

Review of LNG Canada Project: Delays, Policy Changes, and Rising Costs

Will LNG Canada Become the Last LNG Project in British Columbia?

Executive Summary

Developers of new liquefied natural gas (LNG) projects may be looking to LNG Canada's project in British Columbia as a model. It is time to look again.

LNG Canada, a multinational consortium that includes some of the largest oil and gas companies on the planet, passed the first phase of the two-phase project's Final Investment Decision (FID) in 2018. But policy changes, project delays, cost creep, and medium-term LNG pricing in Asia have greatly affected the economics of the first phase and challenge the efficacy of proceeding with Phase 2 (doubling capacity to four liquefaction trains). LNG Canada's Phase 1 project attracted billions of dollars to the oil and gas sector in British Columbia. In only a few years, however, the energy landscape has changed significantly, with a focus on de-carbonization and a reluctance by the oil and gas industry to take on expensive new large-scale projects.

If the project sponsors of LNG Canada had assessed the energy landscape in 2021 instead of 2018, the changing landscape would have weighed much more heavily on their decisions.

LNG Canada began as an arbitrage opportunity to export natural gas trading at record low prices in British Columbia's largest unconventional natural gas play, the BC Montney. The landlocked nature of natural gas in British Columbia caused the province's price of natural gas to trade at a discount relative to other Canadian and U.S. natural gas hubs, making it the ideal natural gas feedstock for LNG Canada. LNG Canada's Phase 1 will take in the equivalent of one-third of natural gas produced from British Columbia in 2020 and transport it across the province to LNG Canada's Phase 1 liquefaction facility in Kitimat, B.C. From there, the liquefied natural gas will be shipped across the Pacific to markets in Asia, where it must compete for market share and cover the costs of this massively expensive LNG project compared to global alternatives. At full capacity, LNG Canada Phase 1 will export 14 million metric tons per year (MTPA) annually to Asian markets.

Since construction of LNG Canada began in 2019, however, several policy changes and operational issues have arisen that affect the project. Policies governing the sustainable development of natural gas production in the BC Montney have slowed the expectation for rapid development of unconventional natural gas production in British Columbia. The lower price environment for associated oil and natural gas

liquids (NGL) in the BC Montney's unconventional natural gas production and the steep decline rates from initial production of wells add to the pressure faced by LNG Canada's equity sponsors, who own a great deal of natural gas assets focused on Montney development.

Additionally, LNG Canada had contracted out the construction and development of the Coastal Gaslink (CGL) pipeline to operator and 35% owner, TC Energy, and is now disputing rising costs at CGL. TC Energy has threatened to suspend construction on parts of the CGL pipeline if the dispute is not resolved, further threatening the economic viability of LNG Canada. The LNG Canada terminal and CGL pipeline may become marginally profitable after the delays and cost overruns.

Market and non-market shifts could turn LNG Canada into a financial albatross.

The major motivation for the LNG Canada project is its equity sponsors' need to generate profit from the Montney gas assets purchased between 2008 and 2012. To avoid more asset writedowns or a fire-sale of their BC Montney assets, the equity sponsors of LNG Canada need the project to succeed to sell their gas to a higher valued market in Asia.

In the three years since the 2018 FID, **these market and non-market shifts have severely tested LNG Canada's long-term economic viability and could turn it into a financial albatross for its sponsors.** The fallout would jeopardize proposed major LNG projects along Canada's western coast, including Ksi Lisims LNG, LNG Canada Phase 2, Woodfibre LNG, and Cedar LNG (equivalent to more than double the capacity from LNG Canada Phase 1). The changing energy market conditions are quickly making LNG Canada a harbinger of the fragile economic profile and high risks for future LNG projects in the province.

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LNG Canada: An Overview and Rationale

LNG Canada is designed as a two-phase project, with a first phase that will produce 14 million tonnes per year (MTPA) of LNG. Its equity owners include global oil and gas giant Royal Dutch Shell (40%); the Malaysian national petroleum company Petronas (25%); Chinese national petroleum firm PetroChina (15%); international trading house Mitsubishi (15%); and Korean gas utility KOGAS (5%).¹ Each equity partner takes their percentage share of the LNG produced to use or resell. Shell retains 5.6 MTPA of LNG capacity, and the remaining 8.4 MTPA owned by the other partners is estimated to be 94% contracted over a weighted average life of 13.4 years.^{2,3,4,5,6,7} The first phase of the project for the 14 MTPA, scheduled to go into service in 2025 or 2026, carries a price tag of almost \$32 billion: \$14 billion for the liquefaction plant and dock, \$12.4 billion of gas production investments in the Montney Basin in northeastern British Columbia, and \$5.1 billion for the Coastal GasLink pipeline connecting the terminal to its gas supplies.⁸

The companies reached an FID—a final investment decision that committed it to move forward with Phase 1 of the project—in October 2018. Construction began in 2019. LNG Canada recently said that its 225,000 cubic meter Phase 1 storage tank is 50% complete, and that it expects liquefaction modules to be delivered during the fourth quarter of 2021. Construction on the Coastal Gaslink Pipeline (CGL), being led and constructed by pipeline company TC Energy, was 30% complete as of summer 2021.^{9,10}

When placed into service in 2025 or 2026, LNG Canada will have the capacity to liquefy and export up to 1.8 million British thermal units (“MMBtu”) per day of natural gas, about 1.8 billion cubic feet per day (BCF/d), which is the equivalent of one-third of total British Columbia natural gas production in 2020.¹¹ The project will move natural gas from the BC Montney formation near the city of Dawson Creek, BC to the province’s coastal liquefaction terminal in the municipality of Kitimat, B.C., through a 415-mile (670-kilometer) pipeline with 2.1 million MMBtu/d of capacity.¹² The pipeline’s \$5.1 billion price tag makes it one of the most expensive in North America at \$12.3 million per mile—more than double the cost for gas

¹ Oxford Energy Institute. [Canadian LNG Competitiveness](#). December 2019.

² Petronas. [Petronas and CNOOC Sign 10-Year LNG Supply Agreement](#). July 2021.

³ Reuters. [LNG Canada gets another buyer as Vitol inks supply deal with Petronas](#). November 2018.

⁴ Reuters. [JERA to buy up to 1.2 million tons per year of LNG from Canada project](#). April 2019.

⁵ Petrol Plaza. [Tokyo Gas signs agreement to purchase LNG from LNG Canada project](#). October 2018.

⁶ Offshore Energy. [Toho Gas inks LNG Canada supply deal](#). October 2018.

⁷ PetroChina Company Limited. [PetroChina invests in Phase 1 of its Canadian LNG Project](#). October 2018.

⁸ The Oxford Institute for Energy Studies. [Outlook for Competitive LNG Supply](#). March 2019.

⁹ LNG Canada. [LNG Canada Mid-Year Update. Summer 2021](#). July 2021.

¹⁰ LNG Canada. [LNG Canada Project Surpasses 50% Completion](#). October 2021.

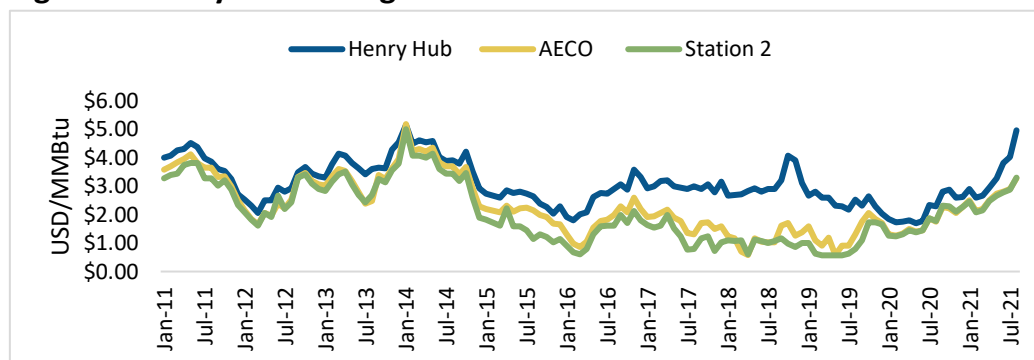
¹¹ Natural Gas Intelligence. [Montney on Track to Become Leading Canadian Natural Gas Play](#). December 2020.

¹² Oxford Energy Institute, *op. cit.*

pipelines on the U.S. Gulf Coast.¹³ The transport contracts are for 25 years, and LNG Canada is contractually obligated to pay for this firm capacity, whether they use it or not.¹⁴

In October 2018, when LNG Canada’s sponsors made an FID for the project,¹⁵ Montney Basin gas was as cheap as it had been in years. Prices in British Columbia’s landlocked Station 2 gas hub forced stranded supplies to sell at a 67 percent discount to U.S. Henry Hub prices, reaching as little as \$0.60 per MMBtu (See Figure 1). LNG Canada project sponsors saw the discount as an opportunity to use cheaply sourced natural gas to feed into an LNG terminal for export to Asia, where prices were much higher. The exports would help LNG Canada sponsors keep their natural gas assets in British Columbia and avoid further major writedowns in asset values or an outright fire sale of natural gas assets.

Figure 1: Henry Hub Divergence From British Columbia Natural Gas Prices



Source: GLJ, *Historical Price Charts*, September 2021.

Note: British Columbia natural gas price at Station 2 trades at an average discount of \$1 per MMBtu over 10 years.

Even though LNG Canada’s infrastructure costs would be almost double those of comparable LNG projects on the U.S. Gulf Coast,¹⁶ the project’s backers, led by global oil and gas giant Royal Dutch Shell, still believed that British Columbia’s cheap gas and low shipping costs to Asia would allow them to earn greater profits from LNG than they could realize by shipping gas to the U.S. and eastern Canada through the AECO gas hub in Alberta. LNG Canada sponsors understood that taking advantage of the arbitrage opportunity in northeast Asia could allow them to continue producing natural gas in British Columbia. The exports would prevent major writedowns or asset impairments to significant Montney gas reserves that might have remained stranded—devoid of economic value and at risk of being erased from the companies’ inventories of developable reserves.

¹³ *Ibid.*

¹⁴ Business Wire. [KKR to Acquire Significant Stake in Canada’s Coastal GasLink Pipeline Project](#). December 2019.

¹⁵ *Ibid.*

¹⁶ The Oxford Institute for Energy Studies, *op. cit.*

Natural Gas Production Is the Key Economic Driver for LNG Canada Sponsors

LNG Canada's backers made the FID in 2018 when other Canadian LNG export projects had stalled or failed. One critical factor set LNG Canada apart from its peers: The project's equity owners hoped to avoid writing down or selling all \$15.8 billion they had spent acquiring upstream natural gas assets in the BC Montney between 2008 and 2012.¹⁷

In 2014, plunging prices for oil, gas and natural gas liquids (NGLs) triggered a mass exodus of international oil and gas companies from Canada,¹⁸ forcing some companies to sell assets similar to those owned by LNG Canada equity owners in British Columbia at an 80% discount.¹⁹ Poor economics for both gas and NGLs forced LNG Canada's owners to choose between an LNG export project or exit the BC Montney entirely and face further write downs on their assets.

LNG Canada's sponsors saw two benefits from the project. First, they expected to capture higher netback selling gas to Asia as LNG than they could realize from North American markets. Second, shipping gas to Asia could alleviate oversupply and downside price pressure on the AECO and BC Station 2 gas hubs, potentially increasing margins for all gas produced in the Montney.

Shell, the initial and leading sponsor of LNG Canada, began accumulating tight oil and gas production, including BC Montney production, with the purchase of Duvernay Oil & Gas for \$5.5 billion in 2008.²⁰ Mitsubishi and KOGAS would follow suit in 2010 with joint venture partnerships with Penn West (now Obsidian Energy) and Encana (now Ovintiv Energy), respectively. Petronas, another LNG Canada partner, made one of the final major transactions in the Montney with the 2012 acquisition of Progress Energy for \$5.9 billion.²¹

Between 2014 and 2020, international exits and reorganizations accounted for \$38 billion of Canadian oil and gas assets sold. Talisman, Devon Energy, EOG Resources,

The project's equity owners hoped to avoid writing down or selling all \$15.8 billion they had spent acquiring upstream natural gas assets in the BC Montney.

¹⁷ IHS Connect. M&A Analytic: Upstream Companies and Transactions. October 2021.

¹⁸ EIA. [Weekly Cushing Cushing. OK WTI Spot Price FOB](#). October 2021.

¹⁹ IHS Connect. *op. cit.* (Includes all acquisitions by LNG Canada and sales of gas assets in the BC Montney. Bighorn. Clearwater. Pouce Coupe. Gundy. and Apache Deep Basin).

²⁰ IHS Connect, *op. cit.*

²¹ *Ibid.*

Total Energies, ConocoPhillips, Murphy Oil, Statoil, Marathon Oil, and APA Corporation all exited major producing areas in Canada.²² Meanwhile, the largest international oil producer, ExxonMobil, remained in Canada and faced a 3 billion barrel writedown of its Canadian assets.²³ ExxonMobil and its subsidiary, Imperial Oil, confirmed a low probability of bringing new oil sands projects to light in a volatile and competitive oil price environment.²⁴ Shell and Ovinitiv joined the exodus by selling \$14.3 billion in Canadian oil and gas assets concentrated mainly in Alberta.²⁵ But the companies remained committed to the BC Montney.

Nowhere were the ebbs and flows of decisions around asset sales tied to LNG more prominent than with Petronas. After purchasing Progress Energy in 2012, the company purchased BC Montney assets in 2014 from Talisman.²⁶ Petronas had plans for its own LNG project, Pacific Northwest LNG, along the British Columbia coast. The project was cancelled in 2016 after failing to obtain an FID.^{27,28} The cancellation led to Petronas putting up some of its Alberta Deep Basin natural gas assets for sale three months later,²⁹ while keeping its natural gas stake in the BC Montney to secure a natural gas supply in British Columbia pending its purchase of 25% of LNG Canada from Shell and KOGAS.³⁰

Optionality in Natural Gas Supply

In 2020, equity partners of LNG Canada owned, either directly or through partnership, some of the largest producing assets in British Columbia (Figure 2).

²² *Ibid.*

²³ IEEFA. ExxonMobil's 2020 financial report: "Re-de-booking" raises questions about actual size of reserves. March 2021.

²⁴ Financial Post. After massive writedown, Imperial Oil says no big projects in coming years. February 2021.

²⁵ *Ibid.*

²⁶ *Ibid.*

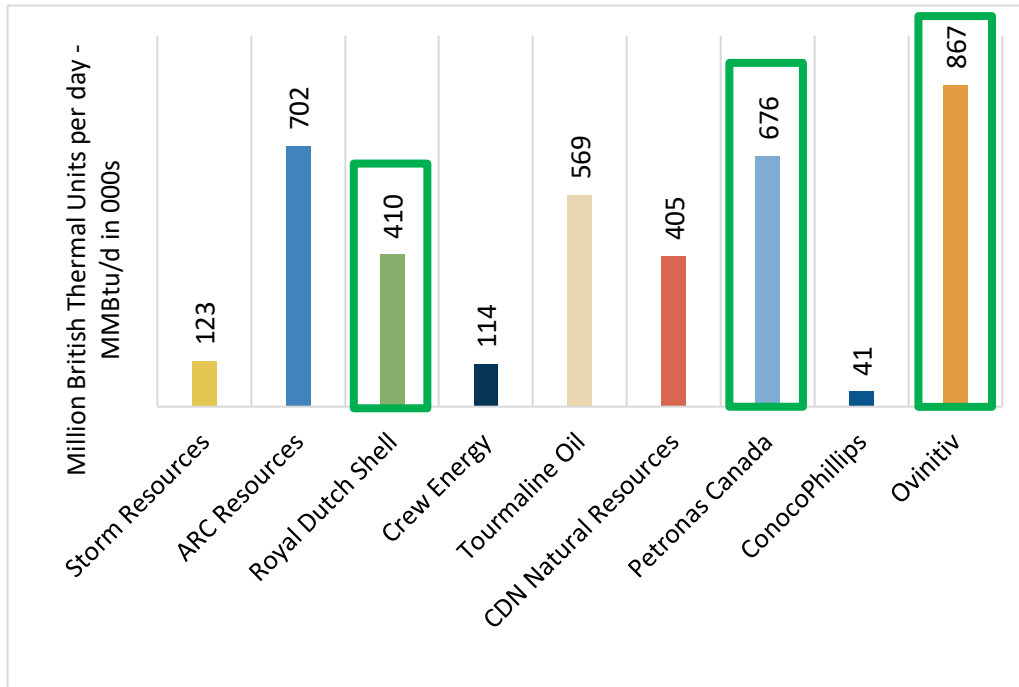
²⁷ Reuters. Petronas Canada LNG project chief sees investment decision in months. April 2016.

²⁸ Petronas. PETRONAS and Partners Will Not Proceed with Pacific Northwest Project. July 2017.

²⁹ Reuters, *op. cit.*

³⁰ Petronas, *op. cit.*

Figure 2: Natural Gas Producers in the BC Montney



Source: Company Reports, Q2 2020 Financial Reports/2020 Annual Information Form/ Company Presentations, Q2 2020.

Note: Total natural gas production reported by each company in British Columbia – predominantly from the BC Montney formation. The above producers control a majority of Montney natural gas production (estimated 95% of production) – Royal Dutch Shell (PetroChina 20% partner), Progress (Petronas 63% partner), Ovinitiv (operating partnerships with KOGAS in Horn River and Mitsubishi in Cutbank Ridge Partnership).

LNG Canada has a distinct advantage over most other North American LNG projects: The owners of the liquefaction facility also own the project’s likely gas supplies. The ownership structure gives LNG Canada’s equity holders valuable options. If market prices for gas are high, LNG Canada owners can tap their own lower-cost supplies. If prices remain low, they buy natural gas feedstock from the market, saving on upstream capital costs. In the 2018 FID announcement, Shell suggested that their Montney gas supplies have a breakeven price of \$2/MMBtu.³¹ But costs have fallen, and Shell recently estimated a \$1.40/MMBtu breakeven price.³² LNG Canada’s ownership of natural gas assets in British Columbia gives it the ability to adjust natural gas feedstock and avoid significant third-party sourcing contracts with natural gas producers.

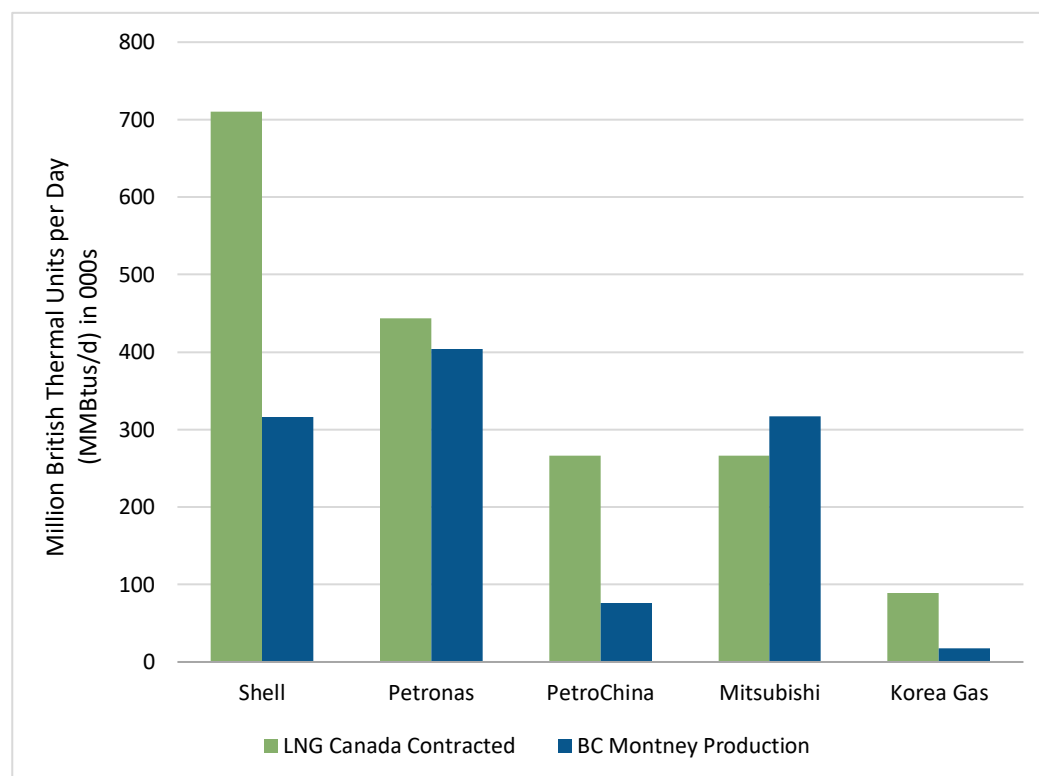
A major setback to the strategy is that LNG Canada’s sponsors produce about 36% less gas than LNG Canada would demand (See Figure 3). If LNG Canada’s sponsors are

³¹ Royal Dutch Shell Plc. [LNG Canada Final Investment Decision](#). October 2018.

³² The Oxford Institute for Energy Studies, *op. cit.*

unable to ramp up gas production fast enough, they may have to rely on market natural gas purchases when the project starts.³³

Figure 3: Feedstock Shortfall Needed to Meet LNG Canada Demand^{34,35}



Note: Based on equity ownership of LNG Canada (Shell (40%), Petronas (25%), PetroChina (15%), Mitsubishi (15%), KOGAS (5%)) and stated production based on Royal Dutch Shell (PetroChina 20% partner), Progress (Petronas 62% partner), Ovinitiv (operating partnerships with KOGAS in Horn River and Mitsubishi in Cutbank Ridge Partnership).

Three factors could contribute to a scenario in which LNG Canada owners may not be able to develop their natural gas assets to meet their respective obligations and benefit from their production options in the BC Montney.

1. **Falling oil prices** could reduce incentives for gas production. Top British Columbia natural gas producers rely on ultra-light oil (condensate) and NGLs to increase the value of their natural gas production. Most liquids-rich or wet natural gas wells in British Columbia can produce 20% to 25% liquids.^{36,37} Sustained declines in oil and NGL prices could result in reduced drilling for wet natural gas wells in British Columbia and Alberta. If the price

³³ *Ibid.*

³⁴ Company Reports. Q2 2020 Financial Reports/2020 Annual Information Form/Company Presentations. Q2 2020.

³⁵ The Oxford Institute for Energy Studies, *op. cit.*

³⁶ Tourmaline Oil. Corporate Presentation. September 2021.

³⁷ Arc Resources Ltd. Investor Presentation. September 2021.

of oil and NGLs remain under pressure and producers are unable to realize higher priced barrels of oil equivalent (boe) that keep each barrel marginally profitable, they may lack an incentive to increase production.

2. **Decline rates** are the most important issue facing unconventional natural gas production in North America. Within roughly 18 months, a new BC Montney well's production will decline by an average of 55% from its initial 30-day average.³⁸ Fast declines create a production treadmill, requiring ever more wells just to keep production flat. If companies are unable or unwilling to drill enough wells to offset declines, the declines could have a dampening impact on future growth in natural gas production rates. Rapid decline rates from hydraulically fractured (fracked) wells—and the massive capital spending required to increase unconventional oil & gas production—were at the root of North American oil and gas companies' decade of negative free cash flows.³⁹

Decline rates are the most important issue facing unconventional natural gas production in North America.

3. **BC's policy changes** went through a dramatic and permanent change in the summer of 2021. Many natural gas producers in the BC Montney paid close attention to the British Columbia Supreme Court's decision in *Yahey v. British Columbia*, which caused a complete halt in British Columbia drilling licences for two months in summer 2021.⁴⁰ The court found that the provincial government had infringed on the rights of the Blueberry River First Nations (BRFN) under the Treaty 8 agreement signed in 1899 between various First Nations and the Canadian government. The court found cumulative impacts of industrial development approved by the provincial government had diminished BRFN's rights within its traditional territory because of adverse effects on the environment that interfered with BRFN's way of life.⁴¹

While the British Columbia government has reached an agreement on existing permits and funding for restoration with the BRFN,⁴² *Yahey v. British*

³⁸ Canada Energy Regulator. *Canada's Energy Future 2018 Supplement: Natural Gas Production*. May 2019.

³⁹ IEEFA. *U.S. Fracking Sector Spills More Red Ink—Again*. November 2019.

⁴⁰ Daily Oil Bulletin. *No New Wells Approved Last Month In B.C.; Province And BRFN Continue To Work On Interim Decision-Making Plan*. September 2021.

⁴¹ Osler. *British Columbia Supreme Court issues precedent-setting cumulative effects decision*. July 2021.

⁴² BC Government News. *B.C. Blueberry River First Nations reach agreement on existing permits, restoration funding*. October 2021.

Columbia has permanently changed the provincial policy, giving the BRFN approval authority over future development projects in its traditional territories. According to the agreement reached between BRFN and the British Columbia government:

“The [BC] Province and Blueberry [BRFN] are now working to finalize an interim approach for reviewing new natural resource activities that balance Treaty 8 rights, the economy and the environment.”⁴³

BRFN’s traditional territories, including parts of the BC Montney, overlap the traditional territories of several other First Nation groups who were not part of this ruling.⁴⁴ Surrounding First Nation groups may be looking at this ruling as setting precedent for their own territorial rights challenges related to Treaty 8 and the cumulative impacts of industrial development.⁴⁵

LNG Canada’s sponsors committed to the BC Montney to establish an integrated gas production and liquefaction business model. This ensured supply options for LNG Canada, supply security, and overall price flexibility. Yet economic factors such as sustained lower oil and NGL pricing; operational factors including fast production declines; and policy factors have all put their strategy at risk. If LNG Canada equity owners are unable to ramp up production significantly, they lose their integration advantage and remain dependent on market natural gas production from third-party producers.

Costly Infrastructure: Coastal Gaslink vs. LNG Canada

The size and scale of LNG Canada make it difficult to integrate the entire value chain, especially when considering almost \$20 billion in infrastructure spending.⁴⁶ Measured per MMBtu of LNG production capacity, the infrastructure costs for LNG Canada dwarf typical LNG projects in the U.S. Gulf Coast (see Figure 4). For LNG Canada to reduce the burdensome infrastructure costs, TC Energy was chosen as owner and operator of LNG Canada’s 415-mile Coastal Gaslink pipeline that would transport 2.1 million MMBtu/d of natural gas (about 2.1 BCF/d) from the BC Montney to the British Columbia coast.⁴⁷ The original estimated price tag of CGL came in at \$4.2 billion, close to 15% of the total cost of LNG Canada. But 3 years into the pipeline’s development the costs and completion dates remain uncertain, with some estimates significantly more than \$5.1 billion.⁴⁸

⁴³ BC Government New, *op. cit.*

⁴⁴ Osler, *op. cit.*

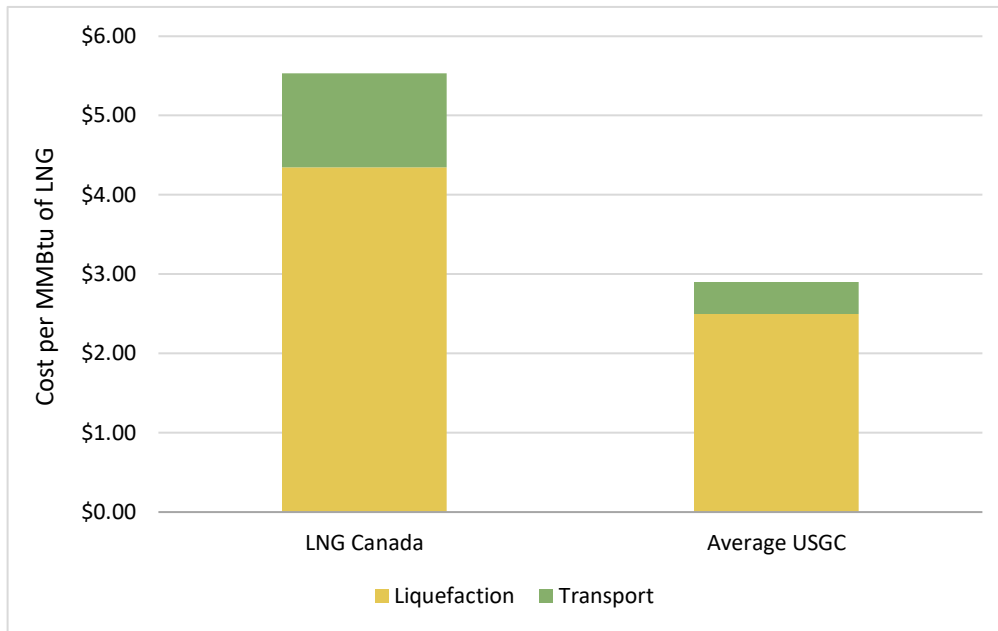
⁴⁵ Vancouver Sun. [Blueberry River First Nations triumphs in court over BC government](#). July 2021.

⁴⁶ The Oxford Institute for Energy Studies, *op. cit.*

⁴⁷ IHS Connect. Liquefaction Project Profile Canada: LNG Canada. July 2021.

⁴⁸ *Ibid.*

Figure 4: Infrastructure Cost per MMBtu LNG Canada vs. USGC^{49, 50, 51}



Note: Estimates averaged from Oxford Institute and IHS estimates on LNG costs including pricing estimates of contracted LNG—infrastructure costs rise in Canada due to greenfield nature of projects and extended proximity from major infrastructure in British Columbia coast and the Rocky Mountains.

CGL is an essential part of moving natural gas from the BC Montney to the British Columbia coast for Asian markets. Unlike Alberta, British Columbia had not built out significant transportation capacity for natural gas and relied on intra-provincial pipelines to get much of its natural gas to foreign markets (see Figure 5). Almost a decade ago, 26% of natural gas from British Columbia was exported directly to U.S. markets, with 57% needing to pass through Alberta to reach Canadian and U.S. markets.⁵² In 2020, 17% was exported directly to the U.S. and 71% was exported through Alberta and to the U.S.

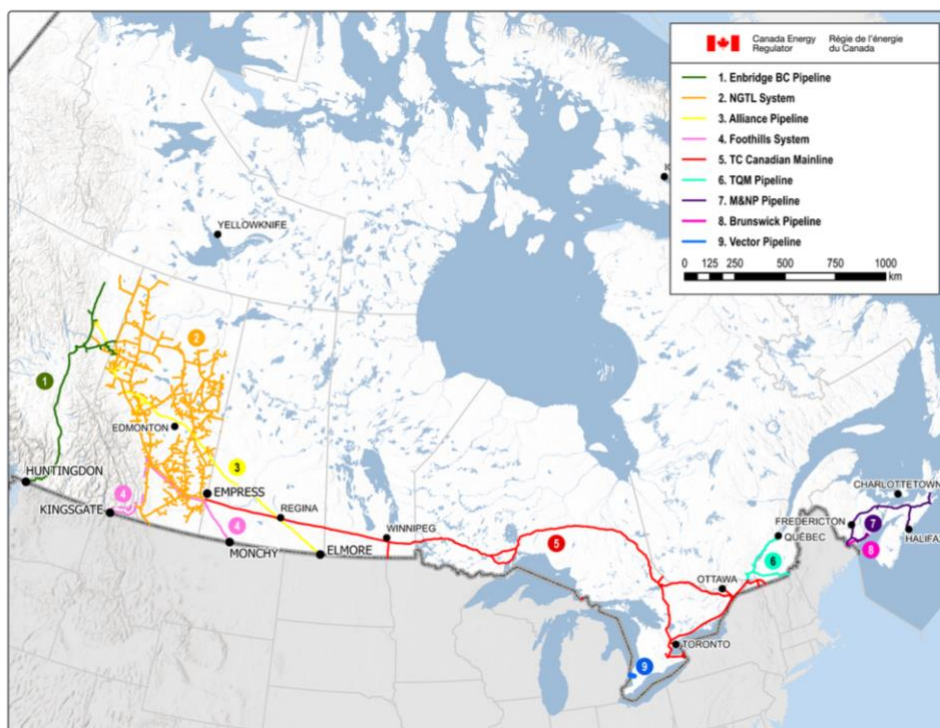
⁴⁹ The Oxford Institute for Energy Studies. [Canadian LNG Competitiveness](#). December 2019.

⁵⁰ Canada Energy Research Institute. [Competitive Analysis of Canadian LNG](#). July 2018.

⁵¹ IHS Connect. [Liquefaction Project Profile Canada: LNG Canada](#). July 2021.

⁵² British Columbia. [Natural Gas and Oil Statistics](#). July 2021.

Figure 5: Major Existing Natural Gas Pipelines in Canada



Source: Canada Energy Regulator, *Natural Gas Pipeline Transportation Systems*, August 2021.
Note: Major pipelines regulated by the Canada Energy Regulator focused on the transportation of natural gas within and exported from Canada.

The CGL pipeline is dedicated to major markets in Asia through LNG Canada. Yet few producers are likely to benefit from this pipeline. LNG Canada equity owners will remain committed to tying in most of their production in the BC Montney into CGL through a network of connecting pipelines just west of Dawson Creek.

Cost Creep of Coastal Gaslink

TC Energy's CGL pipeline has been a problem for LNG Canada due to continued delays and in-construction cost estimate increases since FID in 2018.⁵³ The \$4 billion project announced in 2012 became a \$4.6 billion project after LNG Canada's FID in 2018.⁵⁴ Costs have risen to \$5.1 billion due to permit delays, changing construction scope, and COVID-19 restrictions.⁵⁵

Rising costs create issues for new CGL investors and their potential returns. First, CGL's construction began after reducing the risk of the project's projected cash flows through a 25-year transport service agreement with LNG Canada.⁵⁶ The commitment motivated large private equity investors—including KKR's

⁵³ FitchRatings. *Fitch Affirms TC Energy Corporation at 'A-'; Outlook to Negative*. March 2020.

⁵⁴ IHS Connect, *op. cit.*

⁵⁵ *Ibid.*

⁵⁶ Business Wire. *KKR to Acquire Significant Stake in Canada's Coastal GasLink Pipeline Project*. December 2019.

infrastructure account through a partnership with the National Pension Service of Korea and Alberta Investment Management Corporation—to acquire a 65% interest in the project, providing TC Energy with an after-tax gain of \$456 million.⁵⁷ The participation of private equity in the December 2019 deal was an opportunity for TC Energy to reduce its exposure to CGL, reduce investment risk by bringing on large potential capital contributors to CGL and secure \$4 billion in project financing for 80% of the construction of CGL. However, the new private equity partners altered the power dynamic between LNG Canada and CGL.

As costs rose and TC Energy warned of more cost overruns, the relationship between the pipeline and LNG Canada frayed. TC Energy warned it would need to boost LNG Canada's firm transport rates to LNG Canada so that CGL and its private equity partners could recoup their costs and achieve their targeted returns.⁵⁸ LNG Canada resisted rate increases, however, fearing higher project costs. LNG Canada and CGL are discussing how to share the CGL cost overruns.⁵⁹

**If costs rise by 15%, NPV
becomes negative.**

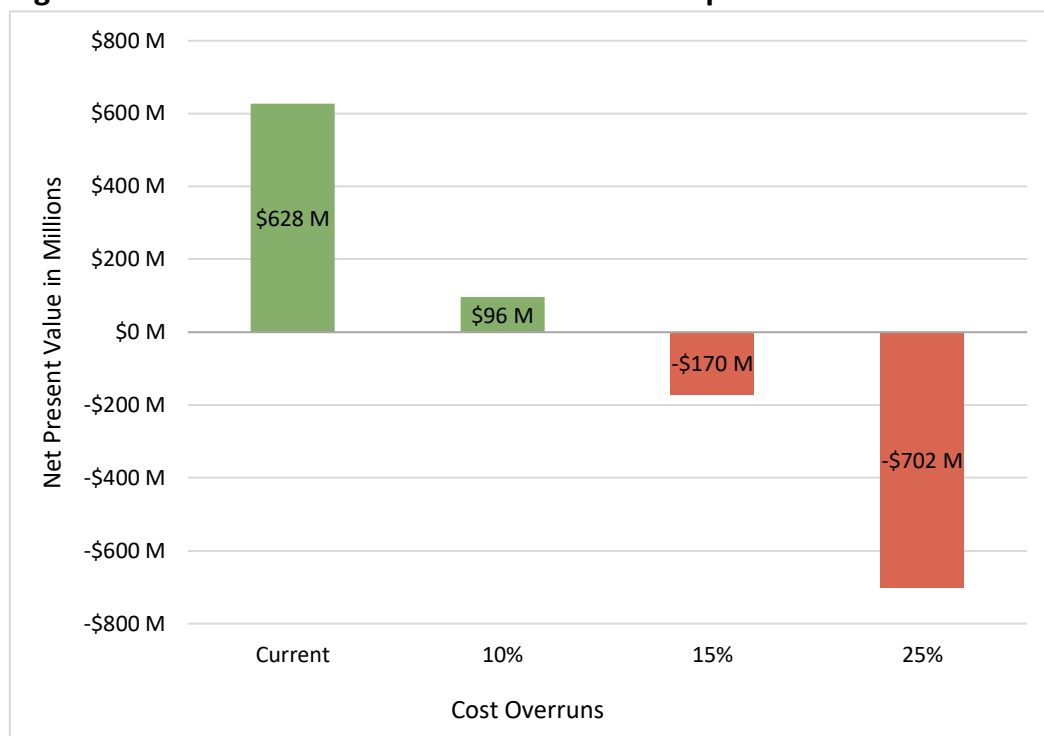
Using different cost overrun assumptions with the net present value (NPV) of CGL's future cash flows, IEEFA finds that CGL faces significant financial risks if it fails to negotiate higher fees. IEEFA estimates that CGL's net present value is currently \$628 million (see Figure 6). If costs continue to rise another 10%, then the NPV of CGL declines to \$96 million. If costs rise by 15%, NPV becomes negative, meaning it would not make sense for TC Energy to finish the project's construction, forcing the company to walk away from its development contracts.

⁵⁷ Reuters. [KKR. Alberta Investment to buy majority stake in Canada's Coastal GasLink](#). December 2019.

⁵⁸ TC Energy. [Management Discussion and Analysis 2020](#). February 2021.

⁵⁹ The Financial Post. [LNG Canada project threatened amid cost dispute over Coastal GasLink pipeline](#). July 2021.

Figure 6: Net Present Value Calculation of CGL Pipeline^{60, 61, 62, 63}



Note: Estimates on capacity of CGL: 2.0 million MMBtu/d, Operating Costs: 40% of Revenue, Capacity 75% in 2026 to 100% in 2029, Inflation: 2%, Tolls: Increasing from CAD \$0.92 to CAD \$1.63 over 29 years, Discount Rate: 6%, Cost of Debt: 3%, Depreciation: Straight line 30-years at CAD \$6.2 billion, Maintenance Capital Expenditures: CAD \$42 million per year, Debt used in development & construction: CAD \$5 billion.

To offset rising costs and lower NPVs, CGL equity owners would need to increase the transportation fees that generate most of their revenue. For LNG Canada, tolls would only increase delivered natural gas feedstock costs. The current average price per MMBtu to move natural gas through CGL for 30 years is about \$1.18/MMBtu.^{64, 65} If costs rise, CGL will have to increase rates by about the same amount of the cost increases, resulting in a potential cost increase for LNG Canada of \$0.38/MMBtu or a 7% increase in the total LNG costs. TC Energy has threatened to suspend certain construction projects along CGL until a settlement is reached over rate increases with LNG Canada.⁶⁶ Any suspension or further delay is likely to exacerbate rising future costs for CGL and LNG Canada.

⁶⁰ The Oxford Institute for Energy Studies, *op. cit.*

⁶¹ Canada Energy Research Institute, *op. cit.*

⁶² Keyera Corp. & Pembina Pipeline. Management Discussion and Analysis 2020. FY 2020.

⁶³ Statistics Canada. [List of depreciation rates under the new asset code classification — Engineering construction \(communication, oil and gas, mining, and other\)](#). November 2015.

⁶⁴ IHS Connect, *op. cit.*

⁶⁵ Canada Energy Research Institute, *op. cit.*

⁶⁶ Reuters. [TC Energy warns Coastal Gaslink pipeline dispute could impact construction](#). July 2021.

The dispute between LNG Canada and CGL over cost overruns reveals the fragility of LNG Canada's finances. In its 2018 FID, Shell anticipated an internal rate of return (IRR) of 13% on the integrated LNG Canada project with a long-term LNG price of \$8.50 per MMBtu delivered to Asia, including shipping.⁶⁷ If LNG Canada is unable to control the price of natural gas feedstock and is unable to mitigate cost increases from CGL, then IRRs may be squeezed. The total cost per MMBtu could rise past \$8.50. The increased cost would leave LNG Canada and its equity partners more exposed to price risks in Asian LNG markets as the project goes into production in 2026.⁶⁸

Changing Economic and ESG Environment

During the depths of the COVID-19 crisis in 2020, global LNG prices fell to their lowest level in history. But recent LNG supply and demand disruptions, along with a rebounding global economy, have caused worldwide spot LNG prices to spike dramatically. The average short-term spot LNG price for a winter peak cargo for delivery to Northeast Asia in November 2021 is now \$38.50/MMBtu,⁶⁹ up from just \$4.90/MMBtu the prior year.⁷⁰

Long-term LNG supply and demand trends in Asia will determine LNG Canada's economic viability.

The short-term trends may mean little for LNG Canada, which won't go into service for at least another four years. Instead, long-term LNG supply and demand trends in Asia will determine LNG Canada's economic viability. According to Fitch Ratings and the five-year JKM future shorter term Asian spot pricing (Figure 7), the influx of projects starting up post-2023 may result in oversupply. Such a glut would cause long-term pricing of LNG to soften into 2026 to an average range of \$7.47 to \$7.72/MMBtu.⁷¹

⁶⁷ Royal Dutch Shell, *op. cit.*

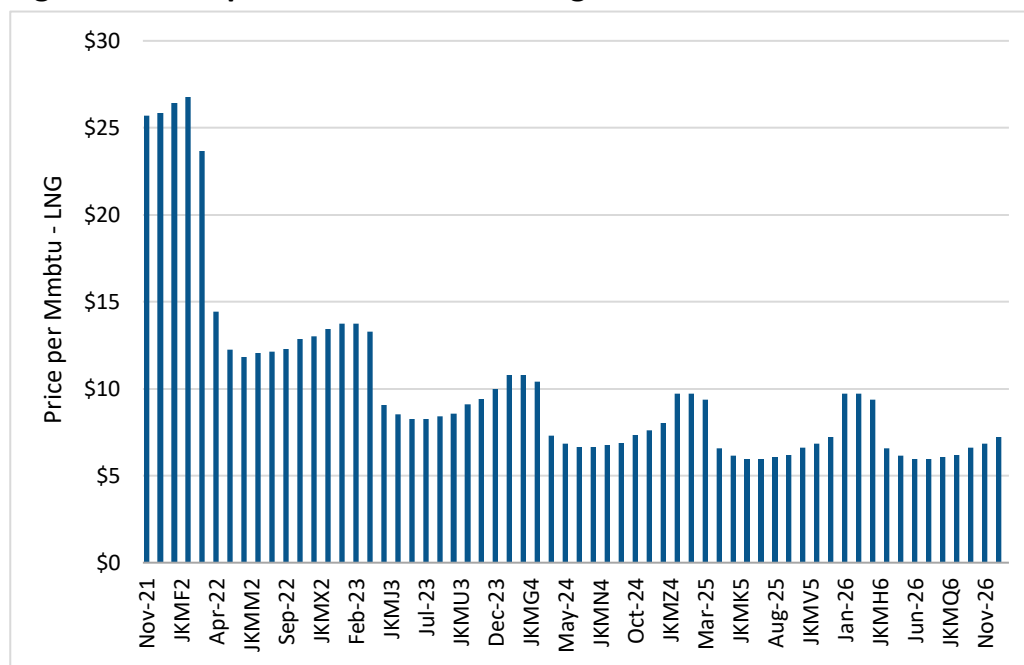
⁶⁸ IHS Connect, *op. cit.*

⁶⁹ Reuters. [Asia LNG price rise on firm Chinese demand. eyes on Russian flow.](#) October 2021.

⁷⁰ Reuters. [Global LNG-Asian LNG prices rise on winter demand expectations.](#) September 2020.

⁷¹ Fitch Ratings. [LNG Oversupply Shrinks. Excess Liquefaction Capacity Is a Risk.](#) January 2021.

Figure 7: JKM Spot Futures Prices Falling Into 2026



Source: CME Group, *JKM Futures Prices*, September 2021.

Note: Future price current LNG buyers in Asia can lock in to purchase JKM priced LNG cargoes later or hedge against future volatility in pricing.

Lower price forecasts highlight the shifting imbalance between global LNG demand and supply. LNG projects are multi-year infrastructure projects that require an in-depth outlook at the time the project plans its first LNG shipment. Projects can be segmented into greenfield and brownfield projects that vary in their execution and timing risks. Brownfield projects often leverage existing infrastructure and facilities, requiring less time, money, and permitting begin construction and development. LNG Canada is a greenfield project because of the new-build pipeline, LNG facility, and ramp-up in BC Montney production needed to complete the project. LNG Canada is expected to take eight years from FID to first LNG shipment in the mid-2020s. Between 2023 and LNG Canada’s completion date of 2025-26, 100 MTPA of new LNG will come online; around 90 MTPA of the 100 MTPA will come from brownfield projects.⁷² The additional capacity will lead to a 23% increase in LNG delivery capacity while demand is expected to rise by 15%.⁷³ All market dynamics point to an oversupplied LNG market as LNG Canada starts to ship in 2025 or 2026.

LNG Canada’s razor-thin margins to generate substantial returns show the project’s sensitivity to Asian LNG prices. Under Shell’s long-term price assumption of \$8.50/MMBtu delivered to Asian buyers, LNG Canada partners require the cost of natural gas to be \$1.40/MMBtu to remain profitable (see Figure 8).

⁷² The Oxford Institute for Energy Studies, *op. cit.*

⁷³ BloombergNEF. *Global LNG outlook 2021-2025 overview*. June 2021.

For our LNG Canada economic analysis, we use Shell’s long-term contracted price, which gives us a delivered (DES) price of \$8.50/MMBtu. Subtracting a long-term shipping charter rate of \$0.90/MMBtu, an estimated liquefaction and loading fee at the LNG Canada terminal of \$4.25/MMBtu, and delivery charges through the CGL pipeline of \$1.24/MMBtu results in a netback price of \$2.11/MMBtu into the CGL pipeline (Figure 8). Then, subtracting the existing priced development costs required to maintain feed gas to LNG Canada of \$0.05/MMBtu leaves producers with a gas price of \$2.06/MMBtu (Figure 8). LNG Canada’s project sponsors feared the continual flooding of its natural gas production to domestic markets in British Columbia and Alberta would further depress long-term pricing of BC Station 2 and AECO markets. Therefore, LNG Canada was the only outlet for the sponsors of LNG Canada to get natural gas to market in a profitable manner.

Figure 8: LNG Canada Economics to Asia^{74,75,76,77,78}

LNG Profit Margin at \$8.50 per MMBtu + 10% Cost Overrun at CGL Pipeline	Shell Optimal Breakeven Groundbirch (\$1.40/MMBtu)	Shell 2018 FID Estimate Breakeven Groundbirch (\$2.00/MMBtu)	Forecast BC Station 2 into 2030 (\$2.40/MMBtu)
LNG Delivery Price	\$8.50	\$8.50	\$8.50
Delivery Costs			
Shipping	\$0.90	\$0.90	\$0.90
Infrastructure Costs			
Liquefaction Cost	\$4.25	\$4.25	\$4.25
CGL Pipeline Cost	\$1.24	\$1.24	\$1.24
Realized Price into CGL Delivered	\$2.11	\$2.11	\$2.11
Cost of Natural Gas			
Total Delivery Cost to CGL	\$1.40	\$2.00	\$2.46
Development Costs - 30 Years	\$0.05	\$0.05	\$0.05
Profit to Natural Gas Producer	\$0.66	\$0.06	-\$0.41
Return on MMBtu	46.9%	2.8%	-15.5%
Breakeven	\$7.84	\$8.44	\$8.91

Note: Estimates used in Figure 6 used for CGL pipeline, assume capital expenditure estimates of \$12.4 billion as estimated by Shell for development of reserves including initial capital expenditure to drill and tie in wells to sustain production over 30 years. Shipping costs assume \$83,000/day, long-term charter rates for LNG cargo, economics assume 10% cost overruns at CGL along with three natural gas price scenarios: Shell lowest-cost natural gas, Shell FID cost natural gas, and market price of natural gas at BC Station 2 and AECO.

⁷⁴ The Oxford Institute for Energy Studies, *op. cit.*

⁷⁵ Royal Dutch Shell Plc (“Shell”), *op. cit.*

⁷⁶ GLJ. [Historical Price Charts](#). September 2021.

⁷⁷ Canada Energy Research Institute, *op. cit.*

⁷⁸ IHS Connect, *op. cit.*

Since LNG Canada's 2018 FID, it is plausible to assume operating costs have fallen enough to justify a \$1.40/MMBtu cost base for natural gas. From 2018 to 2020, operating costs fell 26% from major BC Montney producers that would feed into LNG Canada.⁷⁹ The drop could justify Shell's stated natural gas breakeven price in the Montney falling from \$2/MMBtu to roughly \$1.40/MMBtu.⁸⁰ However, this would imply that LNG Canada's upstream assets would meet all obligations arising from LNG Canada's liquefaction facility and that Shell's breakeven costs are reflective of the costs for Petronas Canada, Ovinitiv, and Obsidian Energy. In a best-case scenario, the breakeven price for LNG Canada's shipments to Asia would be \$7.84/MMBtu which exceeds long-term pricing to Northeast Asia of \$7.47 to \$7.72/MMBtu into 2026 (see Figure 8). If natural gas prices in British Columbia and Alberta continue to rise, or costs climb and LNG Canada is unable to supply all gas from their owned upstream assets, the project's profits are threatened even at Shell's long-term LNG price forecast of \$8.50/MMBtu (see Figure 8). Over the long run, the economic argument for LNG Canada is dwindling as pricing remains depressed, driven by the likelihood of an oversupplied global LNG market into 2023.

Environmental Impact of LNG Canada

Added supplies of LNG for Northeast Asian markets have forced medium-term LNG pricing to remain below estimated costs of LNG Canada. The waning economic argument for LNG Canada has put its environmental record at the forefront. LNG Canada claims lower greenhouse gas (GHG) emissions than other major LNG projects around the world; however, this does not consider dedicated GHG emissions from infrastructure like CGL and upstream investment from LNG Canada sponsors. Accounting for dedicated GHG emissions directly related to LNG Canada, the environmental picture is less optimistic.

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The fossil fuel industry has made countless arguments for natural gas as a transition fuel to a greener global economy. Data from the Energy Information Administration shows natural gas generates around half the CO₂ emissions of a comparable amount of coal when burned.⁸¹ Countries are rushing to natural gas under the rhetoric of natural gas as a bridge fuel to target new GHG emission levels in 2030. Japan has targeted a 46% reduction in GHG emissions from 2013 levels, South Korea has targeted a 40% reduction in GHG emissions from 2017 levels, and China has stated intentions to "phase down" coal use by 2026.⁸² What is not being considered are the goals of British Columbia—the province has set a GHG emissions target of reducing

⁷⁹ Company Reports, *op. cit.*

⁸⁰ The Oxford Institute for Energy Studies, *op. cit.*

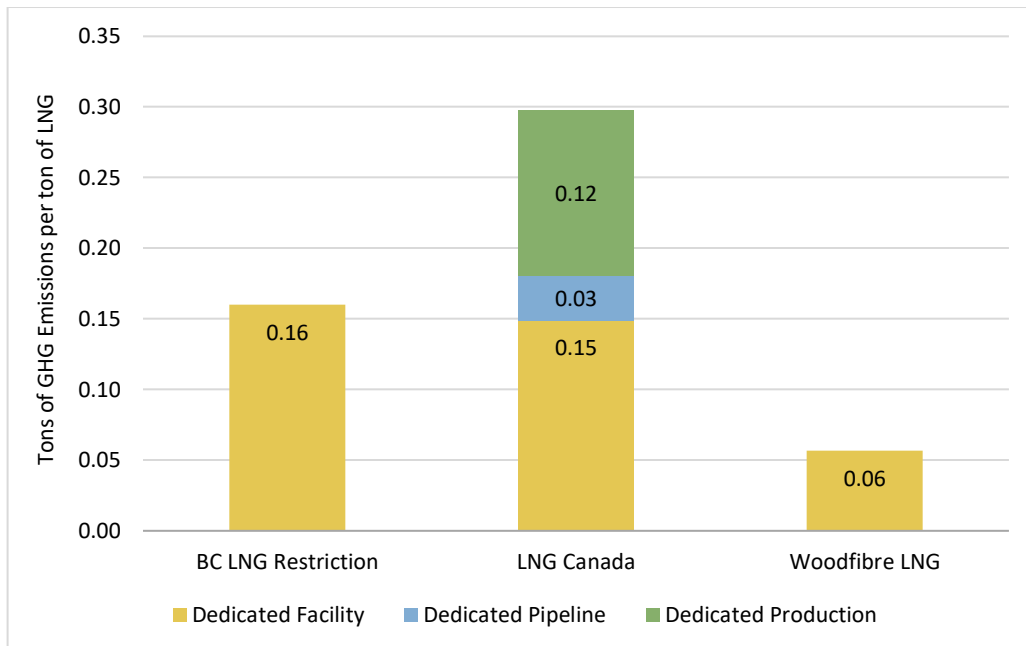
⁸¹ EIA. [How much carbon dioxide is produced when different fuels are burned.](#) June 2021.

⁸² Climate Action Tracker. [Countries.](#) October 2021.

40% of emissions from 2007 levels.⁸³ The data reveal that British Columbia is not on track to achieving 2030 goals as GHG emissions continue to rise. From 2007 to 2018, GHG emissions have risen by 7 percent (or 6 percent if offset projects are included). What is pertinent to environmental objectives in British Columbia is whether LNG Canada is bringing the province toward GHG emissions targets for 2030, or if the British Columbia government considers targets as mere suggestions.

On a relative basis, LNG Canada does not have a spectacular GHG emission record. The 0.15 tons of GHG emissions/ton of LNG exported is low relative to comparable global emissions. Within Canada, LNG Canada is not substantially better than limits imposed in British Columbia for LNG project approvals (see Figure 9).

Figure 9: LNG Canada GHG Emissions Comparables^{84, 85, 86}



Source: GHG emissions measured for Phase 1 take total emissions from ongoing LNG Canada operations and split them in half in the proposed 2-phase development method. LNG Canada assumes the use of natural gas turbines and 100 megawatts of power from Site C. Unlike LNG Canada, Woodfibre LNG will be using hydroelectric for power generation to significantly reduce emissions relative to LNG Canada.

Also, Shell’s analysis of GHG emissions does not even factor in the full dedicated GHG emissions from accompanying projects like CGL and LNG Canada’s upstream assets. The 0.15 tons of emissions per ton of LNG only considers power generation and ongoing annual emissions from operations of LNG Canada over the project’s life (Figure 9). If the GHG emissions of CGL and 1.8 million MMBtu/d of dedicated

⁸³ Clean BC. [2020 Climate Change Accountability Report](#). 2020.

⁸⁴ The Oxford Institute for Energy Studies, *op. cit.*

⁸⁵ LNG Canada. [LNG Canada Export Terminal](#). October 2014.

⁸⁶ Program on Water Governance. [Comparative Analysis of Green House Gas Emissions of Site C versus Alternatives](#). July 2016.

upstream natural gas production are included in this calculation, the emissions per ton of LNG exported rises to 0.30 tons, or twice what was originally indicated by LNG Canada.^{87,88} Total annual dedicated GHG emissions from LNG Canada would increase GHG emissions in British Columbia by another 7 percent.

LNG Canada is a large infrastructure project at the mercy of the ebbs and flows of supply and demand surpluses of LNG in the global market. While the current market is undersupplied, it appears LNG Canada will deliver cargoes into an oversupplied market in the mid-2020s. Subject to pending cost overruns on LNG Canada infrastructure and uncertainties around securing cheap natural gas sources from LNG Canada's own supply of upstream assets, the economic argument for LNG Canada is deteriorating. Also, the project adds to British Columbia's environmental burden, which the government has targeted a 40% GHG emissions reduction from 2007 levels by 2030 but does not remain on track to achieve those targets.

Conclusion

Multinational oil and gas companies are used to considering political risk in their investment decisions for countries with challenging investment landscapes and tensions that prevent massive investment in their fossil fuel industries. Since Shell's first foray into the Montney with the 2008 acquisition of Duvernay Oil Corp. a massive political, economic, and environmental shift has occurred in Canada. The same political risk considerations are a growing part of investing in Canada and large capital-intensive marginal return projects like LNG Canada are not conducive to this investment environment.

LNG Canada's Phase 1 faces general difficulties around growing production from unconventional natural gas wells in the BC Montney; lower priced liquids that had offered better prices to wet natural gas production, policy changes around Montney development in British Columbia; and cost overruns of the CGL pipeline. These factors have increased the cost of LNG Canada past the medium-term outlook for Asian LNG prices in 2024-2026. **With the changes, the backers of LNG Canada might have reconsidered their FID decision had it been made in today's market.**

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At this point, there is not a clear path to an FID for other LNG export projects on the British Columbia coast.

⁸⁷ LNG Canada, *op. cit.*

⁸⁸ Tourmaline Oil, *op. cit.*

As the world shifts to tackle climate change and reduce GHG emissions, the province will need to engage in some hard discussions about LNG Canada's Phase 1 impacts and whether British Columbia is serious about reaching its 2030 climate goals.

LNG Canada once stood as a beacon of optimism for the natural gas industry in British Columbia. Only time will tell if LNG Canada manages to squeeze out profits, or if it becomes another painful lesson for Canada's oil and gas industry.

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