Wood Mackenzie

Economic viability assessment and economic value of Alaska LNG project - Phase 1

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12th September 2024

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Project Background

Wood Mackenzie has worked extensively as an independent consultant on Alaska's energy issues since 2016 to provide an economic analysis of the viability of the cost of supply (CoS) for Alaska LNG (also referred to as AK LNG). Most recently in 2021/22, Alaska Gasline Development Corporation (AGDC) engaged Wood Mackenzie for an updated analysis that included calculating a new base CoS, identifying opportunities to optimize the CoS, a competitive analysis and providing our long-term projections.

Since the last study, AGDC has proposed a phased approach to developing Alaska LNG. Phase 1 involves developing the gas pipeline from the North Slope to Southcentral and Interior Alaska markets. As part of Phase 1, ADGC has engaged Wood Mackenzie for **an independent economic analysis of the proposed gas pipeline** and an **economic benefit analysis** for the state of Alaska.

The information on which this independent report is based has either come from our experience, knowledge and database or it has been supplied to us by AGDC. The opinions expressed in this report are those of Wood Mackenzie. They have been arrived at following careful consideration and enquiry, but we do not guarantee their fairness, completeness, or accuracy. The opinions, as of this date, are subject to change. Please note that for this engagement, we have adjusted our standard base case to reflect disclosed asset-specific information.

This Report is structured across 5 sections:

- Southcentral and Interior Alaska market overview
- Delivered cost of piped gas and scenario analysis
- Analysis of LNG imports as an alternative
- Economic impact of Alaska LNG Phase 1
- Final takeaways and conclusions

The present document covers the first three sections

Contents

Southcentral and Interior Alaska Market Overview

Delivered cost of piped gas and scenario analysis

Analysis of LNG imports as alternative

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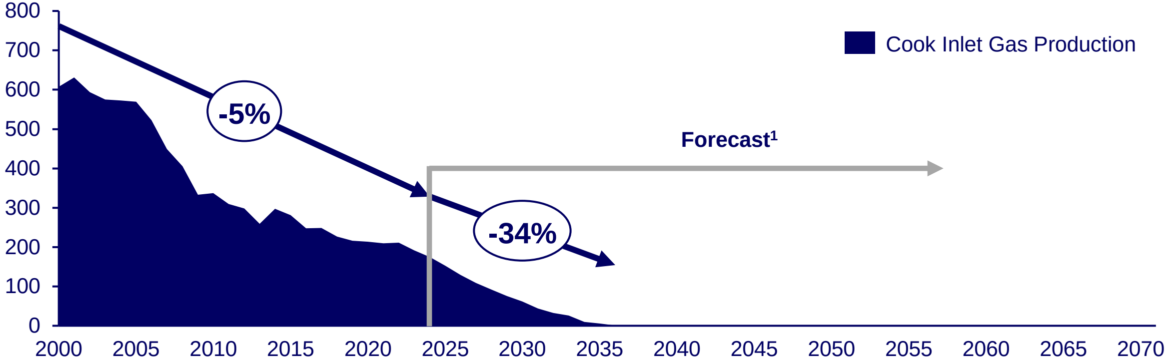
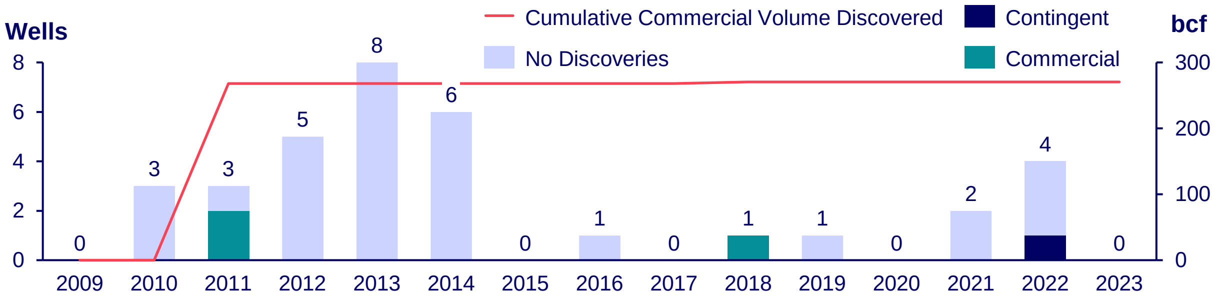
Gas supply has been dwindling, and despite exploration efforts by operators, no new volumes have been discovered in Cook Inlet to replenish the reserves

Cook Inlet gas production
mmcfd



Exploration activity in the Cook Inlet basin



Source: Wood Mackenzie
1. Compounded Annual Decline Rate is 34% driven by production reaching 0 in 2037.

- Cook Inlet production is expected to be depleted by the mid-2030s
- Exploration success in the Cook inlet has been limited:
  - **34 exploration wells** drilled in the last 15 years
  - **9% success rate** with only three commercial discoveries
  - **270 bcf** of reserves discovered in the last 15 years

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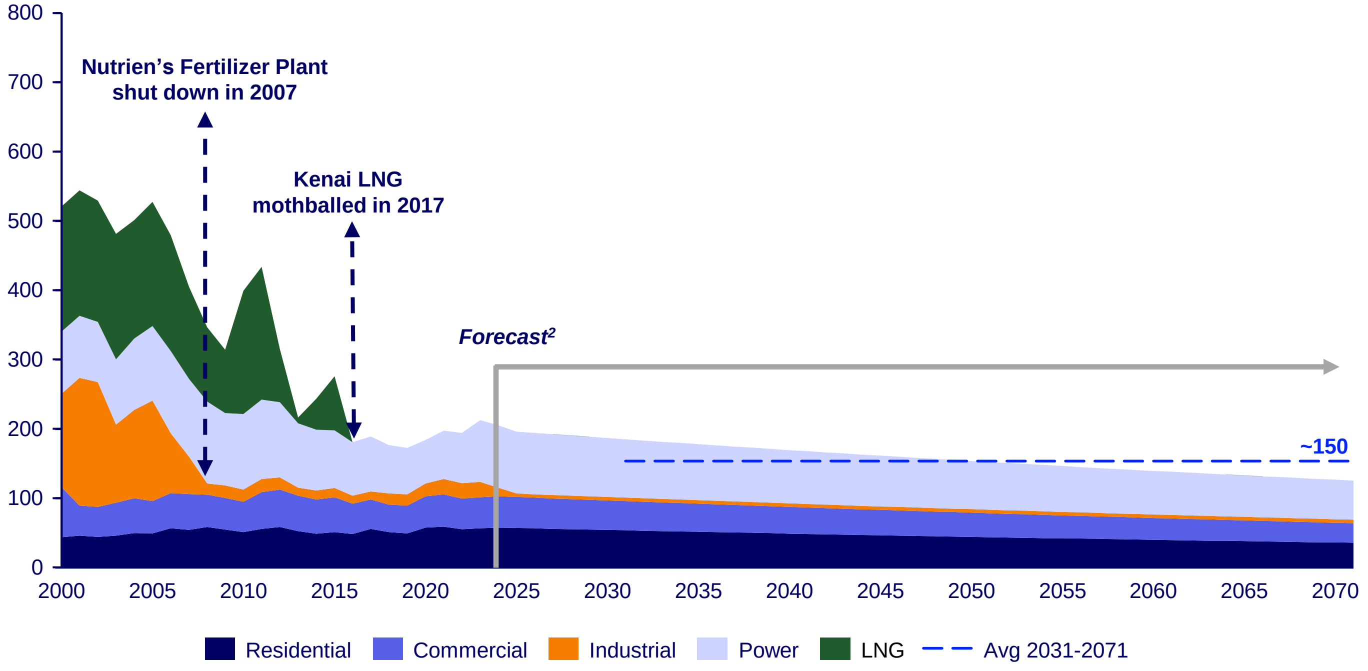
A lack of secure, consistent, and affordable supply of gas has driven a consistent decline (5% CAGR) in gas demand for the past 20 years

Based on Wood Mackenzie's (WM) current demand outlook for Alaska (adjusted for Industrial Sector reporting), we extended the forecast to 2071 to match the operating horizon for Alaska LNG Phase 1.

Due to supply constraints, industrial activity was impacted by the Nikiski Refinery lowering its demand to 5 mmcfd.

Current State gas demand in Alaska[1] (2000–2071)
mmcfd



Source: Wood Mackenzie
1. Excludes North Slope Region In-field gas and considers the rest of regions with gas demand (Anchorage, Mat-Su, and Kenai Peninsula). Refer to Appendix for detailed assumptions. 2. Demand forecast shows WM outlook for 2024-2050, extended to 2071 and adjusted for Industrial reporting (2021-2023).

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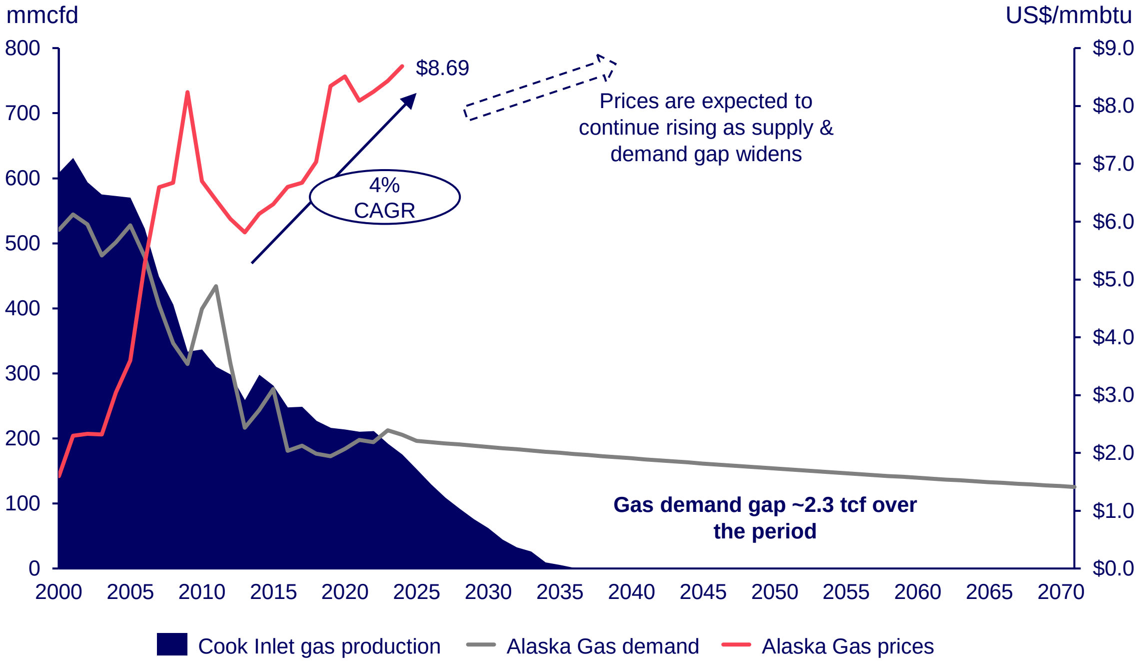
An estimated cumulative demand gap of ~2.3 tcf is projected by the end of this decade which will likely continue to drive gas prices up for Alaska consumers

Cook Inlet gas production/demand[1] and gas prices in Alaska



- Lack of steady gas supply and increasing gas prices have affected industrial development in the region
- Prices will continue to rise as the demand gap expands and reaches an average of 192 mmcfd between 2031 and 2071
- A total of **2.3 tcf** of gas is needed to fill the identified gap from 2031 to 2071, more than 8x the discovered reserves in the last 15 years
  - For this reason, relying on additional production from Cook Inlet is not considered a viable option to meet long-term demand

Source: Wood Mackenzie, Prices from EIA
1. Demand shows WM outlook for 2024-2050, extended to 2071 and adjusted for Industrial reporting (2021-2023)

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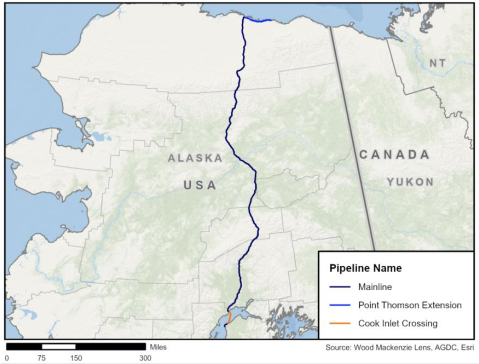
With Cook Inlet gas production recovery proving to be a challenge, two main alternatives to addressing the forecast supply gap are a new gas pipeline and LNG imports

Gas supply alternatives for Southcentral and Interior Alaska market

1. Natural gas supply via pipeline

In Phase 1, a 765-mile, 42-inch diameter mainline pipeline will connect the Southcentral Alaska region with the northern fields, providing a secure and affordable gas supply. In the beginning, the pipeline will supply local and industrial consumption, then expand to provide feed gas for export into LNG markets.

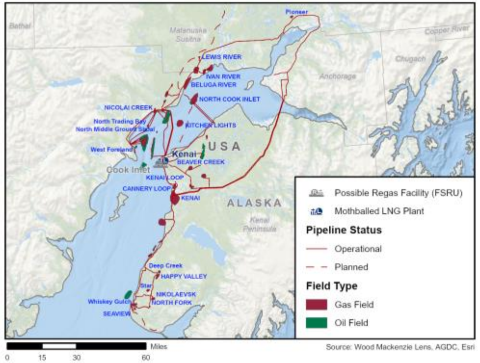


Key stats

- Total capex: From US$10.8 billion to US$14.9 billion for max capacity
- Time to first gas: 2031
- Capacity: 3.3 bcfd at max
- Ability to expand to cover incremental investment in subsequent LNG phases

2. LNG imports[1]

Gas imports via LNG require regas and further downstream infrastructure, including an FSRU dock to take the imported gas and potentially inland storage for operations optimization across yearly seasonality.



Key stats

- Total capex: TBD
- Time to first gas: 3 - 4 years post FID[2]
- Capacity: 400 to 450 mmcfd fit for current demand without increased industrial activity
- Expected utilization: 40 – 45%

Source: AGDC, Wood Mackenzie

1. Map location of the FSRU is illustrative since planned location is pending definition based on receiving port; 2. Excelarate Energy announced in Aug '24 a target commercial start date for LNG imports via FSRU for 2028, suggesting its plans to take FID during 2024, though location of the required dock and overall status of the project is not clear as of writing of this report

Contents

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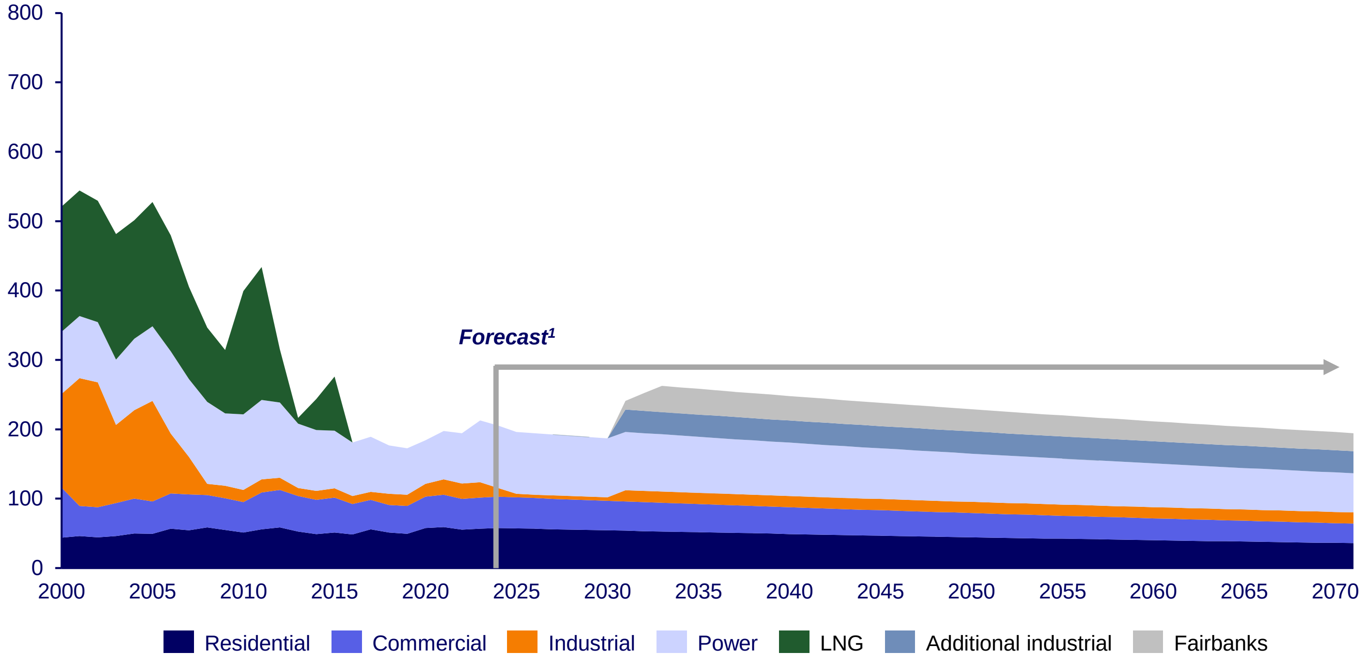
If the Pipeline is built, additional demand will arise from 3 main sources: Fairbanks shifting to gas for energy/heat needs, Nikiski refinery demand recovering, and additional industrial applications

In addition to the Current State demand forecast, as shown in slide 5, the following are anticipated:

- Substitution of oil and wood as primary energy/heat source in Fairbanks[1].
- Industrial gas demand from the Nikiski Refinery shifts to burning propane. Gas demand reduces to 5 mmcfd, then rebounds to 16 mmcfd after the pipeline begins operations.
- New or returning industrial activity will produce an additional gas demand of 32 mmcfd with new gas supply availability[2].

Expected gas demand in Alaska (2000 – 2071)
mmcfd



Source: Wood Mackenzie
1. Fairbanks is a nonattainment area under the EPA. If Alaska LNG Pipeline is built, Fairbanks could change to gas for energy/heat needs. We assume 90% penetration with a 3-year transition (2031 – 2033)
2. In 2001, industrial demand reached 185 mmcfd with population at 632,716. Even though the population is expected to peak in 2033, WM expects enough demographic base to support increased demand back to historic levels via additional uses of natural gas, excluding the Fertilizer Plant (185 total – 137 Fertilizer – 16 Nikiski Refinery = 32).

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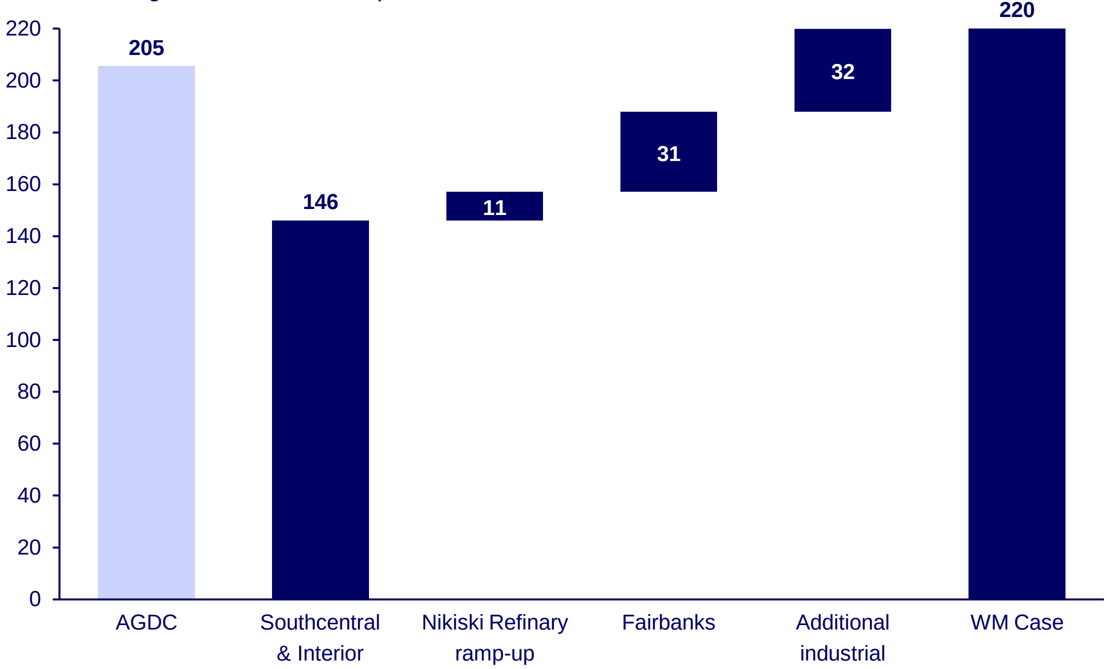
We have built a Wood Mackenzie (WM) case by accounting for current gas demand, adding Fairbanks and incremental industrial applications

- **AGDC input:** demand estimate based on feedback from current utilities and industrials at 75 bcf per year (~205 mmcfd)
- **Southcentral and Interior**: Includes WM forecast for Alaska gas demand with additional considerations:
  - Demand for Southcentral and Interior regions[1]
  - Possibility of storage for optimized capacity usage during seasonal peaks.
- **Nikiski Refinery,** and/or other gas-consuming operations expanding to 16 mmcfd with access to piped gas from 5 mmcfd currently
- **Fairbanks** substitution of oil/wood for gas.
- **Additional Industrial** activity
- **WM Case:** Current State, adjusted for regional demand, plus Nikiski Refinery, Fairbanks, and additional demand

Gas demand for the Southcentral and Interior regions
mmcfd, average for the 2031-2071 period



Source: Wood Mackenzie
1. Outside the Southcentral region, other regions have limited gas access mainly because of infrastructure constraints. 95% of gas demand is considered to come from the Southcentral region.

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Four scenarios were developed and analyzed to account for: existing gas demand (baseload), potential new demand brought by gas availability, and the construction of a 20 mtpa LNG facility

		Components	Average gas demand (mmcfd, 2031-2071)
Scenario 1: Baseload	This includes the Current State demand for gas in Southcentral and Interior Alaska. Plus, additional demand from Fairbanks substitution of oil/wood as gas becomes available to avoid EPA's nonattainment area designation and finally, the ramp-up from the Nikiski Refinery	Current state (Southcentral + Interior) + Fairbanks + Nikiski Refinery	~190
Scenario 2: WM Case	Baseload plus additional gas demand based on historical gas demand for the industrial sector and population growth forecasts. We estimate Industrial demand will reach 48 mmcfd (32 mmcfd additional to 16 mmcfd from the Nikiski Refinery[1]).	Baseload + Additional Industrial Activity	~220
Scenario 3: Additional Industrial demand	This considers the maximum upside from industrial demand based on high-consuming facilities starting operations. This incremental gas demand could come from restarting a previously operating fertilizer plant, a new ammonia plant (brownfield or greenfield) or new data centers.	WM Case + High-consuming industrial plant	~320
Scenario 4: Alaska LNG	The 20 mtpa LNG Facility (Alaska LNG) will require an additional 2,844 mmcfd at full capacity[2]. This demand was added to the WM Case and assumed to come online in 2032 with one 6.7 mtpa train and two more in 2033 and 2034, respectively.	WM Case + Alaska LNG[3]	~2,930

Source: Wood Mackenzie 1. In 2001 industrial demand reached 185 mmcfd with industrial activity and population at 632,716. Even though population is expected to peak in 2033, WM expects enough demographic base to support increased demand back to historic levels via additional uses of natural gas 2. Feedgas estimation considers 7.11% Liquefaction Loss, 1.56% Transport Loss, and 52,000,000 mmbtu/mt and 1,090 Btu/scf conversions. 3. Additional average demand is 2,705 for the 40 years due to phased kick-off of one train per year.

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The delivered cost of piped gas is calculated based on the cost of feed gas plus the pipeline tariff, which covers its capex, opex and a 10% expected return

Delivered Cost of Gas – High Level Considerations

The delivered cost of gas is estimated using a discounted cash flow model with a target ROE of 10% and the following considerations:

- Capex for Phase 1: US$10,769 million[1] (2024)
- One year of construction prep and four years of construction, starting in 2026
- Allowance for Funds Used During Construction (AFUDC) method for construction costs recognition
- 75% debt financing at 6.25% interest rate
- Property tax rate at 0.2%
- Feed gas is purchased at US$1.00 (2024) and escalated at 2% per year
  - Supplied by the Great Bear Pantheon Development of the Aphun and Kodiak fields
- Alaska LNG Phase 1 operating horizon from 2031-2071

Source: Wood Mackenzie, AGDC
1. Includes US$50 million of Property Taxes

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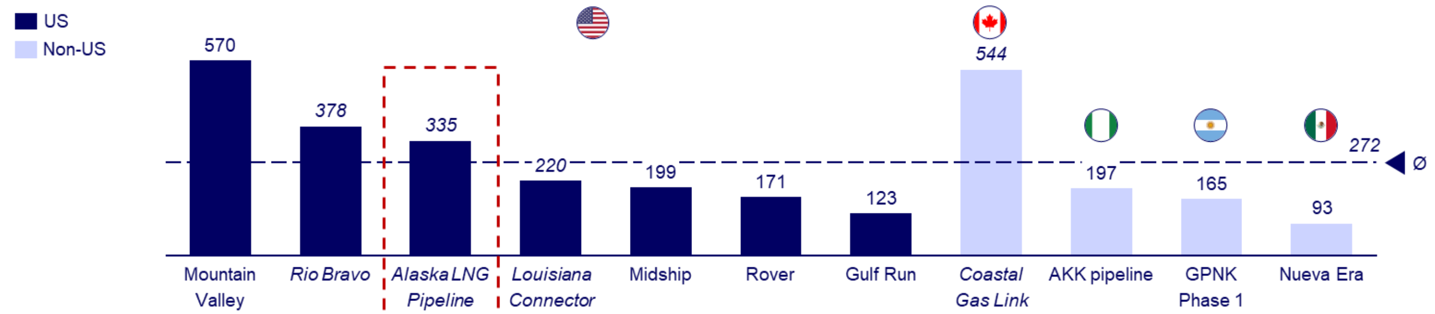
The total estimated cost of the pipeline is US$10.8 billion for Phase 1, well within the range of recently built and proposed pipelines

Pipeline cost benchmark

k US$/in-mi[1], real 2024



	Mountain Valley	*Rio Bravo*	*Alaska LNG Pipeline*	*Louisiana Connector*	Midship	Rover	Gulf Run	*Coastal Gas Link*	AKK pipeline	GPNK Phase 1	Nueva Era
CAPEX (Bn USD)	7.2	2.2	10.8	1.2	1.7	5.1	0.7	10.9	3.0	2.1	0.8
Length (mi)	301	137	765[2]	131	234	711	134	417	382	347	273
Diameter (in)	42	42	42	42	36	42	42	48	40	36	30

Italic labels refer to cost estimation (pipeline not built and operating)

- Mountain Valley and Coastal Gas Link have high costs largely due to specific regional context.
- Specific regions with regulatory challenges that have built new infrastructure, like the US NE and Canada BC, have seen longer timeframes and/or regulatory challenges delays.
- Additionally, economies of scale can be obtained for larger projects. Alaska LNG Phase 1 is two to five times bigger than peers
- However, this could lead to further contingency and/or cost overruns in the estimated cost of the Alaska LNG Phase 1 pipeline, on top of the 20% contingency currently considered

Source: Wood Mackenzie, AGDC; 1. Refers to US$ thousands divided by a composite of diameter and length; 2. Considers the announced 807 miles minus reduction due to lower scope requirement on Phase 1; Selected pipelines have been considered based on diameter, length, recency and main use

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Costs in the first three scenarios account for minimum compression capacity but with Alaska LNG, the cost for compression and a segment to cross Cook Inlet is also considered

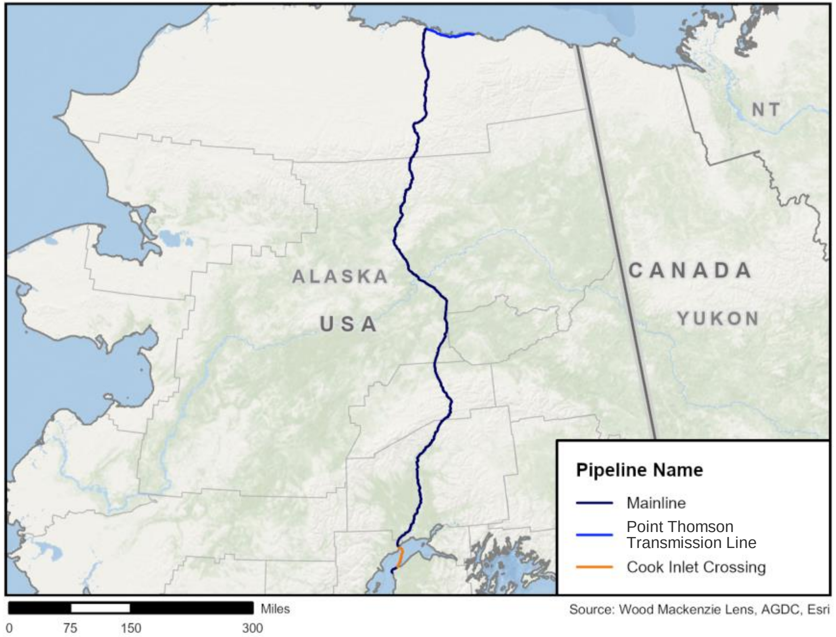
Alaska LNG Pipeline capex by scenario

Real 2024 US$ million

Capex / Scenarios (2024 US$ million)		**Baseload**	**WM Case**	**Additional Industrial demand**	**Alaska LNG**
Phase 1 mainline[1]	$10,769	✓	✓	✓	✓
Compression	$2,485				✓
Cook Inlet + Additional Section	$1,131				✓
Point Thompson Expansion	$564				N.A.[2]
Total Amount	**$14,950**	**$10,769**	**$10,769**	**$10,769**	**$14,385**

- In-state gas demand is burden only by Phase 1 Capex
- Additional cost is considered only for LNG volumes coming online

Alaska LNG Pipeline Scope



Source: Wood Mackenzie Lens, AGDC, Esri

Source: Wood Mackenzie with information from AGDC
1. Considers 20% Contingency and US$50 million of Property Taxes
2. Alaska LNG Scenario does not consider the Point Thompson Expansion cost. In order not to affect the rest of the shippers it must be considered as part of the purchase gas cost for the LNG facility only.

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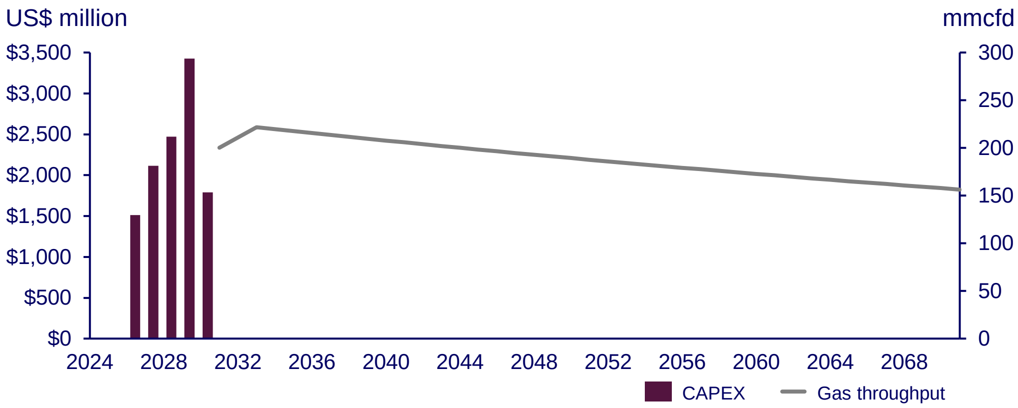
The delivered cost of gas in the Baseload Scenario is US$12.80/mmbtu; this accounts for current utilities and industrial demand, plus energy/heat needs from Fairbanks shifting to gas

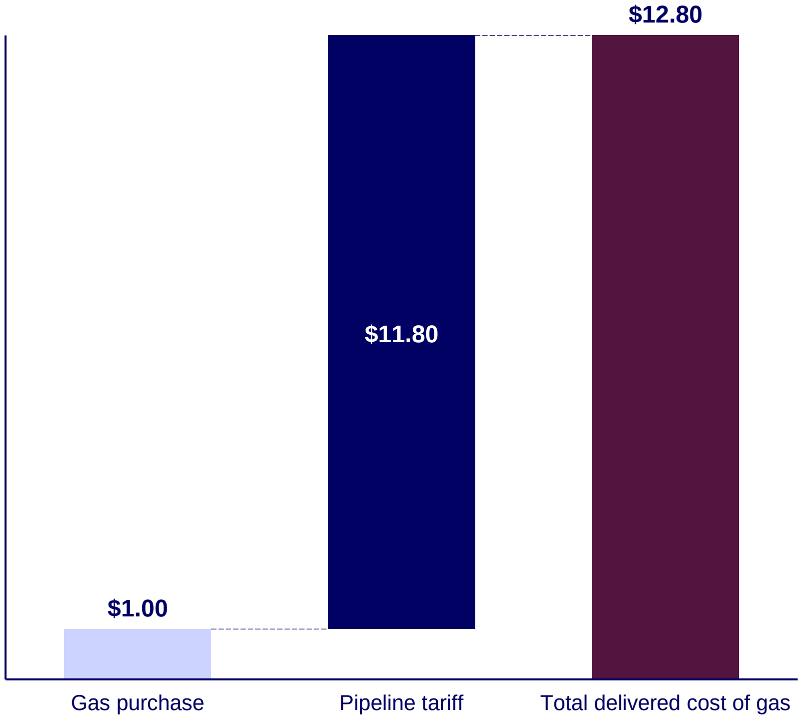
Main assumptions	
Capex[1]	$10,769 (2024 US$ million)
Opex	0.35% (Annual as % of capex)
Average throughput (2031 - 2071)	188 mmcfd
Capital Structure	25% Equity / 75% Debt
Interest Rate	6.25%
Target Return on Equity (ROE)	10%

Gas throughput and capex for Alaska LNG Phase 1 pipeline



Delivered Cost of Gas

Real 2024 US$/mmbtu



Source: Wood Mackenzie

1. US$ 10,769 million capex considers 20% contingency and is reflected in 2024 terms. Inflation during construction and Allowance for Funds Used During Construction (AFUDC) are considered in the model.

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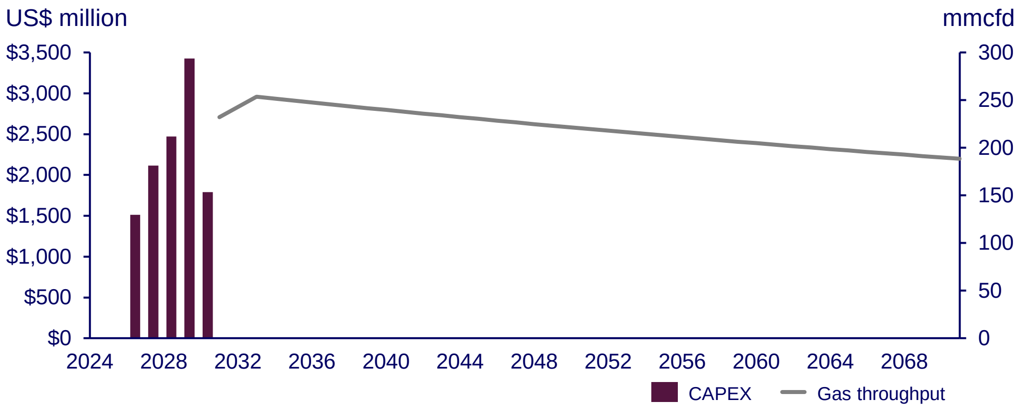
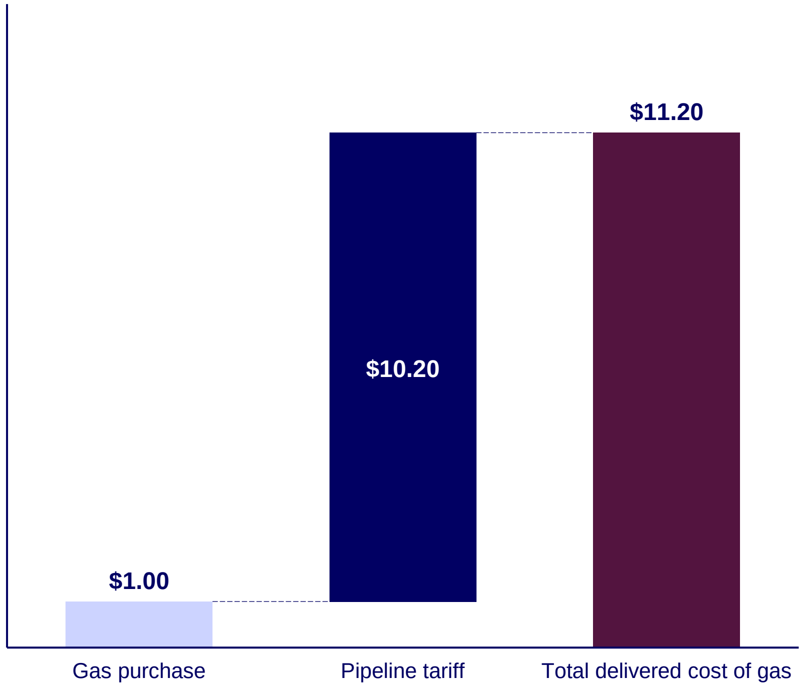
The WM Case includes probable additional industrial demand as a result of new gas supply availability and results in a US$11.20 /mmbtu delivered cost of gas

Main assumptions	
Capex[1]	$10,769 (2024 US$ million)
Opex	0.35% (Annual as % of capex)
Average throughput (2031 - 2071)	220 mmcfd
Capital Structure	25% Equity / 75% Debt
Interest Rate	6.25%
Target Return on Equity (ROE)	10%

Gas throughput and capex for Alaska LNG Phase 1 pipeline



Delivered Cost of Gas
Real 2024 US$/mmbtu



Source: Wood Mackenzie
1. US$ 10,769 million capex considers 20% contingency and is reflected in 2024 US$. Inflation during construction and Allowance for Funds Used During Construction (AFUDC) are considered in the model.

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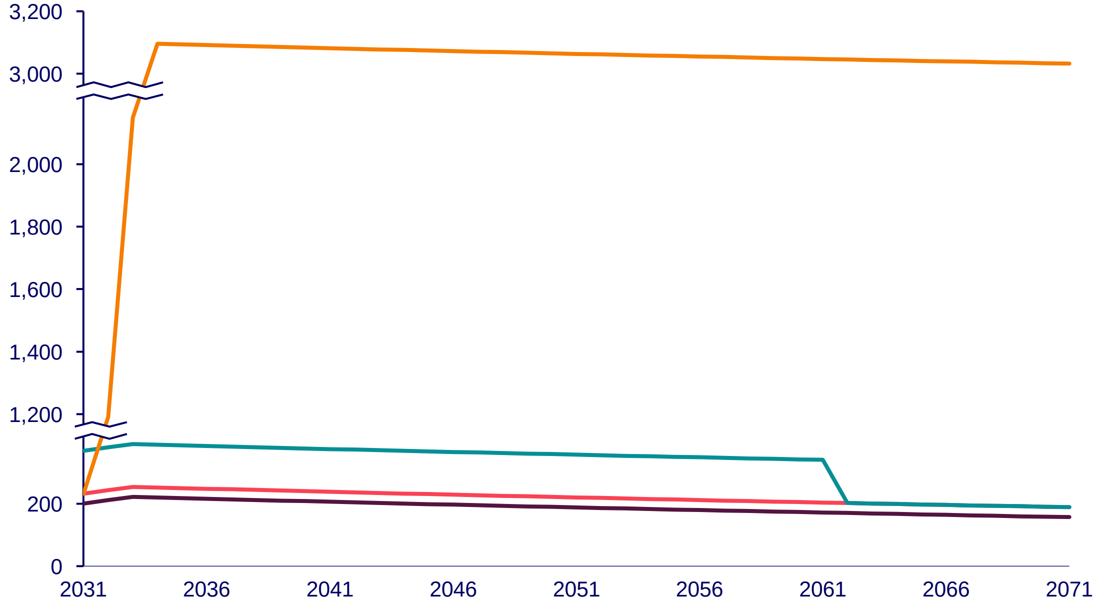
The scenario analysis shows an asymmetrical impact on the delivered cost of gas from a change in demand accruing to the consumers' benefit

Alaska LNG Pipeline Throughput Scenarios
mmcfd



Scenario	**Pipeline capex** 2024 US$ million	**Delivered Cost of Gas** US$/mmbtu
Alaska LNG	$14,385	**$2.23**
Additional Industrial	$10,769	**$8.97**
WM Case	$10,769	**$11.20**
Baseload	$10,769	**$12.80**

Additional compression capacity and Cook Inlet crossing

Source: Wood Mackenzie

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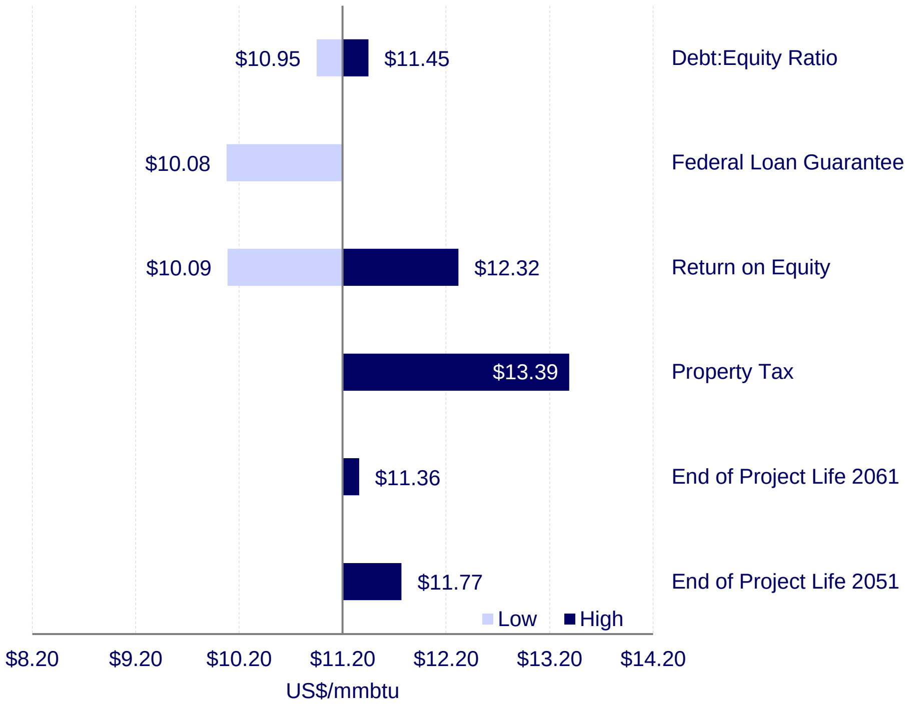
Additional sensitivities showed that securing a Federal Loan Guarantee and reducing Property Tax have the most impact in the cost of gas

Assumptions	Low	Base	High
Leverage – Debt : Equity Ratio	80:20	75:25	70:30
Federal Loan Guarantee	5.00%	6.25%	-
Return on Equity	7.5%	10.0%	12.5%
Property Tax	-	0.2%	2.0%
End of Project Life in 30 years	-	2071	2061
End of Project Life in 20 years	-	2071	2051

Delivered Cost of Gas – Sensitivity analysis on the WM Case Scenario
Real 2024 US$/mmbtu



Source: Wood Mackenzie

Contents

Southcentral and Interior Alaska Market Overview

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The LNG import cost analysis considers three main components (LNG cost, shipping, and regasification) across the value chain, each with a potential range of results

LNG import cost components

1 LNG Cost

- Multiple alternatives exist for securing supply of LNG (i.e. acquiring the molecule), ranging from spot market purchases, long-term supply and purchase agreements (SPA), or taking a tolling position partnering with an LNG developer
- Each alternative provides exposure to its own set of market risks and requires different levels of investment and management

2 Shipping

- LNG being a global commodity provides multiple geographical alternatives that require shipping cost considerations
- Alaska's access to the Pacific means geographical focus in Pacific facing projects, ideally as close as possible (e.g. West Canada projects), though other limitations arise, such as availability of supply or possible ship sizes

3 Regasification

- LNG requires to be re-gasified (transformed back to natural gas) to be consumed
- Regasification costs depends upon configuration of the processing facility e.g.: Land vs. FSRU[1], overall size, storage requirements, levels of utilization, etc.

4 On shore gas reception

- There are potential infrastructure requirements depending on specific circumstances such as costs to access the gas network and/or requirement to have a dock that meets the needs to bring the gas in-land in the case of an FSRU

Range of Cost estimated for LNG Imports

Source: Wood Mackenzie; 1. Floating Storage Regasification Unit

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1 LNG Cost: Multiple types of deals are possible, though JKM or Oil-linked based are the ones expected to be used by Alaska LNG importers

Overview of options to purchase LNG

Type of Deal	Description	Considerations	
Buy LNG at spot market	▪ LNG Purchases on the spot market, without the requirement of a term contract; price determined on each transaction	▪ Subject to supply availability, potential for higher volatility depending on price marker selected/available for purchase	**Unlikely to be used widely to import into Alaska due to risk of supply**
Long-term JKM[1] based price	▪ LNG Purchases via a Sales and Purchase Agreement (SPA), for example, with exposure to a JKM net-back ▪ Price determined by the JKM reported marker	▪ Most liquid and common for deals done in the last decade in Pacific facing projects, preferred by LNG marketers	**Considered for this analysis as imports via an FSRU will likely require long-term supply deals (10 to 20yr range[2])**
Long-term Oil-linked price	▪ Contract purchases based on a formula typically considering a constant plus a percentage of oil price; Price determined by the specific formula and the reported oil price at agreed timeframe	▪ Historically used, but less popular as LNG marketers prefer LNG price marker exposure ▪ Slightly higher management complexity as price formulas are negotiated and reviewed frequently	
Local gas hub-based price	▪ Purchases based on a local gas hub (e.g. 115% of Henry Hub), or self purchase gas in the local market and lift the LNG via a tolling agreement	▪ High degree of complexity as it requires involvement in multiple upstream operations, including the potential requirement to source the gas in a different market ▪ Companies that have inked favorable deals typically have equity positions in the LNG terminals	**Unlikely to be used to import into Alaska due to complexity and further upstream capabilities and capital requirements**

Source: Wood Mackenzie; Henry Hub based deals are mostly for US Gulf Coast LNG projects, though these are not possible to supply Alaska due to Jones Act limits in shipping; 1. JKM refers to the Japan Korea Marker benchmark price 1. Shorter term deals are possible, though the majority of deals in the past 5 years have been 10yrs or longer term and to secure FSRU commitments they would require to be coupled with long-term LNG supply

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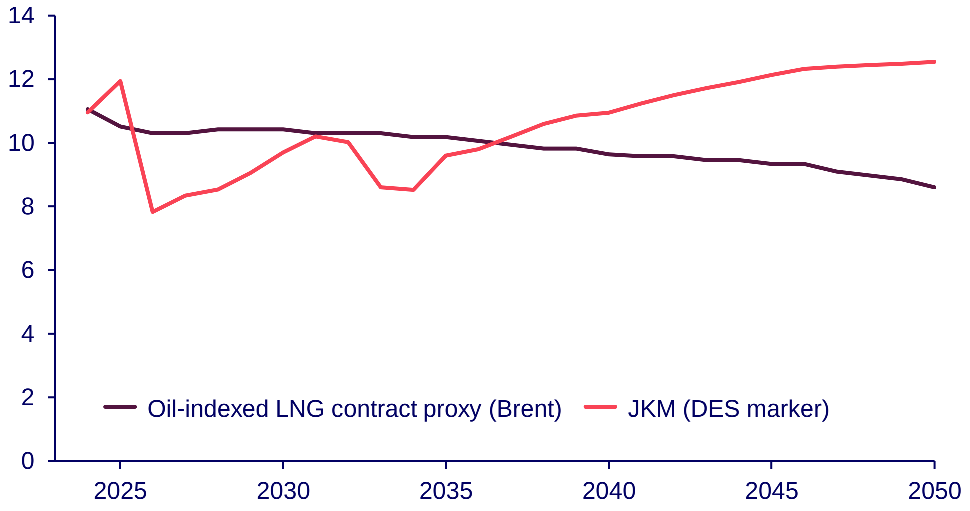
1 Access to LNG in the Pacific will be linked to JKM or Oil-indexed long-term pricing; sellers are likely biased towards accepting JKM netback contracts

LNG Price – Considerations

- Oil linked prices are expected to trend lower as oil prices decline long term in real terms
- LNG supply and demand dynamics decouple with some seasonality in the short term and raise long term
- As JKM marker has matured, liquidity has risen, resulting in increased adoption for LNG deals
- LNG sellers are more likely to prefer **JKM** linked deals for **long term purchase (10 to 20yr range)** agreements, evidenced by the recent dominance of them, though the analysis will consider the two alternatives

LNG price outlook

US$/mmbtu, real 2024



Delivered Price	Period Average	2031-2050 average
JKM (Des)	10.61	11.00
Oil linked (Brent)	9.86	9.64

Source: Wood Mackenzie; Delivered into Japan

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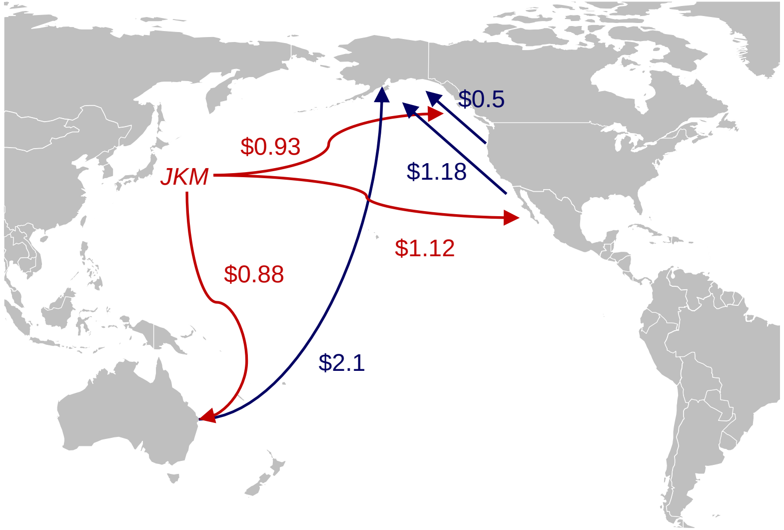
2 **Shipping costs** can impact delivered cost of LNG in the -0.4 to 1.2 /mmbtu range, depending on location of supply

Shipping routes and costs

US$/mmbtu, cost of roundtrip



- The shipping adjustment should generally be positive to Alaska LNG imports due to access to the Pacific and proximity to potential LNG supply area in West Canada
- However, availability of supply in adequate form (e.g. ship size) can prove challenging for which alternative supply sources such as Australia have been considered

Net shipping adjustment (US$/mmbtu)
Considers net back from JKM (subtracting cost from source to JKM) and adjustment to Alaska (adding cost from source to Alaska):

- Canada= (0.93) + 0.5 = (0.43)
- Australia = (0.88) + 2.1 = 1.22
- Mexico = (1.12) + 1.18 = 0.06

- At best JKM could be discounted considering ~(0.43) shipping adjustment. Though portfolio players would generally pocket premiums for any route optimization, giving buyers a full JKM price (without shipping adjustment) as alternative
- We consider the -0.43 to 1.22 as the shipping adjustment range

Source: Wood Mackenzie; Considers netback trips (red lines) with 174,000 m3 ship size and added costs (blue lines) with 75,000 m3 ship size

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3 **FSRUs** generally show low levels of utilization (relative to onshore regas facilities) and regasification costs show correlation to overall size of facilities

FSRU Cost range

mmcfd, US$/mmbtu, real 2024

Average Send Out Capacity (Nominal mmcfd)	Regas Cost (US$/mmbtu)
520 +	0.4 – 0.75
500	~0.75
480	~0.80
410	~1.5
100	2.50

- Operating FSRUs generally show low utilization, ranging from 40 – 45%
- For a ~150 mmcfd estimated demand (South Central demand), nominal capacity would be expected in the 350 – 400 mmcfd range
- We estimate the regas cost would be in the **US$ 1.0 – 1.5 / mmbtu**, though there would be incremental costs to build or adapt receiving infrastructure and further downstream requirements (e.g. site for docking, receiving gas network costs)
- There could also be optimization opportunities, including onshore storage operations to increase utilization, resulting in a lower sized nominal capacity requirement, though there is less availability of small scale FSRUs (i.e. under 200 mmcfd capacity)

Source: Wood Mackenzie; Considers a data set of 48 FSRUs that are operational, under construction, proposed or speculative; Regas costs consider a 40 to 45% utilization

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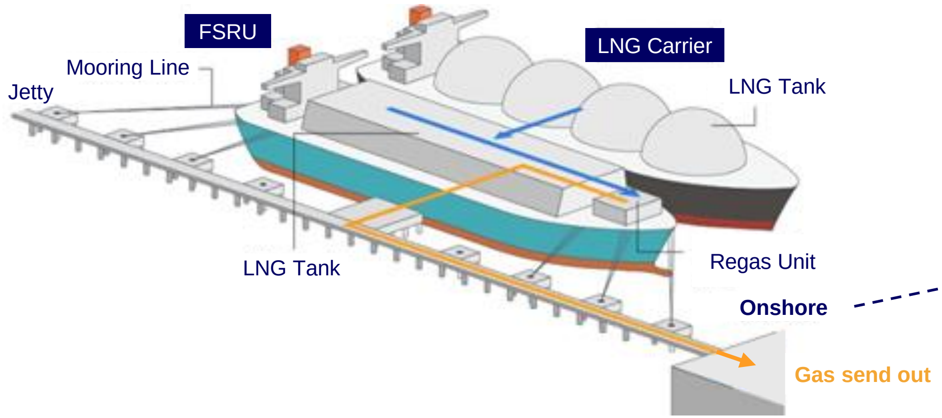
4 **Onshore** reception site is largely dependent on infrastructure configuration, meta-oceanic conditions and specific buildout, requiring additional investment

Illustrative FSRU Onshore Connection

ILLUSTRATIVE



Onshore connection configuration can vary due to multiple factors resulting in additional investment requirements

Additional Capex could be in the US$ 50 – 500 million range. However, as of now Wood Mackenzie is uncertain of a site and/or configuration to be used for the potential FSRU, thus costs and investment requirements are yet to be estimated

Source: Wood Mackenzie; Image from Mitsui OSK Line Blog

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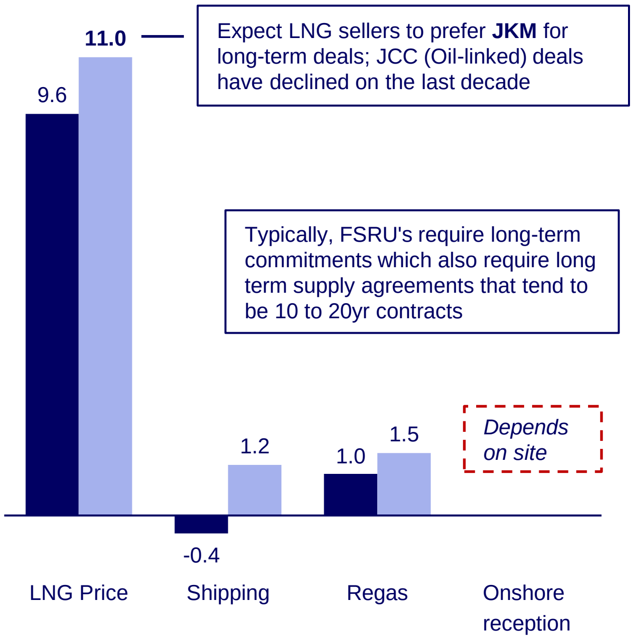
LNG imports estimated at ~US$10.2-13.7/mmbtu, within range of the delivered cost via pipeline, though potential incremental costs downstream of regas have not been considered

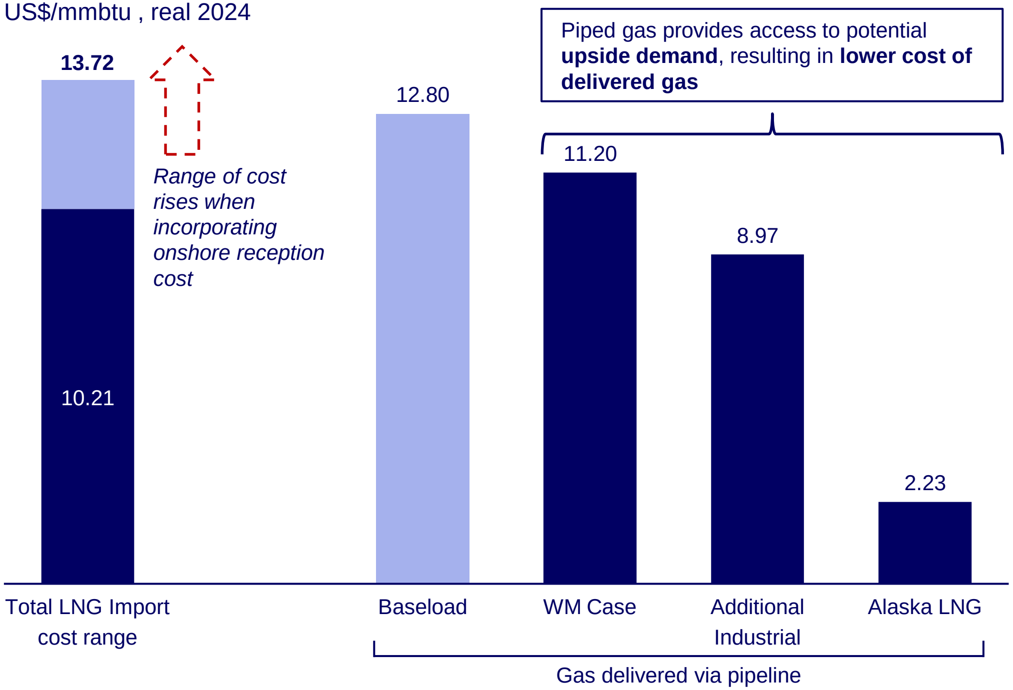
LNG Import cost range per value chain component[1]

US$/mmbtu, real 2024



LNG Import cost comparison vs Gas delivered via pipeline

US$/mmbtu , real 2024



Low end High end

Source: Wood Mackenzie

1. Considers LNG Price average for the 2031 – 2050 Period, Shipping and Regas costs maintained constant in real terms

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Wood Mackenzie

Gas supply via pipeline provides higher economic impact, jobs, and lower delivered costs by stimulating demand, though it requires higher capex and a later first gas

- **Cook Inlet gas supply has declined**, and despite exploration efforts by operators, **no new volumes** have been **discovered**
- Lack of reliable and affordable gas supply drove **decline in demand**, however going forward **supply** is expected to **drop faster** creating a **demand gap of ~2.3 tcf** (to 2071) projected to begin by the end of this decade
- With Cook Inlet gas production proving to be challenging, there are **two main alternatives** to address the forecasted **supply & demand gap**:

	Natural Gas Supply via Pipeline	LNG Imports
	A 765 mile (Phase 1), 42-inch diameter pipeline connecting the Southcentral Alaska region with the North Slope fields	Gas imports via LNG, for which regas and further downstream infrastructure is required
	▪ Cost of delivered gas in the **US$2.23 – $12.8/mmbtu**	▪ Cost of delivered gas in the **US$10.2 – $13.7/mmbtu (plus onshore costs)**
	▪ Time to first gas 2031[3]	▪ Time to first gas potentially 2028[2]
	▪ *Direct, indirect and induced GVA**: ~US$ 10.3 Bn*** ▪ ***2,271 jobs[1]** created during construction and **1,138 in operations***	▪ *Lower capex & lower direct, indirect and induced GVA **~US$0.6 – 1.4 Bn*** ▪ ***568 jobs[1]** during **construction** and **250** in **operations***
	▪ *Provides access to **upside demand** with additional industrial and economic benefits to the state* ▪ ***Reducing emissions** and **removal from EPA's nonattainment** in **Fairbanks** via substitution of oil & wood as primary energy source*	▪ *Focused supply for the Southcentral region* ▪ *No Fairbanks or additional industrial demand*
	▪ *Higher **likelihood** of **full Alaska LNG Project***	

Preliminary Analysis

Source: Wood Mackenzie; 1. Direct, indirect and induced jobs, average per year of each period; 2. First gas of 2028 for LNG imports is dependent on receiving LNG import permits, and Wood Mackenzie is uncertain about the status of those permits. Any delay in permits would likely delay first gas. 3. The AGDC has indicated that the pipeline has all major permits in place

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