8. Climate Change and Greenhouse Gas Emissions

The following subsections of the Application describe the meteorological environment, climate change resilience, GHG emissions, and carbon sinks for the proposed Project. In addition, these subsections describe the potential effects on federal emissions reduction efforts and global GHG emissions, mitigation measures, and the proposed Project's plan to achieve net zero.

The proposed Project temporal boundaries are as follows:

- Construction phase – Estimated 3- to 6-year duration
- Operation phase – Estimated 40+-year duration
- Decommissioning phase – Estimated 2-year duration

Construction is planned to commence as early as 2027+, with an anticipated proposed Project in-service date of 2030+. A detailed proposed Project schedule is outlined in subsection 1.5.1 (Schedule).

The information presented follows the guidelines outlined in the SACC (ECCC 2020).

8.1 Meteorological Environment

The following is a summary of the existing and future conditions of the meteorological environment, focusing on the local and regional climate. Detailed information on these conditions is provided in the CCRA (Appendix G of the Application).

8.1.1 Climate Methods and Scenarios

The CCRA establishes the existing conditions as the "current" climate using available data and climate parameters from the past 5 to 30 years. The future conditions, or projected future climate, consider the expected service life of the proposed Project and therefore look out to the 2050s using the World Meteorological Organization (2022) 30-year standard reference period spanning from 2035 to 2065.

Global climate modelling uses various GHG emissions scenarios, known as Representative Concentration Pathways (RCPs), to project how future climate will behave under different concentrations and rates of GHGs released to the atmosphere (based on 2005 emission levels), as well as different global energy balances depending on socio-economic choices and global mitigation efforts in the coming years. RCPs are based on different assumptions about population, economic growth, energy consumption and sources, and land use over this century. RCPs are established by the Intergovernmental Panel on Climate Change (IPCC), which was established in 1988 by the World Meteorological Organization and United Nations Environment Program to provide policymakers with regular assessments of the scientific basis of climate change, its potential effects and future risks, and options for adaptation and mitigation (IPCC 2014).

The IPCC has established four GHG emissions scenarios based on RCPs by the year 2100:

- RCP 8.5 – emissions continue to rise throughout the twenty-first century with limited measures applied to mitigate emissions output. This is the "business as usual or worst case" scenario.
- RCP 6.0 – an intermediate scenario with medium emission mitigation measures. GHG emissions peak in 2080 and then stabilize after 2100.

- RCP 4.5 – an intermediate scenario with medium to high emission mitigation measures. Emissions peak in 2040 then decline by 2045 to reach 50 percent of 2050 levels after 2100.
- RCP 2.6 – lowest GHG emissions scenario where CO_2 emission decline in 2020 and go to zero by 2100.

Current global estimates reflect the RCP 8.5 emission scenario (which is the most conservative scenario), where limited emission reduction action is taken to reduce CO_2 during the 21st century. The proposed Project CCRA study is based the climate projections on RCP 8.5. The use of a second forcing scenario (RCP 4.5) was considered; however, the RCP 4.5 and RCP 8.5 scenarios produced similar projections for the parameters of interest. Therefore, the CCRA is based only on the projections estimated under the RCP 8.5 worst case scenario.

8.1.2 Meteorological Data

In addition to climate data used in the CCRA, hourly historical climate information was obtained for January 1, 2022, to May 31, 2023 (Government of Canada n.d.a). Data was obtained from the Delta Burns Bog station located at 49°07'33.053" North, 123°00'08.085" West. The station climate ID is 1102415, the World Meteorological Organization (WMO) ID is 71042, and the TC ID is VBB. The following attributes were obtained:

- Dew point temperature
- Relative humidity
- Precipitation amount
- Wind direction
- Wind speed
- Visibility
- Station pressure
- Humidex
- Wind chill

For purposes of this summary, air temperature, precipitation, wind speed, and direction are shown. Air temperature from January 1, 2022, to May 31, 2023, had an average value of 9°C, a maximum of 33°C, and a minimum of -14°C. The maximum hourly precipitation was 9 mm, and the total precipitation from January 1, 2022, to May 31, 2023, was 1,464 mm. Figure 8.1-1 illustrates precipitation and temperature.

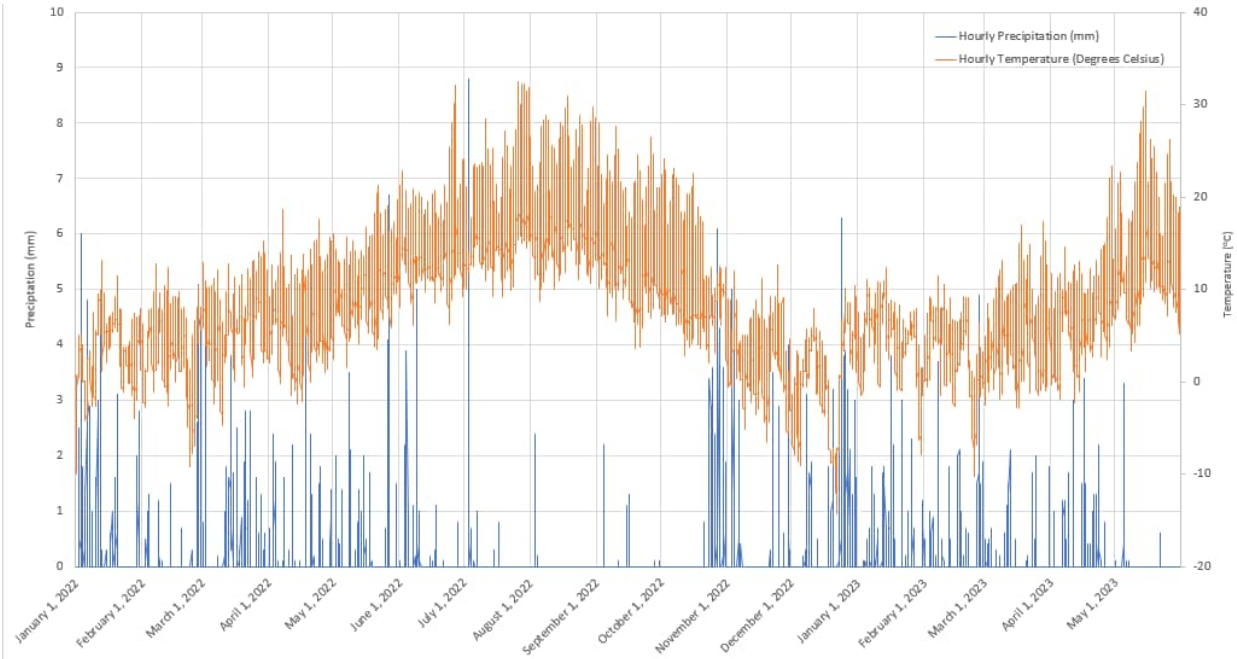


Figure 8.1-1. Precipitation and Temperature at the Delta Burns Bog Station from January 1, 2022, to May 31, 2023

Wind speeds during the same time period ranged from no wind to a gentle breeze, with an average of 0.6 m/s. Wind direction varied throughout the year but blew from an easterly direction 19 percent of the time (11 percent east, 7 percent east-southeast, 1 percent east-northeast) and a northern direction 16 percent of the time (13 percent north, 2 percent north-northeast, 1 percent north-northwest), and slightly less frequently from a southern and westerly direction. Figure 8.1-2 illustrates wind speed and direction.

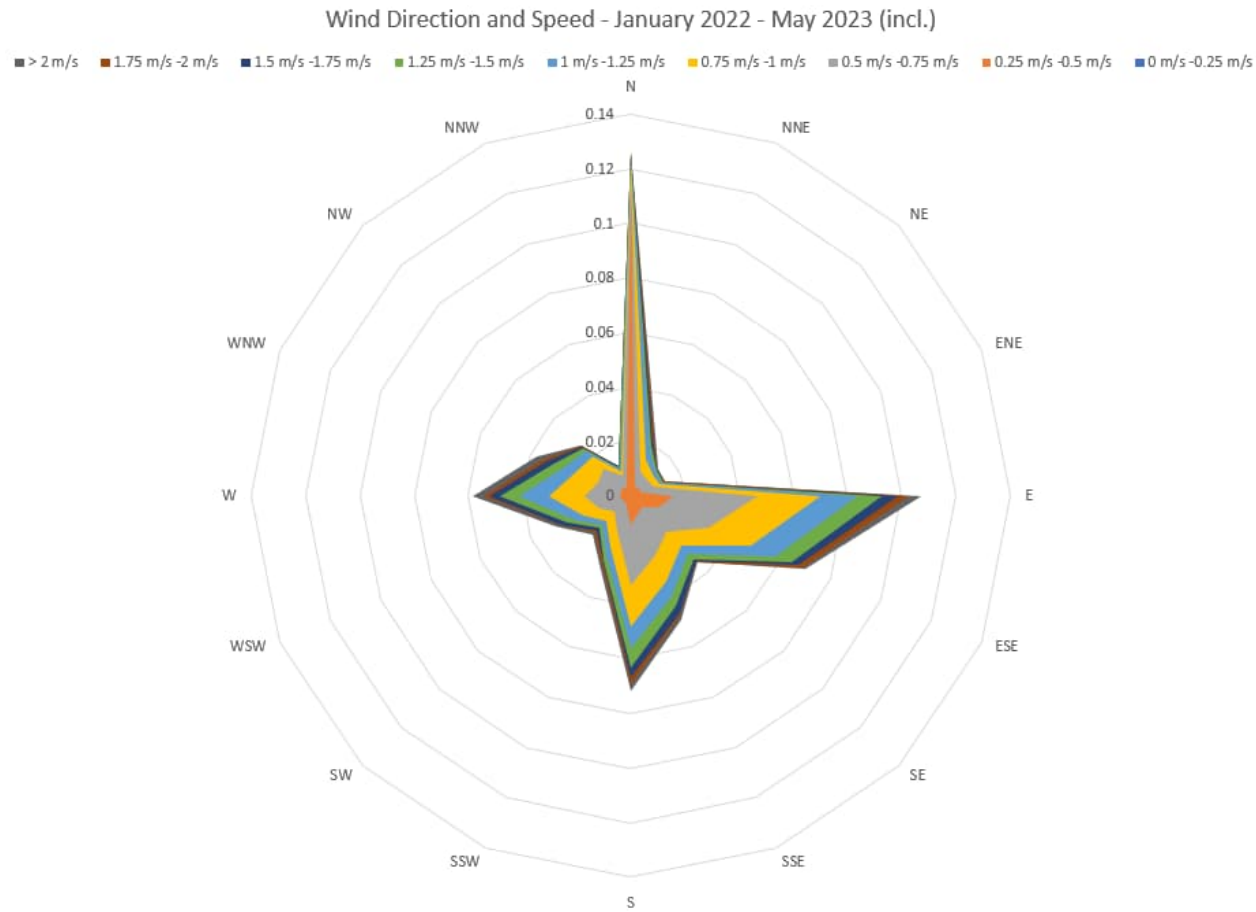


Figure 8.1-2. Wind Speed and Direction at the Delta Burns Bog Station

8.1.3 Climate Hazards

Climate parameters and their respective thresholds were selected based on input from FortisBC. Interviews were conducted with staff to identify meteorological events that have or could have potential effects on the proposed Project components under assessment. These events include those that could cause physical damage to the proposed Project components or result in additional operational and maintenance requirements. Examples of such requirements include increased inspection frequency, temporary closures, equipment shutdowns to restore services, and potential effects on the capacity or functionality of equipment. The selected climate parameters and thresholds aim to capture the relevant climatic conditions that could affect the resilience and performance of the assessed proposed Project components (Table 8.1-1). The total precipitation (subsection A.3 of the CCRA); mean, maximum, and minimum temperatures (subsection A.4 of the CCRA); and extreme wind events (subsection A.5 of the CCRA) can be found in the CCRA (Appendix G of the Application).

Table 8.1-1. Climate Parameters Selected for Resilience Assessment up to 2050s Time Horizon

Climate Parameter	Threshold	Trend	Remarks
Temperature			
Heat wave	Three or more consecutive days when Tmax is equal to or greater than 30°C	Increase	ECCC data (ECCC 2021) indicate events per year for the time frame of 1981 to 2010 (0.05 day per year when daily Tmax was greater than 30°C). Available data indicate these events will increase to 4.2 events per year by the 2050s (ECCC 2021).
Extreme (heat) maximum daily temperature	▪ Number of days when Tmax equals, or exceeds, 32°C ▪ The absolute maximum temperature threshold in the Tilbury Site Data report (FortisBC 2021) is 32.8°C	Increase	This type of event has not occurred at Tilbury Island between 1985 to 2015 (baseline years). In June 2021, the absolute maximum temperature threshold of 32.8°C was reached at the existing Tilbury facility. No effect to operation were recorded. Available data indicate this type of event may occur approximately twice a year in the 2050s (ECCC 2021). The number of days per year with maximum temperatures warmer than 32°C will increase from 0 day in 2025 to 18 days in 2085 (ECCC 2021).
Extreme (cold) minimum daily temperature	▪ Number of days when the minimum daily temperature is cooler than −10°C ▪ The absolute minimum temperature threshold in the Tilbury Site Data (FortisBC 2021) is −12.9°C	Decrease	Available data show temperatures cooler than −10°C have occurred an average of approximately once every 2 years from 1985 to 2015 and are not likely to occur in the 2050s (ECCC 2021).
Changes in seasonal temperature	CDD to exceed 200	Increase	Available data indicate an average CDD of 69 for the 1985 to 2015 period, increasing by a factor of 3.5 to an average of 243 in the 2050s (ECCC 2021).

Table 8.1-1. Climate Parameters Selected for Resilience Assessment up to 2050s Time Horizon

Climate Parameter	Threshold	Trend	Remarks
Precipitation			
Short duration, high intensity-rainfall (events causing local flooding)	▪ Rainfall events that result in greater than, or equal to, 100 mm of rain in 12 hours ▪ Threshold based on rainfall experienced in October 2003 event (Stantec 2018)	Increase	Available data indicate that in the current climate, a rain event resulting in equal to, or greater than, 100 mm of rain in 12 hours has a return period greater than 1:100. The analysis of the available data indicates these events will likely increase in the future by approximately 1:25 event (refer to CCRA [Appendix G of the Application]). The October 2003 rainstorm event produced 195.2 mm of rain in 24 hours in North Delta, B.C. (Stantec 2018). In November 2021, a rainstorm event produced 99.9 mm in 24 hours (ECCC n.d.). FortisBC reported no effects at the existing Tilbury facility from these events. The trend for total precipitation is expected to increase from a median of 1, 172 mm per year in 2025 to 1, 259 mm per year in 2055 (ECCC 2021).
Wind			
Increase in wind speed	▪ Days or events with wind gusts greater than 90 km/hr ▪ Threshold based on reference wind of 95 km/hr (26.4 m/s) in the Tilbury Site Data (FortisBC 2021) and the occurrence of past events in the greater Vancouver, B.C., area in which gusts of more than 90 km/hr caused damages to buildings and natural assets (such as the wind events of 2006 and 2015) (ECCC 2021)	No change	The maximum gust recorded at the weather station near Tilbury (ECCC Delta Burns Bog station) was 64 km/hr, with one event greater than 60 km/hr and five events greater than 50 km/hr (ECCC 2021; data only available from 2011 to 2021). It therefore appears that local winds in the vicinity of the ECCC Delta Burns Bog station (that is, the existing Tilbury facility) are considerably less intense than those in other parts of Metro Vancouver. Based on data trends, it appears that the average change is approximately +2 to +3 km/hr, which is not consequential from a risk assessment perspective (ECCC 2021).

Table 8.1-1. Climate Parameters Selected for Resilience Assessment up to 2050s Time Horizon

Climate Parameter	Threshold	Trend	Remarks
Riverine			
Riverine (Fraser River) flooding	Not determined	Increase	Fluvial flooding (related to the Fraser River) was assessed qualitatively due to the complexity of the parameter (influenced by numerous variables) and insufficient local data to establish necessary thresholds for the assessment.

Notes:

CDD = cooling degree days
km/hr = kilometre(s) per hour
Tmax = daily maximum temperature

A detailed Climate Profile for the proposed Project's study area is included in the CCRA (Appendix G of the Application). Additionally, fluvial flooding is further considered in Section 10.

8.2 Climate Change Resilience

The CCRA identifies potential climate-related potential effects to the proposed Project at a high level and assesses the climate risks over the proposed Project's expected operational life. It presents a detailed resilience analysis of system components for the proposed Project along with potential adaptation measures to manage risks and increase climate resilience, as described in the CCRA report (Appendix G).

Jacobs worked with FortisBC to agree on the boundary conditions of the proposed Project and the proposed Project components to be included in the CCRA. The CCRA covers the planned Phase 2 LNG facility infrastructure components identified within the proposed Project Site:

- Liquefaction Capacity (LNG liquefaction trains)
- Storage Tank (LNG storage tank)

A series of six virtual workshops were facilitated by Jacobs during the assessment process and involved representatives from FortisBC's planning and permitting, safety, operations, engineering, and environmental teams. The workshops established relevant climate parameters (for example, high and low temperatures, or precipitation) and documented the key interactions between these climate parameters and the existing FortisBC assets and their expected effects on the proposed Project. The workshop team assessed the likelihood, severity, and estimated level of risk for each interaction based on the projected change in climate parameters from current conditions to future conditions. The resulting risk scores were validated, and the risk items were prioritized. Risk items for which treatment measures were necessary were determined, and treatment options were established for the selected risks.

The CCRA establishes the existing conditions as the "current" climate using available data and climate parameters from the past 5 to 30 years. The future conditions, or projected future climate, consider the expected service life of the proposed Project assessment and therefore look out to the 2050s based on the World Meteorological Organization (2022) 30-year standard reference period spanning from 2035 to 2065.

The CCRA approach follows the Infrastructure Canada (INFC) Climate Lens methodology and meets the objectives outlined in Section 3 of INFC's Climate Lens General Guidance v1.1 (INFC 2019). The Climate Lens, and therefore the process used for this CCRA, is aligned and compatible with Engineers Canada's Public Infrastructure Engineering Vulnerability Committee's Climate Vulnerability Assessment Protocol (Engineers Canada 2012) and conforms to the requirements of the ISO 31000:2018 Risk Management Framework and the ISO 14090:2019 Adaptation to Climate Change Series of Standards. Furthermore, the process used in this CCRA is consistent with the Guidance on Good Practices in Climate Change Risks Assessment published by the CCME (2021).

A wide range of climate events that could negatively impact the proposed Project's planned operation and maintenance (O&M) were considered for this assessment. Only those thought to have a potential effect on proposed Project assets were included. Climate change data were collected from published literature, applicable reports, and local weather stations in B.C. This data, jointly with interviews with FortisBC staff, informed the projected changes and the climate parameters selected for the CCRA. The proposed Project is anticipated to experience increased future climate scenarios as follows:

- Short duration high-intensity rainfall (precipitation)
- Extreme heat
- Heat waves

Using the highly conservative IPCC RCP 8.5 scenario, personnel and programmable logic controllers (PLCs) at the compressors (or any control equipment) were identified as vulnerable to the effects of the increased precipitation and higher temperatures. They were determined to be at moderate to high risk in future climate conditions. Furthermore, the climate hazards associated with flooding of the Fraser River were assessed qualitatively and determined to pose limited risk to the proposed Project based on the existing dike infrastructure and FortisBC's proposed facility design and O&M procedures.

Although high risks have been identified, many risks can be monitored or mitigated as part of O&M policies and procedures during the lifecycle of the proposed Project components. As a result, the proposed Project is not projected to be substantially vulnerable to effects of climate change based the climate parameters examined and the proposed Project's preliminary design.

The potential cumulative effects on the local environment caused by climate change and the proposed Project are considered to be limited based on design considerations, planning, and regulatory requirements. PLCs at the compressors or any control equipment were the only components determined to have the potential to affect the environment through the temporary release of GHG, which could be caused by temporary flaring if extreme heat causes the equipment to fail. However, given the design standard for this equipment (designed to operate in up to 70°C), this risk can be monitored and mitigated during operation.

The adaptation strategies discussed and documented during the proposed Project workshops provided an initial list of design considerations for moderate and high-risk events. Table 8.2-1 presents potential adaptation measures for major risks, which are intended to be used as a first pass to increase climate resiliency based on currently available technologies, industry standards and practices for design and construction, and FortisBC O&M practices. FortisBC will consider these strategies to increase the resilience of its infrastructure and address climate change vulnerabilities. This is feasible either by enhancing or expanding existing programs and practices, by performing further engineering analysis of higher risks for individual proposed Project components, and by worker safety as part of engineering studies and designs.

Table 8.2-1. Climate Adaptation Measures for Major Risks

Risks	Current Climate Risk Score	Future Climate Risk Score	Asset/Element	Climate Parameter	Actions Available Current (C) + Potential (P)	Costs (Low, Medium, or High)	Effectiveness of Adaptation (Low, Medium, or High)	Time to Implement (Short, Medium, or Long)	Barriers to Action (Such as Cost, Timing, Lack of Information Available, Existing Controls, or Existing Policies)	Staff/Department Responsible for Action	Partners/ Stakeholders That May Support Action	Difficulty of Implementation (Low, Medium, or High)	Monitoring and Evaluation
Major	15	3	Personnel	Extreme cold	▪ HSE policies and training (C) ▪ Appropriate PPE (C) ▪ Snow management/winter maintenance (C) ▪ Places for staff to get out of the weather (C) ▪ Schedule work to minimize cold exposure/staff rotation and use FortisBC Work/Warm-up Schedule (C)	Not considered	Not considered	Not considered	Not considered	Not considered	Not considered	Not considered	Not considered
Major	3	15	Personnel	▪ Heat wave ▪ Extreme heat	▪ HSE policies and training (C) ▪ Appropriate PPE (C) ▪ Places for staff to get out of the weather and obtain water (C) ▪ Connect air conditioning to emergency generator to confirm that system can continue to operate during power outage and extreme heat events (P) ▪ Continue to update HSE policies to confirm their adequacy (P)	▪ Low ▪ Policy updates are required by law, and minimal costs are associated with connecting air conditioning to emergency generator system.	High	▪ Medium ▪ Action to be implemented prior to future climate period	Not considered	▪ Action 1 and 5: Health and Safety ▪ Action 2 and 3: Operations ▪ Action 4: Proposed Project Team (at design/ construction)	Union	Low	None to report (Note: Monitor updating of policies that will be required by WorkSafeBC. Monitor that connection of air conditioning to emergency generator is complete)
Major	3	15	Personnel	▪ Short duration/ high-intensity rainfall ▪ Wind gusts	▪ Generate work safety policy (C) ▪ Appropriate PPE (C) ▪ Install weather station at facility with programmed alarm if gusts or winds exceed threshold (P) ▪ Implement FortisBC's working at heights policy (C)	▪ Low ▪ Weather station will already be necessary for the planned jetty due to wind and wave conditions.	High	▪ Medium ▪ Action to be implemented prior to future climate period	Not considered	▪ HSE for item 1 ▪ Operations for 2 and 3, proposed Project team will put weather station in place, but operations maintain	Union	Low	Not considered
Major	3	10, 15	PLCs at the compressors (or any control equipment)	Extreme Heat	▪ Temperature rated panels (P) ▪ Consider confirming that enclosed control equipment does not exceed maximum design temperature (70˚C for PLCs) (C+P)	Not considered	Not considered	Not considered	Not considered	Not considered	Not considered	Not considered	Not considered

Notes:

HSE = health, safety, and the environment
PPE = personal protective equipment

Overall, the information collected during this CCRA and the input provided by the experts involved indicate existing infrastructure that has been resilient to past extreme events over the past 50-plus years of operation at the existing site. For the proposed Project, considering the climate risks and adaptation recommendations in the CCRA, the design and O&M practices are expected to limit exposure and risks during the service life of the proposed Project components and time horizon of the assessment.

8.3 Proposed Project Emissions

Three TDRs are attached as appendices to address the GHG emissions requirements specified by ECCC in the SACC (ECCC 2020), the draft Technical Guide (ECCC 2021), and the AIR (June 2022).

The GHG Emissions TDRs include the following:

- Upstream GHG Assessment TDR – assesses the upstream GHG emissions in a standalone report as recommended by ECCC (Appendix M of the Application)
- Base Cases GHG Emissions TDR – quantifies the baseline proposed Project pre-mitigation emissions (Appendix N of the Application)
- GHG Net-zero Plan TDR – presents the plan toward net-zero GHG emissions by 2030 (Appendix O of the Application)

The relationship of the Base Case GHG Emissions TDRs to the SACC, draft Technical Guide related to the SACC, and other TDRs is shown in Figure 8.3-1.

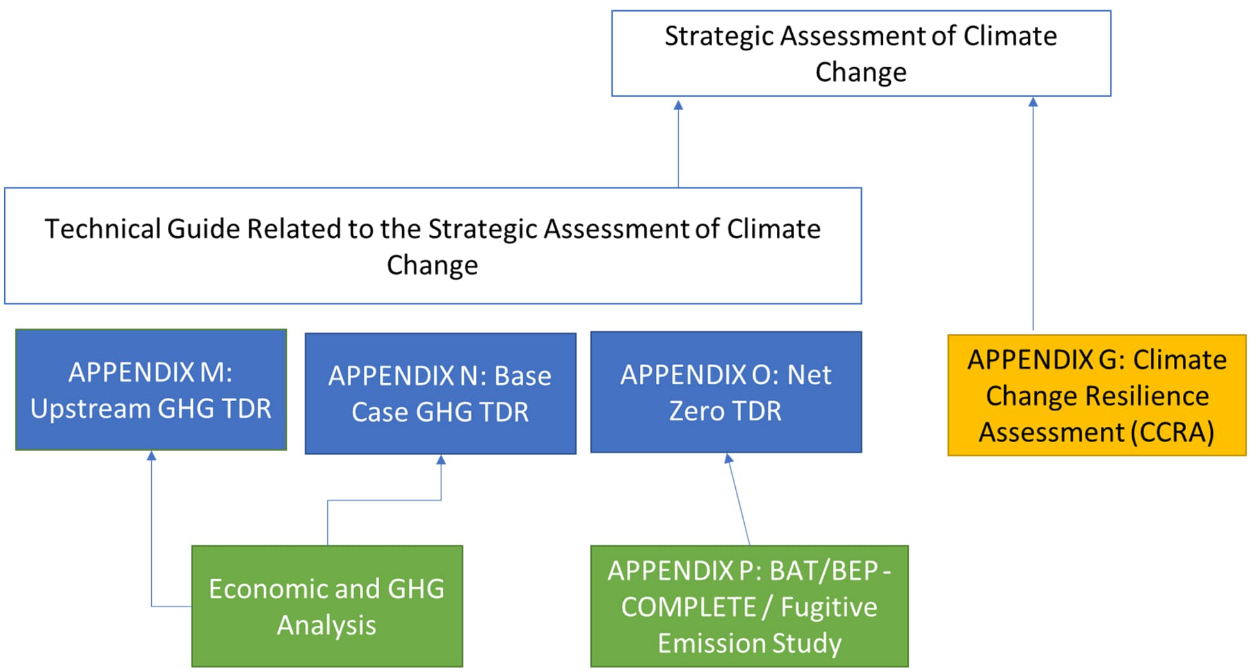


Figure 8.3-1. Relationship Between Greenhouse Gas Emissions Technical Data Reports and Regulatory Documents

The Application has been prepared in accordance with the AIR (June 2022), the requirements specified by ECCC in the SACC (ECCC 2020), and the requirements of the B.C. *Greenhouse Gas Industrial Reporting and Control Act* (*GGIRCA*). Due to concerns received from engagement activities during the Application Development phase AIR (June 2022), the proposed Project will no longer utilize any waterborne delivery of modular components and bulk construction materials to the proposed Project Site.

The Base Case GHG TDR (Appendix N of the Application) quantifies the baseline proposed Project GHG emissions before any mitigation measures are applied (pre-mitigation) and describes the methodology and data used in the quantifications. The GHG mitigation requirements of the SACC (ECCC 2020) and associated draft Technical Guide (ECCC 2021), including efforts to achieve net zero by 2030, are presented in the GHG Net-zero TDR (Appendix O of the Application). GHG emissions from upstream sources are quantified in the Upstream GHG Assessment TDR (Appendix M of the Application). Requirements of the SACC related to climate resilience are covered in the CCRA, which is independent of the GHG Emissions TDRs and included as Appendix G of the Application.

Table 8.3-1 cross references all requirements from the SACC (ECCC 2020), AIR (June 2022), and draft Technical Guide (ECCC 2021) with the sections in the applicable GHG TDRs that address the requirements. The table is sorted by the order in which requirements occur in the SACC. The related AIR (June 2022) and the more specific requirements of the draft Technical Guide are listed in the second and third columns. Requirements with respect to the planning phase and climate change resilience are not listed in Table 8.3-1.

Table 8.3-1. Concordance of Requirements in the Strategic Assessment of Climate Change, Application Information Requirements, and Tech Guide with the Greenhouse Gas Emissions Technical Data Reports

SACC (ECCC 2020) Requirement	AIR (June 2022)	Draft Technical Guide (ECCC 2021) Requirement	GHG TDR and Section
3. Quantification of GHG emissions from a project	8.1. Effects on Climate Change	2. Net GHG Emissions	Appendix N: Base Case GHG TDR Section 6
3.1. Quantification of a project's net GHG emissions	8.1. Effects on Climate Change	2.1. Methodology	Appendix N: Base Case GHG TDR Section 2
3.2. Assessing a project's upstream GHG emissions	8.6. Upstream GHG Emissions Assessment	5. Upstream GHG Assessment	Appendix M: Upstream GHG TDR
3.3. Discussion on the development of emissions estimates and uncertainty assessment	8.1. Effects on Climate Change	2.3. Discussion on the Development of Emission Estimates and Uncertainty Assessment	Appendix M: Upstream GHG TDR subsection 2.6 Appendix N: Base Case GHG TDR Section 4
5. Climate Change Information in the Impact Statement Phase	8.1. Effects on Climate Change	2.5. Impact Statement Phase	Appendix O: Net-zero TDR Section 8
	8.4. Greenhouse Gas Mitigation Measures	3.5. Impact Statement Phase for Projects with a Lifetime Beyond 2050	Appendix O: Net-zero TDR Sections 2 to 4
5.1.1. GHG emissions	8.1. Effects on Climate Change	2.1. Methodology	Appendix N: Base Case GHG TDR Section 22
		2.2. Possible Accident or Malfunction	Appendix N: Base Case GHG TDR Section 3
		2.3. Discussion on the Development of Emission Estimates and Uncertainty Assessment	Appendix N: Base Case GHG TDR Section 4

Table 8.3-1. Concordance of Requirements in the Strategic Assessment of Climate Change, Application Information Requirements, and Tech Guide with the Greenhouse Gas Emissions Technical Data Reports

SACC (ECCC 2020) Requirement	AIR (June 2022)	Draft Technical Guide (ECCC 2021) Requirement	GHG TDR and Section
5.1.2. Impact of the project on carbon sinks	8.2. Impact of the Project on Carbon Sinks	3.5.3. Carbon Sinks 4. Carbon Sinks	Appendix N: Base Case GHG TDR subsection 6.2
5.1.3. Impact of the project on federal emissions reduction efforts and on global GHG emissions	8.3. Impact of the Project on Emissions Reduction Efforts and on Global Greenhouse Gas Emissions	N/A	Appendix O: Net-zero TDR Section 8
5.1.4. GHG mitigation measures	8.4. Greenhouse Gas Mitigation Measures	3.5.4. GHG Legislation, Policies and Regulations	Appendix O: Net-zero TDR Section 4
5.1.4.1. BAT/BEP Determination	8.4.1. Best Available Technologies/Best Environmental Practices Assessment	3.2. BAT/BEP Determination	Appendix O: Net-zero TDR Section 2 Appendix P: BAT Study in Accordance with Strategic Assessment of Climate (BAT report).
5.2. Upstream GHG emissions assessment	8.6. Upstream GHG Emissions Assessment	5. Upstream GHG Assessment	Appendix M: Upstream GHG TDR Section 2
5.3. Plan to achieve net-zero emissions by 2050	8.4.3. Plan to Achieve Net-Zero Emissions by 2050 B.C. EAO letter to FortisBC regarding the B.C. net-zero emissions by 2030 policy[a]	3.5.1. Principles of the Net-Zero Plan 3.5.2. Information Required in the Credible Net-Zero Plan	Appendix O: Net-zero TDR Section 5
7. Climate Change in Decision Making and Conditions	8.5. Canada's Ability to Meet its Environmental Obligations and its Climate Change Commitments	N/A	Appendix O: Net-zero TDR Section 8

[a] B.C. Net-Zero New Industry Policy (NZNIP) letter from B.C. EAO to FortisBC, dated July 19, 2024; Attachment 2, dated July 16, 2024

The Base Case GHG TDR (Appendix N of the Application) quantifies the baseline proposed Project GHG emissions following the guidance from the draft Technical Guide (ECCC 2021) and other references. The Base Case GHG TDR quantifies the proposed Project's net GHG emissions from all three phases of the proposed Project including the following: (1) construction; (2) baseline operation; and (3) decommissioning. The net emissions calculation follows Equation 1 of the draft Technical Guide, which is reproduced as Equation 8.3-1, and reflects conditions before the facility's use of 100 percent renewable fuel during normal operations.

Equation 8.3-1. Net Greenhouse Gas Emissions

$$Net\ GHG\ Emissions = Direct\ GHG\ Emissions + Acquired\ Energy\ GHG\ emisisons - Avoided\ domestic\ GHG\ emissions - Offset\ Measures$$

The net GHG emissions presented in the Base Case GHG TDR include direct GHG emissions and acquired energy GHG emissions. There are no avoided domestic GHG emissions and offset measures considered as part of the baseline proposed Project. The net emissions from the proposed Project for each phase using the methodologies from the SACC are shown in Table 8.3-2 and using the methodology recommended by the B.C. *GGIRCA* in Table 8.3-3.

The net emissions from the proposed Project for each phase using the methodologies from the SACC are shown in Table 8.3-2.

Table 8.3-2. Net Greenhouse Gas Emissions from the Pre-mitigated Proposed Project Federal Strategic Assessment of Climate Change/Environment and Climate Change Canada Method

Phase	GHG Emissions (tCO_2e)				
	(+) Direct GHG Emissions	(+) Acquired Energy GHG Emissions	(-) Avoided Domestic GHG Emissions	(-) Offset Measures	= Net GHG Emissions
Construction – Commencing 2027+					
Construction Period	99,379	N/A	N/A	N/A	99,379
Proposed Project Operation – Beginning 2030+					
Annual Operation[a]	177,957	138 – 3,996	N/A	N/A	178,095 – 181,953
Decommissioning on Proposed Project Closure					
End of Life	2,841	N/A	N/A	N/A	2,841

[a] GHG emissions vary year -to -year from acquired energy from electricity purchases due to varying annual electricity intensities.

Notes:

"N/A" means no GHG emissions or avoided emissions or offsets for this proposed Project phase.

"+" and "-" indicate whether emissions are added or avoided, or offset emission benefits are subtracted in the net emissions equation (Equation 8.3-1).

The net emissions from the proposed Project for each phase using the methodologies from the B.C. *GGIRCA* are shown in Table 8.3-3.

Table 8.3-3. Net Greenhouse Gas Emissions from the Pre-mitigated Proposed Project – British Columbia *Greenhouse Gas Industrial Reporting and Control Act* Method

Phase	GHG Emissions (tCO_2e)				
	(+) Direct GHG Emissions	(+) Acquired Energy GHG Emissions	(-) Avoided Domestic GHG Emissions	(-) Offset Measures	= Net GHG Emissions
Construction – Commencing 2027+					
Construction Period	99,379	N/A	N/A	N/A	99,379
Proposed Project Operation – Beginning 2030+					
Annual Operation[a]	177,957	138–3,996	N/A	N/A	178,095–181,953
Decommissioning on Proposed Project Closure					
End of Life	2,841	N/A	N/A	N/A	2,841

[a] GHG emissions vary year -to -year from acquired energy from electricity purchases due to varying annual electricity intensities.

Notes:

"N/A" means no GHG emissions or avoided emissions or offsets for this proposed Project phase.

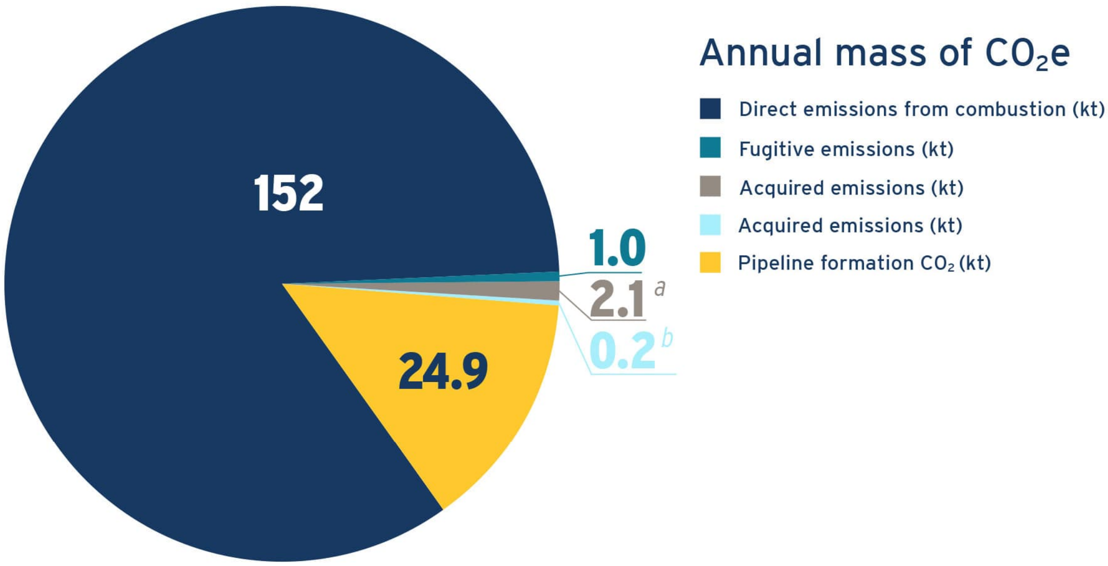
"+" and "-" indicate whether emissions are added or avoided, or offset emission benefits are subtracted in the net emissions equation (Equation 8.3-1).

During the construction phase, GHG emissions will be produced by the combustion of fuel by stationary and mobile equipment used onsite, road delivery of the modules and materials, venting from the initial tank fill, and flaring during commissioning. The emissions are expected to begin in 2027+ and occur intermittently over a 3- to 6-year period, depending on the pace and nature of construction activities. The highest levels of flaring-related emissions are anticipated during plant commissioning.

During the operation phase, the proposed Project will generate direct GHG emissions from combustion in industrial processes, flaring, and fugitive losses, as well as indirect emissions from acquired electricity. Additionally, the facility will serve as the final emission point for the formation (entrained) CO_2, which is naturally present within upstream gas reserves and which travels with the feed gas and must be removed prior to liquefaction. The liquefaction process requires the elimination of all impurities, including CO_2, to ensure the final product meets quality standards.

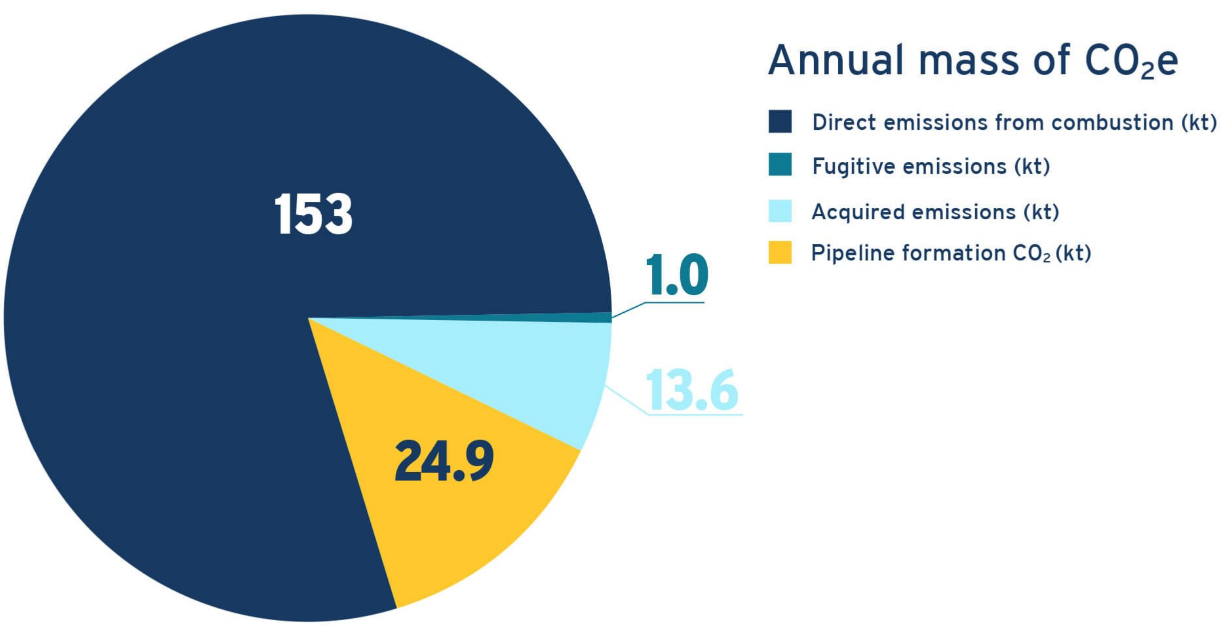
The proposed Project is not anticipated to include any avoided domestic emissions meeting the definitions in the draft Technical Guide (ECCC 2021). The emissions outlined for the operational phase represent the baseline levels before the application of additional mitigation measures, as shown on Figure 8.3-2, under the SACC, and Figure 8.3-3, under the B.C. *GGIRCA*. Emissions from acquired electricity, on Figure 8.3-2, vary over the proposed Project lifespan due to changes in the projected electricity intensity under the SACC methodology.

Given that the proposed Project is expected to operate beyond 2050, it must demonstrate a credible pathway to achieving net-zero GHG emissions by 2050 and beyond in alignment with the federal requirements. Furthermore, under the B.C. NZNIP, new LNG facilities must achieve net-zero GHG emissions by 2030. To meet this target and maintain best-in-class performance, the proposed Project will incorporate 100 percent renewable fuels under normal operations and offset measures for any remaining residual emissions. Details on GHG offset measures are provided in subsection 5.4.2 of the Net-zero TDR (Appendix O of the Application).



a - Average intensity from 2028 to 2037.
b - Average intensity from 2038-2068.
kt = kilotonne(s)

Figure 8.3-2. Overview of the Proposed Project’s Scope 1 and 2 Unmitigated Operational Emissions Under the Strategic Assessment of Climate Change



kt = kilotonne(s)

Figure 8.3-3. Overview of the Proposed Project’s Scope 1 and 2 Unmitigated Operational Emissions Under the *British Columbia Greenhouse Gas Industrial Reporting and Control Act*

Direct GHG emissions are estimated for final decommissioning and demolition upon the end of life of the proposed Project. Given that the proposed Project's operational life is over 40 years, the types of vehicles and equipment that will be required for demolition and available for use at that time is unknown. Emissions for decommissioning were prorated to construction emissions with the conservative assumption that this will include direct tailpipe releases from on- and offroad vehicles and equipment and additional flaring.

The Base Case GHG TDR (Appendix N) documents the specific emission quantification approaches and emission factors for each source. Emission factors, base quantities (such as units of fuel consumed in accordance with Equation 2 of the draft Technical Guide [ECCC 2021]), and associated assumptions are further presented with the full calculation in the Base Case GHG TDR. The GHG emissions have been calculated using the technically accepted methodologies consistent with both those presented in the draft Technical Guide and as required by the B.C. *GGIRCA*. The TDR presents the methodology as recommended both by the draft Technical Guide and as required by the B.C. *GGIRCA*, and documents deviation from these methodologies along with a justification for the approach applied. The only deviations from the methodologies presented were in the calculation of GHG emissions from entrained CO_2, flaring, and fugitive sources. The proposed Project GHG emissions estimate is sufficiently conservative in that the estimate is based on the proposed Project's maximum capacity and design flow gas compositions. The Base Case GHG TDR discusses potential uncertainties in the emissions quantification when the methodology deviates from the approaches recommended, namely in the quantification of emissions from entrained CO_2, flaring, and fugitive sources.

The Base Case GHG TDR includes a discussion on the potential effects of potential accidents or malfunction on the GHG emissions from proposed Project operation. There are two potential scenarios for an accident or malfunction: (1) a process upset or (2) a power outage. If the proposed Project were to experience a loss of electricity or an interruption of natural gas flow, the proposed Project would enter an upset mode, resulting in a temporary increase in the GHG emission rate. The increase in emissions due to process upsets is expected to be less than 1 percent of the annual operational GHG emissions. If the proposed Project were to experience a loss of electricity, the proposed Project would enter a shutdown mode, and the hourly GHG emission rate would be substantially lower than normal operation. Thus, such scenarios are accounted for within the annual operational total.

The proposed Project emissions intensity is calculated as the net annual GHG emissions from operation divided by the maximum design capacity of the proposed Project (in tonnes of LNG produced; Figure 8.3-4). The annual emissions intensity from the operation phase of the proposed Project for the baseline scenario with no mitigation measures, using gas-fired refrigeration and feed gas compression in 2030, is 0.17 $tCO_2e/tLNG$. However, FortisBC has implemented comprehensive design avoidance mitigation measures that significantly reduce the potential carbon emissions. These measures include electrifying the Project refrigeration and feed gas compression processes to reduce Project GHG and CAC emissions [M-17]. With these electrification design considerations implemented, the annual emissions intensity for baseline pre-mitigated scenario in 2030 is reduced to 0.072 $tCO_2e/tLNG$ (SACC method) or 0.077 $tCO_2e/tLNG$ (B.C. *GGIRCA* method), including the CO_2 entrained in the feed gas. If the CO_2 entrained in the feed gas is not accounted for, the annual emissions intensity from the operation phase of the proposed Project for the baseline pre-mitigated scenario in 2030 is 0.062 $tCO_2e/tLNG$ produced.

Under the net-zero mitigated strategy that employs 100 percent renewable fuel sources in the TO, the HOH and the flare system, the potential GHG emission intensity could be further reduced. Using the B.C. *GGIRCA* methodology, the proposed Project could achieve an emission intensity as low as 0.016

$tCO_2e/tLNG$. Under the SACC methodology, the potential emission intensity could be as low as 0.011 $tCO_2e/tLNG$. While the use of renewable fuels would significantly reduce the emission intensity from fuel combustion, these residual emission sources associated with entrained CO_2, fugitive emissions, and acquired energy emissions from electricity use would still contribute to the overall carbon footprint of the proposed Project.

The proposed Project delivers best-in-class emission intensity, far below global average benchmarks and outperforming the top 5% of LNG facilities worldwide. The proposed Project emission intensity will decrease each year of operation due to decreased acquired emissions (decreased electricity intensity) and increased renewable and lower-carbon content of fuels combusted (discussed further in the Net-zero Plan TDR).

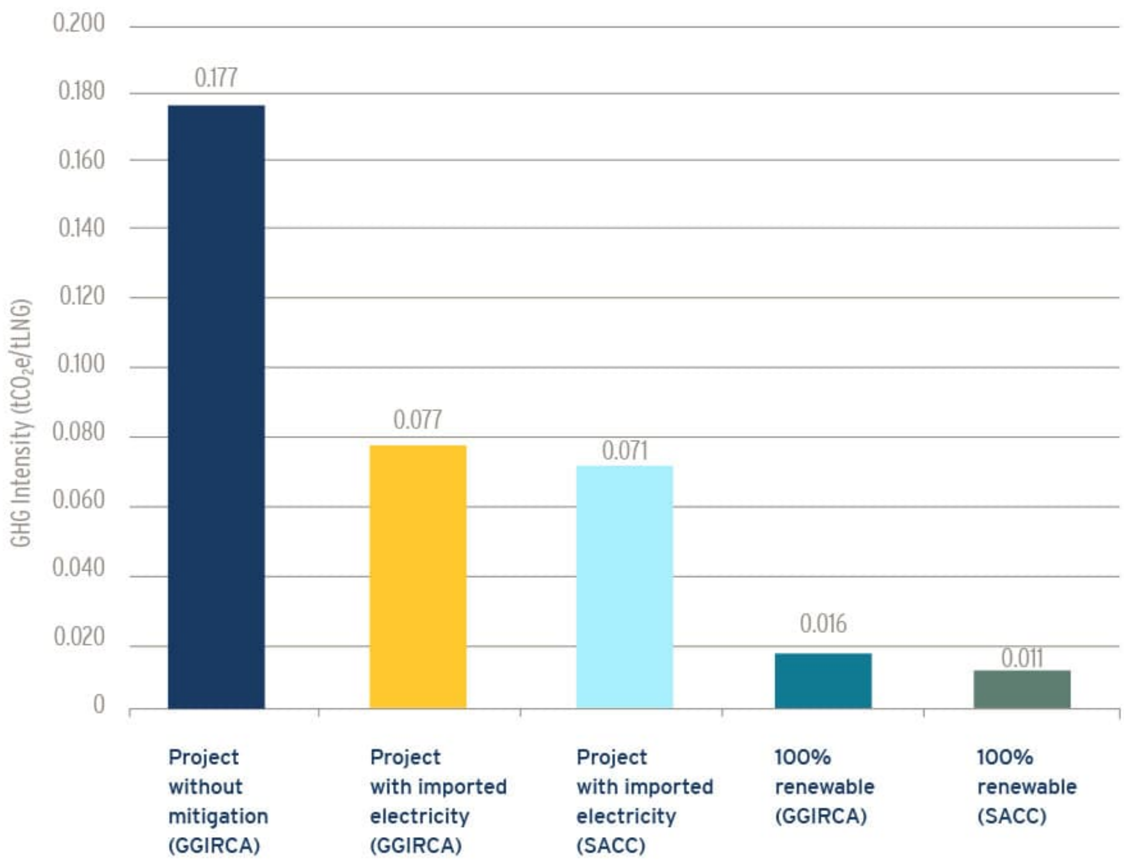


Figure 8.3-4. Greenhouse Gas Emission Intensity for the Proposed Project with and without Mitigation Measures

8.4 Potential Effects of the Proposed Project on Carbon Sinks

The proposed Project will not cause quantifiable changes to carbon sinks from land use changes. The proposed Project Site is expected to have similar use (cleared IL) without any substantial vegetation both pre- and post-proposed Project. The proposed Project Site is currently a brownfield site. The proposed Project Site occupies an area designated for IL use in accordance with the Delta Official Community Plan (Delta 2022), and it is expected to transition to a future industrial use upon proposed Project completion.

8.5 Potential Effects of the Proposed Project on Emissions Reduction Efforts and on Global Greenhouse Gas Emissions

The proposed Project has the potential to reduce local and global emissions by displacing more energy intensive-fuels, as described further in the GHG Net-zero TDR (Appendix O of the Application). The proposed Project will add incremental GHG emissions to the existing Canadian GHG emissions, as shown in Table 8.5-1, and compared to relevant Canadian GHG emissions targets. Operational emissions from the proposed Project are 0.045 percent of the 2030 federal GHG emissions target and 0.53 percent of the 2030 provincial target GHG. Although the proposed Project would result in incremental GHG emissions to existing operation, LNG could replace higher carbon-intensive fuels globally (Affinity 2022). Excluding methane slip, lifecycle studies show LNG produces lower direct (tank-to wake) GHG emissions per power output than other marine fuels, as evident from Figures 3-6 in Pavlenko et al. (2020) comparing lifecycle emissions. Despite contributing emissions, using LNG as a marine fuel could potentially offset higher global emissions compared to conventional marine fuels.

The proposed Project is initially expected to achieve a GHG emission intensity for baseline pre-mitigated scenario of 0.072 $tCO_2e/tLNG$ under the SACC methodology and 0.077 $tCO_2e/tLNG$ under the B.C. *GGIRCA* methodology, accounting for both direct and indirect emissions. If the proposed Project does not proceed, there is a risk of carbon leakage. In early 2023, Canada's largest upstream gas producer commenced exporting Canadian gas to Cheniere Energy Inc. (Cheniere) LNG facility in the U.S. Gulf Coast. A second upstream gas producer has also secured a similar long-term gas supply agreement with Cheniere, signally other Canadian natural gas producers to potentially follow. In such a scenario, if the LNG demand was met by a facility in the U.S Gulf Coast or in the top 5 percent globally, the emission intensity would be of 0.21 $tCO_2e/tLNG$ (U.S. EPA 2021a) and 0.23 $tCO_2e/tLNG$ (Delphi Group 2019), respectively. The CO_2 emissions associated with meeting the demand would be at least three times higher than the proposed Project's intensity and more than four times higher from a facility performing at the global benchmark (0.34 $tCO_2e/tLNG$; Delphi Group 2019).

Table 8.5-1. Proposed Project Baseline Pre-mitigated Scenario Contributions to Federal and British Columbia Emissions

Target	Reduction Target (%)	Annual Emission ($ktCO_2e/yr$)	Proposed Project Contribution (%)
Proposed Project Annual Net Emissions – Federal SACC Method	N/A	180	N/A
Proposed Project annual net emissions – B.C.*GGIRCA* Method	N/A	193	N/A
Federal 2005 Baseline	N/A	730,000	0.025
Federal 2030 Target[a]	40–45	401,500–438,000	0.041–0.045
B.C. 2007 Baseline	N/A	60,800	0.32
B.C. 2025 Target	16	51,100	0.38
B.C. 2030 Target	40	36,500	0.53
B.C. 2040 Target	60	24,300	0.79
B.C. 2050 Target	80	12,200	1.6

Table 8.5-1. Proposed Project Baseline Pre-mitigated Scenario Contributions to Federal and British Columbia Emissions

Target	Reduction Target (%)	Annual Emission ($ktCO_2e/yr$)	Proposed Project Contribution (%)
B.C. Oil and Gas Sector 2007 Baseline	N/A	12,800	1.5
B.C. Oil and Gas Sector 2030 Target	33–38	7,900–8,600	2.2–2.4
Metro Vancouver 2010 Baseline	N/A	14,900	1.3
Metro Vancouver 2030 Target	45	8,195	2.4
Metro Vancouver 2050 Target	100	4,507	4.3

[a] Federal targets were compared against the emission total using the SACC Methodology; B.C. and Metro Vancouver targets were compared against the emission total from the B.C. *GGIRCA* methodology.

Table 8.5-2 compares the proposed Project's emissions intensity with global facilities with similar production capacity, as the vast majority of global production facilities have greater capacities. The GHG intensity comparisons have been extracted from publicly available information from environmental impact assessments (EIAs), sustainability reports, and the U.S. EPA Facility Level Information on Greenhouse Gases Tool. Limitations associated with the use of the public data include the emissions data being based on concept designs rather than operational data and, in some cases, data breakdown and definition of reporting boundaries that are not fully defined. Marine transport–related emissions are excluded from the GHG emissions-intensity assessment boundary.

Table 8.5-2. Comparison of Proposed Project Baseline Pre-mitigated Scenario Greenhouse Gas Emissions Intensity with Global LNG Production Facilities

LNG Project	Location	Power Source	Production Capacity (MTPA)	GHG Emissions Intensity ($tCO_2e/tLNG$)
FortisBC Tilbury Phase 2 LNG Expansion Project (proposed Project)	Delta, B.C.	Grid connected	2.5	0.072[a] and 0.077[b]
Woodfibre LNG (Woodfibre LNG n.d.) (Preconstruction)	B.C.	Grid connected	2.1	0.04
Cedar LNG (2019) (Approved)	Kitimat, B.C.	Grid connected	3.0	0.08
LNG Canada (2014) (Under construction)	Kitimat, B.C.	Natural gas combustion	26.0	0.15
Snohvit Melkøya LNG (Equinor LNG n.d.) (Operating)	Norway	Natural gas combustion with CO_2 sequestration	4.3	0.20
Pluto LNG (Woodside 2021) (Operating)	Perth, Australia	Natural gas compression	4.9	0.36

Table 8.5-2. Comparison of Proposed Project Baseline Pre-mitigated Scenario Greenhouse Gas Emissions Intensity with Global LNG Production Facilities

LNG Project	Location	Power Source	Production Capacity (MTPA)	GHG Emissions Intensity (tCO_2e/tLNG)
Cove Point LNG (U.S. EPA 2021b) (Operating)	Lusby, Maryland, U.S.	Natural gas compression	5.2	0.22
Cheniere Corpus Christi LNG (U.S. EPA 2021a) (Operating)	Texas, U.S.	Natural gas combustion	14.6	0.21

[a] Quantification based on the SACC Methodology.

[b] Quantification based on the B.C. *GGIRCA* Methodology.

8.6 Greenhouse Gas Mitigation Measures

The GHG Net-zero TDR (Appendix O of the Application) describes FortisBC's approach to achieving net zero for the proposed Project. At a high level, the Net-zero Plan addresses four GHG emission streams with different approaches to reducing each to net zero; these are presented in Table 8.6-1.

Table 8.6-1. Proposed Project Baseline Pre-mitigated Scenario Operation Greenhouse Gas Emissions Overview and Mitigated Net-zero Approach

Emission Stream	Annual Mass of CO_2e (B.C. *GGIRCA* – tonnes)[a]	Annual Mass of CO_2e (SACC – tonnes)[b]	Net-zero Approach
Direct Emissions from Combustion	153,414	152,068	▪ Drop-in fuels with a lower-carbon footprint ▪ RNG, a lower-carbon drop-in fuel, is a proven alternative that is commercially available today
Emissions from Fugitive Emissions	1,035	1,035	Implement fugitive emissions management through design and engineering control considerations and effective operational controls [M-41]
Acquired Emissions	13,640[c]	138[d]–3,996[e]	Electrical utility will achieve net zero
Pipeline Formation CO_2	24,854	24.9	Carbon emission offsets through technological or market-acquired offsets once regulatory and technical clarity are achieved [M-32]
Total Annual Emissions	192,943	178,095–181,953	Net zero: Estimated annualized emissions for 2030 and beyond

[a] Quantification based on the B.C. *GGIRCA*.

[b] Quantifications based on the SACC.

[c] B.C. electricity emissions intensity factor for 2024.

[d] Grid intensity in 2068+.

[e] Grid intensity in 2028.

Note: Numbers may not add because of rounding.

The Net-zero Plan is focused on reducing direct greenhouse gas emissions, with the expectation that indirect emissions from electricity use will decline as the power grid transitions to net zero. The current approach maintains the use of 100 percent drop-in renewable fuels for combustion in both the TO, the HOH and the flare system. These renewable fuels are assumed to have an emission intensity of 0 tCO_2e per gigajoule of energy. As a result, the only significant remaining direct emissions are projected to come from sources such as entrained CO_2 and fugitive emissions, totalling 25,889 tCO_2e. Additionally, emissions from acquired electricity from the B.C. grid are estimated at 13,640 tCO_2e. Both of these sources will need to be offset in 2030 and beyond to achieve the plan's net-zero objectives.

8.6.1 Best Available Technologies Determination

The proposed Project is committed to being net-zero emissions by 2030 and maintaining this target upon achieving commercial operation. This will be accomplished through the implementation of a comprehensive Net-zero Plan, the adoption of BAT and practices, and the integration of renewable and lower-carbon energy sources within the operation phase. As the proposed Project progresses, the Net-zero Plan may be updated to ensure it accurately reflects the actual emissions profile, based on final equipment selection and the finalized GHG emissions data. This adaptive approach ensures that the net-zero strategy remains robust, credible, and responsive to real-world operational conditions.

The SACC (ECCC 2020), its accompanying Technical Guide (ECCC 2021), and the CAS Attachment 2 require the Proponent to develop a credible Net-zero Plan utilizing BAT focused on achieving net zero by 2050. Importantly, the term “credible” also conveys an obligation to pursue a pathway that is both realistic and responsible. To support this, FortisBC commissioned a desktop review of BAT to evaluate and identify technologies capable of reducing direct emissions of NO_x, SO_x, and direct GHG emissions from the proposed Project primary emission sources. These technology options were further assessed in light of future uncertainties and grouped into several configurations or bundles that could lead to net zero by 2030, based on current knowledge and anticipated climate objectives. A summary of the BAT determination and conclusions that impact the Net-zero Plan are presented in the GHG Net-zero TDR (Appendix O of the Application), with the full BAT and overview of the bundles presented in TDR (Appendix P of the Application).

As detailed design has not been completed for the proposed Project, the concept has only been advanced to a “basis of assessment” stage. The BAT report was carried out in several stages to ensure the most practical and beneficial technologies were assessed. Stage 1 was identification of technology, Stage 2 was ranking and weighting of the most feasible emission reduction technologies specific to the proposed Project, and Stage 3 was the review of innovative technology on the edge of commerciality. The identification of potential technologies for adoption was based on the identified sources of emissions during operation. These technologies will be put on a technology watchlist and considered during detailed engineering design valuation. Depending on the timeline for attainment of technology maturity, the technologies may be considered and implemented on a case-by-case basis to meet future environmental standards.

Primarily, there are two major GHG emission sources in an LNG plant facility. One is CO_2 and methane contained in the feed gas, and the other is the flue gas produced from fuel gas combustion devices, such as compression, TO, process fired heaters and flaring.

FortisBC’s early decision to use electric-driven refrigeration and compression at Tilbury Phase 2 has the benefit of reducing direct GHG and criteria air contaminant emissions from the refrigerant compression, typically the largest source of direct CO_2 emissions. With the adoption of electric drive compression and refrigeration, the remaining sources of GHG emissions produced annually from the proposed Project are directly from the HOH, TO, TEGF, and fugitive releases, as well as indirectly from acquired electricity. A review of predicted emissions based on the current conceptual basis of assessment and the available engineering information identified the HOH and the TO as the remaining largest contributors to the facilities total GHG emissions (74 percent and 19 percent, respectively). The BAT Screening Study focused on emission reduction technologies focused on the HOH, TO, TEGF, and fugitive sources.

The preliminary feasibility screening of emission mitigations reflects a high degree of uncertainty between now and 2050, and no single technology bundle was determined to be clearly superior. The analysis of technology bundles highlighted the need to maintain flexibility in the selection of process technology adoption at different stages of the proposed Project to support incremental steps of emissions reductions toward net zero by 2050.

FortisBC's final engineering design decisions beyond the basis for assessment involves a multiphase iterative process that evaluates design variables and operating conditions of the proposed Project based on energy efficiency, environmental responsibility, and a safe facility adapted to use drop-in fuels. Safety includes both engineered safety features and a human interface intended to make O&M simple and reduce risk of injury and environmental effects. FortisBC will continue to assess feasible technology options throughout the Application approval process and following the issuance of the EAC. Based on the outcomes of the BAT report, the following technologies will be carried forward to the Front-end Engineering Design (FEED) post-EAC:

- Electric drive gas compression (highest GHG reduction opportunity)
- Gas fuel-fired HOH
- Direct gas-fired TO
- Ultra-low NO_x burners
- TEGF

As stated previously, FortisBC has committed, as a design mitigation measure, to electrify the gas compression and the cooling equipment associated with the liquefaction process in the proposed Project. However, the plan continues using gaseous fuel-fired HOH and TO allows for the most flexibility in fuel use and allows for easy adaptation to use a range of lower-carbon "drop-in" fuel mixes as they become available.

While electrification is often considered environmentally friendly, early analysis suggests that there may not be adequate electrical power available to support the proposed Project without significant capital upgrades, nor is electrification of components considered technically viable at this time. These upgrades may have negative effects on the proposed Project schedule as well as the proposed Project's overall technical or commercial viability. The utilization of a lower-carbon gas "drop-in fuel" option has the advantage of reducing electrical demand by the proposed Project and limits the indirect emissions that would be associated with acquired electricity.

8.6.2 Best Environmental Practices Determination

FortisBC commissioned GreenPath Energy Ltd. (GreenPath) to evaluate global BEP related to fugitive emissions management (GreenPath 2022) and generate a BEP desktop review for the proposed Project to identify areas in which emissions could be reduced. The GreenPath report reviewed existing and emerging technologies related to ambient monitoring systems that can detect substantial leaks between surveys. These systems are currently in place at Tilbury and will continue to be used as part of the proposed Project. FortisBC will continue to evaluate the effectiveness of fugitive emission ambient monitoring systems at the time of detailed design and during proposed Project construction. Table 8.6-2 outlines the BEPs that were identified in the GreenPath (2022) report and are being considered for inclusion in the proposed Project management plans.

Table 8.6-2. Fugitive Emissions Best Environmental Practices Included in the Proposed Project

Best Practice	Details
Implement equipment and component inspections and monitoring plan	Regularly monitor fugitive emissions from pipes, valves, seals, tanks, and other infrastructure components with vapour detection equipment (such as OGI) and maintain or replace components as needed in a prioritized manner. OGI surveys have the potential to reduce fugitive emissions by 40 to 99 percent.
Keep threaded or flanged joints to a minimum	This is a requirement of CSA Z276-22, LNG – Production, Storage and Handling (subsection 9.3.2.2). Any flanged joints in the pressurized loops are torqued to specifications to ensure zero leakage.
Maintain stable tank pressure and vapour space	The BOG system is a closed system designed to capture gas vapours and send it back to the fuel gas system and used as fuel or reliquefied and stored.
Implement closed-system vapour recovery when loading and unloading refrigerant transport vehicles	For truck delivery of refrigerants, closed systems are used. When trucking out heavy hydrocarbon liquids, vapour return lines are installed, as appropriate.
Depressurize and purge equipment to a flare before maintenance	There are some fugitive gas emissions associated with disconnecting equipment and piping for maintenance. It is recommended to initially depressurize the equipment and piping to a flare system. After the piping and equipment have been depressurized, the system is purged with nitrogen to force all the hydrocarbon fluid to the flare. A simple procedure to determine if all the hydrocarbon is purged to the flare can be done by opening a bleed and sampling the gas. When purging is done, the pipes and equipment can be disconnected. Because the current system at Tilbury does not have a flare, a TO to burn off any emissions is used. This best practice will be carried forward for consideration in conjunction with the TEGF.
Tie in sampling systems to the flare	Sample gas should be sent to flare or routed back to the process piping, as far as practical, instead of released directly to atmosphere.
Install seals for refrigerant compressor	Scheduled maintenance and testing will be carried out on the vapour recovery systems to promote continued performance. During design, the seal system will be chosen such that there is minimal leakage from the seals, as far as practical.
Use BOG compressors	BOG compressors function to keep the pressure of the LNG tank within the required range by routing the BOG to a higher-pressure system (that is, pipeline or process/utility unit); therefore, the high availability and reliability of BOG compressors reduces the probability of discretionary flaring of LNG tank vapour when the BOG compressor is not available.

Note:

OGI = optical gas imaging

8.6.3 Plan to Achieve Net-zero Emissions by 2050

As described earlier in this section, the Net-zero Plan (presented in detail in the GHG Net-zero TDR [Appendix O of the Application]) applies a continuous improvement process by applying advanced and emerging mitigation measures as they become technically and economically feasible. To that end, FortisBC will develop and implement a Net-zero Plan that will utilize inputs like the BAT and BEP to ensure the Project's direct operational GHG emissions follow government policies and regulations upon commencement of commercial operation[1] [M-63]. The proposed Project, at current basis of assessment, represents best-in-class emissions intensity due to the use of electrically driven compression. The Project will explore the use of renewable, lower-carbon "drop-in" fuels and other technology solutions. The other technology solutions may include waste heat recovery, carbon removal and utilization, developing technologies, and other offset measures [M-74].

Following issuance of an EAC, the detailed design of the proposed Project and the current state of commercially available, safe, and proven technologies will determine which of the BAT (Appendix P of the Application) will be adopted. The Net-zero Plan assumes the baseline technologies and emissions as presented in the Base Case GHG TDR (Appendix N of the Application) without any additional reductions from BAT applied in the detailed design phase. Some of the BAT identified may not be feasible at the time of detailed design but may be implemented over the proposed Project lifetime, effectively becoming part of the net-zero achievement.

The methodology for calculating the annual GHG emissions from the proposed Project are presented in the Base Case GHG TDR (Appendix N of the Application). The calculations in the GHG TDR represent a baseline annual emissions scenario that does not account for decreasing GHG emissions over time with the introduction of BAT and additional mitigation measures. The annual expected baseline level emissions are expected to be 178,095 to 181,593 tCO_2e per year, which is equivalent to a GHG emissions intensity of 0.072 tCO_2e/tLNG. The proposed Project aims to achieve industry leading GHG emission efficiency by using electric power for gas compression and refrigeration. This approach is designed to make the proposed Project a top performer in reducing emissions both globally and within B.C.

The adoption of additional mitigation measures over the life of the proposed Project will ensure the proposed Project remains best-in class by meeting net zero by 2050. To meet the net zero by 2050 requirement, the proposed Project will include the use of renewable fuels for combustion, carbon utilization, and offset measures. The Net-zero Plan prioritizes reducing direct GHG emissions, as indirect GHG emissions from the use of electricity are expected to decrease as the grid becomes net zero.

To support the proposed Project's GHG reduction efforts, the GHG Net-zero TDR (Appendix O of the Application) quantifies emission reductions based on 100 percent renewable fuel gas for combustion. The natural gas feedstock contains entrained CO_2, which must be removed prior to liquefaction, as it provides no energy value or operational benefit to the process. Currently, there is no technologically efficient solution to reduce this CO_2 stream onsite. Under the most favourable GHG performance scenario, assuming full reliance on renewable fuel, it is anticipated that approximately 26,027 tCO_2e from the entrained CO_2, fugitive emissions, and acquired electricity will need to be offset in 2050 and beyond. The Net-zero Plan outlines strategies to address these residual emissions carbon utilization and the purchase of offset credits.

Although geological storage options for carbon in the Lower Mainland of B.C. are limited, carbon utilization technologies are viable options for the proposed Project. The BAT assessment included a review of potential CO_2 utilization technologies provided by six different companies. Based on current information (Appendix G of the BAT report, Appendix P of the Application), four of the technologies scored a

[1] Commercial operation will begin immediately following commissioning. Commissioning is considered complete when contractual handover of operations is provided for the Phase 2 LNG train to FortisBC.

Technology Readiness Level (TRL) of 8 out of 9. TRLs are a method for estimating the maturity of technologies during the acquisition phase of a program (Government of Canada n.d.b). A TRL of 8 is indicative of the technology development testing and evaluation of whether the technology will meet operational requirements under real-life conditions. The specific carbon utilization options are presented in both the GHG Net-zero TDR (Appendix O of the Application) and the BAT report (Appendix P of the Application).

B.C. has a GHG Emission Offset program, which is a legislated framework created and administered by the Government of B.C. At this time, there are limited offset credits available for use within the energy sector in B.C. to meet carbon-neutral targets. Purchase of offset credits are primarily limited to provincial public-sector organizations as part of the Carbon Neutral Government program under the *Climate Change Accountability Act*. FortisBC anticipates that the B.C. offset program will transform or that a credible voluntary carbon market will exist by the time credits are required for the proposed Project.

8.6.4 Plan to Achieve Net-zero Emissions by 2030

To comply with B.C.'s NZNIP, the proposed Project has developed a Net-zero Plan that outlines a pathway to achieving net-zero GHG emissions by 2030 for new large industrial developments, including LNG facilities. This plan is structured around a continuous improvement framework that emphasizes the adoption of BAT and BEP as they become technically and economically viable. A comprehensive review of this approach, including technology options, implementation strategies, and performance scenarios, is provided in the GHG Net-zero Technical Data Report (Appendix O of the Application).

Implementation begins after the EAC is issued, with detailed design work evaluating which BAT from Appendix P can be practically applied. Each option is assessed for technical fit, environmental benefit, and feasibility, taking into account site-specific constraints and operational needs. Measures with clear disadvantages will be excluded, while promising technologies may be phased in over time.

As the proposed Project progresses, updated data on energy use and emissions will guide performance benchmarking and inform procurement and construction decisions. BAT standards will be embedded in equipment selection and system design, ensuring contractors align with net-zero goals. The plan will be reviewed at least every 5 years to reflect evolving technologies, practices, and regulatory expectations.

FortisBC is committed to achieving net-zero GHG emissions for Phase 2 by 2030. This commitment will be met through the transition to 100 percent renewable drop-in fuels for all direct combustion sources, with the remaining operational emissions addressed through verified offsets beginning in 2030. This approach aligns with the B.C. Net Zero New Industry Policy and is fully detailed in the GHG Net-Zero Technical Data Report (Appendix O).

FortisBC will maintain net-zero performance through the operational life of the facility, supported by ongoing monitoring, adaptive management, and periodic updates to the Net-Zero Plan every 5 years or as requested by the regulator.

8.6.4.1 Net-zero Overview

At a high level, the proposed Project's net-zero approach relies on electrification of the refrigerant and gas compression, a design mitigation choice that reduces the "base" emissions by approximately 60 percent relative to the global practice of utilizing gas-fired compression in LNG facilities.

To bring the remaining emissions to net zero, the plan proposes the use of drop-in renewable fuels to abate Scope 1 combustion emissions (initially relying on RNG but designing the facility to be "hydrogen capable," allowing future conversion to a blended hydrogen or pure hydrogen fuel source). Emissions from combustion represent approximately 85 percent of the pre-abatement emissions, making the use of drop-in fuels a proven, regulatory-supported and highly effective path to net zero.

The most challenging emissions stream to manage to net zero is the CO_2 entrained in the feed gas. This pre-existing CO_2 stream is separated from the feed gas prior to refrigeration; the separated CO_2, now part of the acid gas stream, is then emitted through the TO, where the other constituents of the acid gas (in particular, sulphur compounds) are combusted. The entrained CO_2 represents approximately 16 percent of the pre-abatement emissions. Unless the CO_2 is removed from the feed gas upstream of the proposed Project, reducing this stream to net zero will require the use of eligible B.C. technology offsets or market-acquired offsets.

In 2028, Scope 2 emissions from imported electricity are estimated to equal 7.6 percent of Scope 1 emissions, based on the B.C. *GGIRCA* methodology. This proportion reflects early efforts to electrifying key process such as refrigeration and compression.

Table 8.6-3 summarizes the mechanisms for accelerating net zero from 2050 to 2030.

Table 8.6-3. Mechanisms for Accelerating Net Zero from 2050 to 2030

Emission Stream	2030 Accelerated Net-zero Approach
Gas Refrigerant Compression	By making an early-stage design mitigation decision for electric-driven compression, the proposed Project achieves a nearly 60 percent reduction (250,000 tCO_2e) in Scope 1 emissions. This reduction is over 190 times lower than Scope 2 emissions from acquired electricity (13,608 tCO_2e).
Fugitive Emissions	To manage methane leaks, the proposed Project will implement regular equipment inspection and maintenance. Early design considerations include the use of low-leakage valves, fittings, closed-loop systems, and fugitive sampling ports to minimize emissions during operation.
Direct Combustion Emissions	From day one of commercial operation, the proposed Project will be powered by renewable fuel. To fuel a 2.5 MTPA LNG facility, approximately 2 petajoules per annum of RNG is required. FortisBC's RNG Supply Team has confirmed that this volume will be available as an incremental (noncommitted) volume.
Formation CO_2	Tilbury's ability to manage formation CO_2 is currently limited. Historical CO_2 content delivered to the Tilbury facility was 0.354 mole%, but the current average is down to 0.266 mole%, a reduction of nearly 25 percent since 2021. Depending on the GHG stringency measures implemented by the government on the oil and gas sector, upstream producers may have an incentive to "pass on" more CO_2 in the gas stream, up to the maximum pipeline allowable limit of 2 mole%. To offset any unabated emissions, the proposed Project will use either market-acquired technologically derived credits or be guided by Provincial and Federal policy tools at the time of acquisition.

Note:

mole% = mole percent

To achieve net-zero emissions, several specific measures will be implemented. These measures include reducing fugitive emissions, utilizing drop-in renewable fuels, managing entrained CO_2, and procuring lower-carbon electricity.

FortisBC wants to emphasize that the information in the Application relies on a proposed Project design that is based on a high level of conservative emissions estimates; as such it represents a "high case" and FortisBC continues to search for emissions reduction opportunities in the proposed Project. For example, after conducting early engineering design evaluations, the proposed Project team has determined that fugitive emissions can be effectively managed by incorporating pressure relief valves within a closed system. This innovative approach is expected to substantially reduce unintentional losses and could potentially decrease fugitive leaks by up to 90 percent. By implementing this mitigation solution, the proposed Project will not only reduce emissions but also improve operational efficiency and safety.

The use of renewable fuels offers a credible pathway for the proposed Project to immediately reduce direct emissions from combustion sources. Carbon-neutral renewable fuels will be used exclusively as the combustion fuel, resulting in the abatement of 153, 414 tCO_2e of GHG emissions from direct combustion sources from day one of commercial operation. This is a substantial step toward achieving net-zero emissions by 2030.

The management of entrained CO_2 will depend on factors such as the amount of CO_2 present in the pipeline gas, the design controls for CO_2 capture, the viability of onsite or regional sequestration technologies, and the regulatory framework for offsetting any residual emissions that cannot be effectively managed through these measures.

FortisBC proposes to offset any unabated emissions using either market -acquired offset credits approved by the Government of B.C. or credits generated through technological solutions. The choice between these offsetting approaches will be informed by Provincial and Federal policies in effect at the time of acquisition, as well as the feasibility and cost-effectiveness of available technologies.

In addition to market-acquired offsets, offsets can involve self-generated credits, such as nature-based, technological investments that create offsets, and acquisition of provincially approved offsets. Any acquired offset will need to be retired and removed from circulation to meet the net-zero requirements of the proposed Project.

One challenge related to describing a proposed Project specific offsetting strategy is that the Net-zero Plan is standalone. FortisBC currently owns and operates a wide range of utility infrastructure, both gas and hydro-electrical, across the province and will be addressing net zero for the enterprise in a cost effective-manner on behalf of its customers. This includes the potential investment in assets that generate offsets, long-term contracting of offsets, and pooling of credits and offsets for sale between regulated and nonregulated assets. Although the proposed Project's Net-Zero Plan describes a ring-fenced path to net zero by 2030, it is feasible that the actual execution of the proposed Project's Net-zero Plan will leverage aspects of FortisBC's enterprise-wide net-zero program.

8.6.4.2 Voluntary Offsets Versus Regulated Offsets

Given the proposal to acquire offsets as part of the Net-zero Plan, FortisBC proposes to participate in offset markets that are regulated by Provincial or Federal authorities, rather than acquire voluntary, nonregulated offsets.

8.6.4.3 Uncertainties and Evolving Provincial Regulations and Policies

FortisBC is actively engaged in monitoring and participating in Government of B.C. initiatives associated with the CleanBC Roadmap to 2030 (Government of B.C. n.d.). These initiatives include the implementation of a new carbon pricing system effective April 1, 2024; alignment with the federal output-based pricing system; the aim to eliminate industry methane emissions by 2035; the establishment of an oil and gas emissions cap; the development of a B.C. carbon registry; the expansion of offset protocols; and the introduction of a Provincial industry-based Net-zero Plan by 2050 with the objective of achieving net zero in new LNG projects by 2030. Coordination with these Provincial regulatory policy efforts is crucial to support and accelerate the Net-zero Plan for Phase 2 by 2030.

8.7 Greenhouse Gas Legislation, Policies, and Regulations

Table 8.7-1 provides descriptions of the relevant legislation, policy, and guidance documents applicable to the management of GHG for the proposed Project.

Table 8.7-1. Summary of Relevant Legislation, Policies, and Regulations Applicable for the Proposed Project

Regulation or Policy	Description
Federal	
Canadian Net-Zero Emissions Accountability Act (Government of Canada 2021)	Commits to a national GHG emissions target of net-zero emissions by 2050. Canada's Pan-Canadian Framework on Clean Growth and Climate Change makes commitments to reduce GHG emissions by 30 percent below 2005 levels by 2030. Establishes 5-year national emissions reduction targets for 2030, 2035, 2040, and 2045. The law codifies 2030 and 2050 targets, which are enshrined in legislation. The Act ensures transparency and accountability as the government works to deliver on its targets.
Best in Class Guidance (ECCC 2020)	Guidance for new oil and gas projects subject to a federal IA. Projects will need to demonstrate that the project will integrate advanced technologies and BEPs, including emerging technologies, to minimize emissions; compare the project's emissions with high-performing projects in the world; and develop a plan to achieve net-zero emissions by 2050 if the project will continue to operate after that date.
2030 Emissions Reduction Plan: Clean Air, Strong Economy (Government of Canada 2022a)	Sector-by-sector path for Canada to reach its emissions reduction target of 40 percent below 2005 levels by 2030 and net-zero emissions by 2050.
GHG Reporting Program (Government of Canada 2004)	Section 46 of the *CEPA* requires GHG emissions to be reported via the GHG Reporting Program if facility emissions are greater than 10,000 metric tonnes of carbon dioxide equivalent per year (tCO_2e/yr).
Greenhouse Gas Pollution Pricing Act (Government of Canada 2023)	Implements the federal carbon pricing system. Industrial facilities must comply with the *Output-Based Pricing System Regulations* administered by ECCC.
Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (Government of Canada 2018)	Regulates methane emissions reductions from the oil and gas sector by 40 to 45 percent below 2012 levels by 2025. These regulations form part of Canada's commitments under the Pan-Canadian Framework on Clean Growth and Climate Change.
SACC (ECCC 2020)	Under the *IAA* (2019), the SACC provides a framework for assessing whether a designated project will hinder or contribute to the Government of Canada's ability to meet its environmental obligations and its commitments in respect of climate change targets of 45-50% reduction in GHG emissions from 2005 levels by 2035.

Table 8.7-1. Summary of Relevant Legislation, Policies, and Regulations Applicable for the Proposed Project

Regulation or Policy	Description
Clean Fuel Regulations (amended 2022) (Government of Canada 2022b)	Regulates a reduction in the CI of liquid fossil fuels in Canada, including by reducing emissions from oil and gas production.
Oil and Gas Emissions Cap Regulation (proposed) (Government of Canada 2022c)	Proposed regulation that would cap direct emissions from the oil and gas sector to achieve Canada's GHG emissions reduction target in 2030 and 2050.
Provincial	
GGIRCA (Government of B.C. 2014)	Facilities that emit greater than 10,000 tCO_2e/yr are required to report their emissions.
Climate Change Accountability Act (2007) (formerly the *Greenhouse Gas Reduction Targets Act*) (Government of B.C. 2007)	Includes the following legislated targets for reducing GHG emissions: ▪ 40 percent below 2007 levels by 2030 ▪ 60 percent by 2040 ▪ 80 percent by 2050 B.C. ENV has also introduced the following interim targets: ▪ 16 percent by 2025 ▪ 33 to 38 percent of 2007 levels by 2030 for oil and gas
Flaring and Venting Reduction Guideline (B.C. OGC 2022)	Regulatory requirements and guidance for flaring, incinerating, and venting in B.C. This guideline applies to the flaring, incineration, and venting of natural gas at well sites, facilities, and pipelines regulated under the *ERAA*.
Carbon Tax Act (Government of B.C. 2008)	The B.C. carbon tax was repealed as of April 1, 2025. Previously the Act established a price for GHGs beginning at $10 per tonne in 2008, with planned increases to $170 per tonne by 2030.
NZNIP (Government of B.C. n.d.)	In March 2023, B.C. required new LNG projects to have a credible plan to achieve net-zero emissions by 2030.
Regional	
Metro Vancouver's Climate 2050 Strategy (Metro Vancouver 2019)	Sets a target of 45 percent reduction in GHG emissions from 2010 levels by 2030. The strategy also envisions that by 2030, 60% of the region's energy will come from clean, renewable sources, increasing to 100% by 2050, as applicable to the proposed Project.
Bylaw 1330, 2021 (Metro Vancouver 2021)	GVRD Air Quality Management Bylaw 1330, 2021 enacts Bylaw No. 1082, 2008 to establish fees on emissions of methane and GHGs, including other air contaminants.

Note:

GVRD = Greater Vancouver Regional District

8.8 Upstream Greenhouse Gas Emissions Assessment

A quantitative estimate and qualitative discussion of upstream GHG emissions is presented in the Upstream GHG Assessment TDR (Appendix M of the Application). The assessment addresses ECCC's requirement to produce a standalone report following the guidance provided in the draft Technical Guide (ECCC 2021).

The Upstream GHG Assessment (Appendix M of the Application) includes emissions from natural gas production, processing, and transportation, as natural gas is the only energy feedstock that would be used for the proposed Project. The Upstream GHG Assessment TDR includes two feasible future upstream scenarios. Both scenarios assume that production of LNG would begin in as early as 2028 and continue beyond 2050 at a maximum production of 2.5 MTPA. Both scenarios calculate upstream emissions based on annual emission intensities recommended in the draft Technical Guide (ECCC 2021) for 2028 through 2030. A conservative scenario calculates the upstream emissions holding the annual emission intensities constant at 2030 levels from 2031 through 2050. The net-zero scenario calculates upstream emissions with annual emission intensities declining linearly from 2030 levels to 0 in 2050, in line with Canada's international commitment to achieve national total net-zero GHG emissions in 2050.

In both scenarios, the highest total upstream GHG emissions intensity of 0.327 tCO_2e/tLNG would occur in the proposed first year of production (2030) and slightly decline to 0.317 tCO_2e/tLNG in 2030. In the conservative scenario, the emission intensity would remain constant at 0.317 tCO_2e/tLNG through 2050, whereas it would drop linearly to 0 in the net-zero scenario. Estimated annual total upstream GHG emissions would slightly decline from 818,000 tCO_2e in 2028 to 792,000 tCO_2e in 2030 in both scenarios. Annual upstream emissions would remain constant at 792,000 tCO_2e in the conservative scenario and drop linearly to 0 in the net-zero scenario. A review of upstream GHG emission intensities used in previous assessments was performed to quantify the potential range emission intensities. The maximum estimate of 818,000 tCO_2e in 2028 in this assessment is less than the median of that range.

Canada's efforts to make meaningful reductions in the upstream GHG emissions could be negatively impacted if natural gas is transported to and liquefied elsewhere. Two of Canada's natural gas producers have signed long-term contracts to move Canadian natural gas south of the border to the U.S. This action has a direct effect on increasing gas transportation emissions associated with moving Canadian natural gas from B.C. to the southernmost tip of the North American continent. The relocation of Canadian gas to jurisdictions with less stringent emission reduction policies, along with liquefaction at facilities with higher emission intensity, could have an increased effect on global emission outputs. The proposed Project is strategically positioned to take advantage of responsibly produced B.C. gas and liquefy it locally, enabling Canada to meet its own GHG emission reduction commitments while also supporting global emission reductions.

8.9 References

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