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The Ksi Lisims LNG Project and the Broader Canadian LNG Sector Face Strategic Challenges: An IEEFA Assessment

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Contents

Figures and Tables

Key Findings

The Ksi Lisims LNG project faces significant infrastructure, regulatory, and financial risks that are compounded by a looming global LNG supply glut and thin industry margins.

The Ksi Lisims LNG project faces significant infrastructure, regulatory, and financial risks that are compounded by a looming global LNG supply glut and thin industry margins.

The Canadian LNG industry currently enjoys abundant, relatively low-cost natural gas, but domestic market dynamics are changing.

One of Western Canada's competitive advantages—its closer location to key Asian markets—may be insufficient to ensure long-term project competitiveness.

Executive Summary

The proposed Ksi Lisims liquefied natural gas (LNG) project faces numerous downside risks. Chief among these is the absence of a secured pipeline to transport feed gas to the terminal. The electrification of the facility is a critical factor for proponents to achieve plans for low-emission LNG and to comply with provincial regulations. However, the ability of BC Hydro to supply the terminal electricity within required timelines is uncertain. A lack of dedicated buyers for production exposes the project to significant income volatility and spot market uncertainties. The choice of twin floating LNG barges to hoist the liquefaction process presents additional project risks and delivers fewer economic benefits for local communities. After factoring key infrastructure challenges, inflation and the potential for delays and cost overruns, it becomes highly unlikely that the project can be delivered within the budget estimates initially put forward by its proponents.

Further compounding these challenges are broader industry headwinds: an impending global LNG supply glut, potential domestic gas price volatility and inflationary trade actions that threaten to disrupt global supply chains. While the Canadian LNG industry enjoys abundant and relatively low-cost natural gas, this benefit may prove transient as domestic market dynamics evolve. Producers in Canada must contend with competition from suppliers in other jurisdictions, some with more material and durable competitive advantages. Western Canada's location in closer proximity to key Asian markets presents a structural advantage, but it may be insufficient to ensure long-term project competitiveness.

Stakeholders in an LNG project collectively bear the projects risks but often face disproportionate and sometimes divergent financial, environmental and social outcomes. Provincial and federal governments face negligible direct financial risks due to limited equity stakes in projects and established revenue bases. For members of the public, potential short- to medium-term economic gains must be weighed against long-term risks to affordability, environmental quality and economic stability. Upstream producer investors provide risk capital and are exposed to material risk in a downside scenario; however, they may be able to derive significant benefits even amid market uncertainty and financially challenged projects. For First Nation investors, profit-sharing agreements offer potential income. However, equity stakes could involve the assumption of outsized risks relative to the capacity to absorb losses. Equity owners also face decommissioning and environmental remediation liabilities that may exist long after a project ceases economic operation.

Introduction

The proposed Ksi Lisims liquefied natural gas (LNG) project represents a highly uncertain endeavour in Canada's challenged LNG sector. While the project is promoted as yielding economic benefits, it faces significant downside risks stemming from critical infrastructure gaps, regulatory challenges, community opposition and a lack of committed off-takers. Compounding these challenges are broader industry headwinds: an impending global LNG supply glut, weak demand growth, uncertain domestic gas prices and inflationary trade actions that threaten to disrupt global supply chains. The prospect of slim profit margins leaves little room for error.

This paper explores some of the key challenges facing the Ksi Lisims project and the Canadian LNG industry in general, and the potential pitfalls for LNG project stakeholders. Governments, resource producers, project financiers, First Nations and host communities collectively bear project risks but often face disproportionate and sometimes divergent financial, environmental and social outcomes. Understanding how risks affect each group is essential to assessing the viability of a project.

Background: Ksi Lisims LNG Overview

Ksi Lisims LNG is a proposed floating LNG (FLNG) export facility to be located in northwest British Columbia near Pearse Island, on a location 15 kilometers west of the Nisga'a nation community of Gingolx. The project consists of two floating liquefaction, storage and offloading barges that will receive a total of about 695 billion cubic feet per year (Bcf/yr) of natural gas, to produce up to 12 million tonnes (MTPA) of LNG annually.[1] The LNG is to be exported, targeting markets in the Pacific basin, primarily in Asia. The project is a joint venture between the Nisga'a Lisims Government (a self-governing Indigenous First Nation), Rockies LNG (a coalition of Canadian natural gas producers who collectively represent half of Canada's natural gas reserves), and Western LNG (a Houston-based LNG project developer).[2] The facility plans to use electricity to power motors that drive compressors in the liquefication process that its partners assert will help enable the facility to achieve net-zero emissions over the course of its operations.[3] The project is currently undergoing an environmental assessment and seeking regulatory approvals, with a final investment decision (FID) expected later in 2025.[4]

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[1] Ksi Lisims LNG. Detailed Project Description - Project Overview. April 25, 2022.

[2] Ksi Lisims LNG. Detailed Project Description - Proponent Information. April 25, 2022.

[3] *Ibid*., p. 9 (Project Overview).

[4] Ksi Lisims. Project Schedule. April 22, 2025.

KSI LISIMS Project Faces Critical Infrastructure Gaps, Including the Lack of a Secured Pipeline To Transport Its Feed Gas

The project proponents will have to negotiate construction of a secured pipeline to transport natural gas from the Northern Montney basin to its terminal on the B.C. coast. Managing the constructing of this critical pipeline is a complex task fraught with logistical and regulatory challenges that have significant financial implications.

The project's partners have purchased the Prince Rupert Gas Transmission pipeline (PRGT) project—a proposed 900-kilometer (km) gas pipeline first approved in 2014 to serve the Pacific Northwest LNG project but abandoned due to unfavourable market conditions and indigenous opposition. The partners intend to adapt and reroute the PRGT pipeline to serve as the project's main feed gas line.[5]

Figure 1: Proposed Prince Rupert Gas Transmission Pipeline[6]

Source: British Columbia Energy Regulator.

[5] Prince Rupert Gas Transmission Project. Application for Marine Route Alternative Amendment to EAC. June 21, 2024, p.9.

[6] British Columbia Energy Regulator. Prince Rupert Gas Transmission. Last updated February 28, 2025.

The rerouted pipeline will have to be built through rough mountainous and sensitive marine environments, requiring engineering adaptations, compliance with strict environmental regulations, and extensive consultation with Indigenous communities and private landowners—some of whom are fiercely opposed to the project.

Affected First Nations, including neighbours to the Nisga'a, have launched lawsuits against BC Energy, alleging inadequate consultations and failure to conduct cumulative environmental assessments.[7]

Some critics and stakeholders argue that rerouting the pipeline to terminate at the Pearse Island site of the Ksi Lisims terminal, instead of its original Pacific NW LNG destination, transforms the PRGT into a new project, and as such requires a fresh environmental review.[8]

Reminiscent of the Coastal GasLink Pipeline disputes, indigenous protestors led by the Gitanyow Hereditary Chiefs have established blockades and Indigenous protected areas, seeking to halt progress on the PRGT.[9] These and similar issues were responsible for the Coastal GasLink Pipeline—built to transport natural gas to LNG Canada and other projects—exceeding its budget from an initial estimate of $4.5 billion to a final tally of $14.5 billion. The fallout of these overruns led to disputes among partners, increased transport costs and expensive asset write-downs.[10] While only minor early-stage construction has begun, projected costs for the PRGT pipeline have already doubled—from an initial estimate of $5 billion to between $10 and $12 billion today.[11] This level of cost escalation at such an early stage highlights the significant financial and inflationary pressures facing the project and the broader domestic sector.

[7] The Globe and Mail. B.C. First Nation seeks judicial review to overturn pipeline permit on nearby territory. September 3, 2024. Also see: Gitanyow Hereditary Chiefs. Gitanyow Hereditary Chiefs File Legal Action On Ksi Lisims LNG Project. October 28, 2024.

[8] Gitanyow Hereditary Chiefs. 'We Are Willing To Fight. We Are Not Scared': A New Resistance To LNG Unfolds In Northern 'B.C.' September 9, 2024.

[9] The Narwhal. Opposition to northern B.C. pipeline intensifies as construction begins. August 27, 2024.

[10] Financial Post. LNG Canada, TC Energy disagree on cost overruns for $6.6-billion Coastal GasLink pipeline. March 1, 2021. Also see: TC Energy. TC Energy provides Coastal GasLink Project update. February 1, 2023.

[11] Financial Post. Pivotal pipeline decision looms to determine fate of Canada's next big LNG terminal. May 27, 2025.

The Ability for BC Hydro To Electrify Ksi Lisims Within Required Timelines Is Uncertain

The electrification of the project is a critical factor for proponents to achieve plans for low-emission LNG production and to comply with provincial environmental regulations.[12] Without hydroelectricity, Ksi Lisims LNG will have to rely on natural gas-powered turbines which increase project capital costs by approximately $2 billion.[13] This alternative would also generate an additional 1.8 million tonnes of carbon dioxide-equivalent (CO_2e) emissions annually, jeopardizing the projects stated NetZero ambitions.[14] The North Coast Transmission Line (NCTL) is a 450-km power line intended to supply electricity to industrial projects in Northwest BC. including Ksi Lisims LNG.[15] While Ksi Lisims proponents are not directly involved in developing the transmission system, they have stated that the line, along with an electricity supply agreement with BC Hydro, are critical and key requirements for achieving a positive FID.[16] Currently, no finalized agreement has been established between Ksi Lisims partners and BC Hydro to secure this connection, and a required 100-km spur line to link to the BC Hydro grid remains unbuilt and unfunded. BC Hydro estimates that expanding the NCTL could take up to 10 years, which pushes its completion past Ksi Lisims planned start-up date.[17]

Ksi Lisims is not the only project vying for BC Hydro's power. LNG Canada's Phase 2 expansion, the proposed Cedar LNG project, and other industrial ventures are competing for the same grid capacity.[18] Electricity demand in the province is expected to surge once a stream of proposed LNG and industrial projects come online raising uncertainty about whether BC Hydro will be able to meet all needs. If projects need to be prioritized, Ksi Lisims may be passed over in favour of larger or more advanced projects. If proponents have to resort to carbon offsets to achieve regulatory compliance, Ksi Lisim LNGs operational costs will increase more.

Ksi Lisims recently received a letter from the Office of the Deputy Minister of Energy and Climate Solutions in B.C., inquiring about its plans to achieve net-zero emissions if efforts to connect to the provincial electricity grid fall short—an indication that grid access may be less certain than hoped, and a potential harbinger of a future in which the project proceeds without the connection to BC Hydro, or does not proceed at all.[19]

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[12] Government of British Columbia. New energy action framework to cap emissions, electrify the clean economy. March 13, 2024.

[13] British Columbia Environmental Assessment Office. Assessment Report for Ksi Lisims LNG. November 12, 2024, p. 41.

[14] *Ibid.*, p 498 (24.3.2. BC Hydro Transmission Line and B.C.'s Net Zero by 2030).

[15] BC Hydro. North Coast B.C. electrification. March 2025.

[16] Ksi Lisims. Detailed Project Description - Transmission Line. April 25, 2022, p.30.

[17] Renew Canada. B.C. to build out province's electricity system over the next 10 years. January 17, 2024.

[18] The Narwhal. Docs reveal how much BC Hydro power new LNG and mining projects want. Who will pay for it? April 2, 2025.

[19] B.C Environmental Assessment Office. Letter from CEAO to Ksi Lisims LNG - Net Zero Policy Update. March 28, 2025.

Ksi Lisims' Environmental Assessment Certificate (EAC) Application Faces Public Opposition and Remains Pending Before Provincial Authorities

The EAC approval under British Columbia's environmental assessment process is a prerequisite. The project cannot legally advance without it. The application has encountered substantial opposition, including hundreds of public comments, raising concerns about climate impacts, threats to endangered habitats and potential strains on B.C.'s electricity grid.[20] Legal challenges have also been initiated by affected First Nations.[21] A delay or denial of the EAC application could deter investor confidence and impair the ability of proponents to raise financing for the project.

A Shortfall in Committed Off-Takers/Buyers Exposes the Project to Significant Income Volatility and Market Risk

Although Ksi Lisims LNG has announced two Sales and Purchase Agreements (SPA) with off-takers for a total of 4 MTPA of production,[22] the remaining roughly 70% of projected capacity is currently without a dedicated buyer. If proponents are unsuccessful in securing more buyers, the project may have to resort to the spot market to transact LNG cargoes, creating significant income uncertainty, particularly in the context of an impending LNG glut.[23]

Spot market prices are unstable and subject to abrupt price swings influenced by geopolitical shifts, cyclical weather fluctuations and competition from renewables.[24] Transactions in the spot market are absent the financial protection offered by "take-or-pay" clauses in typical long-term SPA agreements. An oversupplied global market could see spot cargoes deeply discounted or going unsold.

The rise of portfolio players represents an additional hurdle to meeting marketing targets. These are major LNG traders and speculators who value flexibility to adapt quickly to market dynamics and the diversification of supply sources and represent an increasing share of the global LNG market. Portfolio players are increasingly negotiating flexible, shorter-duration LNG purchase agreements (five to 10 years vs. traditional 20-year terms) to adapt to uncertain demand forecasts,

[20] Business Intelligence Vancouver. B.C. environmental review gets earful against Nisga'a's Ksi Lisims LNG. December 6, 2023.

[21] Gitanyow Hereditary Chiefs. Gitanyow Hereditary Chiefs File Legal Action On Ksi Lisims LNG Project. October 28, 2024.

[22] Ksi Lisims LNG. TotalEnergies signs long-term LNG supply deal with Ksi Lisims LNG. May 19, 2025. See also: Ksi Lisims LNG. Ksi Lisims LNG and Shell finalize Sale and Purchase Agreement. January 8, 2024.

[23] IEEFA. Global LNG Outlook 2024-2028. April 25, 2024.

[24] Data Energy. Factors affecting LNG prices. November 5, 2024.

decarbonization pressures and competition from renewables.[25] At the margin, this likely reduces the pool of buyers willing to lock in large volumes over a project's multi-decade lifespan.

Creditors and government support programs that rely on the certainty of long-term SPAs to back projects and advance capital may be deterred by an LNG terminal's excess uncontracted capacity. Creditors may demand higher interest rates to compensate for increased market risk, resulting in more expensive financing, escalating overall project costs.

The Choice of Floating LNG Barges Presents Additional Risks With Fewer Economic Benefits for Local Communities

Although floating LNG (FLNG) barges offer certain theoretical advantages, such as location flexibility, other touted benefits such as lower capital expenditure are not certain and have failed to materialize in some notable projects. Early deployments of the model, such as Shell's Prelude FLNG project, experienced massive cost overruns and operational delays.[26] While Ksi Lisims FLNG barges are to be located near shore as opposed to offshore, which reduces risk and complexity, this technology is still largely unproven and untested in Canadian waters. The relative novelty and associated technical risks may concern potential financiers.

Higher operating costs over the life of a floating terminal could offset any initial capex savings. Marine environments are harsher and require frequent maintenance to prevent saltwater-induced corrosion and mechanical wear. Maintenance activities may also lead to prolonged shutdowns and higher costs.[27]

The ability to achieve economies of scale, moreover, is limited. Unlike onshore facilities such as LNG Canada, which can incrementally expand capacity by adding liquefaction trains (e.g., LNG Canada Phase 2), FLNG units lack modular flexibility. Any expansion often requires the addition of entirely new floating units, which offers limited economies of scale.

Also, the ability of FLNG barges to generate good local jobs is limited. Because FLNG barges are typically constructed overseas in specialized shipyards, the high value engineering, fabrication and construction jobs bypass local workers, leaving mostly just operational roles. Such local jobs are significantly fewer than those offered by onshore facilities and may have less value than similar onshore projects.[28]

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[25] S&P Global. Long-term LNG contract tenures seen shortening amid changing supply-demand dynamics. March 6, 2025.

[26] The Oxford Institute for Energy Studies. Floating LNG Update – Liquefaction and Import Terminals. September 2019, p.6. Also see: Boiling Cold. No winners from Shell's $US17B Prelude floating LNG. May 15, 2020.

[27] The Oxford Institute for Energy Studies. Floating Liquefaction (FLNG): Potential for Wider Deployment. November 2016, p.18.

[28] *Ibid*.

Required Capital Expenditure To Deliver the Ksi Lisims Terminal Will Likely Exceed Estimates Put Forward by Proponents

In an initial submission to provincial authorities in early 2022, proponents of the Ksi Lisims LNG terminal estimated they will incur capital costs of $550-$600 USD per MTPA of LNG, resulting in a total outlay of between roughly $8.3 and $9 billion CAD after adjusting for capacity and exchange rate differentials.[29] This estimate, however, is based on a study conducted almost a decade ago and is likely outdated.

The terminal will commence construction under today's markedly different economic conditions, under which high inflation, currency volatility and ongoing supply chain disruptions have rendered historical pricing benchmarks almost irrelevant. Simply adjusting the USD/CAD exchange rate used in the initial estimate to reflect today's values results in a $1 billion addition to the projects budget—roughly a 12% jump.[30] The actual construction cost increase would likely be higher.

The validity of the initial benchmark can also be questioned. Observed data from other studies conducted by similar organizations indicate that the cost to construct an FLNG plant with similar capacity may range from $1,200 to $1,900 per MTPA of LNG.[31] Taking the midpoint of that range would put total capital costs to deliver the project at roughly $26 billion—almost triple the initial estimate.[32]

[29] Ksi Lisims. LNG Detailed Project Description - Anticipated Costs. April 25, 2022, p.7.

[30] The initial estimate assumes CAD/USD = 0.8; current CAD/USD = 0.72 @ 550USD/MTPA X 12m MTPA capacity.

[31] The Oxford Institute for Energy Studies. Outlook for Competitive LNG supply. March 2019, p.14 (Table 3). Also: Cedar LNG budget $4 Billion @ 3.3 MTPA capacity = $1,200/MTPA.

[32] (1900+1200)/2 = 1550 per MTPA X 12m MTPA = $25.6B.

Table 1: Indicative Liquefaction Plant Cost in $/tpa US$ 2018 and $/mmBtu US$2018

Liquefaction Project Location	MTPA Capacity	$/tpa US$ 2018	$mmBtu*
All Locations	490	946	$3.31
Remote/ High-Cost Locations	280	1,226	$4.29
Qatar	78	482	$1.69
USA Lower 48	61	660	$2.31
West Africa	31	1,084	$3.79
Russia / Arctic	33	1,292	$4.52
Australia	89	1,789	$6.26
Australia (Excl. Gorgon, Ichthys, Wheatstone, Prelude)	52	1,273	$4.46
FLNG	12	1,975	$6.91

**Indicative $/mmBtu based on $3.50/mmBtu per $1000/tpa. Source: LNG Canada FID presentation.*
Source: Oxford Institute of Energy Studies, World Bank, Wood Mackenzie, Federal Reserve Bank of Minneapolis and SyEnergy

Benchmarking and cost comparison in the sector should be understood as indicative rather than definitive. Each LNG project is unique with its own project-specific characteristics and development profile. With that said, after factoring key infrastructure challenges, potentials for delays and overruns, stakeholder opposition, currency volatility and inflation, it becomes extremely unlikely that the Ksi Lisims project as presented can be delivered within its initially proposed budget.

Industry-Wide Headwinds

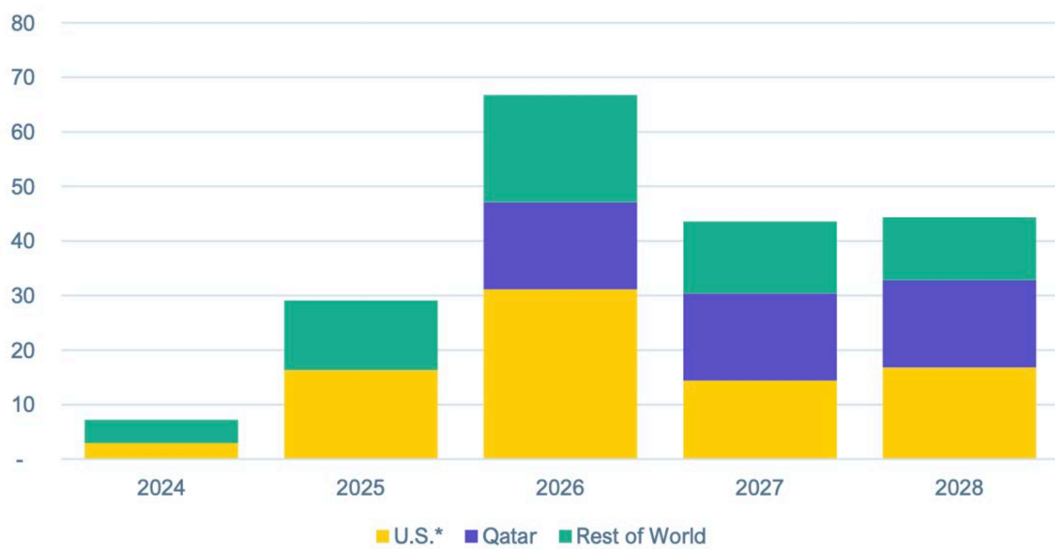
Impending Supply Growth but Weak Market Fundamentals

The global LNG market currently faces an impending supply glut, driven by an unprecedented surge in production capacity set to start coming online in 2025. IEEFA projects global LNG production capacity will rise by about 180 million MTPA by 2030—representing an almost 40% increase in current global supply and the most rapid capacity expansion in the industry history.[33] This view is

[33] IEEFA. Global LNG Outlook 2024-2028. April 25, 2024.

shared by various LNG market analysts, and consensus is building that the tidal wave of supply could have a negative impact on prices in the near term.[34]

Figure 2: Growth in Global LNG Production Capacity (Million Tons per Year)



Source: IEEFA estimates, based on data from the International Gas Union, the International Group of Liquefied Natural Gas Importers, Independent Commodity Intelligence Services, Kpler, Global Energy Monitor, company announcements and financial filings, and news reports.

The supply influx paradoxically coincides with slowing demand growth in key markets. This is particularly true in mature markets such as Europe, where structural declines exist, along with initiatives to transition to renewable energy sources.[35] In China, domestic gas production and pipeline imports are growing faster than LNG imports due to cost advantages and trade tensions with LNG suppliers.[36] In Japan, LNG imports are flat-to-declining as nuclear plants restart and demographics reduce LNG requirements; rather than absorbing cargoes off the global market, Japan may increasingly turn into a competing trader with Canadian LNG, looking to resell surplus volumes to other countries.[37] Emerging LNG markets like the Philippines are actively trying to reduce their exposure to LNG imports via domestic exploration efforts due to high LNG prices.[38]

Vietnam has ambitious gas-to-power plans but has been unable to establish an electricity environment conducive to encouraging the country's national utility, power plant developers, LNG developers, and gas suppliers to sign the long-term contracts necessary to catalyze development. It

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[34] IEEFA. LNG Build-Out in Mexico Based on U.S. Gas: Rising Risks for Consumers. March 2025, p. 12. Also see: CNBC. A 'tidal wave' of natural gas supply—the biggest yet—will reshape global markets, says RBC Capital. October 23, 2024.

[35] IEEFA. Europe's LNG imports decline 19% with gas demand at 11-year low. February 18, 2025.

[36] IEEFA. Shell's rationale for rapid LNG demand growth looks increasingly fragile, despite higher forecasts. March 11, 2025.

[37] IEEFA. Japan's largest LNG buyers have a surplus problem. March 11, 2024.

[38] Business Inquirer. Rising imported LNG prices highlight need for Indigenous gas priority. September 29, 2024.

will be hard for Vietnam to achieve the country's target of 22 gigawatts (GW) of LNG-to-power projects by 2030 without addressing this, with experts projecting the commissioning of only 6 GW to 7 GW.[39,40]

Pakistan's reliance on renewable energy sources is growing, along with a reduced demand for LNG-to-power electricity plants. As a result, the government is diverting LNG cargoes due to current supplies exceeding requirements.[41]

In Bangladesh, affordability concerns and skyrocketing LNG import bills have put a strain on foreign currency reserves, threatening to temper demand and further imports. Fiscal austerity measures proposed by multilateral organizations like IMF are likely to be unpopular and risk undermining competitiveness of key economic sectors.[42]

Other emerging demand drivers, such as data centers to facilitate the growth of artificial intelligence (AI), are uncertain and are being re-evaluated in light of recent innovative and efficiency breakthroughs.[43]

Entering an already oversupplied market could strain financial assumptions and erode returns. With much of the new LNG capacity in western Canada expected to come online in the latter half of the decade, the risk of mistiming market entry grows.

Domestic Production Surge & Feed Gas Cost Pressures

While Canada currently enjoys a competitive edge due to abundant and relatively low-cost natural gas, this advantage may prove transient as domestic market dynamics evolve.

Rising demand for natural gas from existing and upcoming LNG facilities threatens future price stability. Alberta reached record marketable production of 11.2 billion cubic feet per day (Bcf/d) in 2023, driven by increased output from conventional, tight and shale gas formations, and is projected to grow to 11.6 Bcf/d by 2033.[44] However, this growth may be outstripped by rising industrial demand, including oil sands operations, which consumed 3.3 Bcf/d in 2023 and are forecast to require 4.5 Bcf/d by 2033.[45] Simultaneously, LNG Canada's Phase 1 (14 MTPA) and Cedar LNG (3.3

[39] S&P Global. Vietnam's new law evokes cautious optimism for gas-to-power projects. March 24, 2025.

[40] Bloomberg. Vietnam Eyes Huge Wind and Solar Farms to End Coal Use by 2050. April 16, 2025.

[41] The News. Another LNG cargo diverted to protect gas transmission system. March 15, 2025.

[42] IEEFA. Cambodia at a Crossroads: An Economic Assessment of LNG-to-Power Plans. November 2024.

[43] Morningstar. DeepSeek Raises Doubts About Energy Demand Growth Upside. January 27, 2025.

[44] Alberta Energy Regulator. Natural Gas Production. June 2024.

[45] Alberta Energy Regulator. Natural Gas Demand. June 2024.

MTPA) will require about 2.5 Bcf/d of feed gas by 2028, while Ksi Lisims expects to receive approximately 2 Bcf/d.[46]

With more than a dozen proposed projects being considered, the realization of Canada's LNG ambitions might come with a price—a shift from oversupply to tightness and higher prices. Forward curves are already pricing anticipated supply tightness, with gas contracts from next year showing upward momentum.[47] While Alberta gas prices are coming off a very low base and thus have quite some room to run, the structural conditions sustaining current prices are likely to shift as the industry expands and more projects come online.

Competition for feed gas is not the only pressure point the industry faces. A surge in LNG development in North America could strain scarce resources such as skilled labour, specialized equipment and construction materials—as seen during Australia's LNG boom, further driving up costs across the supply chain.[48] These pressures are intensified by the overlapping rollout of continental and provincial LNG projects.

Tariff Crossfire: Volatility in the Global Trade Landscape Adds Uncertainty to the Project Budget and Timeline

The Canadian government has imposed a 25% tariff on imported steel components—such as pipes, modules and pressure vessels critical to LNG construction—in response to similar trade actions from the U.S and to counter dumping from foreign producers.[49] These measures risk escalating capital costs for Canadian LNG projects that rely on competitively priced imports, particularly from Asia. For instance, the Cedar LNG project, a $5.9 billion FLNG venture co-led by the Haisla First Nation, relies on an eight-kilometre pipeline branch connecting to the Coastal GasLink pipeline.[50] A 25% tariff on steel—a key material in pipeline construction—could impose an added burden on already strained budgets.

In addition, an extended trade war spurred by global counter-retaliatory measures risks disrupting supply chains for other specialized components, such as liquefaction turbines or cryogenic storage tanks, which are often sourced from foreign manufacturers. Some suppliers and contractors, wary of rising labour and material costs, may opt for contract renegotiations to protect themselves, further straining project assumptions and timelines.[51] Some may view the current environment as an opportunity for Canadian LNG expansion especially as certain buyers reduce U.S. LNG exposure in

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[46] RBN Energy. AECO Prison Blues - Western Canadian Gas Prices Stuck Behind Bars, Even After Winter Price Surges. March 19, 2025.

[47] Gas Alberta Inc. Market Prices - AECO C Futures Pricing. May 2025.

[48] Energy Today. LNG's next big challenges: high labour costs and low productivity. December 6, 2019.

[49] Government of Canada. Government launches consultations on trade measures to prevent diversion of steel products into Canada. March 22, 2025.

[50] Coastal Gaslink. Cedar Link Project. April 24, 2025.

[51] Bloomberg Law. Venture Global Wants to Redo Some LNG Contracts at Higher Rate. February 13, 2025.

protest or due to concerns over policy and supply unpredictability. Canadian firms may also be able to mitigate some of the tariff-related cost increases by sourcing steel and other components domestically. On the other hand however, certain countries may offer to step up U.S purchases as a concession during trade negotiations while some buyers consider slowly transitioning away from the fuel source altogether as part of a longer-term diversification and energy security strategy.[52] Regardless of what pans out, the current global trade landscape is characterized by widespread uncertainty, policy volatility and inflationary measures—presenting yet another hurdle for proponents and stakeholders of proposed projects.

Tight Margins and Structural Issues Threaten Canadian LNG Competitiveness

Profit margins in the LNG sector are modest and offer a slim buffer against a myriad of risks. The profitability of an LNG project is influenced by the capital costs of the liquefaction plant, price of upstream gas supply and the cost of shipping.[53] LNG project developers in Canada face not only technical and regulatory challenges but must also grapple with a fragile economic model.

Shell's FID presentation for LNG Canada's Phase 1 illustrates the stringent economics that underpin many sanctioned projects.

Table 2: Useful Indicative Figures and Percentages of Delivery at Terminal (Dat) Price, As Provided in LNG Canada's FID Presentation[54]

Upstream Cost of Lean Unconventional Gas Supply	$2.00/mmBtu	23.53%
Tariff on 670km of 48" Gas Pipeline	$0.50/mmBtu	5.88%
Into LNG Plant Gas Supply Price	$2.50/mmBtu	29.41%
Liquefaction Cost (14 MTPA @$1,000/tpa)	$3.50/mmBtu	41.18%
LNG Shipping w Canada/Kitimat to JKTC	$1.00/mmBtu	11.76%
Gross Margin	$1.50/mmBtu	17.64%
Delivery at terminal (JKTC)	$8.50/mmBtu	100%

[52] Gas Outlook. With tariff threat, LNG becoming a source of increasing energy insecurity for Europe. April 18, 2025.

[53] Oxford Institute for Energy Studies. Outlook for Competitive LNG Supply. March 2019.

[54] Oxford School of Energy Studies, *op. cit.*, p. 6.

Source: LNG Canada FID presentation, Oxford SOES

Shell's LNG Canada pro-forma projections assume the long-term average price to deliver LNG to key Asian market (JKTC price benchmark) is $8.50/mmbtu. In this scenario, LNG Canada would generate a 17.6% gross margin of $1.50/MMBtu. This does not take into account key non-operating costs such as taxes, interest on financing, depreciation and administrative overhead. Although at higher average price points the terminal could theoretically generate positive profits and net present value, the current cost structure doesn't leave much room for downside surprises. Unforeseen cost escalations, extended commodity price slumps or regulatory challenges could effectively erode the project's economic returns. The presence of massive sunk capital costs and a protracted payback period for LNG projects, typically stretching over a decade or two, highlight the speculative nature of the sector, underscoring a sometimes-thin line between viable and uneconomic projects.

Producers in Canada must also contend with potential competition from suppliers based in other jurisdictions, some with more durable competitive advantages. Producers that can build plants cheaper or quicker, or who are able to access feed gas sustainably at lower prices, can enjoy a lower break-even point and continue to supply the market even at lower prices with less damage to their bottom line. For example, Qatar boasts some of the world's lowest breakeven prices and is estimated to have incremental unit production costs as low as $0.3/MMBtu—roughly 10% of the global average.[55] The gulf nation with its abundant, easily accessible gas reserves and existing infrastructure will be responsible for a significant chunk of the additional supply expected in coming years.

Western Canada does have a competitive advantage by being sited in closer proximity to key Asian markets. The distance from Kitimat, B.C., to Tokyo, for example, is roughly 7,000 km, less than half the 15,000 km distance for Sabine Pass, Texas. Cargoes from B.C. headed to Asia will thus enjoy relatively shorter shipping times and lower associated costs.[56] The effect of this benefit may be limited, however, as shipping represents a minor percentage of a project's overall cost structure. In the LNG Canada pro-forma above, shipping costs represent just 12% of the topline. While helpful, this advantage alone may not be enough to ensure long-term competitiveness and can easily be outweighed by other structural disadvantages or by competition with stronger competitive edges.

Asymmetrical Risk Distribution Among Key LNG Stakeholders

Stakeholders of uncompetitive LNG projects face multiple downside financial risk scenarios. These range from underutilized terminals due to lack of demand to outright project failure or cancellation, leading to sunk costs or stranded assets.

A typical LNG project may have various stakeholders with distinct interests, objectives and responsibilities. While the risks to the project are collectively borne by all stakeholders, risk exposure

[55] Reuters. Qatar's bigger LNG expansion to squeeze US, other rivals. February 27, 2024.

[56] The Oxford Institute for Energy Studies. Outlook for Competitive LNG Supply. March 2019, p.17.

is distributed unevenly among the various parties, with each group seeking to mitigate their own exposures in different ways.

Understanding how risks affect each group is essential to assess the fundamental viability of a project.

Governments

Provincial and federal governments generally face negligible direct financial risks from LNG project developments due to limited equity stakes in projects, and well-established revenue bases. While royalty and tax revenues tied to project profitability may fail to materialize If projects ultimately fail or global prices collapse, the existence of other ingrained revenue sources and the ability to borrow to fund deficits limits the effect of any financial loss. Indigenous loan guarantee programs offered by the government to encourage First Nation economic participation in infrastructure and resource project developments are limited in size relative to public fiscal capacity and are designed for only a fraction of allocated funds to be allocated to the LNG sector.[57] Therefore, potential losses are capped in the event of any default. National climate commitments and climate actions, however, risk being undermined. Upstream methane emissions from LNG extraction and transport as well as emissions from processes at the terminal could delay the realization of climate goals, promote fossil lock-in and slow the transition to cleaner energy systems. Some political risks also exist for policymakers. If governments approve or support high-emitting projects that ultimately fail to deliver promised economic benefits, they risk alienating segments of their political base who are climate-conscious or concerned about ensuring that economic development initiatives promote thriving communities and good jobs. In addition, they risk alienating advocates against government waste of taxpayer dollars.

Citizens/Taxpayer Households

While LNG projects may offer potential short- to medium-term gains to taxpayers and citizens, long-term risks to affordability, environmental quality and economic stability must also be factored. On the upside, successful projects may stimulate local economic growth, generating employment opportunities including direct jobs for skilled workers and indirect positions in supporting industries. Increased tax revenues can also fund public services and infrastructure improvements that benefit entire communities. However, downside risks are equally significant and are often more immediately felt by households. As seen in other jurisdictions, domestic natural gas prices may increase with rapid expansion of the local LNG industry as supply is diverted to export markets, leading to higher heating and electricity costs for consumers.[58] In addition, the shift towards electrification of industrial facilities may strain hydroelectric resources, potentially driving up electricity rates.[59] Citizens in LNG/resource- dependent regions also face pronounced economic volatility tied to global commodity cycles; boom periods may create inflated real estate prices and cost of living increases, followed by severe downturns resulting in a whiplash effect that can devastate local economies. There are also

[57] Canada Indigenous Loan Guarantee Corporation. Technical Backgrounder - Eligibility Criteria. April 22, 2025, p.5.

[58] IEEFA. Gas exports cost U.S. consumers more than $100 billion over 16-month period. January 29, 2024.

[59] Canadian Centre for Policy Alternatives. Painting itself into a corner: LNG and the climate-affordability trade-off in B.C. May 14, 2025.

environmental, and health concerns related to emissions, local pollution and increased industrial traffic that may weigh disproportionately on vulnerable communities.

Upstream Producer Partners

Upstream producers—*i.e.*, oil and gas companies—that are partners in an LNG project are exposed to direct financial risk in the event of project failure or decline. They are responsible for providing significant amounts of risk capital to advance projects. If things go badly and projections fail to materialize, they will be forced to write off assets, with a direct negative impact on earnings. Generally, these parties are likely to have diversified income streams from alternate business segments, which place them in a better position to weather a downturn while continuing to meet credit obligations and avoid outright defaults. They are also well-placed to raise additional capital in the event of cost overruns and unforeseen project cash calls. The ability to sign long-term supply agreements with off takers also provides an avenue to insulate themselves from some of the market risks that would emerge from declining demand and spot market volatility.

Upstream producers may also be able to derive material benefits in the near-term even amid market uncertainty and challenged projects. First, producers are typically valued based on their net asset value, which includes the quantity of proven reserves they own.[60] Once product evacuation infrastructure is operational and a credible route to market exists, these companies can effectively reclassify reserves from contingent-or-possible to probable-and-proven. By demonstrating market access, these entities may be able unlock the financial value of previously discounted and otherwise stranded reserves. This move, subject to accounting rules and auditor opinion, can significantly enhance book and equity values, improve balance sheets and increase access to financing by leveraging a higher asset base. Second, producers stand to benefit if LNG exports increase natural gas demand and prices within Canada. This would allow gas producers to monetize reserves at healthier prices, boosting cash flows, profits and increasing the value of their overall reserve asset base.

Project Financiers/Creditors

Project financiers provide funding for development and construction of projects in exchange for interest and other payments. Repayment of loan advances are generally tied to cash flows from the project; thus, creditors are exposed to material credit and default risk. A sharp shift in market fundamentals that causes broad declines in revenue would jeopardize project debt service coverage ratios and the ability to repay interest and principal. The Indigenous loan program may help mitigate some default risk, but its limited size relative to the considerable capital requirements of LNG project development ensures that material risks exposures will remain. Lenders will typically seek to protect themselves by financing terminals that have secured long-term contracts with financially stable buyers for the majority of the project's capacity. Such projects have a lower risk of default. In the event that projects are unable to contract off takers for full capacity, however, creditors may demand higher interest rates or greater equity injections to compensate for the additional risk. They could also demand collateral that can be monetized in the event of a default. Financiers—at least in certain

[60] Accounting Insights. How Is the NAV Model Used in Oil and Gas Investments? March 6, 2025.

jurisdictions—must contend with growing regulatory and social pressure to align their lending with climate goals and thus risk reputational damage by continued financing of major, high emitting projects.

Project Contractors

This refers to private entities employed to design and build facilities and infrastructure via engineering, procurement and construction (EPC) contracts. Once construction is complete and the project delivered, contractors can exit with profits secured, largely insulated from the long-term viability and downside risks of the project. During development, however, they remain exposed to certain project risks including cost inflation and liquidity mismatches that, if not managed well, could lead to bankruptcy and project delays.[61] This would affect their ability to compete for future bids and lead to reputational damage in the industry. To hedge risk exposure, some contractors may request guaranteed fixed service fees while passing variable material costs to project owners.[62] This transfer of risk shifts the burden of cost inflation to project owners and has led to some owners seeking to renegotiate their sales and purchase agreements to counter unanticipated overruns.[63] An abrupt project shutdown could also leave contractors exposed to some initial cost outlays that become sunk.

First Nation/Indigenous Partners

By participating as equity investors, First Nation proponents face a dual-reality and complex trade-off. Although profit-sharing agreements offer potential income, equity stakes could involve the assumption of outsized risks relative to the capacity to absorb losses. Unlike larger corporations, these communities may lack diversified assets or cash reserves to withstand prolonged downturns, and—depending on the model of funding employed—may face risks of credit downgrades, debt default or in a worst-case scenario, outright bankruptcy. Equity holders in LNG projects also face the risk of being left with cleanup and environmental remediation liabilities. In the absence of adequate decommissioning reserves, owners may be legally obligated to fund dismantling, site restoration and long-term monitoring. This liability is tail-ended and may crystallize after commercial activity and project revenues have ceased.

Federal and provincial initiatives such as the Indigenous loan program can help mitigate default risks, but do not eliminate them. A loan guarantee typically does not absolve the debtor from the obligation of repayment—but rather, protects the creditor against default. Also, in the case of cost overruns, First Nation partners may be expected to inject more equity to cover operational or capital shortfalls. Responding to capital shortfalls may present additional challenges, especially if the First Nation entity is relying on funding from sources with limited/capped resources, such as the ILGP.[64]

Failure to come up with additional capital could lead to dilution of equity stakes, further subjugating First Nation partners' position as minority shareholders. Minority partners will typically have limited influence over key project decisions and the strategic direction of the project, leaving them vulnerable to the interests of majority partners. A failed investment also would diminish their capital base and reduce their ability to take advantage of future investment opportunities. Unlike a

[61] Reuters. Firm building Qatar Energy-Exxon LNG plant in Texas files for bankruptcy. May 21, 2024.

[62] The Oxford Institute for Energy Studies. LNG Plant Cost Escalation. February 2014, p.19 (Contractor Profit & Risk).

[63] Reuters. US LNG exporters seek to renegotiate deals to cover rising costs. March 10, 2025.

[64] CDEV. Changes to the Indigenous Loan Guarantee Program. March 21, 2025.

corporation that can be dissolved and rebranded, the cultural and reputational capital of some nations may be irreversibly tied to project outcomes.

Non-Partner First Nations

First Nations/Indigenous groups that are not direct investors in a project but are affected parties occupying communities near project facilities and infrastructure might accrue some employment or community benefits from certain LNG export projects via economic benefit agreements. However, these purported benefits may not offset the adverse impacts of these projects.[65] Such communities may face environmental health risks or indirect ecological harm from pollution or habitat fragmentation caused by the project. Sustainable economic opportunities such as ecotourism and fisheries may become threated by a project, undermining traditional livelihoods and age-old income sources. Also, with a fixed pool of public funds allocated to advancing Indigenous economic participation, this group risks being crowded out by current projects, thus reducing their ability to participate in future opportunities.

Conclusion

As investors and stakeholders continue to explore opportunities in Canada for LNG expansion, they must also contend with key emerging challenges and downside risk scenarios that affect the sector. The Ksi Lisims project faces significant hurdles, including infrastructure gaps, market uncertainties and uneven risk distribution among stakeholders. While the project developers praise its potential economic benefits, the viability of the Ksi Lisims project depends on its ability to overcome cost pressures, secure firm commitments and navigate a highly competitive global LNG market and uncertainties about demand trends. At this point, both the project and Canada's broader LNG ambitions remain vulnerable to formidable headwinds.

[65] First Nations Gas Alliance. Benefit Agreements: A Wayfinding Guide. January 25, 2023.

About IEEFA

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