

11 / 22 / 13
&
12 / 09 / 13
GASLINE
ISSUES

<TARGET><BILL></BILL><SUBJECT>11-22-13 and 12-09-13
GASLINE ISSUES</SUBJECT><COMM>HRES28</COMM></TARGET>

ALASKA STATE LEGISLATURE
House Resources Committee

Rep. Eric Feige, Co-Chair

State Capitol Building, Room 126

Juneau, AK 99801 – 1182
Phone (907) 465-4859
Fax (907) 465-3799
rep.eric.feige@akleg.gov



Rep. Dan Saddler, Co-Chair

State Capitol Building, Room 104

Juneau, AK 99801-1182
Phone (907) 465-3783
Fax (907) 465-2293
rep.dan.saddler@akleg.gov

House Resources Committee Meeting

Friday, November 22, 2013

10:00 a.m.

*Room: Anchorage LIO Temporary Location
1st Floor Conference Room # 105
733 West 4th Avenue*

-Agenda-

- I. Call to Order*
- II. Introduction of Committee Members*
- III. PFC Energy – North Slope Gas Commercialization*

Janak Mayer
Nikos Tsafos
- IV. Committee will break at Noon for lunch*
- V. Reconvene at 1:30 p.m.*
- VI. DNR Commissioner Joe Balash*
- VII. Black & Veatch – Alaska North Slope Royalty Study*

Deepa Poduval
Peter Abt
- VIII. Adjournment*

Meeting will be available via teleconference & AK LEG TV

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House Resources Committee Meeting
Monday, December 9, 2013
10:00 a.m.
Room: Anchorage LIO Temporary Location
1st Floor Conference Room # 105
733 West 4th Avenue

-Agenda-

- I. Call to Order*
- II. Introduction of Committee Members*
- III. Black & Veatch – Alaska North Slope Royalty Study*
Deepa Poduval
Peter Abt
- IV. Adjournment*

Meeting will be available via teleconference & AK LEG TV



Summary from North Slope Gas & LNG Symposium

Anchorage, AK: November 22, 2013

Nikos Tsafos & Janak Mayer
Testimony to House Resources Committee

PFC Energy



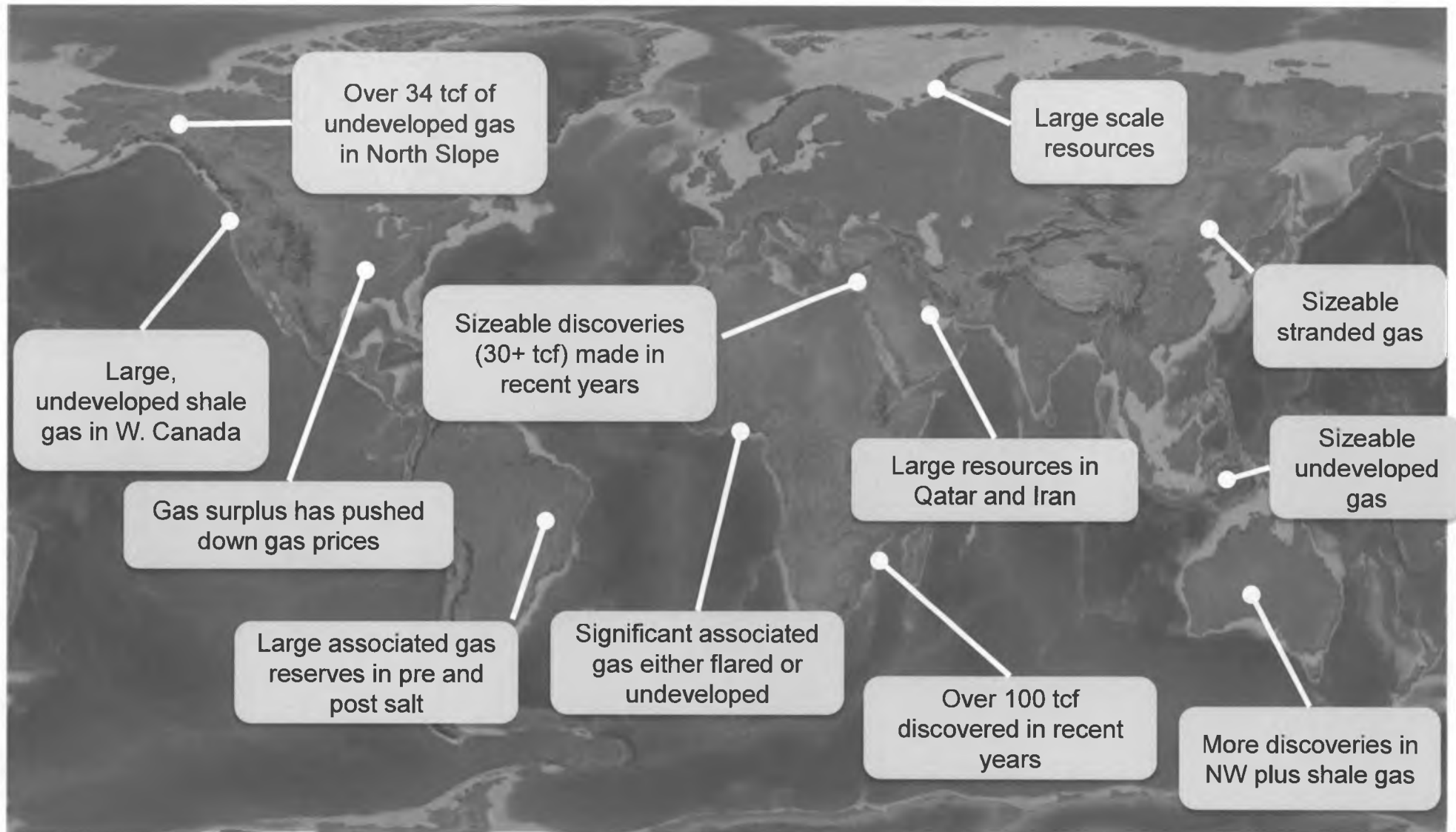
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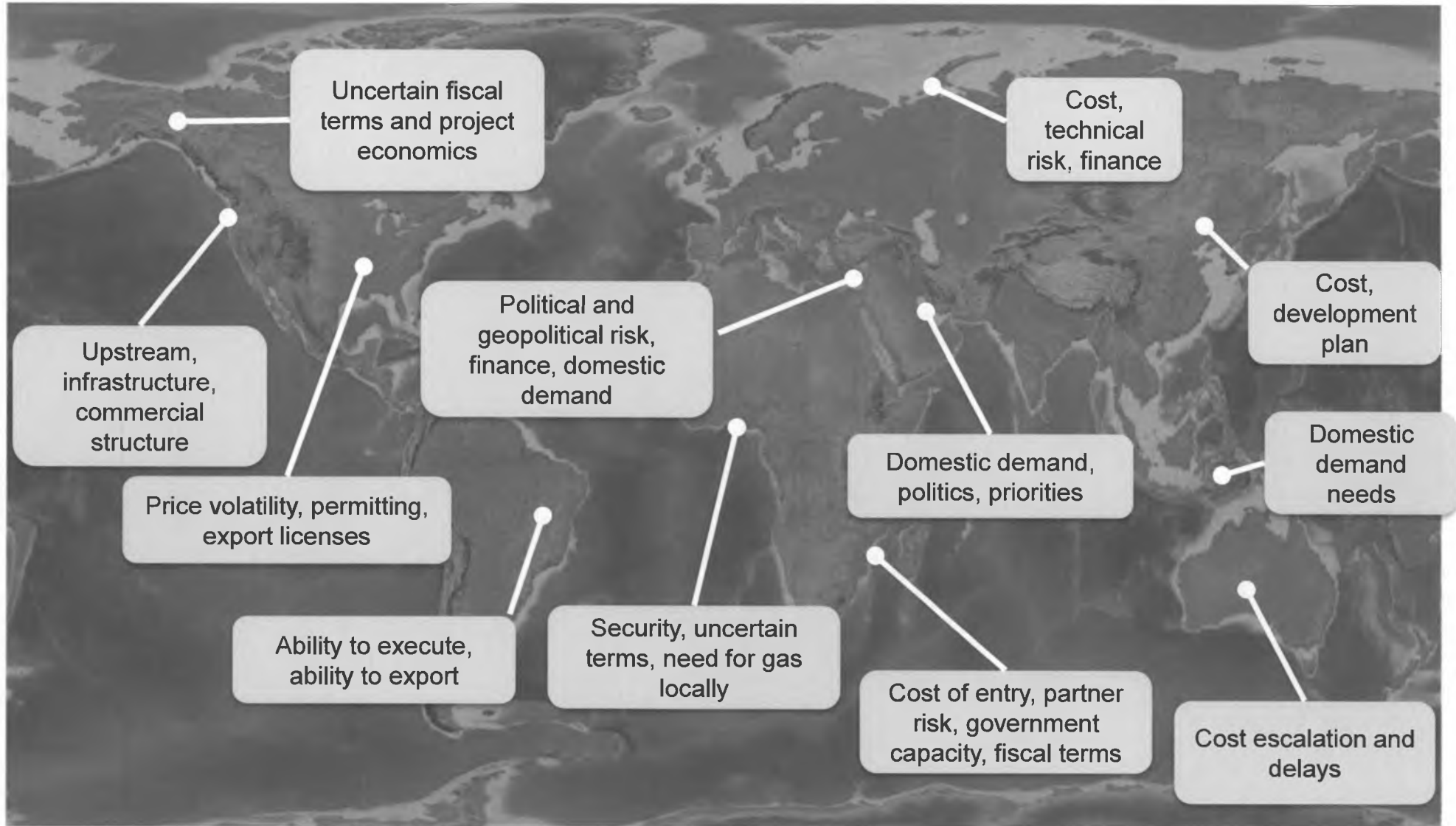
Executive Summary

- 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...



... But Also Risks

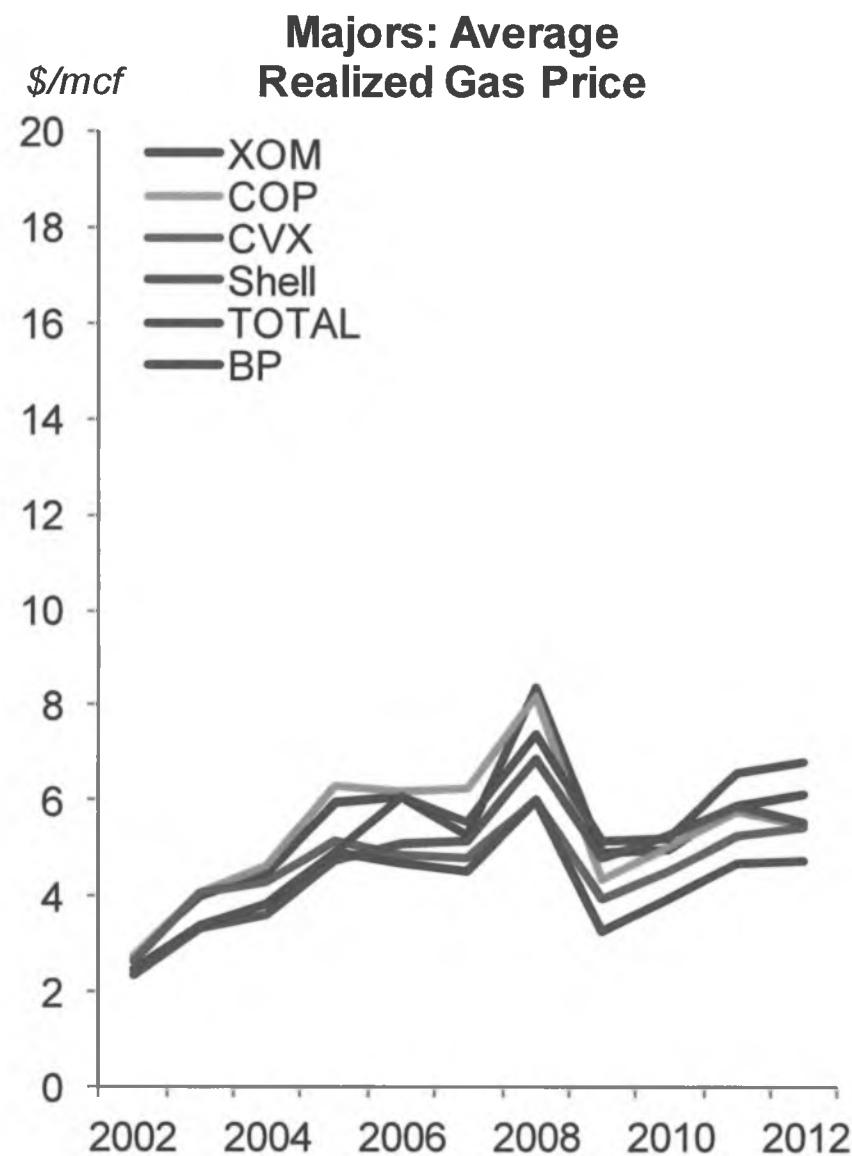
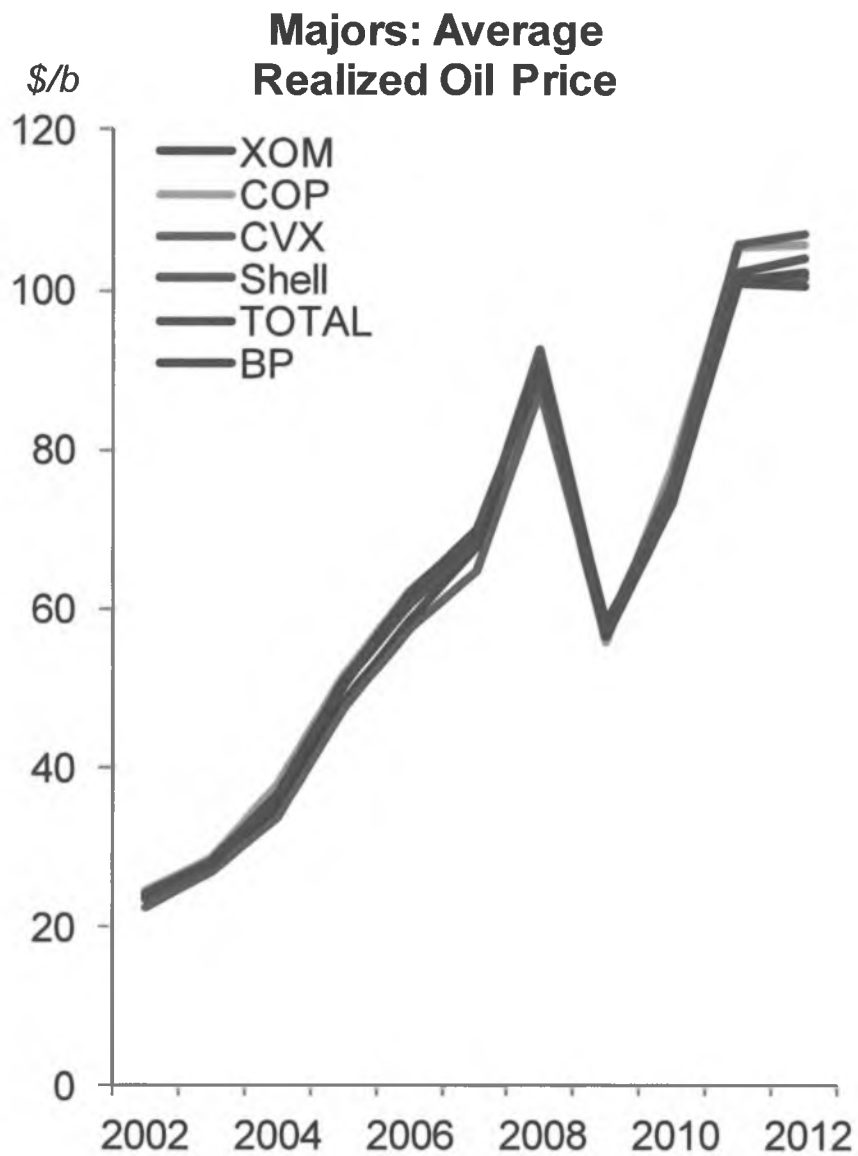




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Think Micro, Not Macro; Gas is Not a Global Market

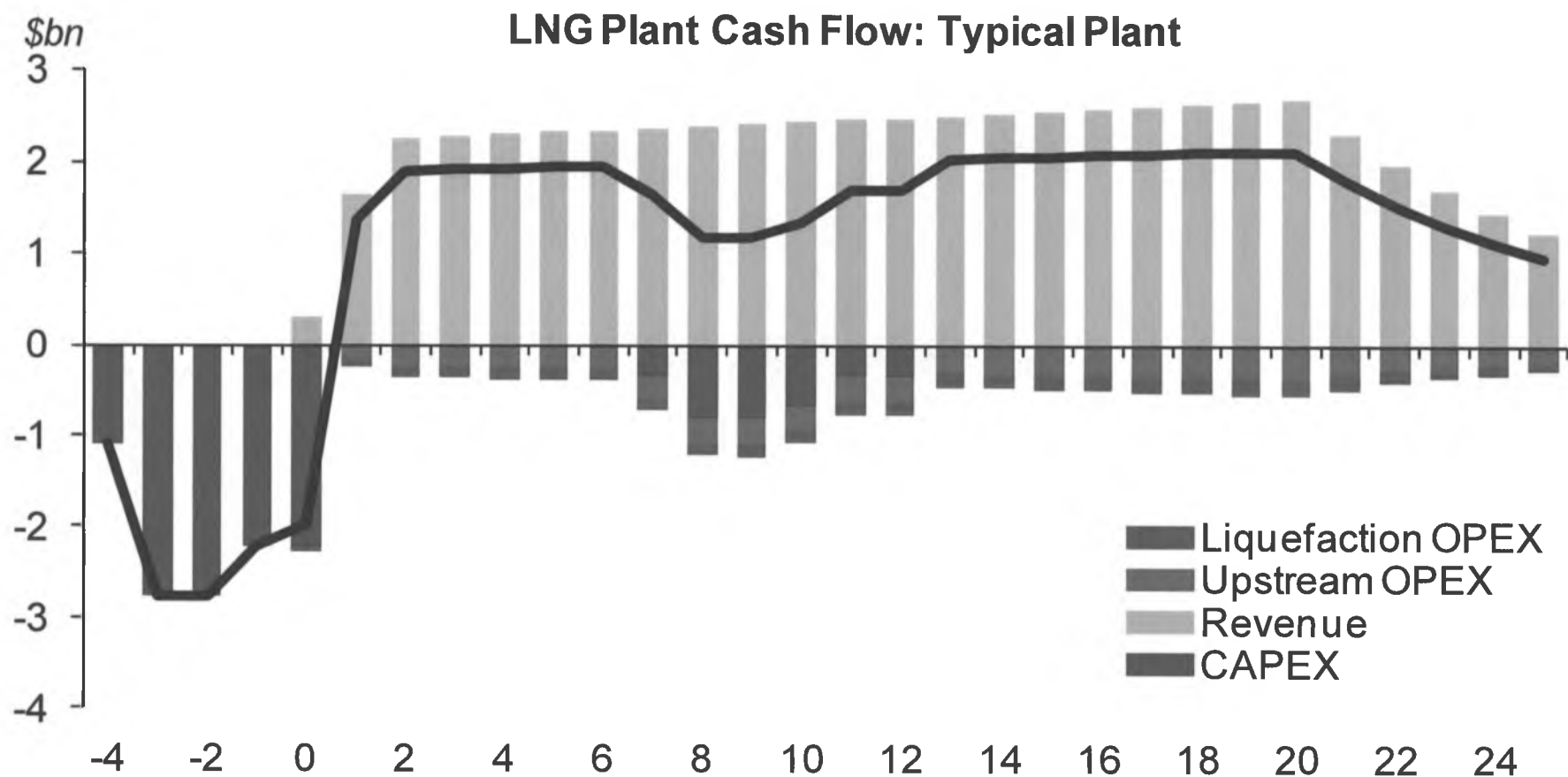


Gas is Very Different Than Oil

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

Sources: BP Statistical Review of World Energy, International Energy Agency, national sources, PFC Energy

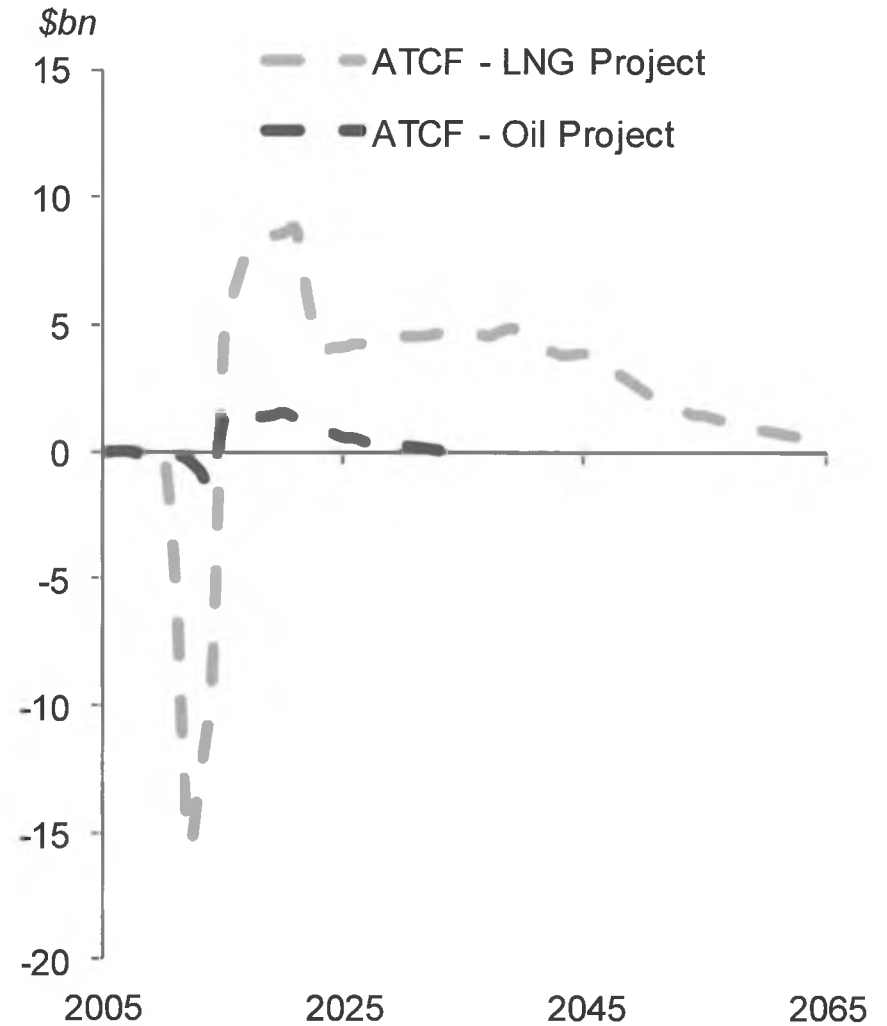
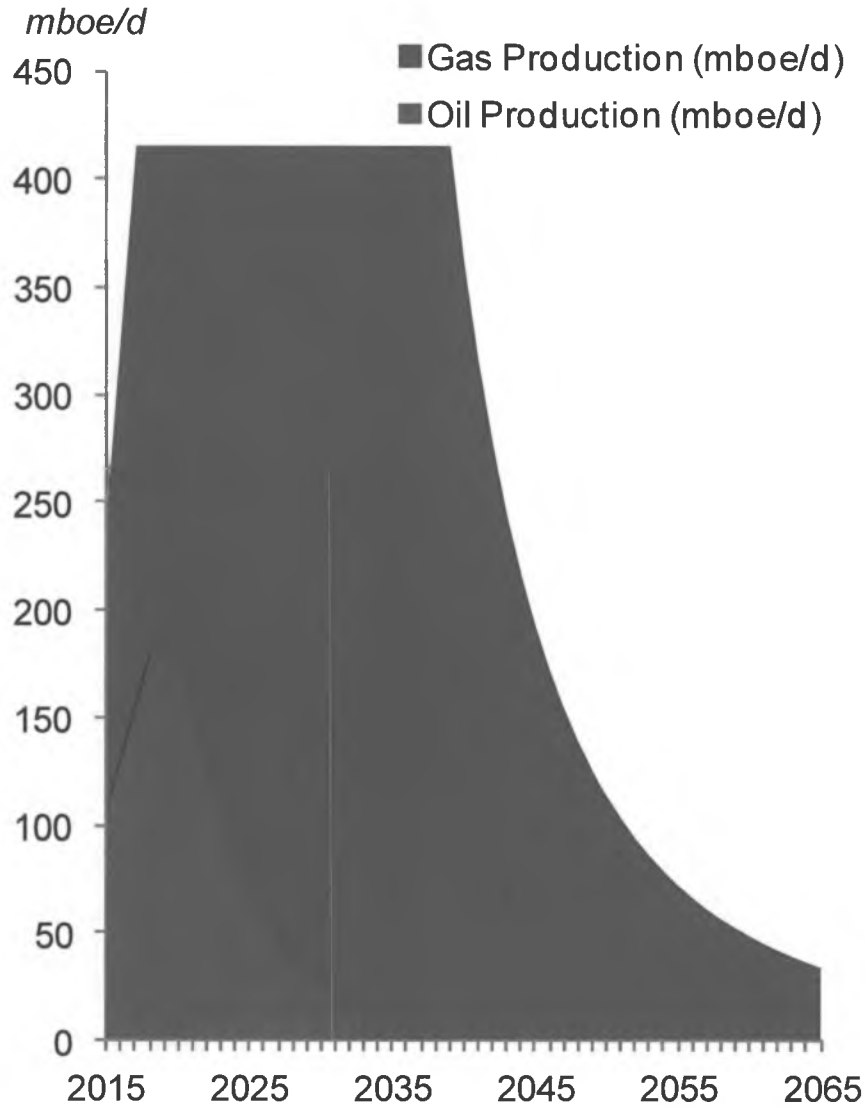
What Does an LNG Plant Look Like?



- 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)

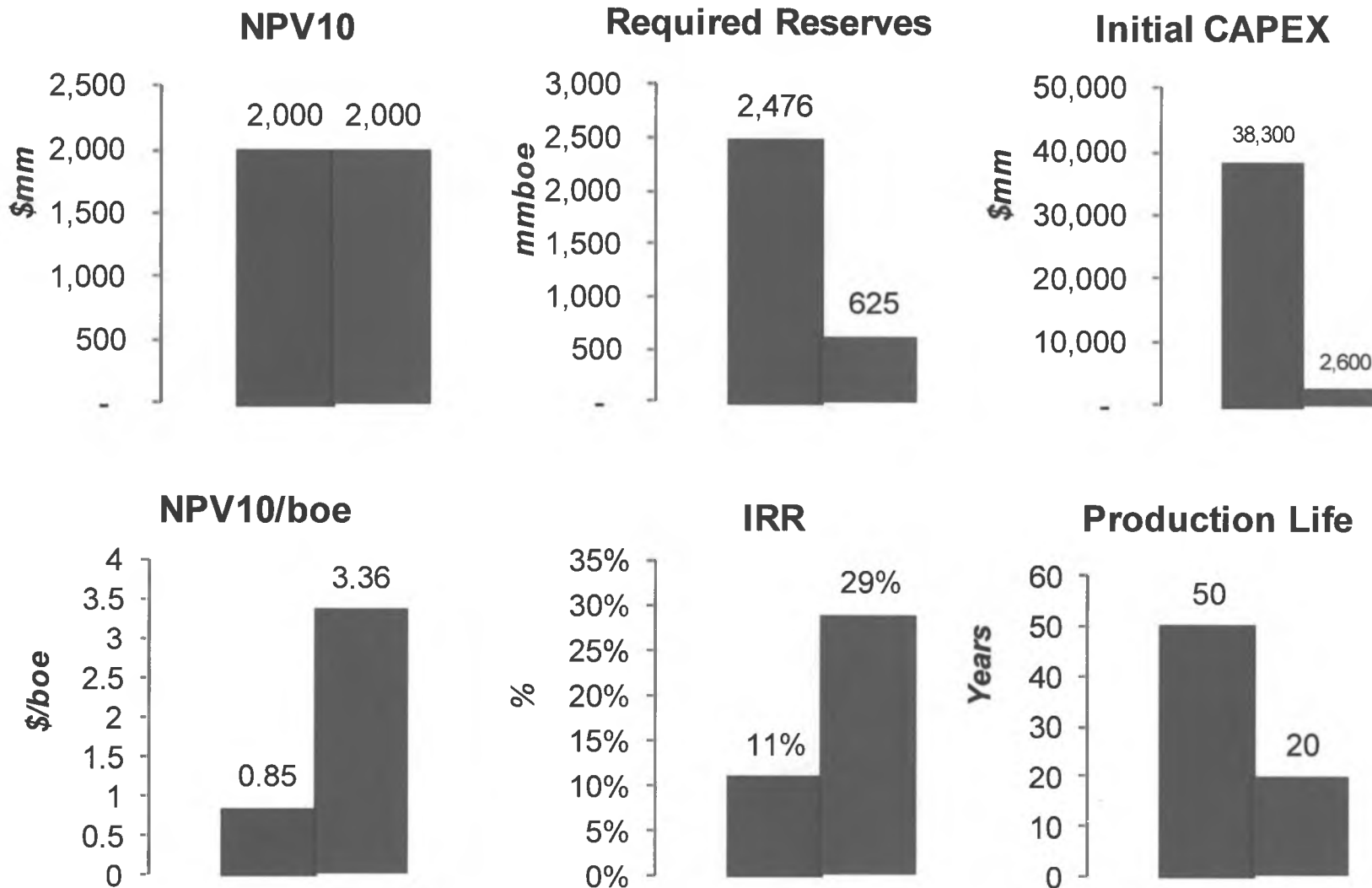
Oil and Gas Have Different Production / Economic Profiles...

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



... and Different Economic Outcomes

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



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 LNG Value Chain

Upstream



Liquefaction



Shipping



Buyer

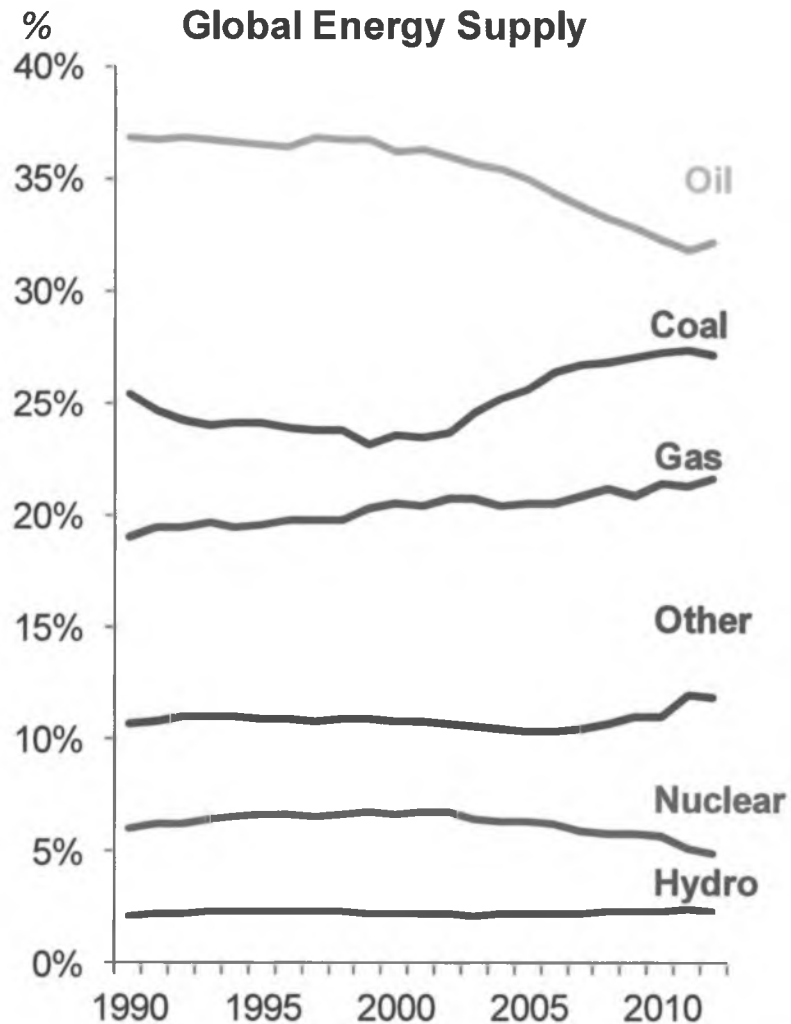
- The companies that will **develop the gas fields** and supply the gas to be liquefied and exported. Usually projects have a primary supply source, but projects will often source gas from multiple fields and/or areas.
- The companies that will **own and operate the liquefaction facility**. These companies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



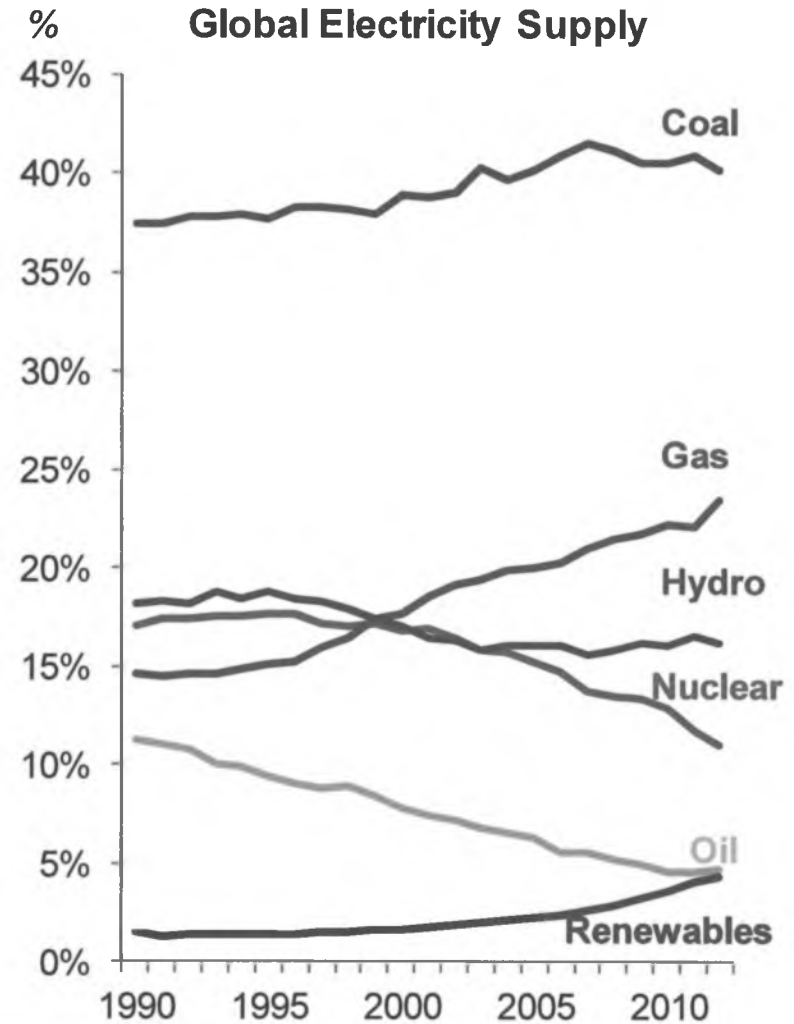
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The World is Turning More and More To Gas

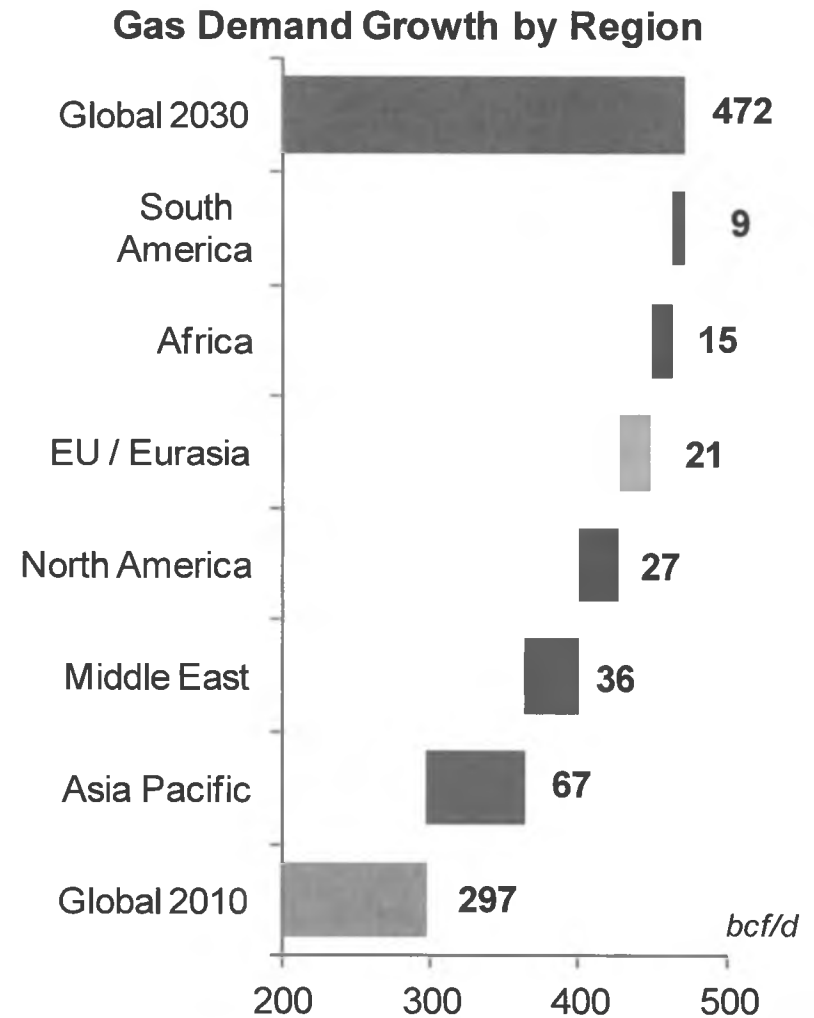
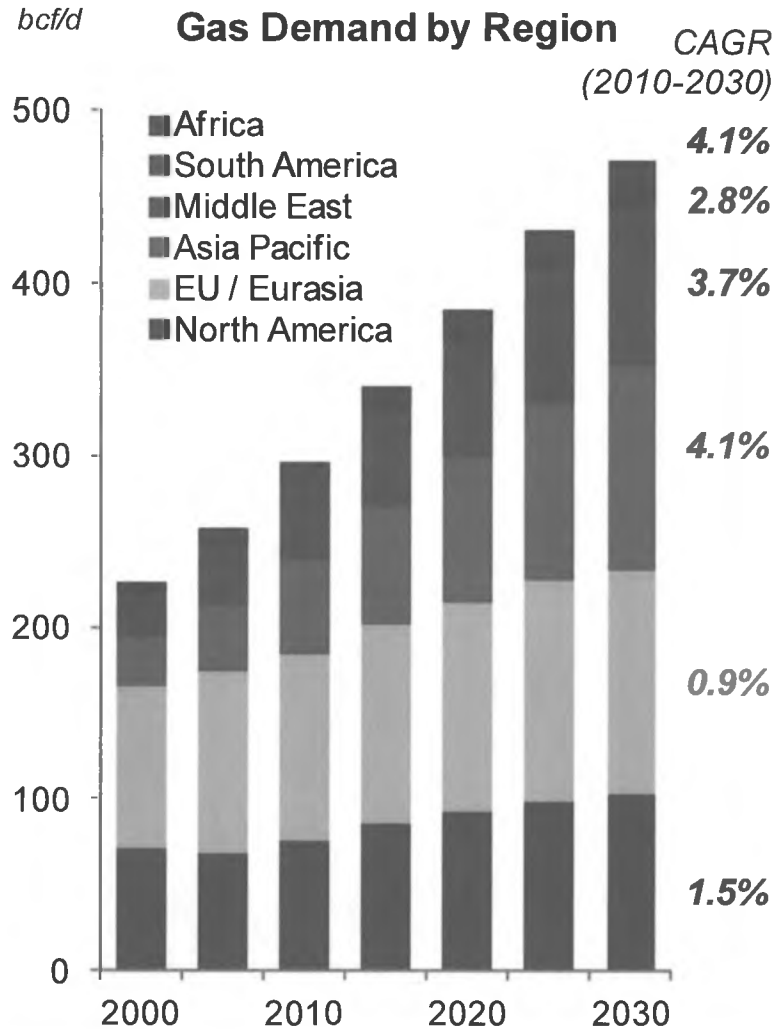


Gas share has risen from 19 to 22%



Gas share has risen from 15 to 24%

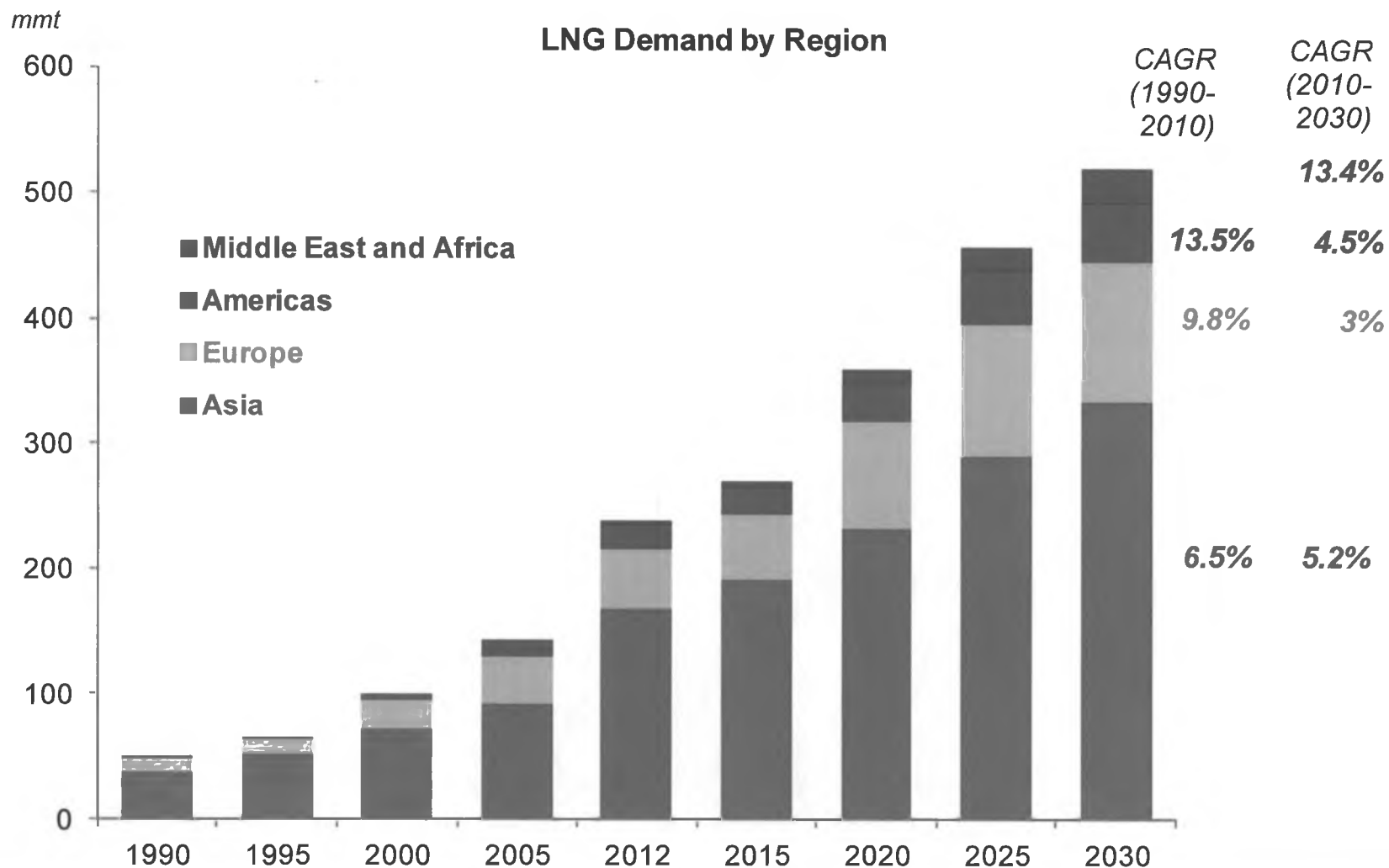
Growth at 2.3% per Year Driven by Asia



Global demand growth of 2.3% p.a.

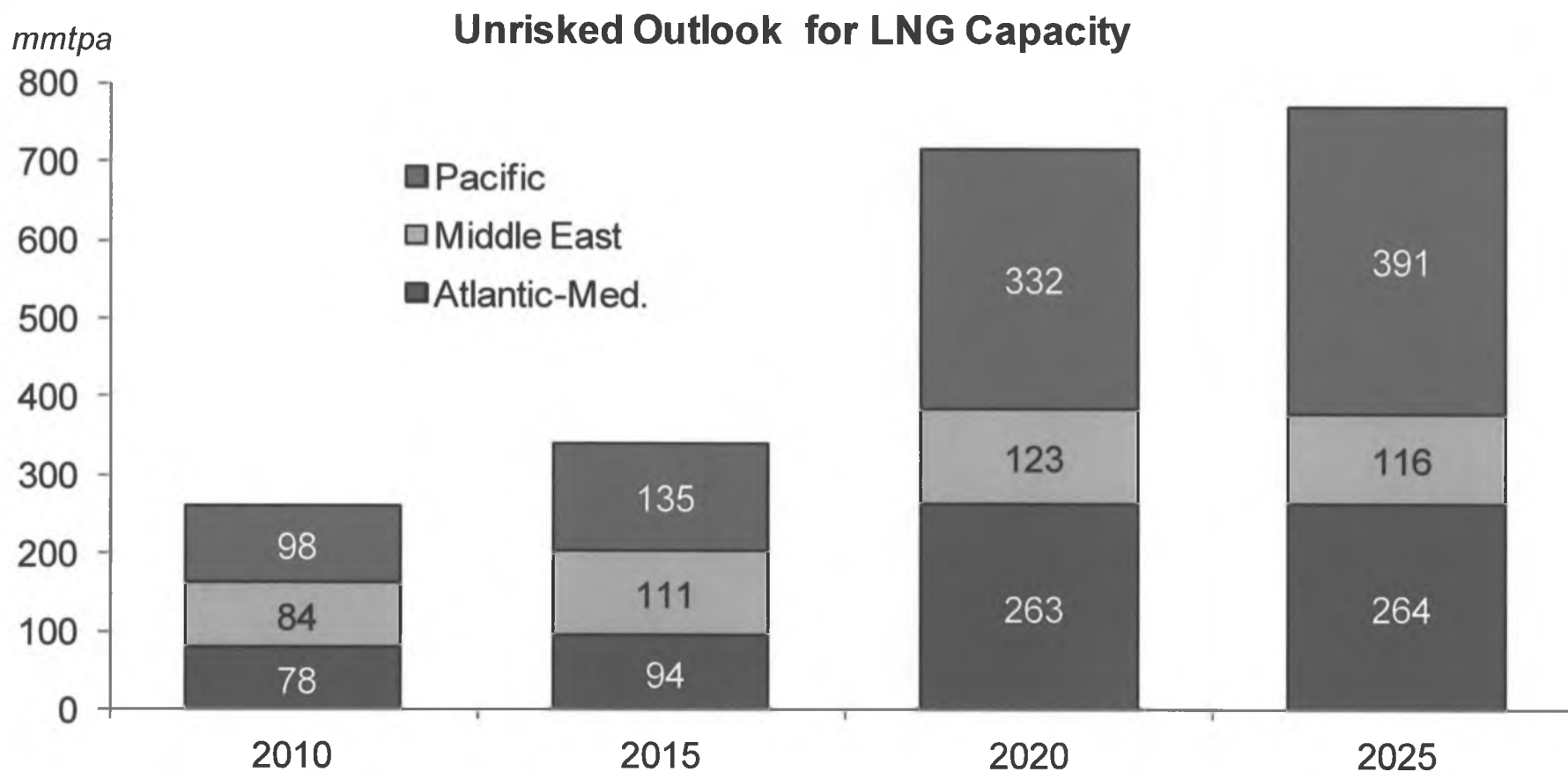
+175 bcf/d = ~3X US 2010 demand

Asia Drives LNG Demand As Well



Asia accounted for 2/3 of growth since 1990 and will make up 2/3 of new demand

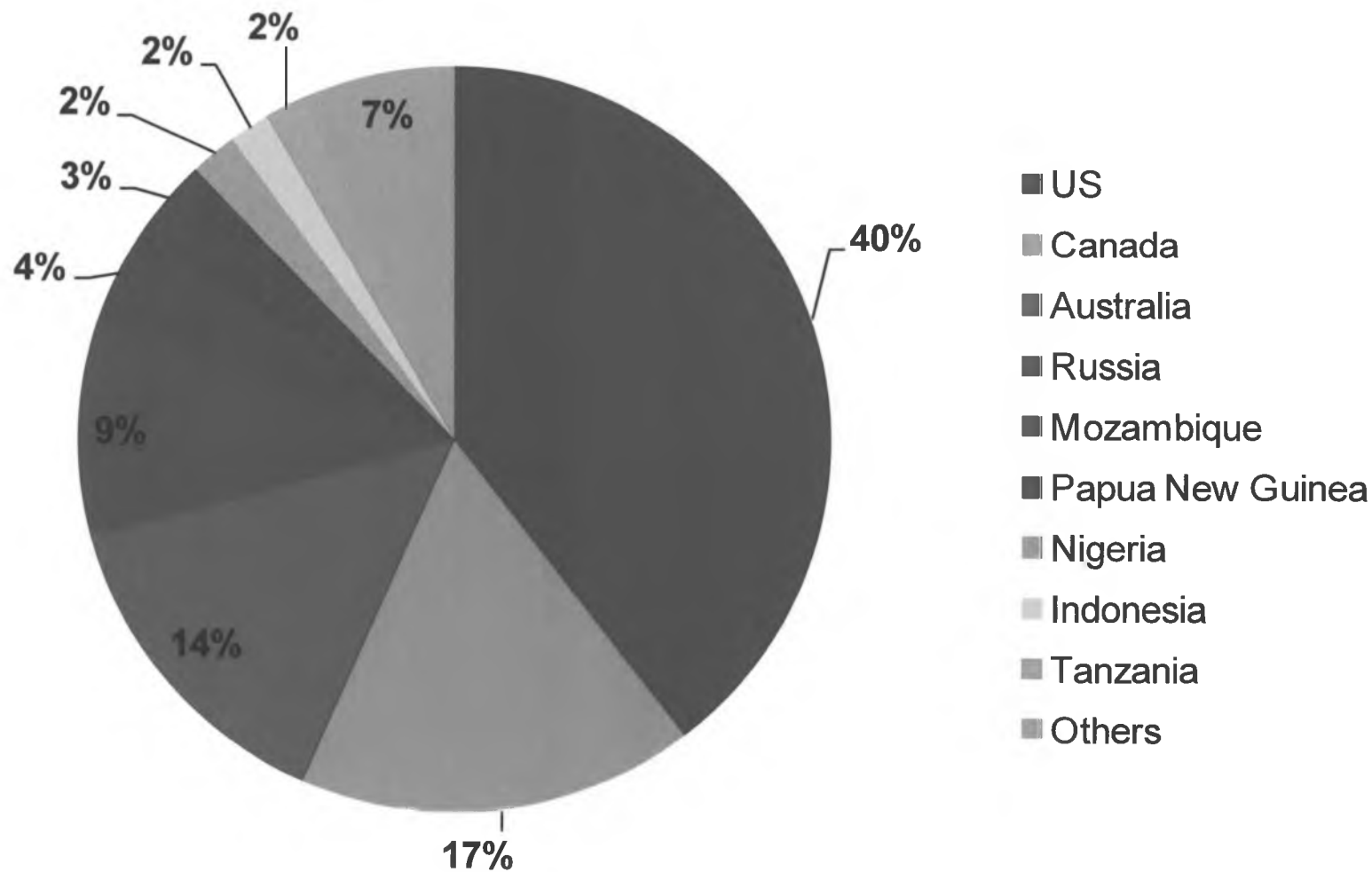
Industry Has Responded with Many and Big Proposals



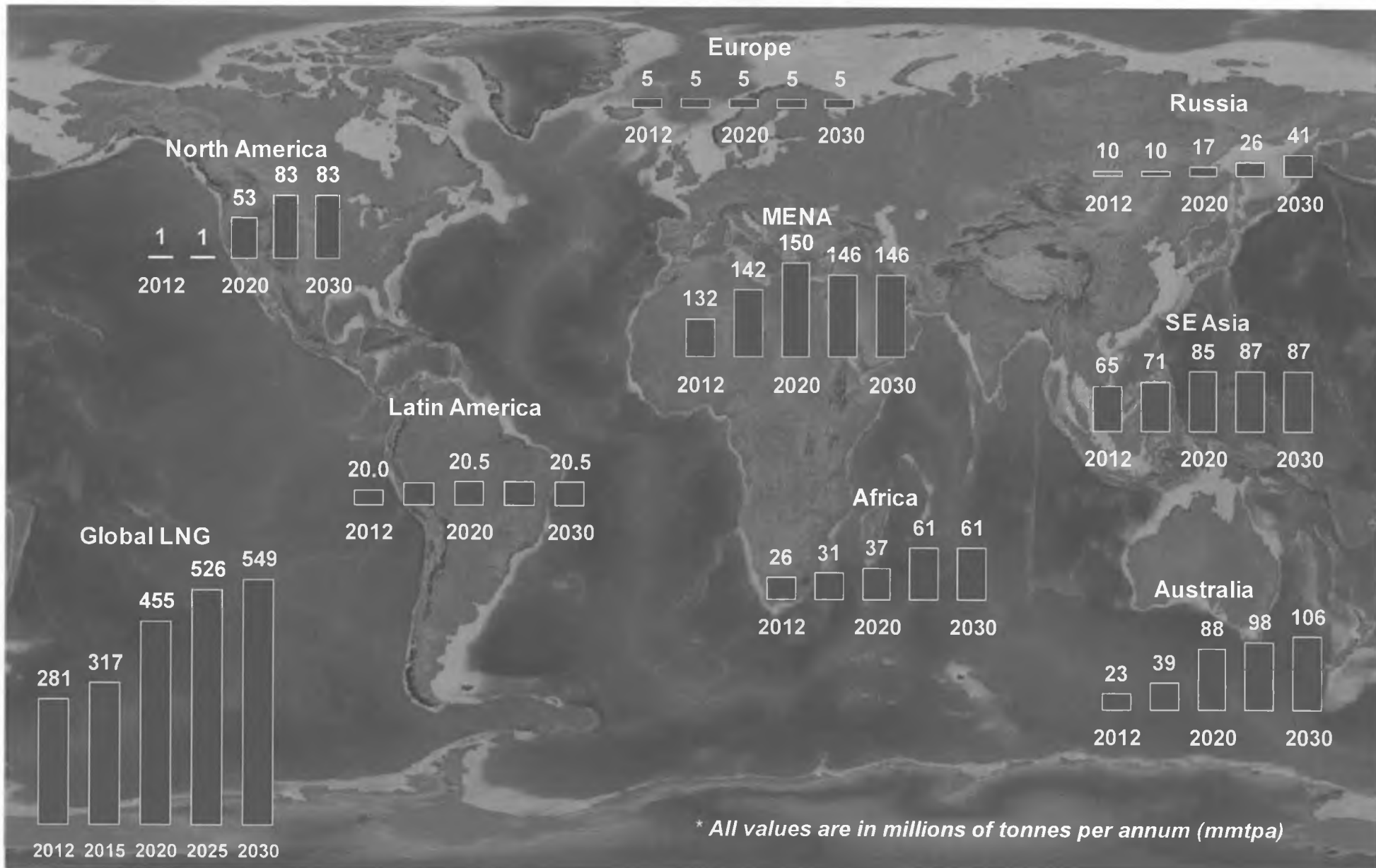
- If all LNG projects were to move ahead according to plan, LNG capacity would grow from 281 mmtpa (2012) to 771 mmtpa in 2030. Clearly, such a build-out is unrealistic.

North America is Largest Prospective Supplier

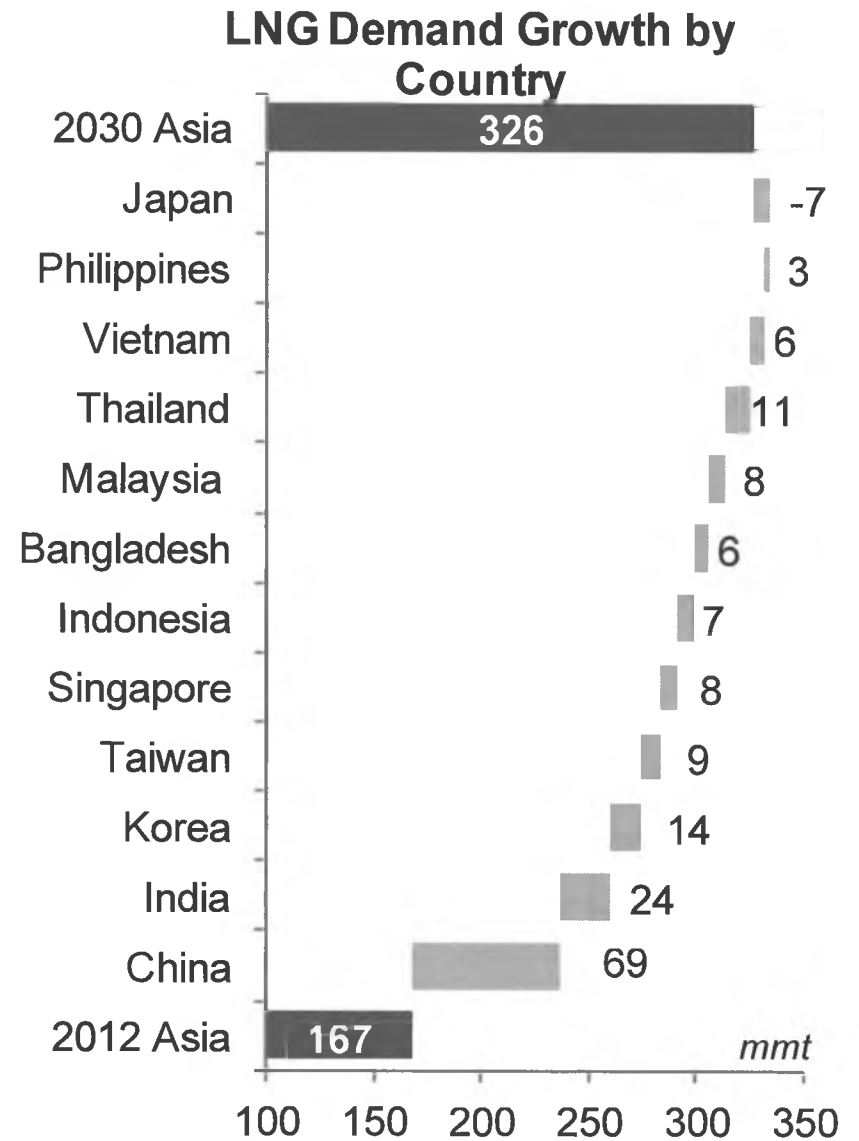
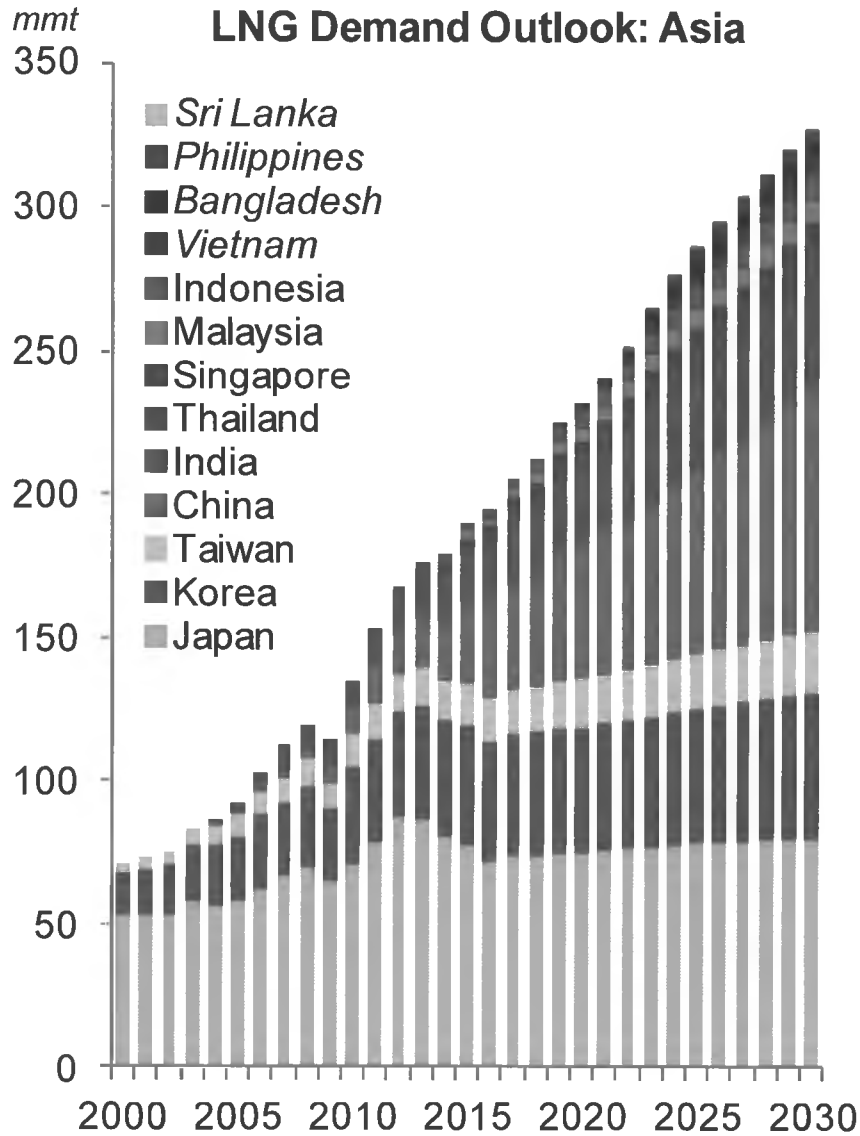
Proposed Liquefaction Plants by Location



Growth Clustered: N. America, Africa, Australia

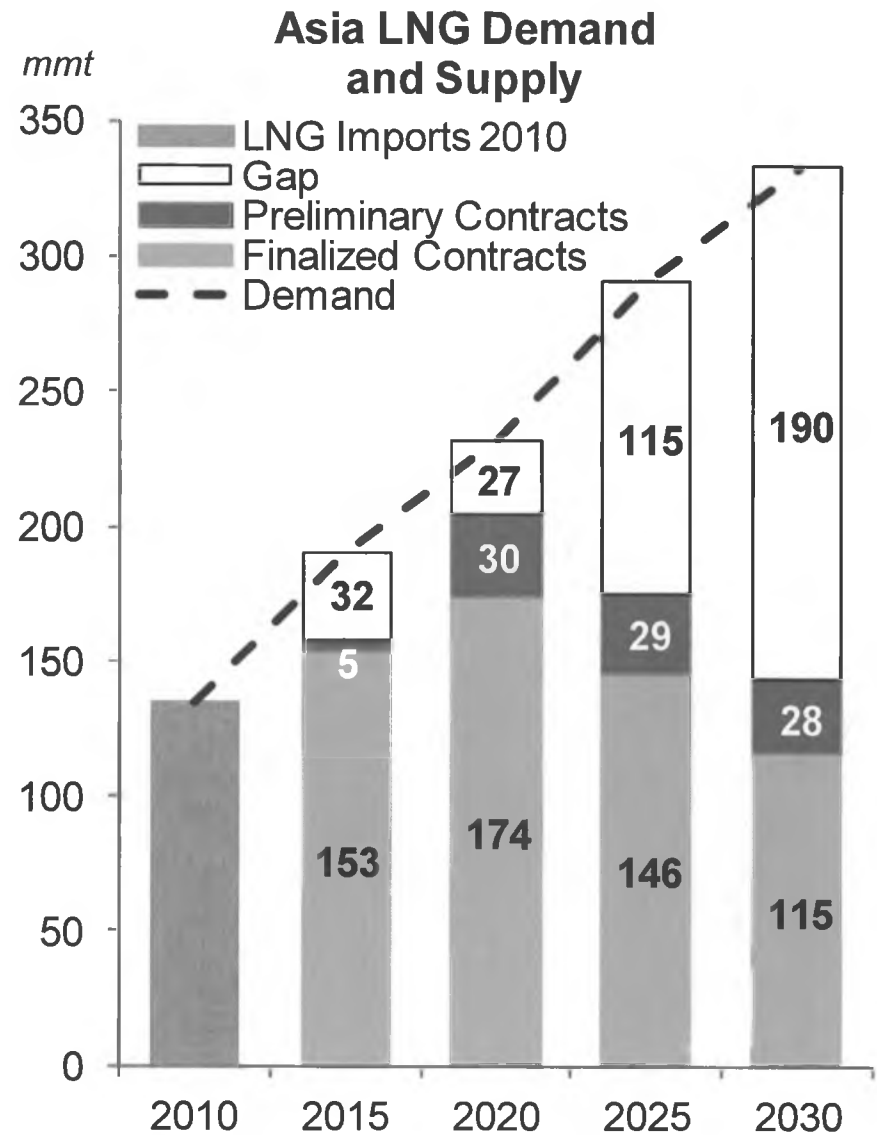


Widespread Growth in Asian LNG Demand



Window into Asia: Small by 2020, Grows Post 2020

- 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.



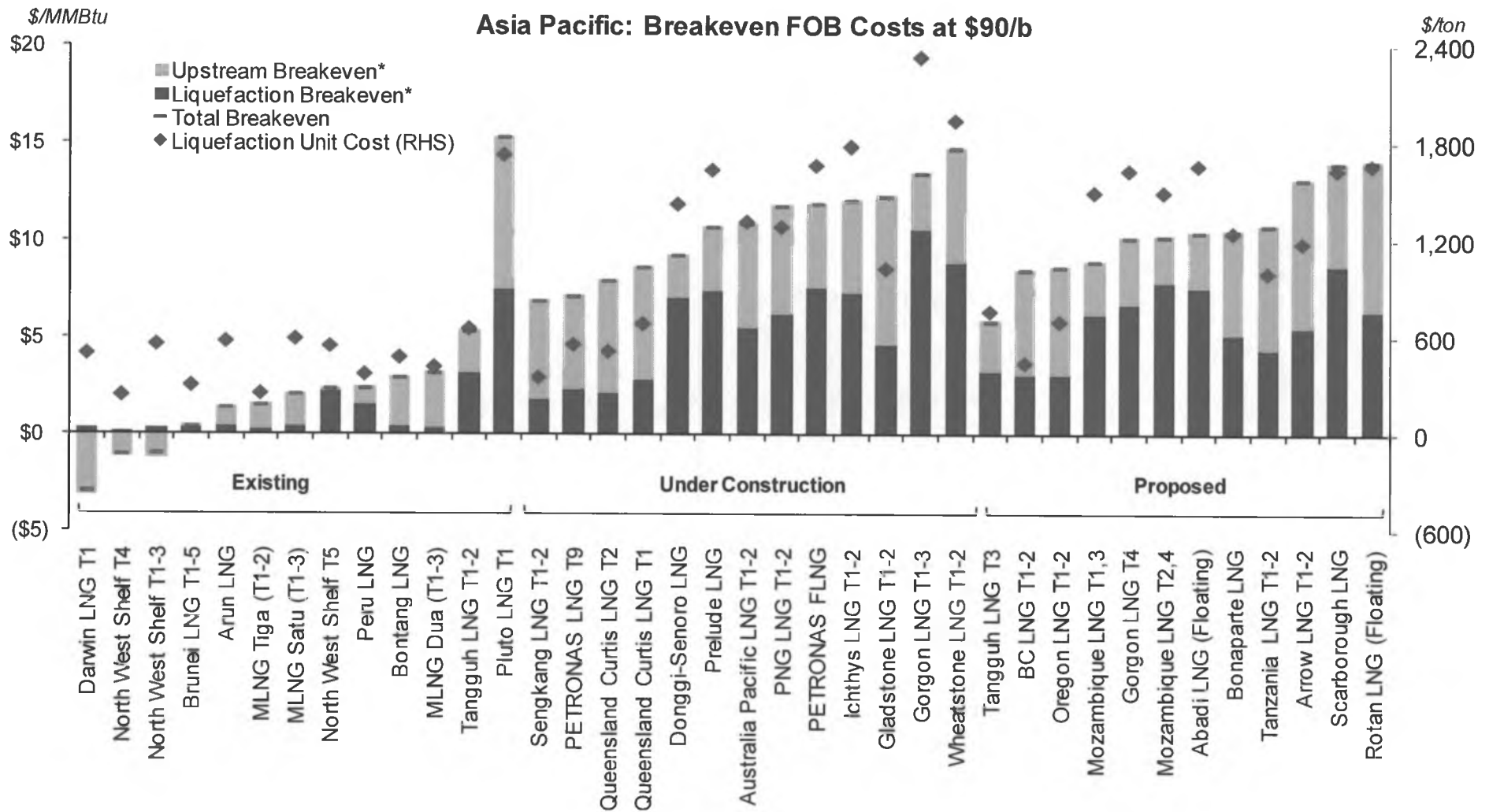
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Oil-Indexed Pricing to Asian Markets

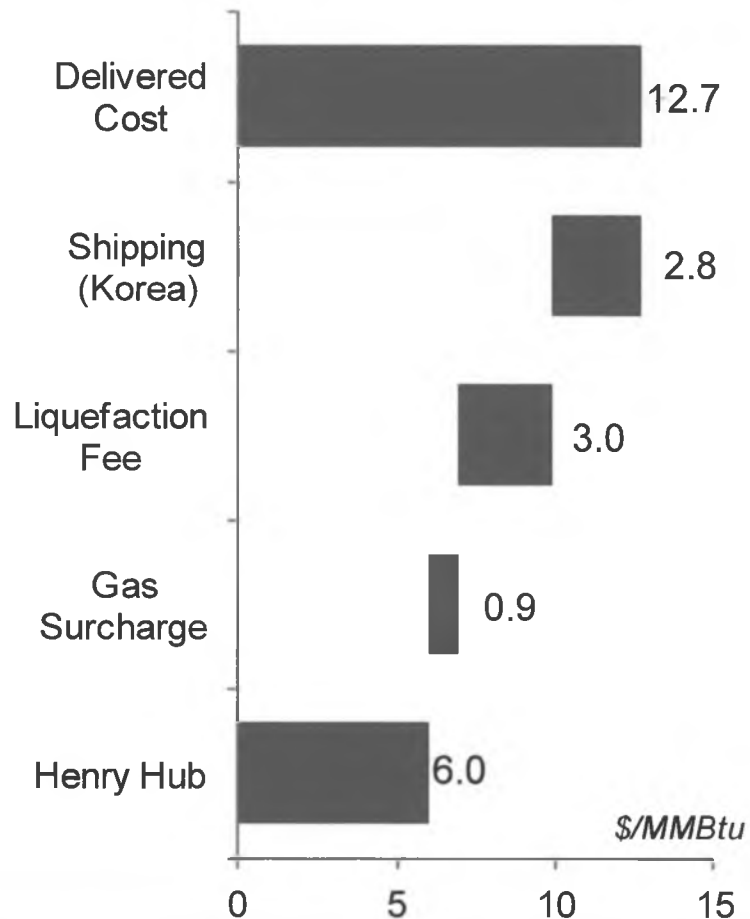
Contract Sales Price Slope --->	0.13x	0.14x	0.15x	0.16x
\$60/bbl Brent	\$7.80	\$8.40	\$9.00	\$9.60
\$80/bbl Brent	\$10.40	\$11.20	\$12.00	\$12.80
\$100/bbl Brent	\$13.00	\$14.00	\$15.00	\$16.00
\$120/bbl Brent	\$15.60	\$16.80	\$18.00	\$19.20
\$140/bbl Brent	\$18.20	\$19.60	\$21.00	\$22.40

New LNG Projects are Expensive



Lower 48 is An Alternative—But Not Necessarily Cheap; & It is Volatile

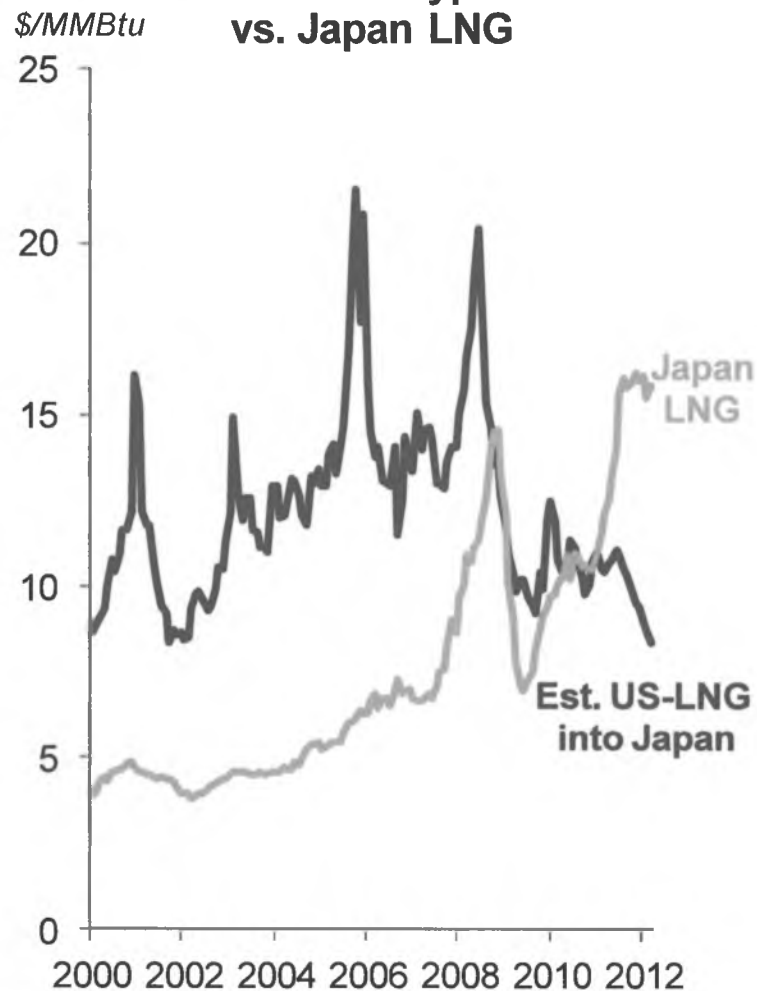
KOGAS Contract with Sabine Pass at \$6 Henry Hub



At \$6/MMBtu, US is not that cheap

Source: Global LNG Service

Sabine Pass-Type LNG vs. Japan LNG



Hub can be cheap but also volatile

Source: Global LNG Service

Does Alaska Have a Shipping Advantage?



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

	Japan / S. Korea	China	India
Southern Alaska	0.67	0.83	1.44
Western Canada	0.82	0.99	1.65
US - GOM	1.89	2.06	1.88
Australia	0.60	0.60	0.62
East Africa	1.18	0.97	0.58

- 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

AK South Central LNG Concept

SCLNG Concept Summary - Upstream

Alaska SCLNG Project
Concept Information

PTU (62 miles east of PBU/GTP area)

- Initial Production System (IPS) project in progress - 2016 SU
- Preliminary SCLNG design basis for PTU:
 - Leverage IPS facilities, add fourteen new wells
 - Add new gas facilities to existing central pad / facilities
 - New 30" gas line from PTU to GTP in Prudhoe Bay
 - Peak workforce - 500-1,500 people

PTU Field Layout



PBU Tie-in (adjacent to proposed GTP location)

- Installation / tie-in managed by Prudhoe Bay Operator
- Tie into existing CGF, deliver gas to new Gas Treatment Plant
- Gas project / deliveries tied to future PBU operations
- Preliminary plan is to inject CO₂ using existing injection systems as appropriate

PBU Central Gas Facility Tie-in



Work Product in Progress

SCLNG - Concept Summary - Midstream

Alaska SCLNG Project
Concept Information

NS Gas Treatment Plant

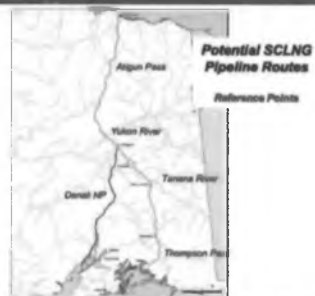
- Designed to remove gas impurities
- Four amine trains with compression, dehydration and chilling
- Prime power generation (5 units, 54kHP)
- All required utilities, infrastructure and camps
- Facility will be modularized, sealed to location
- Peak workforce - 500-2,000 people

NS Gas Treatment Plant Design



Gas Pipeline and Compression Stations

- 800+ mile 42" x80 pipeline
- 3-3.5 billion cubic feet gas per day
- Eight compressor stations (30kHP each)
- Pipeline contents will be treated gas, impurities removed
- Designed to manage continuous and discontinuous permafrost regions
- Expansion potential with additional compression if appropriate
- Five off-take points for Alaska gas delivery
- Peak workforce - 3,500 - 5,000 people



Work Product in Progress

SCLNG - Concept Summary - Downstream

Alaska SCLNG Project
Concept Information

LNG Plant and Storage

- Three 5.8 million tons per annum (MTA) LNG trains
 - Plant receives 2.2 - 2.5 billion cubic feet per day to liquefy
 - LNG production varies with ambient temp (4.9 - 6.3 MTA)
 - Small volume of stabilized condensate produced (~1,000 bbl/day)
- Integrated utility system with all utilities on site
- Two-three 160,000 cubic meter LNG storage tanks
- Peak workforce - 3,500 - 5,000 people

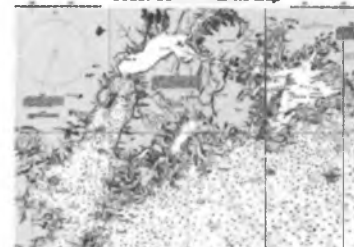
SCLNG Plant and Storage



Marine Offloading Facility

- Conventional jetty and trestle design
- Two berths
- Design based on 15-20 LNG carriers
- Marine support system includes required tugs, security boats
- Peak workforce - 1,000 - 1,500 people

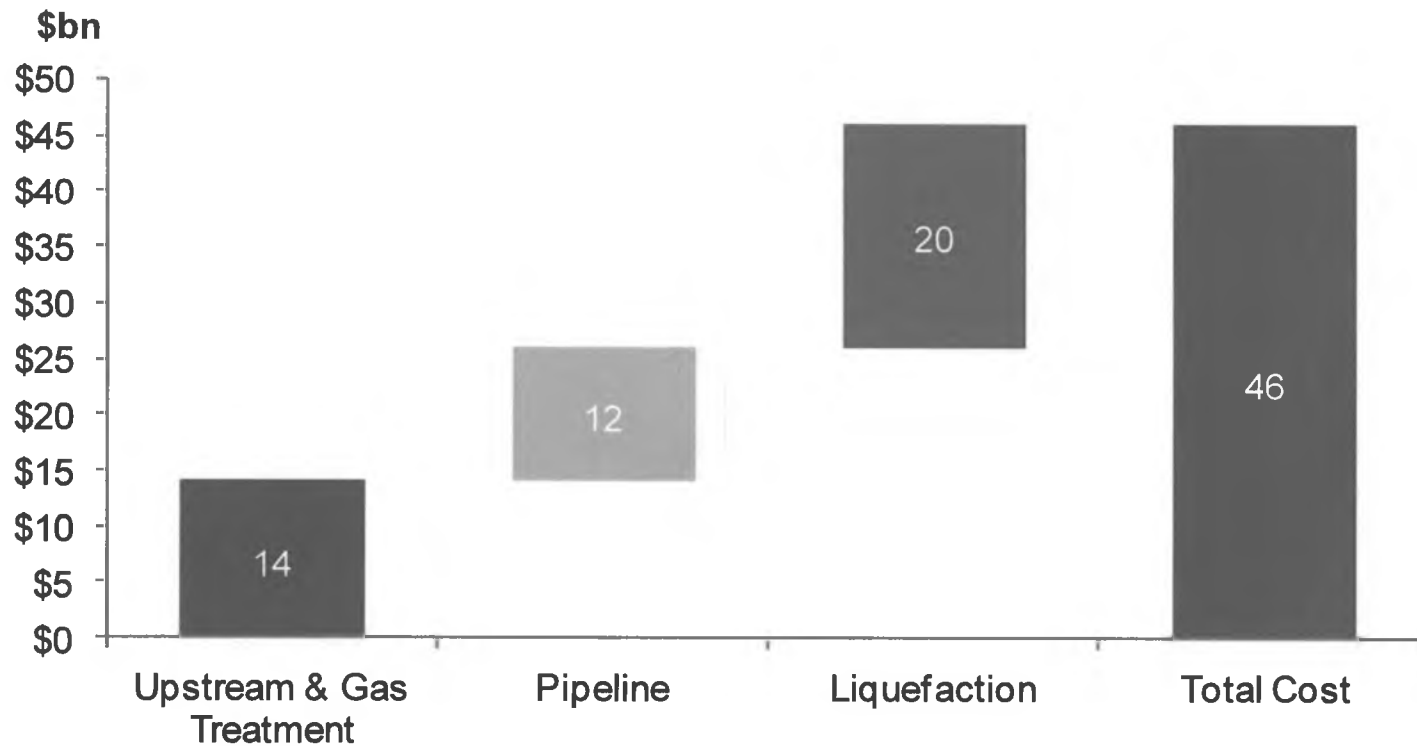
South Central Marine Map



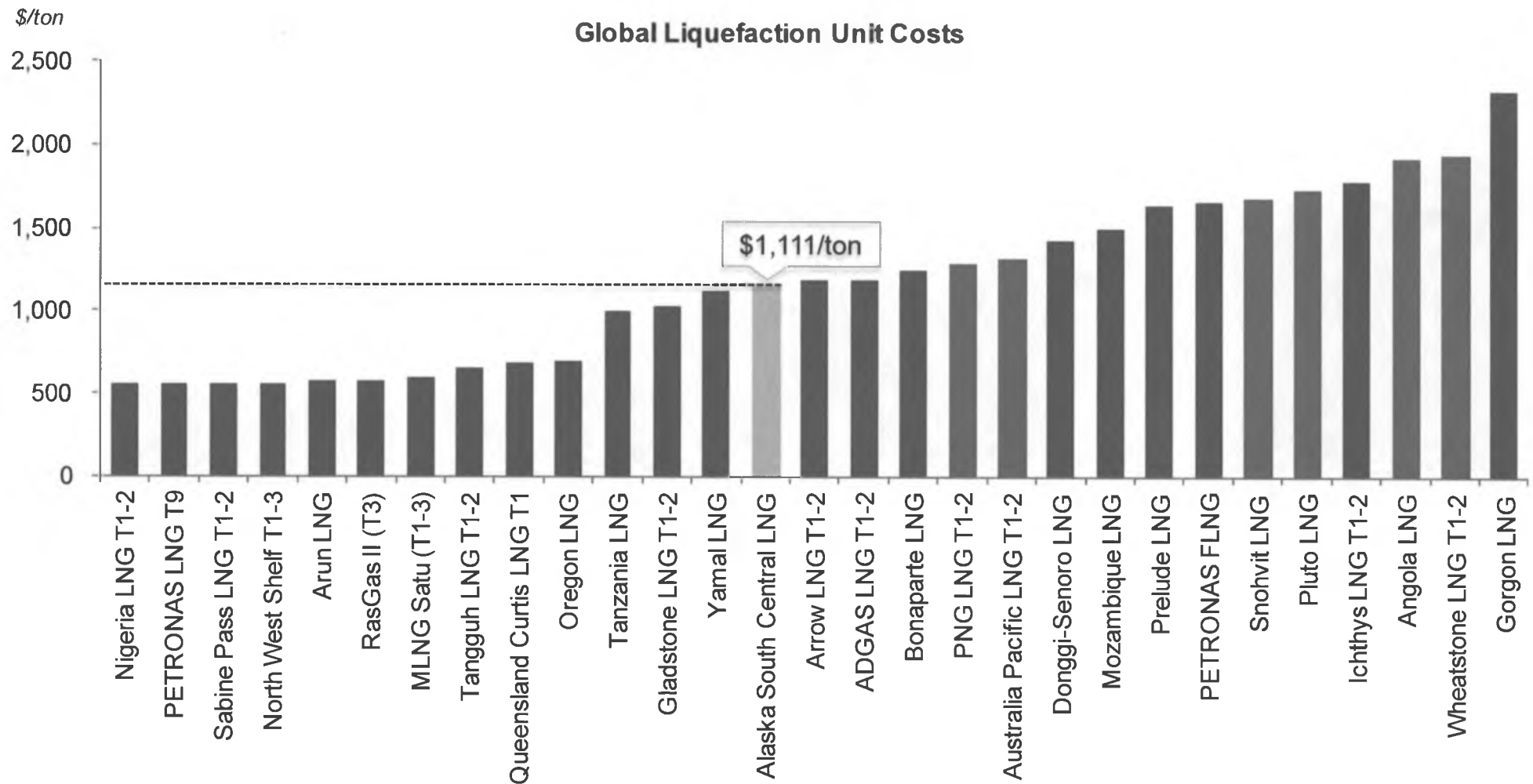
Work Product in Progress

**Estimated total cost:
\$45 - \$60 bn (2011 real dollars)**

Hypothetical Cost Breakdown

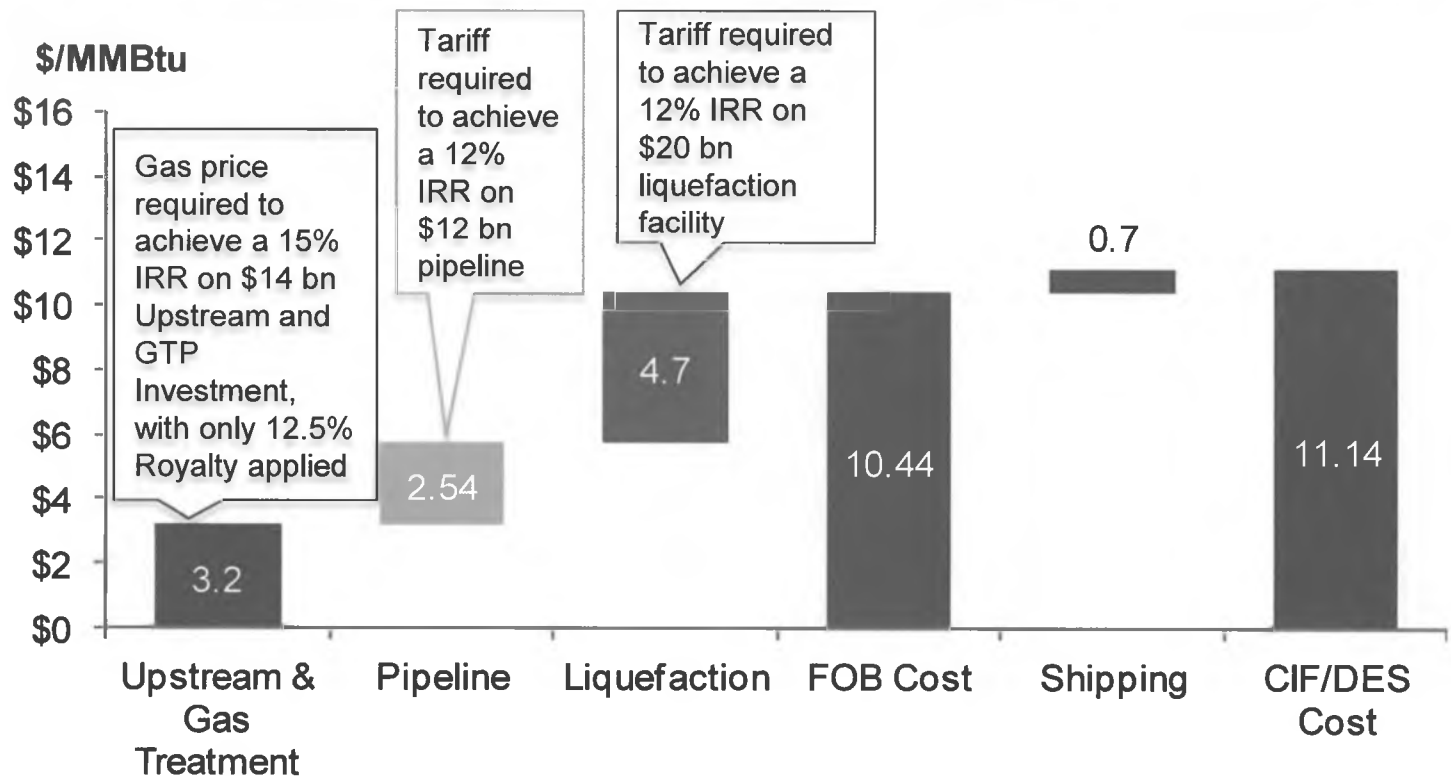


How Would \$20bn for an 18 mmtpa Liquefaction Facility Compare With Other Recent Projects?



Breakeven Economics for Hypothetical \$46bn Project

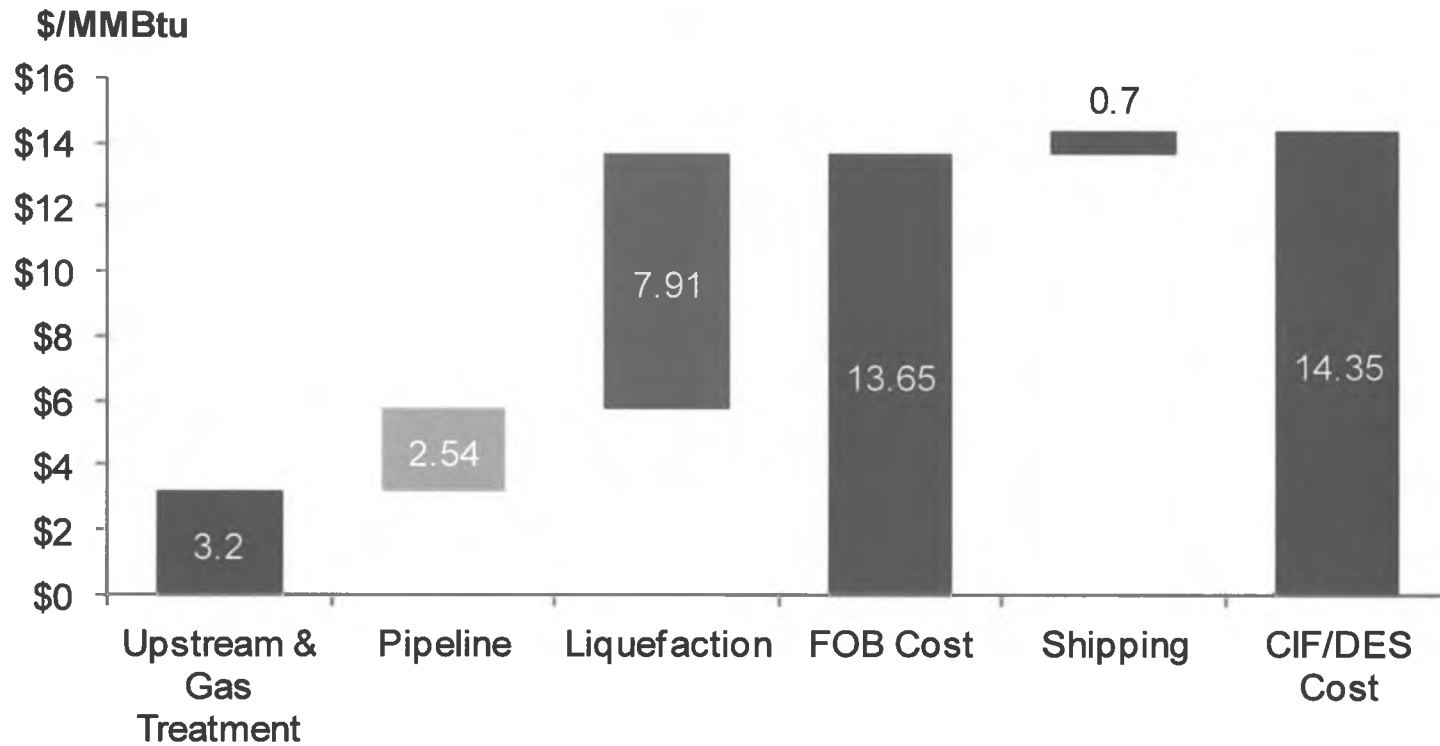
~\$1,111/ton
 At this unit cost level, liquefaction spend would be ~\$20bn



What if Liquefaction reached \$/ton costs of Angola LNG or Wheatstone LNG?

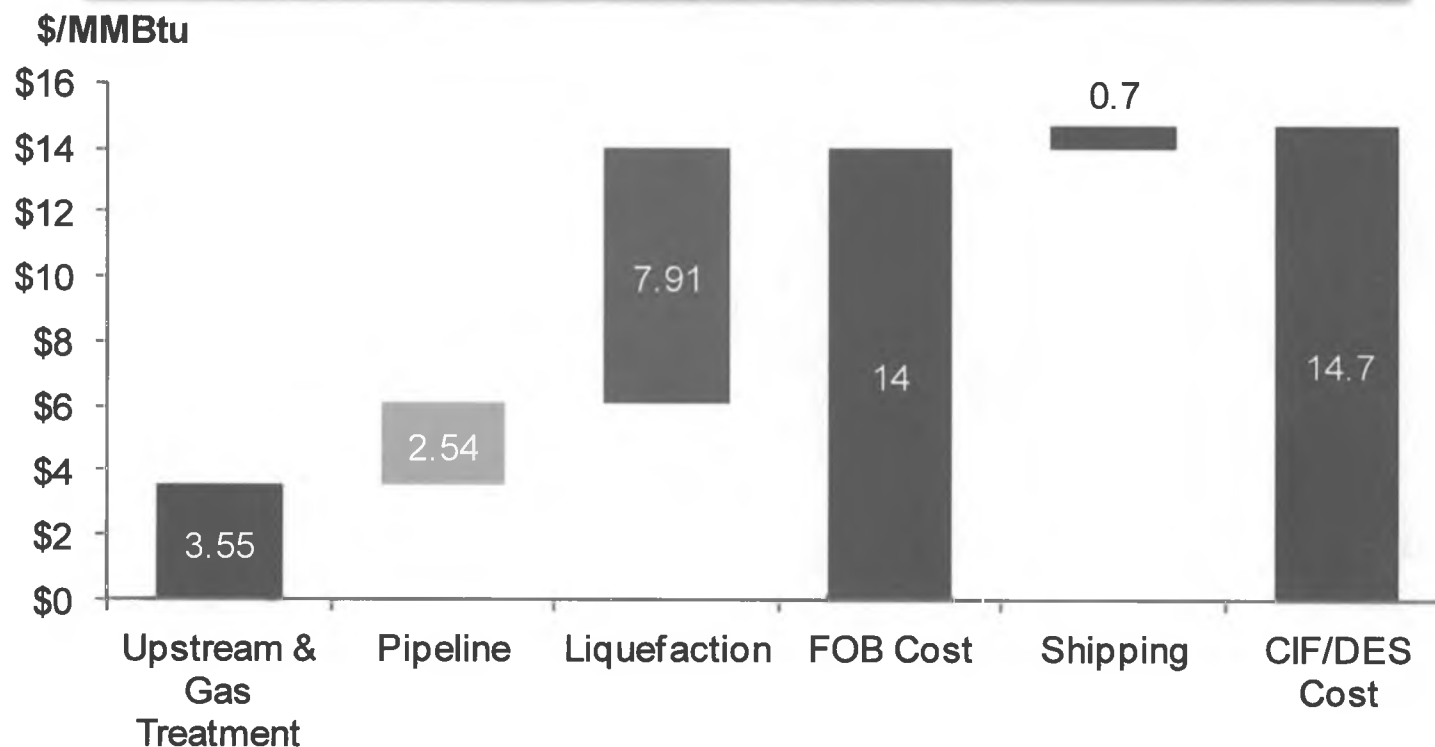
~1,900/ton

At this unit cost level, liquefaction spend would be ~\$33.6bn



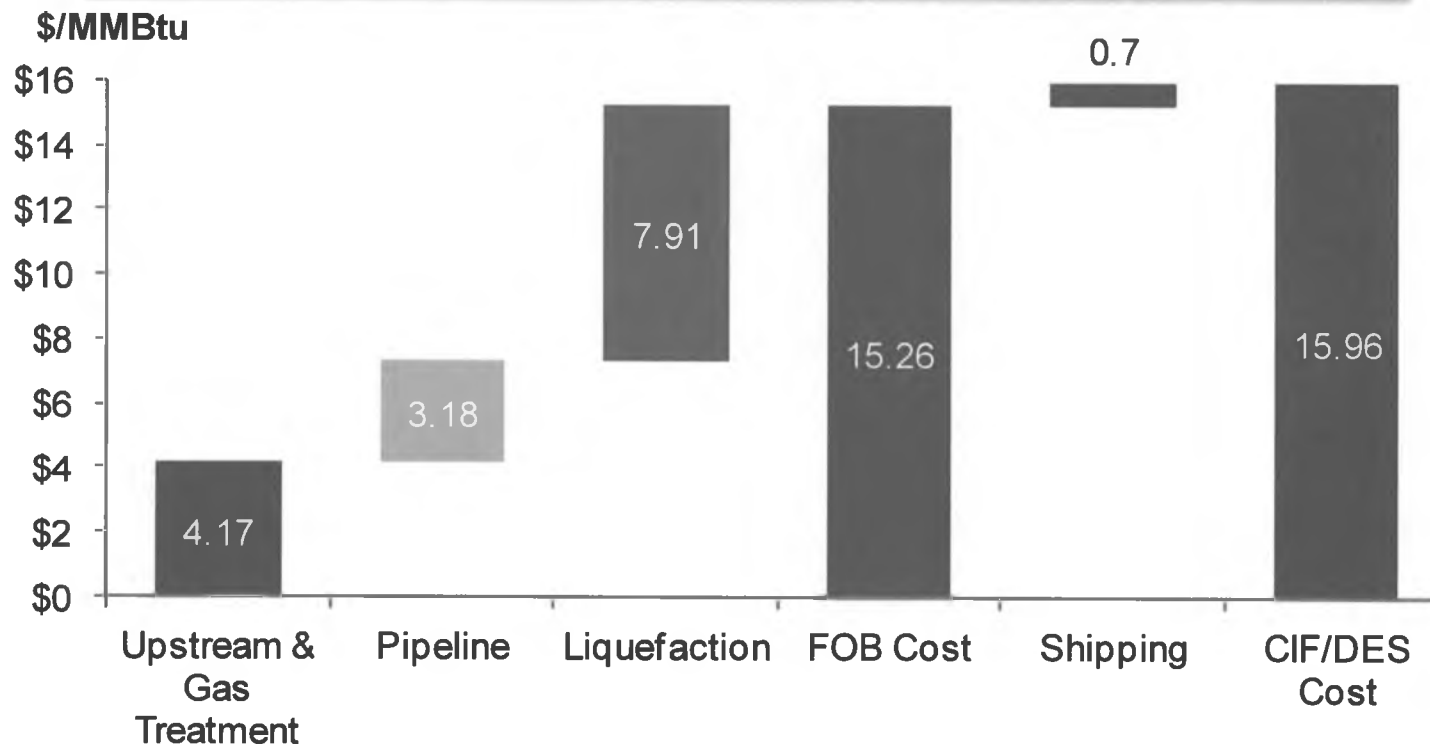
What if Upstream Production Also Faced a 16.7% Royalty and a 35% Production Tax?

*~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?

*~1,900/ton
At this unit cost level, liquefaction spend would be ~\$33.6bn
Total Project Spend would be ~\$64.5/bn*





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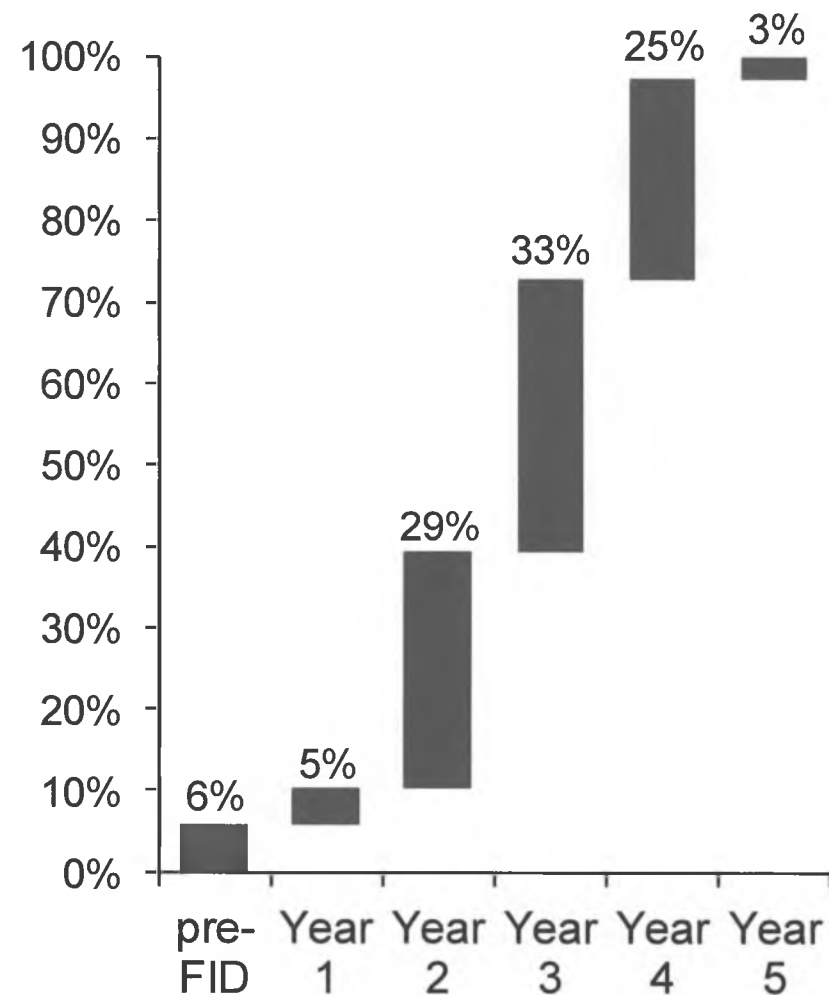
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Lots Needed Before Companies Spend Real Money

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)

Indicative CAPEX for Integrated LNG Project

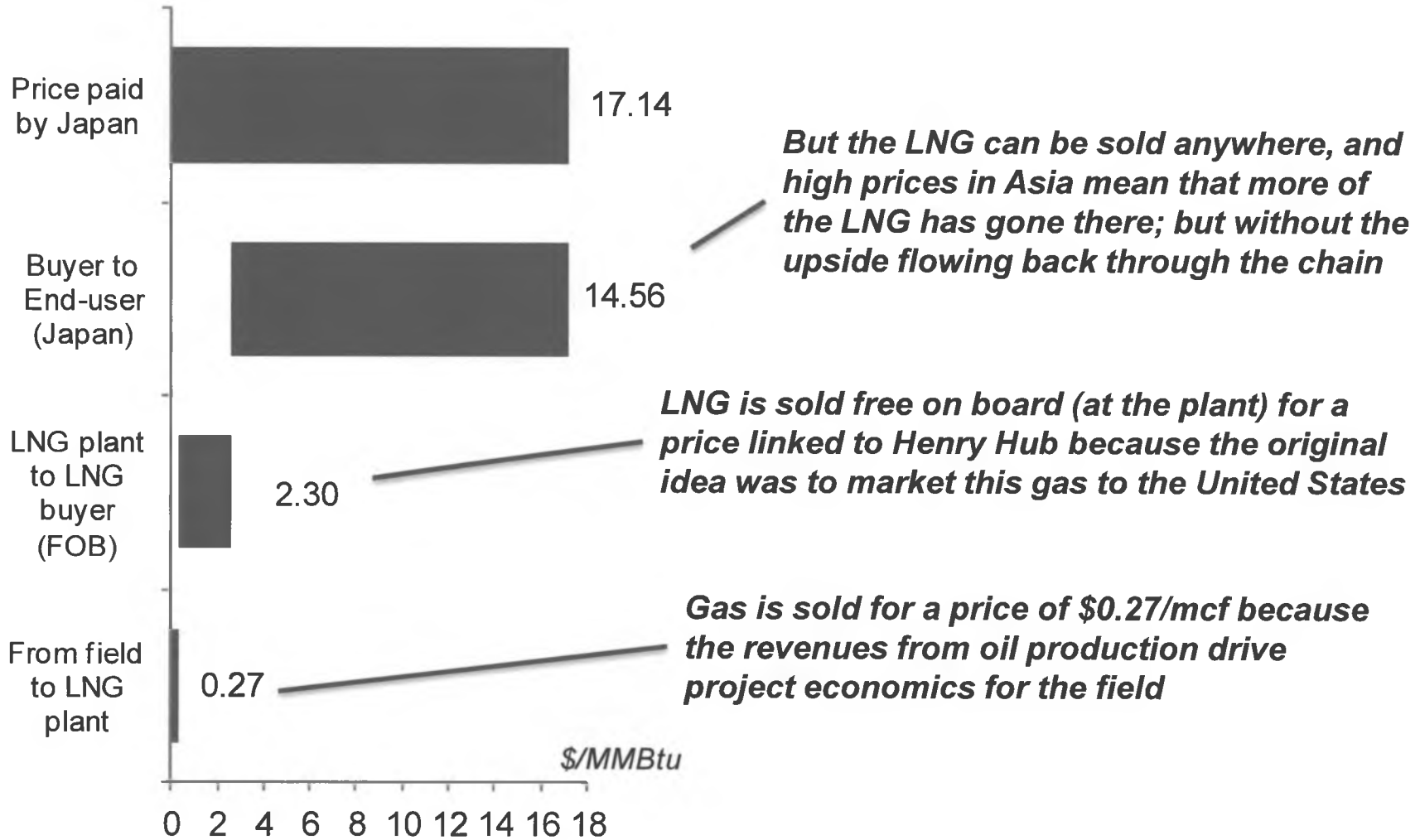


Main Provisions of an LNG Contract

Pricing	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).
Duration	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 (<5) contracts.
Destination Flexibility	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.
Volume Flexibility	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).
Profit Sharing	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).
Non-Compliance	Most contracts have arbitration provisions.
Renegotiation Provisions	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.

Project Structure Really Matters

Equatorial Guinea to Japan Value Chain



The LNG Value Chain

Upstream



Liquefaction



Shipping



Buyer

- 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)

From	To					
	billion cubic metres NG	billion cubic feet NG	million tonnes oil equivalent	million tonnes LNG	trillion British thermal units	million barrels oil equivalent
	Multiply by					
1 billion cubic metres NG	1	35.3	0.90	0.74	35.7	6.60
1 billion cubic feet NG	0.028	1	0.025	0.021	1.01	0.19
1 million tonnes oil equivalent	1.11	39.2	1	0.82	39.7	7.33
1 million tonnes LNG	1.36	48.0	1.22	1	48.6	8.97
1 trillion British thermal units	0.028	0.99	0.025	0.021	1	0.18
1 million barrels oil equivalent	0.15	5.35	0.14	0.11	5.41	1

Source: BP Statistical Review of World Energy 2013

**BUILDING
A WORLD
OF DIFFERENCE**

NOVEMBER 2013

ALASKA NORTH SLOPE ROYALTY STUDY STUDY HIGHLIGHTS

PREPARED FOR THE STATE OF ALASKA



BLACK & VEATCH
Building a world of difference.

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EXECUTIVE SUMMARY – BACKGROUND & SCOPE



- The Alaska Liquefied Natural Gas (AKLNG) project is a proposed project to liquefy Alaska North Slope (ANS) gas and export it as LNG, primarily to Asian markets
- The project is comprised of three main components:
 - Gas treatment plant (GTP),
 - Pipeline
 - Liquefied natural gas (LNG) plant
- The total estimated capital cost of the project is \$45 billion falling within a range of \$39-\$54 billion
- Natural gas to supply the project is anticipated to come from the proven reserves at the Prudhoe Bay and Point Thomson units on the Alaska North Slope
- The key project sponsors are Exxon Mobil, ConocoPhillips and BP (referred to in this study as Producers) with potential participation by TransCanada and the State of Alaska
- Target final investment decision for the project is projected around 2017-18 with a commercial operation date around 2023-24

EXECUTIVE SUMMARY – BACKGROUND & SCOPE



- The AKLNG Project has recently seen momentum with the 3 Producers along with TransCanada coming together to evaluate and advance the AKLNG Project
- The AKLNG Project has the potential to provide hundreds of billions of dollars in value to the State of Alaska as well as the project's investors; the benefits to Alaskans include new revenues, affordable energy supplies, new jobs and economic activity
- The State of Alaska, Department of Natural Resources (DNR) commissioned a study to document and understand four major commercial elements that could influence the various stakeholders' returns from the AKLNG Project:
 - LNG markets
 - Supply chain elements
 - Fiscal framework – International and Alaska
 - Risk allocation/commercial structure

EXECUTIVE SUMMARY – BACKGROUND & SCOPE



- The purpose of this study is to provide information that can help the State to protect its royalty interest in the state's gas and ensure that the State maximizes the value of its natural gas
- The study examined how the State's fiscal terms with a particular focus on royalty terms can affect the success of the AKLNG project in its role as the principal land owner of the oil and gas resources of the North Slope
- The Study was undertaken by a team that included Black & Veatch and Daniel Johnston, Inc. under the leadership of DNR along with support and consultation by Department of Revenue (DOR). Additionally, inputs and assumptions of AKLNG Project sponsors were considered.

EXECUTIVE SUMMARY – BACKGROUND & SCOPE

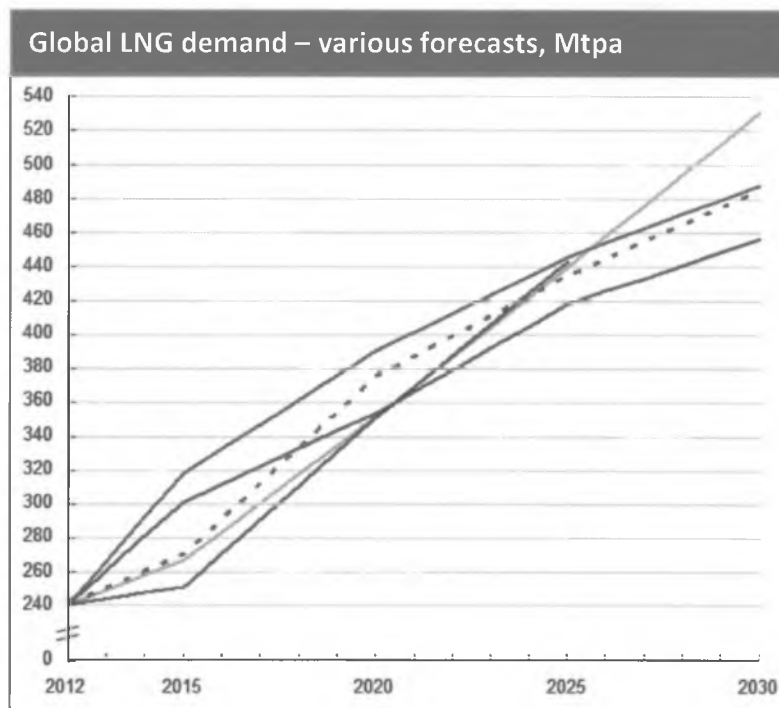


- Assessment of a project of the scope of AKLNG requires examination of numerous complex variables that cannot be determined with a high degree of certainty
- In most cases, a conservative approach was taken when applying forecasts and assumptions
- Many reasonable scenarios can be derived where the AKLNG project is economic, and vice versa
- It should be recognized that market and project related variables, that remain as yet unresolved, can modify the economics as presented here
- The findings in this study represent Black & Veatch's view based on the information available to date and do not necessarily represent the views of the State of Alaska

EXECUTIVE SUMMARY – KEY FINDINGS

LNG Markets

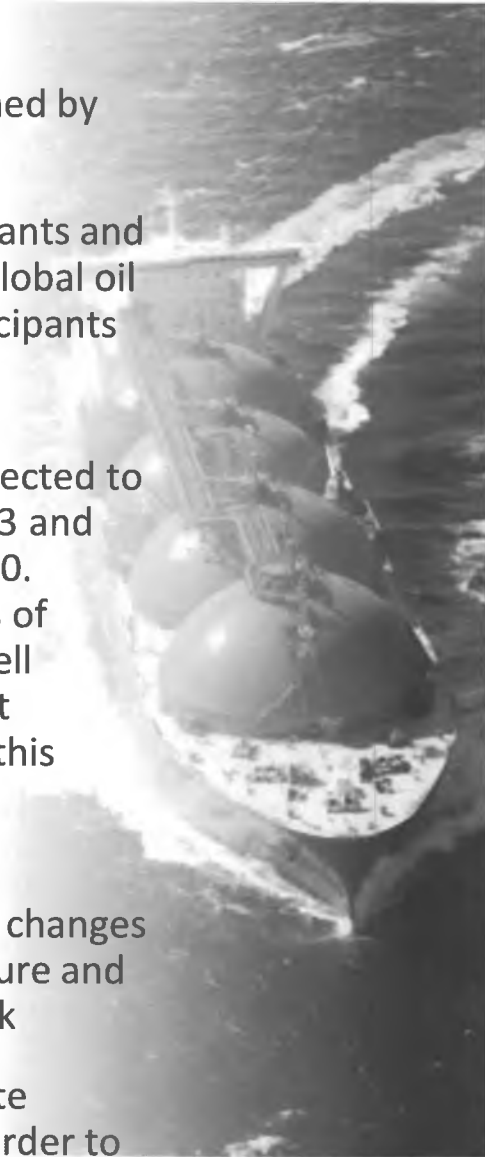
- The LNG market is characterized by highly capital intensive projects underpinned by long-term contractual relationships across the supply chain
- The LNG market is in an illiquid, opaque market consisting of very few participants and is structured on the basis of long-term, 20+ year contracts as opposed to the global oil market which is highly liquid, extremely transparent, comprised of many participants and is structured on the basis of short term trade



Note: Includes AKLNG, other new projects, and projects under development.

Source: Team Analysis, various demand studies

- Global LNG demand is projected to grow by 50% between 2013 and 2020 and to double by 2030. However potential sources of supply are expanding as well thereby creating significant competition for capturing this growing market
- AKLNG project could be economically feasible with changes to the project's cost structure and the state's fiscal framework
- AKLNG will have to compete successfully for buyers in order to meet its targeted 2024 in-service date



EXECUTIVE SUMMARY – KEY FINDINGS



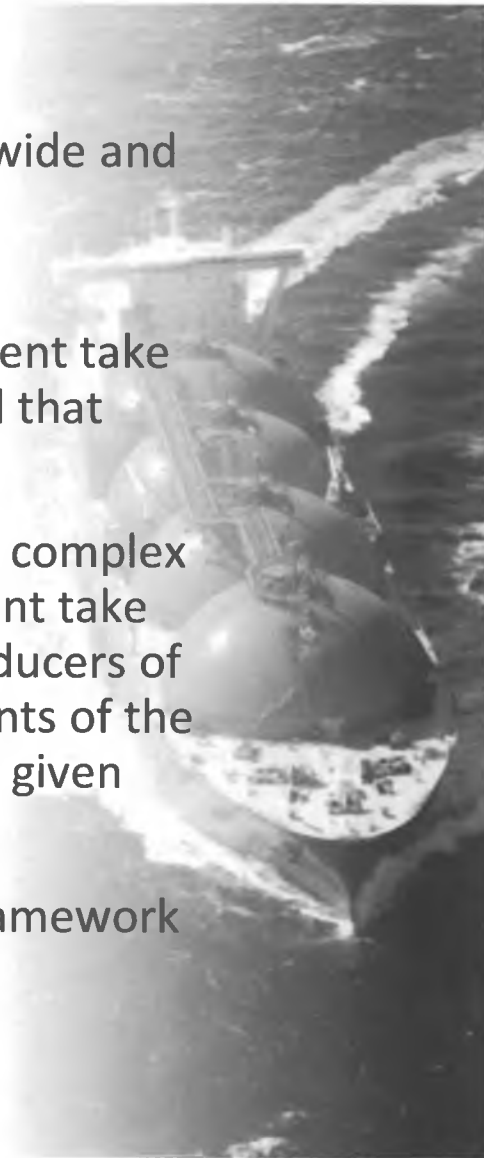
Supply Chain Elements

- In line with the rising costs of LNG projects world-wide, AKLNG project cost estimates have risen by 67% since an equivalent project was evaluated in 2008 to a current estimate of \$45 Billion for the GTP, Pipeline and LNG liquefaction and marine facilities. Equivalent estimates from AKLNG project sponsors are in the range of \$39 - \$54 Billion.
- Large, complex LNG projects typically have an integrated commercial structure from production through liquefaction to give project sponsors maximum control across the supply chain.
- The AKLNG project is expected to have an integrated structure
- Ensuring transparency along the supply chain, open access for third parties and alignment of interests between the State and Producers become challenging with a Producer-owned integrated project.

EXECUTIVE SUMMARY – KEY FINDINGS

Fiscal Framework

- AKLNG is competing for capital with Producers' projects worldwide and for market share with other sources of supply.
- Similar to other oil and gas projects, LNG projects have either concessionary or contractual fiscal systems with total government take ranging from 45% - 80% for comparable LNG projects reviewed that have achieved commercial operation.
- Government take in Alaska in the 70% - 85% range is high for a complex LNG project, although overlapping with the range of government take for the other LNG projects reviewed. Expected IRR for the Producers of approximately 15% for the upstream and midstream components of the project may be insufficient for the Producers to move forward, given their investment alternatives and AKLNG project uncertainties.
- Changes to the project's cost structure and the State's fiscal framework can make the AKLNG Project more economic and competitive.



EXECUTIVE SUMMARY – KEY FINDINGS

Fiscal Framework

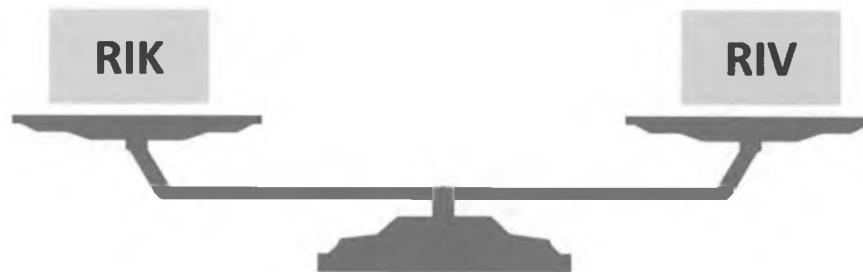
- Incentives including modifications in royalty and/or production tax are among the alternatives available to the State to help improve the relative competitiveness of the project under various scenarios.
- There are various risks to the State from significantly reducing or eliminating its royalty share;
 - Royalties represent Alaska's ownership stake and reducing royalties has implications for the Alaska Permanent Fund
 - Royalty reduction would not protect the State from risks posed by misalignment between the State and Producers interests wherein Producers are able to shift revenues between upstream and midstream components of the project to the detriment of the State



EXECUTIVE SUMMARY – KEY FINDINGS

Fiscal Framework

- In reviewing alternatives for royalty, an election by the State to take its royalty in-kind (RIK) could result in a substantial increase in the State's risk exposure and potential loss of royalty value.
 - An election by the State to take its royalty in-kind could necessitate the need for the State to enter into a large number of complex commercial agreements. The State would be disadvantaged in the creation of such agreements by its statutory and regulatory structure (e.g., the need for legislative modifications), its inexperience in LNG negotiation, its status as a new entrant to the market, and the lack of an LNG supply portfolio to optimize. Risks associated with RIK could result in lower pricing for our LNG
 - Producers have more experience managing the exposures to market risk
- An election by the State to take its royalty in value presents potential for dispute on valuation and deductions and misalignment of interests with the Producers.
 - However, the State has experience in addressing these challenges through settlement agreements that provide more certainty and clarity



EXECUTIVE SUMMARY – KEY FINDINGS

Risk Allocation

- Oil and LNG prices and capital costs emerge as the key factors among the various risks impacting the AKLNG project's economics
- Direct equity participation in the project can align the State with the Producers and reduce the cost structure of project for project sponsors but potentially exposes the State to additional risks
- Commercial terms related to equity participation such as position on the management committee and voting rights will determine the extent to which the State can achieve its objectives for open access and transparency



EXECUTIVE SUMMARY – CONCLUSIONS



- The AKLNG Project can be economically feasible and competitive with changes to the project's cost structure and the State's fiscal framework
- Fiscal and non-fiscal incentives can aid in improving the commercial attractiveness of the project
 - Fiscal – cost sharing, reduction in government take
 - Non-fiscal – stabilization provisions, modifications to existing lease terms such as the notice period of the State's rights to switch between RIK and RIV
- Integrated project ownership of AKLNG by the Producers presents the risk of misalignment wherein project revenues could be moved between the upstream and the midstream components to maximize value to the Producers. These decisions could potentially be to the detriment of the State.

EXECUTIVE SUMMARY – CONCLUSIONS



- Fiscal structure changes beyond stand-alone royalty share or tax rate modification can help in improving project economics and creating alignment:
 - Direct participation by the State in the project
 - Establishment of a gross share of gas in lieu of production tax
- Direct state equity participation in the project can provide key benefits to the State including :
 - Create alignment of interests;
 - Create transparency through the midstream portion of the supply chain;
 - Facilitate third-party access to the mid-stream;
 - Potentially increase State cash flows, and improve producer economics.

EXECUTIVE SUMMARY – CONCLUSIONS



- Going further, establishment of a gross share of gas in lieu of production tax and corresponding equity investment in the project may provide the needed alignment for a competitive project such that the State can maximize the value of its resources.
- The State has the ability to lessen project risk, but will need to weigh those opportunities circumspectly - risk mitigation and commercial agreements need to be addressed carefully to define the State's rights and obligations, manage risk exposure and to achieve objectives of transparency and open access for third parties

LNG MARKETS – SCOPE



- LNG Markets
- Supply Chain Elements
- Fiscal Framework
- Risk Allocation & Fiscal Structure

- Overview of how LNG is being traded and valued in various markets that are available to AKLNG Project
- Analysis of historical and future global LNG pricing trends
- Discussion of supply and demand projections in the LNG market and implications for AKLNG Project

CURRENT LNG MARKET REALITIES

Demand/ key markets

- Highly **concentrated** – 7 countries account for **70%** of demand
- Asia Pacific accounts for **70%** of global trade
- Growing rapidly – **8%** per annum over the past 5 years

Supply

- LNG Supply is also highly **concentrated** – **8** exporting countries provided **83%** of global LNG exports in **2012**
- Liquefaction capacity is rarely developed on a speculative basis
 - Liquefaction facilities typically cost **US\$5-20bn**
 - LNG facilities are generally **project financed**, requiring firm revenue commitments
 - LNG **specifications** vary by each project and between buyers

Contracts/ pricing

- Dominated by long term contracts (**LTCs**)
 - **~75% of global trade** was delivered under LTCs in 2011 and in 2012
 - Trade in Pacific basin is driven by LTCs more than in Atlantic basin
- **No liquid market** to provide price markers for LNG
- Price structure needs to give buyers and sellers reasonable certainty **over 20 years**
- Oil/oil product price linkage has been standard since the 1970s
- This link is usually defined in form of a **formula with slope to oil price and constant**



RECENT MARKET DYNAMICS: SUMMARY

Crude linked contracts

- Crude linked contracts are signed by **most suppliers** excluding North American export terminals
 - **Between 2002-2006**, some **low price contracts** were signed by China/Japan
 - **From 2007**, most recent contracts signed have a **14% - 15 % effective slope** for the relationship of LNG price (\$/Mcf) to crude price (\$/Bbl)

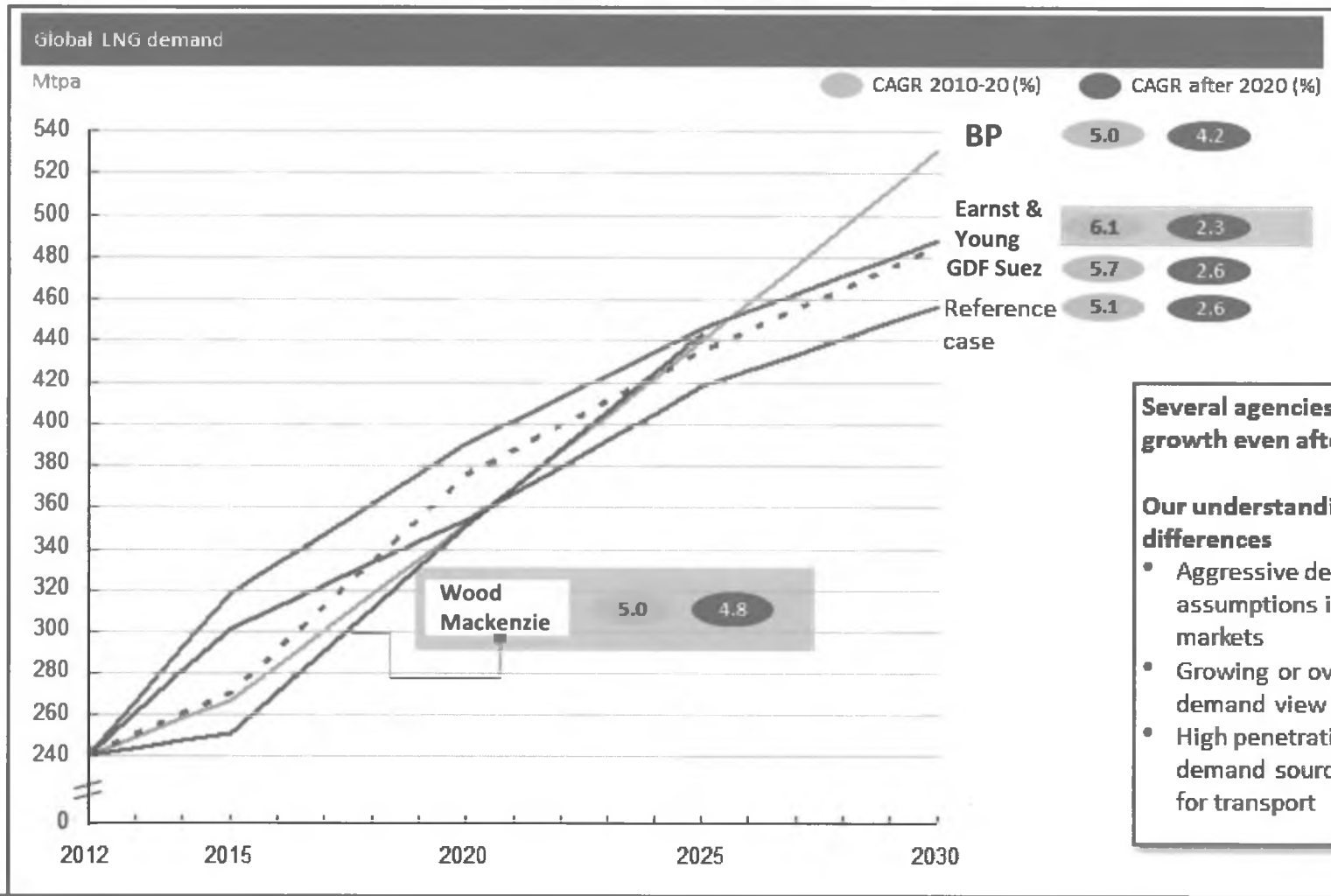
U.S. export contracts

- Emergence of **Henry Hub linked US LNG** tolling agreements has created an alternative to traditional crude linked contracts
 - **Delivered LNG prices** under these are currently **lower** than oil-linked contract prices
 - Buyers in countries such as **Japan** are **increasingly asking for these** and holding back on traditional contracts

Non price features/ players' responses

- Apart from pricing, **duration of contracts**, the **nature of commitment**, **delivery terms** and **LNG specifications** are important features to be considered
- Participants respond to **supply and demand changes** in a number of ways to **protect the price floor**

OUTLOOK FOR LNG DEMAND GROWTH VARIES ACROSS FORECASTING AGENCIES



Several agencies adopt a fast growth even after 2020

Our understanding of key differences

- Aggressive demand growth assumptions in Asia/new markets
- Growing or over-aggressive demand view on Europe
- High penetration of new gas demand sources such as gas for transport

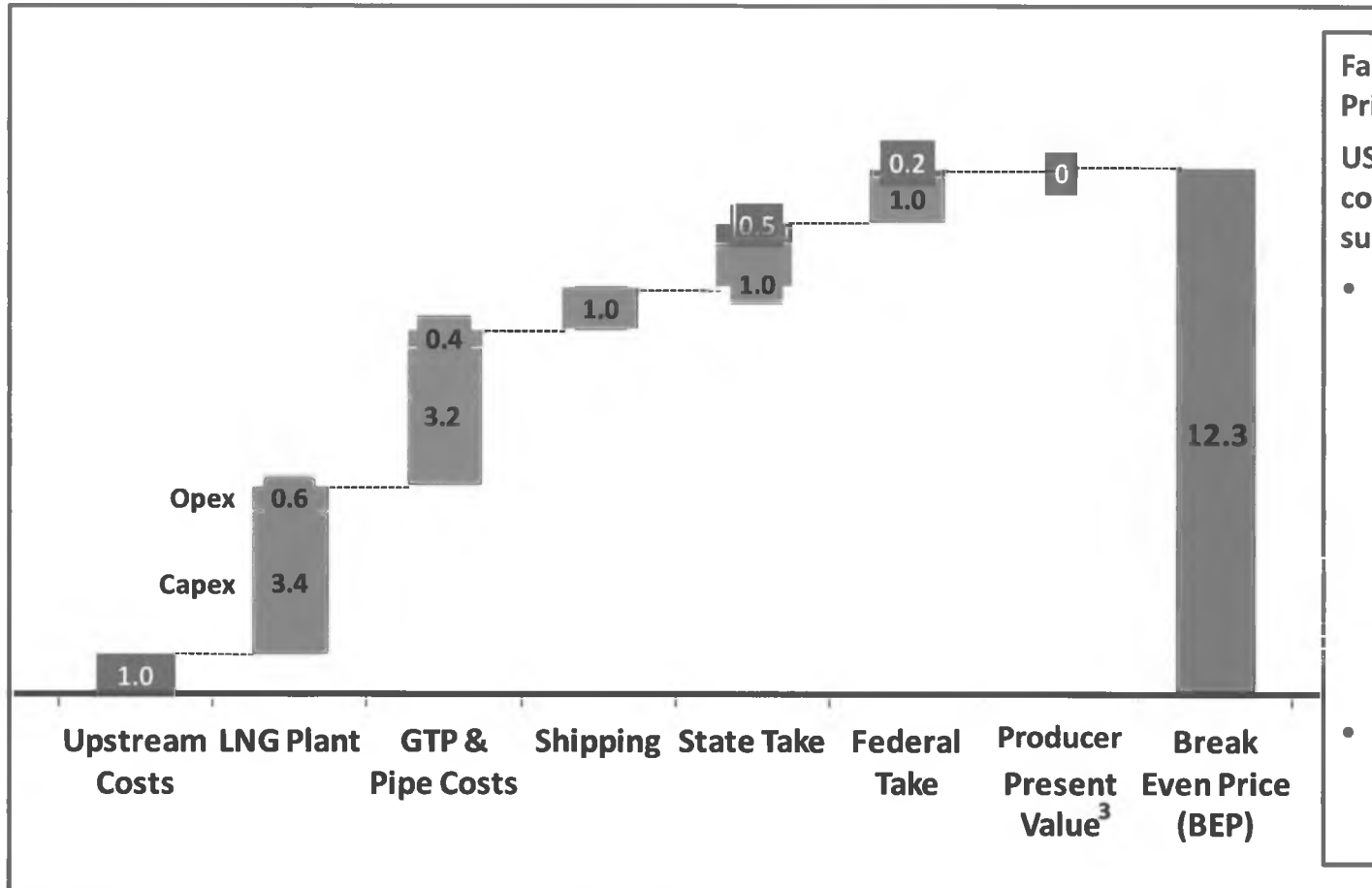
SOURCE: Public reports from or referenced information sourced from Wood Mackenzie; EY; BP; GDF Suez



AKLNG: PRESENT VALUE SHARE OF BREAK EVEN PRICE (ZERO NPV FOR PRODUCERS)

■ Upstream
■ Mid-stream

(2013 real US\$/MMBtu), LNG price delivered ex ship (DES) in Asia



Factors Impacting Break-even Price:
 US\$12.3/MMBtu is a conservative estimate subject to sensitivities

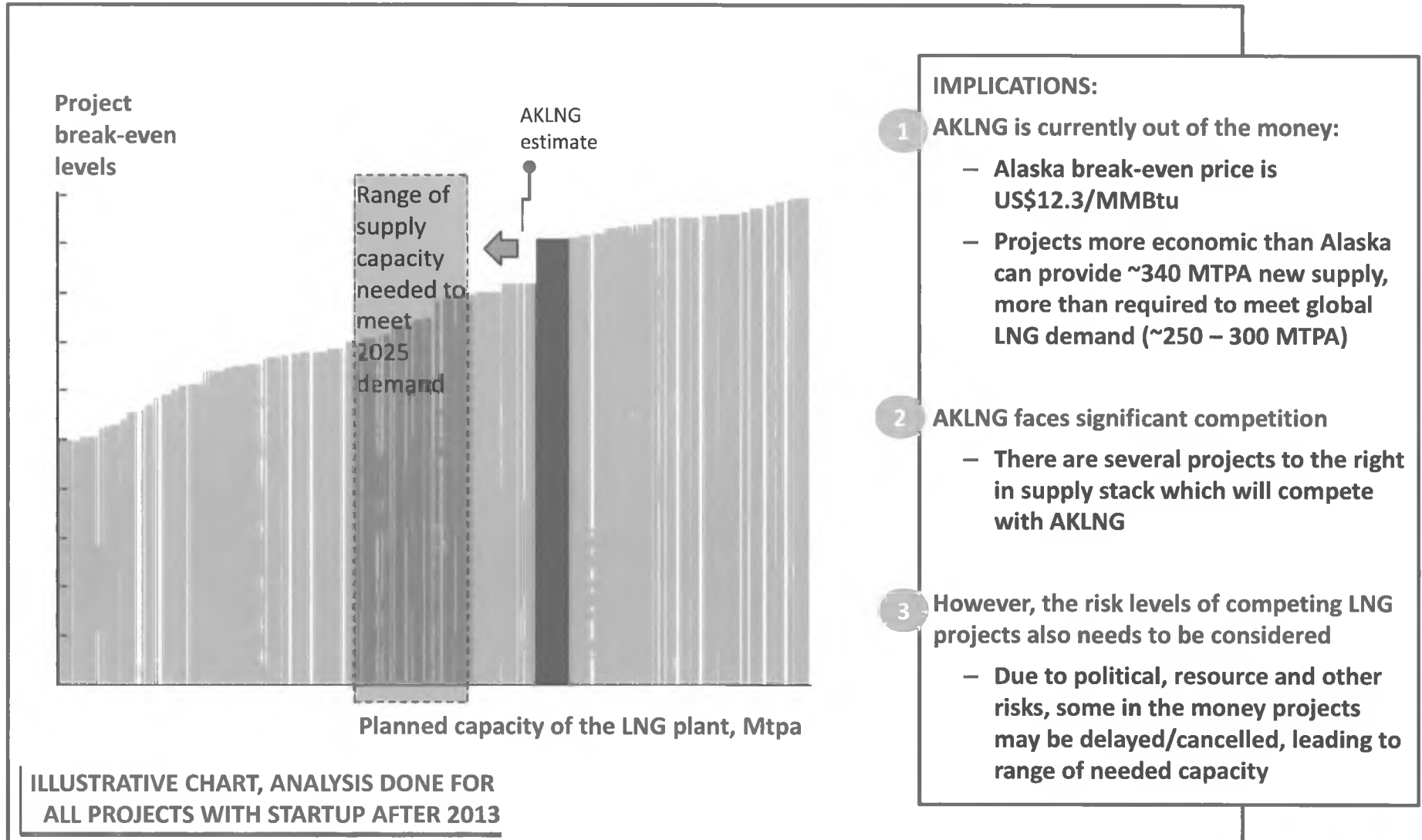
- Can increase the BEP:
 - Lower ambient temperature advantage (currently assumed 3.0 Mtpa²)
 - Negative effect of reduced oil production (currently excluded)
 - Capex increase, labor cost increase
- Can decrease the BEP
 - Capital productivity
 - Lower returns

¹ Discount rate used to calculate present value is 8.5% for mid-stream and 10% for upstream

² Effective ~17.4 Mtpa LNG capacity due to geographic advantage in Alaska

³ Assumes contractor would take on a project where revenue matches its costs, including expected return on equity

ON THE GLOBAL SUPPLY CURVE, AKLNG APPEARS TO CURRENTLY BE OUT OF THE MONEY, MODIFICATIONS REQUIRED FOR COMPETITIVENESS



¹ NPV=0 @ discounted at Weighted Average Cost of Capital

SOURCE: Team Analysis



GROWING LOWER-48 & CANADA APPROVALS MEAN THAT THE OPPORTUNITY FOR NEW PROJECTS COULD NARROW GOING FORWARD

Global LNG opportunity



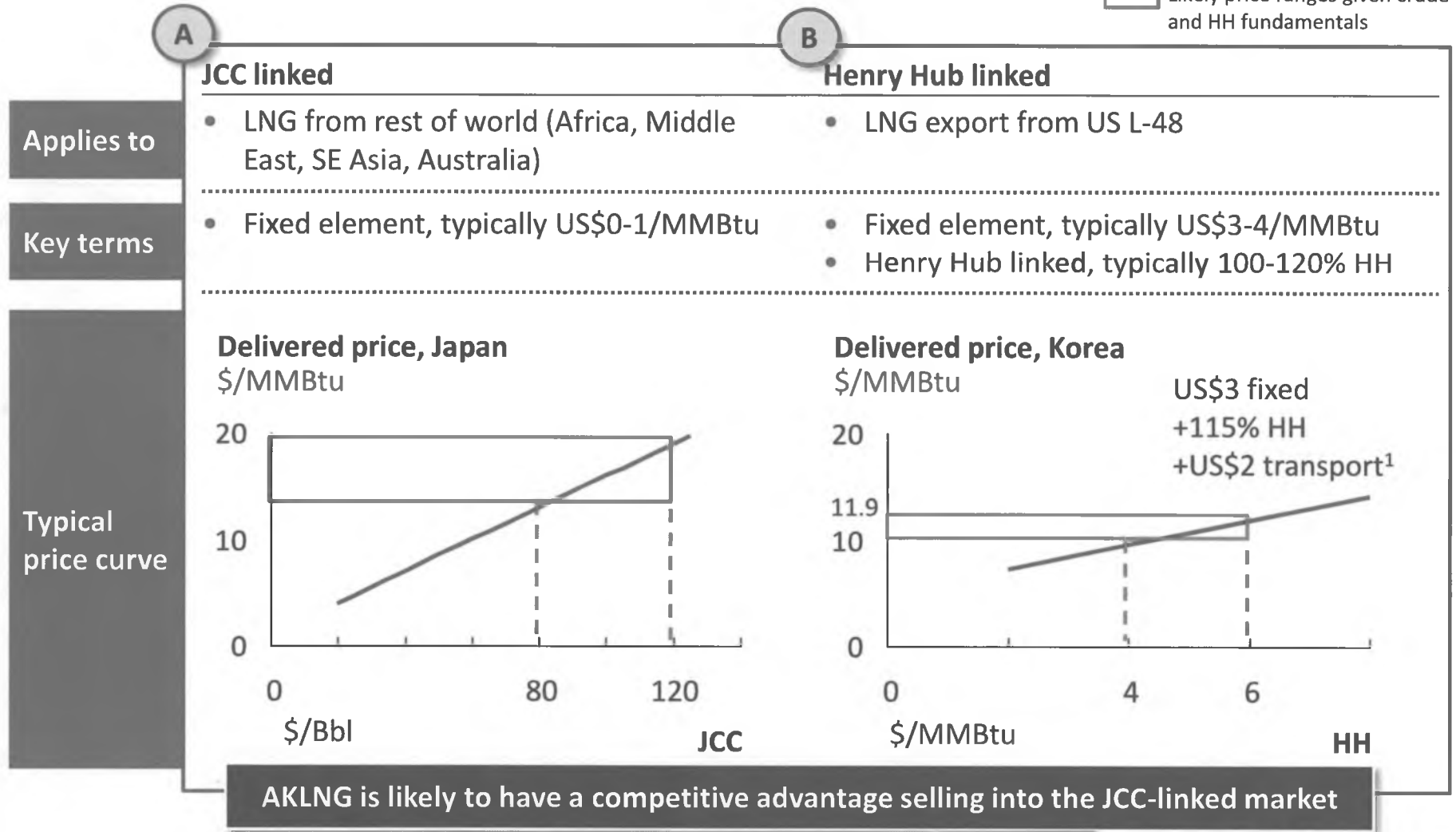
1 While some existing plants are seeing decline in supply, there are several projects already under construction, mostly in Australia

2 Approvals in lower 48 and Canada are adding to this supply fast

3 Estimated ~50 Mtpa remaining opportunity to 2020 and ~30 additional Mtpa opportunity to 2025 after existing and projected approvals

PROSPECTIVE FUTURE US LNG EXPORTS HAVE CREATED AN ALTERNATIVE TO TRADITIONAL CRUDE LINKED LNG CONTRACTING

□ Likely price ranges given crude and HH fundamentals



¹ KOGAS-Cheniere 2012 example, actual contract is FOB, indicative shipping added

Note: US L-48 LNG exports have used a very different contract structure from the rest of the world and this results in lower delivered prices for expected oil and gas price levels

SOURCE: Team Analysis

IN THE LONG RUN THROUGH 2030, LNG MARKET CAN EVOLVE WITHIN A BROAD RANGE



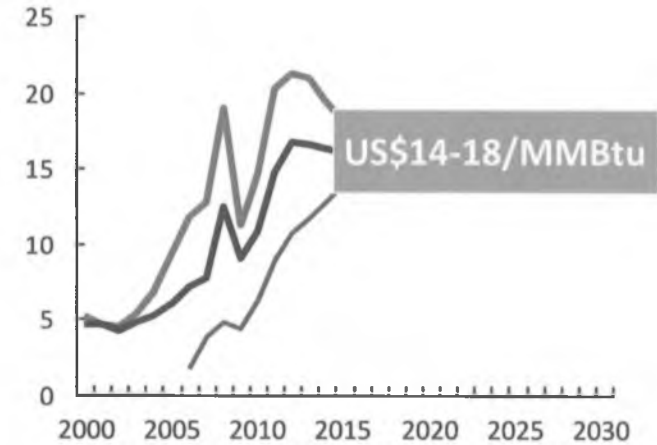
CASE

FACTORS AFFECTING

POSSIBLE PRICE RANGE

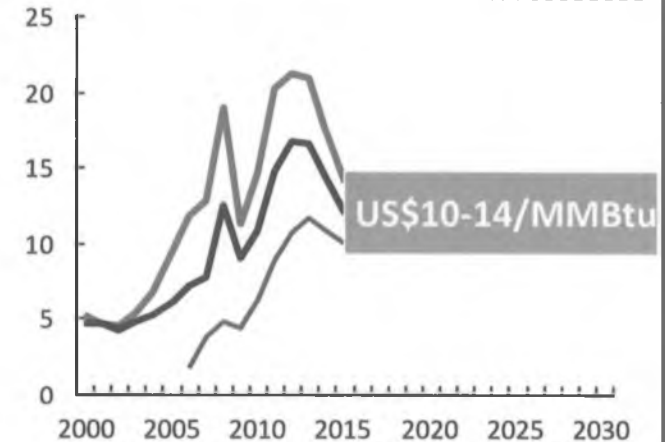
HIGH CASE

- North American LNG exports permitted at slow pace
- Non-NA Conventional supplies compete to serve the remaining demand
- Asian demand grows more rapidly than expected
- High cost LNG projects in Australia and Russia are the marginal supplies
- Sellers continue to demand high slope oil-linked contract terms



LOW CASE

- North American LNG supply is unconstrained and can meet all uncontracted demand
- Low cost non-NA conventional supplies compete directly with North American exports
- Henry Hub linked US exports become the price setter for Asian LNG



SOURCE: Team Analysis



THE MOVEMENT OF LNG PRICES WITHIN THESE RANGES IS EXPECTED TO DEPEND ON THREE KEY FACTORS

Supply-demand balance

- Volume of LNG required
 - Availability of LNG from planned and speculative sources (especially U.S./Canada)
 - Break-even gas price of the marginal supply source
-

Seller market power

- Ability of major producers to maintain pricing discipline
 - Ability and incentives of competing producers to undercut traditional price structures
-

Buyer market economics

- Competitiveness of LNG vs. other energy sources within the Buyers' market

SUMMARY: LNG MARKETS

- 1 The LNG market is characterized by capital intensive projects and long-term contracts across the supply chain
- 2 The LNG market is illiquid and opaque, with few players, in contrast with the liquid and transparent oil market
- 3 LNG demand is expected to grow quickly over the short and long-term, but supply sources are also rapidly expanding
- 4 AKLNG appears to be out of the money within the global LNG supply curve under the status quo; cost and /or fiscal modifications could enhance competitiveness



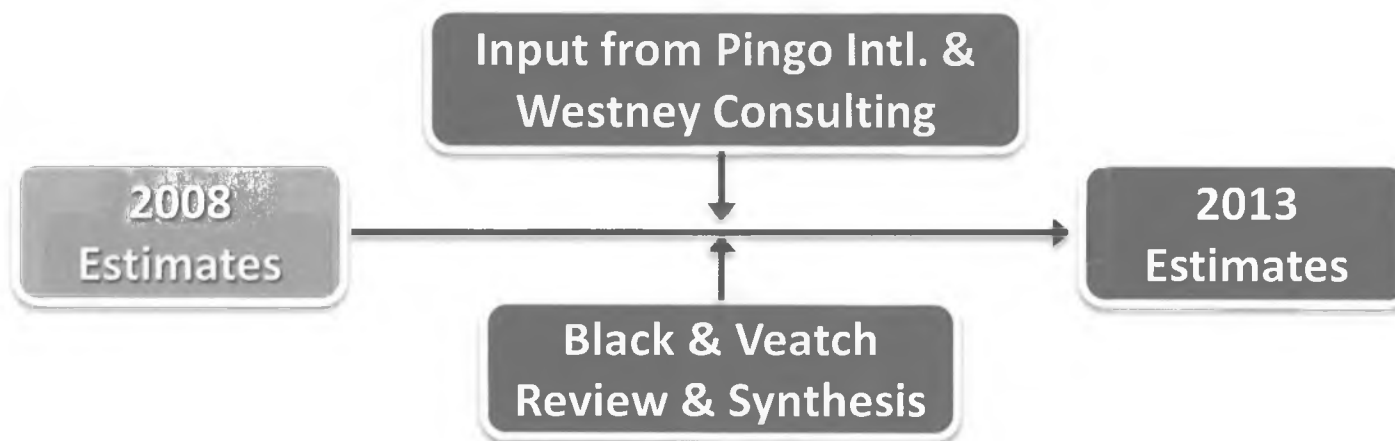
SUPPLY CHAIN ELEMENTS – SCOPE



- LNG Markets
- **Supply Chain Elements**
- Fiscal Framework
- Risk Allocation & Fiscal Structure

- Overview of the current capital cost estimates for the AKLNG Project
- Review of the capital structures that are likely to be applicable to AKLNG Project
- Discussion and assessment of applicable commercial structures for AKLNG Project

PROJECT CAPITAL COSTS UPDATE INCREASES BASELINE AKLNG PROJECT COST TO \$45 BILLION (2013\$)



Supply Chain Element	2008 Estimate ¹	2013 Updates	
		State's Estimate	Producers Estimate
GTP	\$5 Billion	\$10 Billion	\$10 - \$15 Billion
Pipeline	\$8 Billion	\$12 Billion	\$10 - \$15 Billion
LNG	\$14 Billion	\$23 Billion	\$17 - \$24 Billion
Total	\$27 Billion	\$45 Billion	\$37 - \$54 Billion

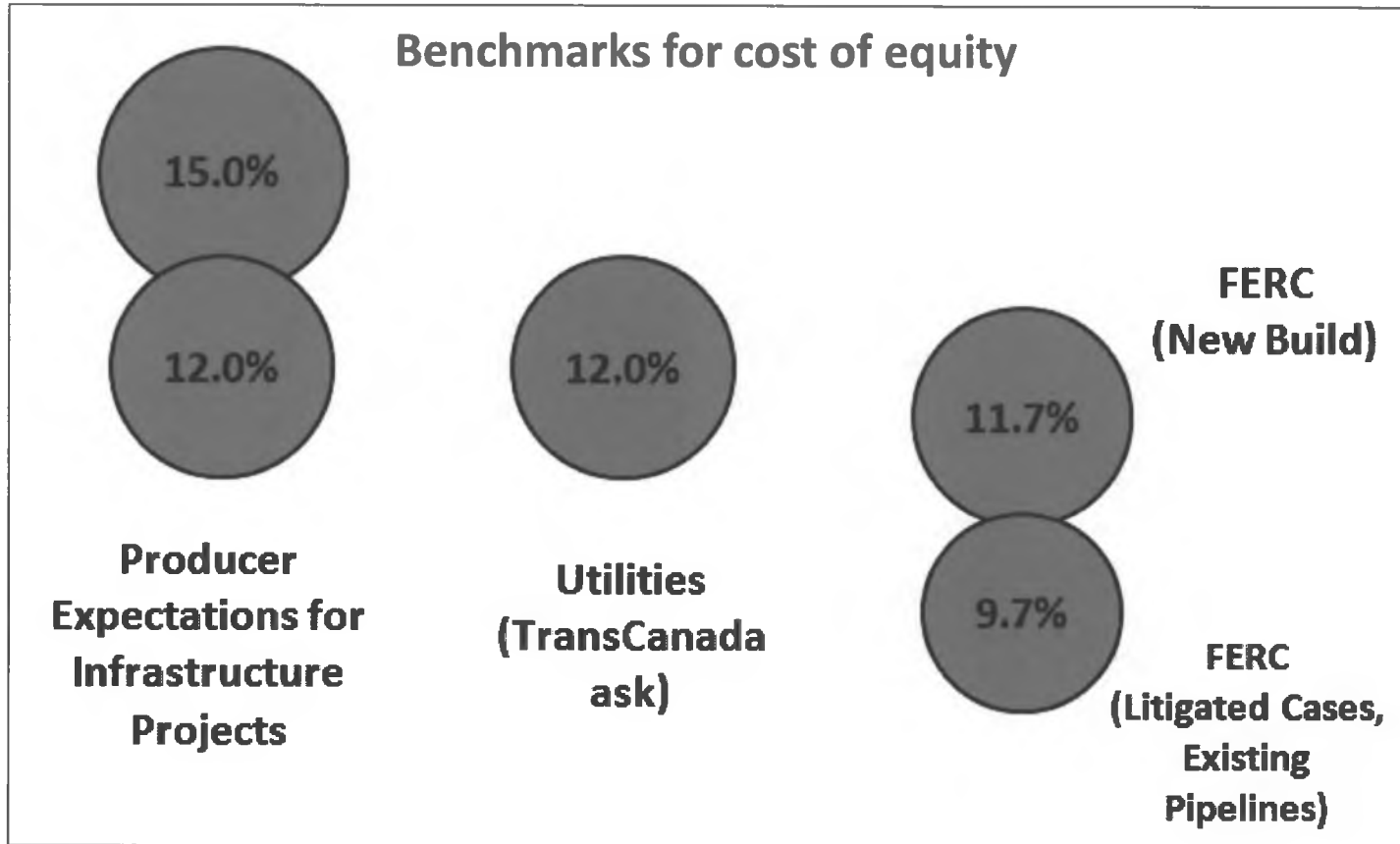
¹ Capital cost for a 2.7Bcf/d LNG project estimated by the State's Technical Team during AGIA proceedings.

CAPITAL STRUCTURES VARY FROM PROJECT TO PROJECT DEPENDING ON RISK PROFILE AND PARTNER PREFERENCES

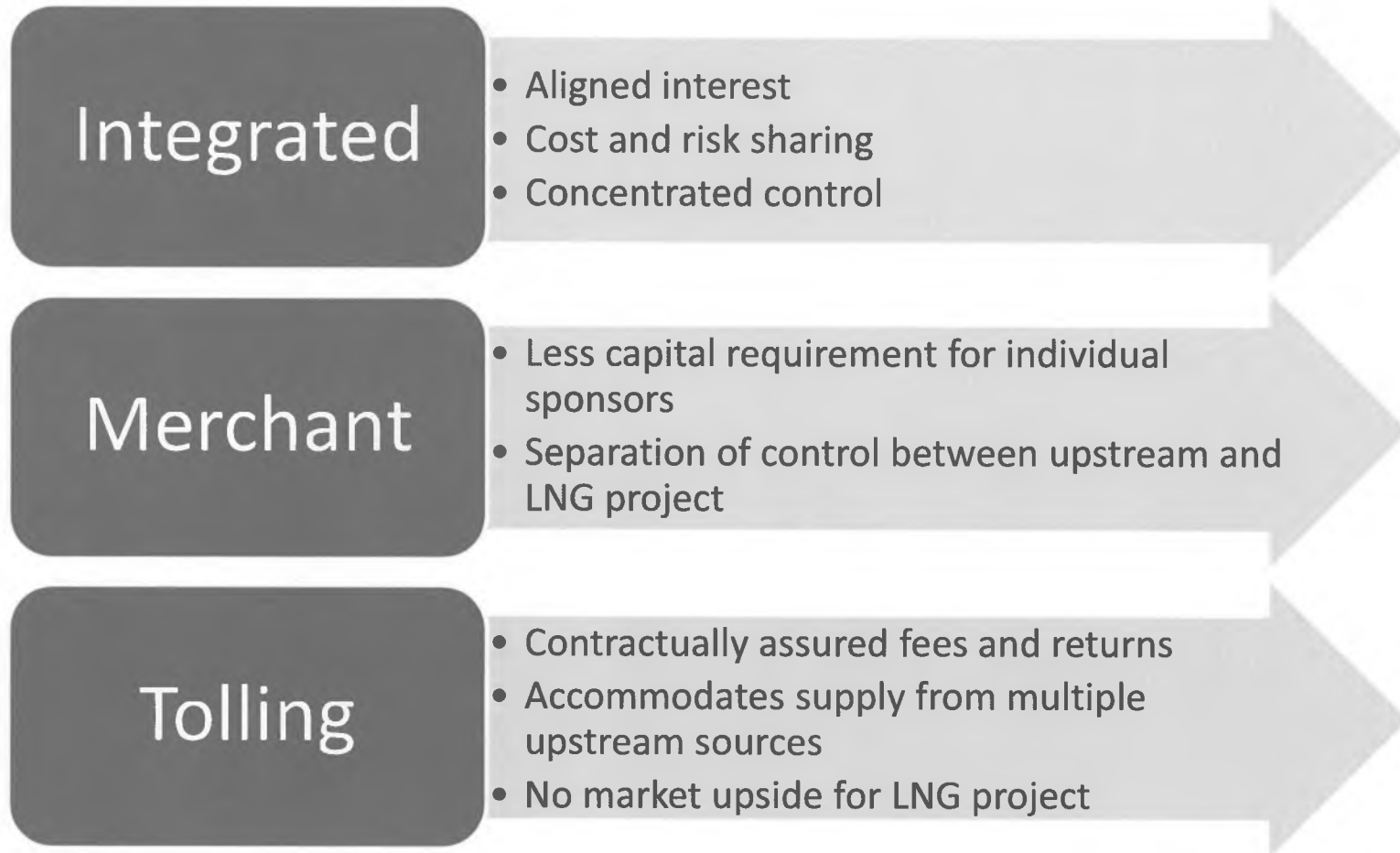
	Partners	Capital Structure (Debt/Equity)	Comments
PNG LNG	ExxonMobil Oil Search Santos National Petroleum Company of PNG Nippon Oil MRDC	70/30	Located at Caution Bay near Port Moresby, Papua New Guinea LNG is expected to have a capacity of 6.9 Mtpa and begin operations in 2014. PNG LNG is an integrated project and was the beneficiary of \$8.3 billion in loans and guarantees from public export credit agencies.
AP LNG	Origin ConocoPhillips Sinopec	70/30	Two train design with a capacity of 9.0 Mtpa and requiring an investment of \$23 billion, Australia Pacific LNG . Train 1 financed \$8.5 billion. Origin operates the upstream segment of the project; ConocoPhillips operates the LNG facility.
Gorgon LNG	Chevron Shell ExxonMobil Chubu Osaka Gas Tokyo Gas	0/100	Gorgon LNG is the world's largest capital investment in an integrated LNG project. The \$53 billion 15 mtpa project is currently under construction and first LNG is expected in 2015. The project is financed through equity contributions from the partners.
Qatargas 2	Qatar Petroleum ExxonMobil	70/30	Qatargas 2 Train 1 produces 7.8 Mtpa , Total is a partner in the second train, which also produces 7.8 Mtpa

The Debt / equity ratio that the market can support for a given project is driven by the financial strength of the partners

PRODUCER EXPECTATIONS OF ROE FOR INFRASTRUCTURE PROJECTS EXCEED FERC-APPROVED ROE FOR NEW BUILDS



COMMERCIAL STRUCTURE OF PROJECT INFLUENCES RISK AND CONTROL

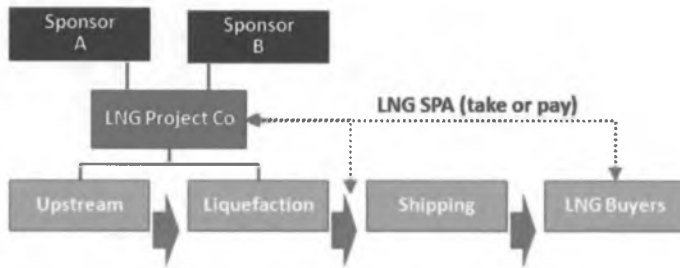


Each structure affects the operations and financing costs of the GTP, pipeline, LNG plant, and the shipper and impacts key criteria important to State - Commercial viability of AKLNG project, open access, expandability, transparency across the supply chain

LNG PROJECT COMMERCIAL STRUCTURES

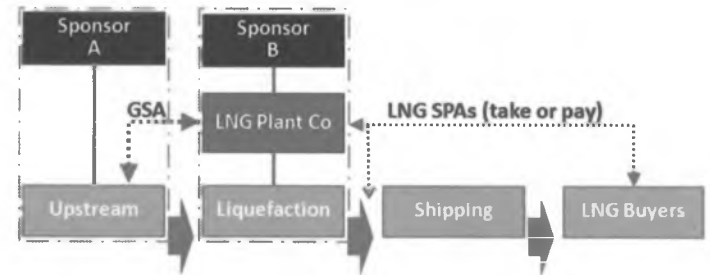
Integrated LNG Project Structure

- **One LNG Project Company**
 - Same multiple sponsors in the upstream and liquefaction segments
 - Common ownership interests across the LNG chain
 - Sales and Purchase Agreement (SPA) directly between LNG Project Co and LNG Buyers – either FOB or DES
 - Examples: PNG, QatarGas II, RasGas, Sakhalin II, Tangguh



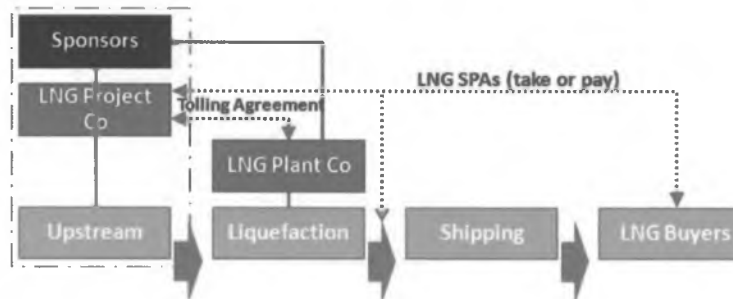
Non Integrated LNG Project Structure (Merchant)

- **Legal Separation Between Sponsors of Upstream and Liquefaction Segments**
 - Different shareholding interests between upstream, midstream and liquefaction
 - Gas Sales Agreement (GSA) between LNG Project Co/Borrower and Upstream shareholders
 - Examples: Peru LNG, QatarGas, NLNG (Nigeria), Brunei LNG



Tolling LNG Project Structure

- **LNG Liquefaction Plant Performs Services For a Fee From Upstream**
 - May have same or different sponsors in the upstream and LNG liquefaction facility
 - Usually limited recourse financing of LNG liquefaction facility with creditworthy tolling agreement counterparty
 - Examples: Egypt LNG, Atlantic LNG Trains 2-4



Sources: Sumitomo, B&V Research

KEY CHARACTERISTICS OF LNG PROJECT STRUCTURES

Structure	Advantages	Disadvantages
Integrated	<ul style="list-style-type: none"> • Equity owners may or may not act together to sell the LNG product from an integrated structure • Control over production • Aligned interests between owners • Cost sharing and potential tax benefits 	<ul style="list-style-type: none"> • Capital requirements are high and span the supply chain • Concentrated control makes expansions and entry of new participants difficult
Merchant	<ul style="list-style-type: none"> • Lower capital requirement if sponsors of upstream and LNG Project Co are different • Meets tax requirements for separate P&L center • Comply with local laws for government ownership of upstream project • Less control by upstream participants over liquefaction facilities 	<ul style="list-style-type: none"> • Less flexibility for equity participants in production of gas and selling LNG – sold uniformly by LNG Project Co • Commodity price risk exposure for LNG Project Co • Can be mitigated with variations of the merchant model, for example, by selling LNG back to project owners' marketing affiliate to insulate the project from risk • Exposure to negotiating power of upstream owners
Tolling	<ul style="list-style-type: none"> • Contractually assured fees and returns <ul style="list-style-type: none"> — Low market risk to LNG Plant Co — Mitigates upstream supply risk for LNG Plant Co • Potential tax benefits if title transfers are taxed • Accommodates supply from multiple sources, entities • Ability to attract other investors/owners to project – lower capital requirements • Facilitates project financing since liquefaction project revenues are not directly exposed to market risks 	<ul style="list-style-type: none"> • No participation in market upside for LNG Plant Co

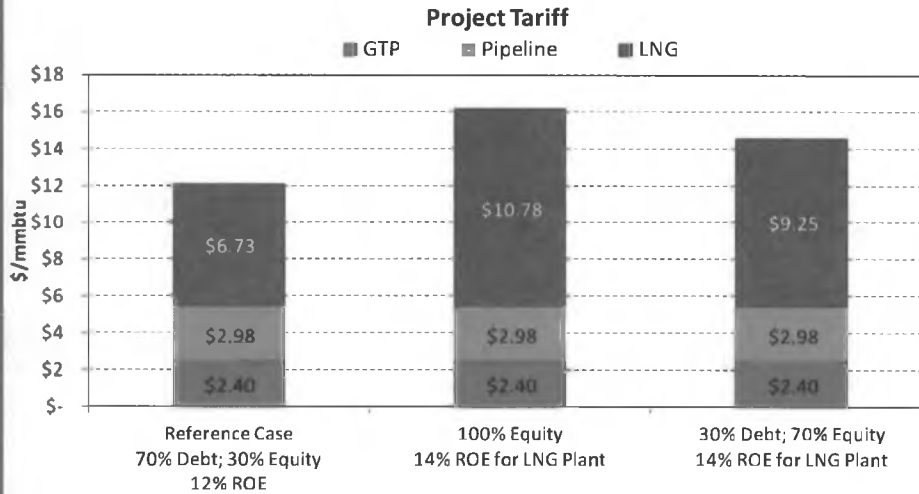
State does not participate in upstream

COMMERCIAL STRUCTURE OF AKLNG PROJECT COULD DRIVE MISALIGNMENT BETWEEN THE STATE AND PRODUCERS

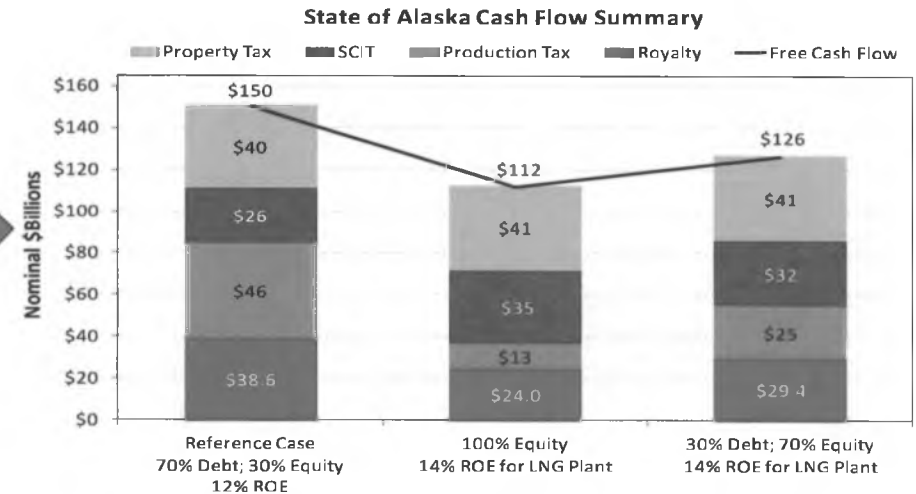
- A Producer-owned project creates risk for the State related to its fiscal revenues due to potential misalignment of interests between the Producers and the State
- The misalignment could be especially pronounced at the LNG Plant which does not fall under FERC's jurisdiction for establishing service rates
- Under various alternate project structures contemplated, there could be incentive for Producers to shift revenues between the upstream and the midstream segment of the project, as a way of increasing Producer take (and thereby reducing the State's take) from the project
- This analysis examines a scenario where the LNG plant's service rates are established using an equity-rich financing structure and with a relatively high return on equity

IT IS CRITICAL TO CREATE ALIGNMENT BETWEEN STATE AND PRODUCER INTERESTS TO ENABLE STATE RECEIVING ITS FULL SHARE OF VALUE FROM THE AKLNG PROJECT

Equity-rich financing structure drives a high tariff for LNG Plant



State could lose billions of dollars of value through misalignment



- Although the State could use regulations as potential safeguards, there is potential for misalignment of interests between the Producers and the State in a producer owned project
 - Areas of potential misalignment include need for transparency, open access and low tariffs
- Transparency within a producer-owned project into costs and cost allocation is likely to be an ongoing challenge for the State
- The risk of misalignment is higher with an LNG project than with a pipeline project driven by the absence of regulation of the LNG plant’s commercial structure or rate setting mechanism by FERC and other pertinent authorities
- Creating alignment between the State and Producers is critical for the State to receive the full value of the AKLNG project

SUMMARY: SUPPLY CHAIN ELEMENTS

- 1** Capital costs for AKLNG project are likely to remain uncertain through the development of the project
- 2** Total midstream project cost estimates from the AKLNG project sponsors range from \$39-\$54 billion
- 3** Complex LNG projects typically have an integrated commercial structure to give sponsors maximum control
- 4** AKLNG is expected to have an integrated structure; ensuring alignment of interests between the State and Producers is challenging and critical with a Producer-owned integrated project



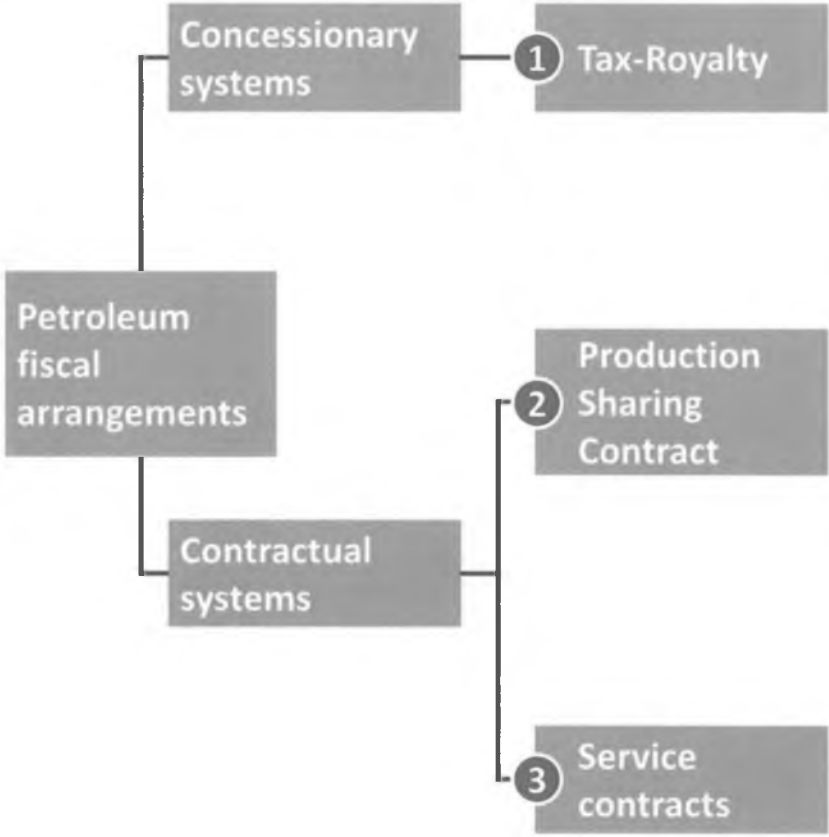
FISCAL FRAMEWORK – SCOPE



- LNG Markets
- Supply Chain Elements
- Fiscal Framework
- Risk Allocation & Fiscal Structure

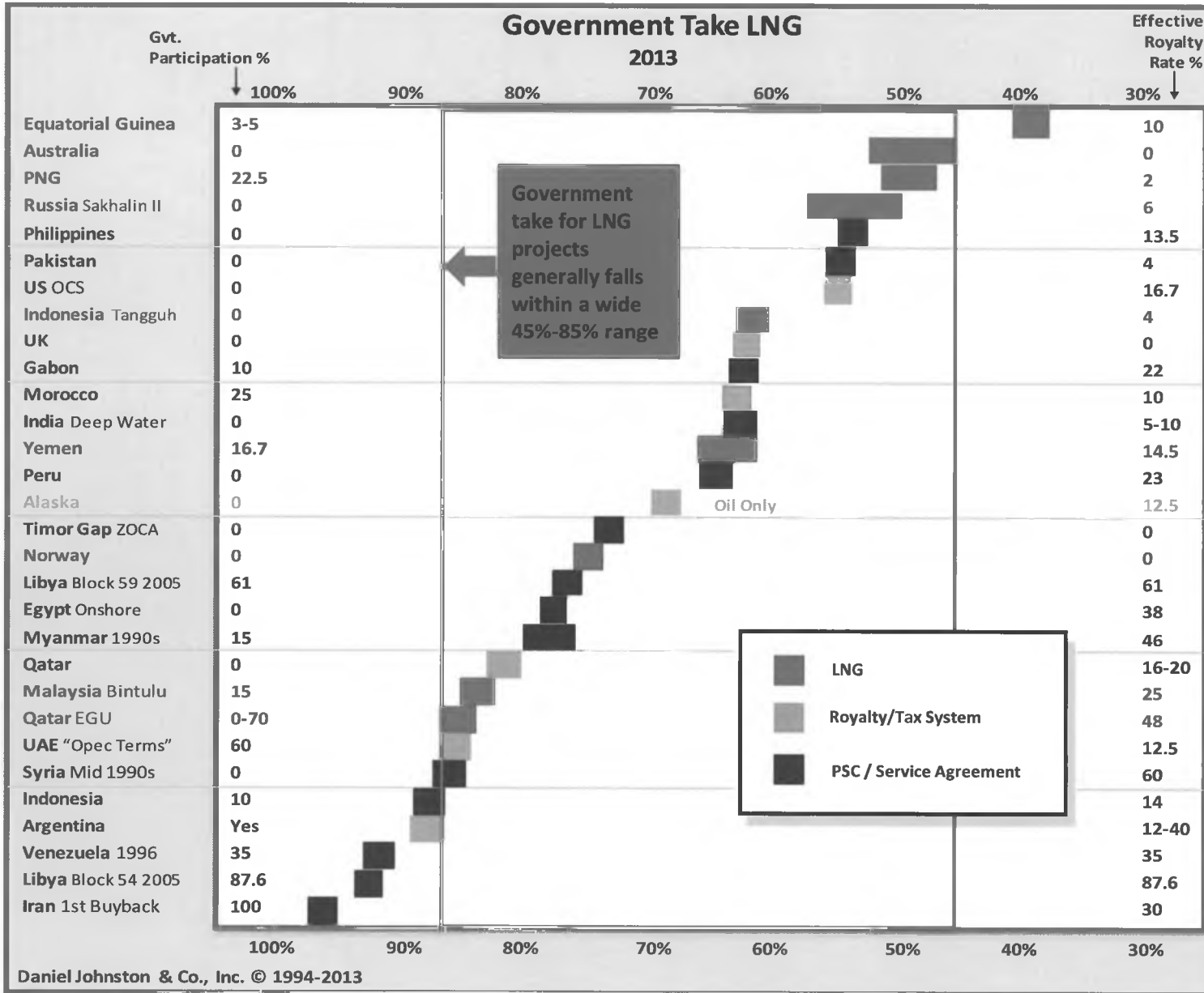
- Overview of the fiscal structures relevant to LNG projects worldwide and comparison with AKLNG Project
- Discussion and analysis of incentives that State could provide to help facilitate the AKLNG Project
- Assessment of how Alaska can leverage its royalty ownership position – royalty in kind relative to royalty in value

THREE MAIN FISCAL SYSTEMS ARE IN USE FOR OIL AND GAS AROUND THE WORLD

Fiscal system	Simple description	Examples
 <p>Petroleum fiscal arrangements</p> <p>Concessionary systems</p> <p>Contractual systems</p> <p>1 Tax-Royalty</p> <p>2 Production Sharing Contract</p> <p>3 Service contracts</p>	<ul style="list-style-type: none"> Title to the hydrocarbons transfers to the company at the wellhead. The host government receives royalties (% of revenues or production) and taxes (% of profits) from the company. Title to hydrocarbons resides with host government Production in kind is shared between the contractor and the government at the export point <ul style="list-style-type: none"> – A basic PSC has royalty, cost oil, profit oil and taxes Title to hydrocarbons resides with host government The contractor is reimbursed and paid a fee, typically in cash. These are rare and unpopular 	<ul style="list-style-type: none"> U.K. U.S. Norway Australia Russia Canada Nigeria Angola Russia Algeria Kazakhstan Indonesia Qatar Iran Iraq Mexico Ecuador Russia

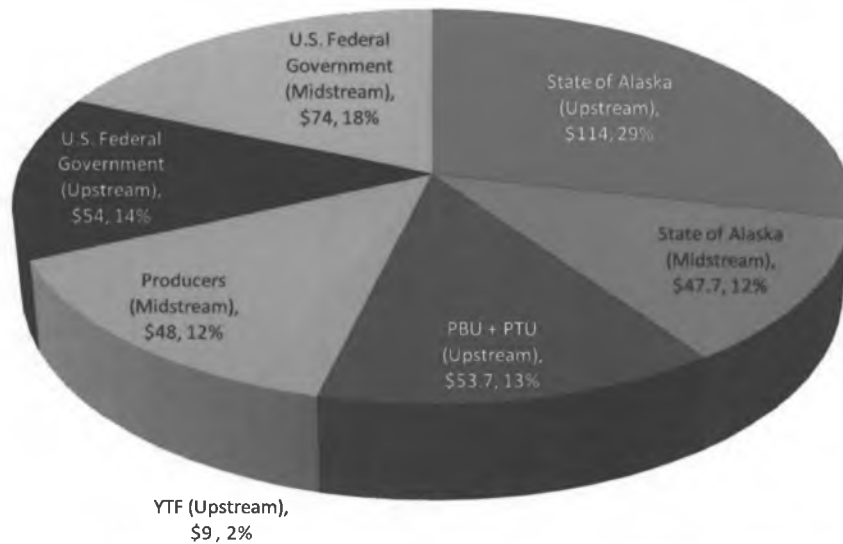
SOURCE: Team Analysis

GOVERNMENT TAKE ON LNG PROJECTS, BY COUNTRY



GOVERNMENT TAKE IN ALASKA IS BETWEEN 70%-80% UNDER SB21/MAPA FISCAL STRUCTURE WITH SIGNIFICANT FEDERAL GOVERNMENT SHARE

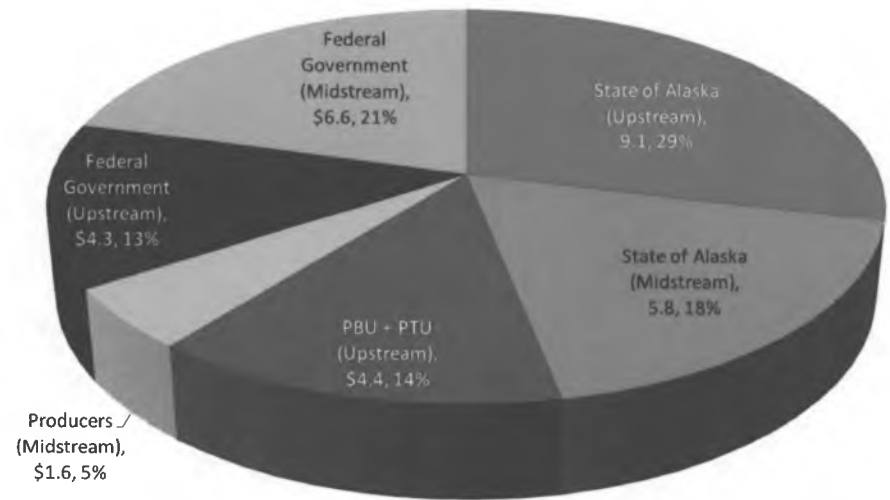
Gasline Impact Total Cash Flow by Stakeholder (Billions)



\$328 Billion in Total Cash Flow

72% Government Share

Gasline Impact NPV₁₀ by Stakeholder (Billions)



\$31.8 Billion in Total NPV

81% Government Share

* Negative NPV for YTF Fields of \$-0.1B not shown

With current levies alone, government take is significant in the context of LNG projects worldwide

FISCAL & NON-FISCAL LEVERS ARE AVAILABLE TO INFLUENCE AKLNG PROJECT

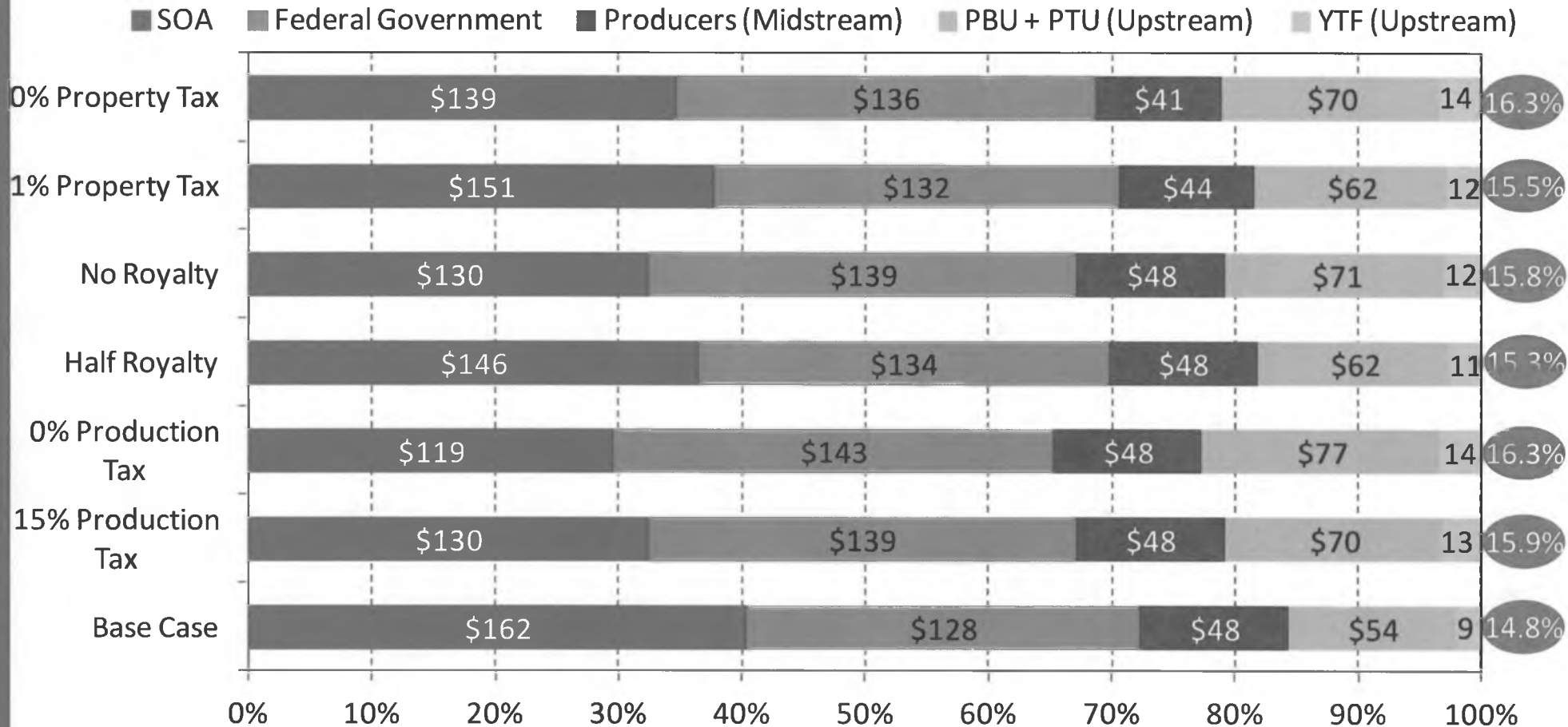
Sample levers	Benefits	Testing impact
<ul style="list-style-type: none"> • Governments have multiple fiscal levers, e.g., <ul style="list-style-type: none"> – Replace royalty with profits-based tax – Accelerated depreciation – Capital allowance (Deduct more than 100% of capex) – Tax credits – Enhance lifting entitlement – Direct capital contributions • Governments have various non-fiscal options: <ul style="list-style-type: none"> – Stabilizing provisions – Intl. arbitration dispute resolution – Increase IOC lifting entitlement (for booking barrels) 	<ul style="list-style-type: none"> • Results are: <ul style="list-style-type: none"> – Lower Government Take – Defer Government Take – Reduce cost exposure – increases IOC IRR – Reduce IOC Risk • Results are: <ul style="list-style-type: none"> – Reduce IOC Risk – Enhance IOC comfort/confidence – IOCs should be more willing to invest 	<ul style="list-style-type: none"> • Effect: <ul style="list-style-type: none"> Internal Rate of Return Break-even prices NPV Government take • Will help determine level of impact in attracting new investment • Effect is difficult to see with financial metrics

SOURCE: Team Analysis



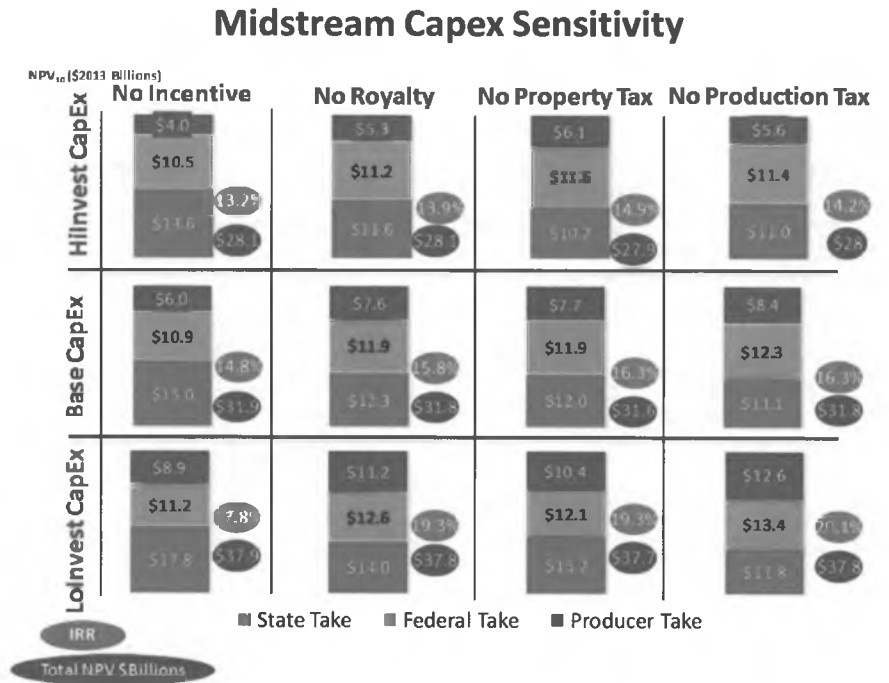
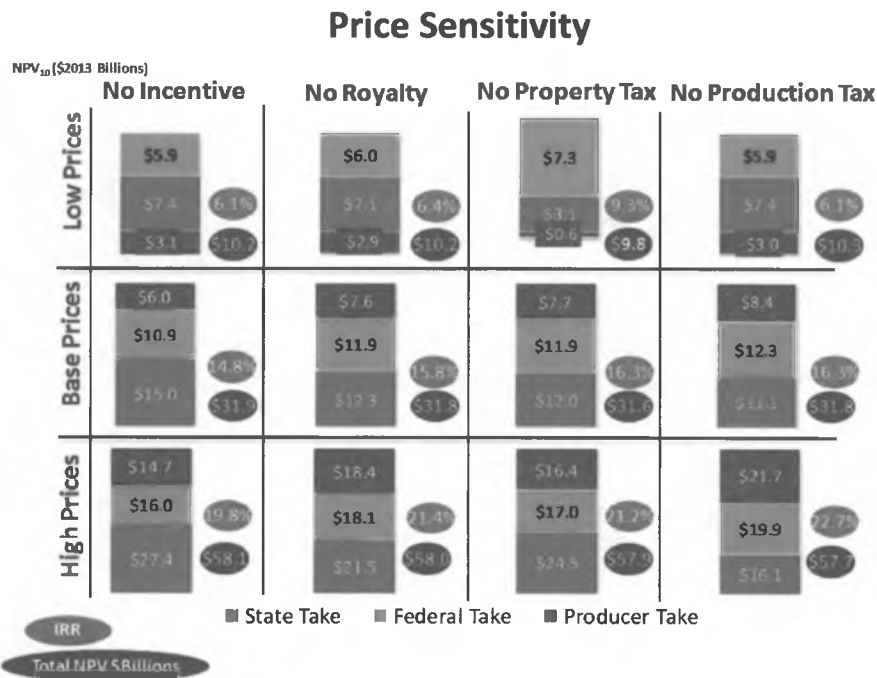
ELIMINATING ROYALTY, PRODUCTION TAX, OR PROPERTY TAX BRINGS GOVERNMENT TAKE FOR AKLNG PROJECT DOWN TO 65-70%

Share of Cash Flow



% Producer (Upstream + Midstream) IRR

IMPACT OF FISCAL LEVERS UNDER DIFFERENT PRICE AND CAPEX MARKET CONDITIONS - NPV₁₀ (\$2013 BILLIONS)



- The analysis demonstrates that market prices dominate the AKLNG project's economics dwarfing all other variables considered
- Royalty, property tax and production tax reductions are beneficial in improving Producer NPVs and IRRs from the project and reducing State take.
- Overall government take impacts are dampened because ~35% of value transferred from the State to Producers goes to the Federal Government through federal income taxes
- To the extent that the State provides incentive to the AKLNG project through a value transfer, alternate mechanisms that reduce the leakage of this value to the federal government could be more effective in benefitting the AKLNG project

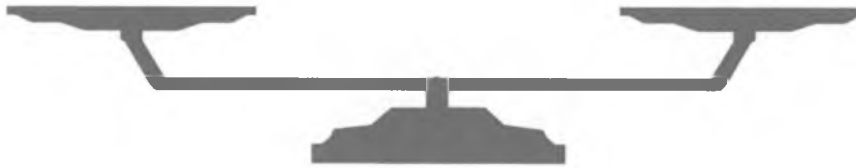
ROYALTY ALTERNATIVES – IN KIND OR IN VALUE

- **The State has an option of taking its royalty share from the AKLNG Project either in kind or in value**
- **Taking royalty in kind can be an incentive to Producers that potentially relieves their obligation to treat, transport, liquefy, ship and market the State's share of gas, depending on the mechanism and location of transfer of gas to the State**
- **There are various considerations with regard to the State taking its royalty (or tax share) in kind that must be taken into account**



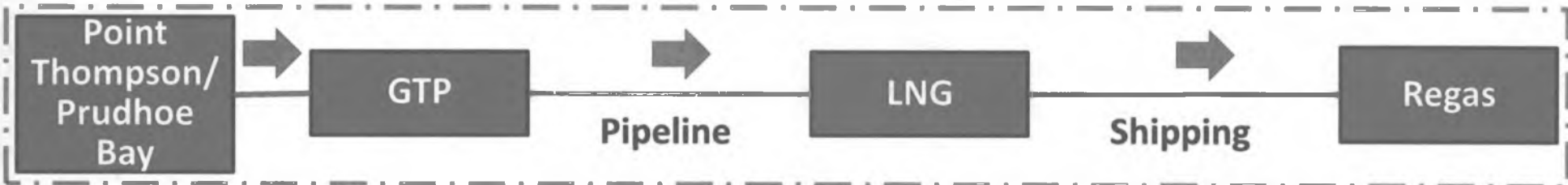
ROYALTY IN KIND VS. ROYALTY IN VALUE

	Advantages	Disadvantages
Royalty In-Kind	<ul style="list-style-type: none"> • Attractive to producers • Reduces valuation disputes • Reduces commercial uncertainty for project • Provides the State with better market insight 	<ul style="list-style-type: none"> • Exposes State to various additional risks • Requires modifications to current legislation and authority • Requires marketing expertise • Credit requirements for shipper agreements
Royalty In-Value	<ul style="list-style-type: none"> • Status quo, familiarity • No direct firm capacity commitments • RIV auditing and management capabilities currently exist 	<ul style="list-style-type: none"> • Lack of transparency • No third party access (TPA) • Valuation disputes: higher of; actual market price realized • Gaming over cost deductions • Not preferred choice of producers



Note: Equity participation with or without In-Kind Gas is another alternative for the State to consider and has been addressed separately

RIK RISK PROFILE IS INFLUENCED BY THE LOCATION OF TITLE TRANSFER FROM THE STATE TO BUYER



Risks:	Inlet GTP	Inlet Pipeline	Inlet LNG	FOB	DES
	<ul style="list-style-type: none"> •Volume •Price 	<ul style="list-style-type: none"> •Volume •Price •Capex (GTP) •Operational risk (GTP) •CO₂ disposal & gas quality •Balancing/scheduling •Credit risk (GTP) •Force majeure 	<ul style="list-style-type: none"> •Volume •Price •Capex (GTP+P) •Operational risk (GTP+P) •CO₂ disposal & gas quality •Balancing/scheduling •Credit risk (GTP+P) •Force majeure 	<ul style="list-style-type: none"> •Volume •Price •Capex (GTP+P+LNG) •Operational risk (GTP+P+LNG) •CO₂ disposal & gas quality •Balancing/scheduling •Credit risk (GTP+P+LNG) •Force majeure 	<ul style="list-style-type: none"> •Volume •Price •Capex (GTP+P+LNG+S) •Operational risk (GTP+P+LNG+S) •CO₂ disposal & gas quality •Balancing/scheduling •Credit risk (GTP+P+LNG+S) •Force majeure
Risk Profile					
Rewards:	Inlet GTP	Inlet Pipeline	Inlet LNG	FOB	DES
	15% JCC – S – LNG – P –	15% JCC – S – LNG – P –	15% JCC – S – LNG – RP	15% JCC – S – RP	15% JCC
Reward Amt	GTP – RP	RP			
Risk Premium:	Inlet GTP	Inlet Pipeline	Inlet LNG	FOB	DES
	.5% - 1.5%	.25% - .75%	.5% - 1.5%	.25% - .75% (of JCC)	

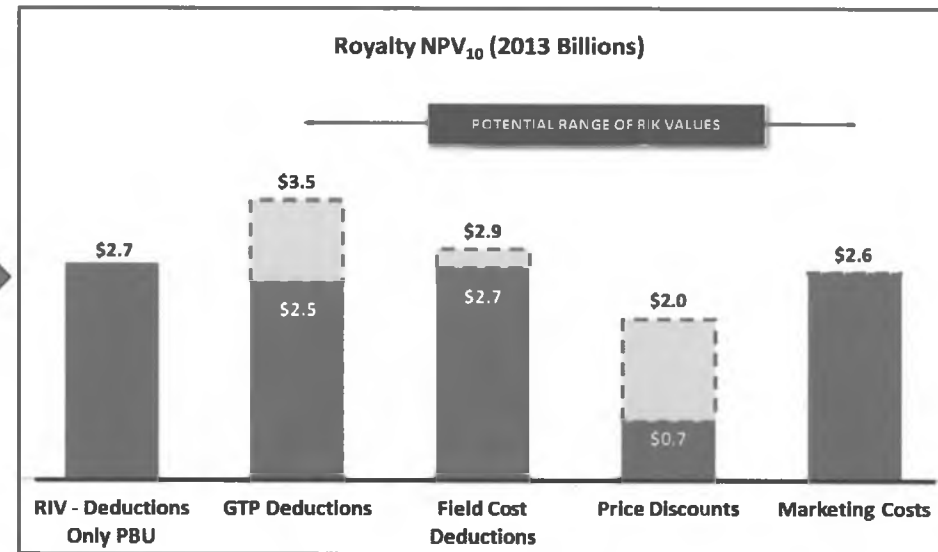
Abbreviations: GTP: Gas Treatment Plant JCC: Japanese Crude Cocktail
 P: Pipeline RP: Risk Premium
 S: Shipping

Source: Team assessment

IMPLEMENTING RIK PRESENTS CHALLENGES AND HENCE, COSTS FOR THE STATE RELATIVE TO RIV

NPV losses to the State from going RIV could be as much as 75% of value relative to RIV

COST DRIVER	RIV	RIK
GTP Costs	Only PBU is currently allowed to deduct GTP costs for royalty calculation	GTP costs will likely be borne by State for all fields
Upstream Field Cost Allowance ("FCA")	PBU is currently allowed an Upstream FCA	Upstream FCA for all fields, potentially
Higher of Provision	Higher of provision creates price protection, offers ~3% uplift in royalty value	No higher of provision for price protection
Sales Price Discount	Theoretically, State achieves a portion of Producer's full value	State expected to suffer discounted prices due to market inexperience and lack of diversity of supply; Discount to LNG sales price of the LNG multiplier in the 1% to 3% range examined as range
Marketing Costs	No marketing costs, but audit costs	Marketing costs of \$7-\$15 million a year
Credit Costs	Credit cost borne by Producers	Borne by State



RIK CREATES ADDITIONAL RISK AND COST FOR THE STATE RELATIVE TO RIV

- **Taking its royalty in kind could potentially expose the State to significant risks including:**
 - The State would need to build its own marketing organization to take care of origination, logistics, contract administration, accounting, etc. if it chooses to market the gas
 - State would face challenges in competing with the Producers who have well established LNG marketing expertise and global portfolios
 - State would be subject to counterparty risk in all of the contracts it enters into across the LNG supply chain
 - State would need to make firm capacity commitments along the LNG supply chain, which could total up to \$1 billion per year
 - State could realize negative royalties if the LNG price is too low
 - State would face production volume risk (if production exceeds or falls short of its sales commitments)
- **Producers have the experience of dealing with market uncertainties and would need to help the State address these risks if an RIK path is pursued**

SUMMARY: ALASKA FISCAL FRAMEWORK

- 1** Government take, at 70-85%, is high for a project of this complexity, and estimated IRR of approximately 15% may be insufficient for Producer investment relative to their alternatives
- 2** Well designed incentives to lower project costs and modify fiscal structure can help make the AKLNG project competitive in market
- 3** The State taking its royalty as RIK could result in a substantial increase in risk & potential loss of value for the State – Producers have more experience managing associated risks



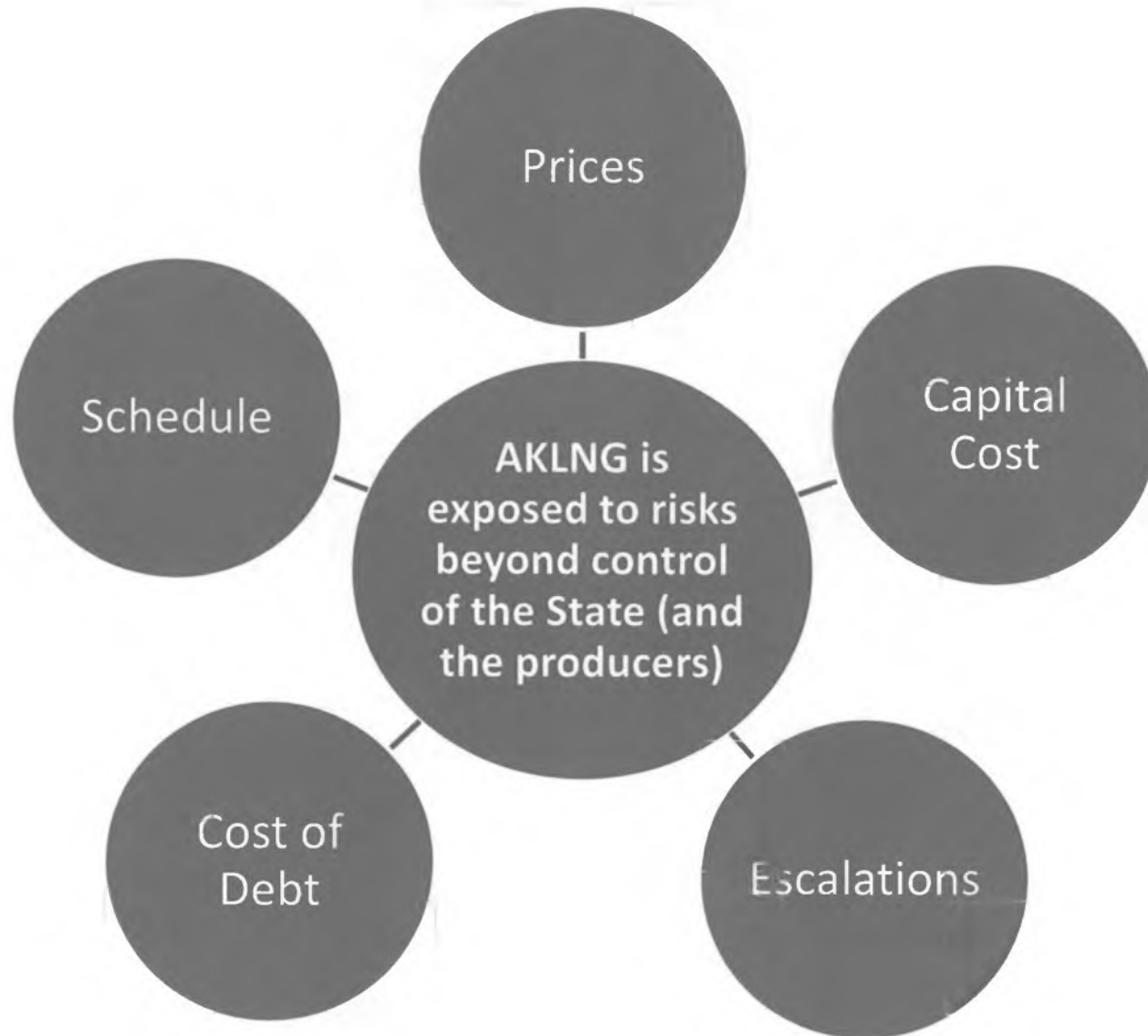
RISK ALLOCATION & COMMERCIAL STRUCTURE – SCOPE

- LNG Markets
- Supply Chain Elements
- Fiscal Framework
- Risk Allocation & Fiscal Structure

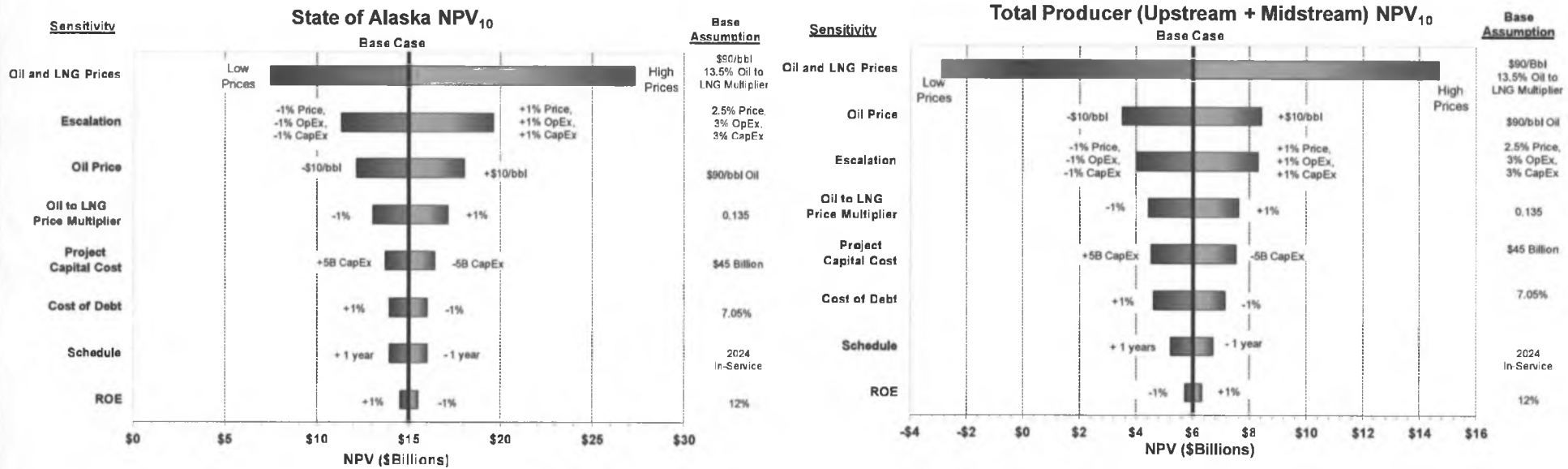


- Overview of key risks that could impact the AKLNG Project stakeholders and risk management
- Assessment of alternatives for financial, equity participation by State in AKLNG Project

THERE ARE VARIOUS UNCERTAINTIES RELATED TO THE AKLNG PROJECT THAT COULD IMPACT THE ECONOMIC BENEFITS TO THE DIFFERENT STAKEHOLDERS



PRICE AND CAPITAL COST RELATED UNCERTAINTIES EMERGE AS THE KEY FACTORS DRIVING THE PROJECT ECONOMICS



¹ Base Price = \$90/bbl oil price in \$2013; LNG Price per MMBtu = 0.135*Oil Price + \$1
 High Price = \$120/bbl oil price in \$2013; LNG Price per MMBtu = 0.15*Oil Price + \$1
 Low Price = \$60/bbl oil price in \$2013; Henry Hub Price = \$4/MMBtu in \$2013; LNG Price per MMBtu = HH+\$6

² The escalation sensitivity captures a variation in the assumption related to annual change in capital costs, operating costs and oil and gas prices

RISK ALLOCATION AND MANAGEMENT

Cases of risk allocation

- Cost and time risks in **project execution** depend on the nature and extent of project organization apart from market factors
 - Of the **recent LNG projects**, most have a **single operator** for upstream, transport and liquefaction
 - **Integrated project** case has been successful in **high cost project execution** (Snøhvit case example)

Cases of risk mitigation

- **Market risk management** is executed by LNG projects in two ways:
 - **Pre-FID commitments:** Majority of project volumes are contracted before FID to ensure market. Example: Gorgon, APLNG
 - **End user participation:** Several projects have equity stake of end buyers providing ensured-market for corresponding equity volumes. Example: Tangguh, Sakhalin II

State participation and implications

- Where the **Government participates** in LNG projects is usually via **NOCs** with LNG majors who bring in LNG project experience
- **State's equity participation** in the project **can allow** state to capture an **upside** in prices but exposes it **further** to a **down-side**
- Examples: Snøhvit, Yemen LNG, Angola LNG

EQUITY PARTICIPATION BY THE STATE OF ALASKA COULD HAVE TANGIBLE BENEFITS FOR THE PROJECT AS WELL AS THE STATE

- To the extent that the State transfers value to the Producers through a modification of fiscal terms as an incentive for the AKLNG project, **obtaining an equity interest in the project in exchange for that transfer of value** is more beneficial to the State than a simple reduction in fiscal take
- **Greater alignment of economic interests** between the State and Producers
- State ownership **lowers the upfront capital cost** to Producers creating potential economic uplift
- Allows for **TCPL equity participation** and operation of the pipeline and GTP
- Equity in all phases could facilitate greater **transparency in the AKLNG Project**
- Allows State to influence **access for third parties** in the most critical potential bottlenecks of the project – pipeline and marine terminal
- Equity investment in the supply chain, while allowing SOA a seat at the table, **does not necessarily provide for a vote in the decision making process**
- **Joint Venture Agreement structuring** is critical

ALTERNATIVES FOR THE STATE TO PARTICIPATE WITH AN EQUITY INVESTMENT IN THE AKLNG PROJECT – DESCRIPTION

Three different alternative structures for equity participation for the State were considered as indicative examples:

Equity Alternative



- The State makes an equity investment across the midstream and receives an equivalent share of gas produced as royalty and tax gas
- Royalties and production tax for oil would continue to be received under SB21/MAPA structure with all upstream costs being allocated to oil
- The analysis assumes a 70/30 debt equity structure for the State's investment with a 5% cost of debt and a 12% return on equity
- Two different equity investment levels were considered as representing lower and upper bounds on the State's equity participation – 15% and 35%

100% State Ownership of Pipeline



- The State invests sufficient equity to entirely own the pipeline component of the midstream
- Producers would pay a tariff to the State for transportation services on the pipeline
- The Producers benefit from the State's lower cost of debt at 5% and a low return on equity requirement of 6% (intended to be equivalent to returns on the Constitutional Budget Reserve Fund) provided as an incentive to the Producers
- The State would benefit through lower netbacks for royalty and production taxes
- To provide an upper and lower bound on the State's contribution, the analysis examines two scenarios, one financed with 100% debt and the other with 100% equity

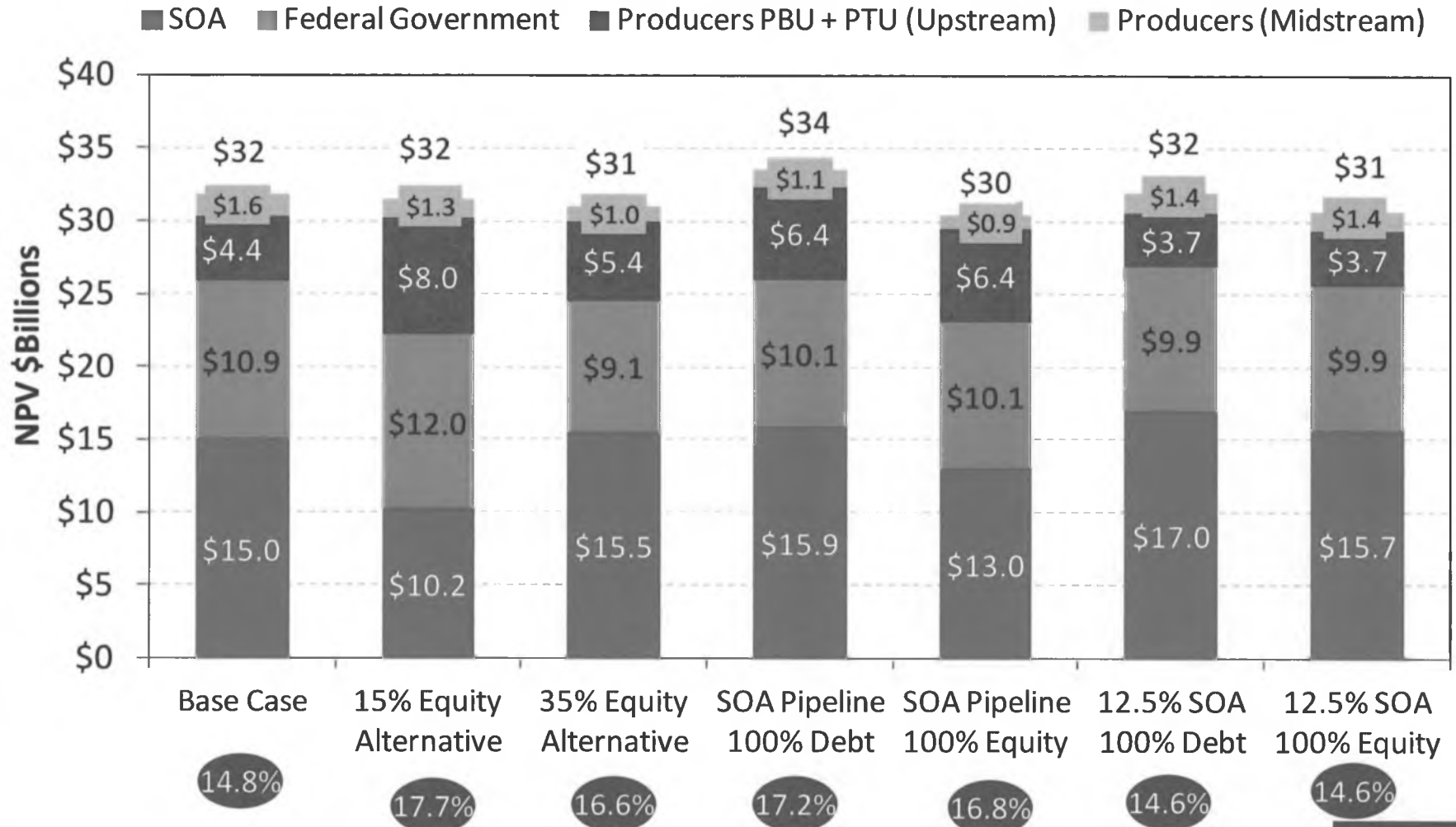
12.5% State Ownership of Midstream



- The State invests to have a 12.5% equity stake across the midstream corresponding to an approximation of its royalty share
- The State's share of the capacity would be utilized to treat, transport and liquefy royalty gas
- The State benefits from having a lower cost of debt at 5% and a low return on equity requirement of 6% (intended to be equivalent to returns on the Constitutional Budget Reserve Fund) rather than allowing a netback based on the Producers higher cost of debt and ROE requirements
- To provide an upper and lower bound on the State's contribution, the analysis examines two scenarios, one financed with 100% debt and the other with 100% equity

STATE EQUITY PARTICIPATION AT APPROPRIATE LEVELS COULD ALLOW SOA AND PRODUCERS TO RETAIN HIGHER SHARE OF PROJECT REVENUES

Stakeholder NPV₁₀ Comparison



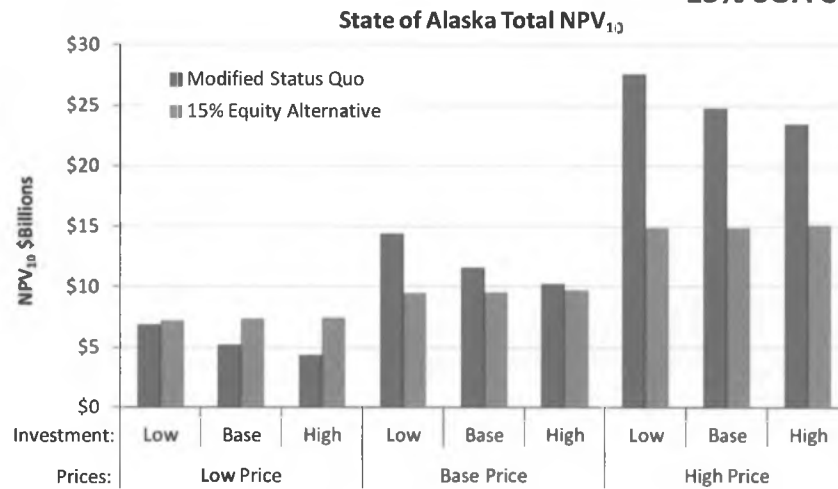
⊙ % Producer (Upstream + Midstream) IRR

APPROPRIATE LEVEL OF STATE EQUITY PARTICIPATION NEEDS TO BE BALANCED TO ACHIEVE BENEFITS TO SOA AND PRODUCERS

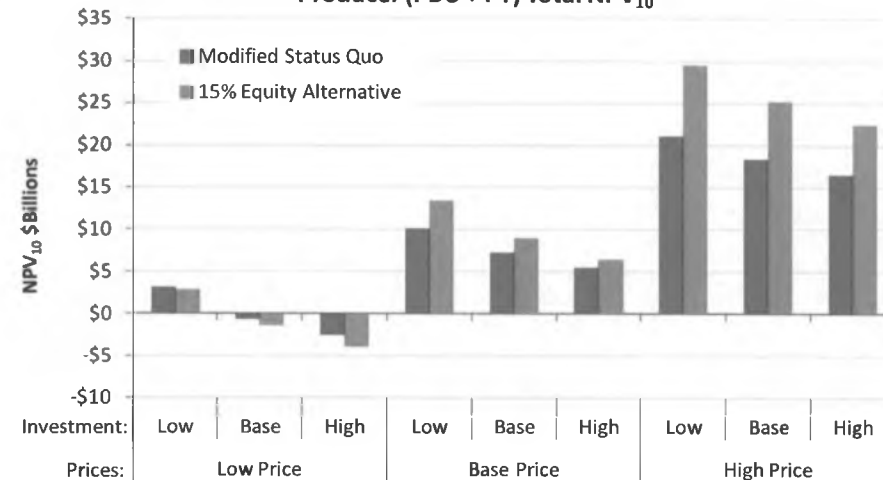
- Scenarios examining a range of capital costs and market prices were assessed to understand whether the equity alternative provides positive economic value to the State relative to status quo under each of the scenarios
- 15% and 35% state equity participation levels in combination with equivalent royalty gas & tax gas were considered as indicators of lower and upper bounds to the State's equity participation
- SB21/MAPA fiscal structure as currently applicable does not include production credits for gas. This analysis assumes a modified status quo wherein the production credits are extended to reflect a \$5/BOE credit for gas, similar to the credit extended to new oil production
- The analysis estimated and compared AKLNG project economics under modified status quo and under the equity alternative for both the State and the Producers across a combination of three price and three capital cost scenarios

EQUITY PARTICIPATION AT 35% MORE BENEFICIAL TO STATE THAN AT 15%

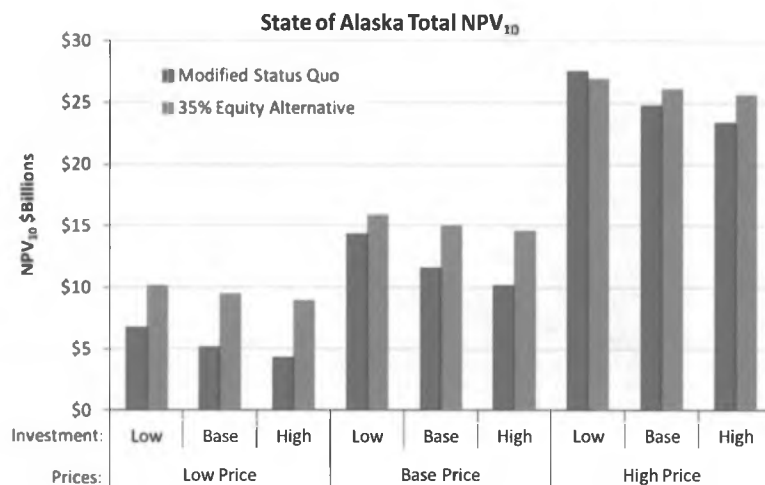
15% SOA equity participation – NPV₁₀



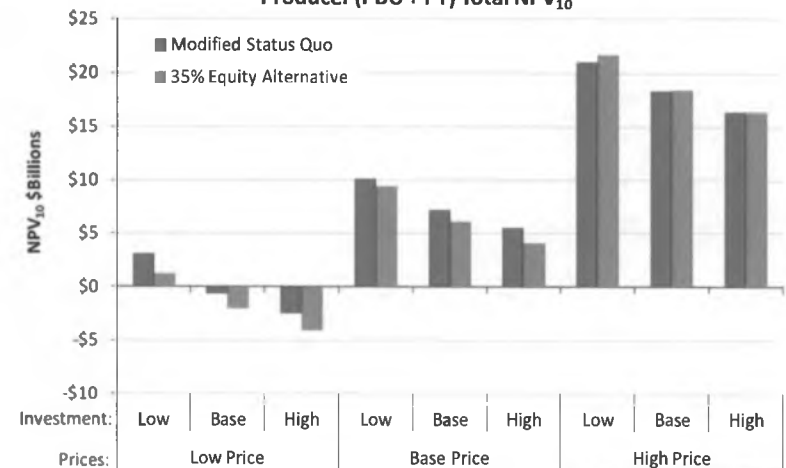
Producer (PBU + PT) Total NPV₁₀



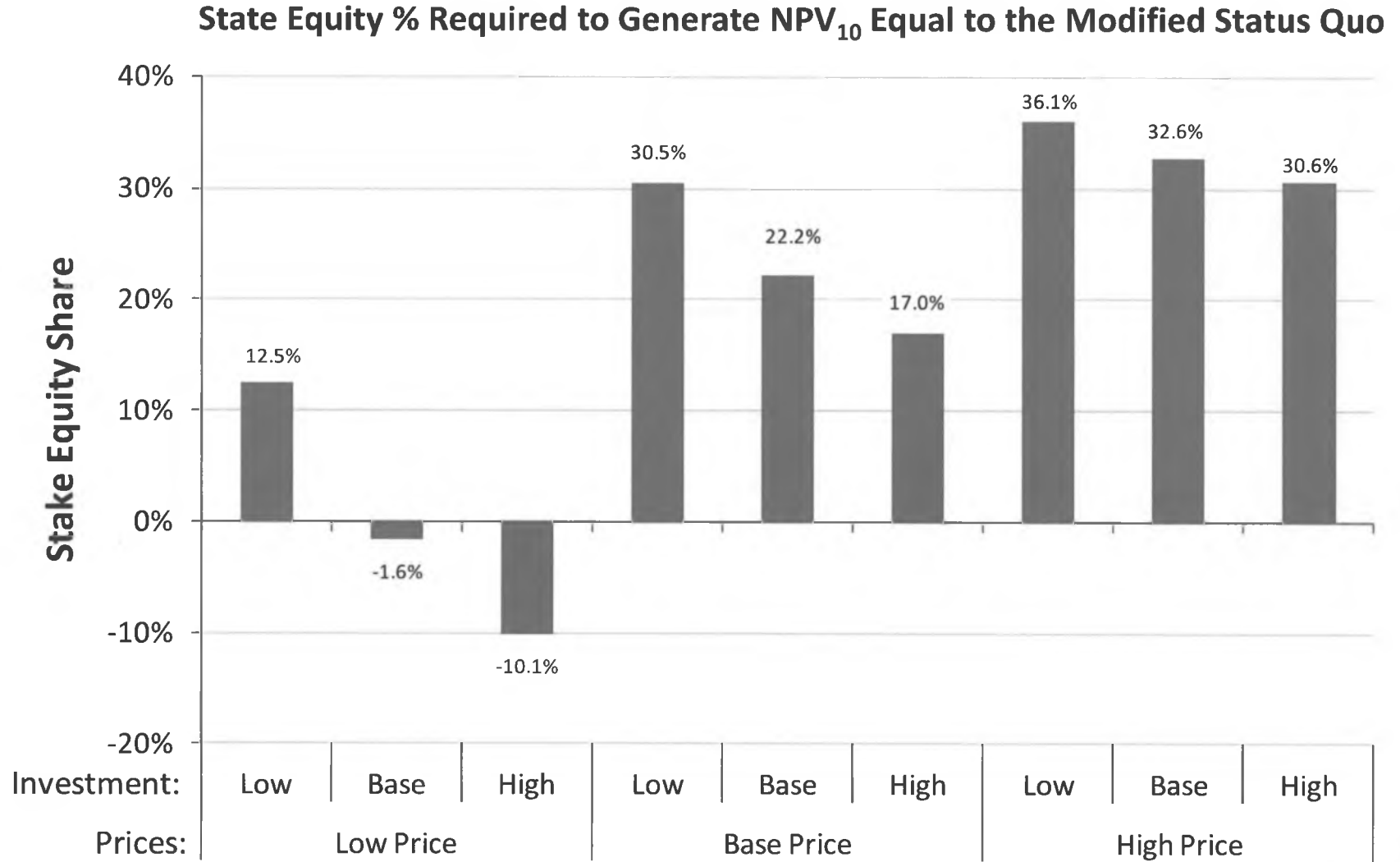
35% SOA equity participation – NPV₁₀



Producer (PBU + PT) Total NPV₁₀



STATE EQUITY PARTICIPATION BETWEEN 20% AND 30% OFFERS NPV₁₀ AT OR ABOVE THE MODIFIED STATUS QUO LEVELS FOR THE STATE



The level of State equity investment required to equal total state NPV₁₀ under status quo varies with market conditions



SOA EQUITY INVESTMENT IN AKLNG CREATES RISK EXPOSURES THAT NEED TO BE CONSIDERED AND MANAGED

- **Cost overruns and cash calls above appropriation level – To the extent that the actual Capex exceeds the budgeted amount the State of Alaska is expected to be responsible for its pro-rata share of the increased costs. This is a significant risk for the State of Alaska given the high cost structure of the AKLNG Project and likely inflationary pressures**
- **As an equity owner, the State assumes all Force Majeure risk throughout the GTP, pipeline and LNG terminal**
- **State has no control over upstream operations and volumes produced by the Producers**
 - Could have excess or insufficient capacity relative to volumes produced
 - Balancing production volumes and volumes through the supply chain on a short-term and long-term basis
- **If the State assigns its equity position to a third party such as TransCanada and contracts for capacity with this third-party, the State will likely have to provide credit support to the entity that would assume the state's equity share in the midstream through long-term commitments for capacity**
- **State would be responsible for all demand charge obligations throughout the life of the contract regardless of gas supply availability and market conditions**
 - Possible that revenues earned on LNG sales would not offset costs of treating, transport and liquefaction resulting in negative cash flows to the State

ENSURING TRANSPARENCY & OPEN ACCESS WILL DEPEND ON THE ACTUAL TERMS NEGOTIATED FOR STATE PARTICIPATION

Commercial Design Option	Implementation to Achieve ...		
	Transparency	Access	Commercial Structures
Equity participation	✓ Each Segment	✓ Each Segment	<ul style="list-style-type: none"> ✓ All Structures • Might be limits on tolling structure
Position on management committee	✓		<ul style="list-style-type: none"> • Integrated
Participation through secondees on GTP, Pipeline and LNG plant teams	✓		<ul style="list-style-type: none"> • Integrated
Undivided joint interest approach “pipe within a pipe”		✓	<ul style="list-style-type: none"> • Integrated
Expansion rights to be negotiated within context of JVA		✓	<ul style="list-style-type: none"> • Integrated

SUMMARY: RISK ALLOCATION & COMMERCIAL STRUCTURE

1 AKLNG faces various risks that could affect the economic benefits; prices and capital cost are key

2 Direct equity participation by the State can offer benefits to all parties involved in the project; accompanying risk profile changes should be managed

3 Various commercial terms related to equity participation will determine whether the State can achieve its transparency and access objectives

