL RIGHTS RESERVED.
2. RECORDED ARCHAEOLOGICAL SITES (DOWNLOADED 20191202), RAILWAYS AND WATER FEATURES PUBLISHED BY AND OBTAINED FROM THE MINISTRY OF FORESTS, LANDS, NATURAL RESOURCE OPERATIONS AND RURAL DEVELOPMENT.
3. HISTORICAL SHORELINE DIGITIZED FROM AERIAL PHOTOS BC783 PHOTOS 68-71. 1949.
4. IMAGERY COPYRIGHT © 20180717 ESRI AND ITS LICENSORS. SOURCE: DIGITALGLOBE,VIVID CANADA WV03. USED UNDER LICENSE, ALL RIGHTS RESERVED.

PROJECTION: NAD 1983 UTM ZONE 10

CLIENT
FORTISBC ENERGY INC.

PROJECT
FORTISBC TILBURY LNG PRODUCTION AND STORAGE FACILITY EXPANSION, DELTA, BC

TITLE
SURFACE EVIDENCE OF HISTORICAL USE

CONSULTANT
GOLDER

YYYY-MM-DD	2020-05-26
PREPARED	CM
DESIGN	JP
REVIEW	CDM
APPROVED	ARM

PROJECT NO.	PHASE	REV.	FIGURE
19134134	8001	0	7

IF THIS MEASUREMENT DOES NOT MATCH WHAT IS SHOWN, THE SHEET SIZE HAS BEEN MODIFIED FROM: 25mm

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LEGEND

- PROJECT SITE
- ASSESSMENT AREA
  "A" ASSESSMENT AREA DESIGNATION
- STUDY AREA
- CADASTRAL BOUNDARY
- ROAD
- RAILWAY
- HISTORIC SHORELINE c.1949
- WATERCOURSE
- WATER OFFSET - 100m

LEGEND

- BOREHOLE (GOLDER & EQE 1996)
- BOREHOLE (GOLDER 2009)
- MACHINE TEST (STANTEC 2014)
- AUGURHOLE (GOLDER 2014A.)
- AUGERHOLE OR BOREHOLE (GOLDER 2014B)
- AUGERHOLE (GOLDER 2015B)
- BOREHOLE (GOLDER 2016)
- AUGERHOLE (GOLDER 2018)

0 80 160
1:4,000 METRES

REFERENCES

1. ROADS OBTAINED FROM GEOGRATIS, © DEPARTMENT OF NATURAL RESOURCES CANADA. ALL RIGHTS RESERVED.
2. HISTORICAL SHORELINE DIGITIZED FROM AERIAL PHOTOS BC783 PHOTOS 68-71. 1949.
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PROJECTION: NAD 1983 UTM ZONE 10

CLIENT
FORTISBC ENERGY INC.

PROJECT
FORTISBC TILBURY LNG PRODUCTION AND STORAGE FACILITY EXPANSION, DELTA, BC

TITLE
PREVIOUS STUDIES OF SUBSURFACE CONDITIONS

CONSULTANT

GOLDER

YYYY-MM-DD	2020-05-26
PREPARED	CM
DESIGN	JP
REVIEW	CDM
APPROVED	ARM

PROJECT NO.	PHASE	REV.	FIGURE
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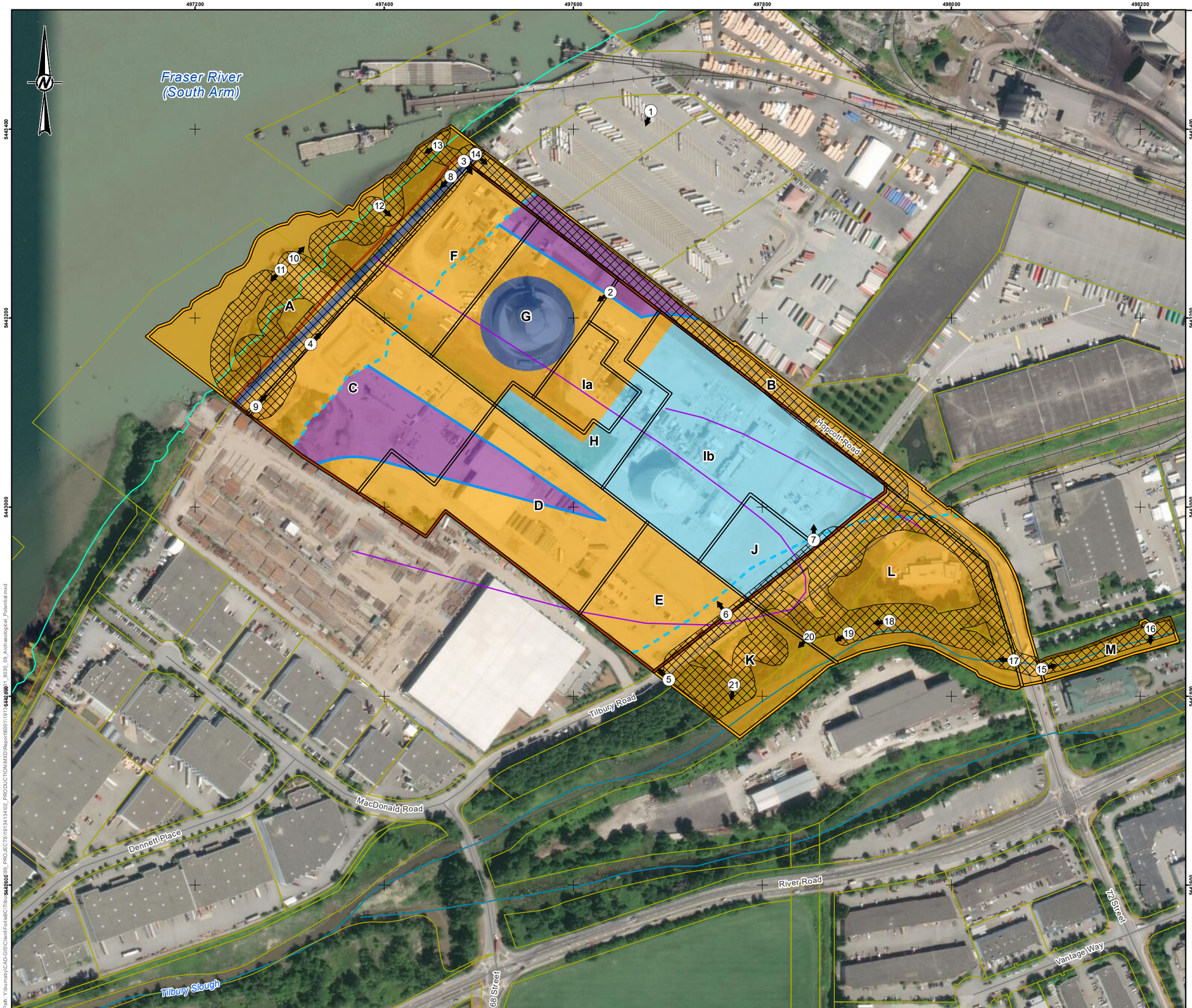

LEGEND

- PROJECT SITE
- ASSESSMENT AREA
  "A" ASSESSMENT AREA DESIGNATION
- STUDY AREA
- CADASTRAL BOUNDARY
- ROAD
- RAILWAY
- HISTORIC SHORELINE c.1949
- RELICT SLOUGH CENTRELINES (INFERRED FROM AERIAL PHOTOGRAPHS OF FIELDS FROM 1949 AND 1954)
- WATERCOURSE
- WATER OFFSET - 100m FROM HISTORICAL SHORELINE AND EXISTING SLOUGH BANK
- WATER OFFSET - 100m FROM RELICT SLOUGH CENTRELINES
- PFR SURVEY TRANSECT
- PHOTO LOCATION AND DIRECTION

ARCHAEOLOGICAL POTENTIAL

- POTENTIAL ASSESSED
- NO POTENTIAL DUE TO DISTANCE (+100 M) FROM WATERCOURSE
- NO POTENTIAL DUE TO PREVIOUS ARCHAEOLOGICAL IMPACT ASSESSMENT
- POTENTIAL REMOVED DUE TO DOCUMENTED CONSTRUCTION IMPACTS

0 80 160
1:4,000 METRES

REFERENCES

1. ROADS OBTAINED FROM GEOGRATIS, © DEPARTMENT OF NATURAL RESOURCES CANADA. ALL RIGHTS RESERVED.
2.HISTORICAL SHORELINE DIGITIZED FROM AERIAL PHOTOS BC783 PHOTOS 68-71. 1949.
3. IMAGERY COPYRIGHT © 20180717 ESRI AND ITS LICENSORS. SOURCE: DIGITALGLOBE,VIVID CANADA WV03. USED UNDER LICENSE, ALL RIGHTS RESERVED.
PROJECTION: NAD 1983 UTM ZONE 10

CLIENT
FORTISBC ENERGY INC.

PROJECT
FORTISBC TILBURY LNG PRODUCTION AND STORAGE FACILITY EXPANSION, DELTA, BC

TITLE
ARCHAEOLOGICAL POTENTIAL

CONSULTANT
GOLDER

YYYY-MM-DD	2020-02-26
PREPARED	CM
DESIGN	JP
REVIEW	CDM
APPROVED	ARM

PROJECT NO.	PHASE	REV.	FIGURE
18105553	8001	0	9

IF THIS MEASUREMENT DOES NOT MATCH WHAT IS SHOWN, THE SHEET SIZE HAS BEEN MODIFIED FROM: 25mm

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LEGEND

- PROJECT SITE
- ASSESSMENT AREA
  "A" ASSESSMENT AREA DESIGNATION
- STUDY AREA
- CADASTRAL BOUNDARY
- ROAD
- RAILWAY
- HISTORIC SHORELINE c.1949
- RELICT SLOUGH CENTRELINES (INFERRED FROM AERIAL PHOTOGRAPHS OF FIELDS FROM 1949 AND 1954)
- WATERCOURSE
- WATER OFFSET - 100m FROM HISTORICAL SHORELINE AND EXISTING SLOUGH BANK
- WATER OFFSET - 100m FROM RELICT SLOUGH CENTRELINES

ARCHAEOLOGICAL POTENTIAL AND SENSITIVITY

- POTENTIAL ASSESSED AT SURFACE OR NEAR SURFACE
- DEEP POTENTIAL NOT REMOVED
- DEEP POTENTIAL SUBSURFACE DATA ABSENT
- DEEP POTENTIAL LIKELY REMOVED
- NO ASSESSED POTENTIAL (ABSENT OR REMOVED)

0 80 160
1:4,000 METRES

REFERENCES

1. ROADS OBTAINED FROM GEOGRATIS, © DEPARTMENT OF NATURAL RESOURCES CANADA. ALL RIGHTS RESERVED.
2.HISTORICAL SHORELINE DIGITIZED FROM AERIAL PHOTOS BC783 PHOTOS 68-71. 1949.
3. IMAGERY COPYRIGHT © 20180717 ESRI AND ITS LICENSORS. SOURCE: DIGITALGLOBE,VIVID CANADA WV03. USED UNDER LICENSE, ALL RIGHTS RESERVED.
PROJECTION: NAD 1983 UTM ZONE 10

CLIENT
FORTISBC ENERGY INC.

PROJECT
FORTISBC TILBURY LNG PRODUCTION AND STORAGE FACILITY EXPANSION, DELTA, BC

TITLE
ARCHAEOLOGICAL SENSITIVITY

CONSULTANT
GOLDER

YYYY-MM-DD	2020-05-26
PREPARED	CM
DESIGN	JP
REVIEW	CDM
APPROVED	ARM

PROJECT NO.	PHASE	REV.	FIGURE
18105553	8001	0	**10**

LEGEND

- PROJECT SITE
- ASSESSMENT AREA
  "A" ASSESSMENT AREA DESIGNATION
- STUDY AREA
- CADASTRAL BOUNDARY
- ROAD
- RAILWAY
- WATERCOURSE

ARCHAEOLOGICAL RECOMMENDATIONS

- CONDUCT AIA PRIOR TO CONSTRUCTION (LOCAL AREAS OF PRIOR DISTURBANCE, SUCH AS BURIED PIPELINES EXCEPTED)
- PROCEED WITH CFMP FOR ANY WORKS; FOR WORKS EXTENDING IN DEPTH BELOW 40 cm CONDUCT AIA AND/OR MONITORING (DEPENDANT ON TYPE OF WORK)
- PROCEED WITH CFMP FOR ANY WORKS; FOR WORKS EXTENDING IN DEPTH BELOW 4.0m CONDUCT MONITORING (DEPENDANT ON TYPE OF WORK)
- PROCEED WITH CFMP FOR ANY WORKS

0 80 160
1:4,000 METRES

REFERENCES

1. ROADS OBTAINED FROM GEOGRATIS, © DEPARTMENT OF NATURAL RESOURCES CANADA. ALL RIGHTS RESERVED.
2. IMAGERY COPYRIGHT © 20180717 ESRI AND ITS LICENSORS. SOURCE: DIGITALGLOBE,VIVID CANADA WV03. USED UNDER LICENSE, ALL RIGHTS RESERVED.

PROJECTION: NAD 1983 UTM ZONE 10

CLIENT
FORTISBC ENERGY INC.

PROJECT
FORTISBC TILBURY LNG PRODUCTION AND STORAGE FACILITY EXPANSION, DELTA, BC

TITLE
SUMMARY OF ARCHAEOLOGICAL RECOMMENDATIONS

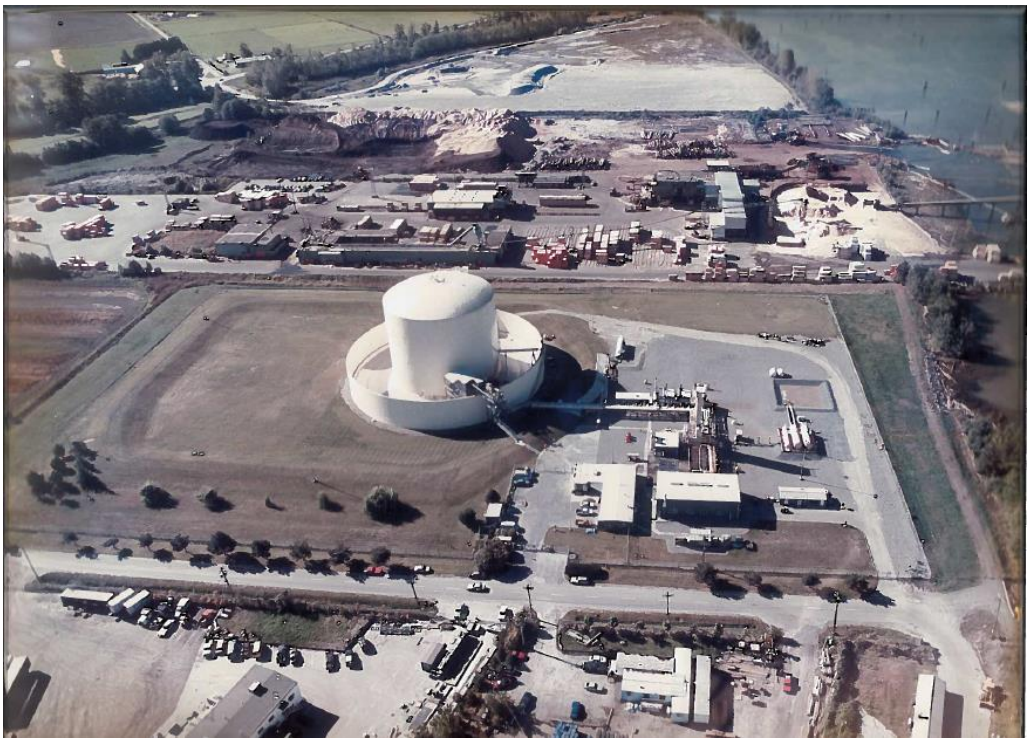
CONSULTANT
GOLDER

YYYY-MM-DD	2020-05-26
PREPARED	CM
DESIGN	JP
REVIEW	CDM
APPROVED	ARM

PROJECT NO.	PHASE	REV.	FIGURE
18105553	8001	0	11

APPENDIX A

Select Photographs



Photograph 1: Aerial view to southwest, 1995, of peakshaving facility with original storage tank, supporting infrastructure, surrounding concrete dam (white), and earthen berm. Area to west of the berm is still agricultural field, while the two properties to north are occupied by the sawmill, and piles of wood waste from the mill, respectively (image courtesy of FortisBC).

Photograph 2: Original storage tank under construction with original ground surface stripped, and gravel base over wooden piles (not visible) under the tank (image courtesy of FortisBC).

Photograph 3: View south from dyke into assessment area F, with original tank and supporting infrastructure.

Photograph 4: View north along dyke, in assessment area A with assessment areas C and F to the right.

Photograph 5: View northwest from Tilbury Road over assessment areas E and D towards C and A,.

Photograph 6: View northwest at transition between assessment areas E, Ib and J, with original and Phase 1A storage tanks.

Photograph 7: View north to electrical sub-station, assessment area Ib, near the intersection of Hopcott and Tilbury roads.

Photograph 8: View southwest along dyke, assessment area A. Assessment area C to the left. Note boulder armouring to the right, and trees that have likely grown within the last 50 years.

Photograph 9: View northeast with upgraded dyke top to the left and assessment area C to the right.

Photograph 10: View northwest from stub wharf toward rail terminal jetties and intertidal area of assessment area A.

Photograph 11: View southeast of intertidal area in assessment area A from stub wharf.

Photograph 12: View of rip-rap armouring from older dyke construction in assessment area A.

Photograph 13: View west of piles believed to be the remains of a wharf built prior to 1939 in assessment area A.

Photograph 14: View southwest down Hopcott Road of assessment area B from the dyke.

Photograph 15: View northwest from Tilbury Road of brushed area within pipeline right of way; rush-filled portion of Tilbury Slough to right, assessment area M.

Photograph 16: View south over Tilbury Slough near where pipeline crosses it, near the west end of assessment area M.

Photograph 17: View southeast from Tilbury Road of Tilbury Slough, assessment area L.

Photograph 18: View southeast in Tilbury Slough, assessment area L.

Photograph 19: View southeast of Tilbury Slough, near the boundary between assessment areas K and L.

Photograph 20: Large cedar tree near in assessment K in partially forested area. This tree is mature and may be observed standing alone near Tilbury Slough in aerial photographs dating back to 1939.

Photograph 21: A pump station and standpipe near the bank of Tilbury Slough and the southern edge of assessment area K.

APPENDIX B

Stó:lō Research and Resource Management Centre Database Search Review

SRRMC TUS Database Search Result – Data Sheet
PROJECT: 2019-252 Moore - Tilbury LNG Facility
REQUESTED: C. Moore/Golder Associates Ltd.
DATE: December 2, 2019

The information provided in this report is the result of a digital database review for the above referenced project conducted by the Stó:lō Research and Resource Management Centre (SRRMC) on behalf of Golder Associates Ltd. This review is limited in scope and is not to be considered a comprehensive treatment of First Nations interests or concerns associated with the proposed project. This assessment focuses on the relationship between cultural heritage resources defined in the Stó:lō Heritage Policy and the proposed project plan(s). This report is intended to provide information useful to Golder Associates Ltd. and FortisBC in the archaeological overview assessment process. This report does not constitute consultation and does not in any way satisfy or complete the First Nation consultation requirements of Golder Associates Ltd. and FortisBC with the Stó:lō Nation, the Stó:lō Tribal Council, the S'ólh Téméxw Stewardship Alliance, or any other First Nations or First Nations organizations.

***Findings*:**

1. *Sxwôxwiyám*
2. *Halq'eméylem* Place Name
3. GIS Modeled Travel Route
4. Archaeological Potential

***Sxwōxwiyám*: 1 within the Study Area (as depicted in Figure 1)**

Site ID	Type	Translation/Significance	Proximity
Stó:lō 2012i47s119	*Sxwôxwiyám: Xéyt*	Fraser River from Spuzzum Creek to the mouth of the river; "river" * the Fraser River is also designated as a sensitive waterway in the Stó:lō Land Use Plan (*S'ólh Téméxw* Use Plan; SRRMC 2018)	within

Sxwōxwiyám relate to core and integral elements of Stó:lō cultural traditions and identity. *Sxwōxwiyám* form a connection and articulation among the collective identity and ancestral relations shared between the Stó:lō, broadly, as connected to villages and tribes at more local levels. These types of cultural heritage sites are among the most highly significant types of sites recognized by the Stó:lō. Often these places are directly related to Transformer Narratives. The significance of *Sxwōxwiyám* to the Stó:lō community and the need to maintain their integrity with regard to all forms of potential impact cannot be overstated.

10-7201 Vedder Road
Chilliwack, BC V2R 4G5
604.824.2420 phone
604.824.0278 fax

www.srrmcentre.com
admin@srrmcentre.com

***Halq'eméylem* Placename: 1 within the Study Area (as depicted)**

Site ID	Location	Proximity
Stó:lō 2012i47s119	Fraser River from Spuzzum Creek to the mouth of the river; "river" * the Fraser River is also designated as a sensitive waterway in the Stó:lō Land Use Plan (*S'ólh Téméxw* Use Plan; SRRMC 2018)	within

Places on the landscape with Halq'eméylem names are important to distinguish, in that they have the potential to provide insight into the cultural significance of a particular place, such as the significance of the geographic location itself, activities or events that took place there, or stories of the distant past, when the world was transformed into its present form (*sx̱wóx̱wiyám*). There are over 700 Halq'eméylem place names throughout S'ólh Téméxw. They also exist as places of power in a living landscape, upon which people seek spiritual power through various Stó:lō ceremonial and ritual activities.

GIS Modeled Travel Route1: 1 within the Study Area (as depicted)

Site ID	Location	Proximity
2014r72s56	modeled east-west along the south shore of the Fraser River	within

GIS-modeled trails are travel routes that are either thought to exist, but their existence has not been verified, or modeled to exist based on other known factors such as the movement of people in a specific area. GIS-modeled trails require ground-truthing.

The GIS-Modeled Travel Route identified above was extrapolated based on findings and characteristics of documented trails reviewed in the Tracking the Ancestors pilot study (1999). Trails were recorded and modeled at a scale of 1:130,000. A buffer is used to display the general location of the trails.

All of *S'ólh Téméxw* was used for hunting and resource gathering activities. Stó:lō use of the surrounding area for fishing, hunting, gathering, and spiritual use has been documented by a variety of sources including traditional use studies, oral history, and ethnography.

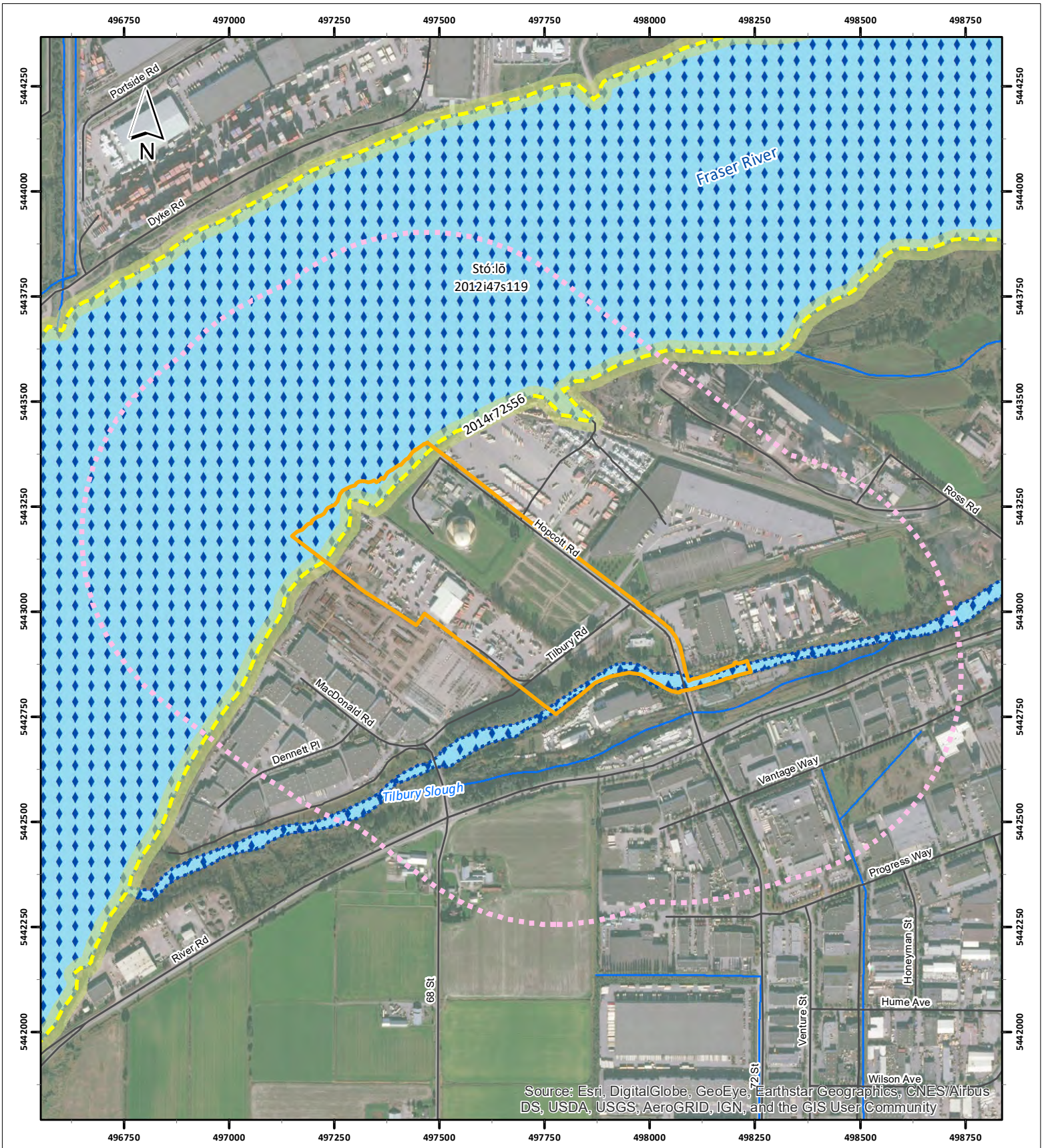
Archaeological Potential

The Study Area has archaeological potential because it is located along the Fraser River, and it is in close proximity to *Halq'eméylem* named places and modeled travel routes.

If you have any questions about the content of this report, the Stó:lō Heritage Policy and/or its implementation, please contact me at (w) 604-824-2425, (c) 604-819-5271 or email at lisa.dojack@stolonation.bc.ca. Additional information regarding specific sites identified in this database evaluation is available for review in the archives on-site at the SRRMC in the Stó:lō Resource Management Centre office in Chilliwack.

Sincerely,

Lisa Dojack, M.A.
Project Archaeologist/GPR Specialist
Stó:lō Research and Resource Management Centre



SRRMC TUS Database Search Result
PROJECT: 2019-252 Moore - Tilbury LNG Facility
REQUESTED: C. Moore/Golder Associates Ltd.

GIS: SBF
November 29, 2019

Study Area
500 m Buffer
GIS-Modeled Travel Route
Road
Sxwōxwiyám/Halq'eméylem Placename
Water

0 100 200 300 400 m

1:12,000

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Appendix Q

CONSULTATION AND ENGAGEMENT

Appendix Q-1

INITIAL PROJECT DESCRIPTION

Tilbury Phase 2 LNG Expansion Project

Initial Project Description

February 2020

List of Contributors to the Initial Project Description

Contributors	Credentials	Section(s)	Relevant Experience
Todd Smith	P.Eng.	Section 2 (Project Overview)	20+ years experience in engineering, construction and business development for energy projects and utilities
Ian Finke	P.Eng., MBA	Section 2 (Project Overview)	20+ years experience in engineering and business development for various industries
Olivia Stanley	MA, Public Policy	Section 11 (Engagement and Consultation with Indigenous Groups)	6 years of Indigenous engagement experience
Courtney Hodson	BBA	Section 12 (Engagement and Consultation with Governments, the Public and other Parties)	4 years of Stakeholder engagement experience
Lynne Chalmers	M.Sc., Conservation Ecology	All	11 years of experience writing environmental impact assessments for oil and gas projects
Carmen Holschuh	M.Sc., R.P.Bio.	All	15 years of BC and oil and gas regulatory experience
Tara Lindsay	B.Sc., RPP, P.Ag.	All	12 years of BC and oil and gas regulatory experience
Mike Climie	B.Sc., R.P.Bio., P.Biol.	Section 10 (Environmental, Economic, Social, Heritage and Health Effects)	12 years of BC and oil and gas regulatory experience
Andy Smith	M.Sc., R.P.Bio., P.Biol.	Section 10 (Environmental, Economic, Social, Heritage and Health Effects)	20+ years of experience in ecology

Contents

Appendixes

Tables

Figures

Acronyms and Abbreviations

AIF	Archaeological Information Form
AIA	Archaeological Impact Assessment
AOA	Archaeological Overview Assessment
BC	British Columbia
BC CDC	BC Conservation Data Centre
BC *EAA*	BC *Environmental Assessment Act*
BC EAO	BC Environmental Assessment Office
BCF	billion cubic feet
BC MFLNRORD	BC Ministry of Forests, Lands, Natural Resource Operations and Rural Development
BC *OGAA*	BC *Oil and Gas Activities Act*
BC OGC	BC Oil and Gas Commission
BCUC	British Columbia Utilities Commission
CAC	criteria air contaminant
CAD	Consultative Areas Database
CEA	Cumulative Effects Assessment
CH_4	methane
cm	centimetre(s)
CNA	Cowichan Nation Alliance
CO_2	carbon dioxide
CO2e	carbon dioxide equivalent
CO_2e/year	carbon dioxide equivalent per year
COSEWIC	Committee on the Status of Endangered Wildlife
CPCN	Certificate of Public Convenience and Necessity
CSA	Canadian Standards Association
CTS	Coastal Transmission System
Delta	City of Delta
DFO	Fisheries and Oceans Canada
DPD	Detailed Project Description
EA	Environmental Assessment
EAC	Environmental Assessment Certificate
EMP	Environmental Management Plan
FBC	FortisBC Inc.
FEED	Front-End Engineering Design
FEI	FortisBC Energy Inc.
FortisBC	FortisBC Holdings Inc.
GBA+	Gender-based Analysis Plus
GHG	greenhouse gas
ha	hectare(s)

HCA	*Heritage Conservation Act*
IA	Impact Assessment
IAA	*Impact Assessment Act*
IAAC	Impact Assessment Agency of Canada (replaced CEAA)
IBA	Important Bird Area
IPD	Initial Project Description
km	kilometre(s)
km^2	square kilometre(s)
kV	kiloVolt(s)
LNG	liquefied natural gas
LSA	Local Study Area
m	metre(s)
m^3	cubic metre(s)
masl	metre(s) above sea level
mtpa	million tonne(s) per annum
NO	nitrogen oxide
NRCan	Natural Resources Canada
OBE	Operating Basis Earthquake
OCP	Official Community Plan
OIC	Order-In-Council
PGV	Peak Ground Velocity
PJ	petajoule(s)
Project	Tilbury Phase 2 LNG Expansion Project
Project Site	7651 Hopcott Road, on Tilbury Island in the City of Delta, British Columbia
QEP	Qualified Environmental Professional
ROW	right-of-way
RSA	Regional Study Area
SARA	*Species at Risk Act*
SSE	Safe Shutdown Earthquake
t/d	tonnes per day
TBD	to be determined
TLU	Traditional Land Use
VC	Valued Component
WesPac	WesPac Midstream Ltd.
WMA	Wildlife Management Area

1. Introduction

FortisBC Holdings Inc (FortisBC) with its natural gas subsidiary FortisBC Energy Inc. is proposing to expand its existing liquefied natural gas (LNG) facility at 7651 Hopcott Road, on Tilbury Island in the City of Delta (Delta), British Columbia (BC) (Figure 1-1) (the Project Site).

The Tilbury Phase 2 LNG Expansion Project (the Project) is being proposed to increase the production and storage of LNG to improve security of supply to FortisBC's approximately 1.1 million natural gas customers in BC and to supply incremental LNG to the marine transportation and export markets. The Project also introduces opportunities to upgrade existing infrastructure to current design standards and technologies and to align with the Government of BC's CleanBC Plan.

The Project comprises an expansion of up to 162,000 cubic metres (m^3) (approximately 4.0 petajoules [PJ]) of LNG storage and up to 11,000 tonnes per day (t/d) of LNG production. The Project will receive natural gas at the Project Site through established pipeline systems. It will connect to FortisBC's existing LNG facilities (such as, vapourization and gas send-out facilities) to support security of natural gas supply to gas utility customers and the proposed WesPac Midstream Ltd. (WesPac) Tilbury Marine Jetty project for marine LNG bunkering and LNG export.

This Initial Project Description (IPD) was prepared in accordance with guidance under both the Federal *Impact Assessment Act* (*IAA*) and the BC *Environmental Assessment Act* (BC *EAA*). Tables of Concordance referencing the locations of required information in this IPD are provided in Appendix A and B, respectively.

There is a need to increase the LNG storage in the Region as back-up to the Regional gas supply system. LNG production will be constructed as LNG market demand is realized. This could be in the form of two or more LNG production trains built initially or phased over multiple years with ultimate completion anticipated prior to 2028. Detailed engineering and construction for the Project is expected to begin in 2021/22.

The Project is located within Delta, on a long-standing brownfield site owned by FortisBC and zoned as I7: High Impact Industrial for uses including natural gas and petroleum products. The existing FortisBC LNG facility includes the original production and storage facility in operation since 1971 (base plant), a Phase 1 production and storage expansion in operation since 2018 (Phase 1A), and ancillaries including power supply, gas supply, and both natural gas and LNG distribution facilities to serve public utility customers. Parts of the Project are expected to occur within the footprint of the existing 50-year-old liquefaction and storage plant. Facilities that are not a part of this Project include the existing production and storage facilities including Phase 1 expansions as these activities do not trigger a Provincial Environmental Assessment (EA) pursuant to the BC *EAA* or Impact Assessment (IA) pursuant to the Federal *IAA* and *Physical Activities Regulations* and are independent of the Project.

The proposed Tilbury Phase 2 LNG expansion project is reviewable under the current BC *EAA* (*Reviewable Projects Regulation*) and under Canada's *IAA* and *Physical Activities Regulations.* Further details about the Provincial and Federal processes is provided in Section 8. Appendix A provides a concordance table for guidance from the BC Environmental Assessment Office (BC EAO), as well as the Impact Assessment Agency of Canada (IAAC), *Information and Management of Time Limits Regulations*.

The EA Application completed for the WesPac Tilbury Marine Jetty project (submitted in March 2019), situated adjacent to the Project, is the closest EA to the Project Site. Publicly available information from that EA will be reviewed and any relevant information will be incorporated into the EA prepared for the current Project. In addition, Stantec Consulting Ltd. conducted an Archaeological Impact Assessment (AIA) in 2013 for the FortisBC Phase 1A expansion and it is expected WesPac will be conducting and AIA on FortisBC's property related to the Marine Jetty Project. The AIA will also be reviewed for any relevant information for the EA.

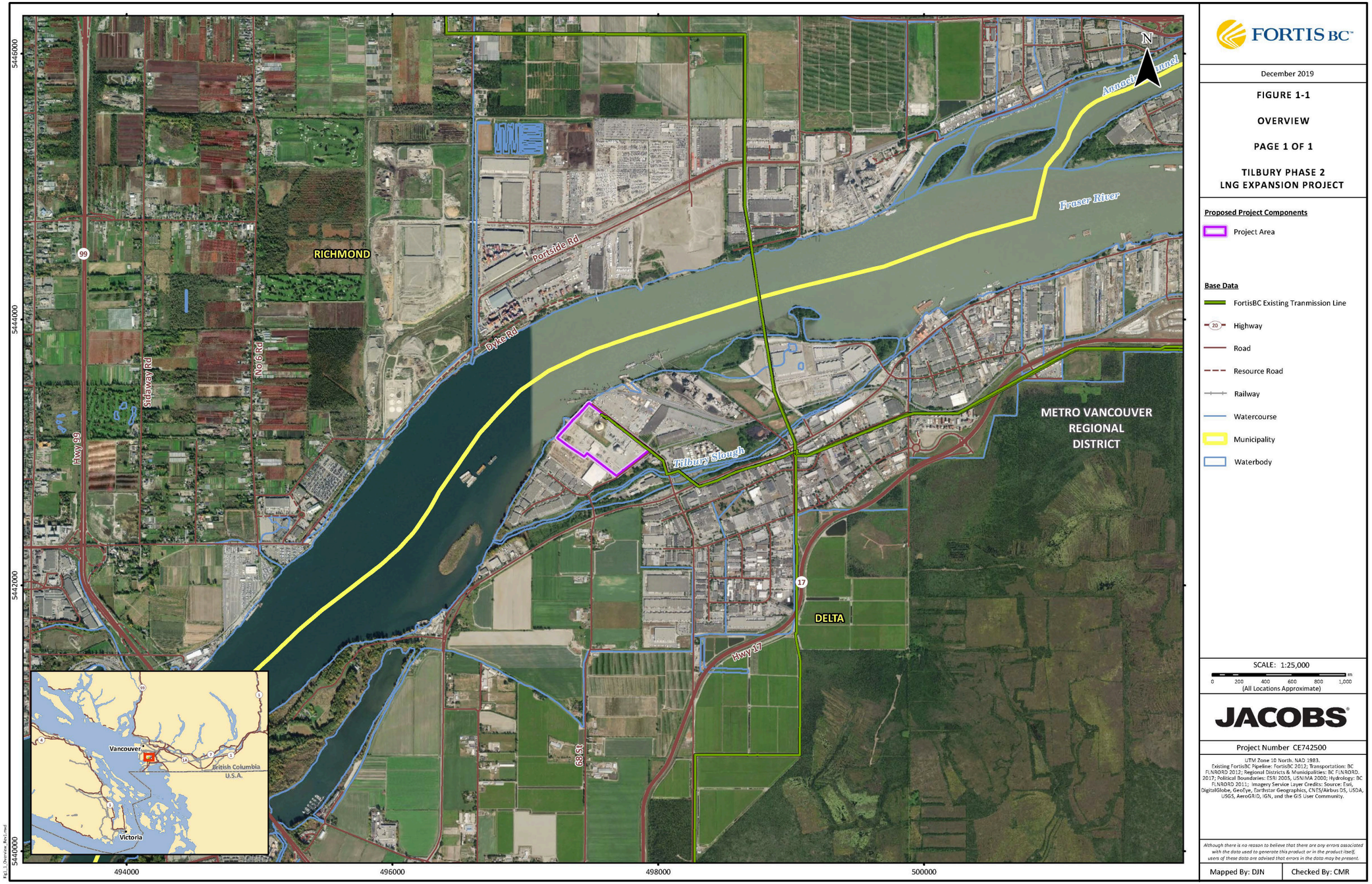

Figure 1-1. Project Overview

1.1 Proponent Information

1.1.1 Project Contacts

Table 1-1. Project Information and Key Contacts

Project Name	Tilbury Phase 2 LNG Expansion Project
Proponent	FortisBC Holdings Inc.
Proponent Corporate Address	16705 Fraser Highway Surrey, BC V4N 0E8
Proponent Website	http://www.fortisbc.com
Project Website	https://talkingenergy.ca/project/tilbury-LNG-expansion-project
Proponent President and CEO	Roger Dall'Antonia
Principle Contacts for the EA	Todd Smith Business Development Manager Tel: 604-785-6514 Email: todd.smith@fortisbc.com

1.1.2 Corporate Overview

FortisBC Holdings Inc. (FortisBC) has subsidiary companies that include gas, LNG, and alternative energy utilities in BC. FortisBC Energy Inc. (FEI) is the gas utility and owner/operator of the Tilbury LNG facility. FEI is a subsidiary of FortisBC, a BC based company, which is a subsidiary of Fortis Inc. a publicly traded company on both the TSX and NYSE. Fortis Inc. is also the parent company of FortisBC Inc. (FBC) an electrical utility operating in BC. Combined, FortisBC and FBC employ more than 2,400 people, working to deliver natural gas, electricity, and energy solutions to 1.2 million customers across 135 communities in BC. FortisBC owns and operates approximately 49,000 kilometres (km) of natural gas transmission and distribution pipelines, and FBC owns and operates approximately 7,260 km of electric transmission and distribution power lines and four hydroelectric generating plants. FortisBC's infrastructure assets include BC's largest underground natural gas storage facility and two LNG production and storage facilities.

FortisBC is committed to supporting BC's transition to a low-carbon economy. To do this successfully, a balance needs to be achieved with respect to financial, environmental, and social factors. In 2018, FortisBC released its plan to reduce emissions, the Clean Growth Pathway to 2050, as part of the consultation surrounding the Province's CleanBC strategy. The Clean Growth Pathway outlined four key areas to make substantial reductions in greenhouse gas (GHG) emissions across the Province including positioning BC as a vital domestic and international LNG provider to lower global GHG emissions.

In September of 2019, FortisBC announced one of the most ambitious emissions reduction targets in the Canadian utility sector by committing to work to reduce customers' emissions by 30 percent overall by the year 2030. FortisBC aims to achieve its "30 by 30" target in part by supporting a shift away from higher emitting energy sources such as coal, bunker oil, and diesel to cleaner burning LNG in the global market for energy. FortisBC's focus on sustainability is about prioritizing the health and well-being of customers, communities, the environment, and employees. FortisBC is an equal opportunity employer and supports an inclusive and diverse work-force.

FortisBC is committed to building effective Indigenous relationships and to ensuring the structure, resources, and skills necessary to maintain these relationships are in place. To meet this commitment, the actions of FortisBC and its employees are guided by the principles included in FortisBC's Statement of Indigenous Principles included in Section 11.4.

FortisBC is committed to delivering safe, reliable energy in an environmentally responsible manner to all of the communities that we serve. This commitment is guided by our Safety and Environment Policy and is supported by an Environmental Management system. As part of meeting this commitment FortisBC will:

- comply with safety and environmental legislation, and operate in accordance with accepted industry practices and standards, and require the same of our contractors
- commit to injury and incident prevention, the conservation of resources, and the prevention of pollution
- identify and manage operational hazards, and minimize risks that have the potential for adverse consequences
- train employees to be aware of and meet their responsibilities in the areas of safety and environmental stewardship
- communicate openly with employees, the general public, and all stakeholders about activities and the potential impacts on safety and environment
- support community-oriented safety and environmental initiatives and programs
- review the safety and environmental policy on a regular basis, regularly monitor safety and environmental performance, and strive for continual improvement

The Tilbury LNG facility has been providing natural gas to customers safely and reliably since 1971. It contributes to security of supply, reliability, and operational flexibility for FortisBC's natural gas customers. As a regulated public utility, FEI has an obligation to meet current and future natural gas requirements. Demand for natural gas is growing as, for instance, the marine transportation segment transitions toward LNG fuel in order to meet international emissions regulations, save on fuel costs, and reduce their reliance on diesel and marine oils. Marine operators including BC Ferries and Seaspan Ferries currently operate LNG fueled vessels and are planning to expand their fleets. FortisBC is also providing LNG and compressed natural gas as fuel for on road transportation customers including trucking fleets, waste haulers, and bus fleets helping them transition to a lower emission fuel. Since 2017, FortisBC has been supplying LNG into purpose-built shipping containers for customers who export to China. These shipments are an efficient way to move LNG to small-scale industrial or residential customers for their heating and electricity needs as an alternative to coal and oil.

FortisBC's LNG facilities have a variety of special features designed for the safe production and handling of LNG - including active monitoring, control, and alarm systems. In addition to the Tilbury LNG facility, FortisBC owns and operates the Mt. Hayes LNG facility located approximately 6 km northwest of Ladysmith BC, and the Aitken Creek underground natural gas storage facility near Fort St. John. The Mt. Hayes LNG facility holds approximately 70,000 m^3 (1.7 PJ) of LNG and the Aitken Creek facility has a working gas capacity of approximately 85 PJ (77 billion cubic feet [BCF]) (FortisBC 2016).

The Mt. Hayes LNG facility is operated by FortisBC and is owned by a limited partnership called Mt. Hayes Limited Partnership with FortisBC and local Indigenous partners as co-owners. This partnership has been in place since 2011 and demonstrates the commitment and mutual benefits of working together with Indigenous Groups.

FortisBC has received Provincial Environmental Assessment Certificates (EACs) on two projects. Southern Crossing Natural Gas Project, an approximately 300 km natural gas pipeline from Yahk to Oliver, BC received an EAC (E99-03) in 1999 and was constructed in 2000. The Eagle Mountain-Woodfibre Gas Pipeline Project, an approximately 50 km natural gas pipeline from Coquitlam to Squamish, received an EAC (E16-01) in 2016.

1.1.2.1 The Tilbury LNG Facility

The original Tilbury LNG facility was constructed in Delta on Tilbury Island in 1971 and has been operating successfully as a storage and peak shaving facility for the benefit of natural gas utility customers in BC. A peak shaving facility allows for uninterrupted supply to customers under peak

demand (winter) conditions or during periods of gas supply disruption by re-gasifying the stored LNG and injecting it back into the local grid as gas send-out. The original Tilbury LNG facility has LNG production of approximately 60 t/d and LNG storage of 28,000 m^3 (0.69 PJ). In addition to the liquefaction and storage tank, the original Tilbury LNG facilities also include LNG vaporizers for returning liquid to a gas, interconnects (gas feed and send-out), liquefaction refrigerant storage and truck loading. Portions of the nearly 50-year-old LNG facility may be retired and removed as part of the normal course of the regulated utility business at some point in the future. These activities will be considered and coordinated with all other activities at the FortisBC Tilbury LNG facility including operation of Phase 1 LNG facilities and construction of the proposed Project and will be subject to authorizations and permits from applicable regulators including the BC Utilities Commission (BCUC) and BC Oil and Gas Commission (BC OGC).

FortisBC began construction of its Tilbury "Phase 1" Expansion in 2014, which was approved by the BC government through BC Order-in-Council (O.C. 557/2013) Direction No. 5 to the BCUC under the *Utilities Commission Act* (OIC). The OIC approves certain projects that the BC government determined were in the public interest for the public utility to undertake and how costs should be treated by the BCUC, the Provincial regulator for public utilities. The facilities that make up the Phase 1 Expansion included in the OIC comprises:

- Phase 1A facilities: additional LNG production, storage tank, and truck loading facilities (LNG storage: 46,000 m^3 [1.1 PJ]; liquefaction: 700 t/d)
- Phase 1B facilities: connecting to Phase 1 tank, additional LNG production, and distribution
- Coastal Transmission System (CTS) expansion: various FEI gas transmission expansion projects including the upgrade of an approximately 1 - 3 km line between Tilbury Gate Station and Tilbury LNG facility (Tilbury Gate Station).

None of the Phase 1 expansion facilities, either on their own or collectively, trigger an environmental or impact assessment under either Provincial or Federal legislation.

The Phase 1 facilities are described in more detail as follows for context as existing or in-progress activities separate and distinct from the proposed Project.

Phase 1A was constructed between 2014 and 2018 and has been in operation since 2018. Phase 1A includes natural gas liquefaction of approximately 700 t/d and an LNG storage tank (Phase 1 tank) of approximately 46,000 m^3 (1.1 PJ) and has received BC OGC facility permits and Metro Vancouver emission permits.

Phase 1B facilities are in design and engineering stages with an in-service-date planned for 2023. Phase 1B facilities include natural gas liquefaction of up to 2,000 t/d bringing the total facility liquefaction capacity to a maximum of 2,760 t/d (base plant plus both Phase 1A and 1B). Both Phase 1A and 1B liquefaction facilities are or will be connected to the existing Phase 1 tank. Phase 1 facilities may also include new LNG vapourizers to provide reliable gas send-out capacity from the Phase 1 tank. The CTS Tilbury Gate Station gas transmission expansion is to upgrade this short segment for seismic integrity and increase gas send-out capacity. Both Phase 1A and 1B liquefaction facilities use electric drives for the compression needed for natural gas liquefaction to minimize emissions. There are no power generation facilities on-site other than back-up power for emergency systems. Power is provided from BC Hydro's Arnott Substation. Additional upgrades to the power supply are anticipated for Phase 1B including an approximately 6 km, 230 kilovolt (kV) power line from the BC Hydro Arnott substation. This upgrade will consider the Project needs such that further upgrades can be minimized or avoided to reduce costs, disturbance, and impacts.

Phase 1 facilities or activities, either separately or collectively, do not trigger an EA or IA under either Provincial or Federal legislation or regulations. The Province has approved Phase 1 to proceed since 2013 and are currently either in operation or engineering stage. Phase 1 would proceed independently of the proposed Project. Phase 1 facilities can be built and operated independent of Phase 2 and are needed and would proceed whether or not the proposed Project proceeds. The Project would utilize certain existing and Phase 1 facilities including an interconnect with Phase 1 230-kV substation on-site

(for liquefaction), and connection to the LNG vaporizers (from the Project LNG tank) to provide additional LNG for incremental gas send-out duration to support the natural gas system and resiliency. Phase 1 facilities or activities have been and will be subject to regulatory and permitting review including public and Indigenous consultation requirements through the BC OGC and other agencies. Figure 1-2 shows the Tilbury existing and Phase 1 expansion facilities. Table 1-2 provides a summary of the Tilbury existing and Phase 1 expansion facilities and activities. A description of the proposed Project (Phase 2) is provided in the next section.

Existing plant modifications and Phase 1 projects are subject to ongoing regulatory oversight and public and Indigenous consultation requirements as required by the BCUC, BC OGC, and various other permitting agencies. BC OGC public and Indigenous consultation and notification requirements are described in the Consultation and Notification Regulation under the BC *Oil and Gas Activities Act* (BC *OGAA*) and the Oil and Gas Activity Application Manual (BC OGC 2019). Prior to submitting an application to the BC OGC, FortisBC is required to formally notify and consult potentially affected land owners, rights holders, and Indigenous Groups. Stakeholders and Indigenous Groups have an opportunity to provide written responses to the proposed application. FortisBC is required to address all written responses before the BC OGC will accept an application. The application will include a record of all responses from stakeholders and Indigenous Groups and details about how responses were addressed. In addition, anyone with an interest or concern about the proposed activity and/or its proposed location can make a written submission to the BC OGC at any time during the application process.

WesPac is proposing to construct a marine jetty next to the Project Site to supply LNG to the marine transportation sector and for export. WesPac's project is separate and distinct from the proposed Project. The WesPac project is currently undergoing a combined Federal and Provincial EA, under a substituted Provincial process that is led by the BC EAO that includes assessments for shipping and loading activities that considers the Phase 1 and Project LNG production and distribution capacities.

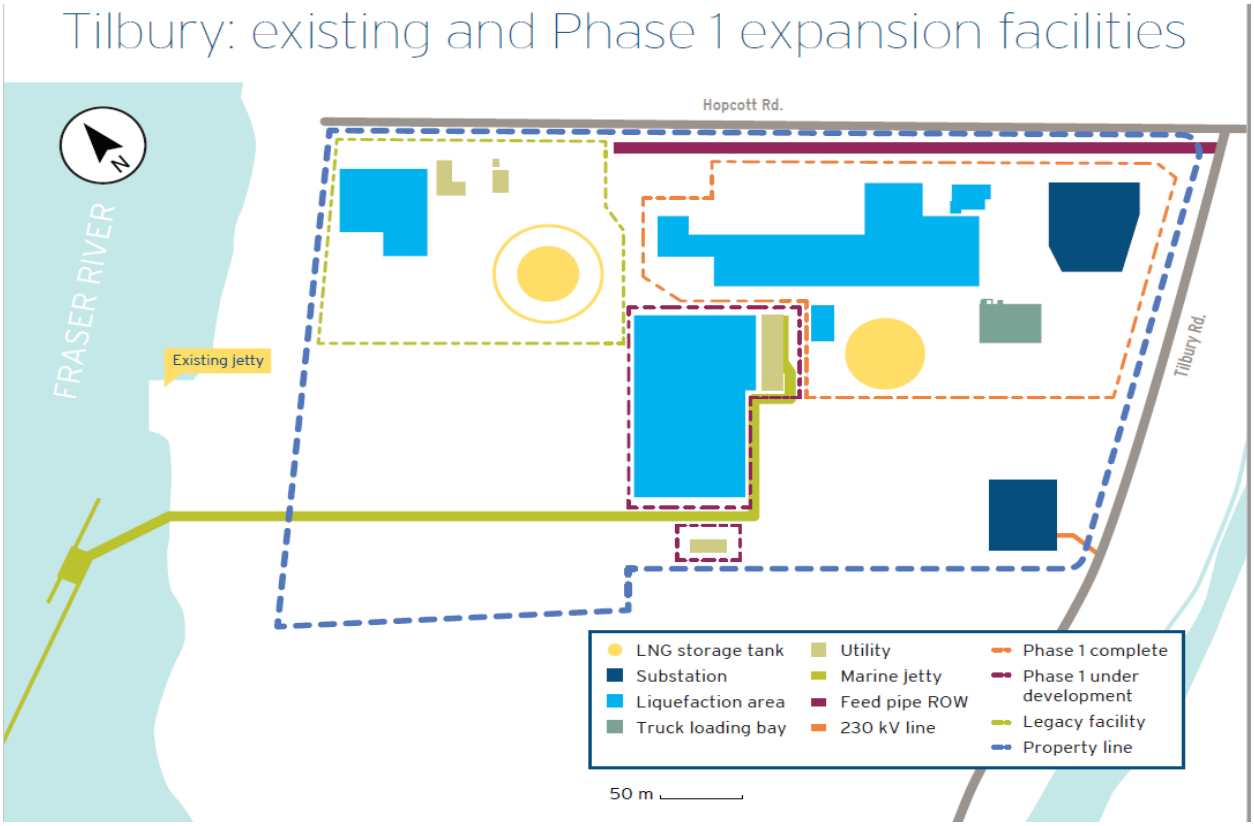

Figure 1-2. Existing and Phase 1 Facilities
Source: FortisBC

Table 1-2. Tilbury Existing and Phase 1 Facilities

Phase / Expansion	Description	In-Service Date	Size	Owner	Key Regulator
Tilbury base plant	Original LNG facility	1971	Tank: 28,000 m^3 (0.69 PJ) LNG: 60 t/d	FEI	BCUC / BC OGC / Metro Vancouver
Tilbury base plant retirement	Retirement and removal of original 50-year-old facilities as required and approved by BCUC and BC OGC	N/A	As above and including related systems	FEI	BCUC / BC OGC
Tilbury 1A	Additional tank, load-out facilities, and liquefaction	2018	Tank: 46,000 m^3 (1.1 PJ) LNG: 700 t/d	FEI	BCUC / BC OGC / Metro Vancouver (emissions)
Tilbury 1B	Incremental liquefaction, and gas send-out facilities	2023	LNG: up to 2,000 t/day	FEI	BCUC / BC OGC / Metro Vancouver (emissions)
Power line	Additional power supply from BC Hydro's Arnott substation to Tilbury site	2022	6 km of 230 kV power line	TBD	BCUC (utility service)
CTS (Gas transmission upgrade)	Upgrade to gas transmission facilities between Tilbury Gate Station and Tilbury LNG facility	2022	1 - 3 km, 30-inch natural gas transmission pipe	FEI	BCUC / BC OGC

Notes:

TBD = to be determined – Discussions ongoing with BC Hydro
N/A = Not applicable

2. Project Overview

The Project comprises an expansion beyond the existing and Phase 1 facilities of up to 162,000 m^3 (4.0 PJ) of LNG storage and up to 11,000 t/d of LNG liquefaction. The LNG storage tank is needed to provide security of public utility service and resiliency against possible interruptions of natural gas supply to the Region (as occurred in the winter of 2018-2019) but will also be sized and designed to have capacity to meet the future demands of the LNG bunkering and export markets. The LNG production will be built in phases of one or more 'liquefaction trains' to meet market demand. The proposed Project, also referred to as Tilbury "Phase 2", is detailed in Table 2-1 and shown in Figure 2-1.

The Project storage tank and liquefaction capacity trigger a review under Provincial (the *Reviewable Projects Regulation*) and Federal (*IAA – Physical Activities Regulations*) legislation.

Detailed engineering for the Project is expected to begin in 2021; the tank installation will be a priority whereas liquefaction trains may be phased over multiple years depending on demand. The LNG storage tank is a priority, required to provide security of supply to FortisBC's approximately 1.1 million natural gas customers including homes, businesses, schools, hospitals, government operations, transportation customers, and industries.

Table 2-1. Tilbury Proposed Phase 2 Facilities

Phase	Description	In-Service Date	Size	Owner	Key Regulator
Tilbury 2 Tank	LNG storage tank	2024	Tank: up to 162,000[1] m^3 (4.0 PJ)	FortisBC or FEI	BC EAO / IAAC Threshold: 136,000 m^3
Tilbury 2 Liquefaction	LNG liquefaction trains	2024-2028	Up to 11,000 t/d	FortisBC	IAAC Threshold: 3,000 t/d

In late fall of 2018, the region experienced a significant natural gas supply disruption. In light of this incident, FortisBC has re-evaluated resiliency and operational flexibility within our system and have concluded that additional local area storage is needed to prevent widespread outages (short duration) and/or allow planned curtailment to avoid a system-wide collapse (loss of system pressure).

Without additional system resiliency, these gas supply disruptions or constraints have the potential of causing widespread and long-lasting natural gas outages for FortisBC's customers and the region as a whole. Natural gas is the primary heating source for many in the region with low temperatures possible through the winter season. The Project's proposed LNG storage and incremental liquefaction will provide additional resiliency to the FortisBC natural gas system.

In addition, demand for cleaner burning fuels is growing globally as new emission regulations come into force. Countries like China are shifting their fuel mix away from coal and oil in order to reduce their GHG emissions and to improve their air quality and health outcomes.

Furthermore, Vancouver is well positioned to be an LNG marine bunkering hub as ship owners are increasingly moving to LNG powered ships in order to meet stringent International Marine Organization emission regulations that came into force in 2020. Availability, price, quality, and infrastructure are all critical to creating this cleaner fueling hub that will allow additional coastal vessels and trans-Pacific shipping companies to commit to securing new vessels powered by LNG instead of bunker or diesel oil. The need for additional and secure supplies of LNG is critical for this industry transition.

[1] Based on energy density of 23.9 gigajoules/m^3 of LNG

The Project Site has been used for natural gas liquefaction and storage for nearly 50 years. The original site expanded in the past to include adjacent properties to the south and west and has undergone upgrades and changes over time. In 2014, FortisBC began work on the Phase 1 expansion of both LNG production and storage. The Project will benefit from FortisBC's extensive experience in BC including LNG operations and recent and important construction and commissioning experience of Tilbury 1A along with understanding of the issues that go with building and operating LNG facilities at this location.

With the Project expansion of up to 162,000 m^3 (4.0 PJ) of LNG storage, the total Project Site LNG storage could be up to 236,000 m^3 including the base plant Tilbury storage tank and the existing 1A storage tank. Should the base Tilbury storage tank be decommissioned and removed, the total Project Site LNG storage will be up to 208,000 m^3. Additionally, the Project will increase the production of LNG at the Project Site from less than 3000 t/d to up to 13,760 t/d including the base liquefaction plant or up to 13,700 with the base plant removed.

Figure 2-1 shows the Phase 2 Project facilities (with existing and Phase 1 in background).

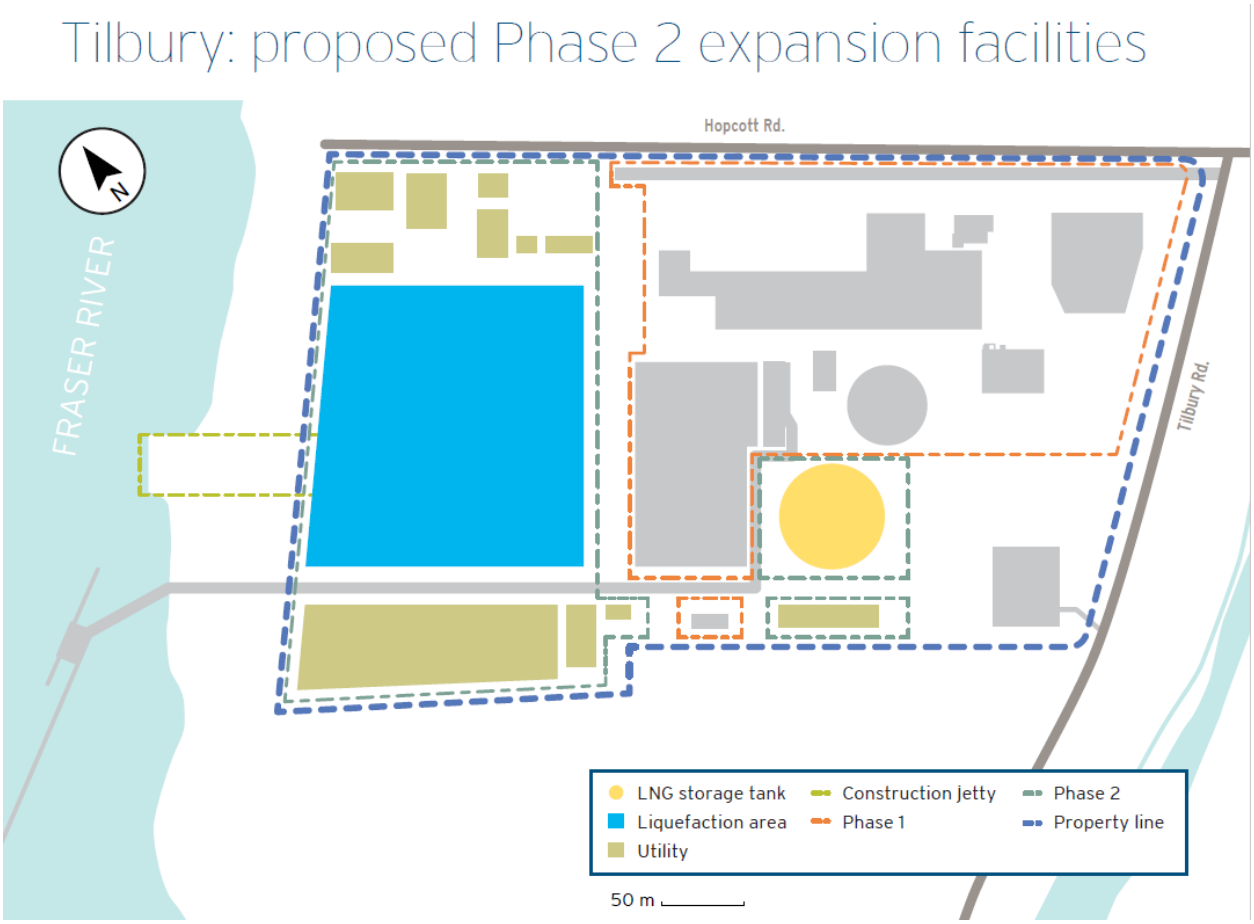

Figure 2-1. Phase 2 Project Facilities
Source: FortisBC

2.1 Project Components

Table 2-2 provides a brief description of the components for the Project. Updated information will be provided in the EA Application.

Table 2-2. Project Components

Project Component	Description of Component
Temporary Construction Components	
Construction support facilities	Material offloading of pre-assembled equipment modules will be required with access from the Fraser River. An existing construction jetty that is expected to be upgraded as part of the WesPac Jetty project and for Phase 1 projects may require additional upgrades to accommodate barge unloading of Project equipment modules during construction.
Construction materials delivery	In addition to the larger equipment module delivery by river, existing roadways and Project Site access points will also be used.
Construction laydown and staging	In addition to FortisBC's property, additional off-site laydown and storage space will be required especially during later/overlapping construction phases. Local options will be identified, assessed, and determined based on the specific requirements. Off-site laydown and storage may not be required for Phase 2 storage tank as this is expected to be constructed first and would be erected on-site with materials scheduled to arrive as needed.
Construction Infrastructure / Service	Existing Project Site service will be used (such as, power, water) where remote power/lighting is required portable generator systems or temporary construction power will be used.
Water management and hydro-testing	Hydro-testing of the LNG tank and certain piping systems will be required. This will involve a significant volume of water and discharging of the water. Given the volumes river water may be utilized which will require filtration / treatment both before using for hydro-testing (to prevent contamination) and post use to allow returning to the river in a state of equivalent or better condition. In addition, rainwater management systems will be required for the Project Site during construction.
Operation Components	
LNG Storage	Full containment storage tank with up to 162,000 m^3 (4.0 PJ) of working storage. Components of the LNG storage tank include ground improvements, foundations, double wall (full containment) construction, LNG pumps, boil-off gas management system including gas compressors, insulated piping, access stairways, lighting instrumentation, control, and safety systems.
Natural gas receiving	Existing FortisBC pipelines and right-of-way will be used to bring natural gas to the Project Site. Additional metering/distribution and control skids will be needed to distribute gas to specific liquefaction operating units.
Natural gas processing and liquefaction	Expected to be built in trains / phases depending on market demand for a total installed capacity of up to 11,000 t/d. • From the metering/distribution and control skid natural gas will enter gas pre-treatment to remove components in the natural gas not compatible with the cryogenic liquefaction process. Pre-treatment includes filtration, separators, and adsorption processes • Combustion of waste streams with energy recovery to provide thermal regeneration of certain pre-treatment processes including continuous thermal oxidation and periodic combustion of vent / relief gases • Electric drive refrigerant compressors and air cooling used in the liquefaction process • Refrigerant unloading, storage, and makeup system • Instrument air and nitrogen generator systems, firewater system, storm and wastewater handling systems, potable and de-mineralized water systems • LNG transfer and boil-off gas management systems • Fire, safety, security emergency response, and protection systems designed to meet or exceed applicable standards
Supporting Infrastructure	The following facilities will be permanently installed for the life cycle of the Project and will support the safe operation of the facility: • Project Site administration, control room(s), site grading, roadways, lighting, security, and safety facilities • Liquid hydrocarbon/chemical storage and handling facilities (including truck loading) • Electrical substations and step-down transformers connected to BC Hydro or FortisBC power systems • Additions to potable water, firewater, waste water and storm water systems from existing Project Site systems

2.2 Infrastructure Requirements

The Project Site has been used for natural gas processing and storage for nearly 50 years and is located in a largely industrial setting adjacent to the Fraser River. Much of the necessary utilities and infrastructure are present or readily expandable. Access roadways are existing and recently upgraded to support trucking traffic in the area and connection to major transportation arteries including the South Fraser Perimeter Road (Highway 17).

Material offloading from the Fraser River of pre-assembled equipment modules will be required for the Project which would also include marine transportation of vessel/barges along the Fraser River through Sand Heads. An existing jetty on the Fraser River connected to the FortisBC Project Site will be upgraded as part of the proposed WesPac Jetty project for construction purposes. The Project may require additional upgrades to the construction jetty for barge unloading of equipment modules to accommodate the weight / size of Project modules. This would be a temporary construction activity. Project Site power is available (provided by BC Hydro). Additional power supply is being planned as part of the Phase 1 facilities which would be sized to provide sufficient power for the Project. Construction laydown and storage can be accommodated on the Project Site in the early construction stages; however, nearby construction laydown and storage may be required as the Project Site is built-out over time and available space becomes limited.

The peak workforce during construction will vary from 300 to 500 depending on the Phase and is based on a modular construction methodology. A construction camp is not required given the proximity to local trades and accommodations. Workforce transportation to and from Project Site will be developed to limit parking on-site. Approximately 80 incremental full-time equivalent positions will be created once the Project is in full operation. This includes management, skilled technicians, engineers, administrative, trained operators, supervisory, and service trades. These are considered progressive, transferable, and high paid positions in a mostly unionized setting. The location is close to established communities, including Indigenous Groups, services, and educational facilities. Direct employment through the Front-End Engineering Design (FEED), engineering, procurement, and construction phase has not been converted to person-years but will be a significant source of employment for this Project with numerous local services available for this work.

2.3 Project Schedule

The preliminary schedule for the Project is provided in Table 2-3. Least risk work windows will be considered during project schedule planning for construction near any sensitive environmental features such as fish-bearing watercourses. No other seasonal timing constraints have been identified.

Table 2-3. Preliminary Project Schedule

Task	Timing
Submit IPD to BC EAO and IAAC to initiate EA	Q1 2020
Assessment Certificate application to BC EAO under substituted process (requested)	Q4 2020
Anticipated EA Certificate Approval	Q4 2021
Permitting (synchronous or concurrent permitting with EA Review)	2021/2022
Construction of LNG storage tank	2022 - 2024
Phased Construction of LNG liquefaction facilities	2022 -2028
In-Service	2024 to 2028
Decommissioning and Abandonment	40+ years

2.4 Alternative Means of Carrying Out the Project

The Project proposes to use electrical compressor drives with power provided by BC Hydro. Existing power supply is expected to be expanded as part of current Phase 1 expansion plans to include a 230-kV power supply to the Project Site from the BC Hydro Arnott substation located less than 6 km away. Alternatives to using BC Hydro-supplied power include self generation and/or gas combustion compressor drives. This alternative would increase emissions.

Numerous gas pre-treatment and liquefaction technology alternatives exist. Selection during FEED will consider economic as well as process, reliability, efficiency, and environmental factors including emissions.

Alternative construction methods to bringing pre-fabricated equipment modules to Project Site and assembly on-site include ‘stick build’ or site fabrication. Some Project components will be constructed at site because modularization is either not possible or not feasible while other Project components are well suited to modular construction to reduce site work, congestion, and construction schedule. To the extent that FortisBC Operations continue to utilize base plant facilities, the timing and/or scale of the Project could be adjusted.

2.5 Alternatives to the Project

Alternative locations for LNG storage and/or liquefaction have been considered; however, no alternative site has been identified that provides an existing brownfield industrially zoned and LNG operating site, existing infrastructure including gas supply, access to tidewater and availability of expansion space.

Other potential alternatives could include reduced Project size or not proceeding with certain components of the Project. Not proceeding with the storage tank component of the Project would put the natural gas supply system in BC and Greater Vancouver region at increased risk of disruption which would have significant economic and public utility customer impacts. Not proceeding with the liquefaction component of the project would result in foregoing economic opportunities and global emission reduction opportunities.

3. Project Location

The Project Site is located on the existing Tilbury LNG facility property on Tilbury Island, within the Tilbury Industrial Park, adjacent to the Fraser River in Delta (Figure 3-1). The legal description of the Tilbury site is Lot 1 District Lot 135 Group 2 New Westminster District Plan EPP28232 except Plan EPP 36476. PID: 029-263-301. FortisBC currently operates an existing LNG facility, which occupies the northern portion of the 7651 Hopcott property (closest to the Fraser River). Coordinates of the approximate centre of the Project Site are 49 08’28”N and 123 01’ 57”W and elevation is approximately 1 metre above sea level (masl). FortisBC will seek access to the temporary construction jetty along the Fraser River adjacent to the FortisBC property in cooperation with any water lot leaseholders to support the use of the construction jetty for the Project.

Neighbouring properties are used for industrial purposes with the nearest resident being approximately 700 metres (m) to the southwest of the Project Site, although the closest residential area is approximately 5 km away. Public access to the Project Site is limited, although there is public use of the dike to the north of the property along the Fraser River. The Project is located on private property owned by FortisBC, and there is no land based recreational access to the Project Site.

Photograph 1: *View of Tilbury facility with new storage tank in foreground, and original tank in the background.*

A summary of Indigenous Groups near the Project Site is provided in Section 11, Table 11-1. FortisBC will update this list as the Project moves forward, with input from Indigenous Groups and as advised by regulatory agencies. Research on Traditional Land Use (TLU) information surrounding the Project Site will be conducted in consultation with the corresponding Indigenous Groups as applicable.

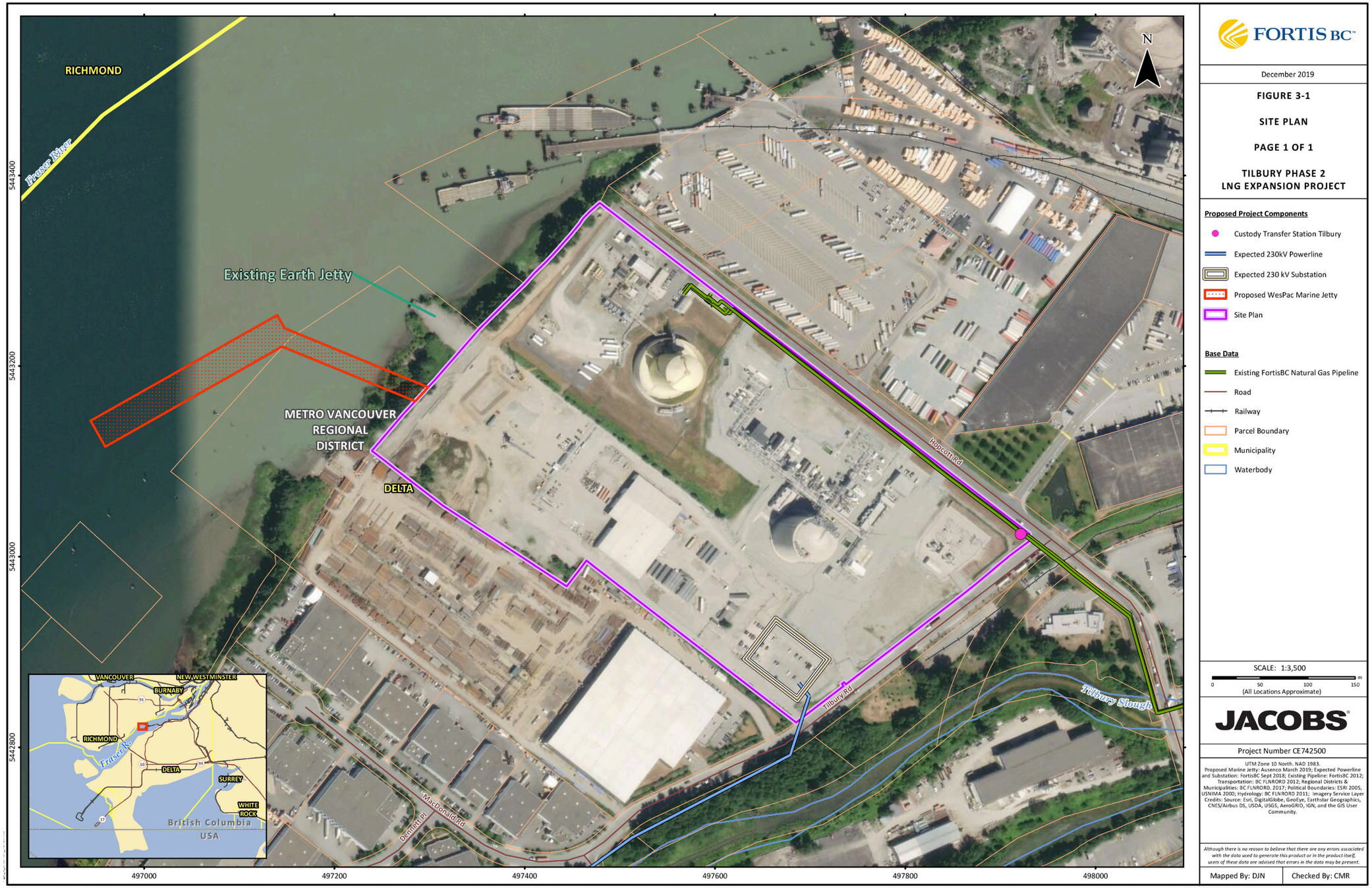

Figure 3-1. Project Site Plan

4. Spatial Boundaries

The EA / IA will consider the potential significant adverse effects of the Project on the five pillars of environmental, economic, social, heritage, and health values. As planning for the Project advances, FortisBC will work with relevant regulatory authorities, potentially affected Indigenous Groups, and stakeholders to identify concerns and issues with the Project, and this will inform the selection of valued components (VCs) under each of the five pillars listed previously.

Spatial boundaries for the VCs will encompass the geographic extent of measurable potential environmental, economic, social, heritage, and health effects of the Project. Preliminary spatial boundaries were determined by the potential zones of interaction between a VC and the Project. The spatial boundary may be limited to the Project footprint or extend beyond the physical boundaries of the area of the Project component, since the distribution or movement of a VC can be Local, Regional, or even broader.

The Project footprint includes the land area directly disturbed by the Project construction activities, including associated physical works and activities. The Local Study Area (LSA) encompasses the area in which the VC is most likely to be affected by the Project. The Regional Study Area (RSA) includes the LSA, and the area beyond the LSA boundaries where the predicted likely residual effects from the Project may act in combination with those of existing and reasonably foreseeable developments and activities to cause cumulative effects.

The preliminary spatial boundaries for assessing Project effects on the pillars, including preliminary VCs, are provided in Table 4-1. These will be further refined following VC selection and further scoping exercises.

Table 4-1. Preliminary Spatial Boundaries

Pillar	LSA Boundary and Rationale	RSA Boundary and Rationale
Environment	The LSA will be defined for each Environmental VC and will be based on the zone of influence of the Project on the VC. The selection of the LSA will be informed by: • Guidelines for Air Quality Dispersion Modelling in British Columbia (BC MOE 2008) for potential effects to air quality (to be refined through modelling) • British Columbia Noise Control Best Practice Guideline (BC OGC 2009) where potential interactions are anticipated to occur with the acoustic environment • the Project footprint plus a 100 m buffer around the Project Site for potential effects to vegetation resources • the footprint of the proposed facility plus a 1 km buffer to the northeast, south, and southwest for potential effects to wildlife resources • a separate LSA for marine birds to encompass the nearshore waters of the Fraser River • freshwater fish habitat in the Fraser River with the potential to be affected by project development for potential effects to fish and their habitat (LSAs from other VCs such as vegetation and wetlands will inform the fish LSA) • an approximate 1-km-wide band for potential effects to surface water quality	The RSA will be defined for each Environmental VC and will be based on the potential interaction of the effects of the Project with the effects of other existing or future effects on the same VC. The selection of the RSA will be informed by: • results of air dispersion modelling • BC OGC guidelines on acoustic effects, indicating that the RSA for the acoustic environment will extend 5 km from the Project boundary • the RSA for vegetation will consist of a 1 km buffer surrounding the Project boundary • the RSA for wildlife resources will consist of a 15 km buffer surrounding the Project boundary. The nearby locations of National Wildlife Areas and WMAs will further inform the RSA • the RSA for fish and fish habitat consists of the South Arm of the Fraser River downstream of the Project Site to Sand Heads including a 500 m buffer upstream. The locations of nearby sloughs and WMAs will further inform it

Table 4-1. Preliminary Spatial Boundaries

Pillar	LSA Boundary and Rationale	RSA Boundary and Rationale
Economic	The LSA for Economic conditions includes Delta, which comprises three urban communities: Ladner (administrative centre), Tsawwassen, and North Delta	The RSA for Economic conditions is the City of Delta and Metro Vancouver.
Social	The LSA for Social conditions will include: • Delta, including Ladner (administrative centre), Tsawwassen, North Delta, and boundaries of Indigenous Group communities where it can be reasonably expected that direct, identifiable effects from the proposed Project will occur for potential effects to Infrastructure and Services • all lands with a potential viewpoint of Project components for potential effects to Visual Quality This includes the area within foreground (less than 1 km from the Project boundary) and middle ground (1 to 5 km from the Project boundary) • communities with the greatest potential to experience direct community health effects as a result of the Project within Fraser Health Area for potential effects to Community Health and Well-being	The RSA for Social Conditions will include: • the City of Delta within Metro Vancouver for potential effects to Infrastructure and Services • the area beyond the LSA to within 10 km of the Project Site for Visual Quality. This RSA will be further refined based on the farthest reasonable distance at which the Project may be visible • all communities within the Fraser Health Area for potential effects to Community Health and Well-being
Heritage	The LSA for the archaeological and Heritage resources assessment will be the area of ground disturbance for the Project.	The RSA for the archaeological and Heritage resources assessment will be the same as the LSA.
Health	The LSA for the assessment of potential Health risks to humans from potential changes to air quality will be the same as that for air quality.	The RSA for the assessment of potential Health risks to humans from potential changes to air quality will be the same as that for air quality.

Note:

WMA = Wildlife Management Area

5. Land and Water Use

The Project Site is located within the Municipal boundary of Delta on Tilbury Island on the southern shoreline of the South Arm of the Fraser River (Figure 1-1). The Project Site is located on easements within the FortisBC property, located at 7651 Hopcott Road. As described in the Delta Official Community Plans (OCPs), the Project occupies an area intended for Industrial Land Use (OCP, Map 5 – Industrial and Utility Designations) (Delta 2019a). The FortisBC property where the Project will be located is designated as I7 (Special Industrial) which allows for the manufacturing, processing, finishing, and storage of natural gas. As such, the Project is consistent with the OCP for the Project Site (Figure 1-2). Marine transportation during construction including delivery of equipment modules along the Fraser River would occur along established shipping lanes and following the requirements of the applicable authorities including Transport Canada.

Information on Indigenous Groups with established or asserted traditional territories that overlap with the Project Site is provided in Section 11.1. Research on TLU surrounding the Project Site will be conducted in consultation with the corresponding Indigenous Groups, as applicable. As a result of constructing the Project on a brownfield site, there is no indication that the Project will require access to or use of lands currently used for traditional purposes by an Indigenous Group.

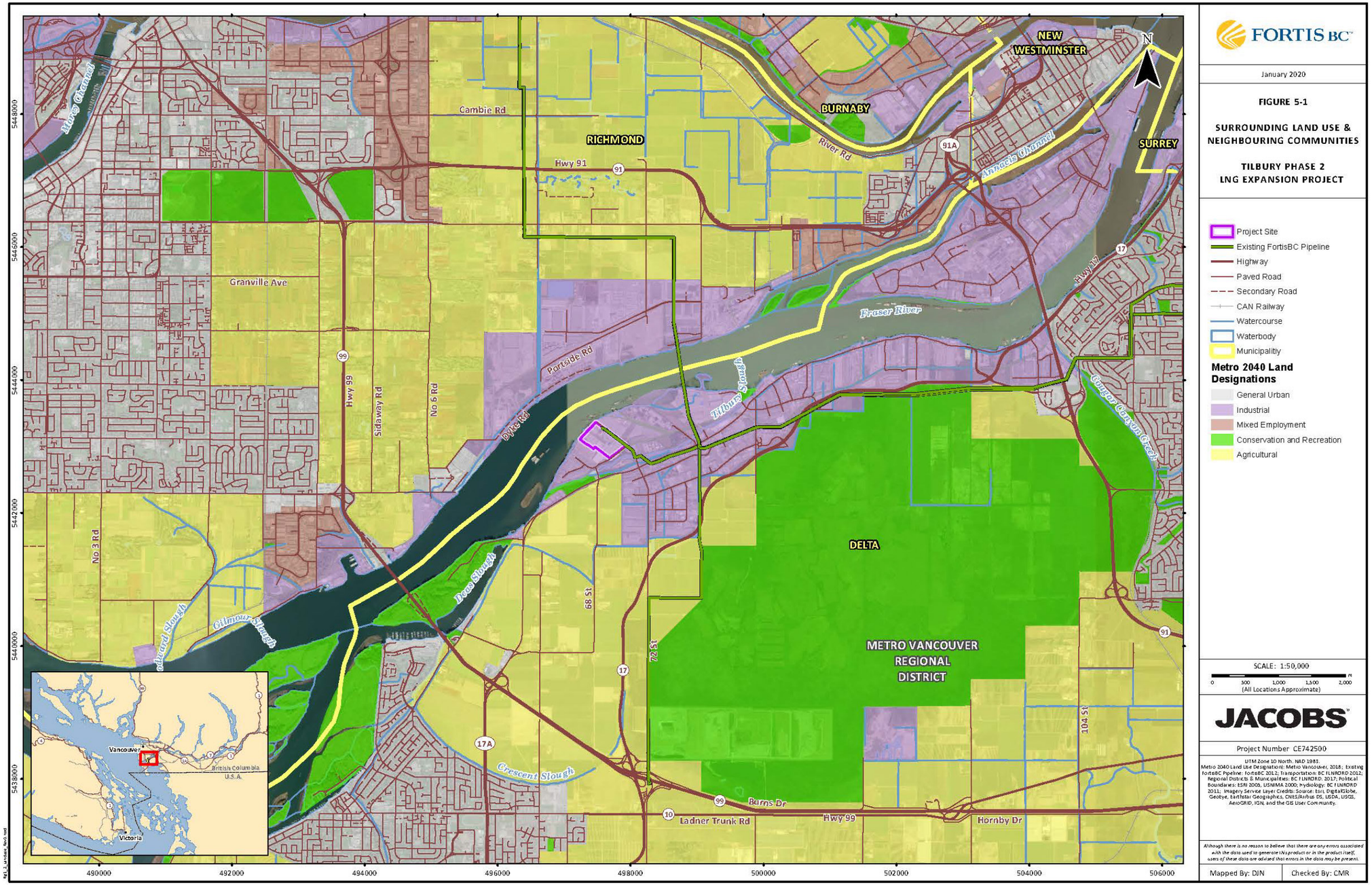

Figure 5-1. Surrounding Land Use and Neighbouring Communities

6. Emissions, Discharges and Waste

Project activities associated with all phases of the Project, including construction, operations, and decommissioning, have potential to affect the atmospheric environment through the emission of criteria air contaminants (CACs) and GHGs.

Table 6-1 provides a preliminary estimate of Project-related GHG emissions (expressed in terms of carbon dioxide equivalents) and their sources per Project phase. A discussion of these and other emissions, discharges, and waste is provided in sub-section 6.1.

Table 6-1. Estimated Direct GHG Emissions per Phase

Phase	Duration	Emission Type(s)	Emission Source(s)	CO_2e/year
Construction	3 years	CO_2, CH_4, NO, other hydrocarbons and particulate matter.	• construction vehicles and equipment • delivery of material (including gravel for grading) • ground stabilization • concrete for tank and foundations • perlite in cold box (uses giant furnaces) • marine traffic • clearing and grading	• 2,235 tonnes of CO_2e/year
One-time Venting	Single occurrence	CH_4	• commissioning / cool-down of process equipment and tank with LNG	• 6,560 tonnes of CO_2e
Operations	40+ years	CO_2, CH_4, NO, other hydrocarbons and particulate matter.	• operation of electric drive compression liquefaction facility • operational vehicles and equipment • thermal oxidizers, gas flare, and fired heaters • transportation, Project Site maintenance, and equipment operations • transferring LNG, resulting in fugitive emissions	• 203,000 tonnes of CO_2e/year (direct) • 23,500 tonnes of CO_2e/year (acquired energy)
Decommissioning	2 years	CO_2, CH_4, NO, other hydrocarbons and particulate matter.	• construction vehicles and equipment • disposal of material	• 2,514 tonnes of CO_2e/year

Notes:

CO_2 = carbon dioxide
CO_2e/year = carbon dioxide equivalent per year
CH_4 = methane
NO = nitrogen oxide
GHG emissions are usually expressed as carbon dioxide equivalents (CO_2e), which represent GHG emission quantities in terms of their global warming potential relative to CO_2.

In accordance with the Draft Strategic Assessment of Climate Change guidance, the Net GHG emissions are estimated to be 9 million tonnes CO_2e. This estimate is based on FortisBC's preliminary understanding of the Project activities and equipment and includes the following elements:

- direct GHG emissions
- acquired energy GHG emissions
- transferred surplus energy GHG emissions
- CO_2 captured and stored
- avoided domestic GHG emissions
- offset credits

This estimate of Net GHG emissions will be updated during future stages of the assessment process based on refined Project information and discuss global GHG reduction potential from displacing other fuels.

6.1 Other Emissions Discharges and Waste

The following is a discussion of estimated expansion-related emissions, discharges, and waste and their sources per Phase. These may include but are not limited to:

- light, noise, and vibration emissions
- emissions of atmospheric contaminants
- silt and soil from roads and soil storage areas
- sanitary waste
- construction water (such as, process water discharges, equipment and facilities wash down water, along with dust suppression water runoff)
- storm water runoff
- firewater runoff in the event of an emergency
- solid wastes, such as household and industrial wastes associated with facility operations
- hazardous waste such as used motor and hydraulic oils, contaminated filters, used chemical cleaning fluids, and paints

Project design and planning phases will consider the following measures to reduce emissions to the land, air, and water during construction, operations, and decommissioning:

- Air quality and noise will be monitored during construction, operation, and decommissioning, as necessary.
- Equipment selection will consider efficiency and emissions including GHG contribution.
- Equipment, machinery, and vehicles will be maintained to reduce emissions and prevent spills.
- Discharges from the facility will be controlled in accordance with codes and regulatory requirements.
- Solid and liquid waste will be stored in containers and transported to appropriate disposal and recycling facilities.
- Sanitary sewage and storm water management will follow regulatory requirements.
- Contaminated areas on the Project Site will be managed in accordance with acceptable regulatory standards.

During construction, FortisBC will implement an Environmental Management Plan (EMP) to drive compliance with environmental requirements. Environmental Inspectors will be accountable for overseeing environmental compliance during the construction of the Project. The Environmental Inspectors will be chosen based on qualifications as well as specific experience and understanding of LNG facility construction techniques. The Environmental Inspectors will have the authority to stop work in the event of an environmental emergency.

During operations, FortisBC will refer to their existing Environmental Management System, environmental standards, and guidance documents that will be updated, where required, as a result of the Project.

6.1.1 Construction

Construction activities that may contribute to emissions, discharges, and waste include:

- site preparation
- clearing
- fill and grading
- compaction
- construction of buildings and other structures
- marine vessels moving construction materials/equipment to site
- hydro testing water from tank and piping systems
- initial cool-down/fill of LNG tank with LNG

Transportation of construction materials and equipment on land can contribute to increase in fugitive dust emissions. Vehicles and equipment release criteria air contaminants. Equipment, machinery, and vehicles will be maintained to reduce emissions. Higher levels of truck deliveries would occur at certain times of the construction schedule (such as, concrete pours) where as many as 65 deliveries per day could be expected for short periods. Other periods of construction could have very few deliveries; an average day would consist of six deliveries. Marine transportation of equipment modules can contribute to emissions from vessels. Diesel or LNG powered tugs/vessel engines could power vessels/barges. Approximately 25 vessel/barge deliveries are expected resulting in 50 vessel movements over a 2- to 3-year construction period.

Construction noise will be generated through various activities and may increase daytime ambient sound levels from vehicles and equipment. Any light emissions during nighttime activities will be based on safety and security lighting. Noise and light impacts will be considered in design decisions to mitigate impacts from construction and operations activities.

Options for test water disposal include:

- disposal at an approved facility
- discharge into the sanitary sewer system
- treatment and discharge to the Fraser River in accordance with applicable regulations and permits

Construction storm water management and sediment and erosion control measures will be included in the EMP. Solid wastes will be generated from site preparation and construction activities. Solid waste will be disposed of or recycled at appropriate facilities. The storage, handling, and disposal of hazardous waste will be managed in accordance with regulatory requirements and measures outlined in the EMP. The EMP will outline measures to prevent and manage hydrocarbon spills during construction.

6.1.2 Operations

It is estimated that operations of the electric drive compression liquefaction facility will result in approximately 203,000 tonnes of CO_2e emissions per year based on 11,000 t/d of Project LNG production (assuming operation 24 hours/day and 345 days/year). Electric drives and air cooling will be used for liquefaction, which reduces overall emissions. Gas- and diesel-powered operational vehicles and equipment will generate atmospheric emissions from combustion of fuels. During operations, the main sources of air emissions (NO, CO_2, sulfur dioxide, hydrocarbons, and particulate matter) are from thermal oxidizers, gas flare, and fired heaters. Other sources of air emissions may include transportation, Project Site maintenance, and equipment operations. LNG storage tanks are designed to be closed loop systems with no normal venting or emissions other than the initial cool-down and fill in the construction phase. Pressure safety relief venting from the LNG tank is possible but is not considered normal operations.

During operations, potential sources of noise include air coolers, cooling towers, compressors, pumps, and vehicle traffic. Similar to the construction phase, any nighttime light emissions will be the result of on-site lighting for health and safety purposes. All noise and light emissions will be managed in accordance with FortisBC standards and will meet regulatory requirements.

Water discharges will be processed on-site and will be disposed of through existing wastewater management infrastructure, in accordance with applicable regulatory requirements.

Solid and liquid wastes may be generated from operation of the facility and will be managed in accordance to an updated operations plan for the facility. Where feasible, the volume of waste generated during operations will consider opportunities for material reduction at source, re-use, recycling, and recovery. Solid waste will be disposed of or recycled at appropriate facilities.

Refer to Section 10.9 for mitigation and management procedures addressing operational accidents and malfunctions.

6.1.3 Decommissioning

Emissions, discharge, and waste associated with decommissioning and closure will include air emissions from combustion engines, noise emissions from machinery activities, storm-water runoff, and waste from equipment and structure removal. Emissions will be short-term, only during the decommissioning phase. Decommissioning activities will follow regulatory requirements and FortisBC policies and plans in place at the time of decommissioning.

7. Construction, Operations, Decommissioning, and Abandonment Phases

7.1 Project Construction and Operations

The Project will require the following Project Site preparation, construction, and operations activities as outlined in Table 7-1.

Table 7-1. Description of Project Activities

Site Preparation
• Site planning by phase • Mobilization of construction equipment, temporary offices, and materials to the site by truck • Clearing, filling, and grading of mostly paved/disturbed site • Provide construction power • Re-location/improvements to storm water and erosion and sediment control measures • Ground preparation, geotechnical and archeological assessments and work permitted for the site to improve load bearing of the soil (could include pre-loading and geotechnical ground stabilization)
Construction
• Ground improvements and civil works including foundations and structures • Construction of electrical step-down transformers from 230 kV substation, including associated on-site Project power lines • Construction of LNG storage tank. Installation of related piping, pumps, and boil-off compressors. Piping connections to existing plant (LNG vapourization) and to the Tilbury Pacific LNG Marine Jetty) • Construction of the gas supply interface and pre-treatment systems • Upgrading/reinforcing the construction jetty, if required • Transporting equipment modules up the Fraser River, mooring at the temporary construction jetty, and offloading at site. It is estimated that 25 vessel/barge deliveries will be required during the 3-year construction period. The vessel/barge deliverables are expected to come from Sand Heads lighthouse at the mouth of the Fraser River along the shipping channel of the South Arm of the Fraser River to the Project Site. • Transporting, setting, and final assembly construction of liquefaction train modules • Construction of thermal oxidizer/flare for combustion of waste and emergency vent streams • Connections of liquefaction trains to LNG tank, power, utilities, safety, and control systems • Construction of administration/control, maintenance, utility, and safety facilities • Commissioning of phased equipment installation including initial cool-down and fill of LNG lines and Tank • Site clean-up, installation of security • Anticipated emissions, discharges, and waste: – Atmospheric (air, noise, light) – Collected sanitary waste (liquid and solid)
Operation
• Receipt of natural gas via piping from FortisBC natural gas metering station • Pre-treatment of natural gas to remove components of pipeline natural gas not compatible with liquefaction process • Storage of refrigerants and liquid hydrocarbons and trucking for removal/delivery • Liquefaction of the natural gas (using electric compression drives and air cooling) • Transfer LNG and LNG storage • LNG boil-off gas management • Transfer of stored LNG to distribution (existing vapourization / send-out, LNG marine jetty) • Control, inspection, and maintenance of Project components • Emissions include: – Atmospheric (air, noise, light, combustion, emergency flaring/venting)

7.2 Project Decommissioning and Reclamation

The Project Site is zoned for industrial use; therefore, at the end of the Project's operational life (that is, 40+ years) the Project facilities may be decommissioned in accordance with regulations applicable at that time, including BC OGC permitting requirements, and in consideration of preferred land uses at that time.

Decommissioning activities may include:

- De-energizing, decommissioning purging and dismantling of LNG facilities
- Re-purposing and recycling of materials and equipment
- Reclamation of the Project Site for alternate use

The Project Site would then be prepared for its next use. The schedule for decommissioning activities will be developed during FEED.

8. Regulatory Context

The following sections describe the legislative and regulatory context for the Project including the BC *EAA*, the Federal *IAA*, and other anticipated permits and approvals. The Project also introduces opportunities to upgrade existing infrastructure to current design standards and technologies and to align with new environmental policies (such as, the Government of BC's CleanBC Plan).

8.1 BC *Environmental Assessment Act*

The Project will trigger a Provincial EA pursuant to the BC *EAA* as it exceeds the trigger for assessment as follows:

> *"the modification results in an increase in the capability of the project to store one or more energy resources, other than electricity, by a quantity that can yield by combustion ≥ 3 PJ of energy or, for liquefied natural gas, increase by ≥136 000 m^3."* (Part 4, Table 8, Column 3, Criteria (1)(b) *Reviewable Projects Regulation*)

The Project includes adding storage of up to 162,000 m^3 (4.0 PJ) which would increase the total storage at the Project Site to 236,000 m^3 (5.8 PJ) with the existing base plant Tilbury tank remaining which exceeds the 136,000 m^3.

FortisBC has met with the BC EAO to provide an overview of the Project and initiated discussions related to EA process and timing and consultation.

8.2 Federal *Impact Assessment Act*

The Project will also be subject to the Federal IA process under the *IAA*. Section 38(d) of the *Physical Activities Regulations* includes;

> ***38*** *The expansion of one of the following: (**d**) an existing facility for the liquefaction, storage or regasification of liquefied natural gas, if the expansion would result in an increase in the liquefied natural gas processing or storage capacity of 50% or more and a total liquefied natural gas processing capacity of 3 000 t/day or more or a total liquefied natural gas storage capacity of 136 000 m^3 or more, as the case may be."*

FortisBC has met with the IAAC to provide an overview of the Project and initiated discussions related to IA process and timing and consultation.

The Project includes adding liquefaction of up to 11,000 t/d for a total facility LNG production of up to 13,760 t/d. The Project represents a liquefied natural gas processing increase of more than 50 percent and total liquefied natural gas processing capacity exceeding 3,000 t/d.

The Project include adding LNG storage of up to 162,000 m^3 (4.0 PJ) for a total facility LNG storage of up to 236,000 m^3 (5.8 PJ). The Project represents an increase in LNG storage capacity of more than 50 percent and total LNG storage capacity of more than 136,000 m^3. Therefore, the Project would be considered a physical activity pursuant to the *Physical Activities Regulations* and is thereby reviewable under the *IAA*.

Given that both the Federal and Provincial EA processes are triggered, FortisBC will ask that the Province request the Federal Minister of Environment and Climate Change to approve the substitution of the BC EA process for the Federal IA process. If substitution is approved for the proposed Project, it is expected that the BC EAO will conduct the EA/IA in accordance with the conditions set out in the Substitution Decision, and at the end of the assessment process the BC EAO will provide its report to both the Provincial and Federal Ministers for their consideration.

8.3 Other Permits and Approvals

The following section outlines potential additional permits that may be required before the Project construction can begin (Table 8-1). Consultation with regulatory agencies is required to confirm permit requirements. FortisBC plans to make permit applications concurrent with the EA review process to optimize efficiency of combined processes and schedule.

Table 8-1. Preliminary List of Additional Permits and Approvals for the Project

Approval	Agency	Legislation/ Regulation	Application Considerations
Facility Permit or Amendment	BC OGC	BC *OGAA*	An amendment to the existing facility permit or new facility permit is required for the construction and operation of the expansion. The amendments could be completed in phases to align with the construction phases. Requires site-specific environmental baseline fieldwork, detailed engineering information, and consultation with Indigenous Groups and public stakeholders prior to EA Application submission.
AIF	BC OGC and BC MFLNRORD	BC *OGAA*	All oil and gas development proposed in BC requires an AIF to be submitted to the BC OGC. The AIF indicates whether the proposed development will require a further AIA. Major projects that cover substantial areas typically require an AIA. An AIA was conducted on the Phase 1A portion of the Project Site in 2013. The AIF can be completed prior to finalizing the AIA; however, the approval would be conditional on completion of an AIA.
Waste Discharge Authorization	BC OGC	BC *OGAA*	Disposal of hydrostatic or other waste water to the aquatic environment will require an Authorization. This will be applied for as part of the Facility Permit Amendment Application to the BC OGC.
Heritage Inspection Permit	BC MFLNRORD	*HCA* (Section 12.2)	An AOA would be completed for the Project. The AOA would determine if further archaeological assessment (such as, an AIA), is required. An AIA would require a Heritage Inspection Permit. Engagement with potentially affected Indigenous Groups will be required during the preparation and review of the Application.
Heritage Site Alteration Permit	BC OGC	*HCA* (Section 12.4)	A Heritage Site Alteration Permit will be required to alter (meaning to change in any manner) an archaeological site. Typically follows a Heritage Inspection Permit and/or Heritage Investigation Permit. An AIF must be completed in advance. Engagement with potentially affected Indigenous Groups will be required during the preparation and review of the Application.
CPCN (for public utility assets)	BCUC	*BC Utilities Commission Act*	A CPCN approval is needed prior to construction of public utility assets over a dollar threshold. The BCUC conducts public hearings to determine whether the project is necessary and in the public interest based on evidence gathered in the public hearing.
First Nations Heritage Permits	Various Indigenous Groups	*Indigenous policies*	Several Indigenous Groups issue permits for archaeological work conducted in their territory.

Table 8-1. Preliminary List of Additional Permits and Approvals for the Project

Approval	Agency	Legislation/ Regulation	Application Considerations
Request for Review and *Fisheries Act* Authorization for Paragraph 35(2)(b)	DFO	*Fisheries Act*	An assessment under the *Fisheries Act* would be completed by a QEP. A Request for Review by DFO may be recommended by the QEP if clearing of riparian vegetation or instream disturbance could result in serious harm to fish that are part of a commercial, recreational, or Aboriginal fishery, or to fish that support such a fishery. After reviewing the Request for Review, DFO will determine if an authorization under the *Fisheries Act* is required.
Navigable Waters Application for Approval	Transport Canada	*Canadian Navigable Waters Act* *Section 5*	An approval is required for any major works located in, on, over, under, through or across any navigable water, regardless of whether it is listed in the Schedule; or a work (other than a minor work) that is located in, on, over, under, through or across navigable water that is listed in the Schedule.
General Permit Applications	BC MFLNRORD	*Wildlife Act*	Required for amphibian salvage, wildlife sundry, fish research at watercourse crossing, and fish salvage.
Waste Discharge Permit	Metro Vancouver	*Bylaw 299*	Required to discharge hydrostatic test and other construction waste water (excluding contaminated water) to the sanitary sewer system.
Building Permit	Delta	*Local Government Act*	A building permit would be required from Delta for new structures on the Project Site.
Development Permit	Delta	*Local Government Act*	Form and Character and Environmental Protections Development Permits may be required for the changes to the Project Site. Consultation is required with Delta to confirm Development Permit requirements.
Demolition Permit	Delta	*Local Government Act*	A demolition permit would be required for the demolition of existing structures.
Tree Cutting Permit	Delta	*Bylaw 7415*	A Tree Cutting Permit is required from Delta for removal of any trees with a diameter of 20 cm or greater measured at 1.4 m above its base.

Notes:

AIF = Archaeological Information Form
AOA = Archaeological Overview Assessment
BC MFLNRORD = BC Ministry of Forests, Lands, Natural Resource Operations and Rural Development
cm = centimetre(s)
CPCN = Certificate of Public Convenience and Necessity
DFO = Fisheries and Oceans Canada
HCA = Heritage Conservation Act
QEP = Qualified Environmental Professional

9. Federal Involvement – Financial Support, Lands and Legislative Requirements

There are no Federal lands or reserves that will be used for the purpose of carrying out the Project. The Project will not require Federal financial support and is located in an area that has not been the subject of Federal regional environmental studies. During construction, equipment and supplies may be delivered via the Fraser River to the Project Site. The portion of the Fraser River next to the Project Site is understood to be within Provincial jurisdiction. The closest Federal lands to the Project Site are on the southern tip of Tilbury Island. The parcels are narrow strips of land in the riparian area of the Fraser River and a side channel. The closest parcel is 150 m to the southwest and encompasses a portion of the Tilbury Island dike, which is used as a public walking trail and directly across the Fraser River from the Project Site (approximately 900 m north) is a complex of Federally-owned industrial parcels on Lulu Island. The businesses directly adjacent to the river include Lulu Island Terminal, Coast 2000 Terminals, and Westran Portside Terminal. Potential Federal permits and approvals are listed in Section 8.2 and 8.3.

10. Environmental, Economic, Social, Heritage and Health Effects

This section includes a brief overview of the potential environmental, economic, social, heritage, and health effects, and proposed mitigation, as they are currently understood, that may arise from construction, operation, decommissioning, and abandonment for the Project. The understanding of potential effects of the Project will be further refined through development and engagement activities and will be addressed during the development of the VC selection document, and ultimately in the Application for an EAC. A desktop evaluation was completed that included reviewing historical environmental evaluations of the Project Site, accessing government databases and reviewing environmental studies conducted near the Project Site, including for the WesPac Marine Jetty Project.

10.1 Environmental Impacts on Federal Lands, in a Province other than British Columbia, or outside of Canada

The Project Site is located on private land owned by FortisBC within the Municipal boundaries of Delta and a portion of the Fraser River, within Provincial jurisdiction. Potential changes to the environment as a result of carrying out the Project are not anticipated to interact with or impact Federal lands, a Province other than BC, or outside of Canada. Potential trans-BC-boundary effects will be determined during the development of the EAC Application, but could include, for example, air quality and GHG emissions.

10.2 Physical Environment

The Project Site is located near the Fraser River, in the Fraser Lowlands section of the Georgia Depression Physiographic Region. The Fraser River flows through glacio-fluvial and alluvial deposits, ending in a delta approximately 10 km downstream of the Project Site. Bedrock types are dominated by sedimentary, volcanic, and granitic (Dakin n.d.).

The Project Site is on generally flat terrain and drains generally to the west and northwest by way of a drainage ditch, which is understood to flow into the Tilbury Slough, approximately 100 m south of the Project Site. The slope of the land ranges from 0-2 degrees throughout the development site.

10.2.1 Geology and Soils

Surficial materials at the Project Site are typical of flood plain or deltaic deposits, composed of very deep silts, sands, and clays. These unconsolidated materials are deposited in layers and extend up to 200 m below the surface of the ground. The soil stratigraphic profile of the Project Site shows silt or clay loams to a depth of approximately 5 m, overlaying deep (~25 m) deposits of Fraser River sand, which is situated on top of very deep (> 100 m) marine deposits (Golder 2013).

The Project Site elevation is approximately 1 masl and is typical of flood plain sites, with a fluctuating water table and soils that are saturated during the winter months due to poor drainage, flat topography and dense, fine-textured soils (Green and Klinka 1994).

Based on information collected from a geotechnical assessment conducted in 2013, the water table at the Project Site is high, with ground water being encountered between 0.5 m and 1 m below the surface of the ground (Golder 2013).

Soil densification at the Project Site will be conducted to meet seismic requirements, to support the load of the LNG tank, and to ensure a stable surface for constructing the facility.

Soil densification and ground improvement activities will result in the excavation and removal of large amounts of surficial material from the Project Site, as well as the deposit of large amounts of sand and gravel. This may result in the generation and mobilization of sediment, which could have an adverse effect on nearby watercourses.

FortisBC will control sediment production and mobilization through erosion control measures and sediment collection or settling facilities. Ground and surface water will be controlled through measures such as Project Site isolation, damming, or pumping around work areas.

10.2.1.1 Contaminated Soils and Groundwater

The entire Project site was historically used for agricultural purposes. In the early 1970s, the western portion of the Project Site was occupied by a sawmill and the eastern portion was developed for the Tilbury LNG facility. The Project Site was subject to numerous environmental investigations and remediation efforts from 1991 to 2014. A Certificate of Compliance under the *Contaminated Site Regulation* was obtained for the western portion of the Project Site, formerly the sawmill site. This area has since been developed with additional infrastructure as part of the Phase 1 expansion of the Tilbury LNG facility. Additional investigations of soils and groundwater will be completed on the Project Site during the preparation of the EA Application.

10.2.1.2 Natural Hazards

No geotechnical hazards (such as, mass wasting) have been identified that would affect the Project Site. Seismicity was identified as a natural hazard that has the potential to adversely affect the Project.

10.2.2 Water and Aquatic Systems

The property boundary extends between 20 m and 30 m southeast of the Fraser River. Between the Project Site and the Fraser River is a dike, which is maintained by Delta. The construction jetty extends past the dike and into the river. The south end of the property is approximately 100 m north of Tilbury Slough, a side channel of the Fraser River. The Project Site has been mostly cleared for industrial purposes and has no natural watercourses. There are a series of drainage ditches located on the property that serve to drain surface water from the Project Site. Site drainage enters Tilbury Slough via a culvert located at the southwest end of the property.

Flood protection measures, as outlined by Delta during the building permit process, will be incorporated into building design and/or ground improvement plans.

Expansion construction will be primarily in the upland areas away from the Fraser River and Tilbury Slough with the exception of upgrades to an existing construction jetty to use as a temporary material offloading jetty during construction. Upgrades to the construction jetty could include the installation of piles, placement of fill and rip rap and vegetation removal. Dredging of the area around the jetty may be required to increase river depth. The extent of upgrades will depend on the state of the earth jetty at the time of construction of the Project. The earth jetty may be upgraded prior to the construction of the Project by either the WesPac Tilbury Marine Jetty Project or for use on other ongoing FortisBC Tilbury LNG facility site upgrades.

Potential effects to the aquatic environment resulting from upgrading and use of the construction jetty, including increased marine traffic during construction may include localized changes in flow direction, velocity, scouring, and sedimentation. Potential impacts to fish and fish habitat are discussed below in Section 10.3.3. Sediment and erosion control measures will be implemented to reduce water quality impacts to the aquatic environment from construction activities.

It is expected that the upgrades would be temporary, and the construction jetty would be restored following construction since it is not needed for operation of the Tilbury LNG facility.

Hydrostatic testing of the LNG storage tank and piping will be required prior to commissioning; however, test water will be collected, tested, and discharged either to the sanitary sewer system or if approved under certain conditions and applicable Waste Disposal Authorizations, to the river.

10.3 Biological Environment

The biological components addressed in this section are vegetation, wildlife, and aquatic resources (fish, marine mammals, amphibians, and their habitat).

Wildlife use within the Project Site is primarily limited to a small (that is, approximately 50 square metres) treed area at the southwest corner of the property, adjacent to the drainage ditch that separates the Hopcott Road properties from the Tilbury Road property. Wildlife species common to the Delta area (such as, coyote and songbirds) are common at the Project Site; however, the area has limited value for wildlife in its present condition.

The nearest fish-bearing watercourses to the Project Site are the Fraser River and Tilbury Slough on the south side of Tilbury Road. A series of drainage ditches run along the property edges of the Project Site. The drainage ditches are not fish-bearing due to a lack of habitat and accessibility but do have amphibian habitat potential.

Detailed information on the biological resources of the Project Site is presented in the following sections.

10.3.1 Vegetation

The Project Site is situated in the Coastal Douglas-Fir Biogeoclimatic Zone, although it is transitional to the Coastal Western Hemlock Zone. The Coastal Douglas-Fir Biogeoclimatic Zone has warm dry summers and mild wet winters (Delong et al. 1991). The Project Site was previously cleared of natural forest and has been heavily disturbed, with the majority of the Project Site being used for industrial purposes.

Vegetated areas within the Project Site include drainage ditches along the southeast perimeter of the site as well as a small area of riparian vegetation on the bank of the Fraser River. The drainage ditches are dominated by plant species that are common on disturbed and riparian sites. Riparian vegetation associated with the ditch system is a combination of natural and introduced species. Where the ditch is not draining, standing water has accumulated and a riparian plant community exists. The riparian vegetation along the Fraser River is deciduous-dominated young forest with an understory dominated by plant species that are common on disturbed and riparian sites.

A desktop background review of plant and ecosystem communities at risk with the potential to occur at the Project Site was completed. Information and data were collected through a desktop review of publicly available datasets (DataBC, iMapBC, HabitatWizard, BC Conservation Data Centre [BC CDC], Species at Risk Public Registry). The results identified two Provincially- and Federally-listed plant species that may be present within the Project footprint, Vancouver Island beggarticks (*Bidens amplissima*) (*Species at Risk Act* [*SARA*] Schedule 1, Special Concern, BC Blue-listed) and streambank lupine (*Lupinus rivularis*) (*SARA* Schedule 1, Endangered, BC Red-listed) as well as two Provincially-listed species, two-edged water starwort (*Callitriche heterophylla* var. *heterophylla*) (not *SARA*-listed, BC Blue-listed) and Henderson's checker-mallow (*Sidalcea hendersonii*) (not *SARA*-listed, BC Blue-listed) (BC CDC 2019). These species are known to occur within the tidal zones of the Fraser River and are found along the shoreline of marshes, wet meadows, bogs, ditches, stream banks, and lake margins at low elevations (SCCP 2019). A known occurrence of two-edged water starwort has been identified approximately 15 km upstream of the Project Site (BC CDC 2019). Project construction will be primarily in the upland areas away from the river, though some riparian and instream vegetation will be affected for the temporary material offloading jetty.

BC CDC results identified 10 Blue-listed ecological communities and 24 Red-listed ecological communities that may occur in the Coastal Douglas-Fir Biogeoclimatic Zone in Delta. These include 7 estuary communities, 14 upland communities, and 13 wetland communities. Due to the highly disturbed nature of the vegetation cover on the Project Site, it is not anticipated any of these ecological communities occur there.

Mitigation measures will include:

- surveying for Provincially- and Federally-listed plant species prior to construction
- preventing the spread of Noxious weeds and invasive, non-native species
- minimizing disturbance to the Riparian Zones of the Fraser River and Tilbury Slough
- preparing an EMP following completion of detailed design.

Potential effects of the Project on the upland vegetation communities at the Project Site would be limited, as vegetation has been previously removed from most of the Project Site. The upgrades to the construction jetty for construction are expected to result in a short-term reduction of instream and riparian vegetation as a result of dredging, installation of piling, and placement of fill.

10.3.2 Wildlife

Wildlife use is primarily limited to the few underutilized portions of the Project Site. A small treed area at the southwest corner of the property has been documented to have periodic stick nests for breeding birds. Nesting may occur within the riparian area of the Fraser River and marine mammals and waterfowl are known to use the river for foraging and as a transportation corridor. The Project Site may provide suitable habitat for several reptile species (such as, garter snakes).

The Project Site is bordered to the northwest and southeast by Important Bird Area (IBA) BC 017: Boundary Bay – Roberts Bank – Sturgeon Bank (Fraser River Estuary) that supports at least 50 species of shorebirds, as well as a variety of raptors and waterfowl. Patches of forest within the IBA provide important nesting and roosting habitat for Great Blue Herons and raptors, including Bald Eagles, while tidal flats and agricultural fields within the IBA provide foraging habitat for overwintering and migratory birds (IBA Canada 2019).

A desktop background review of wildlife species at risk with the potential to occur at the Project Site was completed. Information and data were collected through a desktop review of publicly available datasets (DataBC, iMapBC, HabitatWizard, BC CDC, Species at Risk Public Registry). The results identified nine *SARA* Schedule 1 terrestrial species that potentially may occur on-site: the Blue-listed Great Blue Heron (*Ardea herodias fanini*); Blue-listed Short-Eared Owl (*Asio flammeus*); Yellow-listed Common Nighthawk (*Chordeiles minor*); Red-listed Barn Owl (*Tyto alba*); Blue-listed Olive-sided Flycatcher (*Contopus cooperi*); Blue-listed Barn Swallow (*Hirundo rustica*); Blue-listed Band-tailed Pigeon (*Patagioenas fasciata*); and Red-listed Pacific Water Shrew (*Sorex bendirii*), and Red-listed Pacific painted turtle – Pacific coast population (*Chrysemys picta* pop. 1) (BC CDC 2019).

There are recorded occurrences of Barn Owl nest sites within the Tilbury Slough, directly south of the Project Site. Although it is possible that the 16 identified species at risk use the Project Site for dispersal, foraging, cover, and/or roosting, it is unlikely that they use it for breeding or nesting as the Project Site is primarily a heavily disturbed industrial site with low habitat potential. Mitigation measures will include measures such as conducting clearing outside the breeding bird window, where feasible, or conducting bird nest sweeps by a QEP.

The Pacific Water Shrew uses riparian habitat and is known to occur near (within 2 km) to the Project Site. Sections of the perimeter drainage ditch may provide suitable riparian habitat; however, the lack of connectivity to other watercourses, along with the discontinuous nature of the water within the ditch, make it unlikely that it would be used for anything other than dispersal.

Marine mammals that may be present in the Project Site include harbour seals (*Phoca vitulina*) (not *SARA*-listed, BC Yellow-listed), Stellar sea lion (*Eumetopias jubatus*) (*SARA* Schedule 1 – Special Concern, BC Blue-listed) and California sea lion (*Zalophus californianus*) (not *SARA*-listed, BC Yellow-listed) (BC CDC 2019). The harbour seal is widely distributed and may occur within or adjacent to the Project Site, while the Stellar sea lion is unlikely to be present. Sea lions congregate in the Fraser estuary during the eulachon run; rafts of greater than 100 California sea lions have been observed as far as 50 km upstream of the mouth (likely upstream of the Project Site) (Bigg 1985).

Construction of the Project is not expected to substantially change habitat for potential species at risk in the area due to the previously disturbed nature of the Project Site. The main habitat value for wildlife occurs in conjunction with the perimeter drainage ditch and the riparian areas next to the Fraser River, which will be partially affected by the Project.

Construction activity would likely temporarily displace small mammals, marine mammals, and birds from using nearby adjacent areas during the construction phase; however, alternative habitat is available in the surrounding area. Impacts resulting from increased marine traffic during construction may include the potential for collision with marine mammals; however, it is anticipated to be low risk. The resulting potential effects are considered to be minimal.

Operation of the LNG facility are expected to pose little threat to wildlife populations in the area. Increased traffic along nearby roads and activity in and around the Project area footprint may temporarily discourage use by small mammals and birds during periods of activity. However, these species can habituate to routine human activities and adverse effects on wildlife use of nearby areas are expected to be minimal.

10.3.2.1 *Migratory Birds Convention Act*

Forty-one birds listed by the *Migratory Birds Convention Act* (Government of Canada 1994) have the potential to occur within the region (BC CDC 2019); of these, 15 are considered rare or accidental (summarized from Toochin 2018 and eBird 2019). Migratory birds have the potential to migrate through or nest within or adjacent to the Project Site. Suitable breeding habitat for most species is absent from the Project Site with the exception of riparian forest on the Fraser River that may be suitable for some songbirds such as olive-sided flycatcher (*Contopus cooperi*) (*SARA*- and Committee on the Status of Endangered Wildlife [COSEWIC]-listed, Provincially Blue-listed).

Vegetation removal will cause a reduction in potentially suitable nesting and foraging habitat for migratory birds and construction activity may cause migratory birds to temporarily avoid the Project Site and immediately adjacent areas. Potential effects are considered minimal due to the highly disturbed nature of the site and the small area of vegetated habitat affected. Mitigation measures described previously are expected to result in minimal risk to the Project associated with migratory birds.

10.3.3 Fish, Amphibians, and Their Habitat

The property boundary is adjacent to the riparian area of the Fraser River, but separated by a dike that is maintained by Delta. However, the jetty extends past the dike and into the river. The south end of the property is approximately 100 m north of Tilbury Slough, a side channel of the Fraser River. The Fraser River estuary is known to support 78 different species of fish, including 7 salmon species and several Provincially-listed Red- and Blue-listed species, and Federal Species at Risk, including White Sturgeon (Lower Fraser River Population) (*Acipenser transmontanus*). This population of sturgeon was assessed as Threatened by COSEWIC in Canada in 2012 and is Red-listed in BC (BC CDC 2019). The Fraser River is one of three rivers in BC where White Sturgeon spawn (Lehigh Hanson Materials Ltd. 2019), though spawning habitats are expected to be located further upstream of the Project Site in less depositional environments. However, the shoreline habitats near the Project Site may provide important rearing habitats for juvenile White Sturgeon.

Eulachon (*Thaleichthys pacificus*) is a small anadromous schooling species of fish that provides a food source for other fishes (for example, White Sturgeon) and marine mammals. Eulachon is considered Endangered by COSEWIC and is under consideration for listing on Schedule 1 of *SARA* (DFO 2019). This species of fish is Blue-listed (Special Concern) in BC (BC CDC 2019). Important migratory habitats for Eulachon are expected to be present in the Fraser River adjacent to the Project Site.

Salmonids of conservation concern that occur near the Project Site include species of trout and char and all five species of Pacific salmon. Westslope Cutthroat Trout (*Oncorhynchus clarki lewisi*) is designated as Special Concern under the *SARA* and Bull Trout (*Salvelinus confluentus*) are under consideration for

SARA listing (DFO 2019). These species, in addition to coastal cutthroat trout (*Oncorhynchus clarkia clarkia*), are Blue-listed in BC (BC CDC 2019).

Several populations of sockeye salmon (*Oncorhynchus nerka*) are listed by COSEWIC as Endangered, including the Cultus Lake population in 2002/2003 and seven more populations recognized in 2017 (ECCC 2019). COSEWIC in 2017 also listed two sockeye populations as Threatened and five as Special Concern. These populations of Pacific salmon migrate past the Project Site in the Fraser River, including spawning adults and out-migrating smolts. A small proportion of sockeye are “river-type” and may use the lower Fraser River for rearing, rather than using lakes (Johannes et al. 2011).

The Thompson and Chilcotin River steelhead (*Oncorhynchus mykiss*) populations in BC were classified in 2018 by COSEWIC as Endangered and recommended for emergency listing under the *SARA* (ECCC 2019). These populations may migrate past the Project Site during adult and juvenile stages.

The shoreline habitats adjacent to the Project Site, including in and around the proposed jetty workspace, are expected to provide important rearing habitats for a number of salmonid species, particularly in areas with tidal marsh vegetation and riparian cover.

The drainage ditch in the center of the property contains a small, wetland like habitat that may support amphibians. Should removal of the ditch or associated vegetation be required, the Proponent will conduct an amphibian salvage program.

As there are no expected activities taking place in or around Tilbury Slough, including riparian areas, mitigation measures beyond the current Project design are not necessary for this feature. The key issue to manage during construction will be to prevent sediment from entering the drainage ditch and flowing into Tilbury Slough through management of site drainage and installation of erosion and sediment control measures.

Some impacts to fish and fish habitat are anticipated while upgrading the existing construction jetty to use as a temporary material offloading jetty during construction. Activities associated with construction and operation of the jetty that may impact fish and fish habitat include: Project Site preparation, removal of existing structures, dredging, fill placement, removal of instream riparian vegetation, construction of temporary pilings and jetty, and increased river traffic. Potential impacts may include:

- Alteration or loss of fish and benthic invertebrate habitats, including from:
  - Direct overlap of Project footprint
  - Removal of instream vegetation
  - Removal of riparian vegetation
  - Changes in habitat morphology
- Disruption of habitat use, including from:
  - Altered flows
  - Altered migratory pathways
  - Temporary increase in turbidity and total suspended solids
  - Temporary noise and vibrational effects
- Fish mortality or injury, including from:
  - Placement of materials and operation of equipment
  - Temporary increase in turbidity and total suspended solids
  - Temporary noise and vibrational effects

Mitigation measures will be developed during jetty design to reduce impacts of construction and operation the jetty on fish and fish habitat. No impacts to fish and fish habitat are anticipated to result from increased marine traffic during Project construction.

10.4 Economic Conditions

The Project Site is located within Delta in Metro Vancouver. Metro Vancouver conducts regional land use planning in partnership with 21 Municipalities, Electoral Area A, and 1 Treaty First Nation. Metro Vancouver is home to more than 50 percent of BC's population (Regional Prosperity Initiative 2018).

In 2016, approximately 65.7 percent of the Metro Vancouver population aged 15 years and over were in the labour force. The unemployment rate at that time was 5.8 percent compared to 6.7 percent in BC overall (Statistics Canada 2017a). Employment demand is anticipated to increase 1.2 percent on average every year up to 2028, which is faster than the average annual growth of 1.1 percent in BC (WorkBC 2018).

According to the 2016 Census, the prevalent occupations in Metro Vancouver included sales and service occupations and business, finance and administration occupations, trades, transport, and equipment operators, and related occupations (Statistics Canada 2017a). The largest industries in Metro Vancouver include wholesale and retail trade, health care and social assistance, and professional, scientific, and technical services (WorkBC 2018).

The Project is expected to provide approximately 110 incremental permanent jobs during the operational life of the expansion.

A wide range of economic benefits will emerge in relation to the proposed Project, including employment, gross domestic product, labour income, and government revenues through taxes and royalties, as well as the enhancement of workforce and business capacity. The expansion will create employment and contracting opportunities during planning and construction, and during Project operations. The expansion will also provide bidding opportunities for local and Indigenous contracting work. Additional benefits include ongoing property taxes paid to local government. Development of the Project will contribute to continued development of BC's natural gas resources; this in turn creates jobs and royalty revenue for the Provincial government, which helps pay for social services.

10.5 Social Conditions

The Project Site is located on Tilbury Island, in Delta within Metro Vancouver. The Project Site also includes a portion of the Fraser River on the north end of Tilbury Island. Delta is approximately 180 square kilometres (km^2), bordered by the Fraser River on the north, the United States border and Boundary Bay on the south, the City of Surrey on the east, and the Strait of Georgia on the west. The Project Site is located on industrial lands and not within the boundaries of any Provincial parks, conservation areas, Agricultural Land Reserves, or ecological reserves.

At the time of the 2016 Census, Metro Vancouver had a population of 2,463,431, an increase of 6.5 percent from 2011. In 2016, Delta had a population of 102,238, with population growth being smaller than in Metro Vancouver with an increase of 2.4 percent from 2011 (Statistics Canada 2017b). Agriculture and farming have historically been the economic drivers in Delta; however, Delta has seen considerable industrial development and Tilbury Island is one of the fastest growing industrial areas in Greater Vancouver (Delta 2019a) and is zoned as Industrial in the Future Land Use Plans (OCP, Map 2 – Future Land Use Plan) (Delta 2019a).

Generally, the employment and income effects of projects can lead to positive social outcomes, such as supporting recreation and tourism activities as well as potential effects on local employment and goods/services supply driven by the workers. Accommodation for construction and operation workers is not expected to have a noticeable effect on the local population as the Project Site is located in an urban environment. No effect on the use or availability of current infrastructure and services is anticipated.

The Fraser River is an important transportation route and is home to numerous industrial facilities and cargo terminals that handle logs, steel, machinery, and general industrial cargo. The Fraser River is also used for commercial and recreational purposes including boating, fishing, tourism, and marine

transportation among other activities. Impacts to the use and availability of the Fraser River are expected to be negligible because the increase river traffic and construction activities associated with the temporary construction jetty represent a negligible incremental increase to existing river traffic. Existing navigation channels, safety requirements and communication with other river users are expected to effectively manage potential effects to navigation safety and river use by recreational and commercial users. Potential effects on the rights of Indigenous Groups, including current use of lands and resources for traditional purposes resulting from project activities, including increased marine transportation during construction, have been addressed in section 11.5.

FortisBC's consultation plan for the Project will consider population effects including availability and access to local housing, provision of services and infrastructure and potential impacts to community well-being as a result of the expansion. Project construction and operation will also be managed with local and regional economic priorities and activities.

When assessing potential socio-economic Project effects, the principles of Gender-based Analysis Plus (GBA+) will be applied to determine whether there are different impacts for subsets of the population.

10.6 Heritage Resources Conditions

The *HCA* (Government of BC 1996) provides for the protection of BC's archaeological resources and applies to archaeological sites predating 1846, whether they are located on public or private land. The *HCA* also confers automatic protection upon heritage sites that predate 1846 or sites with unknown dates that could predate 1846, regardless of whether they are recorded in the Provincial Heritage Site Register, whether they are located on Crown land or private property, and whether they are in a disturbed or intact context. Post-1846 historic sites can be protected by Ministerial Order, Designation by an OIC or a Municipal bylaw; however, most post-1846 historic sites are not protected in BC.

The Archaeology Branch of BC MFLNRORD is responsible for administering the *HCA* and oversees archaeological work in the Province. The Archaeology Branch conducts permitting in relation to heritage inspections, investigations, and Project Site alteration. Heritage resources assessment and management provisions in the *HCA* are compatible with the requirements of the *Canadian Environmental Assessment Act, 2012*.

Delta has an established Heritage Register listing a variety of historically significant sites. Heritage sites are protected through Heritage Designation that is achieved on a site-by-site basis through Municipal bylaws. Any changes to Designated Heritage Properties must meet requirements set out in the protection bylaw and require OIC approval (Delta 2019b).

An AIA was conducted in the area southeast of the existing facility for the Tilbury Phase 1A expansion. Although there were no significant archaeological remains within the AIA, ground-altering activities associated with expansion construction have the potential to alter archaeological or historical sites, features, and objects located in areas where previous AIA work has not been conducted.

Given that areas with heritage resource potential have not all been subject to a desktop-based assessment or field inspection, there remains a data gap and detectable heritage resources may be present and potentially be affected by expansion activities. FortisBC will conduct field investigations in areas with archaeological or historical potential prior to, or concurrent with, expansion construction activities. If heritage resources are encountered during subsequent studies, avoidance (that is, re-design of expansion components) of heritage resources will be the primary mitigation when feasible.

10.7 Health Setting

The construction of the expansion will result in short-term increases in noise levels, air emissions from construction equipment operation, increased marine traffic during construction, and dust from vehicle use of access roads. This may cause adverse potential health effects to residents, Indigenous Groups, and nearby river users.

It is expected that operation of the Project will result in noise and air emissions. FortisBC will work to minimize Project emissions to the air, land, and water and emissions will be within applicable regulatory requirements.

The EA will conduct noise and air quality assessments and modeling to understand the potential effects of the Project on air quality and the acoustic environment, and to ensure that appropriate mitigation is conducted to avoid or reduce those potential effects.

10.8 Anticipated Cumulative Effects

A Cumulative Effects Assessment (CEA) will be completed for the Project. The CEA will evaluate the residual environmental and socio-economic effects directly associated with the Project, in combination with the likely residual effects arising from other projects and activities that have been or will be carried out in the Project study areas. These include the existing and Phase 1 Tilbury LNG facility, the proposed WesPac Tilbury Marine Jetty project, and other existing and proposed developments in the Tilbury industrial area and along the Fraser River. The other projects and activities to be included in the CEA will be identified as the Project planning progresses.

Detailed methodology and rationale used to determine if the Project is expected to have significant adverse cumulative effects and how the other projects will be identified will be provided in FortisBC's Application for an EAC. The EAC Application and the CEA will be informed by:

- approved land use plans that designate the most appropriate activities on the land base
- baseline studies and historical data that factor in the effects of past development and set out the current conditions
- potential overlapping impacts due to present developments

Potential trans-BC-boundary effects will be determined during the development of the EAC Application, but could include, for example, air quality and GHG emissions.

10.9 Accidents and Malfunctions

The EAC Application will provide a summary of potential accidents or malfunctions which could occur in connection with the Project, the potential effect of such incidents on the environment, and mitigation measures that will be implemented as part of the Project design.

Potential accidents or malfunctions could result in release of LNG, flammable liquids, or pressurized gas from ruptured piping or equipment during commissioning or operation resulting in the risk of overpressure, fire, and injury to personnel. Natural gas, the refrigerants used in the liquefaction process, and LNG vapours are flammable in a specific range of fuel to oxygen ratio. Methane, the main component in natural gas and LNG, is flammable in a range of between approximately 5 to 15 percent methane gas to air ratio. In this ratio the mixture would burn if there is an ignition source present. LNG is a cryogenic liquid, meaning it is extremely cold and if spilled or released can cause localized freezing and/or burns on contact with skin. The design, construction and ongoing operation/maintenance of LNG facilities shall meet stringent codes and standards requirements. Hazard Identification, Hazard and Operability Studies, and Safety Integrity Level Studies are conducted during phases of engineering and design. Permitting, is done through BC OGC including reviews of design and risk assessments. Prevention is a key focus; however, emergency management plans are also developed to develop response plans according to industrial codes / standards and in partnership with local emergency responders. Training, drills, and practice emergency exercises are conducted with emergency responders to ensure response plans are effective and ready throughout the life of the Project.

10.10 Effects of the Environment on the Project

FortisBC understands that potential effects of the environment on the Project must be considered and appropriately mitigated to the extent possible. Extreme weather events are a key concern for the environment causing potential effects to the Project.

10.10.1 Seismicity

Southwestern BC, including the Lower Mainland, is located within a seismically active area. Seismic conditions are primarily related to the subduction (sliding) of the oceanic Juan de Fuca plate beneath the continental plate. Large megathrust earthquakes can occur along the subduction zone, typically at intervals of several hundred years (NRC Research Press 2013). The last such earthquake on the subduction zone near Vancouver Island is estimated to have occurred in 1700 and would have been felt over a wide area, including at the Project Site.

Research conducted by Natural Resources Canada (NRCan), the Geological Survey of Canada, and others has led to revisions of the National Building Code with respect to the probability of a seismic event, changing from a 475-year return period (10 percent probability of occurrence in 50 years) to a 2,475-year return period (2 percent probability of occurrence in 50 years). This has led to the modification of geologic models for building design related to seismic events.

Based on these updated geologic models, NRCan has developed an online calculator to estimate seismic hazard at any given location in Canada (NRCan 2017). Using this calculator, Peak Ground Velocity (PGV) values were calculated for the Project Site to provide an indication of seismic hazard. Values are for firm soil (Soil Type C) and reflect the new baseline return period.

At the Project Site, the PGV value is 0.564 metres per second, giving it a seismic hazard value of high. This is confirmed by seismic hazard mapping (NRCan 2010), which categorizes the seismic hazard in the Lower Mainland as high.

10.10.1.1 Seismic Design and Mitigation

The current edition of the Canadian Standards Association (CSA) Z276, which applies to LNG production, storage, and handling, specifies two levels of earthquake motions that need to be considered during facility design.

1) Operating Basis Earthquake (OBE), based on a 10 percent probability of exceedance within a 50-year period (corresponding to a 1:475-year event or approximately 1:500 years). This is the same as the design basis earthquake used in the present National Building Code, discussed as follows. The structures and systems will be designed to remain operable during and after the OBE.
2) Safe Shutdown Earthquake (SSE), based on a 5 percent probability of exceedance within a 50-year period (approximately 1:1,000 years return period). There will be no loss of containment capability of the tank and it will be possible to isolate and maintain the LNG container during and after the SSE.

The LNG facility will be designed to the higher standards encompassed in the proposed revisions of the various codes, incorporating the most recent knowledge, and predictions of the potential seismic motions. The proposed CSA Z276 requirements for the OBE and SSE seismic events will be used as a minimum standard.

Shaking from a very large subduction earthquake could last much longer than the shaking from a smaller event, although the local ground motions might be similar, depending on the distance and attenuation characteristics. The longer period of shaking will therefore be considered in the design of the facilities.

There are approximately 300 LNG storage tanks of this size and type in the world. Many of these tanks are located in parts of the world that are more seismically active than the Project location, such as Japan, Korea, Turkey, and Greece. Through industry experience, the methods for seismic design are well known and well accepted in the international engineering community. The LNG storage tank, buildings, equipment, and piping proposed for the expansion location meet industry accepted best practices for seismic design.

10.10.2 Flooding

Tilbury Island is located on the flood plain of the Fraser River, near its confluence with the Pacific Ocean. The Project Site is approximately 1 masl and is protected from flooding by a dike along the River, at the north end of the property. Flooding on the Fraser River is usually related to the spring freshet, when snowmelt in the upper reaches and tributaries of the Fraser River combine to fill the system. However, flooding in the Lower Mainland can occur when low pressure storms, bringing heavy rains and winds, combined with high tides (Delta 2019c).

The Lower Mainland Region, including at the Project Site, is at risk from flooding due to the hazard from being at the Fraser River's lowest reaches. Additionally, the consequence associated with a flood is severe due to the large number of people and amount of infrastructure on the flood plain (Fraser Basin Council 2013). Delta administers an extensive system of dikes and drainage structures built to protect the Delta from flooding. The system has been rebuilt a number of times over the years and is currently engineered to withstand a 200-year flood event (Delta 2019c). As previously mentioned, flood protection measures, as outlined by Delta during the building permit process, will be incorporated into building design and/or ground improvement plans.

10.11 Proposed Monitoring Programs

To confirm the effects of the Project and the effectiveness of the applied mitigation, FortisBC will develop and implement monitoring programs during the construction and operations phases of the Project, as appropriate and in collaboration with Appropriate Government Authorities. The monitoring programs will be developed in collaboration with Indigenous Groups during the preparation of the EAC Application and will be refined throughout the EA process. An Environmental Management Program will also be completed following detailed design.

11. Engagement and Consultation with Indigenous Groups

11.1 Identified Indigenous Groups

A review of the Consultative Areas Database (CAD) has identified 17 Indigenous Groups whose established or asserted traditional territories overlap with the Tilbury LNG facility. Squamish Nation and Kwantlen First Nation were not identified in the CAD report but have been included in this list due to their interest in the WesPac Tilbury Marine Jetty project, which is located near the proposed Project. Additionally, Métis Nation British Columbia has been included, as well as the People of the River Referrals Office.

Table 11-1 provides a summary of the locations of each Indigenous group and approximate distances of their administrative offices from the Project Site. The estimated distances do not represent traditional territories, rights, title or use of the area for traditional purposes. See Appendix C for detailed maps of traditional territories, treaty lands, and reserve locations.

Table 11-1. Identified Indigenous Groups that may be affected by the Project
(shown in alphabetical order)

Indigenous Group	Location* and *First Nations Land Management Act* Status	Approximate Distance of Administrative Office from the Project+
Cowichan Tribes [a,b]	The Cowichan Tribes is made up of seven traditional villages. Today, the Cowichan Tribes have nine reserves (Cowichan 1, Cowichan 9, Est-Patrolas 4, Kakalatza 6, Kil-Pah-Las 3, Skutz 7, Skutz 8, Theik 2, and Tzart-Lam 5), located on southeast Vancouver Island in Duncan, near Cowichan Bay and the Cowichan River. The main community, Cowichan 1, is located in Duncan and is the closest to the Project Site. Please refer to Figure C-1 in Appendix C for specific locations of each reserve within the Hul'qumi'num Treaty Group collective traditional territory. The marine traditional territory spans across the Strait of Georgia to include a narrow corridor on the mainland, which includes the Project area (BC Treaty 2019a). Cowichan Tribes has signed a framework agreement under the *First Nations Lands Management Act.*	64 km
Halalt First Nation [a,b]	Halalt First Nation has two reserves (Halalt Island 1 and Halalt 2). The main community, Halalt 2, is located on southeast Vancouver Island in Chemainus. Halalt Island 1 is the closest to the Project Site on Willy Island, east of Vancouver Island at the mouth of the Chemainus River. Please refer to Figure C-1 in Appendix C for specific locations of each reserve within the Hul'qumi'num Treaty Group collective traditional territory. The Hul'qumi'num Treaty Group Statement of Intent consists of core territory and a marine territory. Core traditional territory encompasses a portion of southern Vancouver Island from north of Duncan to Ladysmith, west to Cowichan Lake, east to the Gulf Islands, including the Strait of Georgia and the South Arm of the Fraser up to its confluence with the North Arm; the marine territory extends past that confluence to Yale, which includes the Project area (BC Treaty 2019a). Halalt First Nation has not signed a framework agreement under the *First Nations Lands Management Act.*	57 km
Katzie First Nation	Katzie First Nation has five reserves (Barnston Island 3, Graveyard 5, Katzie 1, Katzie 2, and Pitt Lake 4), which are located on the lower mainland in Pitt Meadows, Langley, and Barnston Island. Katzie 1 is the main community and Barnston Island is the closest to the Project Site. Please refer to Figure C-2 in Appendix C for specific locations of each reserve within the Katzie traditional territory. Katzie First Nation asserts TLU rights within its traditional territory, which includes Pitt Meadows, Maple Ridge, Coquitlam, Surrey, Langley, and New Westminster, including the Project area. (BC Treaty 2019b). Katzie First Nation has signed a framework agreement under the *First Nations Lands Management Act.*	27 km

Table 11-1. Identified Indigenous Groups that may be affected by the Project
(shown in alphabetical order)

Indigenous Group	Location* and *First Nations Land Management Act* Status	Approximate Distance of Administrative Office from the Project†
Kwantlen First Nation	Kwantlen First Nation has seven reserves (Langley 2, Langley 3, Langley 4, Langley 5, McMillan Island 6, Pekw'xe:yles and Whonnock 1), centred around the confluence of the Stave and Fraser Rivers. The main community, McMillan Island, is the closest to the Project Site located in the Fraser River, north of Fort Langley. Please refer to Figure C-3 in Appendix C for specific locations of each reserve within the Kwantlen traditional territory. Kwantlen traditional territory extends from Richmond and New Westminster in the west, to Surrey and Langley in the south, east to Mission, and to the northernmost reaches of Stave Lake (Kwantlen First Nation n.d.). Kwantlen First Nation has signed a framework agreement under the *First Nations Lands Management Act.*	34 km
Lake Cowichan First Nation [b]	Lake Cowichan First Nation has one reserve, known as Cowichan Lake or Ts'uubaa-asatx, which is located on Vancouver Island, approximately 30 km west of Duncan, on the east end of the Town of Lake Cowichan. Please refer to Figure C-1 in Appendix C for the specific location of Cowichan Lake within the Hul'qumi'num Treaty Group collective traditional territory. Lake Cowichan First Nation has signed a framework agreement under the *First Nations Lands Management Act*.	83 km
Lyackson First Nation [a,b]	Lyackson First Nation has three reserves (Lyacksun 3, Porlier Pass 5, and Shingle Point 4). All three reserves are located on Valdes Island, between Gabriola Island to the north and Galiano Island to the south, directly opposite of the mouth of the Fraser River in the Strait of Georgia. Shingle Point 4 is the main community and Lyacksun 3 is the closest to the Project Site. Please refer to Figure C-1 in Appendix C for specific locations of each reserve within the Hul'qumi'num Treaty Group collective traditional territory. The marine traditional territory spans across the Strait of Georgia to include a narrow corridor on the mainland, which includes the Project area (BC Treaty 2019a). Lyackson First Nation has not signed a framework agreement under the *First Nations Lands Management Act.*	57 km
Métis Nation British Columbia	Represents approximately 90,000 self-identified Métis people throughout BC, including 39 Métis Chartered Communities. The Provincial office is located in Surrey, BC.	25 km
Musqueam First Nation	Musqueam First Nation has three reserves (Musqueam 2, Musqueam 4, and Sea Island 3), which are located along the west coast of the lower mainland in Vancouver, Richmond, and Delta. Musqueam 2 is the main community, located at the mouth of the North Arm of the Fraser River, within the City of Vancouver. Musqueam 4 is the closest to the Project Site, located near Canoe Pass on the south arm of the Fraser River. Please refer to Figure C-4 in Appendix C for specific locations of each reserve within the Musqueam traditional territory. The Musqueam Consultative Area overlaps the project area and the Musqueam Declaration of 1976 asserts Aboriginal rights to the lands from Howe Sound eastward to the height of land, including the watershed draining into English Bay, Burrard Inlet, and Indian Arm; south including the Coquitlam River to the Fraser River; across to the south bank of the Fraser River and proceeding downstream in the South Arm to the sea (Musqueam 1976). Musqueam Nation has signed a framework agreement under the *First Nations Lands Management Act.*	15 km
Penelakut Tribe [a,b]	Penelakut Tribe has four reserves (Galiano Island 9, Penelakut Island 7, Tent Island 8, and Tsussie 6). These are located directly opposite of the mouth of the Fraser River in the Strait of Georgia on Galiano Island, Penelakut Island, Tent Island, and in Chemainus on southeast Vancouver Island. Penelakut Island 7 is the main community and Galiano Island 9 is the closest to the Project Site. Please refer to Figure C-1 in Appendix C specific locations of each reserve within Hul'qumi'num Treaty Group collective traditional territory. Core traditional territory includes a portion of southern Vancouver Island from north of Ladysmith, west to Lake Cowichan, east to the Gulf Islands. The marine traditional territory spans across the Strait of Georgia to include a narrow corridor on the mainland, which includes the Project area (BC Treaty 2019a). Penelakut Tribe has signed a framework agreement under the *First Nations Lands Management Act.*	48 km

Table 11-1. Identified Indigenous Groups that may be affected by the Project
(shown in alphabetical order)

Indigenous Group	Location* and *First Nations Land Management Act* Status	Approximate Distance of Administrative Office from the Project†
Seabird Island Band [d]	Seabird Island has two reserves (Pekw'xe:yles and Seabird Island). The main community is Seabird Island, located in the District of Kent on the Fraser River 3 km east of Agassiz. Pekw'xe:yles is the closest to the Project Site located on the north bank of the Fraser River within the District of Mission. Please refer to Figure C-6 in Appendix C for specific locations of each reserve within the Stó:lō traditional territory. Seabird Island Band has signed a framework agreement under the *First Nations Lands Management Act.*	95 km
Semiahmoo First Nation	Semiahmoo has one reserve, fronting Semiahmoo Bay at the Canada-United States border, approximately 1 km southeast of White Rock. Please refer to Figure C-5 in Appendix C for the specific location of the Semiahmoo reserve within the Semiahmoo traditional territory. Semiahmoo First Nation has not signed a framework agreement under the *First Nations Lands Management Act.*	24 km
Shxw'ōwhámél First Nation [d]	Shxw'ōwhámél First Nation has four reserves (Kuthlath 3, Ohamil 1, Pekw'xe:yles, and Wahleach Island 2). Ohamil 1 is the main community located on the left bank of the Fraser River, 7 km north of Laidlaw. Pekw'xe:yles is the closest to the Project Site located on the north bank of the Fraser River within the District of Mission. Please refer to Figure C-6 in Appendix C for specific locations of each reserve within the Stó:lō traditional territory. Shxw'ōwhámél First Nation has signed a framework agreement under the *First Nations Lands Management Act.*	105 km
Skawahlook First Nation [c]	Skawahlook First Nation has three reserves (Pekw'xe:yles, Ruby Creek 2, and Skawahlook 1). Ruby Creek 2 is the main community located on the right bank of the Fraser River, adjacent to the District of Kent. Pekw'xe:yles is the closest to the Project Site located on the north bank of the Fraser River within the District of Mission. Please refer to Figure C-6 in Appendix C for specific locations of each reserve within the Stó:lō traditional territory. The Stó:lō traditional territory, known as S'olh Temexw, extends from Yale to Langley, BC (Stó:lō Service Agency. n.d.). Skawahlook First Nation has signed a framework agreement under the *First Nations Land Management Act.*	106 km
Soowahlie First Nation [d]	Soowahlie First Nation has three reserves (Grass 15, Pekw'xe:yles, and Soowahlie 14). Soowahlie 14 is the main community located on the left bank of the Chilliwack River, 13 km south of Chilliwack. Pekw'xe:yles is the closest to the Project Site located on the north bank of the Fraser River within the District of Mission. Please refer to Figure C-6 in Appendix C for specific locations of each reserve within the Stó:lō traditional territory. Soowahlie First Nation has signed a framework agreement under the *First Nations Land Management Act.*	77 km
Squamish First Nation	Squamish Nation has 24 reserves distributed between the Squamish-Lillooet Regional District and Metro Vancouver Regional District, from southwest of Whistler to Vancouver, including Gibson's Landing and the area north of Howe Sound. The largest proportion of Squamish members reside on several urban reserves in the City of Vancouver, North and West Vancouver, and the District of Squamish. The closest reserve to the Project Site is Kitsilano 6. Please refer to Figure C-8 in Appendix C for the names and specific locations of each reserve within the Squamish traditional territory. Squamish First Nation has signed a framework agreement under the *First Nations Land Management Act.*	18 km
Stó:lō Nation	The Stó:lō Nation is an amalgamation of 11 Stó:lō communities, with many reserves located throughout the Fraser Valley. Member Nations include Aitchelitz First Nation, Leq'á:mel First Nation, Matsqui First Nation, Popkum First Nation, Shxwhá:y Village, Skawahlook First Nation, Skowkale First Nation, Squiala First Nation, Sumas First Nation, Tzeachten First Nation, and Yakweakwioose First Nation. Aitchelitz First Nation, Leq'á:mel First Nation, Matsqui First Nation, Shxwhá:y Village, Skawahlook First Nation, Skowkale First Nation, Squiala First Nation, Sumas First Nation, Tzeachten First Nation, and Yakweakwioose First Nations have signed a framework agreement under the *First Nations Land Management Act.*	78 km

Table 11-1. Identified Indigenous Groups that may be affected by the Project
(shown in alphabetical order)

Indigenous Group	Location* and *First Nations Land Management Act* Status	Approximate Distance of Administrative Office from the Project+
Stó:lō Tribal Council	Members of the Stó:lō Tribal Council include Chawathil First Nation, Cheam First Nation, Kwaw-kwaw-Apilt First Nation, Seabird Island Band, Shxw'ōwhámél First Nation, Soowahlie First Nation, and Sq'éwlets First Nation. These communities have many reserves located throughout the Fraser Valley. The Chawathil First Nation, Cheam First Nation, Kwaw-kwaw-Apilt First Nation, Seabird Island Band, Shxw'ōwhámél First Nation, Soowahlie First Nation, and Sq'éwlets First Nation have signed framework agreements under the *First Nations Land Management Act.*	97 km
Stz'uminus First Nation [a]	Stz'uminus First Nation has four reserves (Chemainus 13, Oyster Bay 12, Say-la-quas 10, and Squaw-hay-one 11). Chemainus 13 is the main community and is the closest to the Project Site, located on southeast Vancouver Island directly opposite of the mouth of the Fraser River in the Stuart Channel. Please refer to Figure C-7 in Appendix C for specific locations of each reserve within the Stz'uminus traditional territory. Stz'uminus First Nation has signed a framework agreement under the *First Nations Land Management Act.*	61 km
Tsawwassen First Nation	Tsawwassen First Nation has 725 ha of Treaty Lands located on the upland areas between the Tsawwassen ferry terminal and the container port at Roberts Bank. Another 62 ha of fee simple land is located near Boundary Bay and on the Fraser River along Canoe Pass. The main Tsawwassen community is on the southern aspect of the Fraser River delta, on the west side of the peninsula that separates Boundary Bay from the Salish Sea. The Project is not on Tsawwassen treaty lands. Please refer to Figure C-9 in Appendix C for specific locations of Tsawwassen Treaty Lands and Treaty Related Lands within the Tsawwassen First Nation Treaty Area. Tsawwassen First Nation has not signed a framework agreement under the *First Nations Land Management Act.*	13 km
Tsleil-Waututh Nation	Tsleil-Waututh Nation has three reserves (Burrard Inlet 3, Inlailawatash 4, and Inlailawatash 4A). Inlailawatash 4 and 4A are located at the mouth of the Indian River and head of the Indian Arm of the Burrard Inlet. Burrard Inlet 3 is the main community and is closest to the Project Site, located in North Vancouver on the shore of the Burrard Inlet, approximately 2 km east of the north end of the Second Narrows Bridge. Please refer to Figure C-10 in Appendix C for specific locations of each reserve within the Tsleil-Waututh traditional territory. Tsleil-Waututh has not signed a framework agreement under the *First Nations Lands Management Act.*	19 km

[a] Members of the Cowichan Nation Alliance
[b] Members of the Hul'qumi'num Treaty Group
[c] Members of the Stó:lō Nation
[d] Members of the Stó:lō Tribal Council
* (Government of BC 2019a; INAC 2019; Métis Nation British Columbia 2019; Stó:lö Research and Research Management Centre 2016; WesPac 2015, 2019)
+ Google maps
Note:
ha = hectare(s)

11.2 Summary of Information Regarding Established or Asserted Indigenous Rights, Title, and Other Interests

Through existing relationships and engagement with local Indigenous Groups on various activities related to the Project, the Proponent has some understanding of Indigenous rights and title interests in the Project area. Each of the Indigenous Groups identified in Table 11-1 has, or asserts claims of, rights and title to the lands, water, and resources within their traditional territories. This includes, but is not limited to, the use of terrestrial, freshwater, marine, and other resources within those territories for traditional purposes (WesPac 2015). Associated activities include, but are not limited to, fishing, hunting, trapping, and gathering activities for food, materials, trade, medicines, and traditional ceremonies (WesPac 2015).

Where rights and title interests in the Project area are known, they are summarized as follows. At the time of writing, complete information on each of the identified Indigenous Groups is not readily available. FortisBC intends to work with each Indigenous Group during the Early Engagement Phase to identify the interests of each group. In addition, Early Engagement Phase will serve to further develop how each Indigenous Group prefers to be characterized in this section, including any additional information identified as important. Further information on Indigenous rights, title, and other interests will be provided in the Detailed Project Description (DPD). Refer to Sections 11.2 to 11.3 for details on preliminary engagement activities, key issues raised to-date, and plans for ongoing engagement.

11.2.1 Cowichan Tribes

Cowichan Tribes is part of the Hul'qumi'num Treaty Group. The Hul'qumi'num Treaty Group in Stage 4 of the BC Treaty process, Agreement in Principle negotiations (BC Treaty 2019a). The Hul'qumi'num Treaty Group Statement of Intent consists of core territory and a marine territory. Core traditional territory includes a portion of southern Vancouver Island from north of Ladysmith, west to Lake Cowichan, east to the gulf islands. The marine traditional territory spans across the Strait of Georgia to include a narrow corridor on the mainland, which includes the Project area (BC Treaty 2019a). Refer to Figure C-1 in Appendix C for a map of the Hul'qumi'num Treaty Group collective traditional territory.

Cowichan Tribes is also a part of the Cowichan Nation Alliance (CNA). CNA is a collective of Indigenous Groups who represent their members in rights and title negotiations. Each of the groups associated with CNA represent the direct descendants of the historic Cowichan Nation. The Cowichan Nation has been an Indigenous people within the meaning of Section 35 of the *Constitution Act*, 1982 since prior to European contact in or about the 1790s and is today comprised of five groups – the Cowichan Tribes, Stz'uminus First Nation, Penelakut Tribe, Halalt First Nation, and Lyackson First Nation – within the meaning of Canada's *Indian Act*. The Cowichan Tribes, Stz'uminus First Nation, Penelakut Tribe, Halalt First Nation, and Lyackson First Nation are the continuation of the Cowichan people existing prior to European contact, continuing through 1846 and Indian Reserve creation. Halalt First Nation has stated that the historic CNA exclusive Aboriginal title area includes the entirety of Tilbury Island.

The CNA have commenced legal action to reclaim the historic village site of Tl'uqtinus and other proximal lands in what is present day Richmond and Delta including the right to fish in the south arm of the Fraser River (CNA 2019). The historic village site of Tl'uqtinus is located approximately 515 m north of the project site on the opposite side of the Fraser River. The trial began September 9, 2019.

In 2012 FortisBC partnered with Stz'uminus First Nation and Cowichan Tribes as equity partners in the Mt. Hayes LNG Storage facility. Each Nation invested $5.7 million, creating jobs and economic opportunity in their communities. As a result, the region received $70 million in investment, which included sourcing local suppliers for goods and services, direct local employment during construction and 12 full-time operations jobs at the facility.

11.2.2 Halalt First Nation

Halalt First Nation is part of the Hul'qumi'num Treaty Group. The Hul'qumi'num Treaty Group in Stage 4 of the BC Treaty process, Agreement in Principle negotiations (BC Treaty 2019a). The Hul'qumi'num Treaty Group Statement of Intent consists of core territory and a marine territory. Core traditional territory encompasses a portion of southern Vancouver Island from north of Duncan to Ladysmith, west to Cowichan Lake, east to the Gulf Islands, including the strait of Georgia and the South Arm of the Fraser up to its confluence with the North Arm; the marine territory extends past that confluence to Yale, which includes the Project area (BC Treaty 2019a). Refer to Figure C-1 in Appendix C for a map of the Hul'qumi'num Treaty Group collective traditional territory.

Halalt First Nation is also a part of the CNA. CNA is a collective of Indigenous Groups who represent their members in rights and title negotiations. Each of the groups associated with CNA represent the direct descendants of the historic Cowichan Nation. The Cowichan Nation has been an Aboriginal people within the meaning of Section 35 of the *Constitution Act*, 1982 since prior to European contact in or about the 1790s and is today comprised of five groups – the Cowichan Tribes, Stz'uminus First Nation, Penelakut

Tribe, Halalt First Nation, and Lyackson First Nation – within the meaning of Canada's *Indian Act*. The Cowichan Tribes, Stz'uminus First Nation, Penelakut Tribe, Halalt First Nation, and Lyackson First Nation are the continuation of the Cowichan people existing prior to European contact, continuing through 1846 and Indian Reserve creation. Halalt First Nation has stated that the historic CNA exclusive Aboriginal title area includes the entirety of Tilbury Island.

Halalt First Nation has reported that there are locations of importance along the South Arm of the Fraser River, most notably the ancestral village and resource site of Tl'uqtinus, which is located on the north shore opposite Tilbury Island (WesPac 2019). The CNA have commenced legal action to reclaim the historic village site of Tl'uqtinus and other proximal lands in what is present day Richmond and Delta, including the right to fish in the south arm of the Fraser River (CNA 2019). The historic village site of Tl'uqtinus is located approximately 515 m north of the Project Site. The trial began September 9, 2019.

11.2.3 Katzie First Nation

Katzie First Nation is in Stage 4 of the BC Treaty process, negotiating an Agreement in Principle with Canada and the province (BC Treaty 2019b). Katzie First Nation asserts TLU rights within its traditional territory, which includes Pitt Meadows, Maple Ridge, Coquitlam, Surrey, Langley, and New Westminster, including the Project area. (BC Treaty 2019b). This territory overlaps with other Indigenous Groups from the CAD search results including Tsawwassen, Musqueam, Stó:lō, and Tsleil-Waututh First Nations, as well as the Hul'qumi'num Treaty Group (BC Treaty 2019b). Refer to Figure C-2 in Appendix C for a map of Katzie First Nation traditional territory.

11.2.4 Kwantlen First Nation

Kwantlen First Nation has seven reserves in the lower mainland located in the Township of Langley, Maple Ridge, and Mission (INAC 2019). The main Kwantlen communities are located on McMillan Island and near the confluence of the Stave and Fraser Rivers. Kwantlen traditional territory extends from Richmond and New Westminster in the west, to Surrey and Langley in the south, east to Mission, and to the northernmost reaches of Stave Lake (Kwantlen First Nation n.d.). Refer to Figure C-3 in Appendix C for a map of Kwantlen First Nation traditional territory.

Until 2018, Kwantlen First Nation was part of the Stó:lö Tribal Council. In 2016, Kwantlen First Nation signed a 3-year Kwantlen Forest Consultation and Revenue Sharing Agreement. Kwantlen First Nation is not currently involved in treaty negotiations with the Province of BC (Government of BC 2019b).

Kwantlen First Nation owns and operates four businesses under the Seyem' Qwantlen Business Group that provide construction contracting services, land development services, and resource management (SQBG 2015).

11.2.5 Lyackson First Nation

Lyackson First Nation is part of the Hul'qumi'num Treaty Group. The Hul'qumi'num Treaty Group in Stage 4 of the BC Treaty process, Agreement in Principle negotiations (BC Treaty 2019a). The Hul'qumi'num Treaty Group Statement of Intent consists of core territory and a marine territory. Core traditional territory includes a portion of southern Vancouver Island from north of Ladysmith, west to Lake Cowichan, east to the Gulf Islands. The marine traditional territory spans across the Strait of Georgia to include a narrow corridor on the mainland, which includes the Project area (BC Treaty 2019a). Refer to Figure C-1 in Appendix C for a map of the Hul'qumi'num Treaty Group collective traditional territory.

Lyackson First Nation is also a part of the CNA. CNA is a collective of Indigenous Groups who represent their members in rights and title negotiations. Each of the groups associated with CNA represent the direct descendants of the historic Cowichan Nation. The Cowichan Nation has been an Aboriginal people within the meaning of Section 35 of the *Constitution Act*, 1982 since prior to European contact in or about the 1790s and is today comprised of five groups – the Cowichan Tribes, Stz'uminus First Nation, Penelakut Tribe, Halalt First Nation, and Lyackson First Nation – within the meaning of Canada's *Indian Act*. The Cowichan Tribes, Stz'uminus First Nation, Penelakut Tribe, Halalt First Nation, and Lyackson

First Nation are the continuation of the Cowichan people existing prior to European contact, continuing through 1846 and Indian Reserve creation. Halalt First Nation has stated that the historic CNA exclusive Aboriginal title area includes the entirety of Tilbury Island.

The CNA have commenced legal action to reclaim the historic village site of Tl'uqtinus and other proximal lands in what is present day Richmond and Delta including the right to fish in the south arm of the Fraser River (CNA 2019). The historic village site of Tl'uqtinus is located approximately 515 m north of the project site. The trial began September 9, 2019.

11.2.6 Métis Nation British Columbia

Métis Nation British Columbia represents approximately 90,000 self-identified Métis people throughout BC, of which 18,000 are Provincially-registered (Métis Nation British Columbia 2019). Métis Nation British Columbia also represents 39 Métis Chartered Communities, of which 6 are located in the lower mainland and 3 are located in south Vancouver Island (Métis Nation British Columbia 2019). These include Chilliwack Métis Association, Fraser Valley Métis Association, Golden Ears Métis Society, North Fraser Métis Association, Nova Métis Heritage Association, Waceya Métis Society, Cowichan Valley Métis Association, Mid-Island Métis Nation Association, and the Métis Nation of Greater Victoria Association (Métis Nation British Columbia 2019).

The Métis Nation British Columbia is recognized by the Federal Government, the Province of BC, and the Métis National Council as the governing Nation for Métis in BC (Métis Nation British Columbia 2019). In 2003, Métis Nation British Columbia established their constitution to implement a self-governance and legislative structure, including an objectively verifiable citizenship process (Métis Nation British Columbia 2019). The mission of Métis Nation British Columbia is to develop and enhance opportunities for Métis Chartered Communities and Métis people in British Columbia by providing culturally relevant social and economic programs and services (Métis Nation British Columbia 2019).

11.2.7 Musqueam Nation

Through existing relationships and past engagement activities with Musqueam Nation, FortisBC is aware that Musqueam has a proven right to fish in Canoe Passage as defined in the Supreme Court of Canada Sparrow case (Supreme Court of Canada 1990).

The Musqueam Consultative Area overlaps the project area and the Musqueam Declaration of 1976 asserts Aboriginal rights to the lands from Howe Sound eastward to the height of land, including the watershed draining into English Bay, Burrard Inlet, and Indian Arm; south including the Coquitlam River to the Fraser River; across to the south bank of the Fraser River and proceeding downstream in the South Arm to the sea (Musqueam 1976). Refer to Figure C-4 in Appendix C for a map of Musqueam Nation traditional territory.

11.2.8 Penelakut Tribe

Penelakut Tribe is part of the Hul'qumi'num Treaty Group. The Hul'qumi'num Treaty Group in Stage 4 of the BC Treaty process, Agreement in Principle negotiations (BC Treaty 2019a). The Hul'qumi'num Treaty Group Statement of Intent consists of core territory and a marine territory. Core traditional territory includes a portion of southern Vancouver Island from north of Ladysmith, west to Lake Cowichan, east to the Gulf Islands. The marine traditional territory spans across the Strait of Georgia to include a narrow corridor on the mainland, which includes the Project area (BC Treaty 2019a). Refer to Figure C-1 in Appendix C for a map of the Hul'qumi'num Treaty Group collective traditional territory.

Penelakut Tribe is also a part of the CNA. CNA is a collective of Indigenous Groups who represent their members in rights and title negotiations. Each of the groups associated with CNA represent the direct descendants of the historic Cowichan Nation. The Cowichan Nation has been an Aboriginal people within the meaning of Section 35 of the *Constitution Act*, 1982 since prior to European contact in or about the 1790s and is today comprised of five groups – the Cowichan Tribes, Stz'uminus First Nation, Penelakut Tribe, Halalt First Nation, and Lyackson First Nation – within the meaning of Canada's *Indian Act*. The

Cowichan Tribes, Stz'uminus First Nation, Penelakut Tribe, Halalt First Nation and Lyackson First Nation are the continuation of the Cowichan people existing prior to European contact, continuing through 1846 and Indian Reserve creation. Halalt First Nation has stated that the historic CNA exclusive Aboriginal title area includes the entirety of Tilbury Island.

The CNA have commenced legal action to reclaim the historic village site of Tl'uqtinus and other proximal lands in what is present day Richmond and Delta including the right to fish in the south arm of the Fraser River (CNA 2019). The historic village site of Tl'uqtinus is located approximately 515 m north of the project site. The trial began September 9, 2019.

11.2.9 Semiahmoo First Nation

Semiahmoo First Nation is located near the United States Border and near Boundary Bay. The Semiahmoo First Nation is not involved in any treaty process (Government of BC 2019c). Refer to Figure C-5 in Appendix C for a map of Semiahmoo First Nation traditional territory.

11.2.10 Squamish Nation

Squamish Nation traditional territory covers over 673,000 ha of land on the lower mainland and is described as encompassing the area from Point Grey in the south, to Roberts Creek in the west, north to the height of land to the Elaho river headwaters, including the islands of Howe Sound and the Squamish Valley; then southeast to the confluence of the Soo and Green Rivers, south along the height of land to Port Moody, including the Mamquam River and Indian Arm drainages, then west along the height of land to Point Grey (Squamish 2013b). This territory includes the cities of Vancouver, West Vancouver, North Vancouver, Burnaby, Port Moody, the District of Squamish, and the Municipality of Whistler, but does not include the Project area (Squamish 2013b; BC Treaty n.d.). Refer to Figure C-8 in Appendix C for a map of Squamish Nation traditional territory.

The Squamish Nation is currently in Stage 3 of the BC Treaty process, negotiation of a framework agreement (Squamish 2013a; BC Treaty 2019c). In 1993, Squamish Nation submitted their Statement of Intent to begin negotiating Aboriginal rights and title to the lands, waters, and resources within Squamish traditional territory (Squamish 2013a).

11.2.11 Stó:lō Nation

The Stó:lō Nation is the political amalgamation of 11 Stó:lō communities including Aitchelitz First Nation, Leq'á:mel First Nation, Matsqui First Nation, Popkum First Nation, Shxwhá:y Village, Skawahlook First Nation, Skowkale First Nation, Squiala First Nation, Sumas First Nation, Tzeachten First Nation, and Yakweakwioose First Nation (Stó:lō Service Agency n.d.). The Stó:lō Nation is affiliated with several service delivery and political organizations including the Stó:lō Service Agency, the Stó:lō Tribal Council and the Stó:lō Xwexwilmexw Treaty Association (Stó:lō Service Agency n.d.; BC Treaty 2019d). However, these organizations do not service or represent all of the same member communities.

The Stó:lō Xwexwilmexw Treaty Association represents six Stó:lō communities: Aitchelitz First Nation, Leq'á:mel First Nation, Skawahlook First Nation, Skowkale First Nation, Tzeachten First Nation, and Yakweakwioose First Nation (BC Treaty 2019d). The Stó:lō Xwexwilmexw Treaty Association is currently in Stage 4 of the BC Treaty process, advanced agreement in principle negotiations (BC Treaty 2019d).

The Stó:lō traditional territory, known as S'olh Temexw, extends from Yale to Langley, BC (Stó:lō Service Agency n.d.). Refer to Figure C-6 in Appendix C for a map of the Stó:lō Nation collective traditional territory.

11.2.12 Stz'uminus First Nation

Stz'uminus was previously a part of the Hul'qumi'num Treaty Group but departed in 2014.

Stz'uminus First Nation is also a part of the CNA. CNA is a collective of Indigenous Groups who represent their members in rights and title negotiations. Each of the groups associated with CNA represent the direct descendants of the historic Cowichan Nation. The Cowichan Nation has been an Aboriginal people within the meaning of Section 35 of the *Constitution Act*, 1982 since prior to European contact in or about the 1790s and is today comprised of five groups – the Cowichan Tribes, Stz'uminus First Nation, Penelakut Tribe, Halalt First Nation, and Lyackson First Nation – within the meaning of Canada's *Indian Act*. The Cowichan Tribes, Stz'uminus First Nation, Penelakut Tribe, Halalt First Nation, and Lyackson First Nation are the continuation of the Cowichan people existing prior to European contact, continuing through 1846 and Indian Reserve creation. Halalt First Nation has stated that the historic CNA exclusive Aboriginal title area includes the entirety of Tilbury Island.

The CNA have commenced legal action to reclaim the historic village site of Tl'uqtinus and other proximal lands in what is present day Richmond and Delta including the right to fish in the south arm of the Fraser River (CNA 2019). The historic village site of Tl'uqtinus is located approximately 515 m north of the project site. The trial began September 9, 2019.

In 2012 FortisBC partnered with Stz'uminus First Nation and Cowichan Tribes as equity partners in the Mt. Hayes LNG Storage facility. Each Nation invested $5.7 million, creating jobs and economic opportunity in their communities. As a result, the region received $70 million in investment, which included sourcing local suppliers for goods and services, direct local employment during construction and 12 full-time operations jobs at the facility.

We expect to work with the CNA to develop how they would prefer to be characterized in this section. Refer to Figure C-7 in Appendix C for a map of Stz'uminus First Nation traditional territory.

11.2.13 Tsawwassen First Nation

The Tsawwassen traditional territory is in the Lower Mainland and extends from the watersheds that feed into Pitt Lake and burns bog to the Strait of Georgia, including Salt Spring, Pender, and Saturna Islands and includes the Project area (BC Treaty 2019e). Refer to Figure C-9 in Appendix C for a map of the Tsawwassen First Nation treaty area and lands.

The Tsawwassen First Nation is one of few modern Treaty Nations in BC. The Tsawwassen First Nation Final Agreement is a tri-partite agreement between Canada, BC, and Tsawwassen First Nation. It is a comprehensive agreement that provides for the transfer of land and self-government jurisdiction to Tsawwassen First Nation. The final agreement became effective on April 3, 2009 (Tsawwassen First Nation 2019; BC Treaty 2019e).

Under the final agreement, Tsawwassen First Nation has direct control and ownership of 724 ha of land and exercises TLU rights on 10,000 km^2 of traditional territory (shown in Appendix A of the final agreement) (MPWGSC 2010). The Project area is overlapped by Tsawwassen TLU areas but not Tsawwassen lands.

11.2.14 Tsleil-Waututh Nation

The Tsleil-Waututh traditional territory encompasses an area of 190,000 ha reaching from the Fraser River in the south to Mamquam Lake in the north (Tsleil-Waututh Nation n.d.). This territory includes watersheds and wilderness areas in the north and the now urban areas of North Vancouver, Vancouver, Burnaby, Richmond, and Delta to the south (CH2M 2015). Tsleil-Waututh Nation uses their traditional territory for subsistence, as well as for cultural and spiritual activities. For example, Tsleil-Waututh Nation members fish for salmon in the Burrard Inlet and the Fraser River (CH2M 2015). Refer to Figure C-10 in Appendix C for a map of Tsleil-Waututh Nation traditional territory.

Tsleil-Waututh Nation has been in Stage 4 of the BC Treaty process for almost 20 years and are currently waiting for sign off on the Chief Negotiators Table (Tsleil-Waututh Nation n.d.).

11.3 Summary of Preliminary Engagement Activities

FortisBC engagement with communities across BC varies based on their interests and the types of activities that FortisBC is pursuing in their local territories. FortisBC infrastructure is concentrated in population centres such as the Metro Vancouver area. Many of the Indigenous Groups in the area have existing relationships with FortisBC as a result of activities related to the existing Tilbury LNG facility. The two communities that have been most actively engaged with FortisBC on Tilbury activities to date have been CNA and Musqueam Nation.

FortisBC conducted preliminary engagement activities in advance of filing this IPD. The preliminary engagement approach is characterized as follows.

11.3.1 Preliminary Engagement Approach

1) An email notification of upcoming early engagement activities was sent on July 2, 2019 to all Indigenous Groups with consultative areas overlapping the Phase 2 Project area. The notification included an approximate date of July 9, 2019 upon which the Draft Project Description would be sent and the requested date of July 31, 2019 to return comments. The purpose of this notification was to provide advance notice to allow Indigenous Groups to appropriately resource review if they wished to comment on the early draft.
2) A draft IPD Description was sent on July 12, 2019 to Indigenous Groups with consultative areas overlapping the Phase 2 Project area. Indigenous Groups were asked to provide comments on the IPD by August 2, 2019. This period is 21 days.
3) Five Indigenous Groups responded to the initial communication regarding the Project Description. Table 11-2 is a summary of the correspondence received. During the preliminary engagement activities, the project team participated in meetings with Indigenous Groups, responded to questions and discussed next steps regarding the regulatory process.
4) Upon receipt of comments the draft IPD was revised to reflect any comments received from Indigenous Groups.
5) The revised IPD was circulated to all Indigenous Groups that provided comments on the initial draft or indicated an interest in the Project by responding to initial Project communications. The revised IPD was provided on September 16, 2019 with a request that any comments be received by October 2, 2019. Indigenous Groups were advised that FortisBC would continue to address comments received after this date, but they may not be reflected in the draft submitted to regulators. Indigenous Groups were also advised that the Project was in preliminary engagement stages and there would be additional opportunities for engagement through the BC EAO process.

Table 11-2 provides a summary of preliminary engagement activities to-date. Preliminary engagement has focused primarily on information sharing about the Project, the next steps in regulatory review, responding to questions, and recording concerns expressed. At this stage of the Project, we understand that additional work is required for Indigenous Groups to scope out the nature of their concerns.

FortisBC has a longstanding relationship with a number of Indigenous Groups near the Tilbury LNG facility. Engagement activities will draw on these existing relationships to ensure that Indigenous Groups are informed of the proposed Project and aware of the upcoming EA process.

Table 11-2. Summary of Engagement with Indigenous Groups To-Date

Date	Method of Contact	Indigenous Group	Notes
July 2, 2019	Email	• Cowichan Tribes • Penelakut Tribe • Stz'uminus First Nation • Lyackson First Nation • Halalt First Nation	Introductory email sent to each Indigenous Group notifying them of the Project and requesting a meeting to review the Draft Project Description.

Table 11-2. Summary of Engagement with Indigenous Groups To-Date

Date	Method of Contact	Indigenous Group	Notes
		• Katzie First Nation • Kwantlen First Nation • Lake Cowichan First Nation • Musqueam Nation • Stó:lö Nation* • Soowahlie First Nation* • Skowkale First Nation* • Stó:lö Tribal Council* • Seabird Island Band • Semiahmoo First Nation • Shxw'ōwhámél First Nation • Squamish first Nation • Tsawwassen First Nation • Tsleil-Waututh Nation	
July 3, 2019	Email	• Cowichan Nation Alliance	FortisBC confirmed meeting with Cowichan Nation Alliance to discuss the Project.
July 12, 2019	Email	• Cowichan Tribes • Penelakut Tribe • Stz'uminus First Nation • Lyackson First Nation • Halalt First Nation • Katzie First Nation • Kwantlen First Nation • Lake Cowichan First Nation • Musqueam Nation • Stó:lö Nation* • Soowahlie First Nation* • Skowkale First Nation* • Stó:lö Tribal Council* • Seabird Island Band • Semiahmoo First Nation • Shxw'ōwhámél First Nation • Squamish First Nation • Tsawwassen First Nation • Tsleil-Waututh Nation	Draft Initial Project Description was shared with Indigenous Groups.
July 15, 2019	Email	• Katzie First Nation	Confirmed review of Project Description and per diem rate
July 17, 2019	Meeting	• Cowichan Nation Alliance: – Cowichan Tribes – Stz'uminus First Nation – Halalt First Nation – Penelakut Tribe	Meeting at Cowichan Tribes office in Duncan to discuss Project Description and address initial questions or concerns.
July 19, 2019	Meeting	• Tsawwassen First Nation	Meeting at Tsawwassen First Nation to discuss Project Description and address initial questions or concerns
July 25, 2019	Email	• Tsawwassen First Nation	FortisBC sent follow up email to provide additional info and extend invitation to upcoming LNG event in Delta.
July 25, 2019	Letter	• Kwantlen First Nation	Kwantlen provided a letter in response to invitation for review of Project Description and requested to schedule a meeting.
July 29, 2019	Email	• Cowichan Tribes	Cowichan Tribes provided initial comments on the Draft Project Description.

Table 11-2. Summary of Engagement with Indigenous Groups To-Date

Date	Method of Contact	Indigenous Group	Notes
July 30, 2019	Letter	• Musqueam Nation	Musqueam provided a form letter in response to invitation for review of Project Description. Indicated reduced internal capacity at this time due to organizational restructuring but still interested in participating in consultation.
July 31, 2019	Email	• Halalt First Nation	Halalt First Nation provided initial comments on the Draft Project Description.
August 8, 2019	Meeting	• Kwantlen First Nation	Meeting at Kwantlen First Nation to discuss Project Description and address any questions or concerns.
August 8, 2019	Email	• Seabird Island Band	Seabird Island Band responded to the initial email introducing the Project and indicated that they currently have no input at this time.
August 14, 2019	Letter	• Tsleil-Waututh Nation	Tsleil-Waututh Nation sent a letter outlining expectations around consultation and accommodation for the Project.
August 15, 2019	Call	• Cowichan Tribes	Clarification of Cowichan Tribes comments. Cowichan Tribes to seek availability for another meeting with FortisBC end of August.
August 27, 2019	Meeting	• Musqueam Nation	Met with Rights and Title Manager at Musqueam, provided a copy of the Project Description for Tilbury and detailed areas where feedback from Musqueam was requested.
September 16, 2019	Email	• Musqueam Nation • Cowichan Tribes • Halalt First Nation • Stz'uminus First Nation • Penelakut First Nation • Lyackson First Nation • Katzie First Nation • Kwantlen First Nation • Tsawwassen First Nation • Tsleil-Waututh Nation	FortisBC provided revised project description by email to the Indigenous Groups that had provided comments or responded and indicated an interest in being engaged on the Project.
September 16, 2019	Email	• Cowichan Tribes	Email providing additional clarification of comments included in the draft revision.
September 17, 2019	Email	• Tsleil-Waututh Nation	Correspondence with Tsleil-Waututh to confirm next steps for Project meeting in late October.
September 17, 2019	Email	• Tsawwassen First Nation	Acknowledge receipt of revised draft.
September 24, 2019	Site visit	• Kwantlen First Nation	Project team conducted Project Site visit with the Kwantlen First Nation to discuss the Project.
October 2, 2019	Email	• Tsawwassen First Nation	Tsawwassen is interested in providing comments on the Project; however, there are capacity constraints for internal review. Request FortisBC address forthcoming comments at a later date.
October 8, 2019	Email	• Kwantlen First Nation	FortisBC provided meeting notes from Project Site visit September 24, 2019.
October 15, 2019	Email	• Tsleil-Waututh Nation	Invitation to FortisBC for initial project meeting with Tsleil-Waututh Nation's Treaty, Land, and Resource team.

Table 11-2. Summary of Engagement with Indigenous Groups To-Date

Date	Method of Contact	Indigenous Group	Notes
October 24, 2019	Call	• Musqueam Nation	Call with Musqueam to discuss Tilbury 2 project, upcoming milestones, and status of review of the project description draft.
November 14, 2019	Call	• Musqueam Nation	Call with Musqueam to discuss Tilbury 2 project, upcoming milestones. No meeting with the FEI project team requested at this time.
November 28, 2019	Meeting	• Tsleil-Waututh Nation	Initial meeting with Tsleil-Waututh Nation leads for this project.
December 5, 2019	Call	• Musqueam Nation	Call to provide status update on the FortisBC Tilbury project description.

Note:

* Via People of the River Referrals Office

11.3.2 Key Issues Raised

Table 11-3 presents a summary of key issues raised by Indigenous Groups to-date.

Table 11-3. Key Issues Raised by Indigenous Groups to Date

Indigenous Group	Issues Raised	FortisBC Response
Cowichan Tribes	Expressed interest in more detail on the marine shipping container business and Tilbury Project Site layout and general arrangements.	FortisBC to provide additional context
Cowichan Tribes	Expressed interest in more detail about the process for decommissioning and demolition of the old plant.	FortisBC responded that these activities would be subject to BCUC and BC OGC approvals.
Cowichan Tribes	When CNA provides suggestions and input to FortisBC, CNA expects FortisBC to provide a rationale for instances where feedback is not incorporated, as indicated in the preliminary Indigenous engagement plan.	FortisBC agrees to provide such rationale.
Cowichan Tribes	Review period for materials should be at least 3 weeks.	FortisBC will work to achieve this standard, although circumstances may be such that shorter or longer review periods are reasonable. FortisBC will engage Cowichan Tribes in the development of the DPD, including review prior to submission to regulators. FortisBC will provide 3 weeks for Cowichan Tribes to complete this review.
Kwantlen First Nation	Expressed concerns around end of life abandonment of assets: Heightened sensitivity with old ferry dock on Brae island, which was abandoned since 2005 when the ferry stopped operating.	FortisBC spoke of how de-commissioning / abandonment is part of EA review to assess impacts of this phase of project. FortisBC spoke of how 'old' Tilbury plant would be decommissioned and removed and not abandoned in-place.
Kwantlen First Nation	Concerns related to developing infrastructure related to GHG emissions.	This issue will be addressed in the assessment.

Table 11-3. Key Issues Raised by Indigenous Groups to Date

Indigenous Group	Issues Raised	FortisBC Response
Kwantlen First Nation	Cumulative effects of many projects over the years: Concerns with increased shipping (on river), Tilbury Island specifically is under a lot of development.	This issue will be addressed in the assessment.
Kwantlen First Nation	Interest in 'legacy projects' that contribute to bio-diversity.	FortisBC willing to discuss this issue further with Kwantlen.
Kwantlen First Nation	Kwantlen received some 70 or more referrals per month from EAs to permits, which is a challenge for small team to manage.	On invitation of FortisBC Kwantlen to send estimate for capacity funding
Kwantlen First Nation	Kwantlen interested in Tilbury Island and wants to be regularly active in consultation.	FortisBC will continue to meet with Kwantlen to understand their interest in the Project.
Kwantlen First Nation	When and how to request capacity funding.	On invitation of FortisBC Kwantlen to send estimate
Kwantlen First Nation	Would like a Project Site tour ideally with WesPac present to discuss Jetty project also.	FortisBC arranged and site tour completed with WesPac
Kwantlen First Nation	Would like to participate in opportunities including Archeological Assessments.	FortisBC noted that AIA for Project Site may be done as part of application WesPac will be submitting
Tsleil-Waututh Nation	Tsleil-Waututh requires 30 to 45 day review period.	FortisBC will work to achieve this review period within the Early Engagement Phase, including scheduling a meeting following a 30-day period from receiving the IPD as well as providing 30 days to review the DPD prior to submission of regulators.
Tsleil-Waututh Nation	Tsleil-Waututh has concerns around cumulative effects assessment and uses a pre-contact baseline.	This issue will be addressed during the preparation of the Application Information Requirements.
Tsleil-Waututh Nation	Tsleil-Waututh raised concerns around the scope of the assessment, wants upstream impacts from extraction assessed as well.	This issue will be addressed during the preparation of the Application Information Requirements.

11.4 Consultation Plan

FortisBC has developed an Engagement Plan that outlines activities that FortisBC will undertake during the Early Engagement Phase of the EA process. This section provides an overview of these activities.

11.4.1 FortisBC Statement of Indigenous Principles

FortisBC is committed to building effective Indigenous relationships and to ensuring we have the structure, resources, and skills necessary to maintain these relationships.

To meet this commitment, the following principles will guide the actions of the company and its employees:

- FortisBC acknowledges, respects, and understands that Indigenous Peoples have unique histories, cultures, protocols, values, beliefs, and governments.

- FortisBC supports fair and equal access to employment and business opportunities within FortisBC companies for Indigenous Peoples.
- FortisBC will develop fair, accessible employment practices and plans that ensure Indigenous Peoples are considered fairly for employment opportunities within FortisBC.
- FortisBC will strive to attract Indigenous employees, consultants, and contractors and business partnerships.
- FortisBC is committed to dialogue through clear and open communication with Indigenous communities on an ongoing and timely basis for the mutual interest and benefit of both parties.
- FortisBC encourages awareness and understanding of Indigenous issues within its workforce, industry, and communities where it operates.
- To achieve better understanding and appreciation of Indigenous culture, values, and beliefs, FortisBC is committed to educating its employees regarding Indigenous issues, interests, and goals.
- FortisBC will ensure that when interacting with Indigenous Peoples, its employees, consultants, and contractors demonstrate respect, and understanding of Indigenous Peoples' culture, values, and beliefs.
- To give effect to these principles, each of FortisBC's business units will develop, in dialogue with Indigenous communities, plans specific to their circumstances.

As outlined by the FortisBC Statement of Indigenous Principles, engagement activities related to the Project will be guided by a commitment to clear and open communication in a timely manner with local Indigenous Groups.

FortisBC has developed an Engagement Plan, outlining a process that is inclusive of Indigenous Groups potentially affected by the Project. FortisBC will incorporate the principles of GBA+ by deliberately seeking out participation from diverse groups within communities to support an accurate scoping and assessment of potential issues of importance to communities.

The Proponent will undertake a combination of the following based on Indigenous Group feedback.

- Introductory meetings to share information about the Project, seek a point-of-contact, and identify group-specific consultation policies, protocols, or preferences
- Meetings to discuss the proposed Project, provide Project updates, and discuss topics of interest
- Project Site visit
- Invite participation in, and provide feedback on AIA and other studies
- Provide capacity funding to support community-specific assessments or studies
- Offer to facilitate community-specific meetings
- Correspond throughout the pre-application and application phases via Project updates, written correspondence (emails, letters), and phone conversations
- Work with groups to identify training, economic, and employment opportunities

If Indigenous Groups provide comments on the IPD, FortisBC will demonstrate where comments are incorporated within the DPD and provide a rationale for instances where feedback was not incorporated. FortisBC will provide a draft of the DPD to participating Indigenous Groups for review in advance of submission to regulatory agencies.

Indigenous Groups will be provided sufficient time to review materials. Amount of time will vary depending on circumstances such as capacity of the Indigenous Group, the volume of material to review, and the timelines related to the EA generally..

In addition to the methodology and tools the Proponent will use to consult with Indigenous Groups, the Proponent will undertake a public consultation program. Indigenous Groups are welcome to attend all such public events.

11.5 Preliminary Assessment of Potential Impacts to Indigenous Groups Resulting from Project Activities

This section will be further informed by input from Indigenous Groups during the Early Engagement Phase

The following is a preliminary assessment of potential impacts to Indigenous Groups including rights and title, current use of land and resources for traditional purposes, heritage resources, health, and socio-economic impacts as a result of carrying out the Project. The potential effects identified in Table 11-4 below apply to all Project phases and activities, including construction of the temporary construction jetty and associated increases in marine traffic during construction. Further understanding of these impacts is expected to result from consultation and engagement with Indigenous Groups throughout the assessment process. Mitigation measures and appropriate management plans will be developed based on comments received from Indigenous Groups through the EA process.

Table 11-4. Preliminary Identification of Potential Effects to Indigenous Groups Resulting from Project Activities

Category	Potential Effects
Established or asserted Indigenous rights, title, and other interests	• Changes to accessibility of traditional lands, waters, and resources • Changes to the quality of traditional lands, waters, and resources • Changes to availability of traditional lands, waters, and resources • Change in traditional economic activities such as hunting, fishing, and gathering for materials, subsistence, and trade • Change in sense of place and cultural continuity due to changes in accessibility and environmental quality
Current use of land and resources for traditional purposes	• Changes to accessibility of TLU sites • Changes to habitat quality • Changes to the availability, quantity, and quality of traditional lands, waters, and resources • Changes to traditional land use experience due to sensory disturbance such as noise and light • Changes to cultural continuity and intergenerational knowledge transfer due to changes in accessibility and environmental quality
Health and socio-economic conditions	• Sensory disturbance due to increased noise and light levels • Decrease in air quality due to air emissions and dust from vehicle use of access roads • Potential safety risks due to increased traffic and industrial activities • Change in traditional economic activities such as hunting, fishing, and gathering for materials, subsistence, and trade • Change in sense of place and cultural continuity due to changes in accessibility and environmental quality • Increase in employment and contracting opportunities
Physical and cultural heritage, including any structure, site or thing that is of historical, archaeological, paleontological, or architectural significance	• Disturbance or alteration to heritage resources, sites, structures, or features of cultural importance • Change in access to heritage resources, sites, structures, or features of cultural importance • Disturbance or alteration of landscape, waterscape or viewscape impacting cultural experience of lands, waters, and resources

In addition to the potential impacts outlined above, Table 11-5 provides a summary of the key areas of interests that FortisBC anticipates will be raised by Indigenous Groups.

Table 11-5. Summary of Preliminary Interests Identified Through Initial Engagement with Indigenous Groups

Key Areas of Interest	Key Areas of Interest Details
Business opportunities and employment	• Support for community initiatives • Employment and skills training for members
Capacity Funding	• Support for participation and technical expert review
Cumulative Impacts	• Impact of additional development within the project area and along the Fraser River
Heritage Resources	• Presence and protection of Heritage Sites
Permitting and Consultation	• Adequate time for Indigenous participation in the EA / IA process and development of the consultation plan

FortisBC will continue to work with Indigenous Groups to identify the most effective methods of engagement throughout the Project. Engagement will focus on collaboratively addressing concerns raised by Indigenous Groups, minimizing impacts to Indigenous rights and title, and supporting local Indigenous Group access to employment opportunities to benefit economically from the Project.

12. Engagement and Consultation with Governments, the Public and Other Parties

12.1 Summary of Preliminary Engagement Activities

FortisBC has been consulting with government, the public, and other parties on Projects of the Tilbury LNG facility since 2012. FortisBC recognizes the importance of meaningful engagement and strives to develop and maintain strong relationships with all stakeholders. The company's consultation objectives are to raise awareness of the Tilbury LNG facility in neighbouring communities, receive feedback from stakeholders, and respond to any expansion-related inquiries. The following section outlines consultation that has already taken place. Future consultation will build on these existing relationships and engagement activities.

12.1.1 Government

Since 2012, FortisBC has regularly communicated and met in-person with Municipal, Provincial, and Federal governments to provide updates and respond to questions about the company and the Tilbury LNG facility. Through these meetings, FortisBC gained an understanding about community values, and sought recommendations on consultation and engagement. FortisBC regularly meets with Delta to inform them of Project updates and provides advanced notice of FortisBC-related activities taking place in their community. FortisBC also engages municipal staff, local first responders, and other stakeholders in full-scale emergency exercises at the Tilbury LNG facility. FortisBC met with the BC EAO and IAAC in June 2019 to initiate Project discussions.

12.1.2 Public and Other Interested Parties

FortisBC recognizes that the public expects meaningful consultation and engagement and expects work to be conducted in a safe and environmentally responsible manner. The public is interested in learning more about LNG and understanding more about the Project, and FortisBC is committed to providing these opportunities. Through this public engagement, FortisBC will identify issues that have been raised by different interested groups and individuals and will develop an issues tracking table which identifies the issue raised as well as an explanation of how that issue will be addressed.

FortisBC uses a number of communication channels to share information with the public including the company's major projects website: TalkingEnergy.ca, a dedicated Project email and phone number, and through social media platforms.

The company is actively involved in events in the communities near the Tilbury LNG facility, which provide the public with an opportunity to learn more about the company and the facility. FortisBC also participated in information sessions in 2015 and 2019 for the WesPac Tilbury Marine Jetty project EA in Delta and Richmond. This provided the public with opportunities to ask questions about the Tilbury LNG facility and plans for future expansion.

12.2 Proposed Stakeholder Consultation Activities

The focus of FortisBC's stakeholder consultation on the Project will be to ensure that government, the public and other interested parties are informed about the Project, have access to information, and are encouraged to provide feedback throughout the duration of expansion.

FortisBC will also continue to maintain and strengthen relationships developed during previous engagement, primarily with those located near the facility including Delta and Richmond.

12.2.1 Government

FortisBC will continue to meet regularly with local elected officials to keep them informed of the Project and seek their input to help address potential concerns of local residents, businesses, and constituents.

FortisBC will work with local government, the BC OGC, and other Appropriate Government Authorities regarding permitting requirements to maintain transparency, ensure compliance, and address feedback throughout the process.

FortisBC is committed to ensuring the safety of our employees and the public. The company will also explore more opportunities to put on live demonstrations to educate stakeholders and help the public better understand the properties of LNG. FortisBC will continue to seek participation from Municipal staff and local stakeholders in future emergency preparedness exercises.

12.2.2 Public and Other Interested Parties

The next phase of engagement on the Project with the public will begin with an initial notification letter sent to landowners and businesses near the Tilbury facility. The letter will include contact details and a link to the project website should they have any questions or would like more information.

FortisBC will continue to participate in and support events and organizations that are important to the local communities. Continuous presence will allow FortisBC to engage with members of the community on a regular basis, to seek input and address questions and potential concerns throughout the process.

FortisBC has developed an Early Engagement plan to ensure open dialogue is maintained with government, the public, and interested stakeholders and to meet the company's consultation objectives.

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Appendix A
Table of Concordance – *Impact Assessment Act*

Appendix A. Table of Concordance – *Impact Assessment Act* Requirements

The following Table of Concordance cross references sections of this IPD with the list the requirements of an Initial Project Description under the *Impact Assessment Act* (from Section 1.1, Annex 1 of the *Practitioners Guide to Federal Impact Assessments under the Impact Assessment Act* (IAAC 2019).

Item	PD Section	Information Requirements
Part A - General Information		
IPD 1-1	1	The project's name, type or sector and proposed location.
IPD 1-2	1.1.1	The proponent's name and contact information and the name and contact information of their primary representative for the purpose of the description of the project.
IPD 1-3	12	A summary of any engagement undertaken with any jurisdiction or other party, including a summary of the key issues raised and the results of the engagement, and a brief description of any plan for future engagement.
IPD 1-4	11	A list of the Indigenous Groups that may be affected by the carrying out of the project, a summary of any engagement undertaken with the Indigenous peoples of Canada, including a summary of key issues raised and the results of the engagement, and a brief description of any plan for future engagement.
IPD 1-5	1	Any study or plan, relevant to the project, that is being or has been conducted in respect of the region where the project is to be carried out, including a regional assessment that is being or has been carried out under section 92 or 93 of the Act or by any jurisdiction, including by or on behalf of an Indigenous governing body, if the study or plan is available to the public.
IPD 1-6	1	Any strategic assessment, relevant to the project, that is being or has been carried out under section 95 of the Act.
Part B - Project Information		
IPD 2-1	2	A statement of the purpose of and need for the project, including any potential benefits.
IPD 2-2	8.2	The provisions in the schedule to the Physical Activities Regulations describing the project, in whole or in part.
IPD 2-3	2.1 - 2.2 and 7.1 - 7.2	A list of all activities, infrastructure, permanent or temporary structures and physical works to be included in and associated with the construction, operation and decommissioning of the project.
IPD 2-4	2 and 7.1	An estimate of the maximum production capacity of the project and a description of the production processes to be used.
IPD 2-5	2.3	The anticipated schedule for the project's construction, operation, decommissioning and abandonment, including any expansions of the project.
IPD 2-4	2.4	Potential alternative means of carrying out the project that the proponent is considering and that are technically and economically feasible, including through the use of best available technologies; and
IPD 2-5	2.5	Potential alternatives to the project that the proponent is considering and that are technically and economically feasible and directly related to the project.
Part C – Location Information		
IPD 3-1	3	A description of the project's proposed location, including:
IPD 3-2	3 and 4	a) Its proposed geographic coordinates, including, for linear development projects, the proposed locations of major ancillary facilities that are integral to the project and a description of the spatial boundaries of the proposed study corridor;
IPD 3-3	1 and 3	b) Site maps produced at an appropriate scale in order to determine the project's proposed general location and the spatial relationship of the project components;

Item	PD Section	Information Requirements
IPD 3-4	3	c) The legal description of land to be used for the project, including, if the land has already been acquired, the title, deed or document and any authorization relating to a water lot;
IPD 3-5	3	d) The project's proximity to any permanent, seasonal or temporary residences and to the nearest affected communities;
IPD 3-6	11.1 and 11.2	e) The project's proximity to land used for traditional purposes by Indigenous peoples of Canada, land in a reserve as defined in subsection 2(1) of the Indian Act, First Nation land as defined in subsection 2(1) of the First Nations Land Management Act, land that is subject to a comprehensive land claim agreement or a self-government agreement and any other land set aside for the use and benefit of Indigenous peoples of Canada; and
IPD 3-7	9	f) The project's proximity to any federal lands.
IPD 3-8	10.2 and 10.3	A brief description of the physical and biological environment of the project's location, based on information that is available to the public.
IPD 3-9	10.4 to 10.7	A brief description of the health, social and economic context in the region where the project is located, based on information that is available to the public or derived from any engagement undertaken.
Part D – Federal, Provincial, Territorial, Indigenous and Municipal Involvement		
IPD 4-1	9	A description of any financial support that federal authorities are, or may be, providing to the project.
IPD 4-2	9	A list of any federal lands that may be used for the purpose of carrying out the project.
IPD 4-3	8	A list of any jurisdictions that have powers, duties or functions in relation to an assessment of the project's environmental effects.
Part E – Potential Effects of the Project		
IPD 5-1	10.3	A list of any changes that, as a result of the carrying out of the project, may be caused to the following components of the environment that are within the legislative authority of Parliament:
IPD 5-1a	10.3.3	a) Fish and fish habitat, as defined in subsection 2(1) of the Fisheries Act;
IPD 5-1b	10.3.3	b) Aquatic species, as defined in subsection 2(1) of the Species at Risk Act; and
IPD 5-1c	10.3.2.1	c) Migratory birds, as defined in subsection 2(1) of the Migratory Birds Convention Act, 1994.
IPD 5-2	10.1	A list of any changes to the environment that, as a result of the carrying out of the project, may occur on federal lands, in a province other than the province in which the project is proposed to be carried out or outside Canada.
IPD 5-3	11.5	With respect to the Indigenous peoples of Canada, a brief description of the impact — that, as a result of the carrying out of the project, may occur in Canada and result from any change to the environment — on physical and cultural heritage, the current use of lands and resources for traditional purposes and any structure, site or thing that is of historical, archaeological, paleontological or architectural significance, based on information that is available to the public or derived from any engagement undertaken with Indigenous peoples of Canada.
IPD 5-4	11.5	A brief description of any change that, as a result of the carrying out of the project, may occur in Canada to the health, social or economic conditions of Indigenous peoples of Canada, based on information that is available to the public or derived from any engagement undertaken with Indigenous peoples of Canada.
IPD 5-5	6	An estimate of any greenhouse gas emissions associated with the project.
IPD 5-6	6.1	A list of the types of waste and emissions that are likely to be generated — in the air, in or on water and in or on land — during any phase of the project.

Appendix B
Table of Concordance – BC *Environmental Assessment Act*

Appendix B. Table of Concordance – BC *Environmental Assessment Act*

The following Table of Concordance cross references sections of this IPD with the list the requirements of an Initial Project Description under the BC *Environmental Assessment Act* from draft Early Engagement Guidance (EAO October 2019).

Item	PD Section	Information Requirements
General Information and Contacts		
BC-IPD 1-1	1	Project name.
BC-IPD 1-2	1	Project location within the province.
BC-IPD 1-3	1	Project industrial sector and type (e.g., open pit metal mine).
BC-IPD 1-4	1.1.1	Proponent name, mailing address, phone numbers, email address and website URL. Include the name and contact info of the primary representative for the EA.
Purpose and Rationale		
BC-IPD 2-1	2	General rationale for why the project has been proposed.
BC-IPD 2-2	2 and 10.4	Potential project benefits.
Project Status and History		
BC-IPD 3-1	1.1.2.1	Project history, including past ownership
BC-IPD 3-2	1.1.2.1	State if this is a new project or an expansion to an existing operation.
BC-IPD 3-3	1.1.2.1	List any existing permits or tenure in place.
BC-IPD 3-4	Not applicable	Include any previous changes in ownership, if applicable.
BC-IPD 3-5	Not applicable	Describe any previous proposal(s) for the project or a similar proposal and the outcomes and history of the proposal(s).
BC-IPD 3-6	Not applicable	If the project was previously declined or terminated, describe how this proposal differs and how the issues for which the previous proposal was declined or terminated have been addressed.
Project Timing		
BC-IPD 4-1	2.3	Proposed project phases (e.g. construction, operation, decommissioning) and the length of time for each phase.
BC-IPD 4-2	2.3	List seasonal timing constraints.
Project Location, Activities and Components		
BC-IPD 5-1	3, 11.1 and 11.2	Project location in a local and regional context, including proximity to communities or locations of interest to the public, government, or Indigenous nations.
BC-IPD 5-2	2.1 and 7	Proposed project activities and components.
BC-IPD 5-3	2.1	Proposed on and off-site facilities and equipment.
BC-IPD 5-4	2.1 and 7	Provide a brief description of proposed activities related to processing, transportation and/or shipping of materials to/from the site.
BC-IPD 5-5	Not applicable	Include any other project(s) that are needed for the project to proceed and be feasible (e.g. a pipeline would be needed for an oil and gas facility to proceed).
BC-IPD 5-6	1.1.2.1	Include a description of the work has been conducted to arrive at the proposal.
BC-IPD 5-7	2.1	List design or siting constraints that are flexible and those that are not flexible.

Item	PD Section	Information Requirements
BC-IPD 5-8	2.4 and 2.5	List other design or siting options that may be considered.
BC-IPD 5-9	2	Anticipated daily and annual maximum production or operational capacity of the project (if applicable).
Land and Water Use		
BC-IPD 6-1	2	Anticipated project footprint and proposed area of disturbance.
BC-IPD 6-2	5	A description of the land required for the project, including whether the project is located on private lands, provincial or federal Crown lands, or Indian Reserve lands.
BC-IPD 6-3	5	Include the applicable zoning, Agriculture Land Reserve designation, land and resource management plans, and other land use designations (e.g. parks and protected areas) and the legal land descriptions and/or tenure numbers of those lands, if known.
BC-IPD 6-4	1	A description of past uses of the land required for the proposed project, including whether the site has been previously developed.
BC-IPD 6-5	2.1	A description of water requirements for the project, if applicable, and the proposed source of water.
Maps and Shapefiles		
BC-IPD 7-1	1 and 3	Provide local and regional scale maps of the project showing its location, project components and activities, including off-site facilities and activities and any transportation routes (see guidance for map specifications).
BC-IPD 7-2	To be provided in a separate digital submission	Provide shapefiles of the proposed project footprint, known or proposed project components, and transportation corridors (see guidance for specifications on shapefiles).
BC-IPD 7-3	To be provided in a separate digital submission	Please also provide .KMZ files.
BC-IPD 7-4	To be provided in a separate digital submission	Provide shapefiles demonstrating the overlap of known project components with any identified communities or locations of interest to the public. This may include information regarding specific sites of importance to an Indigenous Nation or their territory, if this information is not confidential in nature and an Indigenous Nation has agreed to allow the information to be shared.
Emissions, Discharges and Waste		
BC-IPD 8-1	6	High-level outline of anticipated direct project emissions to land, air, and water, including estimated greenhouse gas (GHG) emissions.
BC-IPD 8-2	6	This information would include direct emissions that are expected to be above provincial or national standards and emissions that have the potential to interact with Indigenous interests, the biophysical environment, and/or the human environment.
Public and Environmental Safety		
BC-IPD 9-1	10.9	Identify potential malfunctions or accidents associated with the project and how they will be managed to support Early Engagement.
BC-IPD 9-2	1.1.2, 12.2	Include any proposed outreach to help Indigenous nations, governments and the public better understand the risks and mitigations.
BC-IPD 9-3	10.9	Show types and magnitude of different accidents and malfunctions and the risk or likelihood for occurrence.
BC-IPD 9-4	11.5 and 12.1	Include any issues raised about public and environmental safety during engagement with Indigenous nations, the public, agencies and stakeholders.

Item	PD Section	Information Requirements
BC-IPD 9-5	10.9	Provide different scenarios when there is real or perceived risk of a malfunction or accident.
Labour		
BC-IPD 10	2.2	A preliminary understanding of the anticipated size of the workforce for each project phase, where the workforce will be drawn from, and where the workforce will be housed.
Alternative Means of Carrying out the Project		
BC-IPD 11-1	2.5	A high-level description of the alternative options for the project, including a rationale for the preferred option that demonstrates how issues raised during engagement have been considered.
BC-IPD 11-2	2.4	The alternative means of undertaking the project including information related to: • use of best available technologies; • technical and economic feasibility; • when known, the potential effects, risks and uncertainties of those alternatives; • Include the preferred option and a rationale for this preference; and • Alternative means may include different options for the project location, project routing, technologies, mitigation, design or other.
Legislative and Regulatory Context		
BC-IPD 12-1	8	The type and size of the project, with specific reference to Environmental Assessment Regulatory Triggers (e.g., the EAO Reviewable Project Regulations and Impact Assessment Agency of Canada triggers).
BC-IPD 12-2	8.3	List of anticipated authorizations and permits, including permits required by Indigenous nations, and timing of these permit applications.
BC-IPD 12-3	Not applicable	Requirements of any applicable agreements between the Province and Indigenous nations, including treaties.
BC-IPD 12-4	Not applicable	Requirements of any applicable international agreements between the Province and state or federal governments.
BC-IPD 12-5	8	Include a description of relevant government policies and if there are any policies that the project may not be compatible with.
BC-IPD 12-6	2.3	Proposed timing for conducting the provincial EA and federal EA, if applicable.
Land Use Plans		
BC-IPD 13-1	5	Identification of relevant land use plans, including Indigenous land use plans
BC-IPD 13-2	Not applicable	Identify if any rezoning that would be required for the project
Indigenous Nation Interests		
BC-IPD 14-1	11.1 and 11.2	Proximity to Indigenous nations' territory, communities, locations of interest, Indian Act reserve lands, lands subject to a Treaty, or lands subject to a land claim agreement.
BC-IPD 14-2	11.2, 11.3.2, and 11.5	A preliminary understanding of Indigenous nations' interests and how the project could impact those interests.
Biophysical Environment		
BC-IPD 15-1	10.2 and 10.3	Natural setting characteristics, including coastal, foreshore, riparian, mountainous, watersheds, and agricultural land.
BC-IPD 15-2	10.2	Disturbed area characteristics, including: brown field; contaminated site(s), and any history of development.

Item	PD Section	Information Requirements
BC-IPD 15-3	10.3	Identification of sensitive or vulnerable species, ecosystems, and/or habitats in the project area.
BC-IPD 15-4	1	A list of existing data, including monitoring reports, previous EAs, regional studies, and/or other sources of information that support the understanding of the existing biophysical conditions.
Human Environment		
BC-IPD 16-1	10.4 and 10.5	Proximity to local communities, including seasonal or temporary residences.
BC-IPD 16-2	10.4 and 10.5	Identification of the Regional District(s) where the project is located or where effects may occur.
BC-IPD 16-3	10	Proximity to important or sensitive community and natural places such as: municipal boundaries, parks, schools, hospitals, housing, water supplies, roads, railways, and protected and recreational areas.
BC-IPD 16-4	10	A list of existing data, including monitoring reports, previous EAs, regional studies, and/or other sources of information that support the understanding of the existing human environment conditions.
BC-IPD 16-5	10.4 - 10.7	Identification of any sensitive or vulnerable economic, social, heritage, or health values that may be affected by the project.
Project Interactions		
BC-IPD 17-1	10 and 11.5	Potential interactions between the project and the biophysical and human environment, including Indigenous interests.
BC-IPD 17-2	Not applicable	A summary of key conclusions of any biophysical feasibility studies undertaken that may be pertinent to understanding potential interactions, if applicable.
BC-IPD 17-3	Table 11-4	This information should be described and presented in a table (see example in Figure 6) and should include an identification of how the project may interact with Indigenous interests.
BC-IPD 17-4	10.8	Identify existing cumulative effects in the region that the project may also interact with.
BC-IPD 17-5	10.1	Identify how the project could be affected by the environment, including natural hazards and climate change risks.

Appendix C
Indigenous Traditional Territories, Treaty Lands and Reserve Locations

Project Location

Populated Place

Highway

Watercourse

Waterbody

First Nation Reserve

Hul'qumi'num Treaty Group Collective Traditional Territory

Park

International Boundary

MAP NUMBER FIG11_1_HUL_QUMI_NUM		PAGE SHEET 1 OF 1
DATE November 2019	REFERENCE CE742500	REVISION 0
SCALE 1:800,000	PAGE SIZE 8.5x11	DISCIPLINE FN
DRAWN SMZ	CHECKED DJN	DESIGN DJN

Hul'qumi'num Treaty Group: Encompassing the traditional territories of the Cowichan Tribes, Halalt First Nation, Lake Cowichan First Nation, Lyackson First Nation and Penelakut Tribe.

Projection: NAD 1983 UTM Zone 10N.
Hul'qumi'num Treaty Group Collective Traditional Territory: BC Ministry of Forests, Lands and Natural Resource Operations 2019; First Nation Reserves: Government of Canada 2018; Project Location: Jacobs, 2019; Hydrography: NRCan 2007-2011; Road: BC FLNRO Digital Road Atlas, 2010; Populated Places: NRCan 2009; Parks: BC Forests, Lands and Natural Resource Operations, 2008 and Natural

Although there is no reason to believe that there are any errors associated with the data used to generate this product or in the product itself, users of these data are advised that errors in the data may be present.

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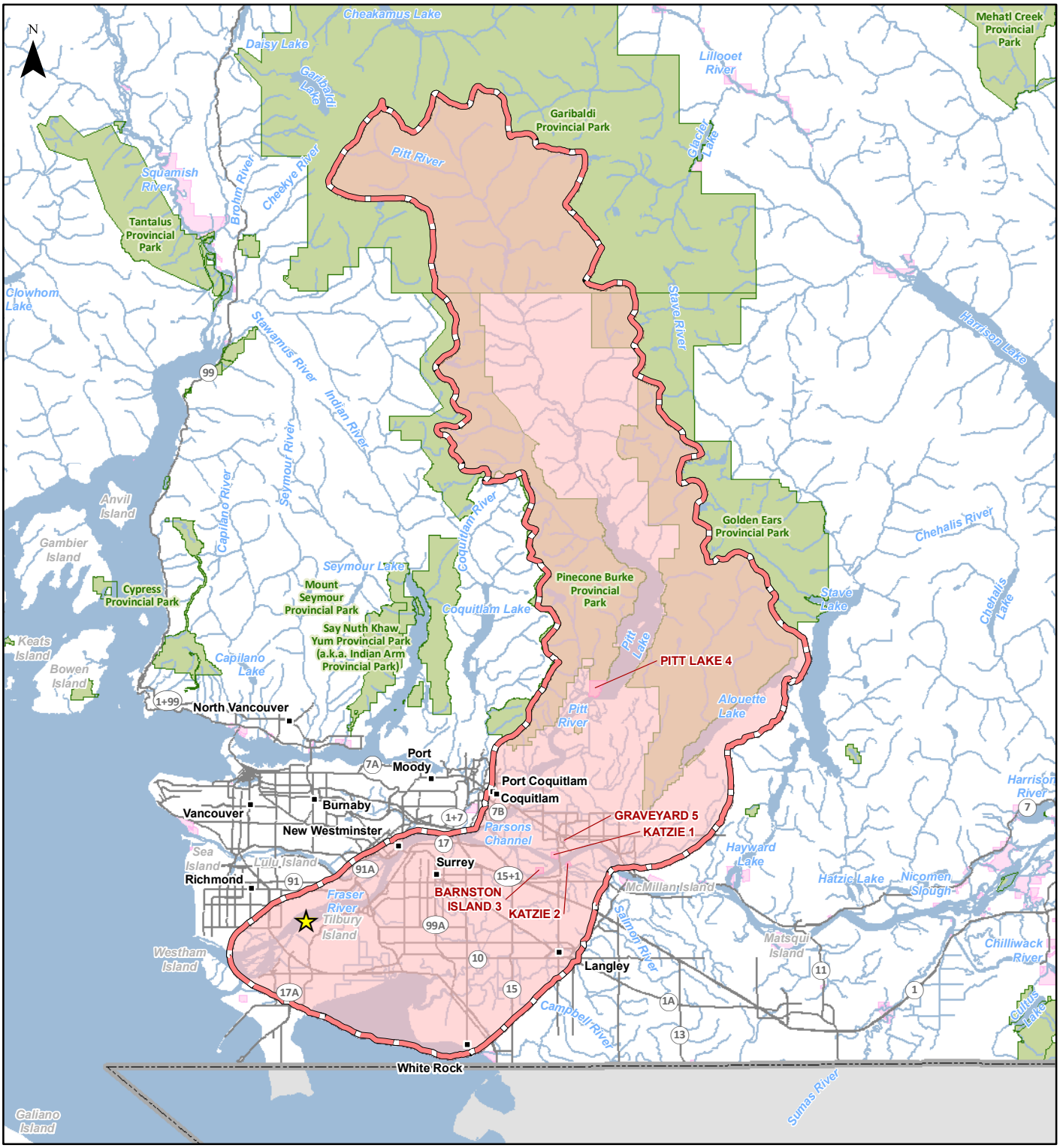
FIGURE C-1
HUL'QUMI'NUM TREATY GROUP COLLECTIVE TRADITIONAL TERRITORY

TILBURY PHASE 2 LNG EXPANSION PROJECT

0 5 10 15 KM

ALL LOCATIONS APPROXIMATE



Project Location

Populated Place

Highway

Watercourse

Waterbody

First Nation Reserve

Katzie First Nation Traditional Territory

Park

International Boundary

MAP NUMBER FIG11_2_KATZIE		PAGE SHEET 1 OF 1
DATE November 2019	REFERENCE CE742500	REVISION 0
SCALE 1:600,000	PAGE SIZE 8.5x11	DISCIPLINE FN
DRAWN SMZ	CHECKED DJN	DESIGN DJN

Projection: NAD 1983 UTM Zone 10N.
Katzie First Nationi Traditional Territory: BC Ministry of Forests, Lands and Natural Resource Operations 2013; First Nation Reserves: Government of Canada 2018; Project Location: Jacobs, 2019; Hydrography: NRCan 2007-2011; Road: BC FLNRO Digital Road Atlas, 2010; Populated Places: NRCan 2009; Parks: BC Forests, Lands and Natural Resource Operations, 2008 and Natural Resources Canada 2012; International Boundary: Geobase 2018.

Although there is no reason to believe that there are any errors associated with the data used to generate this product or in the product itself, users of these data are advised that errors in the data may be present.

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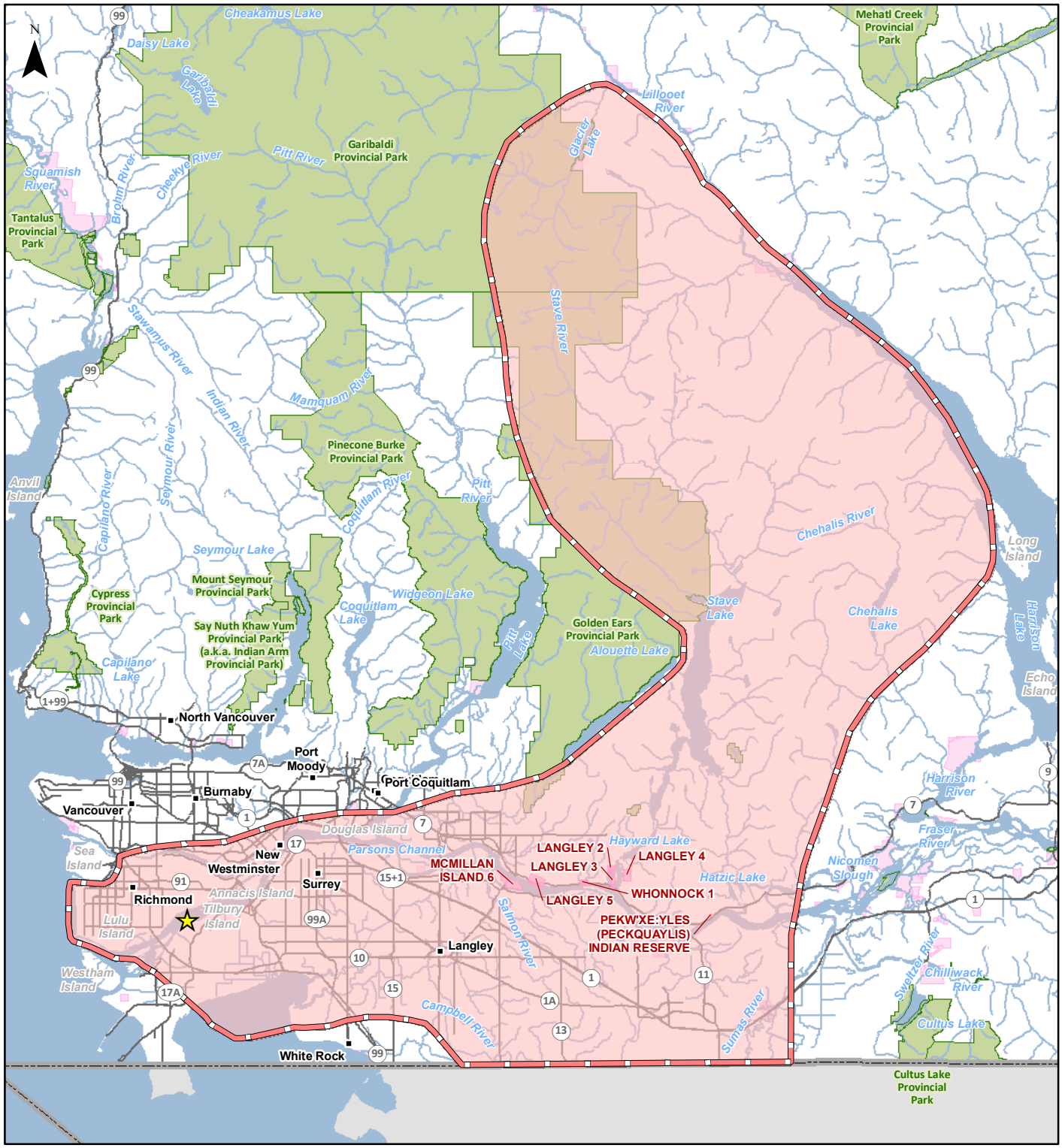
FIGURE C-2
KATZIE FIRST NATION TRADITIONAL TERRITORY

TILBURY PHASE 2
LNG EXPANSION PROJECT

0 5 10 15 20 KM

ALL LOCATIONS APPROXIMATE



Project Location

Populated Place

Highway

Watercourse

Waterbody

First Nation Reserve

Kwantlen First Nation Traditional Territory

Park

International Boundary

MAP NUMBER FIG11_3_KWANTLEN		PAGE SHEET 1 OF 1
DATE November 2019	REFERENCE CE742500	REVISION 0
SCALE 1:600,000	PAGE SIZE 8.5x11	DISCIPLINE FN
DRAWN SMZ	CHECKED DJN	DESIGN DJN

Projection: NAD 1983 UTM Zone 10N.
Kwantlen First Nation Traditional Territory: Jacobs 2019, adapted from June 20, 2019 FCRSA Map; First Nation Reserves: Government of Canada 2018; Project Location: Jacobs, 2019; Hydrography: NRCan 2007-2011; Road: BC FLNRO Digital Road Atlas, 2010; Populated Places: NRCan 2009; Parks: BC Forests, Lands and Natural Resource Operations, 2008 and Natural Resources Canada 2012; International Boundary: Geobase 2018.

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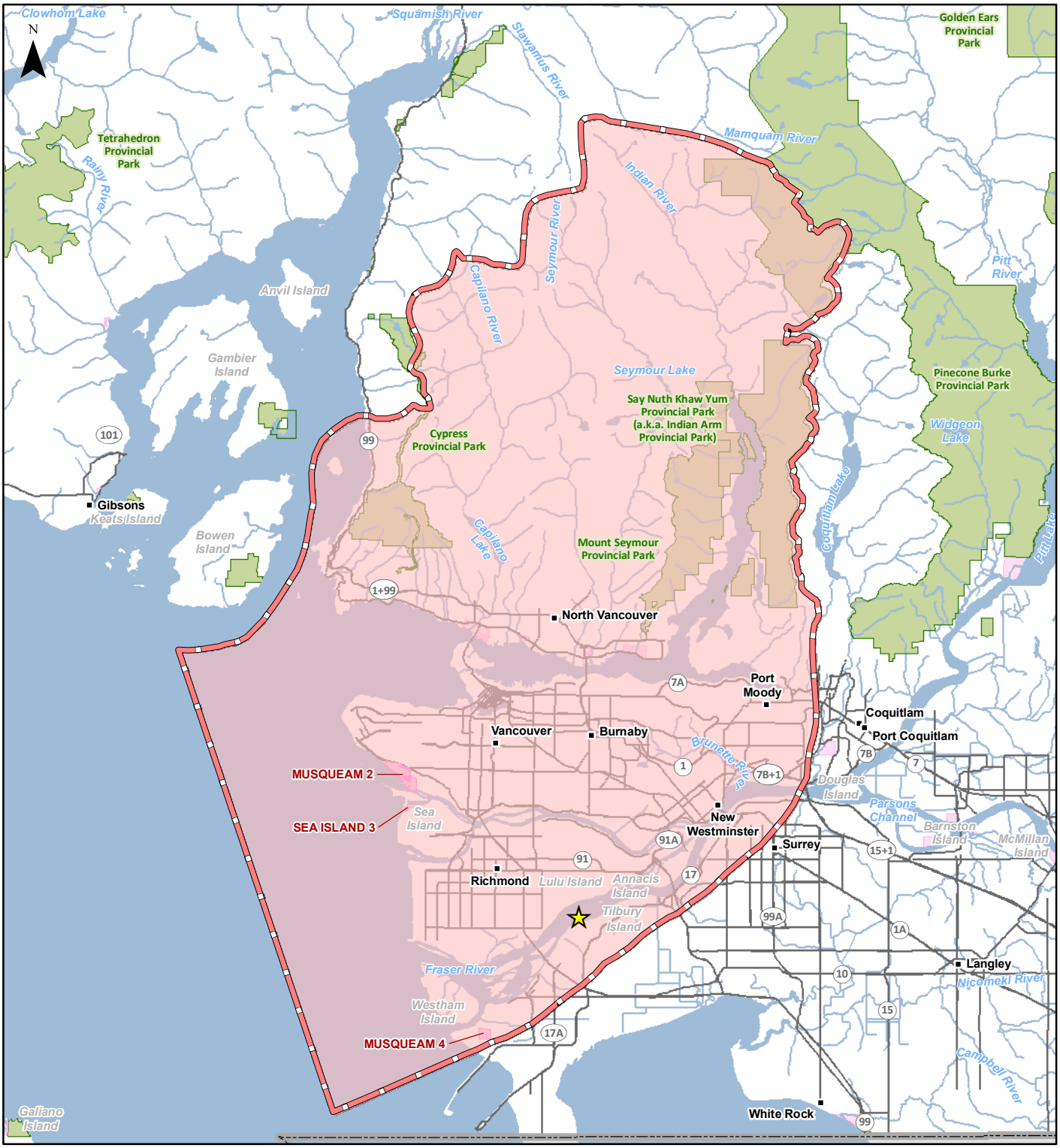
FIGURE C-3
KWANTLEN FIRST NATION TRADITIONAL TERRITORY

TILBURY PHASE 2
LNG EXPANSION PROJECT

0 5 10 15 KM

ALL LOCATIONS APPROXIMATE



Project Location
Populated Place
Highway
Watercourse
Waterbody
First Nation Reserve
Musqueam Nation Traditional Territory
Park
International Boundary

MAP NUMBER FIG11_4_MUSQUEAM		PAGE SHEET 1 OF 1
DATE November 2019	REFERENCE CE742500	REVISION 0
SCALE 1:400,000	PAGE SIZE 8.5x11	DISCIPLINE FN
DRAWN SMZ	CHECKED DJN	DESIGN DJN

Projection: NAD 1983 UTM Zone 10N.
Musqueam NationTraditional Territory: BC Ministry of Forests, Lands and Natural Resource Operations 2019; First Nation Reserves: Government of Canada 2018; Project Location: Jacobs, 2019; Hydrography: NRCan 2007-2011; Road: BC FLNRO Digital Road Atlas, 2010; Populated Places: NRCan 2009; Parks: BC Forests, Lands and Natural Resource Operations, 2008 and Natural Resources Canada 2012; International Boundary: Geobase 2018.

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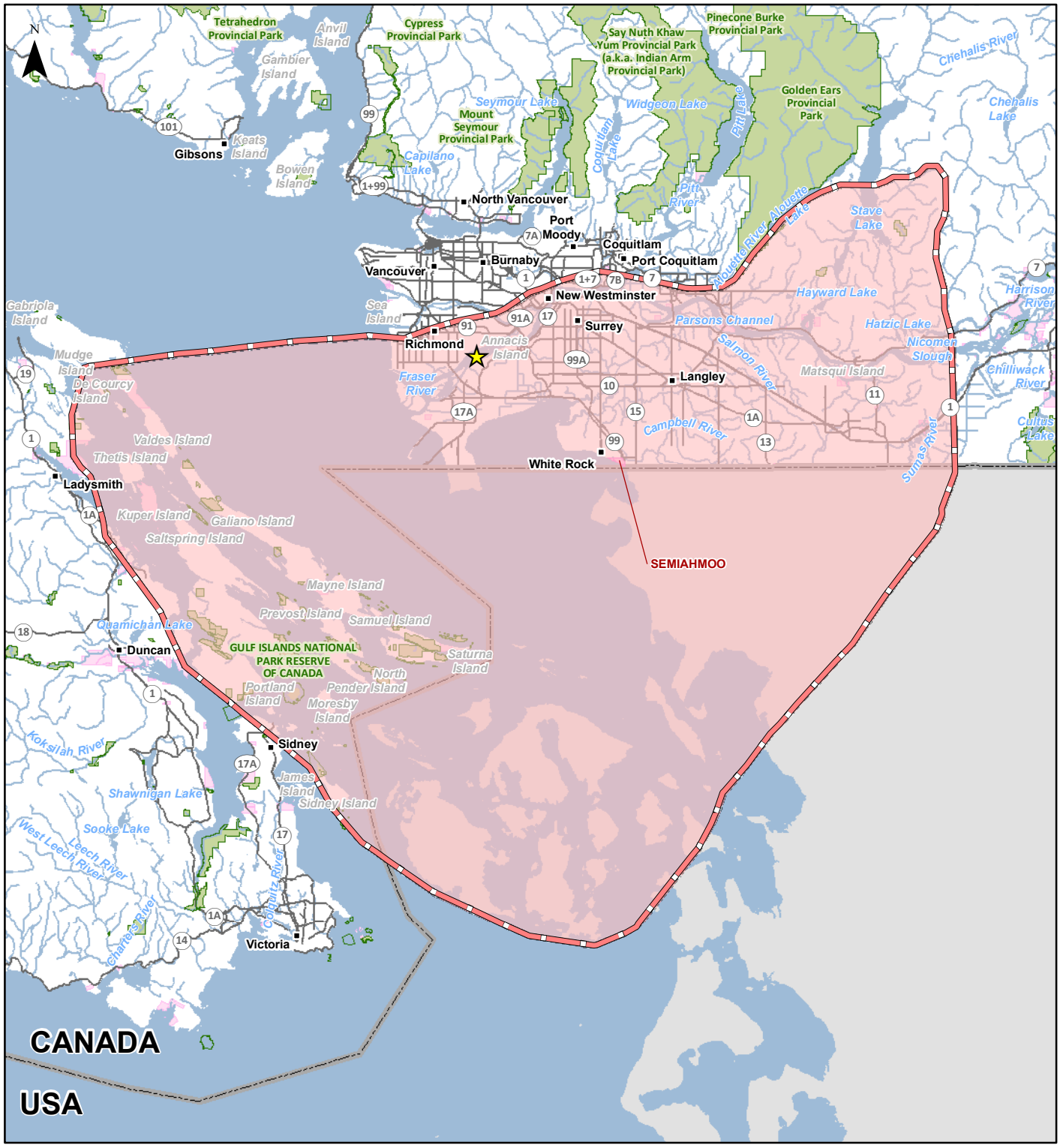
FIGURE C-4
MUSQUEAM NATION TRADITIONAL TERRITORY

TILBURY PHASE 2
LNG EXPANSION PROJECT

0 5 10 15 KM

ALL LOCATIONS APPROXIMATE



Project Location

Populated Place

Highway

Watercourse

Waterbody

Semiahmoo First Nation Traditional Territory

First Nation Reserve

Park

International Boundary

MAP NUMBER FIG11_5_SEMIAHMOO		PAGE SHEET 1 OF 1
DATE November 2019	REFERENCE CE742500	REVISION 0
SCALE 1:775,000	PAGE SIZE 8.5x11	DISCIPLINE FN
DRAWN SMZ	CHECKED DJN	DESIGN DJN

Projection: NAD 1983 UTM Zone 10N.
Semiahmoo First Nation Traditional Territory: Digitized from Port Metro Vancouver; Golder Associates, 2019; First Nation Reserves: Government of Canada 2018; Project Location: Jacobs, 2019; Hydrography: NRCan 2007-2011; Road: BC FLNRO Digital Road Atlas, 2010; Populated Places: NRCan 2009; Parks: BC Forests, Lands and Natural Resource Operations, 2008 and Natural Resources Canada 2012; International Boundary: Geobase 2018.

Although there is no reason to believe that there are any errors associated with the data used to generate this product or in the product itself, users of these data are advised that errors in the data may be present.

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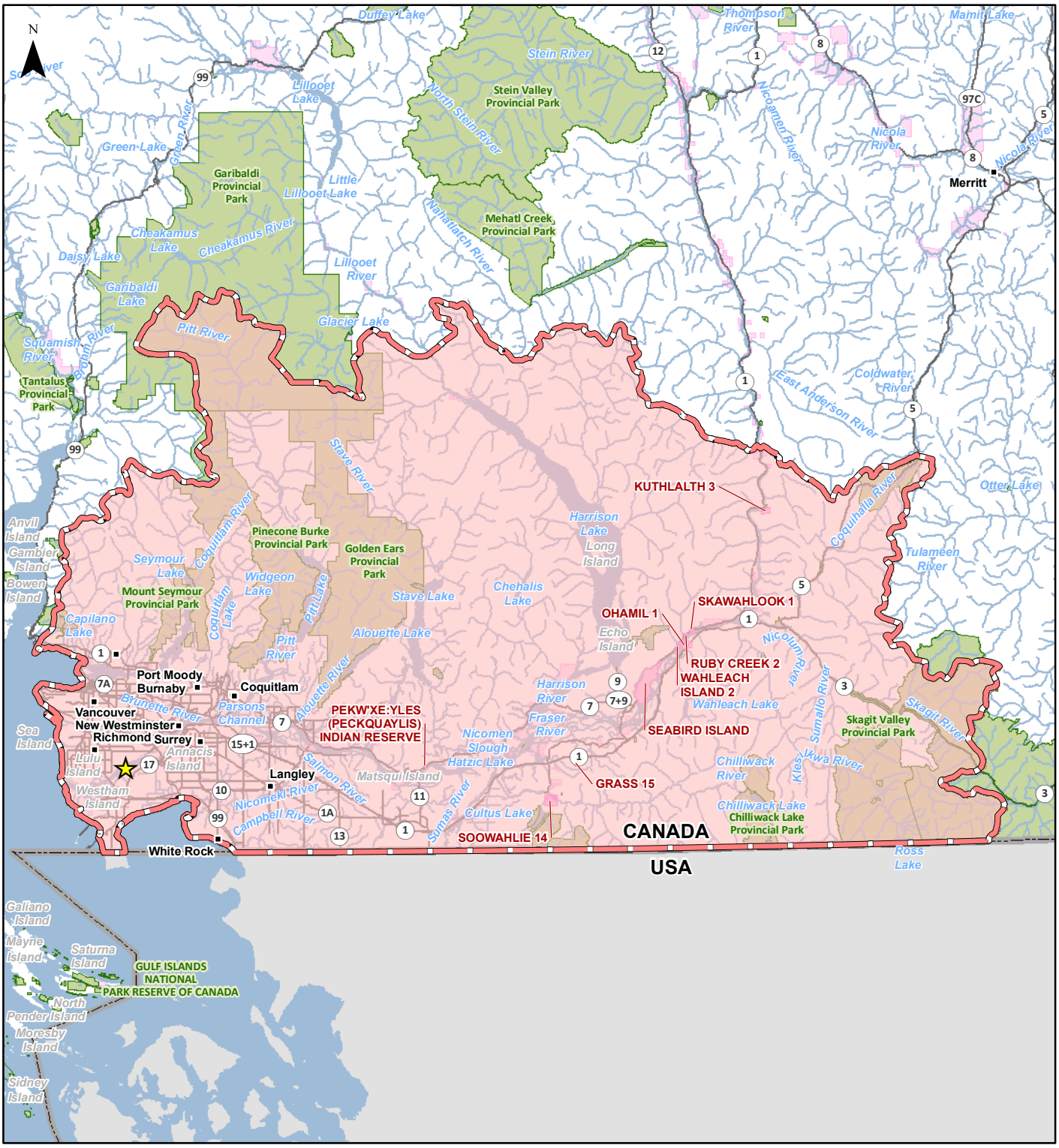
FIGURE C-5
SEMIAHMOO FIRST NATION TRADITIONAL TERRITORY

TILBURY PHASE 2 LNG EXPANSION PROJECT

Kilometers
0 5 10 15

ALL LOCATIONS APPROXIMATE



Project Location
Populated Place
Highway
Watercourse
Waterbody
First Nation Reserve
Stó:lō Nation and Stó:lō Tribal Council Traditional Territories
Park
International Boundary

MAP NUMBER FIG11_6_STO_LO		PAGE SHEET 1 OF 1
DATE November 2019	REFERENCE CE742500	REVISION 0
SCALE 1:1,050,000	PAGE SIZE 8.5x11	DISCIPLINE FN
DRAWN SMZ	CHECKED DJN	DESIGN DJN

Stó:lō Nation and Stó:lō Tribal Council Traditional Territories: Encompassing the Sto:lo Nation and Sto:lo Tribal Council, Soowahlie First Nation, Skawahlook First Nation, Shxw'ōwhámél First Nation and Seabird Island Band

Projection: NAD 1983 UTM Zone 10N.
Stó:lō Nation and Stó:lō Tribal Council Traditional Territories: BC Ministry of Forests, Lands and Natural Resource Operations 2019; First Nation Reserves: Government of Canada 2018; Project Location: Jacobs, 2019; Hydrography: NRCan 2007-2011; Road: BC FLNRO Digital Road Atlas, 2010; Populated Places: NRCan 2009; Parks: BC Forests, Lands and Natural Resource Operations, 2008 and Natural

Although there is no reason to believe that there are any errors associated with the data used to generate this product or in the product itself, users of these data are advised that errors in the data may be present.

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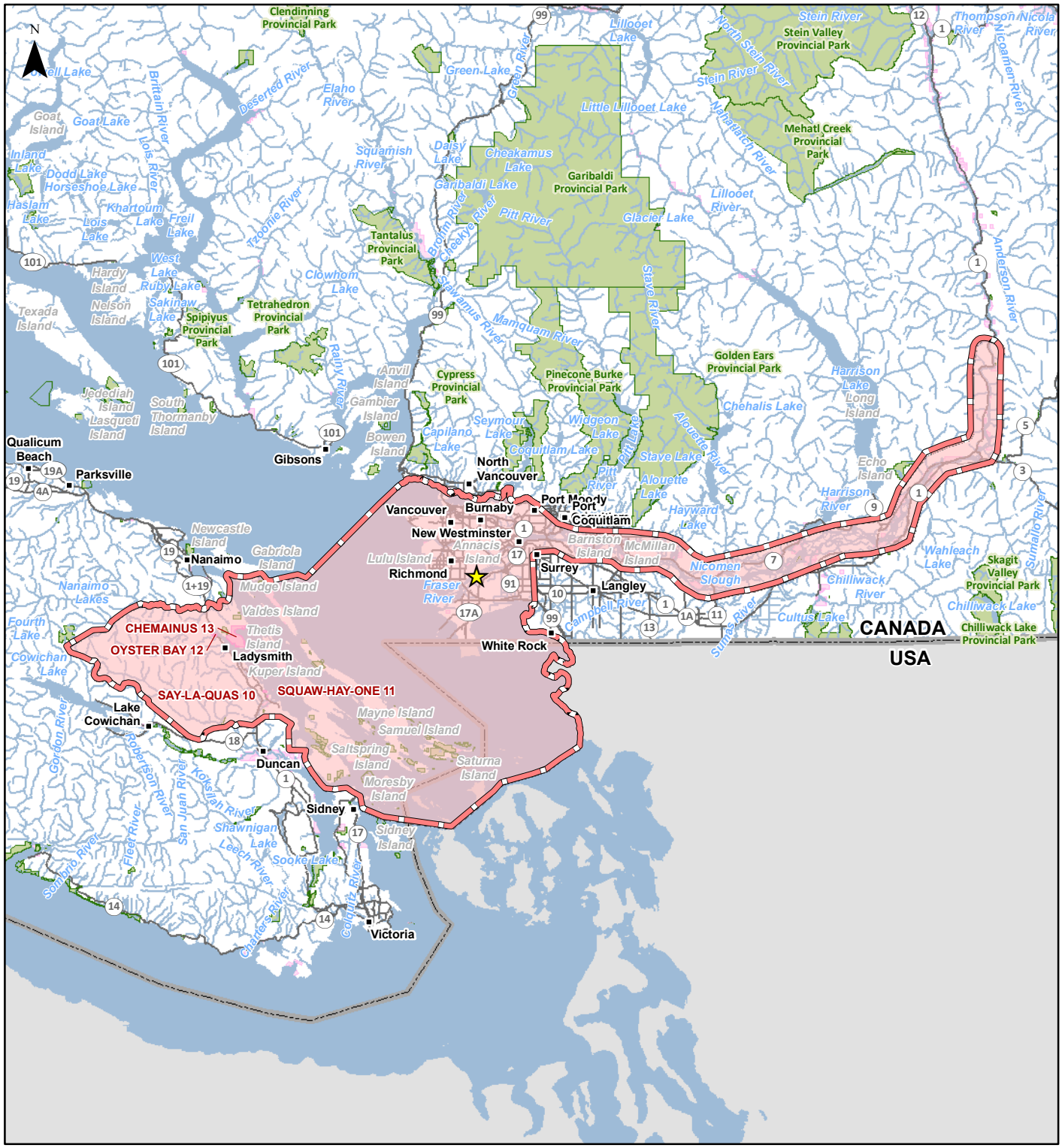
FIGURE C-6
STÓ:LŌ NATION AND STÓ:LŌ TRIBAL COUNCIL TRADITIONAL TERRITORIES

TILBURY PHASE 2 LNG EXPANSION PROJECT

0 5 10 15 20 25 KM

ALL LOCATIONS APPROXIMATE



Project Location
Populated Place
Highway
Watercourse
Waterbody
First Nation Reserve
Stz'uminus First Nation Traditional Territory
Park
International Boundary

MAP NUMBER FIG11_7_STZ_UMINUS		PAGE SHEET 1 OF 1
DATE November 2019	REFERENCE CE742500	REVISION 0
SCALE 1:1,300,000	PAGE SIZE 8.5x11	DISCIPLINE FN
DRAWN SMZ	CHECKED DJN	DESIGN DJN

Projection: NAD 1983 UTM Zone 10N.
Stz'uminus First Nation Traditional Territory: Adapted from Stzuminus Community Map, July 20, 2007; First Nation Reserves: Government of Canada 2018; Project Location: Jacobs, 2019; Hydrography: NRCan 2007-2011; Road: BC FLNRO Digital Road Atlas, 2010; Populated Places: NRCan 2009; Parks: BC Forests, Lands and Natural Resource Operations, 2008 and Natural Resources Canada 2012; International Boundary: Geobase 2018.

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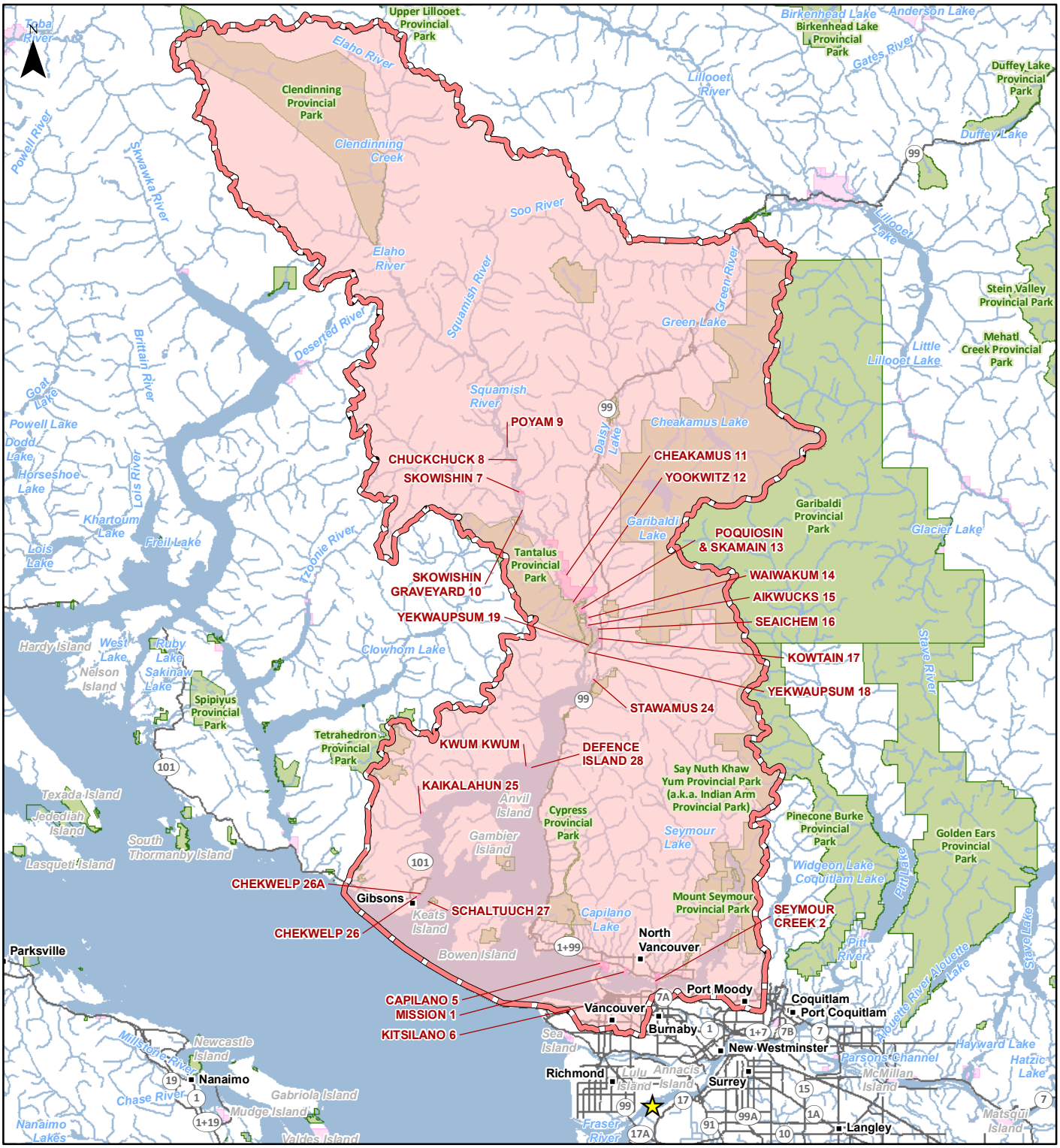
FIGURE C-7
STZ'UMINUS FIRST NATION TRADITIONAL TERRITORY

TILBURY PHASE 2 LNG EXPANSION PROJECT

KM
0 5 10 15 20 25

ALL LOCATIONS APPROXIMATE



Project Location
Populated Place
Highway
Watercourse
Waterbody
First Nation Reserve
Squamish Nation Traditional Territory
Park
International Boundary

MAP NUMBER FIG11_8_SQUAMISH		PAGE SHEET 1 OF 1
DATE November 2019	REFERENCE CE742500	REVISION 0
SCALE 1:815,000	PAGE SIZE 8.5x11	DISCIPLINE FN
DRAWN SMZ	CHECKED DJN	DESIGN DJN

Projection: NAD 1983 UTM Zone 10N.
Squamish Nation Traditional Territory: BC Ministry of Forests, Lands and Natural Resource Operations 2019; First Nation Reserves: Government of Canada 2018; Project Location: Jacobs, 2019; Hydrography: NRCan 2007-2011; Road: BC FLNRO Digital Road Atlas, 2010; Populated Places: NRCan 2009; Parks: BC Forests, Lands and Natural Resource Operations, 2008 and Natural Resources Canada 2012; International Boundary: Geobase 2018.

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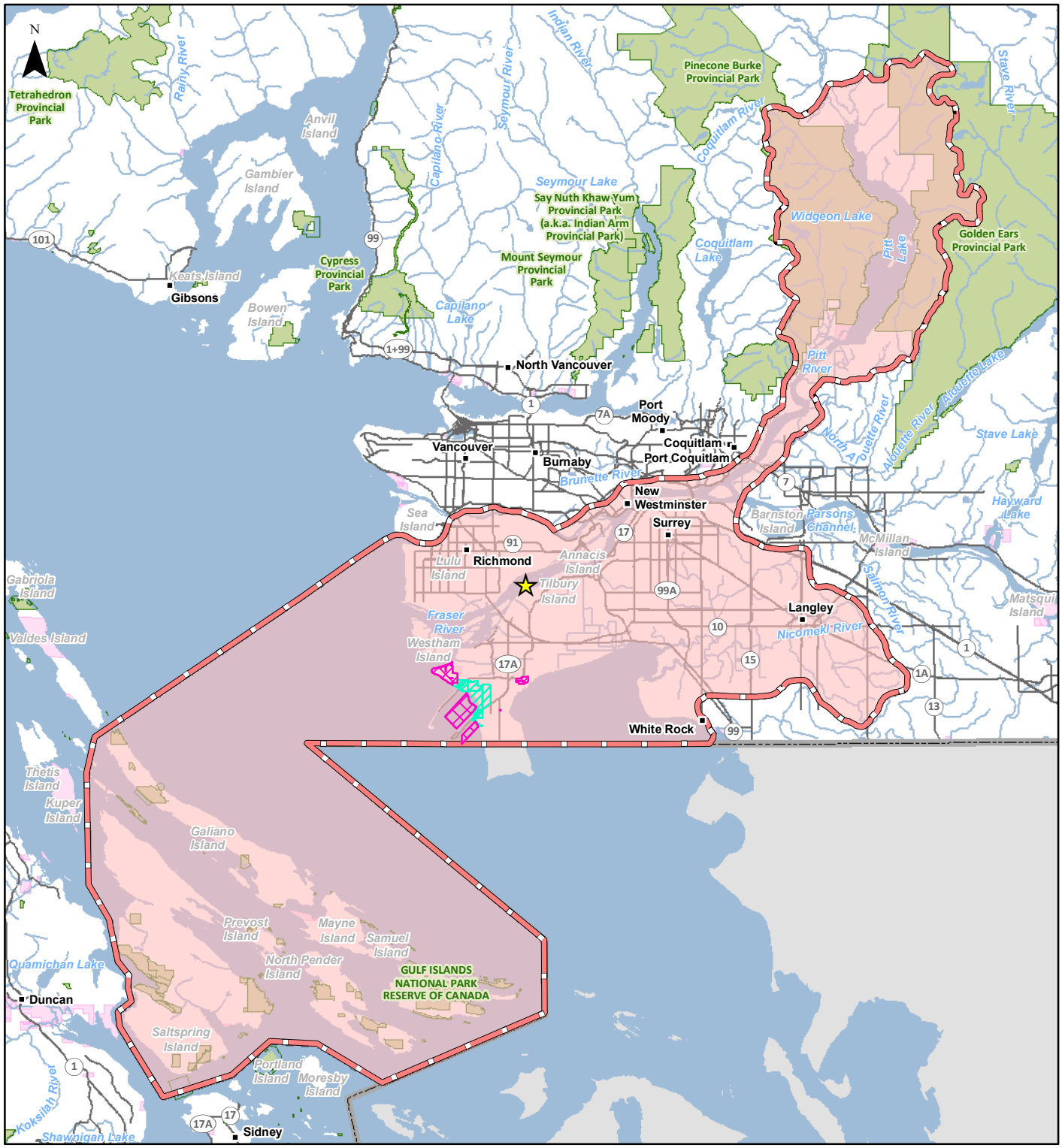
FIGURE C-8
SQUAMISH NATION TRADITIONAL TERRITORY

TILBURY PHASE 2
LNG EXPANSION PROJECT

0 5 10 15 20 KM

ALL LOCATIONS APPROXIMATE



Project Location
Populated Place
Highway
Watercourse
Waterbody
Tsawwassen First Nation Treaty Area
Tsawwassen Treaty Lands
Tsawwassen Treaty Related Lands
First Nation Reserve
Park
International Boundary

MAP NUMBER FIG11_9_TSAWWASSEN		PAGE SHEET 1 OF 1
DATE November 2019	REFERENCE CE742500	REVISION 0
SCALE 1:550,000	PAGE SIZE 8.5x11	DISCIPLINE FN
DRAWN SMZ	CHECKED DJN	DESIGN DJN

Projection: NAD 1983 UTM Zone 10N.
Treaty Area, Treay Lands: Ministry of Indigenous Relations and Reconciliation 2019; First Nation Reserves: Government of Canada 2018; Project Location: Jacobs, 2019; Hydrography: NRCan 2007-2011; Road: BC FLNRO Digital Road Atlas, 2010; Populated Places: NRCan 2009; Parks: BC Forests, Lands and Natural Resource Operations, 2008 and NRCan 2017; International Boundary: Geobase 2018.

Although there is no reason to believe that there are any errors associated with the data used to generate this product or in the product itself, users of these data are advised that errors in the data may be present.

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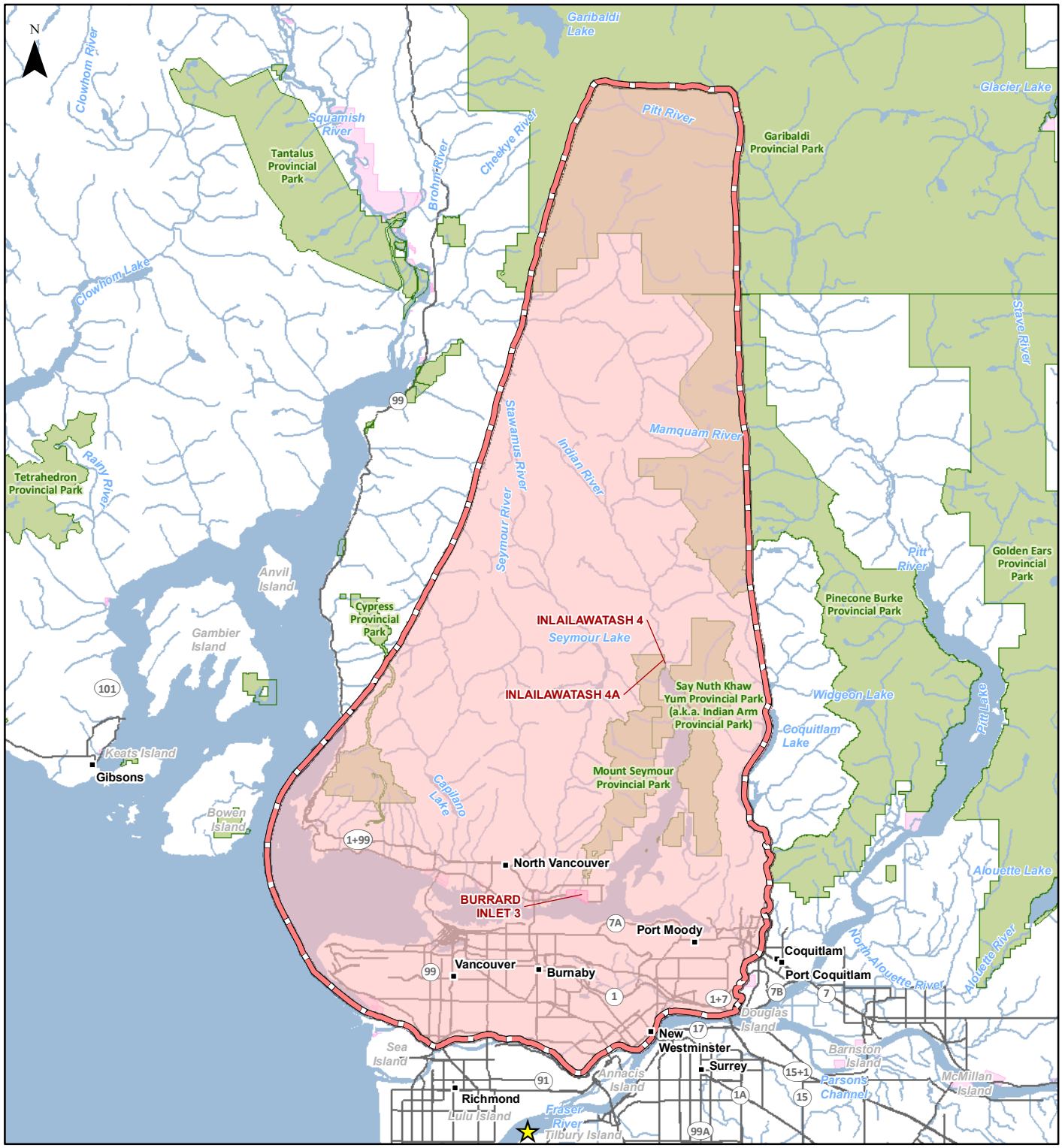
FIGURE C-9
TSAWWASSEN FIRST NATION TREATY AREA

TILBURY PHASE 2
LNG EXPANSION PROJECT

0 5 10 15 KM

ALL LOCATIONS APPROXIMATE



Project Location
Populated Place
Highway
Watercourse
Waterbody
First Nation Reserve
Tsleil-Waututh Nation Traditional Territory
Park
International Boundary

MAP NUMBER FIG11_10_TSLEIL_WAUTUTH		PAGE SHEET 1 OF 1
DATE November 2019	REFERENCE CE742500	REVISION 0
SCALE 1:450,000	PAGE SIZE 8.5x11	DISCIPLINE FN
DRAWN SMZ	CHECKED DJN	DESIGN DJN

Projection: NAD 1983 UTM Zone 10N.
Tsleil-Waututh NationTraditional Territory: BC Ministry of Forests, Lands and Natural Resource Operations 2019; First Nation Reserves: Government of Canada 2018; Project Location: Jacobs, 2019; Hydrography: NRCan 2007-2011; Road: BC FLNRO Digital Road Atlas, 2010; Populated Places: NRCan 2009; Parks: BC Forests, Lands and Natural Resource Operations, 2008 and Natural Resources Canada 2012; International Boundary: Geobase 2018.

Although there is no reason to believe that there are any errors associated with the data used to generate this product or in the product itself, users of these data are advised that errors in the data may be present.

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FIGURE C-10
TSLEIL-WAUTUTH NATION TRADITIONAL TERRITORY

TILBURY PHASE 2
LNG EXPANSION PROJECT

0 5 10 15 KM

ALL LOCATIONS APPROXIMATE

Appendix Q-2

ENGAGEMENT PLAN

Tilbury Phase 2 LNG Expansion Project

Engagement Plan

Revised: June 2020

Contents

Tables

Figures

Version history

Version #	Implemented By	Revision Date	Changes / Reason
1.0	T Smith	*Feb. 26, 2020*	*Launch environmental assessment process for Tilbury Phase 2 LNG Expansion*
1.1	T Smith	Jun. 5, 2020	Updated to reflect COVID-19 impact on engagement: • Added note that engagement activities may be subject to change due to COVID-19, p. 11 • Removed references to “in-person” engagement to also allow for alternate delivery methods such as virtual engagement, p. 20-21 • Added note to say project materials could be mailed locally upon request, p. 21 Updated the name of the EAO representative, p.22

Acronyms and Abbreviations

BC	British Columbia
BC *EAA*	BC *Environmental Assessment Act*
BC EAO	BC Environmental Assessment Office
BC MFLNRORD	BC Ministry of Forests, Lands, Natural Resource Operations and Rural Development
BC OGC	BC Oil and Gas Commission
BCUC	British Columbia Utilities Commission
CAD	Consultative Areas Database
CNA	Cowichan Nation Alliance
Delta	City of Delta
DFO	Fisheries and Oceans Canada
DPD	Detailed Project Description
EA	Environmental Assessment
GBA+	Gender-based Analysis Plus
GHG	greenhouse gas
GIS	Geographical Information Systems
ha	hectare(s)
HTG	Hul'qumi'num Treaty Group
IA	Impact Assessment
IAA	*Impact Assessment Act*
IAAC	Impact Assessment Agency of Canada (replaced Canadian Environmental Assessment Agency)
IPD	Initial Project Description
km	kilometre(s)
km^2	square kilometre(s)
LNG	liquefied natural gas
m	metre(s)
MLA	Member of the Legislative Assembly
MP	Member of Parliament
mtpa	million tonne(s) per annum
OCP	Official Community Plan
PJ	petajoule(s)
Project	Tilbury Phase 2 LNG Expansion Project
Project Site	existing Tilbury LNG Facility site
t/d	tonnes per day
TLU	Traditional Land Use
WesPac	WesPac Midstream Ltd.

General Information and Contacts

Table 0-1. Project Information and Key Contacts

Project Name	Tilbury Phase 2 LNG Expansion Project
Location	7651 Hopcott Road, on Tilbury Island in the City of Delta
Industrial Sector	Oil and Gas
Project Type	LNG Facility
Proponent	FortisBC Holdings Inc.
Proponent Corporate Address	16705 Fraser Highway Surrey, BC V4N 0E8
Proponent Website	http://www.fortisbc.com
Project Website	https://talkingenergy.ca/tilburyphase2
Project Phone Number	1-855-576-7133
Project email	Tilbury.info@fortisbc.com
Proponent President and CEO	Roger Dall'Antonia
Principal Contacts for the Environmental Assessment	Todd Smith Business Development Manager Tel: 604-785-6514 Email: todd.smith@fortisbc.com

Introduction

FortisBC Holdings Inc. (FortisBC) with its natural gas subsidiary FortisBC Energy Inc. is proposing to expand its existing liquefied natural gas (LNG) facility at 7651 Hopcott Road, on Tilbury Island in the City of Delta (Delta), British Columbia (BC) (Figure 1-1) (the Project Site).

The Tilbury Phase 2 LNG Expansion Project (the Project) is being proposed to increase the production and storage of LNG to improve security of supply to FortisBC's approximately 1.1 million natural gas customers in BC and to supply incremental LNG to the marine transportation and export markets. The Project also introduces opportunities to upgrade existing infrastructure to current design standards and technologies and to align with the Government of BC's CleanBC Plan.

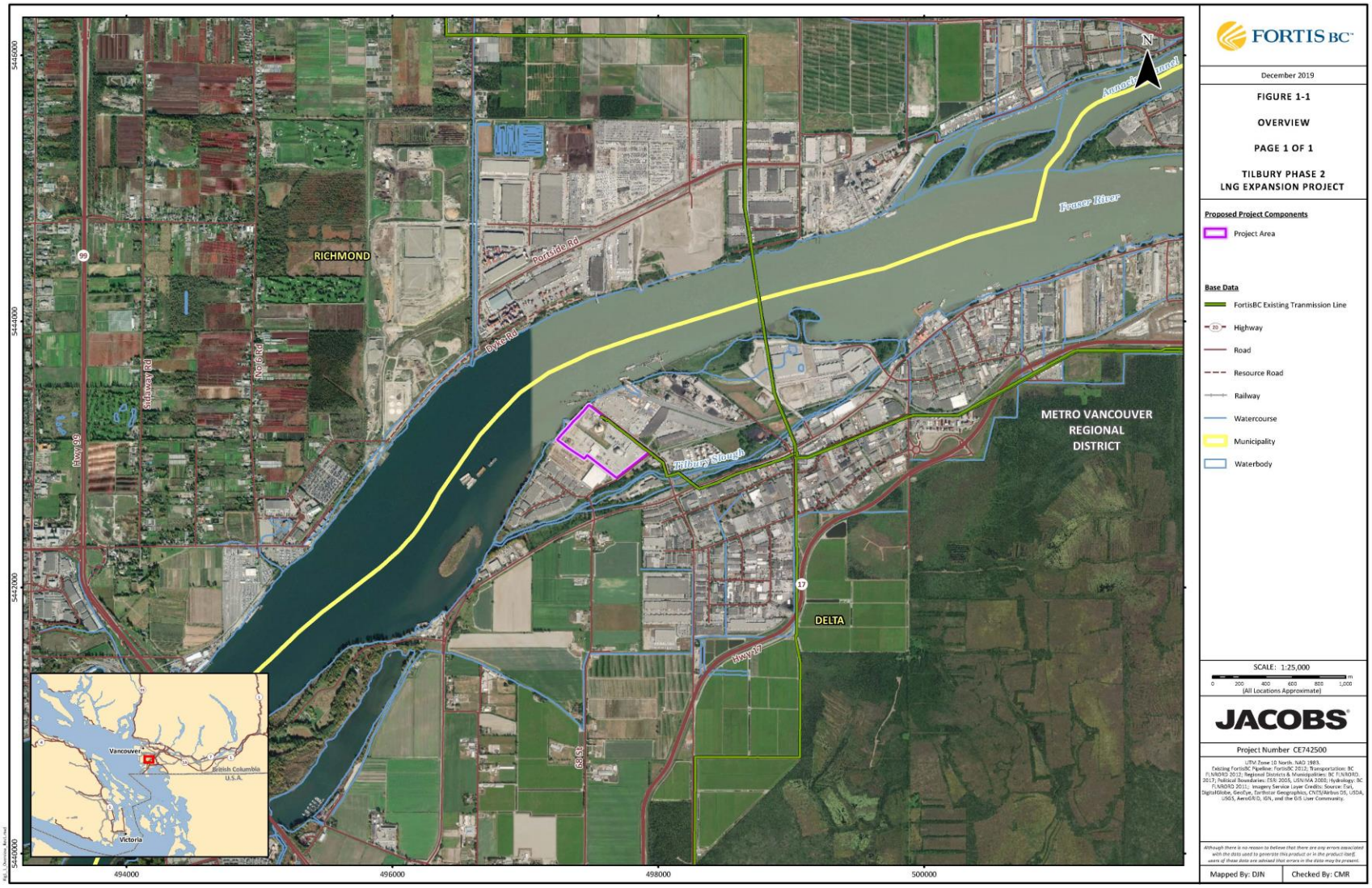
The proposed Tilbury Phase 2 LNG Expansion Project is reviewable under the BC *Environmental Assessment Act* (BC EAA) Reviewable Projects Regulation, Part 4 and under Canada's *Impact Assessment Act* (IAA) and *Physical Activities Regulations*.

FortisBC initiated early engagement with Indigenous Groups and government agencies on the Initial Project Description (IPD) through the second half of 2019. FortisBC will continue to undertake Early Engagement activities on the Project in early 2020. The company has prepared this Engagement Plan to meet engagement requirements under the BC EAA.

FortisBC engaged Indigenous Groups on engagement principles and methods described in this Engagement Plan during the review of draft versions of the IPD. Feedback from Indigenous Groups was incorporated into subsequent versions of the IPD. This information then became the basis of this Engagement Plan. The Engagement Plan is expected to meet a number of objectives including:

- Support transparent sharing of information early in the EA process;
- Outline FortisBC's approach for seeking information and feedback to inform development of the detailed project description (DPD) and subsequent EA processes;
- Provide the methods and activities proposed for engagement with Indigenous nations, the public, municipalities, provincial and federal government agencies, and stakeholders throughout Early Engagement; and
- Develop engagement processes that consider how each party wants to be engaged with.

Figure 1-1. Project Overview Map



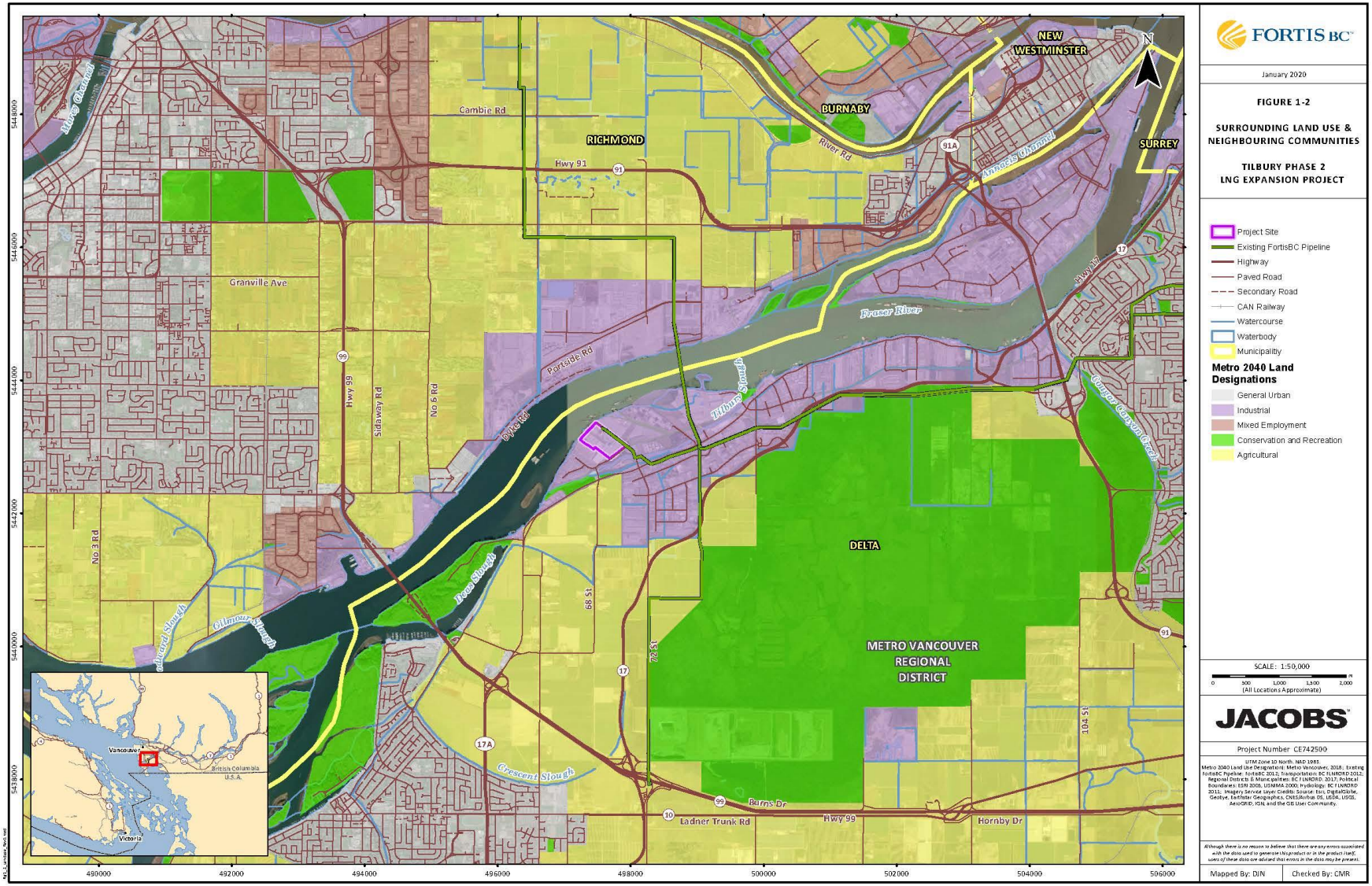
Project Overview

This section offers a brief description of the Project. A more detailed overview is included in the IPD. The Project comprises an expansion of up to 162,000 cubic metres (approximately 4 petajoules) of LNG storage and up to 11,000 tonnes per day of LNG production. The Project will receive natural gas at the Project Site through established pipeline systems. It will connect to FortisBC's existing LNG facilities (such as, vaporization and gas send-out facilities) to support security of natural gas supply to gas utility customers and the proposed WesPac Midstream Ltd. (WesPac) Tilbury Marine Jetty Project for marine LNG bunkering and LNG export.

There is a need to increase LNG storage capacity in the Lower Mainland Region as back-up to the Regional gas supply system. LNG production will be constructed as LNG market demand is realized and could be built all at once or phased over multiple years with ultimate completion anticipated prior to 2028. Detailed engineering for the proposed expansion is expected to begin as early as 2021. Construction is expected to begin as early as 2022.

The Project is located within Delta, on a long-standing brownfield, industrial site owned by FortisBC. The existing FortisBC LNG facility includes the original production and storage facility in operation since 1971 (base plant), a Phase 1 production and storage expansion in operation since 2018 (Phase 1A), and ancillaries including power supply, gas supply, and both natural gas and LNG distribution facilities to serve public utility customers. Parts of the Project are expected to occur within the footprint of the existing nearly 50-year-old base plant. Facilities that are not a part of the Project include the existing production and storage facilities including Phase 1 expansions as these activities do not trigger a Provincial Environmental Assessment (EA) pursuant to the BC *EAA* or Impact Assessment (IA) pursuant to the Federal *IAA* and *Physical Activities Regulations* and are independent of the Project.

Figure 1-2. Land Use Map



Proximity to Communities

The Project is located within Delta, on land owned by FortisBC zoned as I7: High Impact Industrial (Official Community Plan [OCP,] Map 5 – Industrial and Utility Designations) (Delta 2019). This zoning designation allows for the manufacturing, processing, finishing, and storage of natural gas. As such, the proposed expansion is consistent with the Delta OCP for the Project Site.

Delta has three urban communities including Ladner, North Delta and Tsawwassen (OCP, Map 15 – Delta's Urban Communities) (Delta 2019). The closest residential area is approximately 5 kilometres (km) to the southwest in Ladner. Other land use designations south of the Project Site include agricultural (approximately 50% of the land base) and environmentally sensitive areas including the Burns Bog Ecological Conservancy (25% of the land base) (OCP, Map 2 – Future Land Use Plan) (Delta 2019; WesPac 2015).

The City of Richmond is the next closest municipality on the north side of the Fraser River. Land use designations in Richmond directly north of the Project Site include industrial, agricultural, and mixed employment (Richmond 2019). There is some residential occupancy in the agricultural and mixed employment areas of both Delta and Richmond, with potential for residents in the industrial areas.

The Fraser River is an important transportation route and is home to numerous industrial facilities and cargo terminals that handle logs, steel, machinery and general industrial cargo. The Fraser River is also used for commercial and recreational purposes including boating, fishing, tourism and marine transportation among other activities.

Information on Indigenous Groups with traditional territories that overlap with the Project Site is provided in the Indigenous Nation Engagement section of this Engagement Plan as well as Section 11 of the IPD. Each of the Indigenous Groups identified has, or asserts claims of, rights and title to the lands, water, and resources within their traditional territories. This includes, but is not limited to, the use of terrestrial, freshwater, marine, and other resources within those territories for traditional purposes. Associated activities include, but are not limited to, fishing, hunting, trapping, and gathering activities for food, materials, trade, medicines, and traditional ceremonies. Research on Traditional Land Use (TLU) surrounding the Project Site will be conducted in consultation with the corresponding Indigenous Groups, as applicable.

See Tables 4-1, 5-1 and 6-1 for a preliminary list of Indigenous Groups, public stakeholders, municipalities, provincial and federal governments and government agencies identified for engagement in this plan.

Engagement Principles

FortisBC has been consulting with municipalities, provincial and federal governments, Indigenous Groups, the public and other parties on proposed expansions of the Tilbury LNG facility since 2012. FortisBC recognizes the importance of meaningful engagement and strives to develop and maintain strong relationships with all stakeholders and Indigenous Groups. FortisBC will also continue to maintain and strengthen relationships developed during previous engagement, primarily with those located near the facility, including Delta, Richmond, and Indigenous Groups.

The focus of FortisBC's engagement on the Project will be to ensure that municipalities, federal and provincial governments, Indigenous Groups, the public and other interested parties are informed about the Project, have access to information, and are encouraged to provide feedback throughout the Project.

Lists of identified Indigenous Groups, public stakeholders, municipalities, provincial and federal government representatives, and agencies are provided in Tables 4-1, 5-1 and 6-1 respectively. Details including relevant representatives, rationale for inclusion, and methods of engagement are also provided later in the document.

The following is a list of principles that will guide engagement on the Project:

- Inform the public, Indigenous Groups, government and other stakeholders about the Project using plain language to clearly communicate the potential impacts, opportunities and potential solutions associated with the proposed Project.
- Provide timely and relevant updates about the Project to enable Indigenous Groups, the public, government and other stakeholders to provide input during the impact assessment and regulatory processes.
- Gather feedback from Indigenous Groups, the public, government and other stakeholders on the impact of the Project on the community and gather input on their interests related to the Project. Where possible, refine the Project or develop mitigation measures.
- Meet the Indigenous and public consultation requirements of the new provincial EA process. This will include public comment periods where the public can learn more about the Project through its website, ask questions at information sessions and provide feedback.
- Work with the community to ensure engagement is inclusive and designed to reach the diversity of people within the community. The company is committed to incorporating principles of Gender Based Analysis (GBA+) recognizing that inequalities in communities affect people differently and to mitigate barriers that limit participation and engagement from distinct groups in the community.

Written input and feedback from Indigenous Groups, the public, government and other stakeholders, is recorded in engagement logs and issue tracking tables. Engagement logs serve as a record of communications between FortisBC and groups identified for engagement, as well as any follow-up requirements, decisions, and commitments.

FortisBC will maintain an issues tracking table to serve as a record of comments raised during engagement activities and document review, including this Engagement Plan and the IPD. The issues tracking table includes FortisBC's response and how issues raised will be addressed. Feedback from document review is also tracked and incorporated into the corresponding document, including project planning and design considerations.

Note that this engagement plan was filed before the COVID-19 pandemic and some of the engagement activities listed are subject to change based on public health priorities. In-person engagement activities are not aligned with current guidance from public health authorities and will not be feasible at this time.

FortisBC is continuing to engage on projects that are considered vital to our energy infrastructure. We're also taking steps to keep our customers, our employees and the public safe.

- We've cancelled in-person meetings and engagement activities to support physical distancing.
- We're using digital alternatives such as teleconferences, virtual open houses and other digital tools to engage with Indigenous groups, stakeholders and the public.
- We're working with regulatory agencies to ensure any engagement is safe and effective in facilitating meaningful dialogue.

In light of the COVID-19 pandemic, FortisBC requested the Environmental Assessment Office extend Early Engagement on the Tilbury Phase 2 LNG Expansion Project from 90 days to 150 days. This will allow additional time to ensure meaningful engagement with the public, stakeholders and Indigenous groups.

Indigenous Engagement

FortisBC is committed to building effective Indigenous relationships in the areas where we operate. FortisBC adopted a Statement of Indigenous Principles in 2001 that identifies commitments to engagement with Indigenous peoples, and guides the actions of the company and its employees. This Statement can be found at https://www.fortisbc.com/in-your-community/indigenous-relations/statement-of-indigenous-principles and includes the following guiding principles:

- FortisBC acknowledges, respects, and understands that Indigenous Peoples have unique histories, cultures, protocols, values, beliefs, and governments.
- FortisBC supports fair and equal access to employment and business opportunities within FortisBC companies for Indigenous Peoples.
- FortisBC will develop fair, accessible employment practices and plans that ensure Indigenous Peoples are considered fairly for employment opportunities within FortisBC.
- FortisBC will strive to attract Indigenous employees, consultants, and contractors and business partnerships.
- FortisBC is committed to dialogue through clear and open communication with Indigenous communities on an ongoing and timely basis for the mutual interest and benefit of both parties.
- FortisBC encourages awareness and understanding of Indigenous issues within its workforce, industry, and communities where it operates.
- To achieve better understanding and appreciation of Indigenous culture, values, and beliefs, FortisBC is committed to educating its employees regarding Indigenous issues, interests, and goals.
- FortisBC will ensure that when interacting with Indigenous Peoples, its employees, consultants, and contractors demonstrate respect, and understanding of Indigenous Peoples' culture, values, and beliefs.
- To give effect to these principles, each of FortisBC's business units will develop, in dialogue with Indigenous communities, plans specific to their circumstances.

FortisBC values the concerns and feedback provided by Indigenous Groups and recognizes that information shared contributes to project siting, design, mitigation development and ultimately a more successful Project. FortisBC will consult with each Indigenous Group on how they prefer to be engaged, including policies, protocols and traditional approaches to inform the development of the consultation process.

For the purpose of Early Engagement, FortisBC adopted an inclusive approach to engagement with Indigenous Nations and Groups. FortisBC recognizes that some groups identified through the Provincial Consultative Areas Database are political organizations rather than rights holders such as the Stó:lō Nation and Stó:lō Tribal Council. However, FortisBC understands that it is for the Indigenous Nation to decide the appropriate entity to represent their collective interests. FortisBC will engage with Indigenous Groups identified in the Consultation Areas Database, those identified within proximal Environmental Assessments and those specified by the EAO. FortisBC will update Indigenous Groups to reflect all participating Indigenous Nations following Day 90 of the Early Engagement Phase at which point the EAO will provide a list of participating Indigenous Nations.

Identified Indigenous Groups

A review of the Consultative Areas Database (CAD) has identified 17 Indigenous Groups whose established or asserted traditional territories overlap with the Project Site. Squamish Nation and Kwantlen First Nation were not identified in the 2019 CAD report used to develop this table but have been included in this list due to their interest in the WesPac Tilbury Marine Jetty Project, which is located near the proposed Project. Additionally, Métis Nation British Columbia has been included to meet federal government requirements.

Table 4-1 provides a list of the Indigenous Groups identified for engagement, including the title of representatives, method, and frequency of engagement. During the early engagement phase, the proponent will seek to confirm the listed representatives are still accurate and seek permission to include their names within the Project materials including the Detailed Project Description. FortisBC will provide the name of the contact to date to the EAO in a separate document until confirmation of the specific individual is confirmed during the Early Engagement phase.

Table 4-1. Indigenous Groups Identified for Engagement (shown in alphabetical order)

Indigenous Group	Representative	Methods of Engagement
Cowichan Tribes [a,b]	Cowichan Tribes Referrals Coordinator	• Primary method of correspondence is via email and in person meetings as requested by Cowichan Nation Alliance. • Cowichan Tribes is interested in conducting a site visit in the spring.
Halalt First Nation [a,b]	Halalt First Nation Director of Operations, Treaty Halalt First Nation Referrals Coordinator	• Primary method of correspondence is via email and in person meetings as requested by Halalt First Nation.
Katzie First Nation	Katzie Nation Lands Department Referrals Consultant	• Primary method of correspondence is via email and phone. No meeting has been requested to date. • FortisBC will continue to provide milestone updates via email and participate in meetings if requested.
Kwantlen First Nation	Kwantlen First Nation Lands and Resource Coordinator Kwantlen First Nation Lands and Resource Manager	• Primary method of correspondence is via email. • FortisBC has also met in person and facilitated a site visit at the request of Kwantlen First Nation. • FortisBC will continue to provide milestone updates via email and participate in meetings if requested.
Lake Cowichan First Nation [b]	Lake Cowichan First Nation Referrals Coordinator	• Primary method of correspondence is via email. No response has been received to date. • FortisBC will continue to provide milestone updates via email and participate in meetings if requested.
Lyackson First Nation [a,b]	Lyackson First Nation Lands and Resources Office	• Primary method of correspondence is via email. No response has been received to date. • FortisBC will continue to provide milestone updates via email and participate in meetings if requested.
Métis Nation British Columbia	To be determined	• No correspondence with the Métis Nation of British Columbia on this project to date.
Musqueam Nation	Musqueam Nation Project Analyst	• Primary method of engagement is via email and bi-weekly conference call. • No meeting requested at this time.
Penelakut Tribe [a,b]	Penelakut Tribe Economic Development Officer	• Primary method of correspondence is via email and in person meetings as requested by Cowichan Nation Alliance.
Seabird Island Band [d]	Seabird Island Band Chief Administrative Officer	• Primary method of correspondence to date has been email. • Daryl McNeil indicated Seabird Island Band has no comments at this time. • FortisBC will defer to EAO to determine if Seabird Island Band is a participating Indigenous Nation.
Semiahmoo First Nation	Semiahmoo First Nation Chief and Council	• Primary method of correspondence is via email. No response received to date. • FortisBC will continue to provide milestone updates via email and participate in meetings if requested.
Shxw'ōwhámél First Nation [d]	Shxw'ōwhámél First Nation Referrals Office	• Primary method of correspondence is via email. No response received to date. • FortisBC will continue to provide milestone updates via email and participate in meetings if requested.

Table 4-1. Indigenous Groups Identified for Engagement (shown in alphabetical order)

Indigenous Group	Representative	Methods of Engagement
Skawahlook First Nation [c]	To be determined	• Primary method of correspondence is via email to the People of the River Referrals Office. No response received to date. • FortisBC will continue to provide milestone updates via email to the community email inbox and participate in meetings if requested.
Soowahlie First Nation [d]	To be determined	• Primary method of correspondence is via email to the People of the River Referrals Office. No response received to date. • FortisBC will continue to provide milestone updates via email to the community email inbox and participate in meetings if requested.
Squamish First Nation	Squamish First Nation Rights & Title – GIS & Research Officer	• Primary method of correspondence is via email. No response received to date. • FortisBC will continue to provide milestone updates via email and participate in meetings if requested.
Stó:lō Nation	Direct to the member group	• Correspondence will be directed to the specific member community.
Stó:lō Tribal Council	Direct to the member group	• Correspondence will be directed to the specific member community.
Stz'uminus First Nation [a]	Stz'uminus First Nation Lands and Resources Office	• Primary method of correspondence is via email and in person meetings as requested by Cowichan Nation Alliance.
Tsawwassen First Nation	Tsawwassen First Nation Territory Management Coordinator Tsawwassen First Nation Policy Analyst, Policy, and Intergovernmental Affairs Tsawwassen First Nation Manager of Policy & Intergovernmental Affairs.	• Primary method of correspondence is via email and FortisBC has attended one meeting. • FortisBC will continue to provide milestone updates via email and participate in meetings if requested.
Tsleil-Waututh Nation	Tsleil-Waututh Nation Consultation & Accommodation Manager – Environmental Assessments Tsleil-Waututh Nation, Referrals Analyst – Environmental Assessments	• Primary method of correspondence is via email and FortisBC has attended one introductory meeting. • TWN has requested an additional meeting following the review of the Initial Project Description. • TWN has indicated a minimum 30-day review period for materials, FortisBC will schedule this meeting after 30 days within Early Engagement Phase.

[a] Members of the Cowichan Nation Alliance

[b] Members of the Hul'qumi'num Treaty Group

[c] Members of the Stó:lō Nation

[d] Members of the Stó:lō Tribal Council

Summary of Preliminary Indigenous Engagement Activities

Preliminary engagement activities occurred from July to December 2019. The bulk of meetings occurred when FortisBC shared the draft IPD with Indigenous Groups. The communities that have engaged with FortisBC during preliminary engagement are (in order alphabetically):

- Cowichan Tribes
- Halalt First Nation
- Katzie First Nation
- Kwantlen First Nation
- Musqueam Nation
- Penelakut Tribe
- Seabird Island Band
- Stz'uminus First Nation
- Tsawwassen First Nation
- Tsleil-Waututh Nation

FortisBC conducted preliminary engagement activities in advance of filing the IPD. The preliminary engagement approach was as follows.

1. An email notification of upcoming early engagement activities was sent on July 2, 2019 to Indigenous Groups with consultative areas overlapping the Phase 2 Project area. The notification included an approximate date of July 9, 2019 upon which the draft IPD would be sent and the requested date of July 31, 2019 to return comments. The purpose of this notification was to provide advance notice to allow Indigenous Groups to appropriately resource review if they wished to comment on the early draft.
2. A draft IPD was sent on July 12, 2019 to Indigenous Groups with consultative areas overlapping the Project area. Indigenous Groups were asked to provide comments on the draft IPD by August 2, 2019. This period is 21 days.
3. Five Indigenous Groups responded to the initial communication regarding the draft IPD. Table 4-2 is a summary of the correspondence received. During the early engagement activities, the Project team participated in meetings with Indigenous Groups, responded to questions and discussed next steps regarding the regulatory process.
4. Upon receipt of comments, the draft IPD was revised to reflect comments received from Indigenous Groups.
5. The revised IPD was circulated to Indigenous Groups that provided comments on the initial draft or indicated an interest in the Project by responding to initial Project communications. The revised IPD was provided on September 16, 2019 with a request that any comments be received by October 2, 2019. Indigenous Groups were advised that FortisBC would continue to address comments received after this date, but they may not be reflected in the draft submitted to regulatory agencies. Indigenous Groups were also advised that the Project was in preliminary engagement stages and there would be additional opportunities for engagement through the regulatory review process.

Preliminary engagement has focused primarily on information sharing about the Project, the next steps in regulatory review, responding to questions and recording concerns. The intention of these activities was to support all potentially affected Indigenous Groups in understanding the proposed Project at an early stage.

From these early conversations, FortisBC hopes that the information provided assists Indigenous Groups' assessment of the nature of the concerns related to the Project and in turn help FortisBC to ensure respective Indigenous interests are addressed throughout the Project development.

FortisBC has negotiated and signed capacity funding agreements with Indigenous Groups. These include agreements with Musqueam First Nation (2015, 2018) and the Cowichan Tribes (2018) specific to the Project. No other communities have signed a capacity funding agreement with FortisBC.

Key Issues Raised

Table 4-2 presents a summary of key issues raised by Indigenous Groups to date.

Table 4-2. Key Issues Raised by Indigenous Groups to Date

Indigenous Group	Issues Raised	FortisBC Response
Cowichan Tribes	Expressed interest in more detail on the marine shipping container business and Tilbury Project Site layout and general arrangements.	FortisBC to provide additional context. In addition, FortisBC will facilitate a site visit with Cowichan Tribes.
Cowichan Tribes	Expressed interest in more detail about the process for decommissioning and demolition of the old plant.	FortisBC responded that these activities would be subject to BC Utility Commission and BC Oil and Gas Commission approvals.
Cowichan Tribes	When CNA provides suggestions and input to FortisBC, CNA expects FortisBC to provide a rationale for instances where feedback is not incorporated, as indicated in the preliminary Indigenous engagement plan section of the IPD.	FortisBC agrees to provide such rationale.
Cowichan Tribes	Review period for materials should be at least 3 weeks.	FortisBC will engage Cowichan Tribes in the development of the DPD, including review prior to submission to regulators. FortisBC will provide 3 weeks for Cowichan Tribes to complete this review.
Kwantlen First Nation	Expressed concerns around end of life abandonment of assets: Heightened sensitivity with old ferry dock on Brae island, which was abandoned since 2005 when the ferry stopped operating.	FortisBC noted that de-commissioning / abandonment is part of EA review to assess impacts of this phase of project. 'Old' Tilbury plant decommissioning involves removal and not abandoned in-place.
Kwantlen First Nation	Concerns related to developing infrastructure related to Greenhouse Gas (GHG) emissions.	This issue will be addressed in the assessment. During the Early Engagement Phase, FortisBC will seek additional clarification from Kwantlen First Nation on the concern and potential measures to evaluate.
Kwantlen First Nation	Cumulative effects of many projects over the years: Concerns with increased shipping (on river), Tilbury Island specifically is under a lot of development.	This issue will be addressed in the assessment.
Kwantlen First Nation	Interest in 'legacy projects' that contribute to bio-diversity.	FortisBC willing to discuss this issue further with Kwantlen.
Kwantlen First Nation	Kwantlen received some 70 or more referrals per month from environmental assessments to permits, which is a challenge for small team to manage.	FortisBC has requested that Kwantlen send estimate for capacity funding.
Kwantlen First Nation	Kwantlen interested in Tilbury Island and wants to be regularly active in consultation.	FortisBC will continue to meet with Kwantlen to understand their interest in the Project.
Kwantlen First Nation	Would like a Project Site tour ideally with WesPac present to discuss Jetty Project also.	FortisBC arranged and site tour completed Sept. 24 2019 with WesPac.
Kwantlen First Nation	Would like to participate in opportunities including archaeological assessments.	FortisBC noted that archaeological studies for Project Site may be done as part of application WesPac will be submitting. Archaeological assessments are not expected during the Early Engagement Phase, however FortisBC will ensure Kwantlen is

Table 4-2. Key Issues Raised by Indigenous Groups to Date

Indigenous Group	Issues Raised	FortisBC Response
		aware of any studies and opportunities for participation in the future.
Tsleil-Waututh Nation	Tsleil-Waututh requires 30 – 45 day review period, specifically Tsleil-Waututh requested the IPD and an additional review period in advance of the filing of the Initial Project Description.	In response to the request for the IPD, FortisBC provided the IPD to Tsleil-Waututh on January 27 to facilitate review, but indicated additional discussions and meetings are anticipated to take place within the new Early Engagement Phase. The IPD is not materially different than that shared with Tsleil-Waututh for engagement in 2019, as outlined in the Summary of Preliminary Engagement Activities. FortisBC will work to achieve this review period within the Early Engagement Phase, including scheduling a meeting following a 30-day period from receiving the IPD as well as providing 30 days to review the DPD prior to submission of regulators.
Tsleil-Waututh Nation	Tsleil-Waututh has concerns around cumulative effects assessment and uses a pre-contact baseline.	This issue will be addressed during the preparation of the Application Information Requirements.
Tsleil-Waututh Nation	Tsleil-Waututh raised concerns around the scope of the assessment, wants upstream impacts from extraction assessed as well.	This issue will be addressed during the preparation of the Application Information Requirements.

Summary of Planned Indigenous Engagement Activities

Based on engagement with Indigenous Groups to date, FortisBC expects to carry out the following activities during the Early Engagement phase:

1. Ongoing engagement regarding upcoming Project milestones either in person or through a preferred communication method with those Groups. During preliminary engagement activities, FortisBC heard that many Indigenous Groups have capacity constraints that limit their engagement ability. As a result, some Indigenous Groups may not have time for a meeting.
2. To ensure Indigenous Groups still receive relevant information, FortisBC will also provide Project updates through written correspondence (emails, letters), and phone conversations based on the preference indicated by the Indigenous Group. Where they have been provided to FortisBC, communications preferences are included in Table 4-1.
3. Meetings to share information about the Project, discuss topics of interest, seek a point-of-contact and identify group-specific consultation policies, protocols or preferences. If requested by the Indigenous Group, the EAO may also attend to provide additional information on the new process. For the convenience of the Indigenous Group, FortisBC will travel to the respective office that has requested the meeting.
4. Indigenous Groups may wish to participate in a Project Site visit to better understand the geographic location of the Project as well as gain community-relevant information such as the presence of specific plants. To that end, FortisBC understands there is a seasonality element to scheduling to be accommodated where possible. FortisBC will facilitate site visits subject to facility safety requirements.
5. As part of the Early Engagement Phase, the EAO will also be engaging with Indigenous Groups. Where requested, FortisBC will support EAO-led activities such as attending meetings or information sessions.

FortisBC has executed capacity funding agreements with First Nations during the preliminary engagement phase. FortisBC will discuss capacity funding needs during Early Engagement Phase with those Indigenous Groups that reasonably identify areas within the Early Engagement Phase where additional support is needed.

In keeping with the GBA+ principles outlined in the preceding sections, FortisBC will seek input from Indigenous Groups regarding any limitations that may be a barrier to participation in the process for their respective community members. If these limitations exist, FortisBC will consult with the Indigenous Group on best practices to address these barriers.

Early Engagement activities will be documented for inclusion in the Detailed Project Description. To ensure appropriate characterization, FortisBC will provide all meeting participants with draft meeting notes for comment following the meeting within 5 business days.

Incorporating Indigenous Responses and Comments

Through engagement activities completed in 2019, some Indigenous Groups have provided comments related to their respective community on the IPD. The IPD was updated to reflect these comments. Some preliminary comments are technical in nature and require further discussion and analysis. In this case, the next steps within the process will be outlined to show where and when the comments will be addressed.

If Indigenous Groups provide comments on the IPD, FortisBC will demonstrate where comments are incorporated within the DPD and provide a rationale for instances where feedback was not incorporated. FortisBC will provide a draft of the Detailed Project Description to participating Indigenous Groups for review in advance of submission to regulatory agencies.

FortisBC understands that some information shared by Indigenous Groups is sensitive in nature and must be treated in an appropriate manner, as indicated by the respective Indigenous Group(s). When provided confidentially, Indigenous knowledge will be protected from unauthorized disclosure and inappropriate use. Where and when Indigenous knowledge is permitted to be shared, it will be reflected in a clear and transparent manner. Any Indigenous knowledge shared (including Traditional Ecological Knowledge and Traditional Land Use information) will be used in a manner that complies with the laws, customs and protocols indicated by the respective Indigenous Group(s). Further discussions will identify methods to incorporate the information in a way that respects sensitivities and informs relevant project assessments.

Public and Stakeholder Engagement

FortisBC is committed to early and transparent engagement with the public and other stakeholders. Since 2012, FortisBC has identified, met with and maintained relationships with a range of public stakeholders interested in or affected by the expansion of the Tilbury LNG Facility.

Identified Public Stakeholders

Table 5-1 provides a list of public groups, populations, or individuals identified for early engagement. These stakeholders have been included because of their known or anticipated interest in the Project, and/or anticipated effects by the Project. Also included below is engagement that has already occurred with these groups, and planned engagement with these groups.

Based on the location of the Project, and the anticipated level of interest, the community of Delta is expected to be the focus of public consultation activities with additional outreach in Richmond depending on interest. Engagement opportunities will be advertised beyond Delta to reach anyone with interest in the Project in surrounding communities.

These stakeholders include business associations and community organizations with known and/or anticipated interest in the Project. As engagement continues, this plan will be updated, and additional organizations will be added to the list. FortisBC will work with these stakeholders to determine their preferred methods and frequency of engagement.

Table 5-1. Public Stakeholders Identified for Engagement (shown in alphabetical order)

Organization/Group	Representative	Rationale
Boundary Bay Conservation Committee	Mary Taitt	The committee is active in local conservation and has previously expressed interest in the Project.
Burns Bog Conservation Society	Eliza Olsen	The society is involved in the conservation of Burns Bog and has previously expressed interest in the Project.
Delta Chamber of Commerce	Garry Shearer	The chamber represents businesses in Delta and has previously hosted LNG education events for the public.
Delta community		The Project is located in Delta and feedback from the community will help inform the EA process.
Fraser River Industry Assoc.	Parm Heer	The association represents businesses along the lower Fraser River and its members have previously expressed interest in the Project.
Property owners, occupants or tenants within the vicinity of the facility	To be determined	FortisBC will continue to inform previously notified owners, occupants or tenants of future plans and ongoing work at the site.
Richmond Chamber of Commerce	Matt Pitcairn	The chamber represents businesses in Richmond and has previously hosted LNG education events for the public.
Richmond community		The Project is located near Richmond and residents may have an interest in the Project.

Summary of Early Public and Stakeholder Engagement Activities

FortisBC has completed preliminary engagement on the Project with two of the groups listed in Table 5-1 above, the Delta Chamber of Commerce and the Richmond Chamber of Commerce, where an overview of the Project was provided. The chambers expressed general support for the Project, acknowledging the anticipated economic benefits it will bring to their communities. They requested more information about the economic benefits of the Project, and to be kept informed about the Project on a regular basis through email, and face-to-face meetings as appropriate.

Summary of Planned Public and Stakeholder Engagement Activities

The next phase of early engagement on the Project with the groups identified in Table 5-1 will focus on creating opportunities for them to learn more, ask questions, and provide feedback and local knowledge. Early Engagement activities are summarized below, in order of sequence:

1. Upon acceptance by the EAO/IAAC of the IPD, a new project web page will be published at TalkingEnergy.ca containing Project and contact information. The page will contain a high level overview of the Project, instruction on how to get involved in the EA process, a link to the EAO's website where visitors can access the IPD and provide comments during the comment period. The web page will be updated as the Project reaches new milestones and to support the EA process.
2. A notification letter will be sent to the property owners, occupants or tenants in the vicinity of the Project. The letter will include contact details and a link to the Project website should they have questions or would like more information, helping to gauge the level of interest in the Project.
3. An initial email notification will be sent to the organizations and community groups identified in Table 5-1. The notification will include an offer of a meeting.
4. A joint public open house will take place during the public comment period. The open house will include display boards and FortisBC representatives will attend to provide information about the Project and respond to questions from the public.
5. Digital and print ads, including in-language ads, as well as social media will promote the open house and direct the interested public to an online registration page on FortisBC's TalkingEnergy.ca website. FortisBC will pursue reaching the public through chamber events and other community events such as festivals to connect with those who may be unable to attend an open house. The company will engage with municipal representatives and local MLAs to determine which events may be most suitable. At the events, FortisBC would have a booth with presentation materials so the community could learn more and ask questions about the Project.
6. FortisBC will offer to meet with the groups identified in Table 5-1 to provide information and accept feedback about the Project, throughout Early Engagement as appropriate.
7. Shortly after the EAO and IAAC accept the IPD and engagement plan, FortisBC will drop off Project information sheets at MLA and MP constituency offices in the event they receive any inquiries from their constituents.
8. Throughout all engagement on the Project, educational materials such as videos will be shared on social media and on FortisBC websites such as TalkingEnergy.ca to help the public understand LNG and learn more about the Project.

FortisBC will support any EAO-led engagement activities as appropriate by making representatives available, producing presentation materials for any EAO-led engagement activities and advertising any events to help ensure the interested public is informed of these events.

The level of interest and feedback received during early engagement activities will determine the level of future engagement. For example, additional engagement events may be scheduled, depending on public interest at any EAO-led engagement activities. These additional events would be promoted through advertising.

Local knowledge and feedback received from the public through the comment period at any EAO-led engagement activities, at community events and through the Project email address will be compiled in a project tracking table, as well as through the EAO website during the comment period. This information will be considered and may be incorporated into the DPD as appropriate.

FortisBC has considered potentially impacted populations that may be underrepresented by traditional engagement methods. The proposed engagement methods consider different languages, engagement timing and locations, as well as accessibility requirements. This plan will also be publicly posted on the BC EAO's EPIC website. The company is proposing the following measures to reach under-represented communities:

- Any news releases will be distributed to in-language media, and in-language ads inviting the public to any EAO-led engagement activities to help to promote awareness amongst people who speak English as a second language. Furthermore, project information cards will include a statement that says 'Important information, please have translated' in multiple languages, to encourage readers to have the card translated by someone they know in their language.
- Project materials will be both in digital and print form, to ensure that people without access to a computer can learn about the project. These project materials will be mailed upon request to the local community.
- Venues of all public information sessions to be held in the communities of Delta and Richmond will be in accessible locations to public stakeholders. We will ensure venues have automatic doors, elevators and obstacle-free pathways for people who use mobility aids such as wheelchairs. We will also ensure that we have diverse gender representation to facilitate any in-person engagement activities.
- As public safety is our number one priority, we will ensure all venues will be in safe locations. Events will begin during daylight hours and on routes that are accessible by transit.
- FortisBC may also host informal outreach activities such as community pop-up booths and coffee chats. The purpose of these more informal activities is to reach people where they are (i.e. At a shopping centre) and engage with those who may not take the time to attend a more formal event. These additional outreach activities will be at different times, and days, as well as in different locations than any EAO-led engagement activities, in an effort to be accessible to more people.

Municipal, Federal and Provincial Government and Government Agency Engagement

FortisBC is committed to early and transparent engagement with municipalities, federal and provincial governments and government agencies. FortisBC meets regularly with municipal staff, councils and MLAs including Delta regarding public utility operations, planning and activities, as well as the expansion of the Tilbury LNG Facility. FortisBC has a history of public utility service operations in the province and region involving engagement at all levels of government and government agencies. FortisBC is actively involved in developing BC's LNG industry, developing renewable natural gas from waste, transitioning the transportation sector to lower emission alternatives like compressed natural gas and LNG both locally and globally. FortisBC works closely with government agencies to support these initiatives.

The following is a preliminary list of relevant local government plans for consideration during the Environmental Assessment:

- City of Delta Official Community Plan
- City of Richmond Official Community Plan
- Metro Vancouver Regional Growth Strategy
- Port of Metro Vancouver Land Use Plan

Identified Municipal, Provincial and Federal Government Representatives

The following table provides a list of appropriate municipalities, provincial and federal government representatives, and provincial and federal government agencies identified for engagement.

Table 6-1. Municipal Government and Provincial and Federal Government and Government Agencies Identified for Engagement (shown in alphabetical order)

Government	Representative	Rationale
Municipal Governments		
City of Delta	Staff and council	Permitting agency
City of Richmond	Staff and council	Nearby municipality
Metro Vancouver	Staff	Permitting agency
Provincial Government representatives		
Member of Legislative Assembly (MLA) Delta North	Ravi Kahlon	Project is located within Delta
MLA Delta South	Ian Paton	Project is located within Delta
Richmond MLAs	Jas Johal, John Yap, Linda Reid, Teresa Wat	Project is located near Richmond
Federal Government representatives		
Delta Member of Parliament (MP)	Carla Qualtrough	Project is located within Delta
Richmond MP	Kenny Chiu	Project is located near Richmond
Provincial Government agencies		
BC Environmental Assessment Agency (BC EAO)	Fern Stockman	Reviewing agency under the BC *Environmental Assessment Act*
BC Oil and Gas Commission (BC OGC)	To be determined	Permitting agency
BC Utilities Commission (BCUC)	To be determined	Permitting agency
Ministry of Forests, Lands, Natural Resource Operations and Rural Development (MFLNRORD)	To be determined	Potential permitting agency

Government	Representative	Rationale
Federal Government agencies		
Impact Assessment Agency of Canada (IAAC)	Natasha Anderson	Reviewing agency under the *Impact Assessment Act*
Fisheries and Oceans Canada (DFO)	To be determined	Potential permitting agency
Transport Canada	To be determined	Potential permitting agency
Vancouver Fraser Port Authority	To be determined	Potential permitting agency
Environment and Climate Change Canada (ECCC)	To be determined	Potential permitting agency

Summary of Early Municipal, Federal and Provincial Government and Government Agency Engagement Activities

Since 2012, FortisBC has regularly communicated and met in-person with municipal, provincial, and federal governments to provide updates and respond to questions about the company and the Tilbury LNG Facility. Through these meetings, FortisBC gained an understanding of community values, and sought recommendations on consultation and engagement.

FortisBC regularly meets with Delta to inform them of updates to the existing LNG facility and provides advance notice of FortisBC-related activities taking place in their community. In December 2019, FortisBC provided an overview of the Project to senior City staff members. They requested to be kept up to date via email through the City Manager, and no specific feedback about the Project that requires a response or addressing was expressed by the city at this time. FortisBC also engages municipal staff, local first responders, and other stakeholders in full-scale emergency exercises at the existing LNG facility.

FortisBC is also in regular communication with Delta MLAs to keep them apprised of updates regarding the Tilbury LNG facility, and other corporate updates that affect the Delta community. In October 2019, FortisBC provided Ian Paton, MLA Delta South, with an overview of the Project, and committed to keeping him informed as the Project progresses. No specific feedback about the Project that requires a response was expressed at this time.

FortisBC met with the BC Environmental Assessment Office (EAO) and the Impact Assessment Agency of Canada (IAAC) several times between June and December 2019 to initiate Project discussions and plan for adoption of new and revitalized legislation.

Summary of Planned Municipal, Federal and Provincial Government and Government Agencies Engagement Activities

To support the filing of the IPD, an email notification will be sent to all municipal, provincial, and federal representatives identified in Table 6-1. This notification will inform them of how they can get involved, how best to provide feedback on the Project, and an offer to have a meeting and/or provide more information about the Project. FortisBC will seek recommendations from these groups on how best to engage their community on the Project. For instance, optimal locations for the open house/coffee chats, or suggested community events to participate in. We will seek feedback from local government on reaching diverse populations within the community to help ensure engagement activities are inclusive and representative of the community at-large.

All municipal, provincial, and federal representatives listed in Table 6-1 above will also receive an invitation to any EAO-led engagement activities to provide them with an opportunity to learn more, ask questions, observe community/public interest, and to provide feedback on the Project.

The company will continue to work with Delta city staff, the BC OGC, and other government agencies regarding permitting requirements to maintain transparency, ensure compliance, and address feedback throughout the process, and be available for follow up meetings as required. When feasible, visits to the

Project Site will be offered to municipal government representatives, and federal and provincial government and government agency representatives so that they can better understand the proposed Project, ask questions, and provide feedback. FortisBC will also participate in any EAO-led engagement activities with Municipal, Provincial and Federal government representatives and agencies as appropriate.

References

City of Delta (Delta). 2019. *Official Community Plan*. Accessed: May 2019. https://delta.civicweb.net/filepro/documents/37999?expanded=39403,39381&preview=39403.

City of Richmond (Richmond). 2019. *2041 Official Community Plan Land Use Map*. Accessed: November 14, 2019. https://www.richmond.ca/__shared/assets/2041_OCP_Land_Use_Map10716.pdf.

WesPac Midstream Ltd. (WesPac). 2015. *Tilbury Marine Jetty Project Description*. Accessed February 10, 2020. https://iaac-aeic.gc.ca/050/documents/p80105/101701E.pdf

Appendix Q-3

STAKEHOLDER LIST

Tilbury PHASE 2 LNG Expansion & TLSE Stakeholder List

Stakeholder	Email
Carla Qualtrough, Delta Member of Parliament (MP)	Carla.Qualtrough@parl.gc.ca
Ken Chiu, Steveston-Richmond East, MP	kenny.chiu@parl.gc.ca
Alice Wong, Richmond Centre, MP	Alice.wong@parl.gc.ca
Ravi Kahlon, MLA Delta North	ravi.kahlon.MLA@leg.bc.ca
Ian Paton, MLA Delta South	ian.paton.MLA@leg.bc.ca
Jas Johal, MLA Richmond East	jas.johal.MLA@leg.bc.ca
John Yap, MLA Richmond Steveston	john.yap.MLA@leg.bc.ca
Linda Reid, MLA Richmond	linda.reid.MLA@leg.bc.ca
Teresa Wat, MLA Richmond	teresa.wat.MLA@leg.bc.ca
Sean McGill, Delta City Manager	smcgill@delta.ca
Mayor George Harvie, City of Delta	mayor@delta.ca
Delta City Councillors	Dkruger@delta.ca (Dylan Kruger)
	aguichon@delta.ca (Alicia Guichon)
	ljackson@delta.ca (Lois Jackson)
	dcopeland@delta.ca (Dan Copeland)
	jkanakos@delta.ca (Jeannie Kanakos)
	bmcdonald@delta.ca (Bruce McDonald)
George Duncan, City of Richmond Chief Administrative Officer	AdministratorsOffice@richmond.ca
Mayor & Council, City of Richmond	mayorandcouncillors@richmond.ca
Garry Shearer, Delta Chamber of Commerce	garry@deltachamber.ca
Matt Pitcairn, Richmond Chamber of Commerce	mpitcairn@richmondchamber.ca
Parm Heer, Fraser River Industry Assoc.	ParmH@fsd.bc.ca
Eliza Olsen, Burns Bog Society	info@burnsbog.org
Mary Taitt, Boundary Bay Conservation Society	taitt@telus.net
Andrew, BC & Yukon Bldg Trades Council	amercier@bcbuildingtrades.org
Bryan Cox, CEO Canadian LNG Alliance	bcox@bclnga.ca
Stephen Bruyneel, Fraser River Discovery Center	sbruyneel@fraserriverdiscovery.org

Appendix Q-4

SUMMARY OF EMAIL AND TELEPHONE INQUIRIES AND RESPONSES

Date	Concern/Interest	Communication Method	Responded (Y/N)	Additional Comments
9-Jun-20	Project support	Email	Yes	Customer emailed to demonstrate his support of the Project.
10-Jun-20	Procurement	Email	Yes	Customer emailed to inquire about getting on the project bid list. FBC Rep replied thanking him and provided the FEI email for potential procurement opportunities and a hyperlink to the FEI website for the Contractors and Vendors form.
11-Jun-20	Support	Email	Yes	FBC Rep emailed to thank customer for his support and requested feedback during the public comment period by July 16th. Provided a link to EAO website and FEI project website.
16-Jun-20	Postive about project.	Phone call	Yes	Customer left a voicemail introducing himself and inquiring clarification about the storage tank. FBC Representative advised him of the open house and EA comment period. Customer was positive about the project.
16-Jun-20	Interested in where the gas on Vancouver Island comes from and where Tilbury is located.	Phone call	Yes	Customer left a voicemail introducing herself and inquiring about where the gas on Vancouver Island comes from. FBC Rep spoke to the customer and responded with details on FEI pipelines and gas, and advised her of the upcoming open houses.
17-Jun-20	Fiscal project detail.	Phone call	Yes	FBC Rep and customer had a phone conversation where the customer had questions about fiscal project details also informed him on details and about the virtual open house.
17-Jun-20	Open House date and time	Phone call	Yes	FBC rep and customer had a phone call where customer inquired about the open house and he wasprovided with more information.
17-Jun-20	Storage facilty and GHG Emissions	Phone call	Yes	Customer left a voicemail wanting clarification on the details of the new storage facility. FBC Rep had a phone call with the customer and explained to him with LNG was and details on how it is stored. Customer raised concerns about GHG emissions.
18-Jun-20	Location and project details	Phone call	Yes	Customer left a voicemail wondering where the Tilbury facility is, and requested FEI call him back. FBC Rep had a phone conversation with the customer advised him the facility location details project details, and informed him of the open house. Customer was excited about the project and open house.
20-Jun-20	Location and environmental health	Email	Yes	Customer emailed FEI with concerns about the Tilbury expansion project. Topics of concern were the Project location, environmental and human health, climate impacts, GHG emissions, liquefaction leak from earthquake, economic benefits.
22-Jun-20	Indigenous consultation	Email	Yes	Customer emailed with follow up questions regarding information on the Project and the Indigenous community consultation process.FBC Rep responded with information on FEI's engagement plan, provided a hyperlink for the plan, a hyperlink for the Tilbury Project page and a hyperlink for FEI's EAO process. Olivia outlined project process details
23-Jun-20	Project details	Phone call	Yes	Customer left a voicemail requesting details on the LNG storage facility . FBC rep reached out and advised him on the difference between the two tanks and location.
24-Jun-20	Postive about project.	Email	Yes	FBC Rep and Customer had a phone call with on June 11 to answer his question, to which customer requested an emailed response to some of his questions. On June 24, FBC Rep emailed customer answers to his questions as follows: 1. What is Fortis doing in order to reduce CO2 by 30% by 2030 (or Clean BC targets)? In addition to promoting LNG from Tilbury to reduce greenhouse gas emissions for marine and overseas customers, FEI is also energy efficient, working toward renewable gas, continue to invest in sero and low carbon transportation. 2. Is Fortis currently selling renewable energy as an alternative to extracting natural gas? Over 11,500 BC homes and businesses are currently receiving renewable natural gas (RNG).
24-Jun-20	Cost to taxpayers	Phone call	Yes	Customer left a voicemail wondering if the LNG expansion will cost taxpayers more money on their monthly bills. FBC Rep had a phone call with F Mazyn educate her on the project and advise her on the difference between the current and proposed tanks.
2-Jul-20	Increase in monthly invoice.	Email	Yes	Customer emailed FEI to inquire if the facility upgrade would cause an increase in his monthly Fortis bill. FBC replied to mention that the cost is still being determined.

Date	Concern/Interest	Communication Method	Responded (Y/N)	Additional Comments
3-Jul-20	GHG emissions	Email	Yes	FBC Rep replied email with concerns regarding the Tilbury expansion project. FBC Rep replied with detailed information about the project that suggests Tilbury is a good location for a small-scale LNG Facility. Also discussed how the LNG facility helps reduce GHG emissions as it is powered by renewable energy, and outlined the economic benefit of creating jobs through the project.
3-Jul-20	Safety	Email	Yes	Customer emailed FEI with concerns about safety for her and her family from the passing by tankers and possible breaching of the tanks and requested information about whether Tilbury LNG will be supplying Wreck Beach with emergency equipment. FBC Rep replied stating that the Tilbury LNG tank would not be passing Wreck Beach, and that if LNG were to spill, there would be no environmental impacts to the land, water or local air quality.
4-Jul-20	Cost to taxpayers	Email	Yes	Customer emailed FEI wondering what the cost will be to Fortis customers from the Project,was advised the cost is still being determined.
6-Jul-20	Cost to taxpayers	Phone call	Yes	Customer left a voicemail wondering if the new Tilbury expansion would cost the taxpayers more money on their current invoice. FBC Rep had a phone call with her where they discussed why the tank is being upgraded and that prices will not be increasing for the current month.
6-Jul-20	LNG video and project information	Email	Yes	FBC Rep. replied to an email from a customer with some information about LNG and provided hyperlinks to a youtube LNG demonstration video and an LNG safety video.
7-Jul-20	Safety	Email	Yes	Customer emailed FEI to ask how and when storage tanks are tested for integrity after initially being put into service. FBC Rep esponded with Project testing details and information regarding LNG safety and routine testing details.
7-Jul-20	Cost to taxpayers	Email	Yes	Customer emailed FEI wondering if the new Project will result in an additional cost to the senior consumer and how much, was advised the cost is still being determined.
13-Jul-20	Safety	Email	Yes	Customer emailed FEI following up with more questions about the Project: wondering if the tankers will be located in Burrard Inlet, if they will be travelling in the commercial shipping lanes in front of Wreck Beach, questions about directing her to a tanker safety reference guide, and requested direction to the Tilbury LNG Disaster Response Plan. FBC Rep replied responding that FortisBC does not share its emergency response plan with the general public, but shared a hyperlink to the corporate emergency response plan on FortisBC's public website.
14-Jul-20	Project details	Phonecall	Yes	Customer left a voicemail requesting more information about the Project. FBC Rep called him to give him Project location information, reason for expansion and the difference between the current and proposed tank.
21-Aug-20	LNG Inquiry	Email	Yes	Customer wanted to know how long FortisBC has been shipping LNG overseas and how. FBC rep advised since 2017 and ISO container.

Appendix Q-5

BILL INSERT, JUNE 2020

Energy at work

FORTIS BC™

We're planning to upgrade our Tilbury LNG facility

Rendering of potential Tilbury LNG Storage Expansion project

We're preparing to file an application with our regulator, the British Columbia Utilities Commission (BCUC), to upgrade our Tilbury LNG facility.

About the Tilbury LNG Storage Expansion project

This project would add storage capacity, to strengthen and improve the resiliency of the energy system that supplies B.C. homes and businesses with natural gas.

If our application is approved by the BCUC, we'll be one step closer to the construction of a new LNG storage tank. This would provide British Columbians with an additional, backup source of natural gas in the event of a supply disruption.

That's energy at work.

Visit **talkingenergy.ca/tilburyphase2** to learn more.

Questions?
Call us at **1-855-576-7133** or email us at **tilbury.info@fortisbc.com.**

Connect with us

FORTIS BC™
Energy at work

FortisBC Energy Inc. does business as FortisBC. The company is an indirect, wholly owned subsidiary of Fortis Inc. FortisBC uses the FortisBC name and logo under license from Fortis Inc.

(20-006.17 05/2020) *MCC# 904104*

Appendix Q-6

LANDOWNER NOTIFICATION, MAY 29, 2020

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Phone: 604-576-7133

[DATE]

Mr. Sam Sample
Suite 11
123 Anywhere Street
Anytown, ON H0H 0H0

Re: We're planning to upgrade our Tilbury LNG facility

Dear neighbour,

We are working on a new project in your neighbourhood and we would like to get your input. We are proposing to expand our Tilbury Liquefied Natural Gas (LNG) facility in Delta to meet growing LNG demand, while creating economic opportunities for local businesses.

The Tilbury Phase 2 LNG Expansion Project could improve the resiliency of the system that supplies B.C. homes and businesses with natural gas through the construction of a new tank that could triple our site's storage capacity. We would also expand our liquefaction capacity to produce LNG for marine fuelling or for overseas markets.

Environmental Review Process: The Tilbury Phase 2 Project is a reviewable project under the *Environmental Assessment Act* (2018) regulated by the British Columbia Environmental Assessment Office (BCEAO) and the *Impact Assessment Act (2019)* regulated by the Impact Assessment Agency of Canada (IAAC).

The regulatory process began Feb. 27, 2020. However, due to the COVID-19 pandemic, FortisBC requested to extend the provincial Early Engagement, and suspend the federal Planning Phase for 60-days. Now, the regulatory process will restart June 1 with a 45-day public comment period led by these agencies. During this time, you can participate in virtual open houses on June 18 and June 23 from. For more details, and to provide input visit projects.eao.gov.bc.ca or canada.ca/iaac.

Regulated Utility Review Process: As a regulated utility, FortisBC also requires a Certificate of Public Convenience and Necessity (CPCN) from the British Columbia Utilities Commission. We are aiming to submit a CPCN application to the Commission later this year. At that time, we will notify you of additional opportunities to participate in the CPCN process. If approved, project construction could begin as early as 2022 and be complete by 2028.

We are committed to keeping you informed about the project and responding to your questions. Please call us at 604-576-7133, email tilbury.info@fortisbc.com or visit talkingenergy.ca/tilburyphase2, if you would like to know more about the project.

Yours truly,

Courtney Hodson
Community Relations Manager
FortisBC

Appendix Q-7

VIRTUAL OPEN HOUSE QUESTIONS

Questions and Comments from June 18th 2020 -Vitural Open House

Wanted to know how many people are calling in on real time

How does FortisBC reconcile building new fossil fuel infrastructure in a climate emergency?

The 2018 IPCC report states that natural gas can only increase production if it is coupled with carbon capture and storage. What is FortisBC planning to ensure this project is net zero by 2050?

Climate: How is mining, pipelining and selling to customers 5 million tonnes of liquefied fracked gas (which will, when burned, produce at least 14 million tonnes of GHGs- over 100% of BC's 2050 Clean BC

The lack of transparency in this public engagement process is concerning. We do not trust that people that are writing supportive comments for LNG projects like this are real. We believe they may be paid by

Skype is not a good platform for hosting this kind of event. This is not meaningful public engagement.

We do not support LNG projects in BC. FortisBC is not reconciling building new projects with climate in a

What is the estimated vessel traffic during operations for both marine fueling and overseas export? The initial project assessment discusses vessel traffic for construction, but not operations.

Economics: Currently, the spot price of LNG in a glutted Asian market is around US $2.10 (averaging less than $6 over the past 5 years), while, according to the Canadian Energy Research Institute (CERI), the full cost of BC-produced LNG is over US $8 (both per million British Thermal Units (mmBTU)). How does

Shipping: Turning LNG tankers (which can only be filled on one side of the vessel) and barges in a busy, narrow river channel will be problematic. SIGTTO recommends a turning circle of at least 5 times the

Will the TIlbury project incorporate any carbon capture and storage technology?

Economics: Currently, the spot price of LNG in a glutted Asian market is around US $2.10 (averaging less than $6 over the past 5 years), while, according to the Canadian Energy Research Institute (CERI), the full cost of BC-produced LNG is over US $8 (both per million British Thermal Units (mmBTU)). How does
How is the Tilbury LNG Phase 2 project connected to the WesPac Marine Jetty Project? Will this project utilize the marine shipping assessment from WesPac's Marine Jetty project or conduct its own marine

Climate : Burning 5 million tonnes of LNG will produce at least 14 million tonnes of GHGs. That is more than 100% of BC's legislated 2050 Clean BC target for the whole province. How can this be aligned with

You should also know that the audio quality is very poor, and is cutting out often.

Economics/Customer Pricing impact: FortisBC is a regulated utility whose charges to Customers are based on recovering its expenses for service. Building a 5 megatonne LNG plant will cost in excess of $5 Billion. Won't financing for this come out of our (i.e. customers') pockets and raise our heating and food

Pipeline Capacity: How does FortisBC plan to get the gas from N.E. BC to Delta? (Enbridge's Spectra pipeline does not have the capacity to supply a domestic market with the 5 MTPA volume needed for Tilbury LNG). Does FortisBC plan to expand Spectra, build a new pipeline, or utilize the (leaky, 66-year

Why not move away from fossil fuel entirely for our future

Recognizing that the production of natural gas will have a carbon impact here in BC, what is the potential global net reduction of carbon gas emissions as a result of moving our global neighbours off of

Seismic risk: Outline the risks of locating an LNG plant in the area of the Lower Mainland most impacted by a significant seismic event. Japanese LNG import facilities, post-Fukishima, are required to sink their

Continuing to burn fossil fuels as a solution to climate change is insane!

We support LNG projects in BC.

Burning 5 million tonnes of LNG will produce at least 14 million tonnes of GHGs. That is more than 100% of BC's legislated 2050 Clean BC target for the whole province. How can this be aligned with the Bunkering demand: FortisBC gives LNG bunkering of ships in Port of Vancouver as a justification for this multi-million tonne expansion. But- the PoV's 2017 LNG bunkering report predicts an optimistic bas-case bunkering demand of just 129,000 tonnes by 2035, and an PoV owner's survey demand of just

FortisBC 30by30 target: Your IPD suggests that you are counting, toward that target, GHG reductions achieved by Asian Customers substituting LNG for coal in electricity generation plants. How do you know that will happen; how to do you propose BC validates it; and how would those Asian customers be

Will upgrades be required to the current infrastructure leading to Tilbury?

We support LNG in BC and believe that the show stoppers in this discussion are paid by non Canadian

We support LNG projects in BC. FortisBC is doing a great job in reconciling building new projects with

You have talked about natural gas being cleaner to burn than oil and gas. Could you acknowledge the

Insurance: Describe the public liability insurance arrangements for the LNG carriers /barges which will pass close by heavily-populated areas of Richmond and Delta? (we appreciate that most vessels carry cargo and hull insurance – this is about the public liability coverages, where there is no in-force

If there will be no vessel traffic during operations of Phase 2, then why does the project description

Is the planned expansion for export or domestic use? how will it compete with the LNG Canada? or Trust you are taking care of safe connections of big gas pipelines? if it explodes, will it impact us at

I am a contractor, how can I get some business from this opportunity? whom should I contact and what

Will it be possible to minimize light pollution from the facility at night?

Is there opportunity to enhance shoreline vegetation and foreshore fish habitat at the site? Are offsite

Audio is understandable but somewhat distorted. Might help if presenters speak a little slower.

Insurance: Describe the public liability insurance arrangements for the LNG carriers /barges which will pass close by heavily-populated areas of Richmond and Delta? (we appreciate that most vessels carry cargo and hull insurance – this is about the public liability coverages, where there is no in-force

Will there be local job opportunities?

Will Messy Tunnel be removed as told by previous government?

Is there evidence that China would prefer to use LNG or is open to switching to it? Would mean job loss

Is the existing pipeline enough in size or will there be a new pipeline? This project is in high urban

LNG IS NOT a simple “coal out, natural gas in” process -it does not "replace" fossil fuel

Questions and Comments from June 23 2020 -Vitural Open House

Not a question, just wanted to thank you for your presentations and say that Tilbury has operated safely for many years and that this expansion represents a great opportunity for BC. It's clear that it is being

Thank you for the presentation. What specific efforts will been put into staff training?

Will the climate test that is part of federal assessment include upstream emissions from fracking?

FortisBC’s proposal is silent on the local public benefits of this LNG development (to date, the BC-LNG industry has contributed not a dime in public benefits). Please detail the local socio-economic benefits of

How will you consider the Clean B.C. targets for carbon emissions and how the carbon emissions built

Tilbury Pacific LNG Jetty is a proposed jetty (nearing the end of its EA) that will exist only to support the Tilbury LNG Phase 2 Expansion (which is just starting its EA). It seems that if the jetty is approved, then Tilbury Phase 2 LNG Expansion must be approved as to not render the jetty useless. How will the EA for Tilbury LNG Phase 2 Expansion consider the outcome of Tilbury Pacific LNG Jetty? Why has the

How does FortisBC plan to get the gas from N.E. BC to Delta? (Enbridge’s Spectra pipeline does not have the capacity to supply a domestic market with the 5 MTPA volume needed for Tilbury LNG). Does FortisBC plan to expand Spectra, build a new pipeline, or utilize the (leaky, 66-year old) 24” Trans

How is mining, pipelining and selling to customers 5 million tonnes of liquefied fracked gas (which will, when burned, produce at least 14 million tonnes of GHGs- over 100% of BC’s 2050 Clean BC target for The site is only ~ 1 metre above current sea-level. Won't flooding due to sea-level rise (caused in part by

LNG is classified as a HNS (Hazardous and Noxious substance) cargo rated second only to explosives as a shipping risk by the International Maritime organization (IMO). Prone to equipment malfunction and

Seems that Indigenous Nations are required to say yay/nay on a Project within 90 days of the start (Early Engagement) of a project. That seems awfully short/rushed, when the details of the mitigation needs

There have been many instances of earthquakes caused by hydraulic fracturing and deep-well injection of waste in Canada. Please outline the risks of locating an LNG plant in the area of the Lower Mainland that would be most impacted by a significant seismic event. Japanese LNG import facilities, post-

Radioactivity levels in the gas: What assurances can you give that the fracked gas is not contaminated

I am concerned about investing in continued fossil fuel infrastructure, when it is clear, that around the world , we should be moving onto renewables. How does this fit into Canada's goals of lowering carbon

Fighting a fire at a LNG facility on a waterway (opposite a jet-fuel terminal and near fire-prone Burns Bog, where a fire three Summers ago triggered the complete evacuation of Tilbury Island) requires special equipment, such as foam retardant and fire-boats, of which Richmond and Delta have neither.

Both industry-group SIGTTO (Society of International Gas Tanker and Terminal Operators) and U.S. DHS Regulations strongly argue against locating LNG plants near human populations and/or in narrow inland waterways with significant aircraft, ferry, freighter and recreational traffic. This is a good description of

All LNG plants have tall flares to burn boil-off gases and the impurities in the feed gas. What will/would

Will there be local job opportunities on the project?

The creation of this project will de facto create more shipping (that's the goal!) Will the government be able to consider this increase in shipping with this project, or must it remain separate to the actual
Has consultation with Indigenous Nations already commenced? With what Nations?

The Japanese (who have long experience of earthquakes and are the world's biggest LNG importers) bury their LNG storage tanks so spills or ruptures can't go far. In a seismic zone as prone to liquefaction

Turning LNG tankers (which can only be filled on one side of the vessel) and barges in a busy, narrow river channel will be problematic. SIGTTO recommends a turning circle of at least 5 times the ship's
FortisBC is a regulated utility whose charges to Customers are based on recovering its expenses for service. Building a 5 megatonne LNG plant will cost in excess of $5 Billion. Won't financing for this come out of our (i.e. customers') pockets and raise our heating and food preparation costs through the roof

Describe the public liability insurance arrangements for the LNG carriers /barges which will pass close by heavily-populated areas of Richmond and Delta? (we appreciate that most vessels carry cargo and hull insurance – this is about the public liability coverages, where there is no in-force international insurance

Your Phase 1 expansion was built by Bechtel, a U.S. firm. Do you plan to use local suppliers for the site

The Fraser is a flyway for migrating birds. Several years ago, Canada's only LNG import facility (Canaport in N.B., then owned by Irving Oil), fried several thousand songbirds when they flew into the plant's flare

FortisBC does not have a CER Export license (WesPAc Midstream does). So - who would sell the gas to foreign buyers, and who would collect any offset credits (if and when the Canadian and Asian

Who is represented on the Community Advisory Committee for this project?

GHGs, other air pollutants: What air and water emissions will the plant produce (quantity, frequency,

Why has the BC EAO allowed the proponents to assess the Jetty and the associated impacts of marine

For safety reasons, LNG plants need redundant power inputs. Will BCHydro need to build more power

: Burning 5 million tonnes of LNG will produce at least 14 million tonnes of GHGs. That is more than 100% of BC's legislated 2050 Clean BC target for the whole province. How can this be aligned with the

There are considerable health effects to the increased use of LNG (health impacts of climate change etc)

Why is their no linkage of this Project to the Tilbury LNG Marine Terminal Project currently undergoing an Environmental Assessment. This Project, when combined with the marine terminal will have a far

What are the mitigation plans for the impacts on riparian, water, systems?

You say don't mention export as an objective of your project but your partner Wespac has an export permit for the full 3.5 million tonnes per annum. Why are you down playing the role the LNG export

You are counting LNG exports in the 30by30 plan. But - agreement on international trading of carbon offsets (Article 6 of COP21 in Paris) has not been agreed or ratified by any country. Since when has

Currently, the spot price of LNG in a glutted Asian market is around US $2.10 (averaging less than $6 over the past 5 years), while, according to the Canadian Energy Research Institute (CERI), the full cost of

What parameters does IAAC use in evaluating whether / not to allow a substitution ?

Flare(s): All LNG plants have tall flares to burn boil-off gases and the impurities in the feed gas. What

Appendix Q-8

VIRTUAL OPEN HOUSE PAID ADVERTISEMENT

Community

Rotary makes Joop Van Essen newest Paul Harris Fellow

The Tsawwassen Rotary Club has honored Joop van Essen as a Paul Harris Fellow.

Named for the founder of Rotary, the Paul Harris Fellow can be awarded to Rotarians and non-Rotarians who have demonstrated the values of "Service Above Self."

Club members annually nominate a community member worthy of this recognition, and van Essen was a popular choice.

He has volunteered with the South Delta Food Bank for more than 30 years, and for the past several years has managed the operation.


Joop van Essen

Van Essen was quick to acknowledge the many volunteers who support the food bank in assisting members of the community dealing with short or long-term poverty. Through inspiring and managing volunteers, and with the oversight of the Lighthouse Church, the food bank, under his leadership, operates as a stand-alone operation that is completely volunteer-based and free of administrative overhead.

In the words of Tsawwassen Rotary Club member Henk Veldhuis, "Joop is a person of high morals and character and is a friend and an inspiration."

The presentation was made at the club's regular morning meeting on May 21 that was held via Zoom.

In recognition of his service and to support this worthy cause, Rotarians also donated $500 to the South Delta Food Bank.

South Delta 'Mamas' get help from Rotary

Mamas for Mamas South Delta has received an $8,000 donation from a pair of local organizations.

Funding of $4,000 comes from the Rotary Club of Ladner, which resonated with Mamas for Mamas' vision that no mother or caregiver, or child, is left behind, especially during this even more challenging period of COVID-19 restrictions.

Ladner Rotary expanded its donation by attracting matching funds of $4,000 from the Delta Foundation, the community foundation for Delta. Funding for this community relief program came from the Vancouver Foundation.

Mamas for Mamas South Delta is a non-profit that supports mothers in a variety of ways, including filling the gaps in resources.

The donation will help with groceries, diapers, formula, counselling and the part-time, temporary hiring of somebody to deliver and pick up.

Mamas for Mamas South Delta started a year ago with the help of a Neighbourhood Small Grant of $500 from the Delta Foundation.

Tilbury Phase 2 LNG Expansion Project

Public Comment Period & Virtual Open Houses

FortisBC Holdings Inc. is proposing to expand its existing Tilbury LNG Project, a liquefied natural gas (LNG) storage and production facility located on Tilbury Island, in Delta, British Columbia. As proposed, the Tilbury Phase 2 LNG Expansion Project would increase the facility's LNG production capacity by more than 50%, up to 13,700 tonnes of LNG per day for an operational life of at least 40 years. The expansion would allow for a total storage capacity of up to 208,000 cubic metres of LNG and include an additional storage tank and liquefaction facilities.

The Impact Assessment Agency of Canada (the Agency) and British Columbia's Environmental Assessment Office (EAO) have accepted an initial project description for the proposed project, which is subject to both the federal *Impact Assessment Act* and *British Columbia's Environmental Assessment Act*. The Agency and the EAO are working cooperatively for the initial phase of the project's review.

The unique circumstances arising from COVID-19 have presented challenges to the usual approaches of undertaking meaningful public engagement and Indigenous consultation. The Agency and the EAO continue to assess the situation with key participants, adjust consultation and engagement activities, and provide flexibility as needed in order to prioritize the health and safety of all Canadians.

Comments Invited
As part of the cooperative project review process, the Agency and the EAO are inviting the public and Indigenous groups to review the initial project description and provide feedback related to the proposed project. A summary of the document in English or French is also available on the Agency's website at canada.ca/iaac.

Comments received will support the Agency and the EAO in the preparation of a joint Summary of Issues and Engagement for the project. Once completed, the joint Summary of Issues and Engagement will be provided to FortisBC Holdings Inc. to inform the next steps in the process.

Comments only need to be submitted once to either the Agency or the EAO to be considered in both the provincial and federal review processes and may be submitted in either official language. Comments can be submitted online by visiting the project home page on the Canadian Impact Assessment Registry (reference number 80496), or by visiting the EAO's website at projects.eao.gov.bc.ca. Comments received by the Agency and the EAO are considered public and will be published online.

The comment period has been extended to 45 days and will take place **from June 1st to midnight Pacific Daylight Time (PDT) on July 16, 2020**.

Virtual Open Houses
Due to COVID-19 and the associated physical distancing and self-isolation measures, the Agency and EAO will host virtual open houses on June 18, 2020 from 4:00 p.m. to 5:30 p.m. PDT, and June 23, 2020 from 5:30 p.m. to 7:00 p.m. PDT.

The virtual open houses will include presentations on the federal and provincial review processes, a presentation by FortisBC Holdings Inc. on the Tilbury Phase 2 LNG Expansion Project, and opportunities to ask questions online or by telephone. Instructions and hyperlinks to join the online meetings will be found on the EAO's project page website (projects.eao.gov.bc.ca). Participants who prefer to only listen by phone can dial 1-833-968-1918 and use conference ID number 5057416 (June 18) or 6887462 (June 23). The presentations will be recorded and made available online.

Substitution Request
In addition, the Government of British Columbia has requested that the conduct of the federal impact assessment process be substituted to the province. This means if federal and provincial assessments are both required, and the federal Minister of Environment and Climate Change decides that the provincial process is an appropriate substitute for the federal process, the provincial government would conduct the impact assessment of the project on behalf of the Agency, fulfilling the requirements of both the federal *Impact Assessment Act* and *British Columbia's Environmental Assessment Act*.

The Agency is also seeking comments from the public and Indigenous groups on this request.

Additional Details
For more information on the project, the federal review process and alternative means of submitting comments to the Agency, visit canada.ca/iaac. For more information on the provincial review process visit gov.bc.ca/eao.

BRITISH COLUMBIA Canada

Appendix Q-9

STAKEHOLDER NOTIFICATION EMAIL, APRIL 1, 2020

Tilbury Phase 2 Expansion: EAO Early Engagement Timeline Extension Email

Subject: FortisBC Tilbury Phase 2 LNG Expansion Project engagement timeline extended

Hello,

I'm following up on my February 27th email, where I informed you that FortisBC had filed an Initial Project Description with the Impact Assessment Agency of Canada and the B.C. Environmental Assessment Office to begin the assessment process for the Tilbury Phase 2 LNG Expansion Project.

In light of the COVID-19 pandemic, we have asked the Environmental Assessment Office to extend the Early Engagement phase for the Expansion Project from 90 days to 120 days. At the same time, we asked the Impact Assessment Agency of Canada to suspend its timeline on the Project. This will allow more time to ensure meaningful engagement with the public, stakeholders and Indigenous groups.

I will keep you informed if there are any further extensions or if the public comment period is about to get under way. In the meantime, I welcome the opportunity to share more about the Tilbury Phase 2 LNG Expansion Project with you by email or conference call. Please let me know if you have any questions or would like any more information.

Best regards,

Appendix Q-10

STAKEHOLDER NOTIFICATION EMAIL, JUNE 1, 2020

Tilbury Phase 2 Expansion: EAO Early Engagement Re-starting

Subject: FortisBC Tilbury Phase 2 LNG Expansion Project engagement re-starting June 1

Hello,

I'm following up on my April 1st email, where I informed you that FortisBC's Tilbury Phase 2 LNG Expansion Project engagement timeline was extended by the B.C. Environmental Assessment Office, and at the same time, it was suspended by the Impact Assessment Agency of Canada. The purpose of the pause was to allow more time to ensure meaningful engagement with the public, stakeholders and Indigenous groups in light of the COVID-19 pandemic.

I am happy to announce the re-start of both regulated timelines, with the 45-day public comment period beginning on June 1, and concluding on July 16. During the public comment period, you can provide your feedback on the project on the EAO's website, and I encourage you to learn more about the project on our website TalkingEnergy.ca. In addition, there will be two virtual open houses held, and participation details will be posted on the EAO's website in the coming days:

- Thursday, June 18 from 4:30pm - 6pm
- Tuesday, June 23 from 5:30pm - 7pm

Additionally, as a regulated utility, our projects are also reviewed and approved by the British Columbia Utilities Commission. FortisBC is planning to apply for a Certificate of Public Convenience and Necessity (CPCN). We are hoping to submit this CPCN to the Commission in August 2020. If the project is approved, construction could begin as early as 2022 and be complete by 2028.

In the meantime, we would welcome the opportunity to share more about the Tilbury Phase 2 LNG Expansion Project with you by email or conference call at your convenience. Please let me know if you have any questions or would like any more information.

Best regards,

Appendix Q-11

CITY OF DELTA PRESENTATION

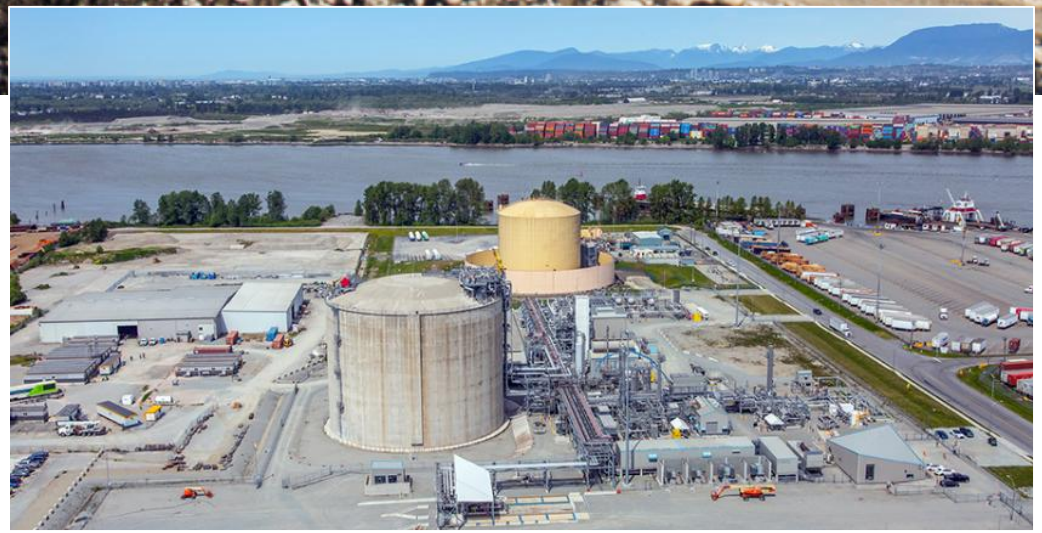
Tilbury LNG Expansion Project

July 22, 2020

Energy at work

FORTISBC™

Tilbury past and present



- In operation since 1971
- Storage and liquefaction expansion commissioned in 2018

Tilbury LNG expansion opportunities

Grow marine LNG

Improve gas system resiliency

Facilitate LNG exports

Tilbury Expansion Project rendering

Tilbury LNG expansion components

Liquefaction unit
0.25 MTPA

Storage tank
up to 1.1 petajoules

Phase 1 in service

Marine jetty

Liquefaction unit
up to 0.65 MTPA

Gas line upgrade
1-3 km

Power line
6 km

Phase 1 in environmental assessment

Phase 1 in development

Storage tank
up to 4 petajoules

Liquefaction units
up to 3.5 MTPA

Phase 2 in environmental assessment

Upcoming Requests for the Tilbury LNG Site

1) Warehouse Demolition

2) Export Jetty access

3) Material Offloading Facility (crossing the flood dike)

4) Hopcott Road proposal

5) Water Lot Rezoning (post Wespac EAC and OGC Crown lease execution)

6) Set Back reduction (not on map)

7) Temporary Work Space (not on map)

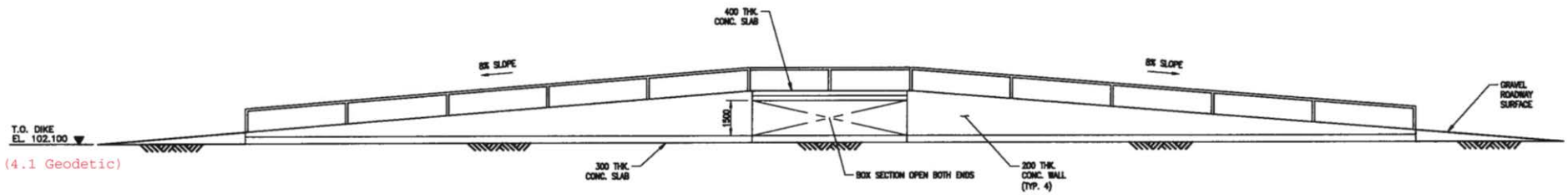
Bunkering Jetty & Easement Crossing (today's focus)

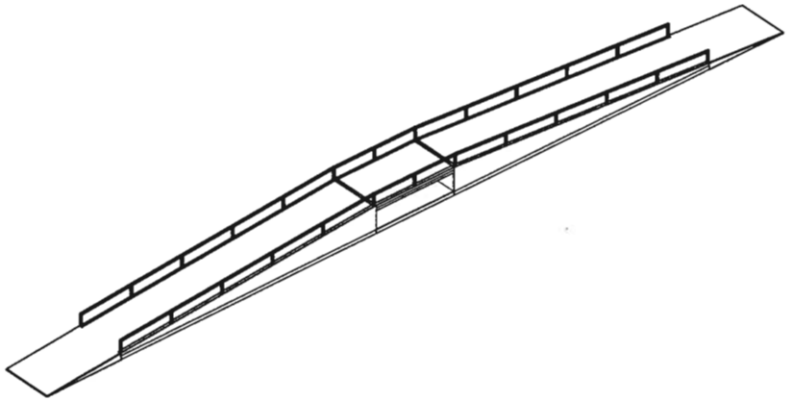
City of Delta & Tilbury Site Interactions

Activity	Start Engagement	Inputs Required	Details
Flood Barrier Crossing	Now	Engineering & Construction Plans	3 crossings are required, a Haul Road and 2 cyro/return lines
Development Set Back Reduction	6 to 9 months	QRA, advanced site layout	A reduction from 30 m to 7.5 m increases developable land by ~9 acres
Water Lot Rezoning	~9 months	EAC, Crown Water Lot Lease	Expecting lease in Q1, 2021
Temporary Work Space	12+ months	QRA, Engineering & Construction Plans	Start conversations in Q3, 2021
Hopcott Road	TBD	QRA, Engineering & Construction Plans	This municipal land is of interest to the Tilbury LNG Development; a proposal is being prepared.
Municipal Permits	Ongoing to 2028	Engineering & Construction Plans	Many permits will be required; examples include Demolition Permit (Warehouse), Building Permit (all developments), Electrical, etc.

Tilbury Bunkering – Dike Crossing
(Preliminary)

Preliminary Elevation Plan

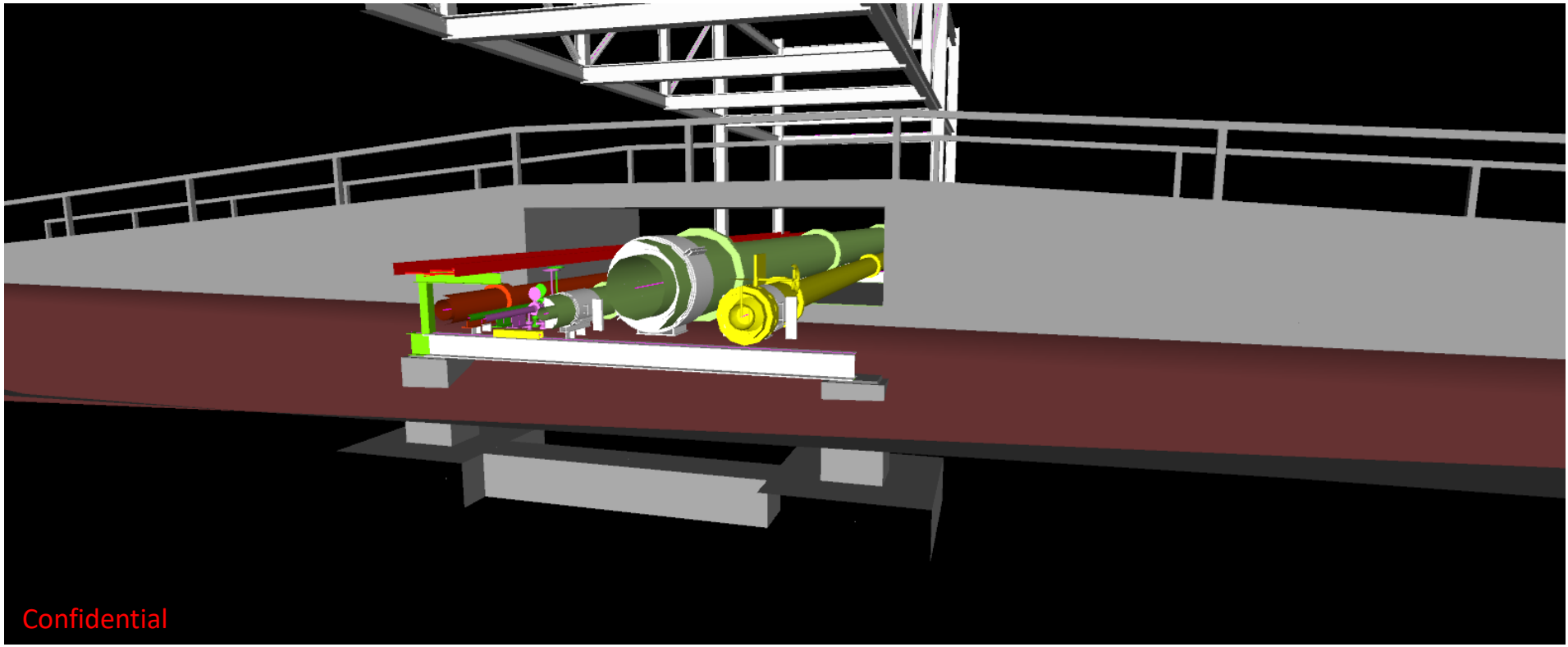




Confidential

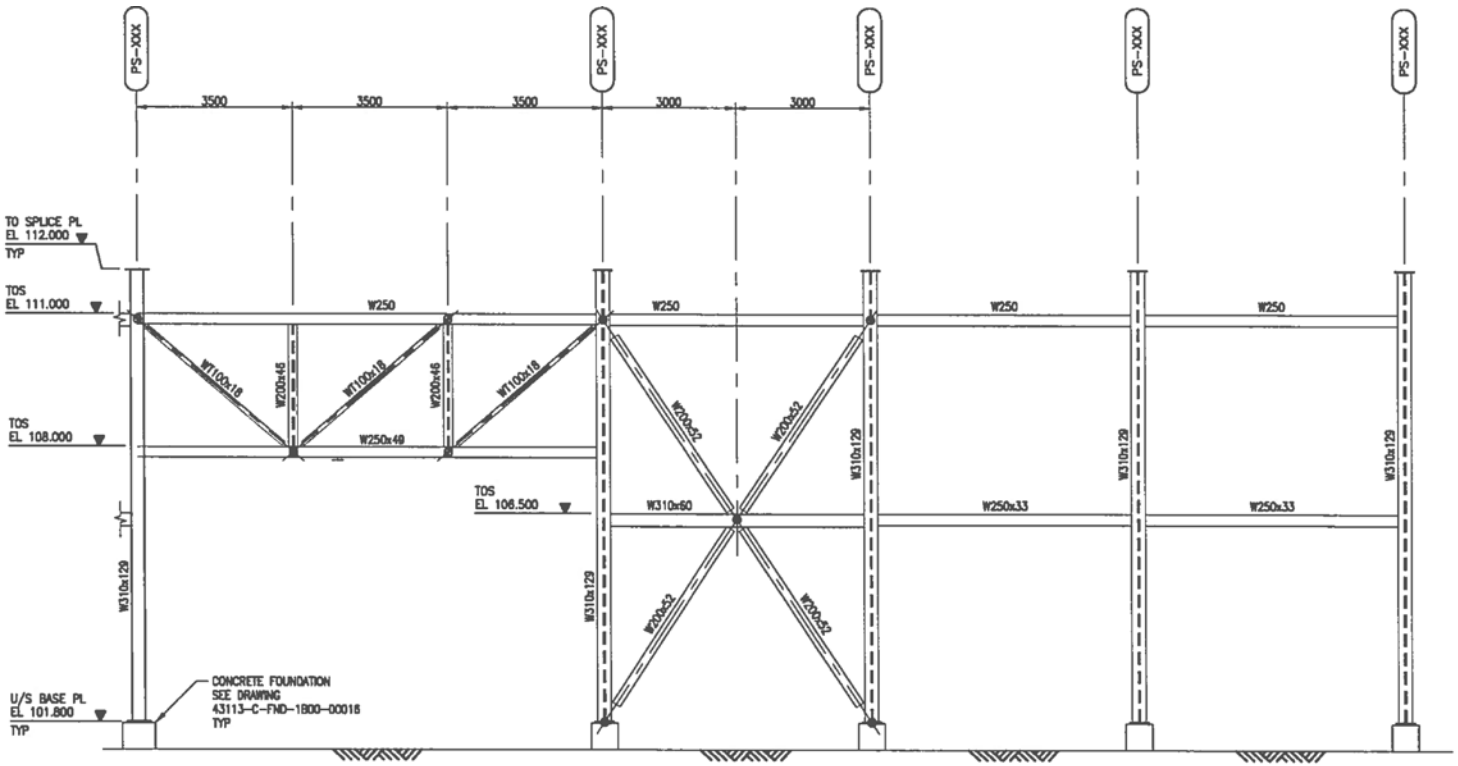
Tilbury Bunkering – Dike Crossing
(Preliminary)

3D Model view



Tilbury Bunkering – Dike Crossing
(Preliminary)

Pipe Rack Bridge to Property Boundary



ELEVATION AT GL 'A' AND 'B'
(LOOKING NORTH)

Confidential

Tilbury LNG Infrastructure: Public Access & Public Safety

Open Discussion

Go Forward

- Next steps
- Feedback requested
- Desired outcomes from each party

Thank you

Energy at work FORTIS BC™

Find FortisBC at:

Fortisbc.com

604-676-7000

Tilbury phone line: 604-576-7133

Email: Tilbury.info@FortisBC.com

Appendix Q-12

DELTA CHAMBER OF COMMERCE LETTER OF SUPPORT

Delta Chamber of Commerce
VOICE OF BUSINESS

July 16th, 2020

Tanner May-Poole
Project Assessment Officer
Environmental Assessment Office
Government of British Columbia
778-698-9185 | Email: Tanner.MayPoole@gov.bc.ca

Re: Letter of Support for the FortisBC Tilbury LNG Phase 2 Expansion Project

Dear Tanner,

Thank you for the opportunity to provide input in the Early Engagement phase of the Environmental Assessment process. The Delta Chamber of Commerce, which represents member businesses across the service, retail, industrial, fishing and farming sectors, acknowledges the vital roles that our community has in nurturing Canada's trade capability and competitiveness.

As home to Canada's largest container terminal, we understand the importance of meeting current customer needs for cost-effective, low carbon alternative fuels for transportation. We also appreciate the importance of Canada's role in the global economy, in leading the transition away from high carbon-emission fuels to meet new global shipping emissions regulations.

FortisBC's Tilbury Liquid Natural Gas (LNG) plant has been safely operating in the Tilbury Industrial Park of Delta since it was first constructed in 1971 and has been producing LNG for marine customers such as BC Ferries and Seaspan Ferries and storing LNG to meet the energy needs of FortisBC customers here in BC for over a decade.

We know from FortisBC's history of engaging with our community, and from their work in Phase 1, that this project provided direct economic and employment benefits for the people of Delta and neighbouring communities. Since the beginning of construction and through Phase 1, FortisBC has demonstrated a notable commitment to the engagement of local contractors – including 28 companies in Delta alone – and that commitment has generated an estimated $60 million in direct economic benefits. Expanding to Phase 2 could bring significantly greater economic opportunity; not only in the initial construction and over 100 local permanent positions and ongoing community contribution through property taxation, but also for our region as a marine LNG hub more ships switch to LNG for fuel as a lower-carbon alternative.

We also note that the construction involved with Phase 2 of the project would result in the decommissioning of the old tank. This would result in not only larger capacity, but also improved safety measures incorporated into the build design. We highlight that this is a 50-year old brownfield, and that the construction work is to be completed within the existing footprint of that site.

Finally, and critically, we want to emphasize that FortisBC has a solid history of safe operations at its Tilbury LNG plant. As noted in the recent City of Delta Staff Report to Mayor and Council, FortisBC and Delta Fire and Emergency Services have a long-standing relationship related to the Tilbury LNG facility dating back to when the facility was first constructed in 1971, which "has included regular reviews of FortisBC's Fire Safety Plan for the site over the years as the facility has evolved and ongoing participation in emergency exercises."[1] As noted in the report, there have been no major incidents and FortisBC will be actively consulting with Delta Fire and Emergency Services throughout the Environmental Assessment Process for the Phase 2 Expansion project.

As a Chamber of Commerce with a long history of representing business Delta, we appreciate the ongoing commitment to safety and shared value for community that FortisBC has expressed in its operations at the Tilbury LNG plant and support its application to move to newer, even safer facilities; and its desire to find an opportunity to be a part of the transition to a cleaner, lower-emission fuel source as the marine and transportation industry moves towards alternatives in the future.

We look forward to continuing to engage on this project.

Sincerely,

Yvonne Anderson
Chair, Board of Directors
Delta Chamber of Commerce

cc: Board of Directors - Delta Chamber of Commerce
Courtney Hodson, Community Relations Manager - FortisBC
Garry Shearer, Executive Director – Delta Chamber of Commerce

[1] https://delta.civicweb.net/document/197474

Appendix R

INDIGENOUS CONSULTATION

Appendix R-1

FEI STATEMENT OF INDIGENOUS PRINCIPLES

Statement of Indigenous Principles

FortisBC is committed to building effective Indigenous relationships and to ensuring we have the structure, resources and skills necessary to maintain these relationships.

To meet this commitment, the actions of the company and its employees will be guided by the following principles:

- FortisBC companies acknowledge, respect and understand that Indigenous Peoples have unique histories, cultures, protocols, values, beliefs and governments.
- FortisBC supports fair and equal access to employment and business opportunities within FortisBC companies for Indigenous Peoples.
- FortisBC will develop fair, accessible employment practices and plans that ensure Indigenous Peoples are considered fairly for employment opportunities within FortisBC.
- FortisBC will strive to attract Indigenous employees, consultants and contractors and business partnerships.
- FortisBC is committed to dialogue through clear and open communication with Indigenous communities on an ongoing and timely basis for the mutual interest and benefit of both parties.
- FortisBC encourages awareness and understanding of Indigenous issues within its work force, industry and communities where it operates.
- To achieve better understanding and appreciation of Indigenous culture, values and beliefs, FortisBC is committed to educating its employees regarding Indigenous issues, interests and goals.
- FortisBC will ensure that when interacting with Indigenous Peoples, its employees, consultants and contractors demonstrate respect, and understanding of Indigenous Peoples’ culture, values and beliefs.
- To give effect to these principles, each of FortisBC's business units will develop, in dialogue with Indigenous communities, plans specific to their circumstances.

Appendix R-2

CONSULTATIVE AREAS DATABASE

SOE Report

Report Name: Report
Report Date: Thu Nov 22 23:38:45 PST 2018
Shape Name: unnamed
Adjacency Buffer: This feature was not buffered.

CAD contact information for the area that was queried is displayed below. Note that a single First Nation boundary may have multiple contacts. As a result it is possible for a contact to show up in the list more than once.

Conflicting Features:

Contact Name	
Contact Title	Chief and Council
Contact Organization	Semiahmoo First Nation
Contact Address	16049 Beach Rd
Contact City	Surrey
Contact Province	BC
Contact Postal Code	V3S 9R6
Contact Phone	604-536-3101
Contact Fax	604-536-6116
Contact Email	

Contact Name	
Contact Title	Chief and Council
Contact Organization	Musqueam Nation
Contact Address	6735 Salish Dr
Contact City	Vancouver
Contact Province	BC
Contact Postal Code	V6N 4C4
Contact Phone	604-263-3261
Contact Fax	604-263-4212
Contact Email	

Contact Name	
Contact Title	Council
Contact Organization	Sto:lo Tribal Council
Contact Address	#2855 Chowat Road. PO Box 440
Contact City	Agassiz
Contact Province	BC
Contact Postal Code	V0M 1A0
Contact Phone	604-796-0627
Contact Fax	604-796-0643
Contact Email	referrals@peopleoftheriver.com or https://www.stoloconnect.com

Contact Name	
Contact Title	Chief and Council
Contact Organization	Seabird Island Band
Contact Address	PO Box 650
Contact City	Agassiz
Contact Province	BC
Contact Postal Code	V0M 1A0
Contact Phone	604-796-2177

Contact Fax	604-796-3729
Contact Email	

Contact Name	
Contact Title	Referrals Administrator
Contact Organization	Soowahlie First Nation c/o People of the River Referrals Office
Contact Address	Building 10-7201 Vedder Road
Contact City	Chilliwack
Contact Province	BC
Contact Postal Code	V2R 4G4
Contact Phone	(604) 824-2420
Contact Fax	(604) 824-0278
Contact Email	referrals@peopleoftheriver.com or https://www.stoloconnect.com

Contact Name	
Contact Title	Referrals Administrator
Contact Organization	Shxw'ow'hamel First Nation c/o People of the River Referrals Office
Contact Address	Building 10-7201 Vedder Road
Contact City	Chilliwack
Contact Province	BC
Contact Postal Code	V2R 4G4
Contact Phone	(604) 824-2420
Contact Fax	(604) 824-0278
Contact Email	referrals@peopleoftheriver.com or https://www.stoloconnect.com

Contact Name	
Contact Title	Referrals Administrator
Contact Organization	Skawahlook First Nation c/o People of the River Referrals Office
Contact Address	Building 10 - 7201 Vedder Road
Contact City	Chilliwack
Contact Province	BC
Contact Postal Code	V2R 4G5
Contact Phone	(604) 824-2420
Contact Fax	(604) 824-0278
Contact Email	referrals@peopleoftheriver.com or https://www.stoloconnect.com

Contact Name	
Contact Title	Council
Contact Organization	Sto:lo Nation
Contact Address	Building 10 - 7201 Vedder Rd
Contact City	Chilliwack
Contact Province	BC
Contact Postal Code	V2R 4G5
Contact Phone	604-858-3366
Contact Fax	604-824-5129
Contact Email	referrals@peopleoftheriver.com or https://www.stoloconnect.com

Contact Name	
Contact Title	Chief and Council
Contact Organization	Katzie First Nation
Contact Address	10946 Katzie Road
Contact City	Pitt Meadows
Contact Province	BC
Contact Postal Code	V3Y 2G6
Contact Phone	604-465-8961
Contact Fax	604-465-5949
Contact Email	

Contact Name	
Contact Title	Chief and Council
Contact Organization	Halalt First Nation
Contact Address	7973 Chemainus Road
Contact City	Chemainus
Contact Province	BC
Contact Postal Code	V0R 1K5
Contact Phone	250-246-4736
Contact Fax	250-246-2330
Contact Email	manager@halalt.org

Contact Name	
Contact Title	Chief and Council
Contact Organization	Stz'uminus First Nation
Contact Address	12611A Trans Canada Hwy
Contact City	Ladysmith
Contact Province	BC
Contact Postal Code	V9G 1M5
Contact Phone	250-245-7155
Contact Fax	250-245-3012
Contact Email	

Contact Name	Tracy Fleming
Contact Title	Referrals Coordinator
Contact Organization	Cowichan Tribes
Contact Address	5760 Allenby Road
Contact City	Duncan
Contact Province	BC
Contact Postal Code	V9L 5J1
Contact Phone	250 748 3196 358
Contact Fax	250-748-1233
Contact Email	tracy.fleming@cowichantribes.com

Contact Name	
Contact Title	Chief and Council
Contact Organization	Lake Cowichan First Nation
Contact Address	313B Deer Road - PO Box 159
Contact City	Lake Cowichan
Contact Province	BC
Contact Postal Code	V0R 2G0
Contact Phone	250-749-3301
Contact Fax	250-749-4286
Contact Email	carole@lcfn.ca

Contact Name	
Contact Title	Chief and Council
Contact Organization	Lyackson First Nation
Contact Address	7973A Chemainus Road
Contact City	Chemainus
Contact Province	BC
Contact Postal Code	V0R 1K5
Contact Phone	1-888-592-5766
Contact Fax	250-246-5049
Contact Email	reception@lyackson.bc.ca.

Contact Name	
Contact Title	Chief and Council
Contact Organization	Penelakut Tribe

Contact Address	PO Box 360
Contact City	Chemainus
Contact Province	BC
Contact Postal Code	V0R 1K0
Contact Phone	250-246-2321
Contact Fax	250-246-2725
Contact Email	

Contact Name	Andrew Bak
Contact Title	Territory Management Officer
Contact Organization	Tsawwassen First Nation
Contact Address	1926 Tsawwassen Drive
Contact City	Tsawwassen
Contact Province	BC
Contact Postal Code	V4M 4G2
Contact Phone	604-943-2112
Contact Fax	604-943-9226
Contact Email	abak@tsawwassenfirstnation.com

Contact Name	
Contact Title	Chief and Council
Contact Organization	Tsleil-Waututh Nation
Contact Address	3075 Takaya Drive
Contact City	North Vancouver
Contact Province	BC
Contact Postal Code	V7H 3A8
Contact Phone	604-929-3454
Contact Fax	604-929-4714
Contact Email	mlerat@twnation.ca

Layers Queried Successfully:

CAD contact information for the area that was queried is displayed below. Note that a single First Nation boundary may have multiple contacts. As a result it is possible for a contact to show up in the list more than once.

Disclaimer:

The Consultative Areas Database (CAD) Public Map Service Report provides preliminary contact information for First Nations who may have with aboriginal interests identified within the area queried.

These contacts are based on knowledge currently available to the Province. Those choosing to provide information and involve First Nations early in a proposed project have the opportunity to develop mutual understanding of the interests around the project. This can be important to successful business planning and project development. CAD Public Map Service users are encouraged to explore making this contact prior to submitting an application for government authorization. This approach gives support to the Provincial consultation process and the goals of the New Relationship.

The information provided is not intended to create, recognize, limit or deny any aboriginal or treaty rights, including aboriginal title, that First Nations may have, or impose any obligations on the Province or alter the legal status of resources within the Province or the existing legal authority of British Columbia. The Province makes no warranties or representations regarding the

accuracy, timeliness, completeness or fitness for use of any or all data provided in the reports.

Appendix R-3

INDIGENOUS NOTIFICATION LETTER

16705 Fraser Highway
Surrey, B.C. V3L 5R7
Fortisbc.com

June 1, 2020

<Name>
<Address>

Via email: <email address>

Dear <Name>,

RE: PUBLIC COMMENT PERIOD COMMENCING FOR FORTISBC TILBURY PHASE 2 LNG EXPANSION PROJECT

FortisBC would like to update <First Nation> regarding the Tilbury Phase 2 LNG Expansion Project ("Tilbury Project"). FortisBC is proposing to expand LNG storage and LNG production capacity at its existing facility located at 7651 Hopcott Road, on Tilbury Island in the City of Delta.

Environmental Review Process

The Tilbury Project is a reviewable project under the *Environmental Assessment Act* (2018) regulated by the British Columbia Environmental Assessment Office (BCEAO) and the *Impact Assessment Act (2019)* regulated by the Impact Assessment Agency of Canada (IAAC).

The Tilbury Project entered the provincial Early Engagement phase and the federal Planning Phase on February 27, 2020. Due to the COVID-19 pandemic, FortisBC requested two 30-day extensions of this Early Engagement phase bringing the total phase from 90 days to 150. In addition, FortisBC requested two 30-day suspensions of the 180-day Planning Phase. The provincial and federal regulators have decided to commence a 45-day public comment period on June 1, 2020. The feedback received from this comment period will help inform our Detailed Project Description, expected to be filed in late-2020.

Regulated Utility Review Process

As a regulated utility, FortisBC also requires a Certificate of Public Convenience and Necessity (CPCN) from the British Columbia Utilities Commission. We are aiming to submit a CPCN application to the Commission later this year. At that time, we will notify you of additional opportunities to participate in the CPCN process. If the application is approved, we estimate that construction could begin as early as 2022 with projected completion by 2028.

FortisBC recognizes that the Tilbury Project is located within the traditional territory of <First Nation>, and we strongly believe in transparent, meaningful engagement with rights holders such as yourselves. We would like to continue ongoing dialogue with your community as we move forward in this process.

In addition to the comment period, FortisBC would be happy to meet with you at your convenience to discuss comments or questions related to the Tilbury Project prior to the submission of the Detailed Project Description and CPCN application.

Sincerely,

16705 Fraser Highway
Surrey, B.C. V3L 5R7
Fortisbc.com

Olivia Stanley
Indigenous Relations Manager
FortisBC

Appendix S

LIST OF ACRONYMS

Acronym	Definition
ACP	Annual Contracting Plan
AFUDC	Allowance for Funds Used During Construction
AIA	Archaeological Impact Assessment
AIF	Archaeological Information Form
AMI	Advanced Metering Infrastructure
AOA	Archaeological Overview Assessment
APEC	Areas of potential environmental concern
ASL	Average service life
BC EAA	British Columbia Environmental Assessment Act
BC EAO	British Columbia Environmental Assessment Office
Bcf	Billion cubic feet
BCUC	British Columbia Utilities Commission
BOG	Boil-off gas
CAD	Consultative Areas Database
CEA	Clean Energy Act
Clough	Clough Enercore
Concentric	Concentric Advisors, ULC
CPCN	Certificate of Public Convenience and Necessity
CTS	Coastal Transmission System
DBRS	Dominion Bond Rating Service

Acronym	Definition
EAA	British Columbia Environmental Assessment Act
EA	Provincial Environmental Assessment
EMP	Environmental Management Plan
EOA	Environmental Overview Assessment
EOC	Emergency Operations Centre
FEED	Front End Engineering Design
FEI	FortisBC Energy Inc.
FLNRORD	The Ministry of Forests, Lands, Natural Resource and Operations and Rural Development
GBA+	Gender-Based Analysis Plus
GHG	Greenhouse gas
Golder	Golder Associates Ltd.
HCA	Heritage Conservation Act
HCB&I	Horton CB&I
HP	High pressure
IA	Federal Impact Assessment
IAA	Canadian Impact Assessment Act
IAAC	Impact Assessment Agency of Canada
ILI	In-line inspection
Jacobs	Jacobs Consultancy Canada Inc.
LNG	Liquefied Natural Gas
LTGRP	Long Term Gas Resource Plan

Acronym	Definition
MMcf/day	million cubic feet per day
MTO	Material take-off
NEB	National Energy Board.
NWMAA	Northwest Mutual Assistance Agreement
NWP	Northwest Pipeline
NYSE	New York Stock Exchange
OBA	Operational Balancing Agreement
OBE	Operating Basis Earthquake
OGC	British Columbia Oil and Gas Commission
PFR	Preliminary Field Reconnaissance
PIP	Partners in Performance
PSI	Preliminary Site Investigations
PwC	Pricewaterhouse Coopers
SCP	Southern Crossing Pipeline
SMCI	Solaris Management Consultants Inc.
SSE	Safe Shutdown Earthquake
TC Energy	collectively, Nova Gas Transmission, Foothills BC and Gas Transmission Northwest
TIMC	Transmission Integrity Management Capabilities
TLSE Project	Tilbury Liquefied Natural Gas Storage Expansion Project
T-SouthSystem	Westcoast Energy's T-South system
TSX	Toronto Stock Exchange

Acronym	Definition
UCA	Utilities Commission Act
UNDRIP	United Nations Declaration of the Rights of Indigenous People
Validation Estimating	Validation Estimating LLC, USA
VITS	Vancouver Island Transmission System
YPCI	Yohannes Project Consulting Inc.
YVR	Vancouver International Airport

Appendix T

DRAFT ORDERS
AND UNDERTAKING OF CONFIDENTIALITY

Appendix T-1

DRAFT PROCEDURAL ORDER

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
Application for Approval of a Certificate of Public Convenience and Necessity for the
Tilbury Liquefied Natural Gas Storage Expansion Project

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On December 29, 2020, FortisBC Energy Inc. (FEI) submitted an application to the British Columbia Utilities Commission (BCUC) for, among other things, a Certificate of Public Convenience and Necessity (CPCN) pursuant to sections 45 and 46 of the *Utilities Commission Act* (UCA) for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion (TLSE) Project (Application);

B. The TLSE Project includes the following:

   i. Construction and operation of a 3 billion cubic feet (Bcf) LNG storage tank;

   ii. Construction and operation of 800 million cubic feet per day (MMcf/day) of regasification capacity;

   iii. Construction or modification and operation of any of the necessary auxiliary systems, including items such as utility pipe racks, in-tank pumps, piping, and connections to the sendout gas pipeline; and

   iv. Demolition of the above-ground portion of the Tilbury Base Plant LNG storage tank and liquefaction facilities;

C. FEI also seeks BCUC approval, pursuant to sections 59 to 61 of the UCA of the following:

   i. The non-rate base TLSE Application and Preliminary Stage Development Costs deferral account, attracting a weighted average cost of capital return until the account enters rate base. FEI proposes to transfer the balance in the deferral account to rate base on January 1 of the year

following BCUC approval of the Application and commence amortization over a three-year period thereafter;

ii. The non-rate base TLSE FX Mark to Market deferral account, with no financing return, to capture the mark-to-market valuation of any foreign currency forward contracts entered into related to construction of the TLSE Project; and

iii. Depreciation and net salvage rates of 1.67 percent and 0.67 percent, respectively, for the new 3 Bcf LNG storage tank;

D. FEI requests that certain portions of Sections 3 and 4 of the Application and certain Appendices to the Application be held confidential, pursuant to section 18 of the BCUC's Rules of Practice and Procedure established by Order G-15-19. Specifically:

i. Critical system asset information in portions of Sections 3 and 4 and Appendices A and C, and all of Appendix B. Confidentiality is requested on the basis that public disclosure of the information could reasonably be expected to result in harm to the safety of the public, FEI's employees and the assets themselves;

ii. Information relating to FEI's efficient supply portfolio in the 2020/2021 Annual Contracting Plan in portions of Section 4 of the Application and Appendix C, the disclosure of which could reasonably be expected to harm FEI's position in the market;

iii. Information relating to engineering, cost estimates and risk assessments filed as Appendices E, F, G, H, I, J, K, L, M and N, which contain operationally sensitive information pertaining to FEI's assets as well as market-sensitive cost information of the various and specific Project components. Confidentiality is requested on the basis that, if disclosed, the information could impede FEI's ability to work safely and reliably operate its gas system assets. Further, FEI intends to contract the majority of the construction of the Project, and providing potential bidders with this information could reasonably be expected to prejudice FEI's negotiating position when procuring contracts, resulting in higher costs for the Project; and

E. The BCUC has commenced review of the Application and considers that a regulatory timetable should be established.

NOW THEREFORE the BCUC orders as follows:

1. A preliminary regulatory timetable for the review of the Application is established, as set out in Appendix A to this Order.

2. FEI is to publish the Public Notice attached as Appendix B to this Order in display-ad format and in the appropriate local news publications to provide adequate notice to the public in the affected service area, as soon as reasonably possible, but no later than the week of February 8, 2021.

3. In accordance with the BCUC Rules of Practice and Procedure, parties who wish to participate in the proceeding may register with the BCUC by completing a Request to Intervene Form, available on the BCUC's website at http://www.bcuc.com/Registration-Intervener-1.aspx by the date established in the Regulatory Timetable attached as Appendix A to this order and in accordance with the BCUC's Rules of Practice and Procedure adopted by Order G-15-19.

4. Pursuant to Rules 19 and 20 of the BCUC's Rules of Practice and Procedure and on the basis set out in Recital D, the request for confidentiality of the information contained in the following documents filed by FEI is granted:

    a. Critical system asset information in the redacted portions of Sections 3 and 4 and Appendices A and C, and all of Appendix B;

    b. Information relating to FEI's efficient supply portfolio in the 2020/2021 Annual Contracting Plan in the redacted portions of Section 4 and Appendix C; and

    c. Information relating to engineering, cost estimates and risk assessments filed as Appendices E, F, G, H, I, J, K, L, M and N to the Application.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment

FortisBC Energy Inc.
Application for Approval of a Certificate of Public Convenience and Necessity for the Tilbury Liquefied Natural Gas Storage Expansion Project

REGULATORY TIMETABLE

Action	Date (2021)
FEI Publishes Public Notice	Week of February 8
Intervener Registration	Thursday, February 25
Workshop	Thursday, March 11
BCUC and Intervener Information Request No. 1	Thursday, March 25
FEI Response to Information Request No. 1	Monday, April 26
Procedural Conference	Thursday, May 13
Further Process	To be determined

bcuc
British Columbia
Utilities Commission

PUBLIC NOTICE

FortisBC Energy Inc. Application for a Certificate of Public Convenience and Necessity for the Tilbury Liquefied Natural Gas Storage Expansion Project

On December 29, 2020, FortisBC Energy Inc. (FEI) filed an application with the British Columbia Utilities Commission (BCUC) for approval of a Certificate of Public Convenience and Necessity for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion Project (Application). The Project will increase the resiliency of FEI's natural gas delivery system by improving FEI's ability to maintain continuity of service to customers in the event of a disruption in the supply of natural gas to FEI's system. The Application seeks to construct and operate a new LNG storage tank and regasification system on FEI's existing Tilbury site located on Tilbury Island, Delta, BC.

To provide your insights, thoughts and perspectives on the Application, submit a letter of comment, request intervener status or register as an interested party at www.bcuc.com/get-involved. All submissions will be posted on www.bcuc.com and will be considered by the Panel in its review of the Application.

HOW TO PARTICIPATE

- **Request intervener status**
- **Submit a letter of comment**
- **Register as an interested party**

IMPORTANT DATES

1. **February 25, 2021** – Deadline to register as an intervener with the BCUC.

For more information on how to participate, please visit our website (**www.bcuc.com/get-involved**) or contact us at the information below.

GET MORE INFORMATION

FortisBC Energy Inc. Regulatory Affairs

16705 Fraser Highway
Surrey, BC Canada V4N 0E8

E: gas.regulatory.affairs@fortisbc.com

P: 604.592.7664

British Columbia Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3

E: Commission.Secretary@bcuc.com

P: 604.660.4700

Appendix T-2

DRAFT ORDER

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

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ORDER NUMBER
C-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
Application for Approval of a Certificate of Public Convenience and Necessity for the
Tilbury Liquefied Natural Gas Storage Expansion Project

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On December 29, 2020, FortisBC Energy Inc. (FEI) submitted an application to the British Columbia Utilities Commission (BCUC) for, among other things, a Certificate of Public Convenience and Necessity (CPCN) pursuant to sections 45 and 46 of the *Utilities Commission Act* (UCA) for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion (TLSE) Project (Application);

B. The TLSE Project includes the following:

   i. Construction and operation of a 3 billion cubic feet (Bcf) LNG storage tank;

   ii. Construction and operation of 800 million cubic feet per day (MMcf/day) of regasification capacity;

   iii. Construction or modification and operation of any of the necessary auxiliary systems, including items such as utility pipe racks, in-tank pumps, piping, and connections to the sendout gas pipeline; and

   iv. Demolition of the above-ground portion of the Tilbury Base Plant LNG storage tank and liquefaction facilities;

C. FEI also seeks BCUC approval, pursuant to sections 59 to 61 of the UCA of the following:

   i. The non-rate base TLSE Application and Preliminary Stage Development Costs deferral account, attracting a weighted average cost of capital return until the account enters rate base. FEI proposes to transfer the balance in the deferral account to rate base on January 1 of the year

following BCUC approval of the Application and commence amortization over a three-year period thereafter;

ii. The non-rate base TLSE FX Mark to Market deferral account, with no financing return, to capture the mark-to-market valuation of any foreign currency forward contracts entered into related to construction of the TLSE Project; and

iii. Depreciation and net salvage rates of 1.67 percent and 0.67 percent, respectively, for the new 3 Bcf LNG storage tank;

D. By Order G-XX-21 dated ###, the BCUC established a preliminary regulatory timetable for the review of the Application which consisted of intervener registration, a workshop and one round of information requests (IRs), followed by a procedural conference;

E. By Order G-##-21 dated ###, the BCUC established the remainder of the regulatory timetable; and

F. The BCUC has reviewed the evidence in this proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 45, 46 and 59 to 61 of the UCA, the BCUC orders as follows:

1. A CPCN is granted to FEI for the Tilbury LNG Storage Expansion Project as described in the Application.

2. FEI is approved to establish the non-rate base TLSE Application and Preliminary Stage Development Costs deferral account, attracting a weighted average cost of capital return until the account enters rate base. FEI is also approved to transfer the balance in the deferral account to rate base on January 1 of the year following the date of this Decision and commence amortization over a three-year period thereafter.

3. FEI is approved to establish the non-rate base TLSE FX Mark to Market deferral account, with no financing return, to capture the mark-to-market valuation of any foreign currency forward contracts entered into related to construction of the TLSE Project.

4. FEI is approved to depreciate the new 3 Bcf LNG storage tank at 1.67 percent.

5. A net salvage rate of 0.67 percent is approved for the new 3 Bcf LNG storage tank.

6. FEI is directed to file with the BCUC the following reports:

    a. Within 30 days of the finalization of the construction contract, a Contract Finalization Report;

    b. Within 30 days of the end of each quarterly reporting period, starting after the submission of the Contract Finalization Report and ending upon the filing of the Final Report, Quarterly Progress Reports;

    c. As soon as practicable but no longer than 30 days upon the identification of a material change including any significant delays or material cost variances, a Material Change Report (which may be filed as part of the Quarterly Progress Report where time permits); and

    d. Within six months of the final in-service date, a Final Report.

7. The BCUC will continue to hold the redacted portions of the Application and appendices listed in the Application cover letter as confidential.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment (Yes? No?)

Appendix T-3

CONFIDENTIALITY DECLARATION AND UNDERTAKING FORM

Confidentiality Declaration and Undertaking Form

In accordance with the British Columbia Utilities Commission (BCUC) Rules of Practice and Procedure, please provide a completed form to the party who filed the confidential document and copy Commission Secretary at commission.secretary@bcuc.com. If email is unavailable, please mail the form to the address above.

Undertaking

I, _____, am representing the party_____ in the matter of FEI Application for a Certificate of Public Convenience and Necessity for the Tilbury Liquefied Natural Gas Storage Facility Expansion Project.

In this capacity, I request access to the confidential information in the record of this proceeding. I understand that the execution of this undertaking is a condition of an Order of the BCUC, and the BCUC may enforce this Undertaking pursuant to the provisions of the *Administrative Tribunal Act*.

Description of document:	Documents filed confidentially in the proceeding, in unredacted form.

I hereby undertake:

(a) to use the information disclosed under the conditions of the Undertaking exclusively for duties performed in respect of this proceeding;

(b) not to divulge information disclosed under the conditions of this Undertaking except to a person granted access to such information or to staff of the BCUC;

(c) not to reproduce, in any manner, information disclosed under the conditions of this Undertaking except for purposes of the proceeding;

(d) to keep confidential and to safeguard and protect the information disclosed under the conditions of this Undertaking;

(e) to return to the applicant, _FortisBC Energy Inc._, all documents and materials containing information disclosed under the conditions of this Undertaking, including notes and memoranda based on such information, or to destroy such documents and materials within fourteen (14) days of the BCUC's final decision in the proceeding; and

(f) to report promptly to the BCUC any violation of this Undertaking.

Signed at _____ this _____day of_____, 202__.

Signature: _____

Name (please print): _____

Representing (if applicable): _____