Summary from North Slope Gas & LNG Symposium

Anchorage, AK: November 22, 2013

Nikos Tsafos & Janak Mayer
Testimony to House Resources Committee
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Executive Summary

- There is growing demand for gas and LNG, in particular in Asia, and most countries need to secure additional LNG to meet their energy needs post 2020. Alaska’s proximity to Asia makes it a natural supply source, although it will face competition from a growing number of new supply sources.

- Shale gas in the United States Lower 48 and in Western Canada will compete with Alaska—and the L48 in particular are a primary destination for suppliers seeking long-term LNG. But higher prices in the United States will potentially undermine the competitiveness of LNG from the Lower 48.

- The companies that are involved in Alaska’s upstream and will likely be involved in LNG have substantial experience with and expertise in LNG. As such, the question is not whether they can do an LNG project but rather will they choose to given competing priorities and outlets for their capital.

- An LNG project from Alaska can be competitive with other projects that are seeking to supply Asian markets—but its competitiveness will depend critically on fiscal terms and on keeping costs down.

- LNG projects are big, complex, risky, multi-stakeholder endeavors that take a lot of time (often decades) and money (billions) to complete. There are multiple ways to structure an LNG project (who participates in which part and in what way) and it is important to develop a structure that aligns all the different partners and project participants and meets their risk-reward appetites.
The New Geography of Global LNG: Many Options…

- Over 34 tcf of undeveloped gas in North Slope
- Large associated gas reserves in pre and post salt
- Large, undeveloped shale gas in W. Canada
- Gas surplus has pushed down gas prices
- Sizeable discoveries (30+ tcf) made in recent years
- Significant associated gas either flared or undeveloped
- Large resources in Qatar and Iran
- Large scale resources
- Sizeable stranded gas
- Sizeable undeveloped gas
- Over 100 tcf discovered in recent years
- More discoveries in NW plus shale gas
… But Also Risks

- Uncertain fiscal terms and project economics
- Cost, technical risk, finance
- Domestic demand, politics, priorities
- Domestic demand needs
- Cost, development plan
- Cost of entry, partner risk, government capacity, fiscal terms
- Cost escalation and delays
- Political and geopolitical risk, finance, domestic demand
- Upstream, infrastructure, commercial structure
- Price volatility, permitting, export licenses
- Security, uncertain terms, need for gas locally
- Ability to execute, ability to export
- Domestic demand needs
- Cost escalation and delays
- Political and geopolitical risk, finance, domestic demand
Think Micro, Not Macro; Gas is Not a Global Market

![Graph of Majors: Average Realized Oil Price](image1)

![Graph of Majors: Average Realized Gas Price](image2)
## Gas is Very Different Than Oil

<table>
<thead>
<tr>
<th></th>
<th>Oil</th>
<th>Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Production</strong></td>
<td>86.1 mmb/d (2012)</td>
<td>54 mmboe/d (2012)</td>
</tr>
<tr>
<td>Middle East</td>
<td>32.5%</td>
<td>Europe/Eurasia 30.7%</td>
</tr>
<tr>
<td>Europe/Eurasia</td>
<td>20.3%</td>
<td>North America 26.8%</td>
</tr>
<tr>
<td>North America</td>
<td>17.5%</td>
<td>Middle East 16.3%</td>
</tr>
<tr>
<td><strong>Reserves</strong></td>
<td>1,669 bn boe (2012)</td>
<td>1,102 bn boe (2012) (ex. shale)</td>
</tr>
<tr>
<td>Middle East</td>
<td>48.4%</td>
<td>Middle East 43.0%</td>
</tr>
<tr>
<td>C. And S. America</td>
<td>19.7%</td>
<td>Europe/Eurasia 31.2%</td>
</tr>
<tr>
<td>North America</td>
<td>13.2%</td>
<td>Asia Pacific 8.2%</td>
</tr>
<tr>
<td><strong>Prices</strong></td>
<td>Brent: $111/b</td>
<td>Henry Hub: $2.86/MMBtu ($17.2/b)</td>
</tr>
<tr>
<td></td>
<td>WTI: $94.1/b</td>
<td>NBP (UK): $9.47/MMBtu ($56.8/b)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Germany: $10.86/MMBtu ($65.1/b)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Japan (LNG): $16/MMBtu ($96/b)</td>
</tr>
<tr>
<td><strong>End-users</strong></td>
<td>Transportation 53%</td>
<td>Power 40%</td>
</tr>
<tr>
<td></td>
<td>Non-energy 15%</td>
<td>Industry 17%</td>
</tr>
<tr>
<td></td>
<td>Industry 8%</td>
<td>Distribution 15%</td>
</tr>
<tr>
<td><strong>Trade</strong></td>
<td>64% crosses border to be consumed</td>
<td>31% crosses border to be consumed</td>
</tr>
<tr>
<td><strong>Marketing</strong></td>
<td>Global market; produce and then decide where / to whom to sell</td>
<td>Needs a market before it is produced</td>
</tr>
</tbody>
</table>

What Does an LNG Plant Look Like?

- **Long lead time** (4 years to build, several years to prepare to build)
- **Large, upfront** investment needed to develop the project (usually, tens of billions)
- **Minimal operating** expenses (only a small fraction of initial investment)
- **Long-term cash** flow (expected revenues for 20+ years)
Oil and Gas Have Different Production / Economic Profiles…

LNG Project vs. Deepwater Oil Project @ $80/bbl

- Gas Production (mboe/d)
- Oil Production (mboe/d)

- ATCF - LNG Project
- ATCF - Oil Project
... and Different Economic Outcomes

LNG Project vs. Deepwater Oil Project @ $80/bbl

NPV10

- $mm
  - 2,000
  - 2,000

Required Reserves

- mmboe
  - 2,476
  - 625

Initial CAPEX

- $mm
  - 38,300
  - 2,600

NPV10/boe

- $/boe
  - 0.85
  - 3.36

IRR

- %
  - 11%
  - 29%

Production Life

- Years
  - 50
  - 20
LNG is Big, Complex, Risky and Multi-Stakeholder

Most of the money is spent after taking a Final Investment Decision (FID); before FID, the project developers:

- Certify **reserves** to ensure that the gas is there
- Sign sales and purchase agreements (**SPAs**) with buyers, which reassure the project developers that they will be able to sell their product. These are usually long-term and obligate the buyer to take the gas.
- Secure **financing**, often external and often non-recourse (whereby the debt is guaranteed by the cash flow of the SPA). External financing is supported by loans and equity from the sponsors.
- Award an engineering, procurement and construction (**EPC**) contract to a company/consortium to **build** the plant
- Finalize all **approvals** (country/federal, state, local)
The companies that will **develop the gas fields** and supply the gas to be liquefied and exported. Usually projects have a primary supply source, but projects will often source gas from multiple fields and/or areas.

The companies that will **own and operate the liquefaction facility**. These companies will assign one or more EPC (engineering, procurement and construction) contractors to build the plant.

Either the **buyer or the seller handles the shipping**. If the buyer arranges for shipping, the sale is considered FOB (Free on Board). If the sellers arranges for shipping, it is consider CIF (Cost, Insurance, Freight) or DES (Delivered Ex Ship).

The buyer can purchase LNG through a short, medium or long-term **contract** or they can purchase an **individual** cargo (called a spot transaction). The buyer can deliver the gas to an end-user (e.g. power plant) or can re-sell the gas.
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The World is Turning More and More to Gas

Gas share has risen from 19 to 22%

Gas share has risen from 15 to 24%
Growth at 2.3% per Year Driven by Asia

Global demand growth of 2.3% p.a.

+175 bcf/d = ~3X US 2010 demand
Asia Drives LNG Demand As Well

Asia accounted for 2/3 of growth since 1990 and will make up 2/3 of new demand.
Industry Has Responded with Many and Big Proposals

If **all LNG projects** were to move ahead according to plan, LNG capacity would grow from 281 mmtpa (2012) to 771 mmtpa in 2030. Clearly, such a build-out is unrealistic.
North America is Largest Prospective Supplier

Proposed Liquefaction Plants by Location

- US: 40%
- Canada: 17%
- Australia: 14%
- Russia: 9%
- Mozambique: 4%
- Papua New Guinea: 3%
- Nigeria: 2%
- Indonesia: 2%
- Tanzania: 2%
- Others: 7%

Summary from North Slope Gas & LNG Symposium | © PFC Energy 2013 | Page 19 | November 2013
Growth Clustered: N. America, Africa, Australia

* All values are in millions of tonnes per annum (mmtpa)
Widespread Growth in Asian LNG Demand

LNG Demand Outlook: Asia

LNG Demand Growth by Country

2030 Asia
Japan
326

Philippines
6

Vietnam
11

Thailand
8

Malaysia
6

Bangladesh
7

Indonesia
8

Singapore
9

Taiwan
14

Korea

India

China

Sri Lanka

Philippines

Bangladesh

Vietnam

Indonesia

Singapore

Thailand

Japan

2012 Asia

0

50

100

150

200

250

300

350

mmt

100

150

200

250

300

350

mmt

2000

2005

2010

2015

2020

2025

2030

mmt

2000

2005

2010

2015

2020

2025

2030

mmt
Based on finalized and preliminary contracts, there is still a window for additional LNG sales into Asia by 2020; the window widens post 2020.

Suppliers must compete to displace the preliminary contracts or must lower price to access new markets.
What Price Can Alaska Expect?

- When buyers have lots of choice, prices tend to fall to the marginal cost of supply; when sellers have lots of choice, prices tend to rise to the cost of alternative fuels / demand destruction.

- The pricing band is quite wide with new projects needing $8-$11/MMBtu to break-even but cost of alternative fuels (oil) being much higher at $16-$18/MMBtu.

- Asian consumers are no longer willing to pay alternative-fuel pricing levels—they demand lower prices and they open to challenging oil indexation system that prevails in Asia.

- Today’s market for long-term supply (post 2016) tends towards a buyer’s market, for e.g. contracts signed for LNG from the United States reflect the marginal cost of supply.

- Evolution of market pricing will hinge on how rapidly new projects around the world advance—if projects get stuck, prices will rise; if projects move forward according to plan, prices will fall.

- Projects can also protect themselves from volatility by offering to give up upside in order to defend against downside risk.
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## Oil-Indexed Pricing to Asian Markets

<table>
<thead>
<tr>
<th>Contract Sales Price Slope ---</th>
<th>0.13x</th>
<th>0.14x</th>
<th>0.15x</th>
<th>0.16x</th>
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<tbody>
<tr>
<td>$60/bbl Brent</td>
<td>$7.80</td>
<td>$8.40</td>
<td>$9.00</td>
<td>$9.60</td>
</tr>
<tr>
<td>$80/bbl Brent</td>
<td>$10.40</td>
<td>$11.20</td>
<td>$12.00</td>
<td>$12.80</td>
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<tr>
<td>$100/bbl Brent</td>
<td>$13.00</td>
<td>$14.00</td>
<td>$15.00</td>
<td>$16.00</td>
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<tr>
<td>$120/bbl Brent</td>
<td>$15.60</td>
<td>$16.80</td>
<td>$18.00</td>
<td>$19.20</td>
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<tr>
<td>$140/bbl Brent</td>
<td>$18.20</td>
<td>$19.60</td>
<td>$21.00</td>
<td>$22.40</td>
</tr>
</tbody>
</table>
New LNG Projects are Expensive

Asia Pacific: Breakeven FOB Costs at $90/b

- Upstream Breakeven*
- Liquefaction Breakeven*
- Total Breakeven
- Liquefaction Unit Cost (RHS)

<table>
<thead>
<tr>
<th>Project</th>
<th>Existing</th>
<th>Under Construction</th>
<th>Proposed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Darwin LNG T1</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>North West Shelf T4</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>MLNG Tiga (T1-2)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MLNG Satu (T1-3)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>North West Shelf T5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bonang LNG</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>MLNG Dua (T1-3)</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tangguh LNG T1-2</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pluto LNG T1</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sengkang LNG T1-2</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PETRONAS LNG T9</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Queensland Curtis LNG T1</td>
<td>0</td>
<td></td>
<td></td>
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<tr>
<td>Donggi-Senoro LNG</td>
<td>0</td>
<td></td>
<td></td>
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<tr>
<td>Prelude LNG</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Australia Pacific LNG T1-2</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PNG LNG T1-2</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ichthys LNG T1-2</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gladstone LNG T1-2</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gorgon LNG T1-3</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wheatstone LNG T1-2</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tangguh LNG T3</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>BC LNG T1-2</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oregon LNG T1-2</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mozambique LNG T1-2</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Abadi LNG (Floating)</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tanzania LNG T1-2</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Aru LNG T1-2</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Scarbourough LNG</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rotan LNG</td>
<td>0</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Lower 48 is An Alternative—But Not Necessarily Cheap; & It is Volatile

At $6/MMBtu, US is not that cheap

Hub can be cheap but also volatile

Source: Global LNG Service
Does Alaska Have a Shipping Advantage?

- All costs along the value chain are variable and depend on the LNG project.
- Shipping costs depend on:
  - Type of Vessel
  - Cost of Vessel
  - Size of Cargo
  - Voyage Distance
  - Running Costs
  - Charter Rate

Alaska’s shipping costs are an advantage:
- Generally superior to East Africa
- Considerably less than expected shipping costs from projects located in US GOM
- But more expensive than Australia

### Shipping Cost ($/MMBtu) – Panama Canal Access

<table>
<thead>
<tr>
<th></th>
<th>Japan / S. Korea</th>
<th>China</th>
<th>India</th>
</tr>
</thead>
<tbody>
<tr>
<td>Southern Alaska</td>
<td>0.67</td>
<td>0.83</td>
<td>1.44</td>
</tr>
<tr>
<td>Western Canada</td>
<td>0.82</td>
<td>0.99</td>
<td>1.65</td>
</tr>
<tr>
<td>US - GOM</td>
<td>1.89</td>
<td>2.06</td>
<td>1.88</td>
</tr>
<tr>
<td>Australia</td>
<td>0.60</td>
<td>0.60</td>
<td>0.62</td>
</tr>
<tr>
<td>East Africa</td>
<td>1.18</td>
<td>0.97</td>
<td>0.58</td>
</tr>
</tbody>
</table>

### Delivered Cost by LNG Value Chain Segment

- Delivered Cost
- Regasification Cost
- Shipping
- Liquefaction Cost
- Feedstock Cost

Delivered Cost $/MMBtu: 0 to 12
AK South Central LNG Concept

Estimated total cost: $45 - $60 bn (2011 real dollars)
How Would $20bn for an 18 mmtpa Liquefaction Facility Compare With Other Recent Projects?

<table>
<thead>
<tr>
<th>Project</th>
<th>Global Liquefaction Unit Costs ($/ton)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nigeria LNG T1-2</td>
<td>$1,111/ton</td>
</tr>
<tr>
<td>PETRONAS LNG T9</td>
<td>$1,550/ton</td>
</tr>
<tr>
<td>Sabine Pass LNG T1-2</td>
<td>$1,450/ton</td>
</tr>
<tr>
<td>North West Shelf T1-3</td>
<td>$1,350/ton</td>
</tr>
<tr>
<td>Arun LNG</td>
<td>$1,300/ton</td>
</tr>
<tr>
<td>RasGas II (T3)</td>
<td>$1,250/ton</td>
</tr>
<tr>
<td>MLNG Satu (T1-3)</td>
<td>$1,200/ton</td>
</tr>
<tr>
<td>Tangguh LNG T1-2</td>
<td>$1,150/ton</td>
</tr>
<tr>
<td>Queensland Curtis LNG T1</td>
<td>$1,100/ton</td>
</tr>
<tr>
<td>Oregon LNG</td>
<td>$1,050/ton</td>
</tr>
<tr>
<td>Tanzania LNG</td>
<td>$1,000/ton</td>
</tr>
<tr>
<td>Yamal LNG</td>
<td>$950/ton</td>
</tr>
<tr>
<td>Alaska South Central LNG</td>
<td>$900/ton</td>
</tr>
<tr>
<td>Arrow LNG T1-2</td>
<td>$850/ton</td>
</tr>
<tr>
<td>ADGAS LNG T1-2</td>
<td>$800/ton</td>
</tr>
<tr>
<td>Bonaparte LNG</td>
<td>$750/ton</td>
</tr>
<tr>
<td>PNG LNG T1-2</td>
<td>$700/ton</td>
</tr>
<tr>
<td>Australia Pacific LNG T1-2</td>
<td>$650/ton</td>
</tr>
<tr>
<td>Donggi-Senoro LNG</td>
<td>$600/ton</td>
</tr>
<tr>
<td>Mozambique LNG</td>
<td>$550/ton</td>
</tr>
<tr>
<td>Prelude LNG</td>
<td>$500/ton</td>
</tr>
<tr>
<td>PETRONAS FLNG</td>
<td>$450/ton</td>
</tr>
<tr>
<td>Sinopec LNG</td>
<td>$400/ton</td>
</tr>
<tr>
<td>Pluto LNG</td>
<td>$350/ton</td>
</tr>
<tr>
<td>Ichthys LNG T1-2</td>
<td>$300/ton</td>
</tr>
<tr>
<td>Angola LNG</td>
<td>$250/ton</td>
</tr>
<tr>
<td>Wheatstone LNG T1-2</td>
<td>$200/ton</td>
</tr>
<tr>
<td>Gorgon LNG</td>
<td>$150/ton</td>
</tr>
</tbody>
</table>

Note: The above costs are illustrative and may not reflect actual project costs. Costs can vary significantly based on project specifics, market conditions, and other factors.
### Breakeven Economics for Hypothetical $46bn Project

<table>
<thead>
<tr>
<th>Component</th>
<th>Cost ($/MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Upstream &amp; Gas Treatment</td>
<td>3.2</td>
</tr>
<tr>
<td>Pipeline</td>
<td>2.54</td>
</tr>
<tr>
<td>Liquefaction</td>
<td>4.7</td>
</tr>
<tr>
<td>FOB Cost</td>
<td>10.44</td>
</tr>
<tr>
<td>Shipping</td>
<td>0.7</td>
</tr>
<tr>
<td>CIF/DES Cost</td>
<td>11.14</td>
</tr>
</tbody>
</table>

**Tariff required to achieve a 12% IRR on $12 bn liquefaction facility**

**Tariff required to achieve a 15% IRR on $14 bn Upstream and GTP Investment, with only 12.5% Royalty applied**

**~$1,111/ton**

At this unit cost level, liquefaction spend would be ~$20bn.
What if Liquefaction reached $/ton costs of Angola LNG or Wheatstone LNG?

~1,900/ton
At this unit cost level, liquefaction spend would be ~$33.6bn

<table>
<thead>
<tr>
<th>Component</th>
<th>Cost ($/MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
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<td>3.2</td>
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<tr>
<td>Pipeline</td>
<td>2.54</td>
</tr>
<tr>
<td>Liquefaction</td>
<td>7.91</td>
</tr>
<tr>
<td>FOB Cost</td>
<td>13.65</td>
</tr>
<tr>
<td>Shipping</td>
<td>0.7</td>
</tr>
<tr>
<td>CIF/DES Cost</td>
<td>14.35</td>
</tr>
</tbody>
</table>
What if Upstream Production Also Faced a 16.7% Royalty and a 35% Production Tax?

~1,900/ton
At this unit cost level, liquefaction spend would be ~$33.6bn
Total Project Spend would be ~$58/bn
# And What If Upstream and Pipeline Costs Were Also 25% Above Base Case?

At this unit cost level, liquefaction spend would be ~$33.6bn. Total Project Spend would be ~$64.5bn.

<table>
<thead>
<tr>
<th>$/MMBtu</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>$0</strong></td>
</tr>
<tr>
<td><strong>$2</strong></td>
</tr>
<tr>
<td><strong>$4</strong></td>
</tr>
<tr>
<td><strong>$6</strong></td>
</tr>
<tr>
<td><strong>$8</strong></td>
</tr>
<tr>
<td><strong>$10</strong></td>
</tr>
<tr>
<td><strong>$12</strong></td>
</tr>
<tr>
<td><strong>$14</strong></td>
</tr>
<tr>
<td><strong>$16</strong></td>
</tr>
</tbody>
</table>

- **Upstream & Gas Treatment**: $4.17
- **Pipeline**: $3.18
- **Liquefaction**: $7.91
- **FOB Cost**: $15.26
- **Shipping**: $0.7
- **CIF/DES Cost**: $15.96
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Most of the money is spent after taking a Final Investment Decision (FID); before FID, the project developers:

- Certify *reserves* to ensure that the gas is there
- Sign sales and purchase agreements (SPAs) with buyers, which reassure the project developers that they will be able to sell their product. These are usually long-term and obligate the buyer to take the gas
- Secure *financing*, often external and often non-resource (whereby the debt is guaranteed by the cash flow of the SPA). External financing is supported by loans and equity from the sponsors
- Award an engineering, procurement and construction (EPC) contract to a company/consortium to **build** the plant
- Finalize all *approvals* (country, local)
### Main Provisions of an LNG Contract

<table>
<thead>
<tr>
<th>Provision</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Pricing</strong></td>
<td>Most LNG contracts are priced relative to oil. In Asia, the predominant oil benchmark is the Japan Customs Cleared Price, the average price of oil imported into Japan. Typically, contracts include a ratio / discount relative to oil. In Europe, gas prices are linked either to oil (heavy / light fuel oil) or to regional hubs—the relative prevalence of the two depends on the market with some markets being almost exclusively oil-linked or hub-based. Increasingly, buyers are interested in LNG contracts that are priced against Henry Hub (the US price marker).</td>
</tr>
<tr>
<td><strong>Duration</strong></td>
<td>Long-term contracts (15-20 years) remain essential for project sanction, while there is a growing tendency to sign medium (5-10) or short-term (&lt;5) contracts.</td>
</tr>
<tr>
<td><strong>Destination Flexibility</strong></td>
<td>In the past, LNG contracts were sold for delivery to a specific market, and the buyer could not deliver the gas to a different destination. Over time, this rigidity has lessened. Destination clauses are now illegal for contracts going into Europe. Contracts with flexible destination clauses are almost a given in the Atlantic Basin, rare in the Asia-Pacific, and have been growing in the Middle East due to Qatar.</td>
</tr>
<tr>
<td><strong>Volume Flexibility</strong></td>
<td>Buyers typically have an upward and downward allowance of ~10-20% of contracted volumes. The rest of the volumes is sold under a take-or-pay provision (where the buyer has to pay for the gas even if they choose not to lift some cargoes).</td>
</tr>
<tr>
<td><strong>Profit Sharing</strong></td>
<td>Some contracts allow the original seller to share the profit in case a cargo is diverted from its original source. Such agreements are illegal in Europe, while the lack of profit sharing has created tension in several contracts (e.g. Equatorial Guinea, Egypt, Trinidad).</td>
</tr>
<tr>
<td><strong>Non-Compliance</strong></td>
<td>Most contracts have arbitration provisions.</td>
</tr>
<tr>
<td><strong>Renegotiation Provisions</strong></td>
<td>Most contracts have some price review provisions. These may occur every 3 to 4 years, though buyers or sellers can trigger a review outside this cycle in exceptional circumstances.</td>
</tr>
</tbody>
</table>
Project Structure Really Matters

Equatorial Guinea to Japan Value Chain

- Price paid by Japan: 17.14
- Buyer to End-user (Japan): 14.56
- LNG plant to LNG buyer (FOB): 2.30
- From field to LNG plant: 0.27

$L/MMBtu

But the LNG can be sold anywhere, and high prices in Asia mean that more of the LNG has gone there; but without the upside flowing back through the chain.

LNG is sold free on board (at the plant) for a price linked to Henry Hub because the original idea was to market this gas to the United States.

Gas is sold for a price of $0.27/mcf because the revenues from oil production drive project economics for the field.
The LNG Value Chain

- The companies that will **develop the gas fields** and supply the gas to be liquefied and exported. Usually projects have a primary supply source, but projects will often source gas from multiple fields and/or areas.

- The companies that will **own and operate the liquefaction facility**. These companies will assign one or more EPC (engineering, procurement and construction) contractors to build the plant.

- Either the **buyer or the seller handles the shipping**. If the buyer arranges for shipping, the sale is considered FOB (Free on Board). If the sellers arranges for shipping, it is consider CIF (Cost, Insurance, Freight) or DES (Delivered Ex Ship).

- The buyer can purchase LNG through a short, medium or long-term **contract** or they can purchase an **individual** cargo (called a spot transaction). The buyer can deliver the gas to an end-user (e.g. power plant) or can re-sell the gas.
Options for Alaska to Participate

**Option #1: Receive revenues through royalty gas**
- In this case, the state receives a share of the production in the form of royalty (cash); the project partners have full responsibility and ownership to pipe the gas, liquefy it and sell the gas (FOB or CIF/DES).
- The key goal in this commercial structure is to create a “fair” transfer price:
  - Delivers value to the state of Alaska
  - Recognizes the risk/reward and capital commitment of each partner

**Option #2: Participate as an equity partner**
- In this case, the state of Alaska participates as an equity partner in the LNG project. Usually this is done through either a national oil company or other state-sponsored investment vehicle. In this structure, the state of Alaska could take royalty in kind and be a supplier into the project.
- The key questions are: where in the chain will the state participate (upstream, pipeline, liquefaction, shipping); with what equity stake; and in what form?

**Selecting the proper option depends on**
- What is the appetite for risk and what kind of risk?
- How to create better alignment between the project partners?
- What kind of commitment will the state make?
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Conclusions

- There is growing demand for gas and LNG, in particular in Asia, and most countries need to secure additional LNG to meet their energy needs post 2020. Alaska’s proximity to Asia makes it a natural supply source, although it will face competition from a growing number of new supply sources.

- Shale gas in the United States Lower 48 and in Western Canada will compete with Alaska—and the L48 in particular are a primary destination for suppliers seeking long-term LNG. But higher prices in the United States will potentially undermine the competitiveness of LNG from the Lower 48.

- The companies that are involved in Alaska’s upstream and will likely be involved in LNG have substantial experience with and expertise in LNG. As such, the question is not whether they can do an LNG project but rather will they choose to given competing priorities and outlets for their capital.

- An LNG project from Alaska can be competitive with other projects that are seeking to supply Asian markets—but its competitiveness will depend critically on fiscal terms and on keeping costs down.

- LNG projects are big, complex, risky, multi-stakeholder endeavors that take a lot of time (often decades) and money (billions) to complete. There are multiple ways to structure an LNG project (who participates in which part and in what way) and it is important to develop a structure that aligns all the different partners and project participants and meets their risk-reward appetites.
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## Glossary and Units

### Glossary
- **CAGR**: Compound Annual Growth Rate
- **CAPEX**: Capital Expenditure
- **CIF**: Cost Insurance Freight
- **DES**: Delivered Ex-Ship
- **EPC**: Engineering Procurement and Construction
- **FEED**: Front-End Engineering and Design
- **FID**: Final Investment Decision
- **FOB**: Free on Board
- **FSRU**: Floating Storage and Regasification Unit
- **HOA**: Heads of Agreement (preliminary contract)
- **IOC**: International Oil Company
- **JV**: Joint Venture
- **JCC**: Japan Customs Cleared
- **MENA**: Middle East and North Africa
- **MOU**: Memorandum of Understanding (preliminary contract)
- **NOC**: National Oil Company
- **OECD**: Organization Economic Cooperation and Development
- **PSC**: Production Sharing Contract
- **SPA**: Sales and Purchase Agreement (finalized contract)

### Units
- **$/B**: Dollars per barrel (oil)
- **BCF/D**: Billion cubic feet per day
- **BCM**: Billion cubic meters
- **CM**: Cubic meters
- **KTOE**: Thousand tons of oil equivalent
- **MMBTU**: Million British thermal units
- **MMCF/D**: Million cubic feet per day
- **MMT**: Million tons (LNG)
- **MMTOE**: Million tons of oil equivalent
- **MMTPA**: Million tons per annum (LNG)
### Unit Conversions

**Natural gas (NG) and liquefied natural gas (LNG)**

<table>
<thead>
<tr>
<th>From</th>
<th>billion cubic metres NG</th>
<th>billion cubic feet NG</th>
<th>million tonnes oil equivalent</th>
<th>million tonnes LNG</th>
<th>trillion British thermal units</th>
<th>million barrels oil equivalent</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 billion cubic metres NG</td>
<td>1</td>
<td>35.3</td>
<td>0.90</td>
<td>0.74</td>
<td>35.7</td>
<td>6.60</td>
</tr>
<tr>
<td>1 billion cubic feet NG</td>
<td>0.028</td>
<td>1</td>
<td>0.025</td>
<td>0.021</td>
<td>1.01</td>
<td>0.19</td>
</tr>
<tr>
<td>1 million tonnes oil equivalent</td>
<td>1.11</td>
<td>39.2</td>
<td>1</td>
<td>0.82</td>
<td>39.7</td>
<td>7.33</td>
</tr>
<tr>
<td>1 million tonnes LNG</td>
<td>1.36</td>
<td>48.0</td>
<td>1.22</td>
<td>1</td>
<td>48.6</td>
<td>8.97</td>
</tr>
<tr>
<td>1 trillion British thermal units</td>
<td>0.028</td>
<td>0.99</td>
<td>0.025</td>
<td>0.021</td>
<td>1</td>
<td>0.18</td>
</tr>
<tr>
<td>1 million barrels oil equivalent</td>
<td>0.15</td>
<td>5.35</td>
<td>0.14</td>
<td>0.11</td>
<td>5.41</td>
<td>1</td>
</tr>
</tbody>
</table>

*Source: BP Statistical Review of World Energy 2013*