

# Comments on SB 275

Senate Resources Committee

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**Nicholas Fulford**

Senior Director, LNG and Energy Transition

**Fernando Rolla**

Senior Economist



# Basis of Opinion

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Staff members who prepared this report hold appropriate professional and educational qualifications and have the necessary levels of experience and expertise to perform the work.

# Agenda

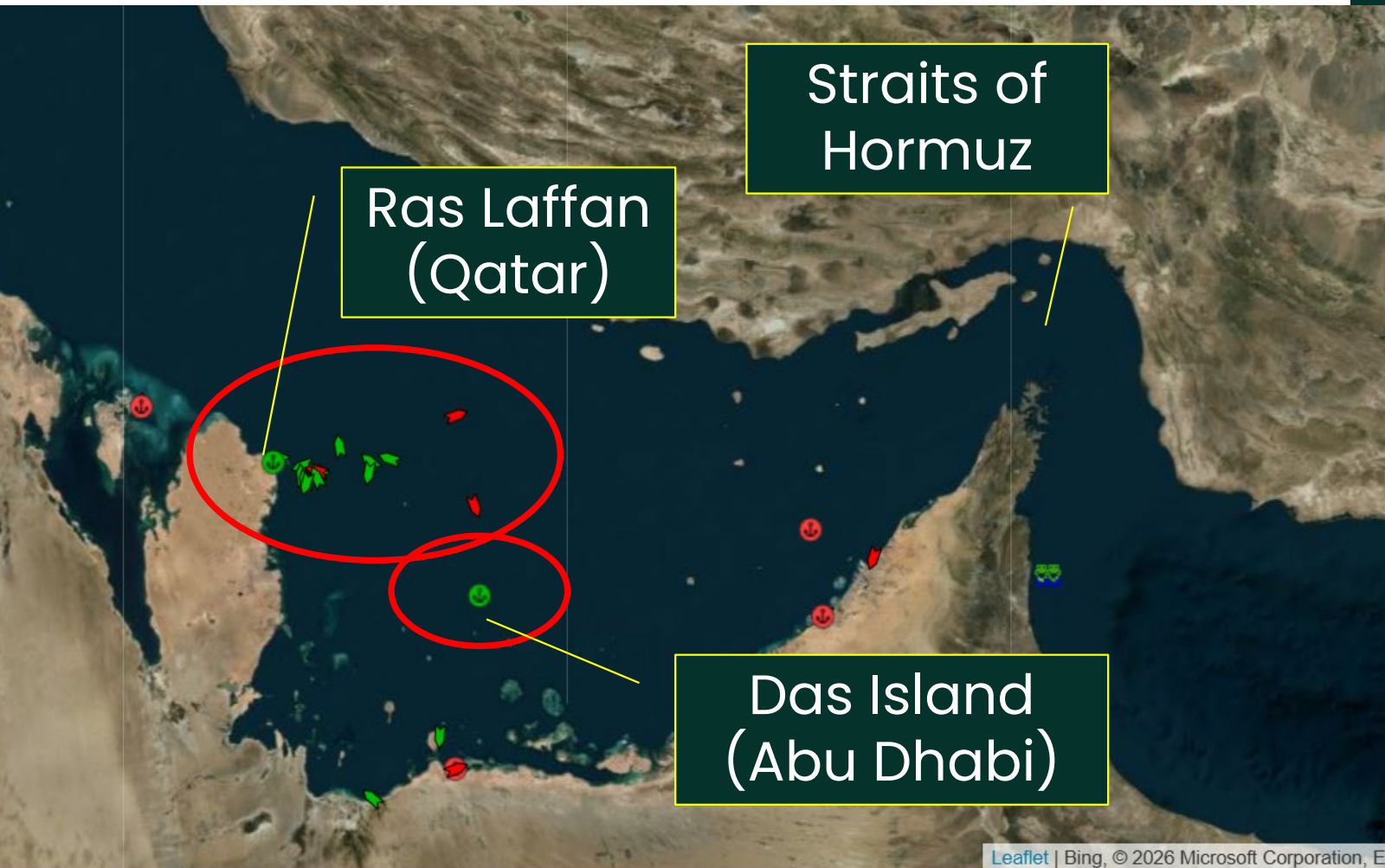
## Topics to be covered

- **LNG Market Developments**
  - Implications for Alaska
- **Project Structure**
  - Effects on state tax revenues
- **Transparency and economic evaluations**
- **Surcharge Proposal**
  - Considerations for project economics
- **Gas Processing/Lease Operating Expenses**
  - Considerations for CO<sub>2</sub> removal plant



# Market Developments

# LNG Market Disruption



- Around 22 LNG carriers currently trapped in Arabian Gulf
- Qatar Energy has declared Force Majeure on their export contracts
- Usual volume 2–3 export cargoes per day (~10bcfd)
- Qatar is one of the biggest three LNG suppliers alongside US and Australia
- Effective loss of 20% of global LNG supply, spot prices up to around \$25/MMBtu.
- Das Island also affected, but smaller export volumes (0.7 bcfd)
- Two Indian flagged LPG carriers were allowed transit on 13<sup>th</sup> March (note these were not LNG carriers)
- Majority of Qatari LNG is for Asia; India and Pakistan worst affected

# Disruption exacerbates existing navigational risks for LNG

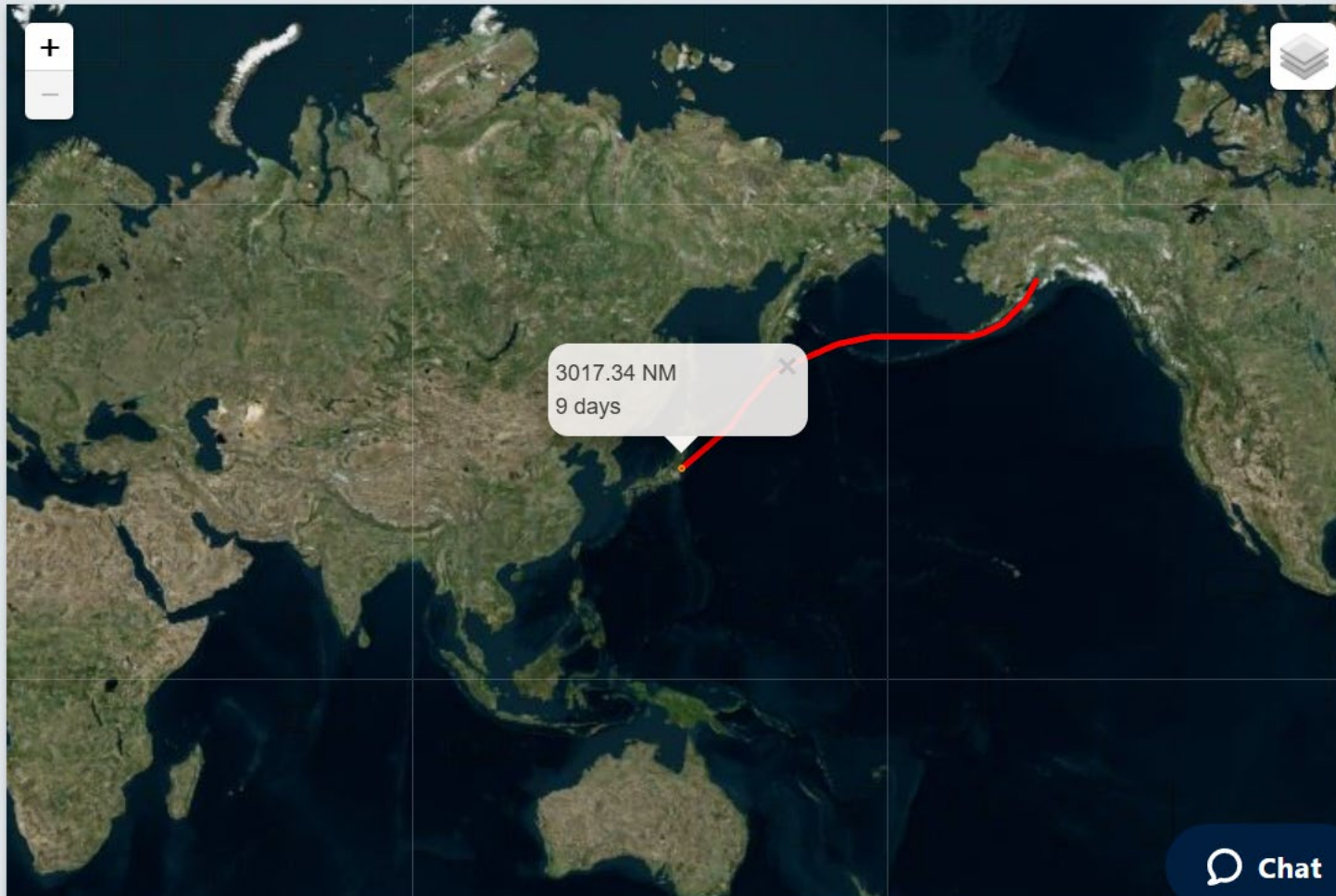
Suez Canal – no LNG transits since January 2024 (200 in 2023)

Russian LNG carrier destroyed March 4th

Panama Canal transits down two thirds in 2024 (drought)

- The disruption in the Arabian Gulf is only the latest (and biggest) impact on LNG shipping in recent years.
- LNG carriers stopped using the Suez Canal in 2024 owing to security issues in the Red Sea.
- Panama Canal transits dropped sharply in 2024 (major impact on US Gulf Coast LNG exports to Asia).
- More recently, a Russian LNG carrier was set on fire and abandoned in the Mediterranean. Currently drifting near Malta.

# Why this matters for Alaska



- Alaska is only around 9 days steaming from major Asian markets.
- No navigational hazards or risks.
- Security of supply now key consideration for buyers. Premium prices may start to emerge for projects outside risk areas.
- Even though Alaska LNG is many years away, buyers likely to seek out lower risk supply routes.
- Lower 48 wholesale gas price pressures on Gulf Coast LNG may add to Alaska LNG appeal.

# Project Structure Considerations

# AK LNG Value Chain

Under SB 138 State's upstream tax and royalty were exchanged for a 25% approx. equity across entire value chain

Upstream taxes and royalty broken out

## North Slope Gas Producers

- Potentially including ExxonMobil, ConocoPhillips and Hilcorp, etc

## Gas Processing Plant

- Removal of CO<sub>2</sub> and H<sub>2</sub>S
- Creates "LNG quality" natural gas

## Gas Transmission Pipeline

- 42" circa. 800 mile pipeline
- Multiple compression stations

## Liquefaction Plant & LNG loading

- Nikiski location
- Marine Exports to LNG customers

## (Gross) Gas Tax and Royalty

- Impact on oil taxes potentially mitigated through SB 275

## Gas Processing Plant

- Potentially subject to State CIT and Property Tax

## Gas Transmission Pipeline

- Potentially subject to State CIT and Property Tax

## Liquefaction Plant & LNG loading

- Potentially subject to State CIT and Property Tax



State revenues vary based on value split upstream / midstream

# Approximate Economic Breakdown

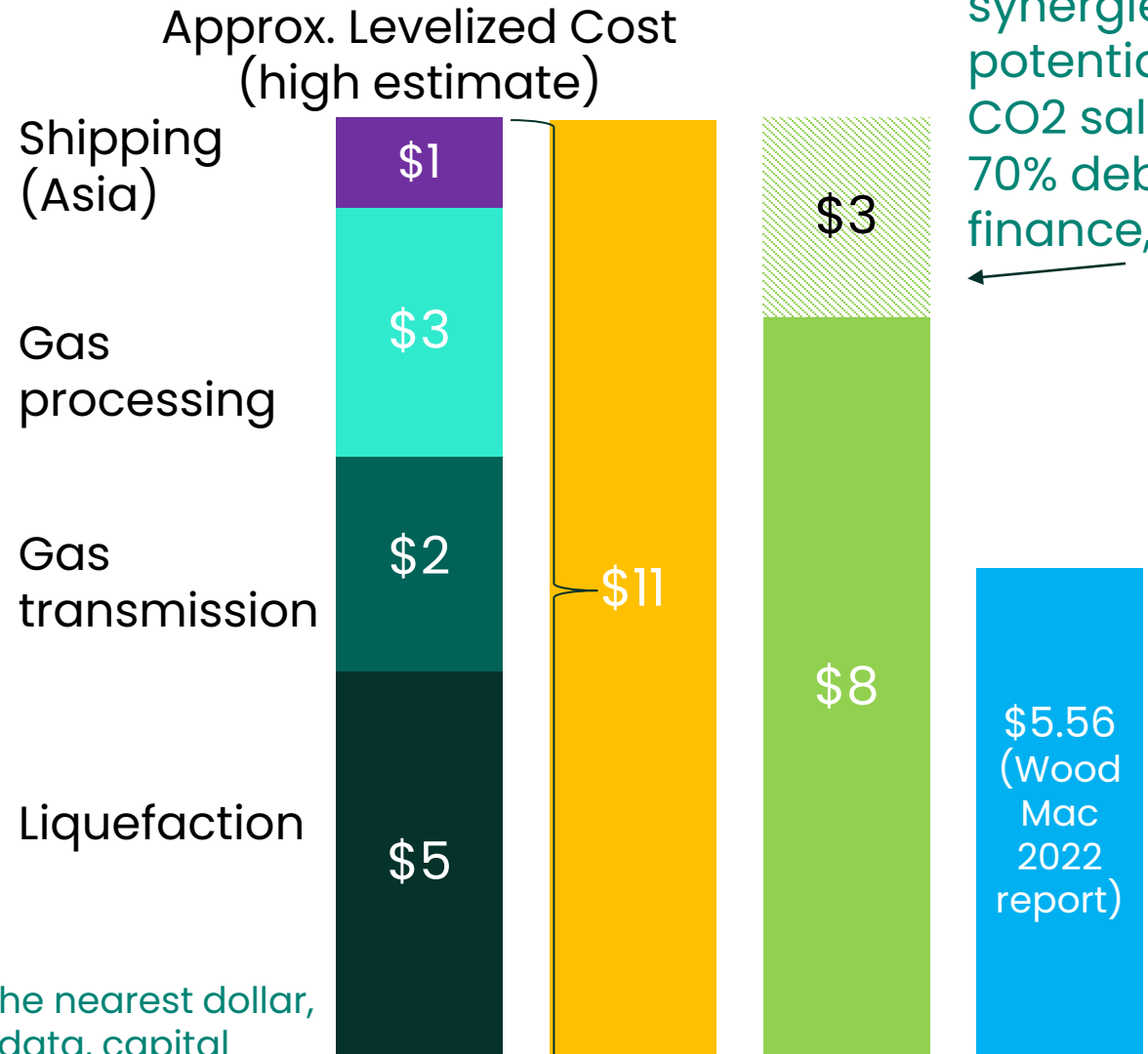
(note: *Illustrative only*, does not reflect actual project costs and economics)

## Assumptions:

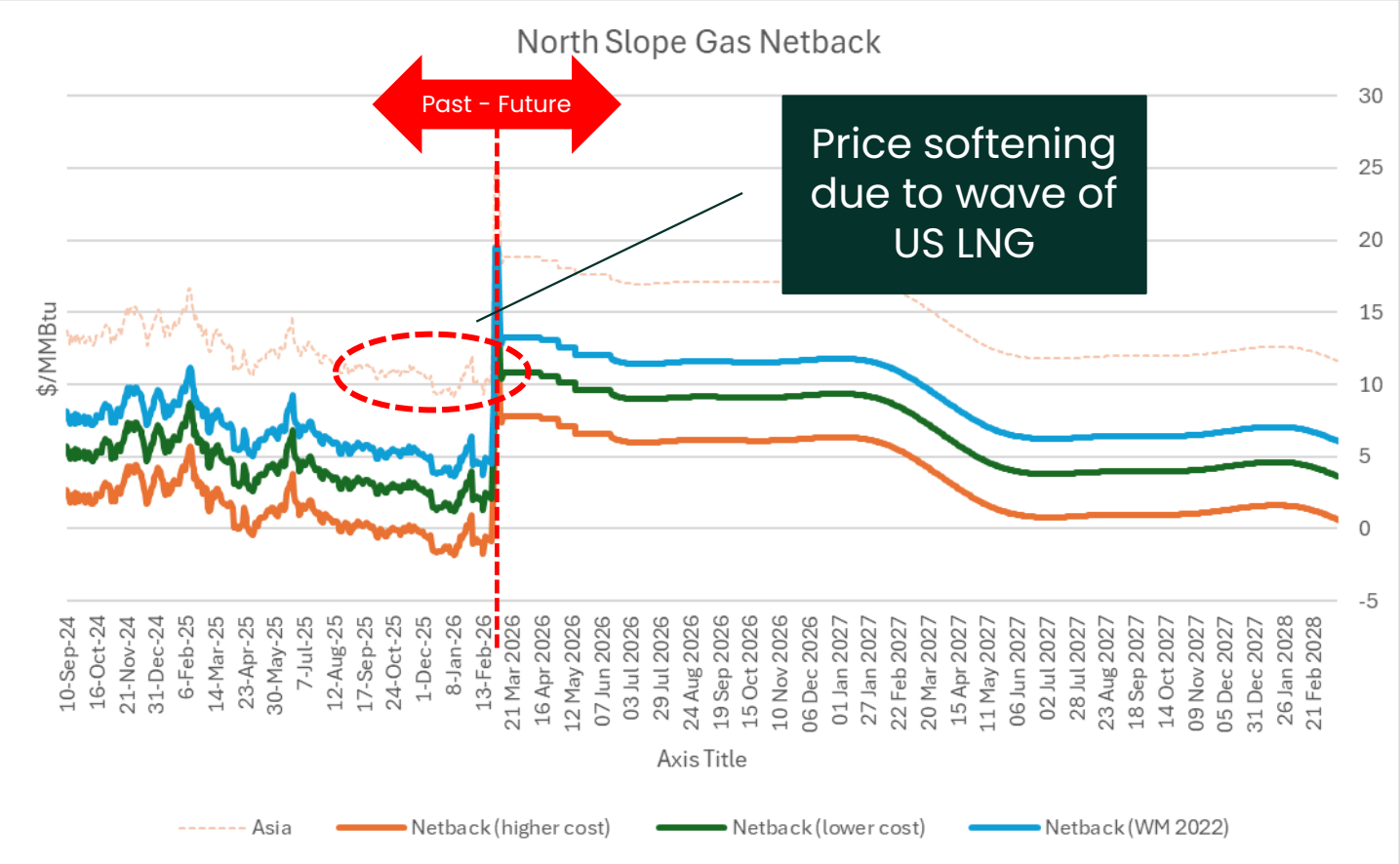
- Cost of liquefaction plant ~ \$25bn (\$1,250 per tonne per annum)
- Cost of pipeline inc. compression ~ \$15bn
- Cost of Gas Processing/CO2 Removal ~ \$10bn
- Cost of shipping to Asia ~ ~\$1/MMBtu
- Each element in the value chain generates approximately a 10% post tax return.
- 9.4% State CIT, 21% Federal CIT

Levelized cost estimates are approximate, and rounded to the nearest dollar, actual levelized costs can only be determined from project data, capital structure, and other key assumptions.

Source GaffneyCline analysis



# Theoretical gas value on the Slope?

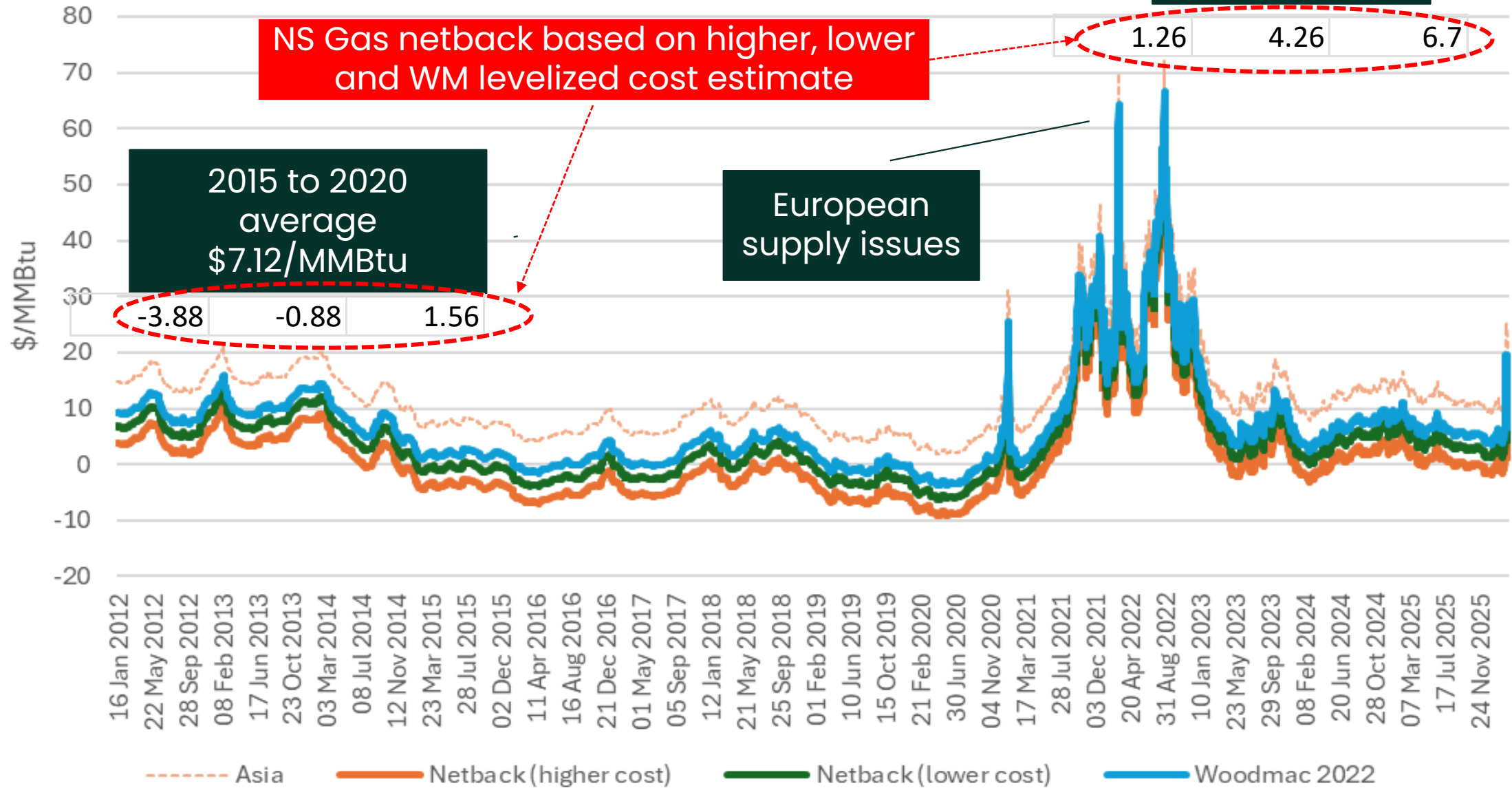


Source: ICIS/GaffneyCline analysis. Uses a combination of historical price data and forward market curves which may not reflect actual price outcomes.

- With the range of levelized cost estimated on the previous slide, the netback to the North Slope is derived using prevailing LNG market prices in Asia, and the current forward market curve.
- This indicates that the value of North Slope gas would be in the range of zero to around \$5 based on Q4 2025/Q1 2026, depending on the levelized cost of processing, storage, liquefaction and shipping dictated by project economics.
- Forward prices suggest a higher netback until prices revert in around 2028.

# Historical Netback

Historic Imputed North Slope Gas Value



# Gas Pricing Options – Fixed Price



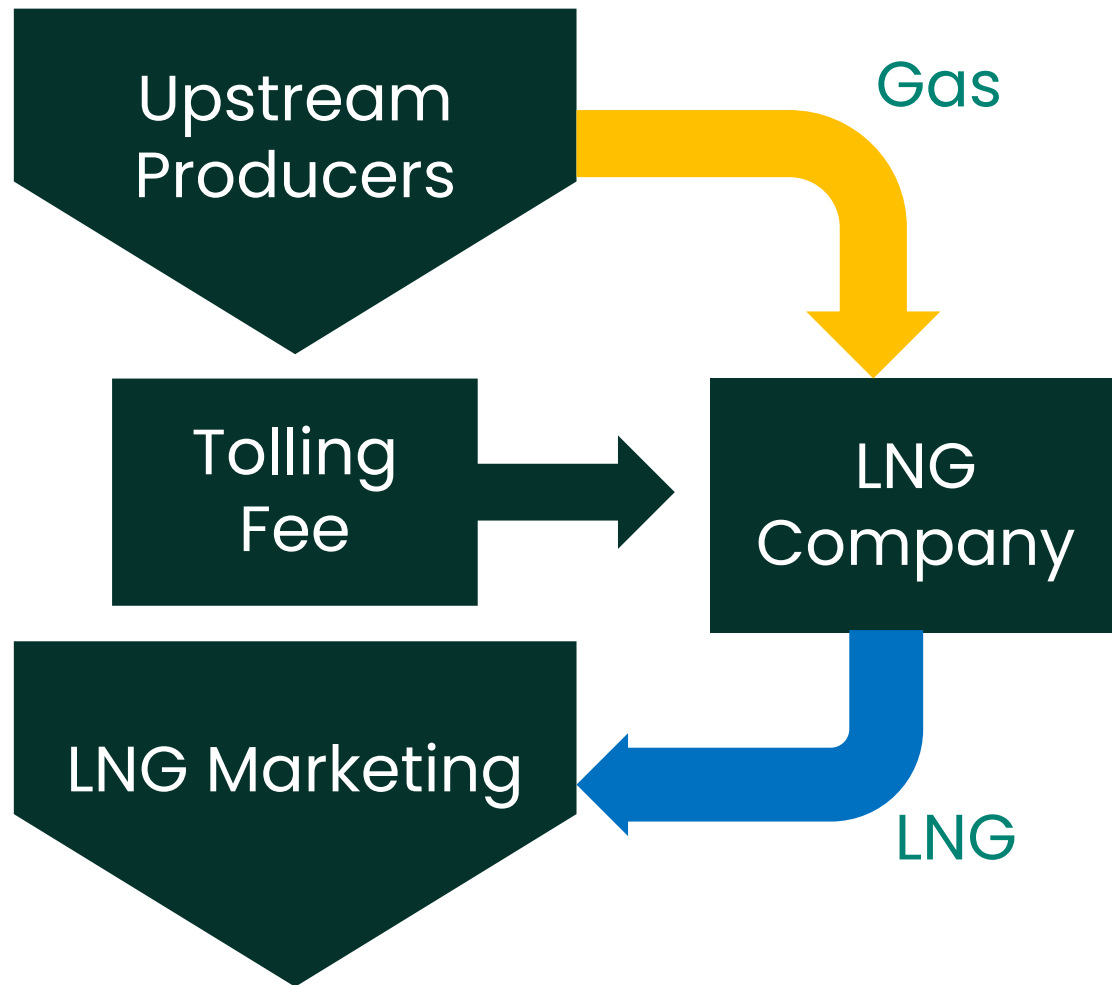
- Gas sold at a fixed price isolates producers from volatility in LNG pricing and assures a profitable sale under all market conditions.
- Pricing will typically comprise a fixed price with indexation, such as inflation.
- LNG pricing risk is largely carried by the LNG company, with the potential for profit upside, but also financial losses.
- **Tax consequence:** Upstream tax and royalty will be relatively stable and predictable. However, sustained upside will be taxed at CIT rates, not upstream

# Gas Pricing Options – Netback



- Gas sold at a netback price allows producers to share in market price upside but also exposes them to downside.
- Pricing will typically comprise a percentage of the sales price (eg 15% of sales price)
- LNG pricing risk is shared by the LNG company, and both upstream and LNG company have the potential for profit upside, but also financial losses.
- **Tax consequence:** Upstream tax and royalty will be variable, but price upside will drive higher government take compared to CIT from the LNG company.

# Gas Pricing Options – Tolling



- Although no explicit mention of a tolling arrangement has been made by Glenfarne/AGDC it remains a possible mechanism.
- A tolling arrangement involves a fixed fee paid to the midstream LNG company (processing, transportation, liquefaction) to produce LNG for onward sale by the upstream owners.
- The returns to the LNG midstream owner are fixed, but profitable.
- The upstream entity carries the entire market risk, and all profits or losses are passed back to them.
- **Tax Consequence:** Tax and Royalty may be based on sales price less tolling fee (and shipping). May result in highest state tax take in high price scenario.

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# Transparency

# Lessons from LNG Canada

- B.C. had access to a “Joint Economic Model” co-developed with Shell to calibrate incentives (PST deferral/performance payments, electricity rate treatment, and carbon-pricing measures). Included access to detailed cost and revenue assumptions under confidentiality.
- Was used to quantify the value of the provincial package which required LNG Canada to share detailed cost, throughput, and pricing assumptions under confidentiality.
- Likely to have been relied on to decide on repeal of previous LNG project taxes, and introduce the Natural Gas Credit which was used to offset against provincial CIT.
- Additional visibility was achieved through disclosure of BC Hydro electricity supply terms.

# Economic Transparency – Global LNG Projects

Jurisdiction & Project	Access mechanism	Level of Disclosure of Information	Lifecycle point	What it was used for
<b>Tanzania – Likong’o (Lindi) LNG (Shell / Equinor)</b>	HGA talks guided by Government Natural Gas Model; macro/financial study with govt. agencies	Price thresholds, capex/opex, fiscal progressivity, DMO impacts	Pre-HGA / fiscal design	Fiscal stability, DMO level, local content, timing to FID
<b>Indonesia – Tangguh LNG (bp)</b>	Plan of Development (PoD) integrated economic case	DCF returns, volumes, capex/opex, CCUS impacts	Pre-FEED / expansion phases	PoD approval, scope/phasing
<b>Mozambique – Rovuma Basin LNG (Areas 1 &amp; 4) (ExxonMobil, ENI etc)</b>	Decree-Law 2/2014: state party to core project agreements; approvals tied to development/financing plans	Integrated LNG value-chain plans and financing structures	Throughout (approvals → expansion)	Fiscal stability, domestic priority uses, expansion sequencing
<b>Papua New Guinea – Papua LNG (ExxonMobil)</b>	Gas Agreement validated; concessions negotiated off project economics	Project returns/fiscal split; integration with PNG LNG	Post-term sheet / pre-FEED validation	Additional state benefits; pipeline/third-party access; national content
<b>Senegal &amp; Mauritania – GTA FLNG (bp)</b>	Inter-governmental agreement + NOC equity	Full integrated economics	Throughout (board/JV cycle)	Revenue share, domestic allocation, expansion to Phase 2
<b>Trinidad &amp; Tobago – Atlantic LNG</b>	Unitization/restructuring of multi-train complex; state modeling	Train valuations, capacity/cargo entitlements, state take	Restructuring stage	Equity split reset, offtake access, fiscal expectations

# Surcharge Implications

# Economic Impact of a 15c/MMBtu Surcharge

- Approximate equivalence\*:
  - State CIT derived from either the gas pipeline or the CO2 removal plant.
  - Property tax of ~2mils
  - 1.5% of LNG sales at delivery point.
  - One third of the shipping cost to Asia.
  - 25% of potential 45Q tax credit revenue from Gas Processing Plant
  - 75% of the efficiency improvement based on the difference in ambient temperatures between Texas and Alaska.
- If the LNG project generates a post tax IRR of 10% without the surcharge, the additional surcharge would reduce it to about 9.64%\*

Note: \*equivalence approximations depend on a range of assumptions including capital cost of the plant, LNG pricing assumptions, discount rates, project life and other factors. They are provided for guidance only.

# Surcharge in Tax Stack: Canada comparison

- Canada Federal CIT rate: 15%
- BC Provincial CIT rate: 12%
- BC Natural Gas Tax Credit: (creates a provincial CIT floor of 9%)
- Effective CIT: ~24% (with NG credit)
  
- US Federal CIT rate 21% (but state tax is allowable)
- Alaska State CIT rate 9.4%
- Effective CIT: 28.43%
- Excluding property tax, a 15c/MMBtu surcharge might increase effective tax rate from 28.43% to between 29.5% and 30.5% depending on a range of assumptions.

Property Tax is the biggest tax feature that differentiates Alaska from Canada

Note: the analysis above is for illustrative purposes only, a detailed financial model and tax calculation would be needed to evaluate the effective tax implications of the surcharge, along with detailed project economic data.

# Gas Processing Plant Considerations – Lease Operating Expense Implications

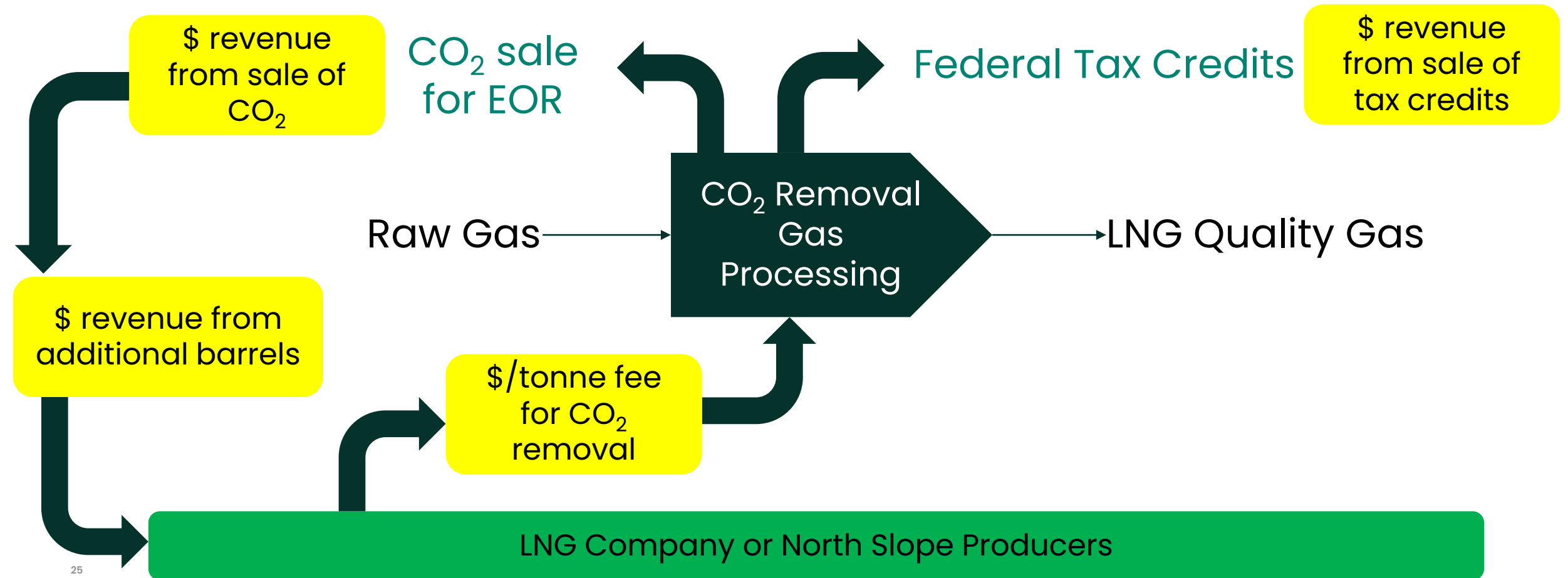
# Gas Processing Plant (CO<sub>2</sub> removal)

- CO<sub>2</sub> removal is essential to bring gas quality to LNG specification.
- A CO<sub>2</sub> removal plant is always present in the LNG value chain, but not on the scale envisaged for AK LNG
- Many Gulf Coast LNG plants now incorporate CO<sub>2</sub> capture in addition to removal, as a result of federal incentives (45Q)
- CO<sub>2</sub> is also used as a mechanism for enhanced (tertiary) oil recovery (EOR).
- Some North Slope oil producing fields are said to be potential candidates.
- In “rule of thumb” terms, one tonne of CO<sub>2</sub> can lead to the production of 2 – 5 barrels of recovered oil, but results vary.
- Oilfield operators will sometimes purchase CO<sub>2</sub> from removal/processing plants. Values can range from zero to around \$20/tonne.
- The owners of the CO<sub>2</sub> removal plant may enter into a sale and purchase agreement with North Slope oil producers.

# Federal Tax Credits for CO<sub>2</sub> Removal

- Under the IRS 45Q mechanism, a tax credit of \$85/tonne is payable for the removal of CO<sub>2</sub> and its permanent geological sequestration or use for EOR.
- Credits apply over a 12-year period, and construction must start before Jan 1, 2033.
- However, monetization of the tax credit can be challenging, and complex tax mechanisms are often seen, such as ownership of the CO<sub>2</sub> removal plant through a Tax Partnership.
- Monetization of the credits is similar to the tax credit system that used to operate in Alaska, with credits being worth some portion of their nominal value (eg 80-90c on the dollar) when sold on to third parties.

# Gas Processing – Potential Revenue Flows



Questions?