NOVEMBER 2013

ALASKA NORTH SLOPE ROYALTY STUDY

PREPARED FOR THE STATE OF ALASKA

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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

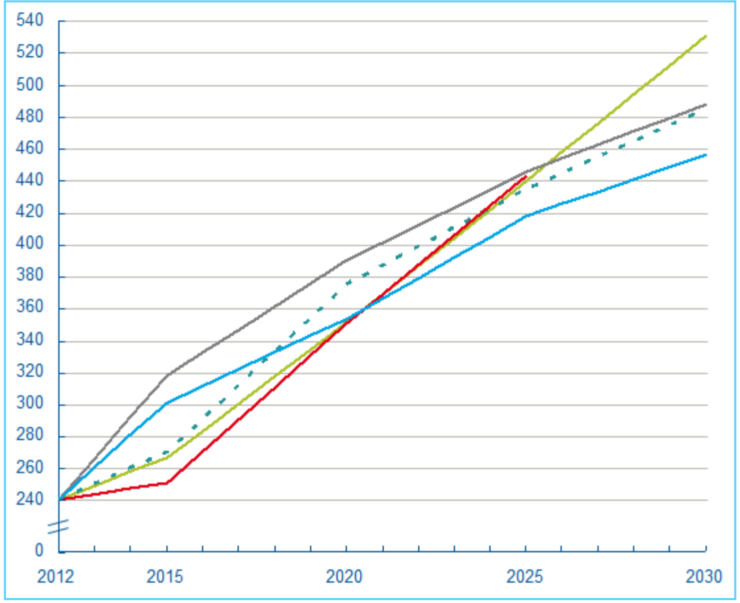
- Assessment of a project of the scope of AKLNG requires examination of numerous complex variables that cannot be determined with a high degree of certainty
- In most cases, a conservative approach was taken when applying forecasts and assumptions
- Many reasonable scenarios can be derived where the 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

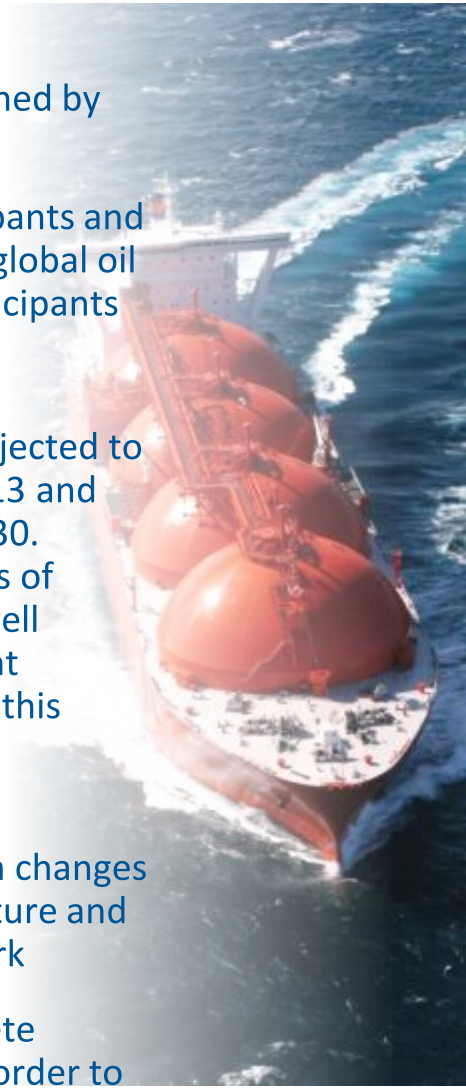
Global LNG demand – various forecasts, Mtpa



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

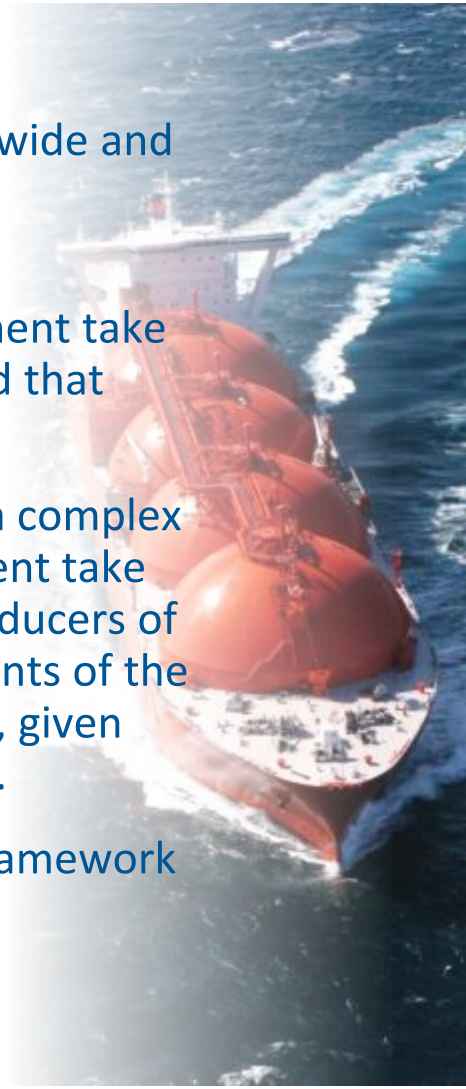
Supply Chain Elements

- 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.



State

Producers

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.

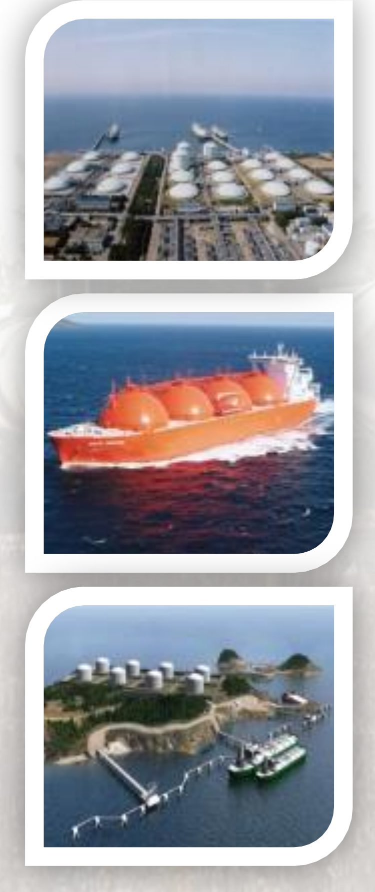
EXECUTIVE SUMMARY – CONCLUSIONS

- 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

PRESENTATION OUTLINE



- **AKLNG Project Overview**
- LNG Markets
- Supply Chain Elements
- Fiscal Framework
- Risk Allocation & Commercial Structure

GLOSSARY OF TERMS USED

Term	Definition	Term	Definition
AGIA	Alaska Gasline Inducement Act	IRR	Internal rate of return
AKLNG	Alaska Liquefied Natural Gas Project	JCC	Japan Crude Cocktail; calculated by taking a trade-weighted average of the most often traded crude products in Japan
APT	Additional profits tax		
BEP	Break-even point		
BOE	Barrels of oil equivalent	JOA	Joint operating agreement
CAGR	Compound annual growth rate	LIBOR	London Interbank Offered Rate
Capex	Capital expenditures	LNG	Liquid natural gas
C/R Limit	Cost Recovery Limit	MMBtu	Million British Thermal Units
CVP	Venezuelan Petroleum Corporation	Mcf	Thousand cubic feet
DD&A	Depreciation, deployment, and amortization	MMscf	Million standard cubic feet
DMO	Domestic Market Obligation	Mtpa	Million metric tonnes per annum
ERR	Effective royalty rate	NGL	Natural gas liquids
FCA	Field cost allowance	NOC	National oil company
FEED	Front end engineering design	NPV	Net present value
FERC	Federal Energy Regulatory Commission	Opex	Operational expenditures
FID	Final investment decision	P.a.	Per annum
FOB	Free onboard	PBU	Prudhoe Bay unit
FTA	Free trade agreement	PDVSA	Venezuelan National Oil Co.
GCA	Gaffney Cline & Associates	P/O Split	Profit Oil Split
GTP	Gas treatment plant	PSC	Production sharing contract
HH	Henry Hub	PVM	Pedro Van Meurs
HOA	Heads of agreement	R Factor	Ratio of Receipts/Expenditures
IOC	Independent oil company		

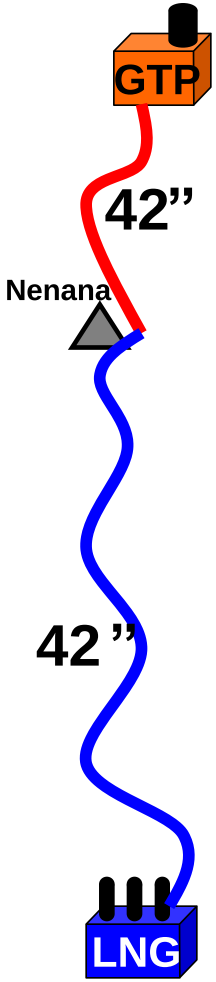
GLOSSARY OF TERMS USED

Term	Definition	Term	Definition
RIK	Royalty in kind	SOA	State of Alaska
RIV	Royalty in value	Supply chain	GTP, pipeline, liquefaction terminal & marine facilities
Ringfence	Segregation of income and costs for tax purposes	Take	Government receipts or revenues
ROE	Return on equity	Tcf	Trillion cubic feet
ROR	Rate of return	TCPL	TransCanada PipeLines
RP	Risk premium	WACC	Weighted Average Cost of Capital
Savings Index	Measure of % of cost savings retained by IOC	WI	Working interest
SCIT	State corporate income tax	YTF	Yet to find
SLD	Straight line depreciation		

INTRODUCTION TO LNG MARKET TERMS

		Description	Usage
UNITS	**Mtpa**	Million metric tons per annum	To measure liquid LNG volumes 1 Bcfd ≈ 7.38 Mtpa
	Bcma	Billion cubic meters per annum	
	Bcfd	Billion cubic feet of gas/day	To measure gas supply/demand 1 Bcfd ≈ 10.344 Bcma
TERMS	**LTCs**	Long term contracts	Recent market dynamics sections
	Spot trade	Short-term trades made outside the long-term contract market	Trade background and outlook
	Discount / return	Rate of return used for discounting cash flows	Cost curves & present value charts
	JCC	Japan crude cocktail	LNG pricing section
	Train	One production line at an LNG facility	Across the document
	Basin	Atlantic or Pacific Basin markets are defined as per major ocean area	LNG trade discussion

OVERVIEW OF AKLNG PROJECT

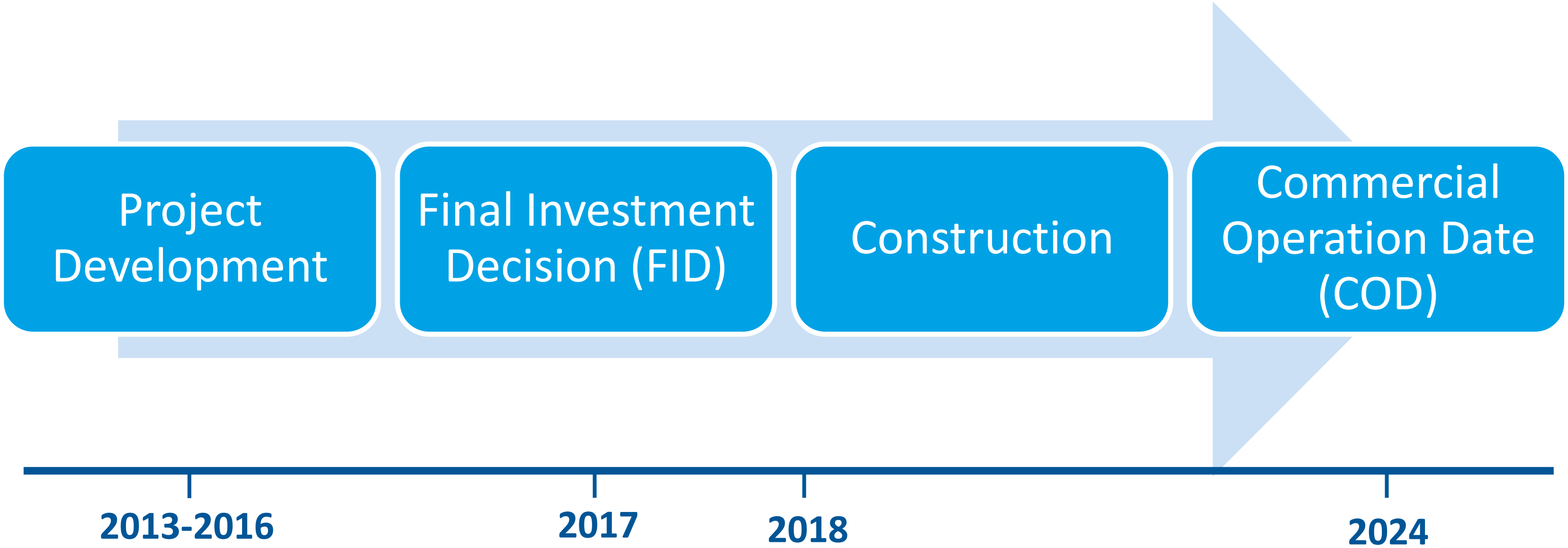


- **Total Midstream project is comprised of a Gas Treatment Plant (GTP), a pipeline and a liquefaction (LNG) plant**
- **3 train initial project**
  - Total capacity of 17.4 Mtpa
- **Timeline for development/ construction:**
  - Schedule – 60 months
  - In-service date for project is 2024
- **Capital cost**
  - ~$1600/Mtpa in 2013$ for liquefaction plant
  - Total midstream capital cost of $45 billion

COMPONENTS & TIMELINE OF AKLNG PROJECT

AKLNG consists of:

Gas Treatment Plant (GTP)	Pipeline	LNG Plant
• $10 billion	• $12 billion • 42” diameter • 8 compressors	• $23 billion • 3 trains • 17.4 Mtpa



Project Development

Final Investment Decision (FID)

Construction

Commercial Operation Date (COD)

ECONOMIC ANALYSIS OF AKLNG PROJECT

- **In order to understand the potential impact of the main fiscal levers that the State could employ to facilitate the AKLNG Project, we examine the economics of the project in this study under base or reference assumptions in this section and with subsequent modifications further in the study**
- **The intent of the analysis is to understand impacts on the returns earned by the Project Sponsors, share of government take and net present values to the stakeholders as a result of key triggers:**
    - Fiscal triggers – royalty, production tax, property tax, equity participation
    - Market triggers – price and capital cost
- **This analysis examines the economic implications of the AKLNG project on the key stakeholders involved, specifically:**
    - State of Alaska
    - Project Sponsors – Exxon Mobil, BP and ConocoPhillips
    - Federal Government
- **It should be noted that there are several factors that remain significant uncertainties related to the AKLNG project including capital costs and market prices, which could materially influence the economics presented here**

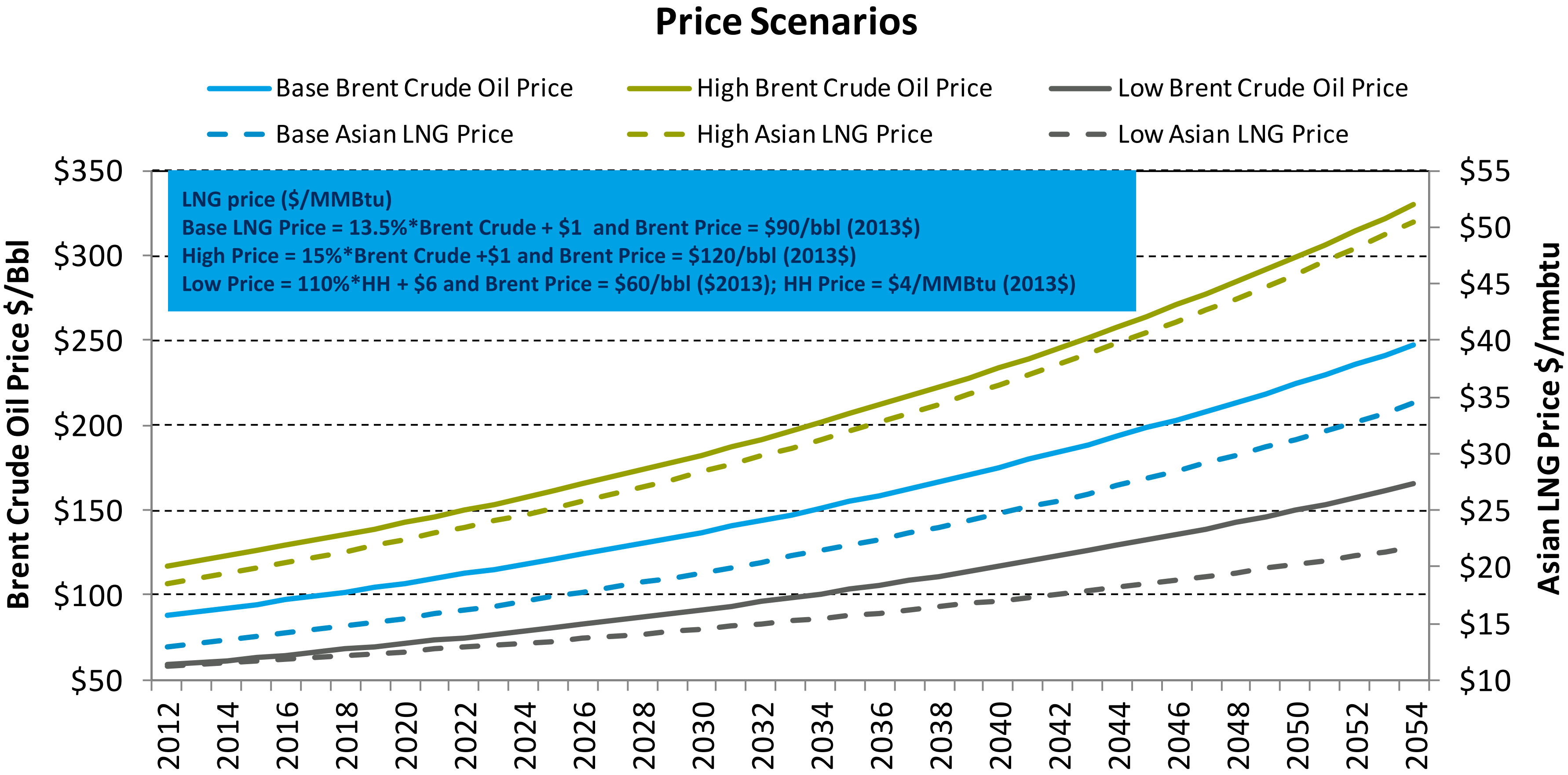
STUDY APPROACH & UNCERTAINTIES

- **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**
- **The economics, as presented in this study represent an approach based on the information available to date and it should be recognized that market and project related variables, that remain as yet unresolved, can modify the economics as presented here**

SELECTED KEY ASSUMPTIONS

Input	Assumption
Project Capital Cost	$45 Billion (2013$)
Project Schedule (In-Service)	February 2024
Project O&M	$407 million/yr (2013$)
Debt/Equity	70%/30%
Debt Rate (GS)	7.05%
ROE	12.0%
O&M Escalation	3.0%
CapEx Escalation	3.0%
Inflation	2.5%
Depreciation / Contract Life	30 Years
Production Period	30 Years

THREE PRICE SCENARIOS WERE ASSUMED FOR THE PURPOSE OF THIS STUDY



LNG price ($/MMBtu)
Base LNG Price = 13.5%*Brent Crude + $1 and Brent Price = $90/bbl (2013$)
High Price = 15%*Brent Crude +$1 and Brent Price = $120/bbl (2013$)
Low Price = 110%*HH + $6 and Brent Price = $60/bbl ($2013); HH Price = $4/MMBtu (2013$)

Note: Nominal prices. Assumes 2.5% inflation rate.

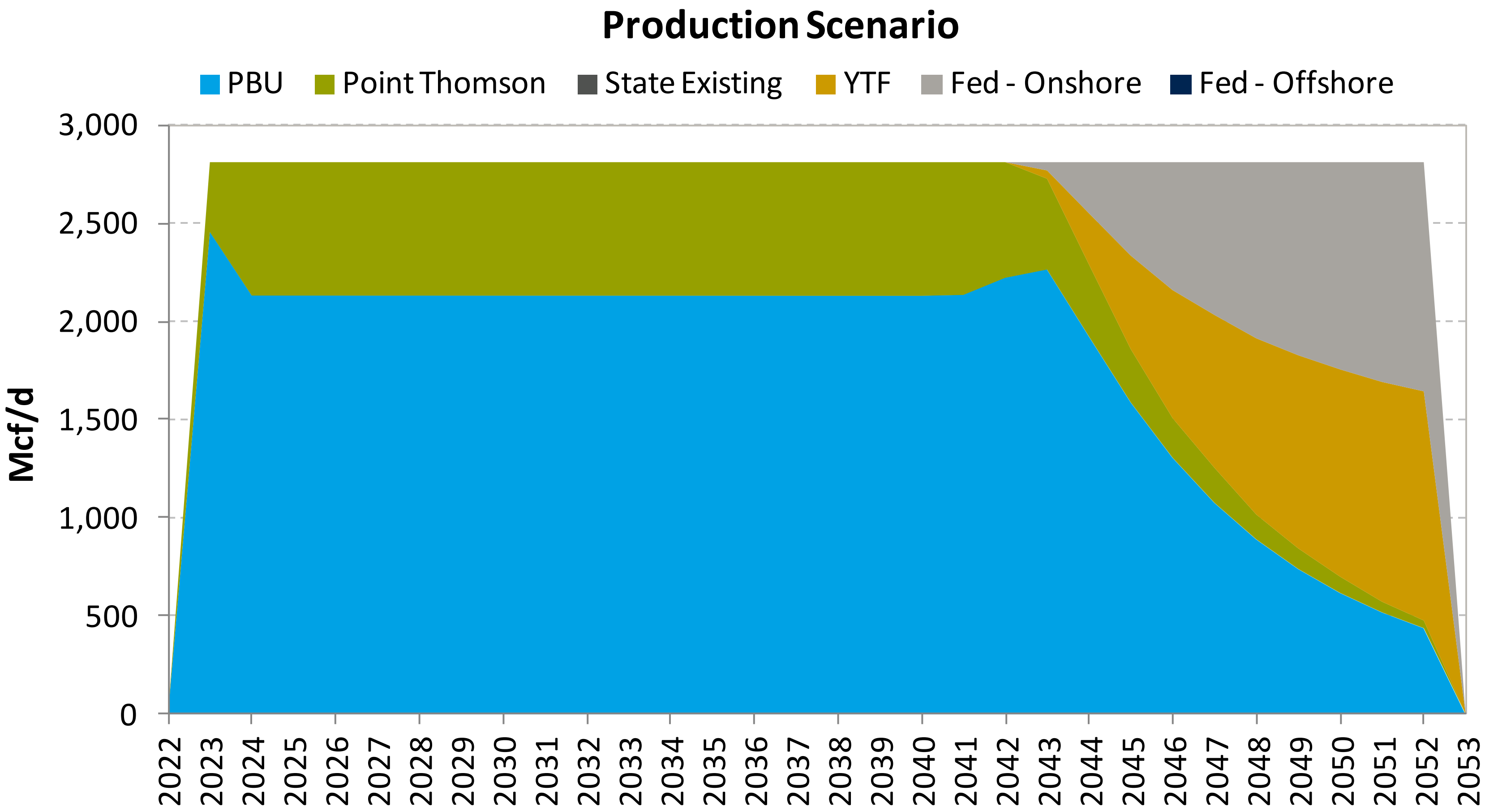
THREE CAPITAL COST ESTIMATES WERE CONSIDERED FOR SCENARIO ANALYSIS WITHIN THIS STUDY

- **Baseline capital cost estimate for the project is $45 billion based on the State's technical team's assessment of the capital costs of the different midstream components reviewed by Black & Veatch experts**
- **The study also looked at scenarios with lower and higher capital costs based on the estimates made by the Producers related to the AKLNG Project**
- **Midstream capital cost ranges utilized (for GTP, Pipeline and LNG plant):**
  - **Low capital cost estimates - $39 billion**
  - **High capital cost estimates - $54 billion**

PRODUCTION FOR THE BASELINE LNG PROJECT IS ASSUMED TO COME FROM PRUDHOE BAY AND POINT THOMSON FIELDS

- **Production for the project was assumed to come primarily from the Prudhoe Bay (PBU) and Point Thomson (PT) fields**
- **When production from PBU and PT fields is insufficient to fill the pipeline, production from yet-to-find fields is assumed to be sufficient to keep the project fully utilized**
  - YTF production is assumed to be divided equally between State and Federal onshore fields
  - The analysis assumes that the YTF fields are not owned by the 3 Producers
  - YTF field owners are assumed to commit to capacity on the GTP, pipeline and LNG plant and pay tariffs to the AKLNG Project owners
  - The economics of the YTF producers cannot be fully captured during the period of analysis being considered here because their investment late in the analysis period will not fully bear out its returns. The analysis of the returns to project Sponsors hence ignores costs and revenues of the YTF producers.

PROVEN RESERVES ARE EXPECTED TO SUPPLY SUFFICIENT PRODUCTION TO THE AKLNG PROJECT UNTIL 2042



OVERVIEW OF SB21/MAPA ALASKA FISCAL STRUCTURE APPLICABLE TO AKLNG PROJECT

- **Royalty: 12.5%+ depending on lease agreement**
- **Production Tax:**
    - 35% production tax rate
    - Production credit of $5/bbl for new oil or sliding scale from $0-$8/bbl for oil
    - Gross revenue exclusion of 20% for new oil and gas; additional 10% if royalty is more than 12.5%
    - Loss carryforward credit of 35% after 2014
- **Property tax: 2%**
- **State Corporate Income Tax : 9.8% of apportioned worldwide income**

OTHER KEY ASSUMPTIONS

- 100% Producer-owned integrated project
- Equity share of each of the producers is determined by the volume of gas they each contribute to the project over its initial 30 year period of operation
- The term “midstream” when used within the context of the AKLNG project refers to the GTP, pipeline and LNG plant for simplification. Note that an LNG plant is generally classified as a downstream project component but that distinction is not made in this study.

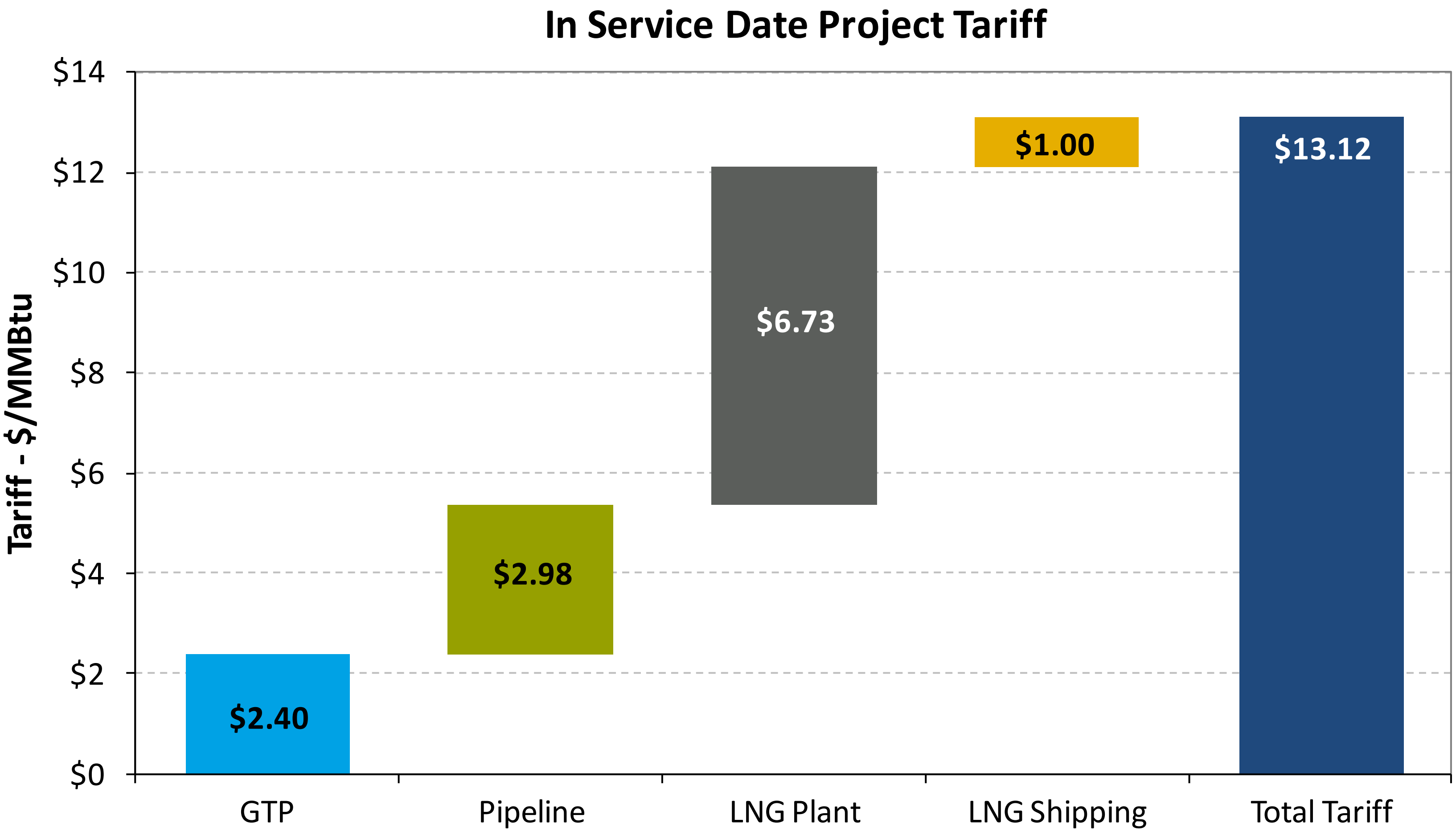
IMPACT OF THE GAS LINE: CASH FLOWS AND NPVS CALCULATED ARE THE *DIFFERENCE* BETWEEN OIL + GAS AND OIL ONLY OPERATIONS

Oil + Gas $$$$$$

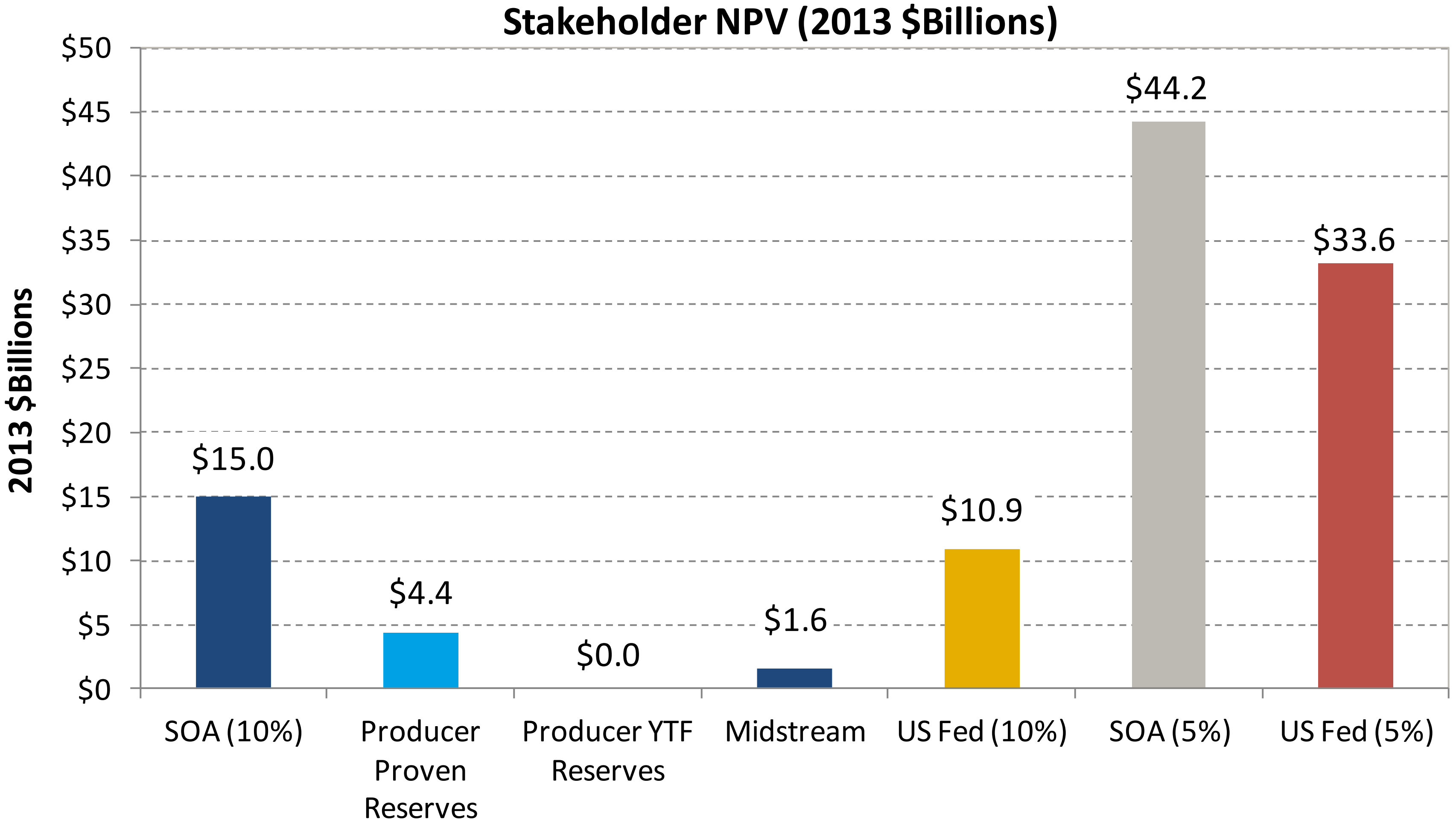
– Oil Only $$

Cash Flows from Gas $$$$

PROJECT IN SERVICE TARIFF IS ESTIMATED TO BE ~$13/MMBTU (IN 2024)

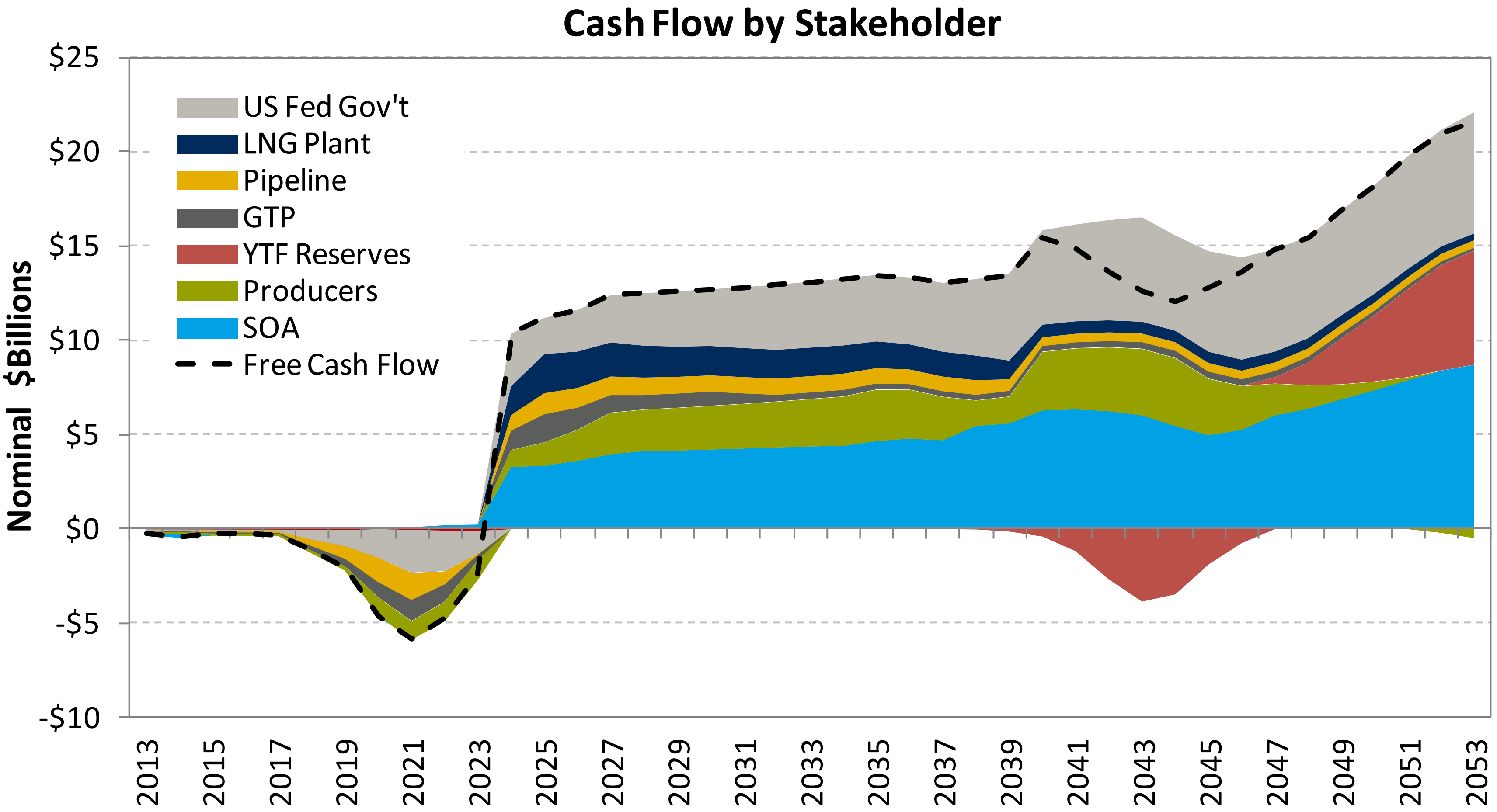


STAKEHOLDER NPV 2013$ BILLIONS



Discount rate of 10% assumed for Producers

CASH FLOW BY STAKEHOLDER OVER LIFE OF PROJECT



CONTENTS

QUESTIONS TO ANSWER BY ITEM AND COVERAGE IN THIS REPORT

	Questions to answer	**Covered in this report through**
1. LNG Markets	How is LNG currently being traded and valued in the various markets available to a North Slope LNG project?	Holistic framework of LNG contract pricing drivers, globally tailored to specific markets Historic LNG supply/demand and link to pricing Global LNG cost curve for future projects, including North Slope LNG's potential fit / attractiveness
	What are current commercial and pricing trends?	Historic and current LNG pricing, including drivers Forecasted global and regional (e.g. Pacific basin) LNG pricing across core scenarios
	How are supply deficiencies and excess managed?	Overall framework of levers to manage supply

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

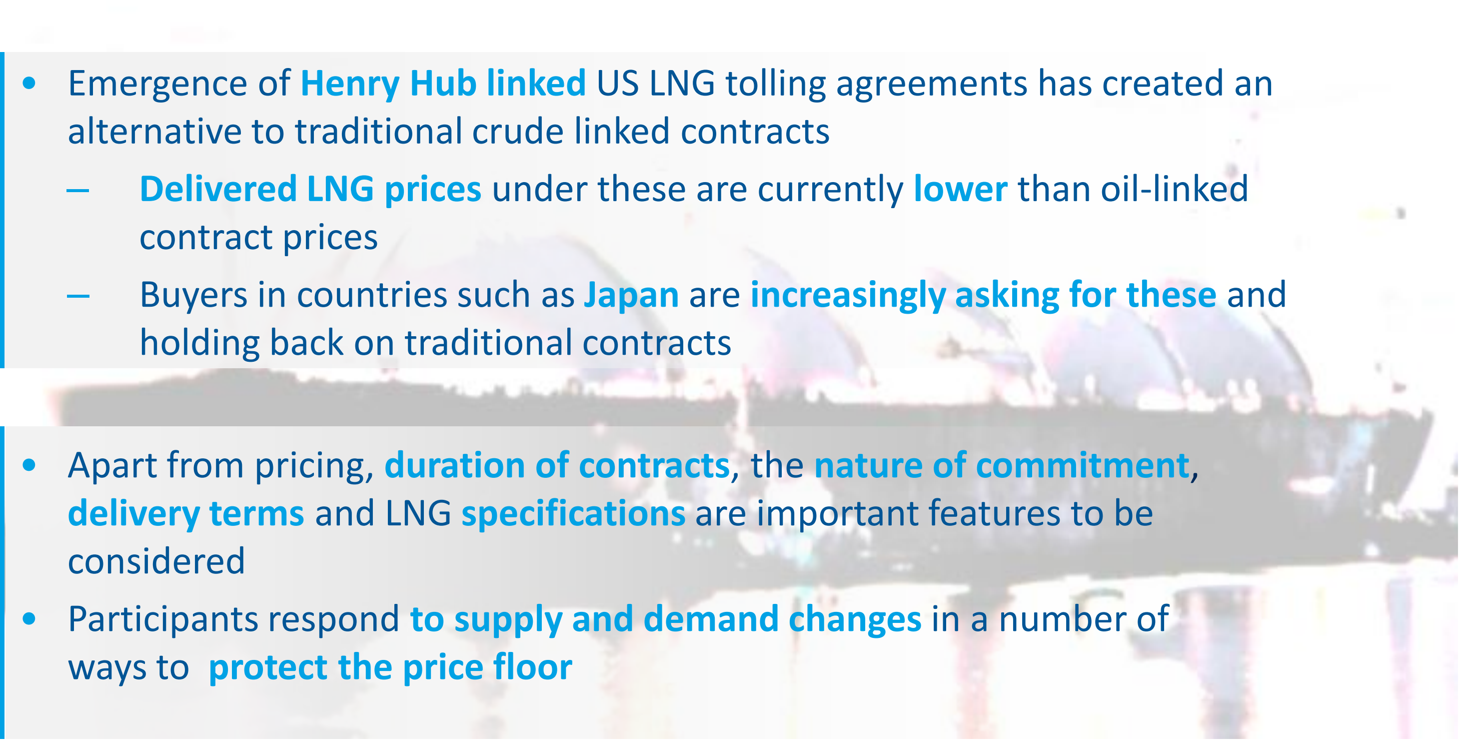
- LNG Supply is also highly **concentrated** – **8** exporting countries provided **83%** of global LNG exports in **2012**
- Liquefaction capacity is rarely developed on a speculative basis
  - Liquefaction facilities typically cost **US$5-20bn**
  - LNG facilities are generally **project financed,** 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**

SOURCE: BP Statistical review of world energy; GROUPE INTERNATIONAL DES IMPORTATEURS DE GAZ NATUREL LIQUEFIE (GIIGNL), Team Analysis

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**

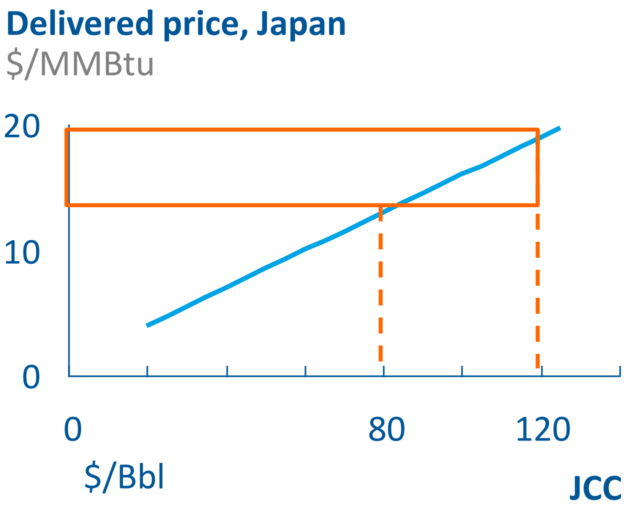
SOURCE: Team Analysis

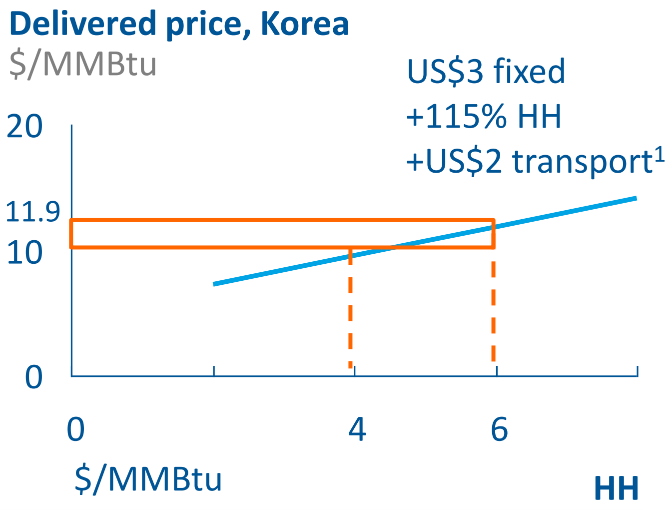
PROSPECTIVE FUTURE US LNG EXPORTS HAVE CREATED AN ALTERNATIVE TO TRADITIONAL CRUDE LINKED LNG CONTRACTING

	A **JCC linked**	B **Henry Hub linked**
Applies to	• LNG from rest of world (Africa, Middle East, SE Asia, Australia)	• LNG export from US L-48
Key terms	• Fixed element, typically US$0-1/MMBtu	• Fixed element, typically US$3-4/MMBtu • Henry Hub linked, typically 100-120% HH

Typical price curve

▭ Likely price ranges given crude and HH fundamentals


Delivered price, Japan
$/MMBtu


Delivered price, Korea
$/MMBtu

US$3 fixed
+115% HH
+US$2 transport[1]

AKLNG is likely to have a competitive advantage selling into the JCC-linked market

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[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

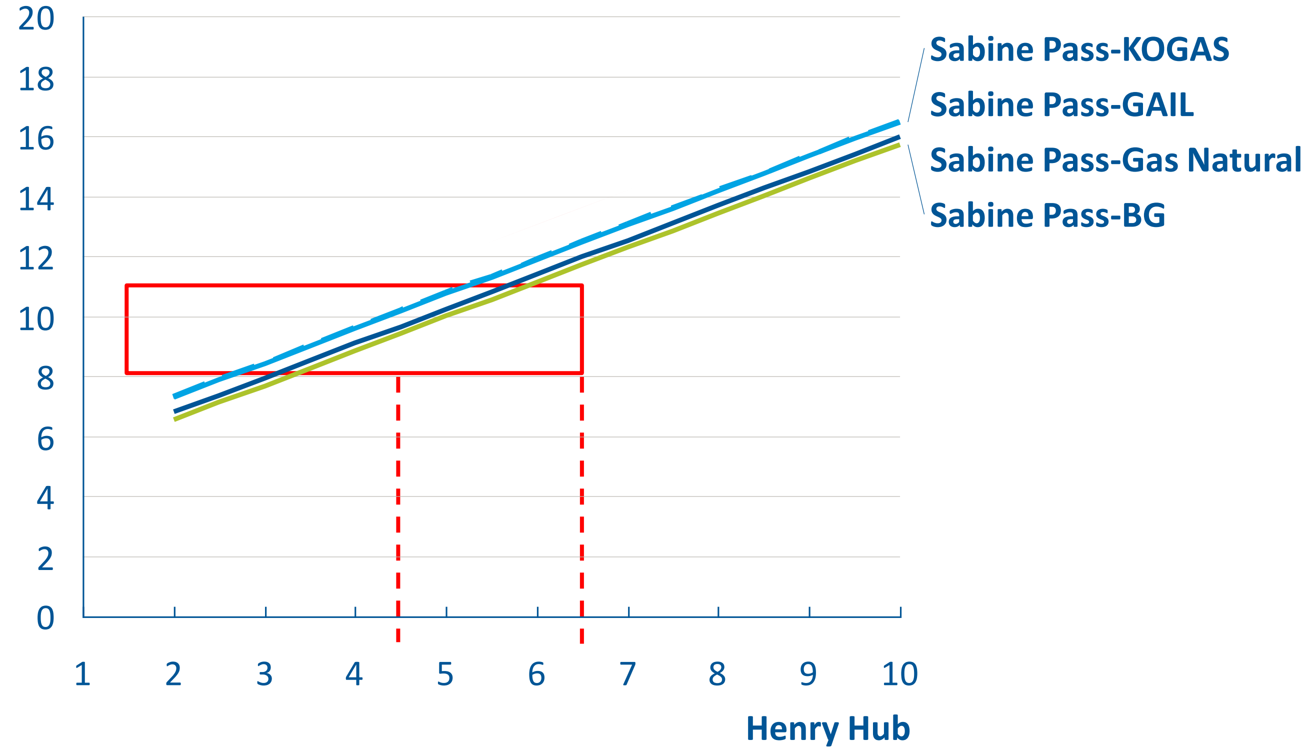
SOURCE: Team Analysis

B BUYERS FROM U.S. LNG EXPORT TERMINALS HAVE SIGNED HENRY HUB LINKED TOLLING AGREEMENTS

🟥 Likely price ranges

Cheniere (Sabine Pass) LNG contract price

US$/MMBtu (Delivered in Asia - $2/MMBtu shipping added)



Other U.S. contracts

- **Freeport LNG:** Osaka Gas, Chubu Electric, BP Energy
- **Cameron LNG:** GDF Suez, Mitsubishi & Mitsui
- **Cove Point:** Sumitomo & GAIL

> *"Anecdotally, owners of US export terminals are seeing **progressively higher tolling charges**, with the most recent deals said to **close the pricing gap** an expected crude linked contract at Kitimat."*
>
> *- Industry Expert*

SOURCE: Team Analysis; press search; annual filings

B

SELECTED U.S. LNG TERMINAL TOLLING AGREEMENTS

	Toller	Off take capacity	Gas price	Tolling fee US$/MMBtu	Term
Sabine Pass	BG Group	5.5 Mtpa (Train 1)	115% of NYMEX HH	2.25-3.0	20 + 10 years
	Gas Natural Fenosa	3.5 Mtpa (Train 2)	115% of NYMEX HH	2.5	20 years
	KOGAS	3.5 Mtpa (Train 3)	115% Indexed to HH	3.0	20 years
	GAIL	3.5 Mtpa (Train 4)	115% of NYMEX HH	3.0	20 years
Freeport	Osaka Gas	4.4 Mtpa (Train 1) (between them)	Not disclosed	Not disclosed	20 years
	Chubu Electric				20 years
	BP Energy	4.4 Mtpa (Train 2)			20 years
	SK E&S	4.4 Mtpa (Train 3) (between them)			20 Years
	Toshiba				20 Years
Cameron	GDF Suez	4 Mtpa	Not disclosed	Not disclosed	20 year
	Mitsubishi	4 Mtpa			20 years
	Mitsui	4 Mtpa			20 years
	Joint venture agreement calls for GDF Suez, Mitsubishi and Mitsui to each acquire 16.6% equity in the existing (regas) facilities and the liquefaction project				
Cove Point	Pacific Summit Energy (Sumitomo)	2.63 Mtpa	Indexed to HH	Not disclosed	20 years
	GAIL	2.63 Mtpa	Indexed to HH		20 years
	Sumitomo also signed HOAs to supply 1.4 Mtpa to Tokyo Gas and 800,000 Mtpa to Kansai Electric from the Cove Point project for 20 years at US Henry Hub gas prices				

Freeport & Cameron price terms are likely to be tolling arrangements

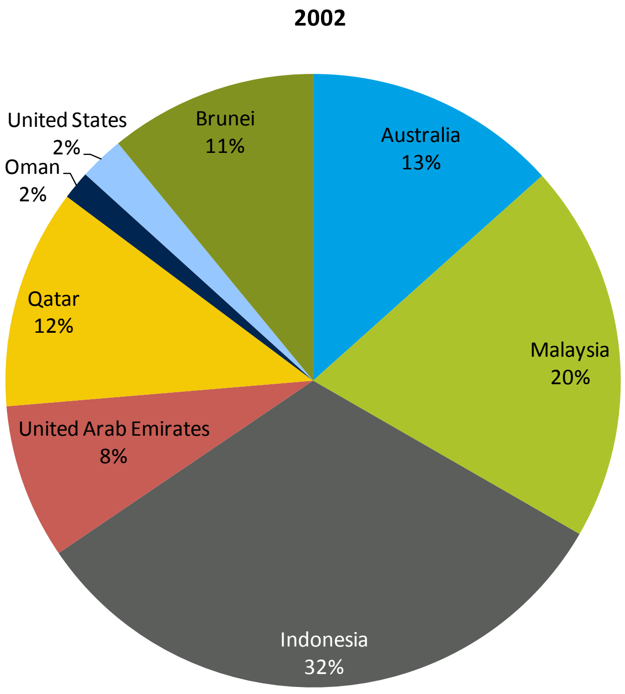
[1] 15% linked to inflation

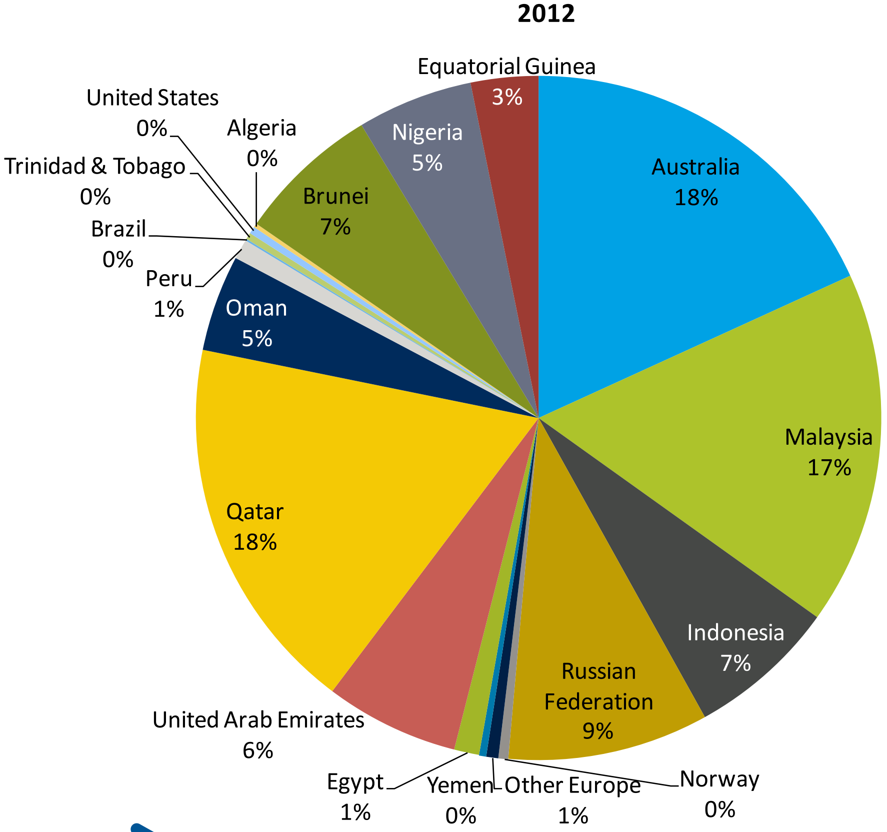
Note: All U.S. LNG exports need federal approval

SOURCE: Company websites; press releases; presentations; trade press

DIVERSIFICATION OF SUPPLY IS INCREASINGLY IMPORTANT – JAPAN INCREASED THE NUMBER OF ITS SUPPLIERS FROM 8 TO 19 BETWEEN 2002 AND 2012

Share of Delivered Volumes to Japan





Total Delivered Volumes: 53.8 Mtpa → **Total Delivered Volumes: 88.1 Mtpa**

SOURCE: BP Annual Statistical Review

RECENT CONTRACT STRUCTURES – COMPARISON OF NON-PRICE FEATURES

	JCC linked	HH linked (Sabine Pass example)
Typical duration	• 20-30 years	• 20 years and 10-year option to extend
Commit-ment	• Take or pay, often up to 100% levels for LNG (~US$15/MMBtu) • Cargoes that are paid for but not taken can be taken in later years	• Buyers only commit to pay fixed fee for liquefaction (~US$3/MMBtu) • Unused capacity cannot be carried over
Delivery point	• Free on Board (FOB) where buyer arranges shipping or Delivered ex Ship (DES) where shipping is included in contract price	• FOB only – buyer must arrange shipping
Specifi-cation	• Often “rich LNG” (i.e. including LPGs). This is preferred by some Asian buyers as it provides LPG to their chemicals industries	• “Lean LNG” for Gulf and East coast terminals; rich gas could be an option for West Coast/Canada

SOURCE: Team Analysis

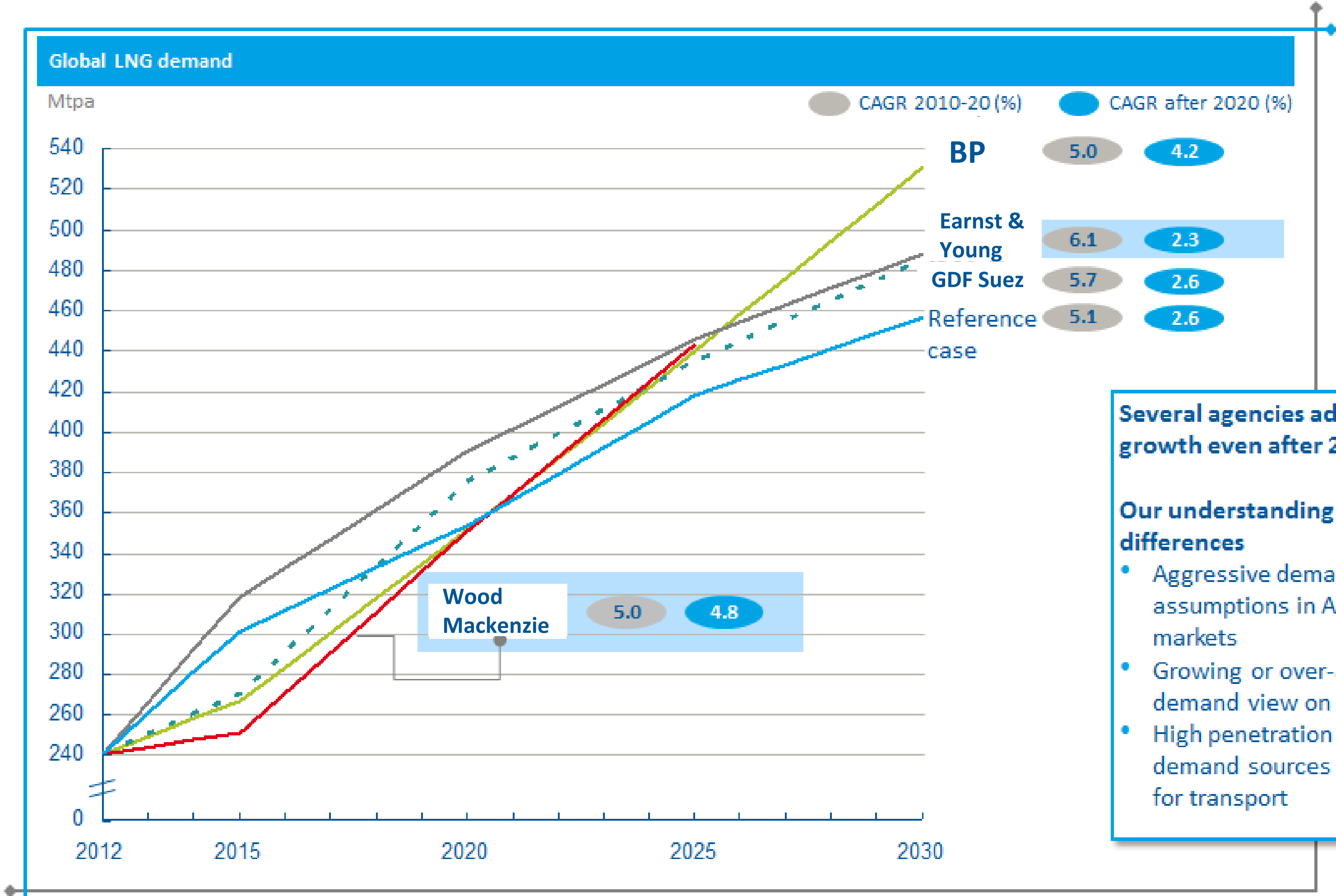
PLAYERS HAVE HISTORICALLY USED A COMBINATION OF SEVERAL FACTORS TO MANAGE SUPPLY-DEMAND

	Situation	Response	
Absorbing higher volumes	LNG supply grew rapidly between 2004 – 2007, flattening from 2007-2009	Growing LNG was absorbed into demand markets	Tepco KoGas
Shifting off capacity	Pluto expansion to T2 can be done quickly	Start-up of Pluto T2 delayed to 2014	Woodside
Spot opportunity	Angola LNG not able to secure long term sale agreements	Set up trading arm in London and actively looking to trade in spot market	Angola
Changing contractual terms other than price	Players such as India not willing to pay >US$12/MMBtu LNG prices	Shorter period LNG contracts signed to find a current market but not commit supply in long term	QatarGas
Qatar balancing	Abrupt growth in supply in market	Players with flexible supply such as Qatar take effective supply off the market	QatarGas
Marginally lowering price	Abrupt growth in supply in market	NWS lowered price slope offering by 1% from Qatar to secure contracts	Woodside

Most of these levers can also be used by players going forward

SOURCE: Team Analysis

OUTLOOK FOR LNG DEMAND GROWTH VARIES ACROSS FORECASTING AGENCIES



Several agencies adopt a fast growth even after 2020

Our understanding of key differences

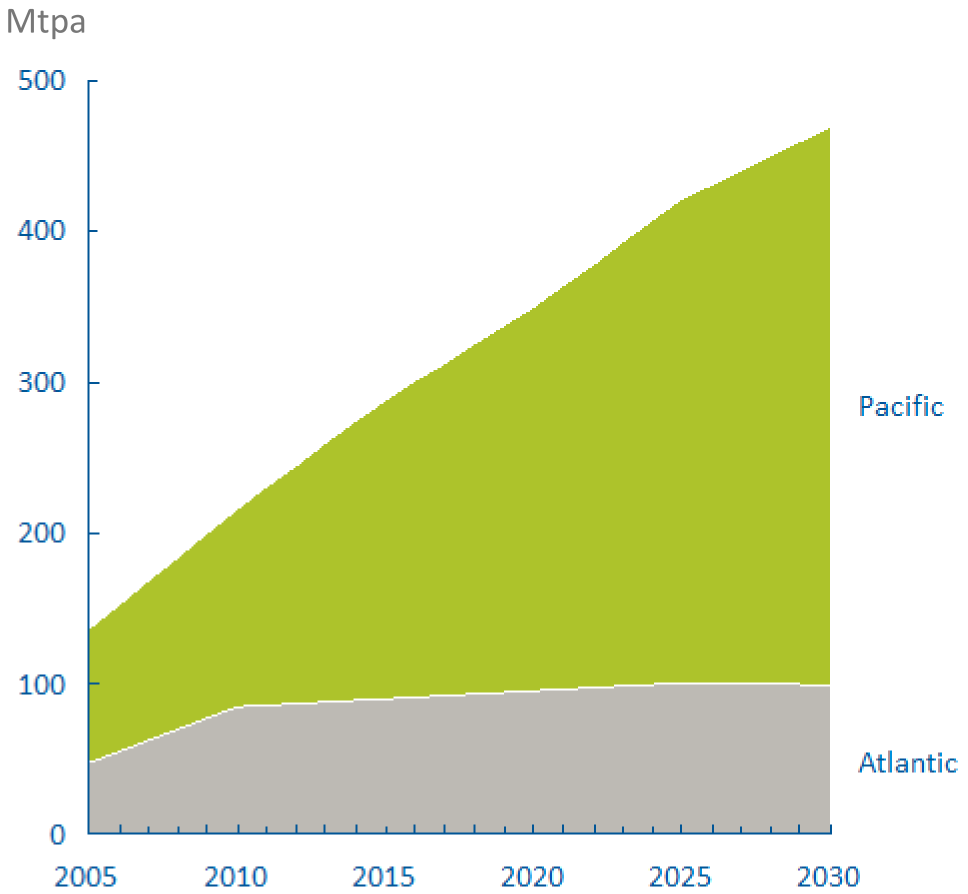
- Aggressive demand growth assumptions in Asia/new markets
- Growing or over-aggressive demand view on Europe
- High penetration of new gas demand sources such as gas for transport

1 Mtpa = 1.379 Bcma used

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

BASE CASE: ASIA PACIFIC IS EXPECTED TO LEAD THE OVERALL GROWTH

Bottom up modelled LNG demand – reference case



Basin CAGR

2005-10	2010-20	2020-30
8%	14%	6%

PACIFIC BASIN
- Growing demand in existing Asian markets
- New markets emerge

2005-10	2010-20	2020-30
13%	4%	2%

ATLANTIC BASIN
- Flat demand in Europe
- Domestic production grows in Americas

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[1] LNG demand is modeled based on a demand and supply scenario, global LP optimization and LNG and pipeline analysis with regional expert views

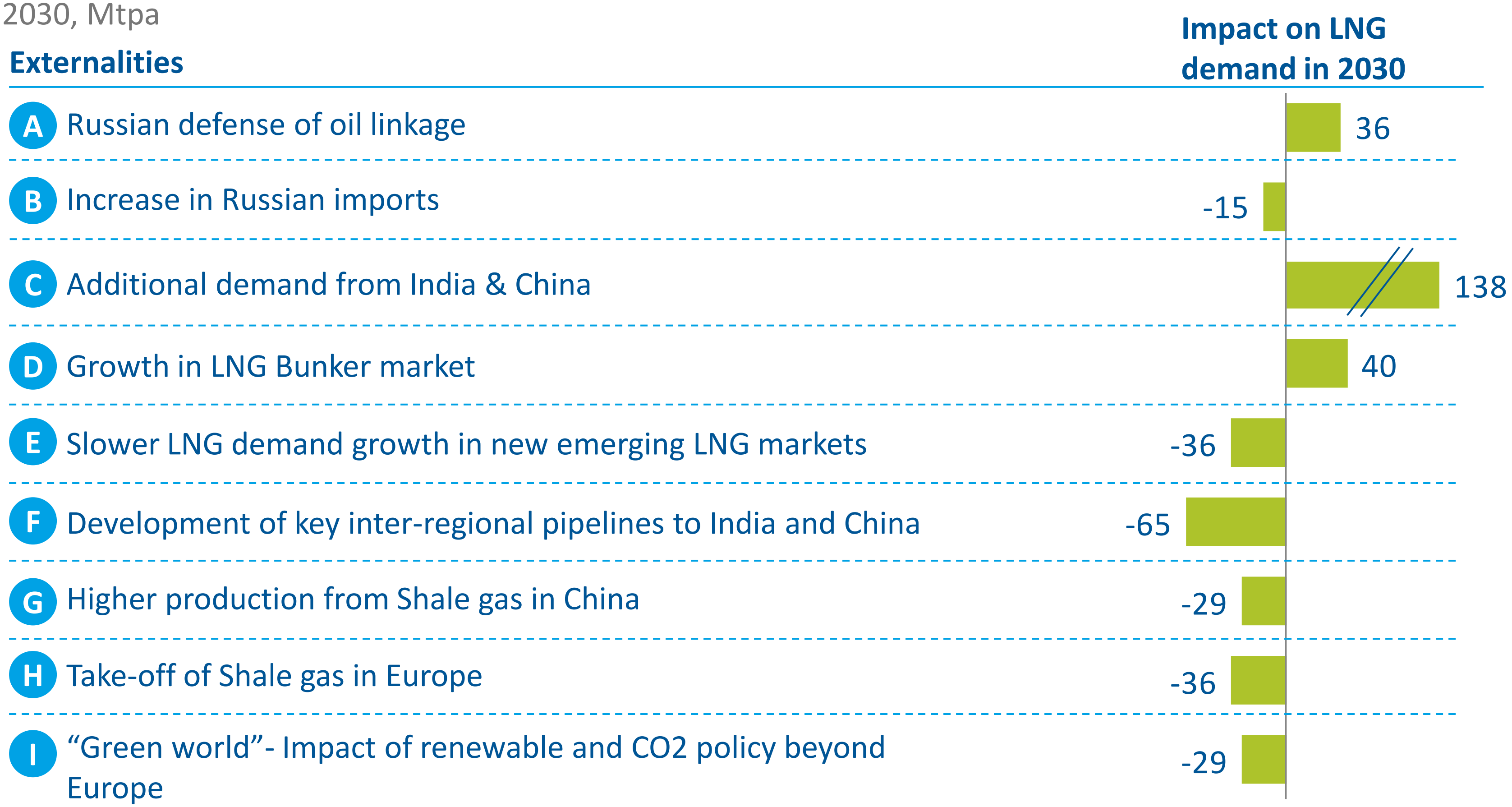
[2] New Asian markets include Singapore, Thailand, Indonesia, Malaysia, Bangladesh, Pakistan, Philippines, New Zealand

SOURCE: Team Analysis

KEY UNCERTAINTIES EXPLAIN POSSIBLE DIFFERENCES IN LNG DEMAND OUTLOOKS

Impact on LNG demand

2030, Mtpa

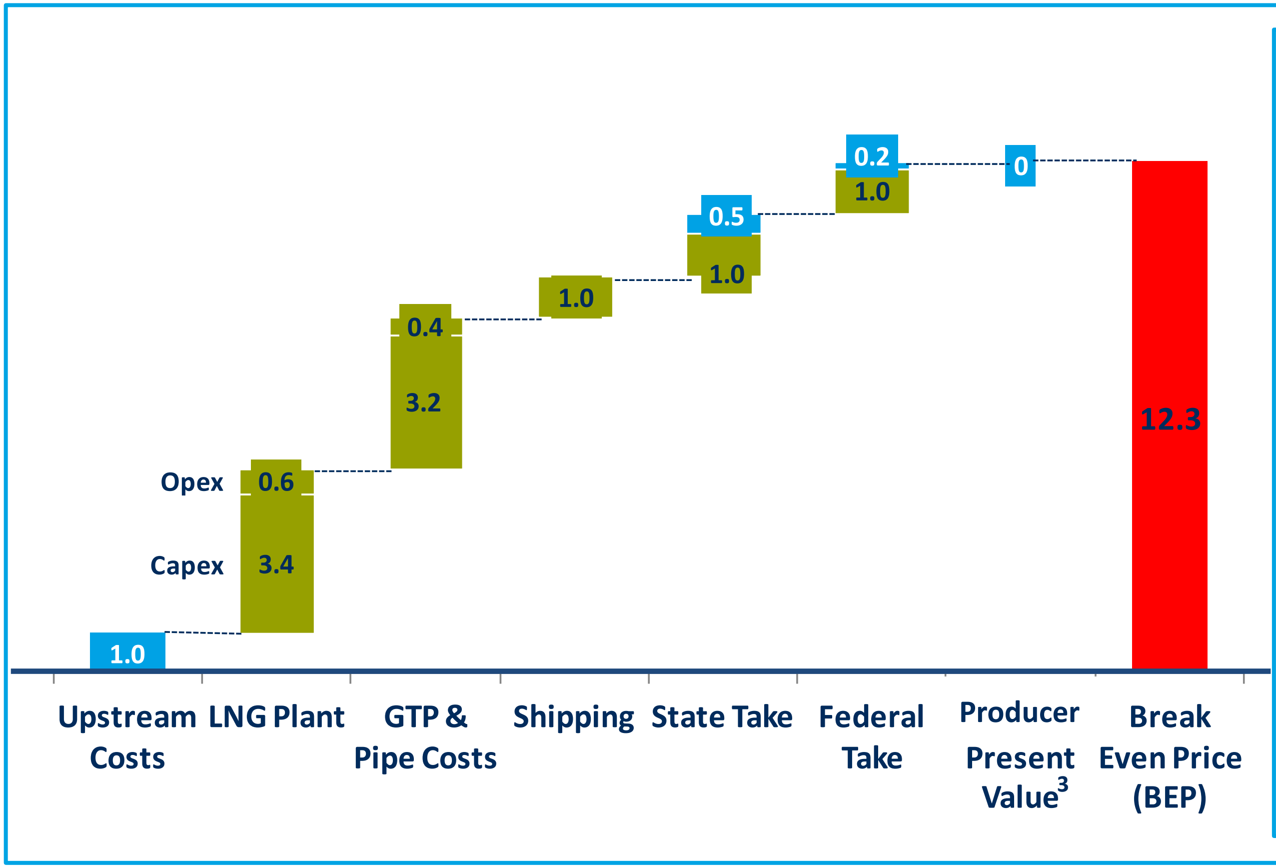


Externalities	Impact on LNG demand in 2030
A Russian defense of oil linkage	36
B Increase in Russian imports	-15
C Additional demand from India & China	138
D Growth in LNG Bunker market	40
E Slower LNG demand growth in new emerging LNG markets	-36
F Development of key inter-regional pipelines to India and China	-65
G Higher production from Shale gas in China	-29
H Take-off of Shale gas in Europe	-36
I "Green world"- Impact of renewable and CO2 policy beyond Europe	-29

SOURCE: Team Analysis

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

(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 Mtpa[2])**
  - **Negative effect of reduced oil production (currently excluded)**
  - **Capex increase, labor cost increase**
- **Can decrease the BEP**
  - **Capital productivity**
  - **Lower returns**

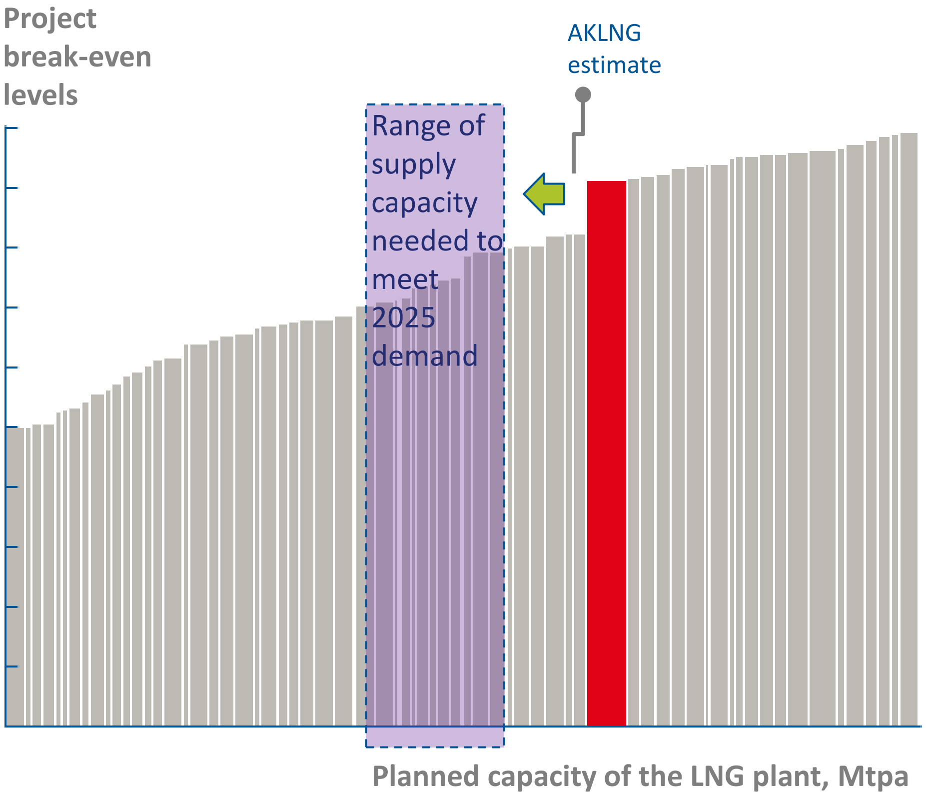
[1] Discount rate used to calculate present value is 8.5% for mid-stream and 10% for upstream

[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

SOURCE: Team Analysis

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



ILLUSTRATIVE CHART, ANALYSIS DONE FOR ALL PROJECTS WITH STARTUP AFTER 2013

IMPLICATIONS:

1 **AKLNG is currently out of the money:**

- Alaska break-even price is US$12.3/MMBtu
- Projects more economic than Alaska can provide ~340 MTPA new supply, more than required to meet global LNG demand (~250 – 300 MTPA)

2 **AKLNG faces significant competition**

- There are several projects to the right in supply stack which will compete with AKLNG

3 **However, the risk levels of competing LNG projects also needs to be considered**

- Due to political, resource and other risks, some in the money projects may be delayed/cancelled, leading to range of needed capacity

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

SOURCE: Team Analysis

SEVERAL APPROVALS FOR LNG EXPORT TO NON-FTA COUNTRIES IN L-48 AND CANADA ARE ALREADY IN PLACE

North America proposed LNG export facilities

		Facility	Owner	Initial Capacity Bcfd	Expected in-service	Export license
Brown-field	7	Carib Energy	Crowley Maritime	0.03	2016	F
	🟨	Sabine Pass	Sabine Pass	2.2	2016	U
	🟨	Freeport - I	Freeport	1.4	2018	U
	🟨	Lake Charles	Lake Charles	2	2018	U
	🟨	Cove Point	Dominion Cove Point	0.77	2019	U
	1	Freeport - II	Freeport	1.4	2021	F
	2	Cameron	Cameron	1.7	2021	F
	9	Elba Island	Southern LNG	0.5	2022	F
	10	Gulf LNG	Gulf LNG Liquefaction	1.5	2025	F
	12	Golden Pass	Golden Pass	2.6	2025	F
Green-field	🟨	Kitimat LNG	Chevron/Apache	0.65	2018	U
	🟨	Douglas Channel	LNG Partners/Haisla Nation	0.12	2018	U
	🟨	Pacific Northwest	PETRONAS	1.0	2018	U
	🟨	LNG Canada	Shell/Mitsubishi/Kogas/Petrochina	3.13	2021	U
	8	Brownsville	Gulf Coast LNG	2.8	2021+	F
	3	Jordan Cove	Jordan Cove	1.2	2021+	F
	4	Oregon LNG	Oregon LNG	1.25	2021+	F
	5	Cheniere	Cheniere Marketing	2.1	2021+	F
	6	Lavaca Bay	Excelerate	1.38	2021+	F
	11	Cambridge (floating)	Cambridge Energy	1.07	2025+	F
	13	South Texas LNG (floating)	Pangea LNG	1.09	2025+	F
	15	Main Pass Energy Hub (floating)	Freeport McMoRan Energy	3.22	2025+	F

🟨 Already approved to all countries

U Approved to all countries

F Approved to FTA[1] countries

\# Position in DOE queue

FTA Countries

- **Australia**
- **Bahrain**
- **Canada**
- **Chile**
- **Columbia**
- **Costa Rica**
- **Dominican Republic**
- **El Salvador**
- **Guatemala**
- **Honduras**
- **Israel**
- **Jordan**
- **Korea**
- **Mexico**
- **Morocco**
- **Nicaragua**
- **Oman**
- **Panama**
- **Peru**
- **Singapore**

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[1] **Free Trade Agreement**

SOURCE: U.S. Department of Energy; International Group of LNG Importers; Pacific Northwest LNG; Team Analysis

THIS MEANS 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

HOWEVER, MANY OF AKLNG'S COMPETITORS ARE FLOATING FACILITIES OR WILL DEAL WITH POLITICAL RISK – 1/2

	Partners	Location	Capacity (mtpa)	Capital cost[1] ($bn)	Comments
Abadi Floating T1	INPEX Shell	Southeast Indonesia	2.5	10.0	Deciding on a floating LNG design, Abadi could reduce its environmental impact and save on costs
BP LNG Libya	BP National Oil Corp (Libya)	Libya	-	-	Currently on hold due to political uncertainty and safety risk to personnel
Mozambique LNG	Anadarko ENH, Mitsui Bharat Videocon PTTEP	Northeast Mozambique	10.0	15.0	Lack of infrastructure and an uncertain regulatory climate weigh against Mozambique's strategic location that allows access to Asian and European markets
Snohvit – T2	Statoil Petoro Total GDF Suez RWE Dea	Hammerfest, Norway	4.3	5.0	Currently on hold, pending further gas discoveries
Pluto T3	Woodside Tokyo Gas Kansai Electric	Karratha, Western Australia	4.2	14.9	The offshore floating facility has had to overcome 2 years of delays and a temporary shutdown in its first year of operations

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[1] Source: Press releases

HOWEVER, MANY OF AKLNG'S COMPETITORS ARE FLOATING FACILITIES OR WILL DEAL WITH POLITICAL RISK – 2/2

	Partners	Location	Capacity (mtpa)	Capital cost[1] ($bn)	Comments
Bonaparte	GDF Suez Santos	Timor Sea, Australia	2.0	-	The floating facility is facing delays and questions regarding GDF Suez's commitment to the project. May miss the opportunity to achieve competitiveness due to its late startup date
Greater Sunrise	ConocoPhillips Woodside Shell Osaka Gas	Timor Sea, Australia	4.0	12.0	Project owners opted for a floating facility to cut costs, causing Timor-Leste regulators to hold up the project
BG Tanzania	BG	Tanzania	-	5.0	Prospective Tanzanian projects face regulatory risk. Tanzanian government has rejected offshore LNG terminals because onshore projects will help the domestic economy more
Block 2 Tanzania	Statoil	Tanzania	-	5.0	Prospective Tanzanian projects face regulatory risk. Tanzanian government has rejected offshore LNG terminals because onshore projects will help the domestic economy more

AKLNG could have a measurable political and technical advantage

[1] Source: Press releases

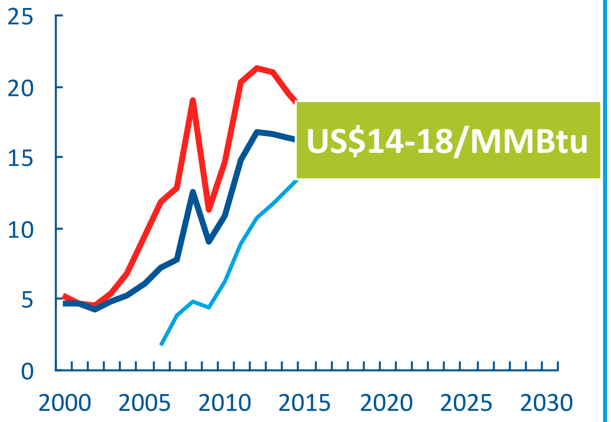
IN THE LONG RUN THROUGH 2030, LNG MARKET CAN EVOLVE WITHIN A BROAD RANGE

🟥 Japan Crude Cocktail
🟦 LNG import to Japan
🟦 LNG import to China
🟩 Typical price range for new Asian LNG contracts

CASE | **FACTORS AFFECTING** | **POSSIBLE PRICE RANGE**

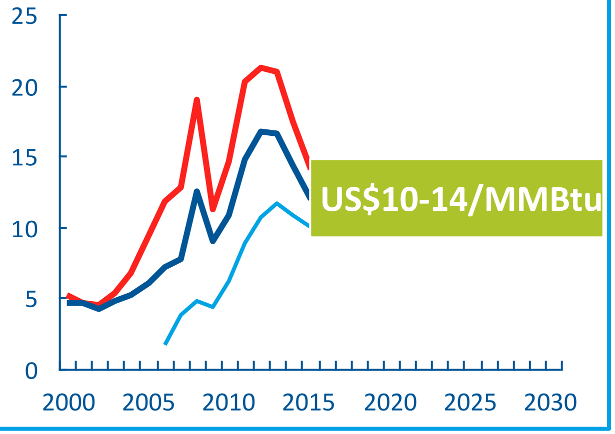
HIGH CASE

- 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

SOURCE: Team Analysis

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

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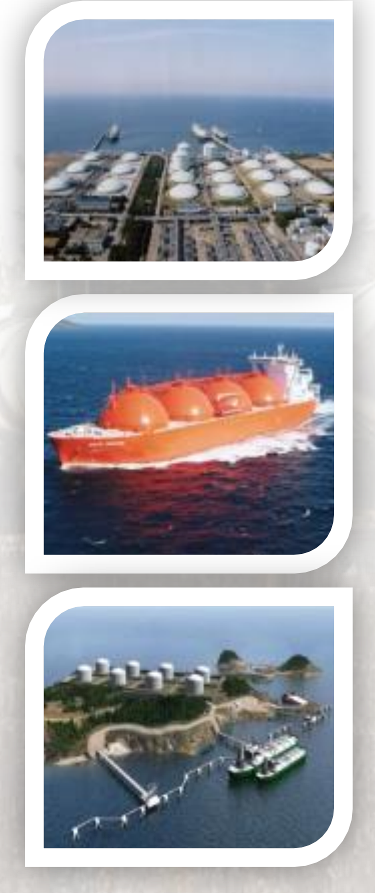
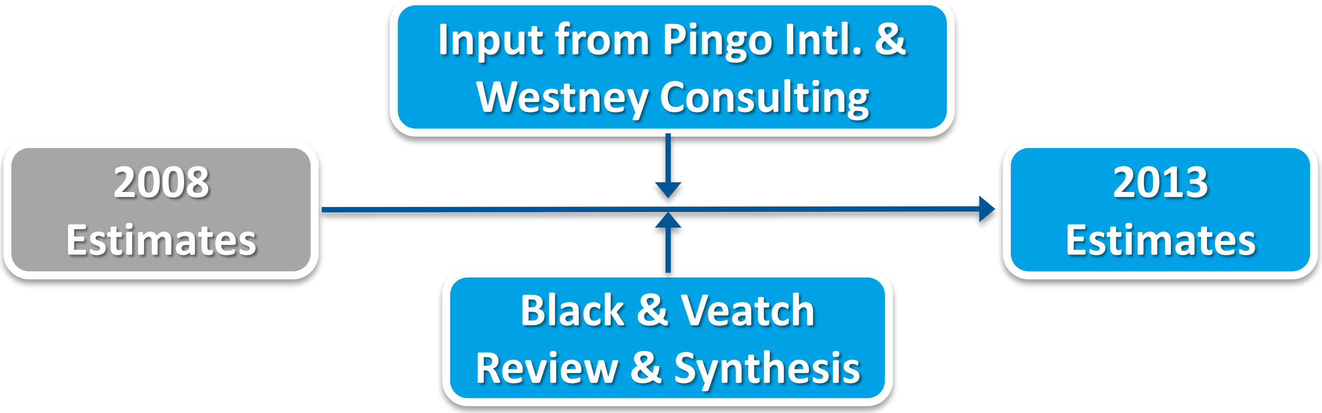


QUESTIONS TO ANSWER BY ITEM AND COVERAGE IN THIS REPORT

	Questions to answer	Covered in this report through
2. Supply Chain Elements	• What are the current cost estimates for the AKLNG project?	• Review of cost estimates from SOA's technical experts by B&V Technical specialists
	• What capital structures and equity rates are applicable to this project?	• Review of capital structures and equity rates from other LNG projects in peer countries
	• What are the appropriate commercial structures that may evolve for this project?	• Listing and descriptions of commercial structures for other LNG projects • Examples from LNG projects in peer countries

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



Input from Pingo Intl. & Westney Consulting

2008 Estimates

2013 Estimates

Black & Veatch Review & Synthesis

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**

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

ESCALATION OF GTP CAPITAL COSTS FROM PREVIOUS ESTIMATES

GTP Cost Factor	2008 Assumptions	2013 Updates
Breakdown by Sub-Element	• $5 Billion - Total Project Cost	• $10 Billion - Total Project Cost – $6 Billion - Base Cost – $2 Billion - Labor, Productivity & Risk Contingency – $2 Billion - Owner’s Cost
Uncertainties in Estimates		• $1 - 2 Billion on Total Project Cost • Main risk factors: – Project scope – Cost of skilled work force

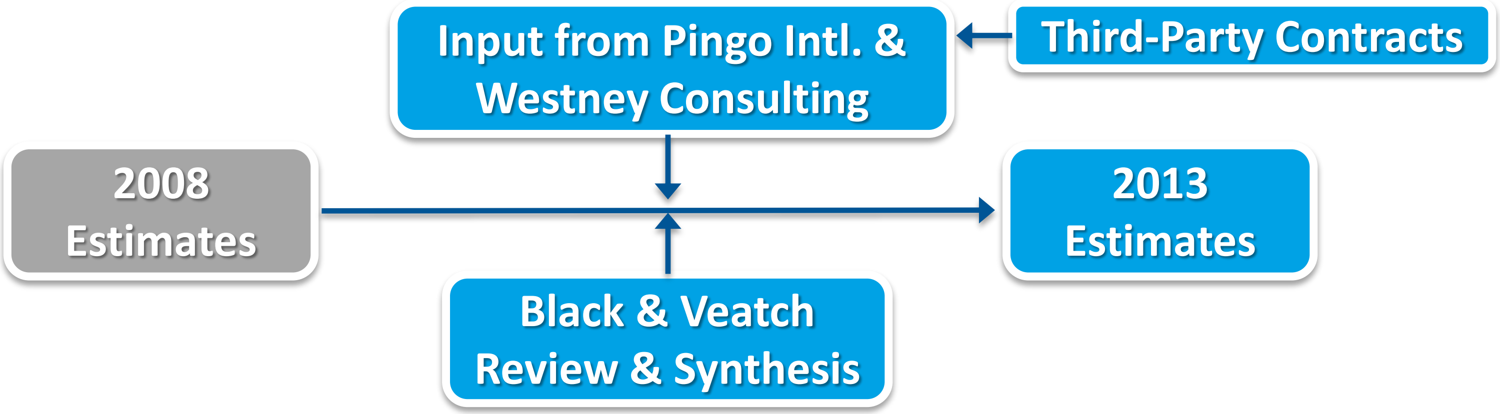
REDUCTION IN PIPELINE CAPITAL COSTS TO ACCOMMODATE PIPE SIZE AND LATEST DESIGN INFORMATION

Pipeline Cost Factor	2008 Assumptions	2013 Updates
Pipeline Diameter	• 48 inches; 42 inches	• 42 inches – Less steel – Lower installation costs
Compressor Stations	• 6 compressor stations • Pipeline operating at 2,500 psi	• 8 compressor stations • Pipeline operating at 2,050 psi • Gas heat content of 1,100 Btu/scf
Net of Design Changes		• Cost reduction from smaller diameter is greater than cost increase for additional compressors • Labor and material cost increases drive overall increase in pipeline costs

LNG PLANT COST ESTIMATES HAVE INCREASED; DRIVEN BY LABOR PREMIUMS

LNG Cost Factor	2008 Assumptions	2013 Updates
Facility throughput		• 3 trains @ 5.8 Mtpa each • Total capacity of 17.4 Mtpa • Input gas at 2.5-3 Bcf/d and 1,100 Btu/scf
Breakdown by Sub-Element	• $14 Billion - Total Project Cost	• $23 Billion - Total Project Cost – ~$1,600/ton • $1,200/ton base • 35% adder (including 10% for Alaska-specific materials/logistics and 25% premium for labor)
Uncertainties in Estimates		• Upwards to $2,500/ton driven mostly by labor and productivity uncertainties

PROJECT OPERATING COSTS ARE ESTIMATED AT HIGH LEVEL GIVEN THE PRELIMINARY NATURE OF PROJECT DEFINITION



Supply Chain Element	State Estimate	Observations	Producer Estimate
GTP	2% capex		2% capex
Pipeline	1% capex	• Producer estimate seems high relative to industry peers	2% capex
LNG	2% capex	• Producer estimate equivalent to \$0.58/MMBtu at 90% utilization • Industry averages are \$0.50-\$0.80/MMBtu	2% capex

SHIPPING COSTS ARE DRIVEN BY THE NUMBER OF SHIPS AND CHARTER RATES NEGOTIATED

Illustrative Cost of Shipping for Ex-Ship Sales for State of Alaska Sales Volumes

Commercial Factor	Shipping portfolio design characteristics
Off-Take	• 20%
Portfolio Sales	• 50% JKT • 25% China • 25% India
Ocean Tankers	• **5-7 ships at ~$230 Million each**
Shipping Contracts	• Long-term time charters with ship owners • Annual payments of ~$33 Million per ship • $75K/day with $65K fixed & $10K subject to inflation • Performance Guarantee required to ship owner

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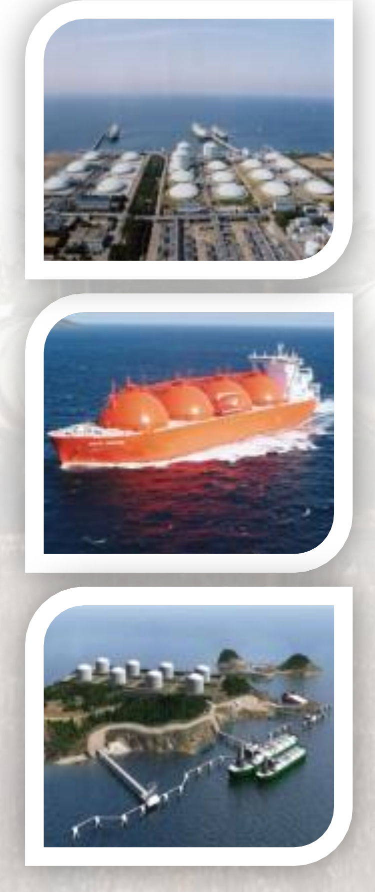


CAPITAL STRUCTURES VARY FROM PROJECT TO PROJECT DEPENDING ON RISK PROFILE AND PARTNER PREFERENCES

	Partners	Capital Structure (Debt/Equity)	Comments
NLNG	NNPC Shell Eni Total	**50/50**	Located on Bonny Island, **Nigeria LNG** produces 22 Mtpa and is comprised of 6 trains. High equity component due to location risk.
Ichthys	INPEX Total Tokyo Gas Osaka Gas Chubu Toho Gas	**60/40**	Currently under construction, project located in Darwin, Australia, **Ichthys LNG** is expected to produce 8.4 Mtpa when operations commence in ~2017. JBIC financing
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
Angola LNG	Sonangol Chevron BP Total Eni	**0/100**	**Angola LNG** commenced operations in 2013 after years of delays. All equity structure was necessitated by project location, structure and timing risks. Plant capacity is 5.2 Mtpa.

A combination of debt and equity weighted towards debt, i.e. 70/30 Debt/Equity, is commonly used – either at a project level or on the sponsors balance sheets

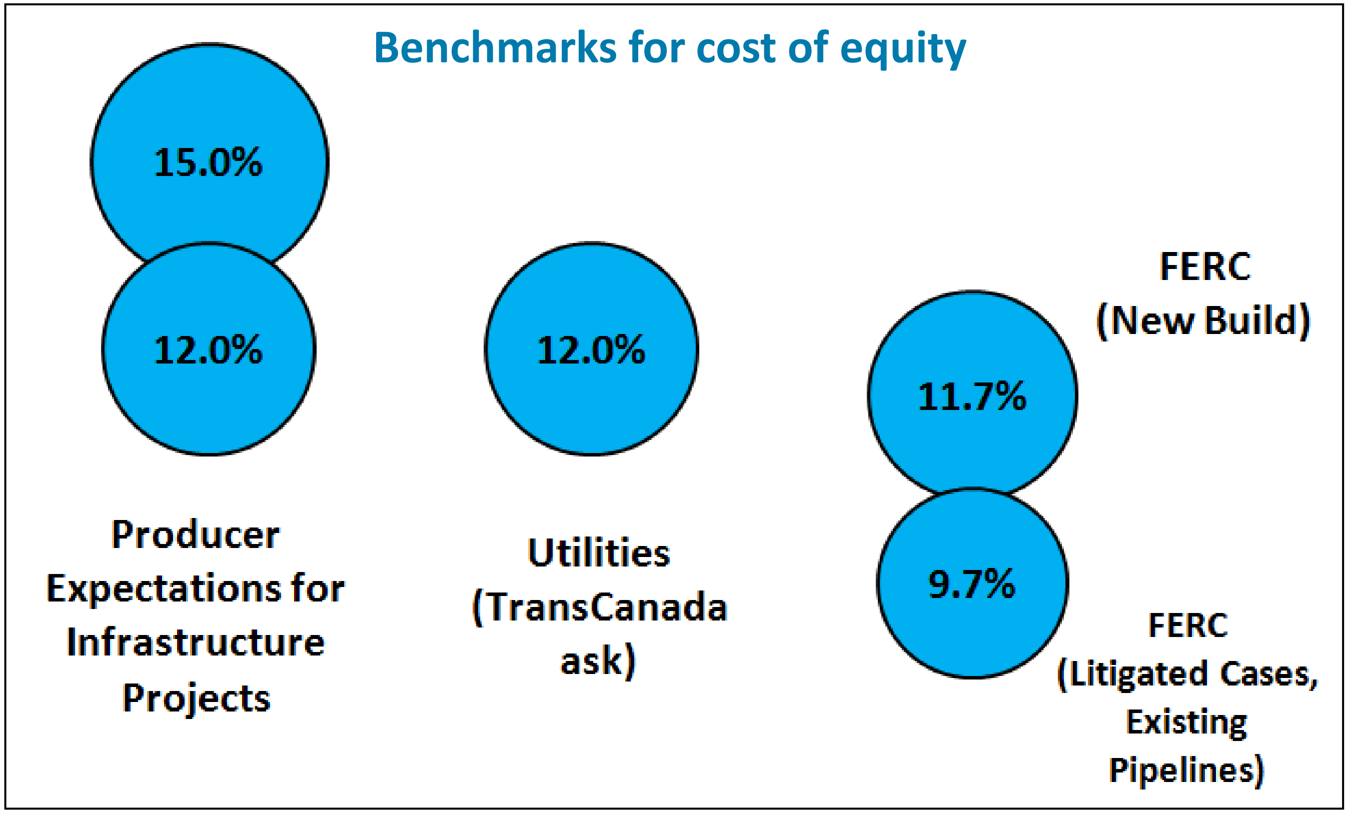
CAPITAL STRUCTURES VARY FROM PROJECT TO PROJECT DEPENDING ON RISK PROFILE AND PARTNER PREFERENCES

	Partners		Capital Structure (Debt/Equity)	Comments
PNGLNG	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. PNGLNG is an integrated project and was the beneficiary of $8.3 billion in loans and guarantees from public export credit agencies.
APLNG	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 mpta project is currently under construction and first LNG is expected in 2015. The project is financed through equity contributions from the partners.

THE DEBT / EQUITY RATIO THAT THE MARKET CAN SUPPORT FOR A GIVEN PROJECT IS DRIVEN BY THE FINANCIAL STRENGTH OF THE PARTNERS

- Current market supports 70/30 with possibility of 75/25 debt/equity ratio on integrated and tolling structure projects
- Compared with AKLNG, Qatargas financing is most similar in scope and quality of partners should project finance be pursued by project sponsors
- Gorgon structure is the most similar in scope and quality of partners if an all equity, balance sheet financed structure is preferred by project sponsors

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



COMMERCIAL STRUCTURE OF PROJECT INFLUENCES RISK AND CONTROL

Integrated

- Aligned interest
- Cost and risk sharing
- Concentrated control

Merchant

- Less capital requirement for individual sponsors
- Separation of control between upstream and LNG project

Tolling

- Contractually assured fees and returns
- Accommodates supply from multiple upstream sources
- No market upside for LNG project

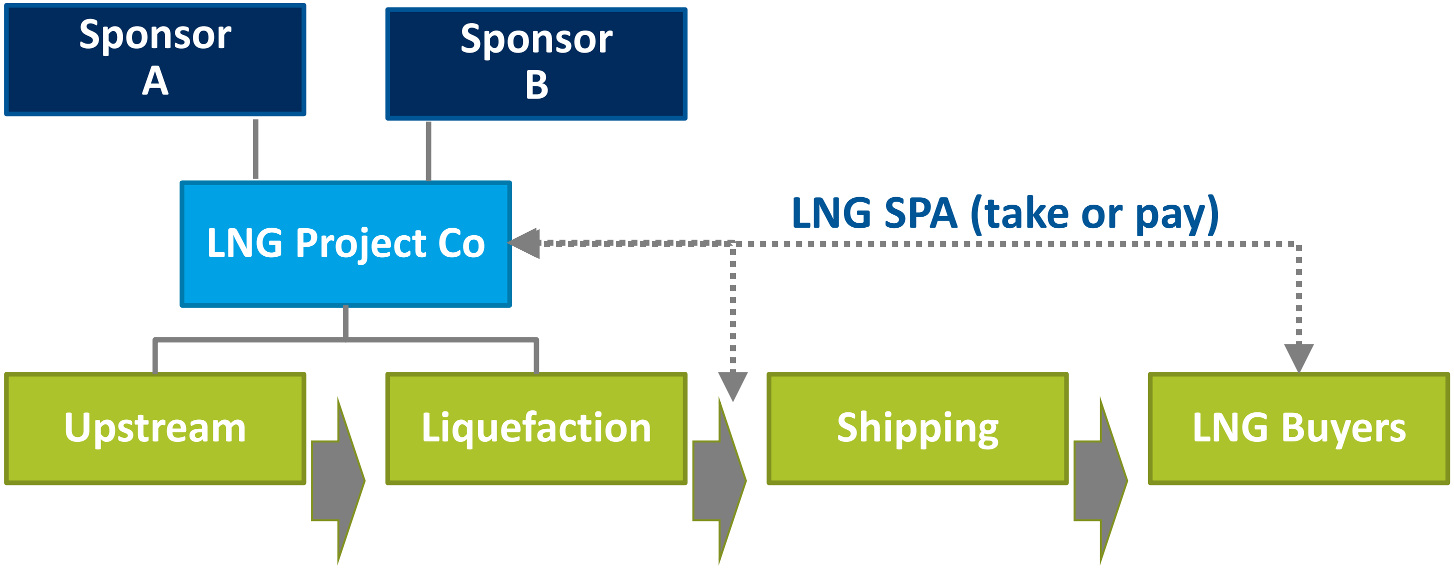
Each structure affects the operations and financing costs of the GTP, pipeline, LNG plant, and the shipper

ACHIEVEMENT OF KEY OBJECTIVES FOR THE STATE ARE DEPENDENT ON THE PROJECT'S COMMERCIAL STRUCTURE

- **It is important to understand how the ultimate structure of the AKLNG project could impact the criteria that are important to the State:**
  - Commercial viability of AKLNG project
  - Open access
  - Expandability
  - Transparency across the supply chain

INTEGRATED LNG PROJECT STRUCTURE

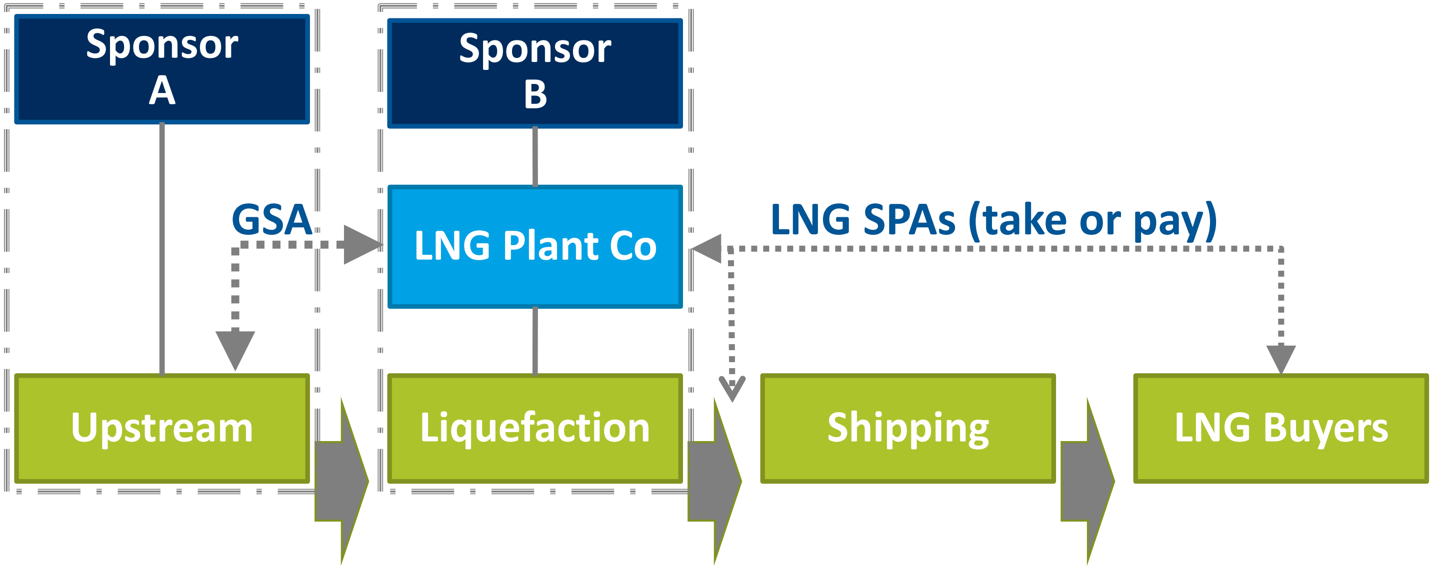
- **One LNG Project Company**
  - Same multiple sponsors in the upstream and liquefaction segments
  - Common ownership interests across the LNG chain
  - Sales and Purchase Agreement (SPA) directly between LNG Project Co and LNG Buyers – either FOB or DES
  - Examples: PNG, QatarGas II, RasGas, Sakhalin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



Sources: Sumitomo, B&V Research

NON INTEGRATED LNG PROJECT STRUCTURE (MERCHANT)

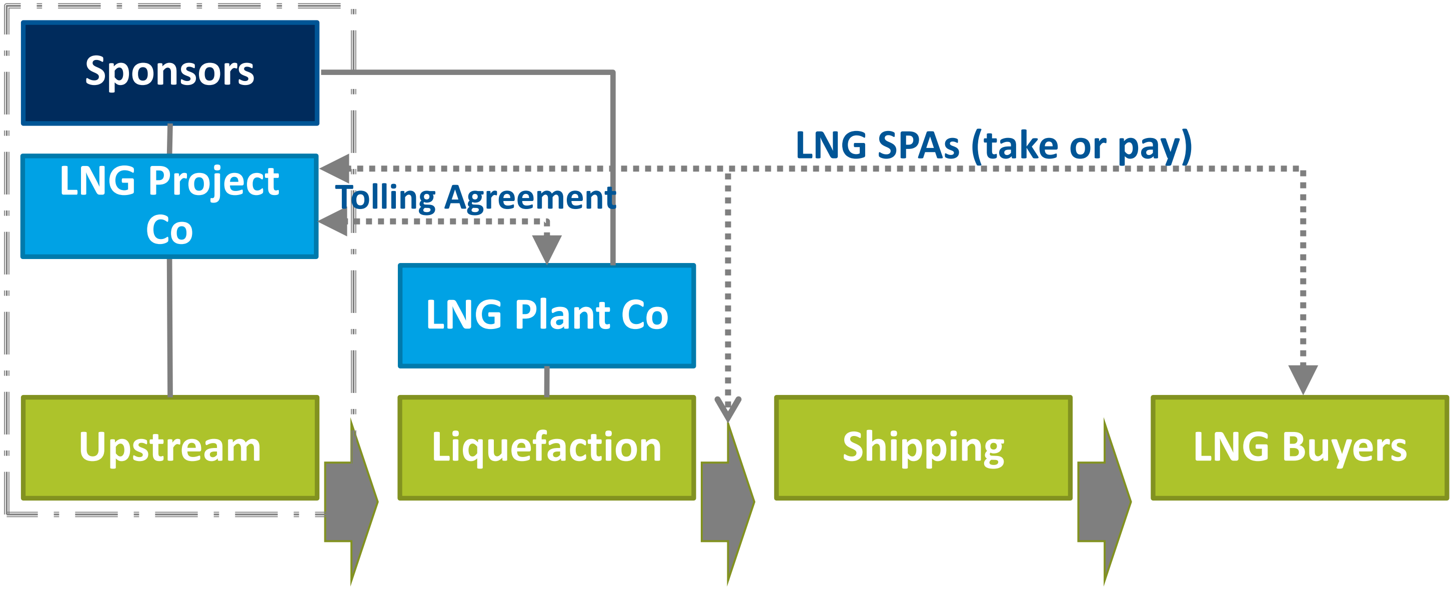
- **Legal Separation Between Sponsors of Upstream and Liquefaction Segments**
  - Different shareholding interests between upstream, midstream and liquefaction
  - Gas Sales Agreement (GSA) between LNG Project Co/Borrower and Upstream shareholders
  - Examples: Peru LNG, QatarGas, NLNG (Nigeria), Brunei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



Sources: Sumitomo, B&V Research

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	• 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	• Capital requirements are high and span the supply chain • Concentrated control makes expansions and entry of new participants difficult
Merchant	• 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	• 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	• Contractually assured fees and returns — 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	• No participation in market upside for LNG Plant Co

State does not participate in upstream

MOST LNG PROJECT STRUCTURES LEAN TOWARDS AN INTEGRATED STRUCTURE

Project	Startup	Upstream	Transport to liquefaction plant	Liquefaction
Darwin LNG	Dec 2005	ConocoPhillips		
EG LNG	May 2007	Marathon		
Snøhvit	Oct 2007	Statoil		
Sakhalin II	Mar 2009	Gazprom		
Tangguh	Jul 2009	BP		
Yemen LNG	Nov 2009	Total		
Peru LNG	Jun 2010	Pluspetrol	Transportadora de Gas del Peru	Hunt Oil
Pluto LNG	Jun 2012	Woodside led		
Angola LNG	Jul 2013	Multiple	Sonangol/Chevron led	
QC LNG	2014	QGC (BG)		
Gorgon LNG	2015	Chevron-led		
APLNG	2015	Origin, ConocoPhillips		
Sabine Pass	2015	Multiple	Multiple	Cheniere
Wheatstone	2016	Chevron + Apache	Chevron	

Source: Team Analysis

CASE EXAMPLE FOR INTEGRATED SUPPLY CHAIN STRUCTURE: PAPUA NEW GUINEA (PNGLNG)

Background

- Location: Papua New Guinea
- Cost: $19 billion (includes upstream development costs and 435-mile pipeline to LNG plant
- Under construction; first gas 2014
- Capacity: 0.9 Bcfd (6.9 Mtpa)

	Upstream → Transport to liquefaction plant → Liquefaction
Equity Owners	ExxonMobil (33.2 percent), Australian-based firms Oil Search Ltd. (29 percent) and Santos Ltd. (13.5 percent), Japan Papua New Guinea Petroleum Co. and Nippon Oil Exploration Ltd. (combined 4.7 percent). The three state-controlled Papua New Guinea firms (totaling 19.6 percent) are Mineral Resources Development Co. Ltd., Petromin PNG Holdings Ltd. and The Independent Public Business Corp. of Papua New Guinea.
LNG Buyers	China Petroleum and Chemical Corp. (Sinopec) at almost 100 billion cubic feet per year, Osaka Gas Co. Ltd. at almost 75 bcf per year, Tokyo Electric Power Co. Inc. at almost 90 bcf per year and Taiwan's Chinese Petroleum Corp. at almost 60 bcf per year.
Project Structure	Integrated 70% Debt, 30% Equity
Benefits	Integrated structure allows risk across entire supply chain to be equally shared, all parties bear the risk of cost overruns. Fully integrated project structure along with Japanese participation in the midstream and as customers allowed for JBIC financing offering under favorable terms.

Source: Team Analysis

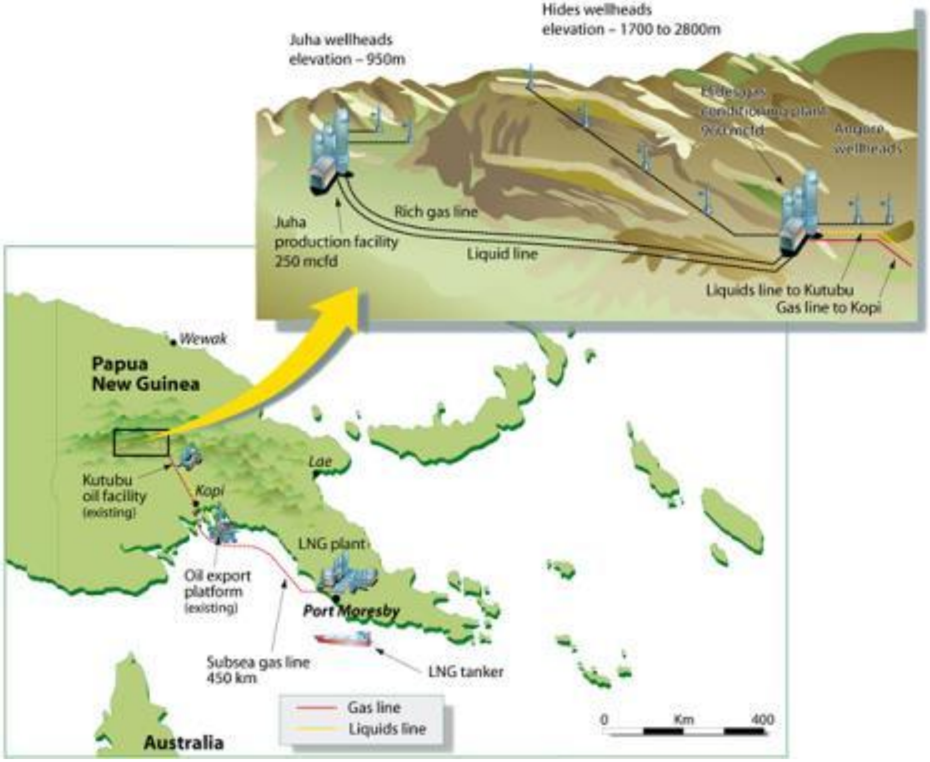
PNGLNG VS. AKLNG

Similarities

- Primarily driven by interests of **ExxonMobil** and stranded gas reserves
- **High cost**, complex project constructed in harsh conditions
- **Risks of midstream supply chain shared** based on equity ownership
- **Local participation** with 3 Papua New Guinea entities (19.6% equity)

Differences

- **Project finance** @ 70/30
- XOM participation allowed for US Export-Import Bank to provide $3 billion in loans and guarantees to the project
- **XOM provided debt** of $3.5 billion in addition to equity
- **LNG sold by Project company** not individual equity holders



Source: B&V Research

CASE EXAMPLE FOR INTEGRATED SUPPLY CHAIN STRUCTURE: AUSTRALIA PACIFIC (APLNG)

Background

- Location: Queensland State, northeast coast of Australia
- Cost: $23 billion (includes gas field development costs)
- Gas supply is from coal seam production
- Service start: Under construction;
  first gas from Train 1 in 2015, followed by Train 2 in 2016
- Capacity: 1.2 bcf/d (9.0 Mtpa)

	Upstream	Transport to liquefaction plant	Liquefaction
Equity Owners	Origin (37.5%), ConocoPhillips (37.5%), Sinopec (25%)		
LNG Buyers	Sinopec: 7.6 Mtpa for 20 years Kansai Electric Power: 1 Mtpa for 20 years		
Project Structure	Integrated throughout the supply chain, upstream includes the development of coal bed methane		
Benefits	Integrated structure allows risk across entire supply chain to be equally shared, all parties bear the risk of cost overruns. 90% of project volume sold to Sinopec		

Source: Team Analysis

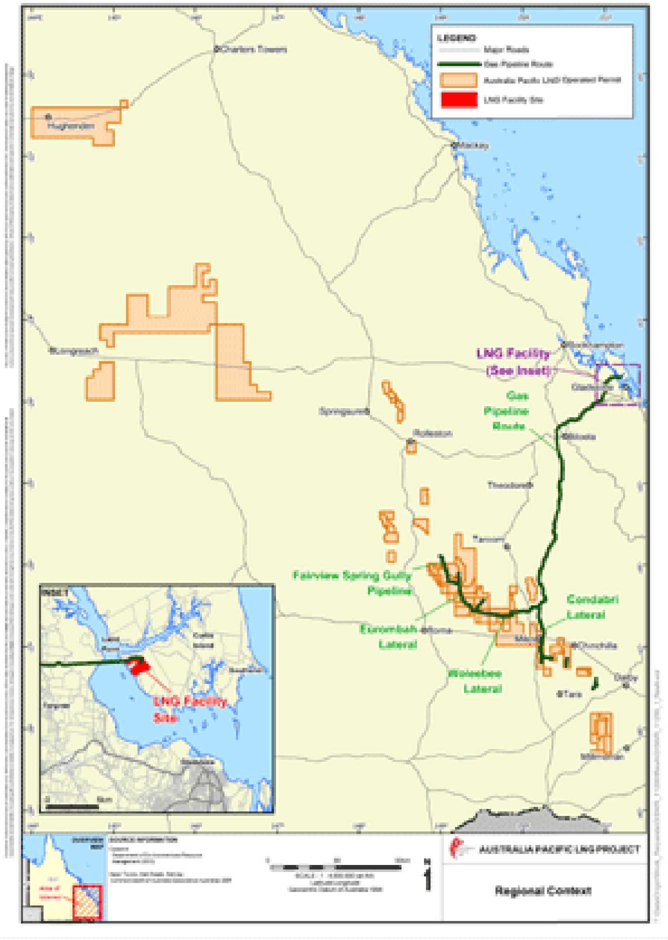
APLNG VS. AKLNG

Similarities

- Primarily driven by **interests of large producers** with excess gas reserves
- **Long distance pipeline** required (~320 miles)
- **Risks** of supply chain **shared** based on equity ownership
- In addition to LNG exports incremental **gas supply is expected to serve local** power generation markets in Queensland

Differences

- **LNG sold by Project company** not individual equity holders
- **Primary Buyer** (Sinopec) is an equity participant



Source: B&V Research

CASE EXAMPLE FOR INTEGRATED SUPPLY CHAIN STRUCTURE: GORGON LNG

Background

- Location: Northwest coast of Australia
- Cost: $52 billion (includes gas field development costs)
- Service start: Under construction; first gas 2015
- Capacity: 2 bcf/d (15.6 Mtpa)

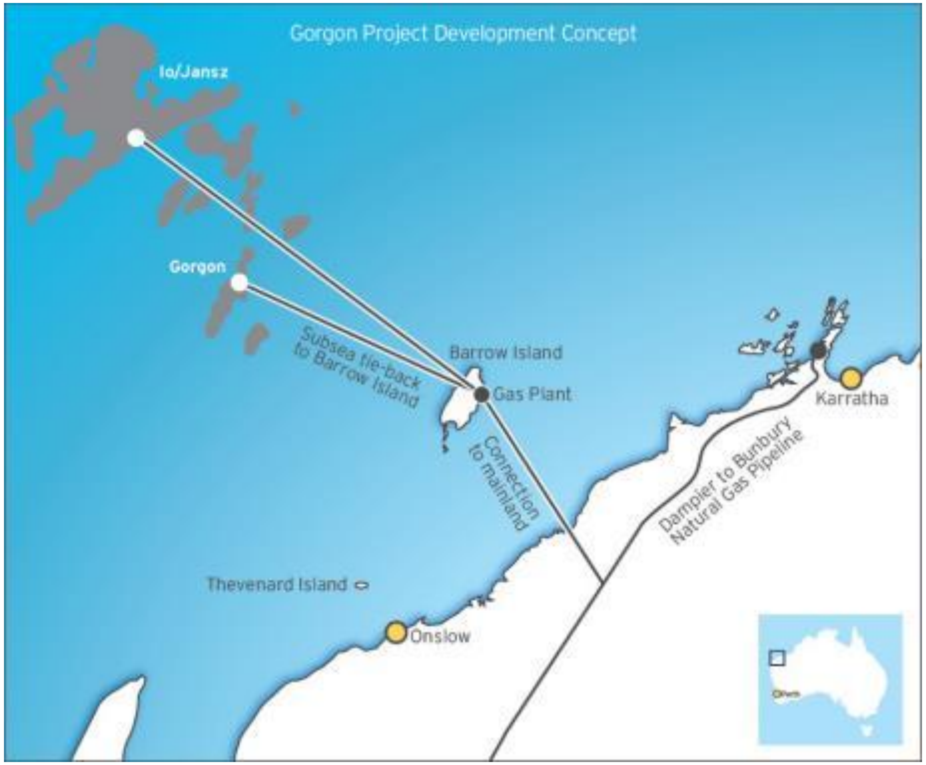
	Upstream	Transport to liquefaction plant	Liquefaction
Equity Owners	Chevron (47.3%), Shell (25%), ExxonMobil (25%), Osaka Gas (1.25%), Tokyo Gas (1%), Chubu Electric Power (0.417%)		
LNG Buyers	Chevron has SPA's with the 3 Japanese utilities Osaka Gas, Tokyo Gas and Chubu as well as GS Caltex of Korea. ExxonMobil's customers include Petronet (1.5 Mtpa) and PetroChina (2.3 Mtpa). Shell has entered into SPAs with PetroChina as well and has a MOU with Gujarat State Petroleum Corp of India for about 1.0 Mtpa.		
Project Structure	Upstream separate equity interests, midstream transportation and liquefaction is integrated, Equity lifting rights. 100% equity financed.		
Benefits	Integrated structure allows risk across entire supply chain to be equally shared, all parties bear the risk of cost overruns. Fully integrated project structure along with Japanese participation in the project allowed for JBIC financing for Japanese partners.		

Source: Team Analysis

GORGON VS. AKLNG

Similarities

- Primarily driven by **interests of large producers** with stranded gas reserves
- **High cost**, complex project requiring **gas treatment** and **carbon sequestration** facilities
- **Risks** of midstream supply chain **shared** based on equity ownership
- Each producer has **equity lifting** rights equal to production shares
- In addition to LNG exports approximately 100-300 MMcf/d of the produced gas is expected to serve **local markets** in Western Australia



Differences

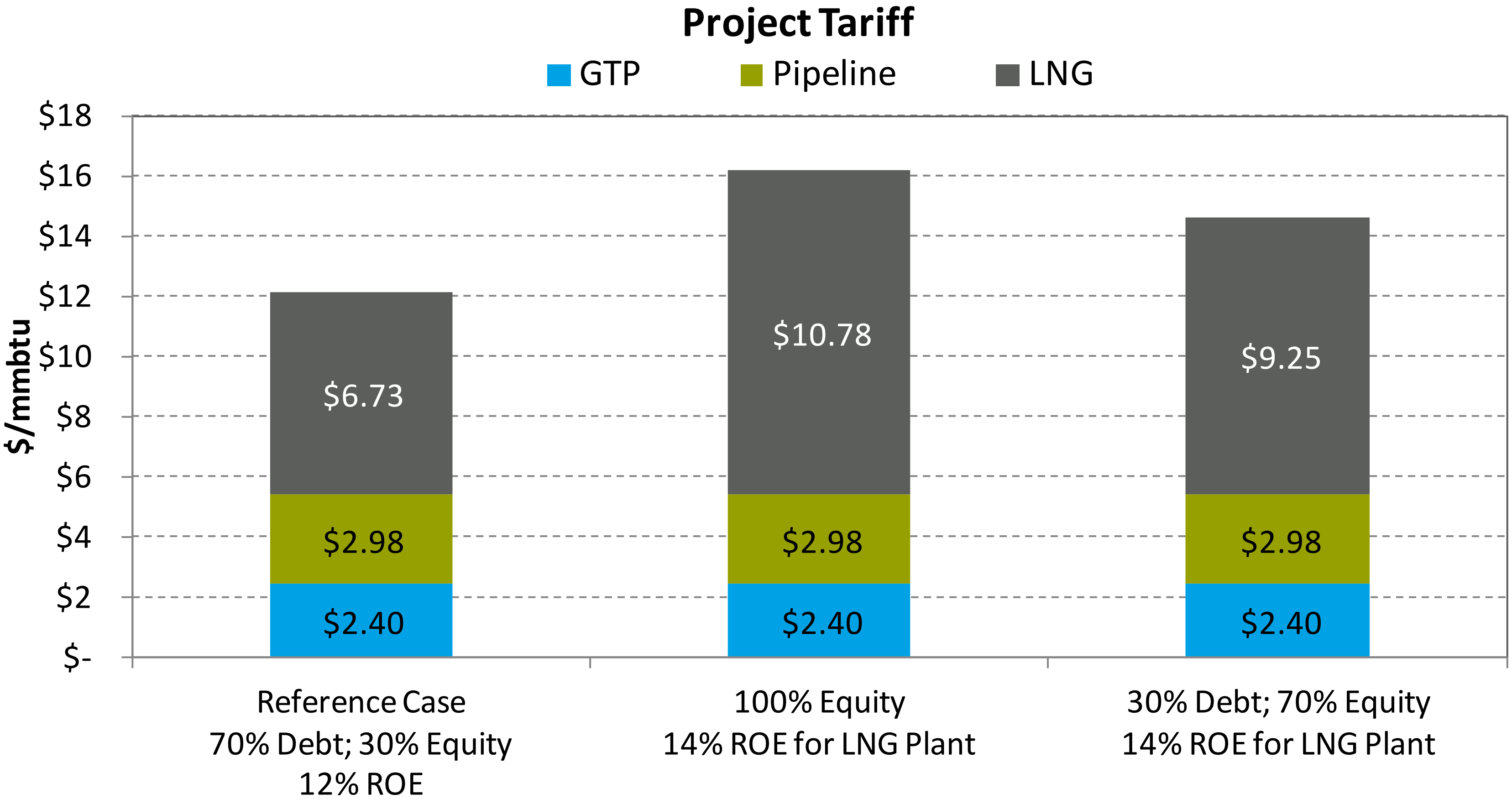
- **No equity participation by State or Federal governments (no RIK or tax gas)**

Source: BV Research

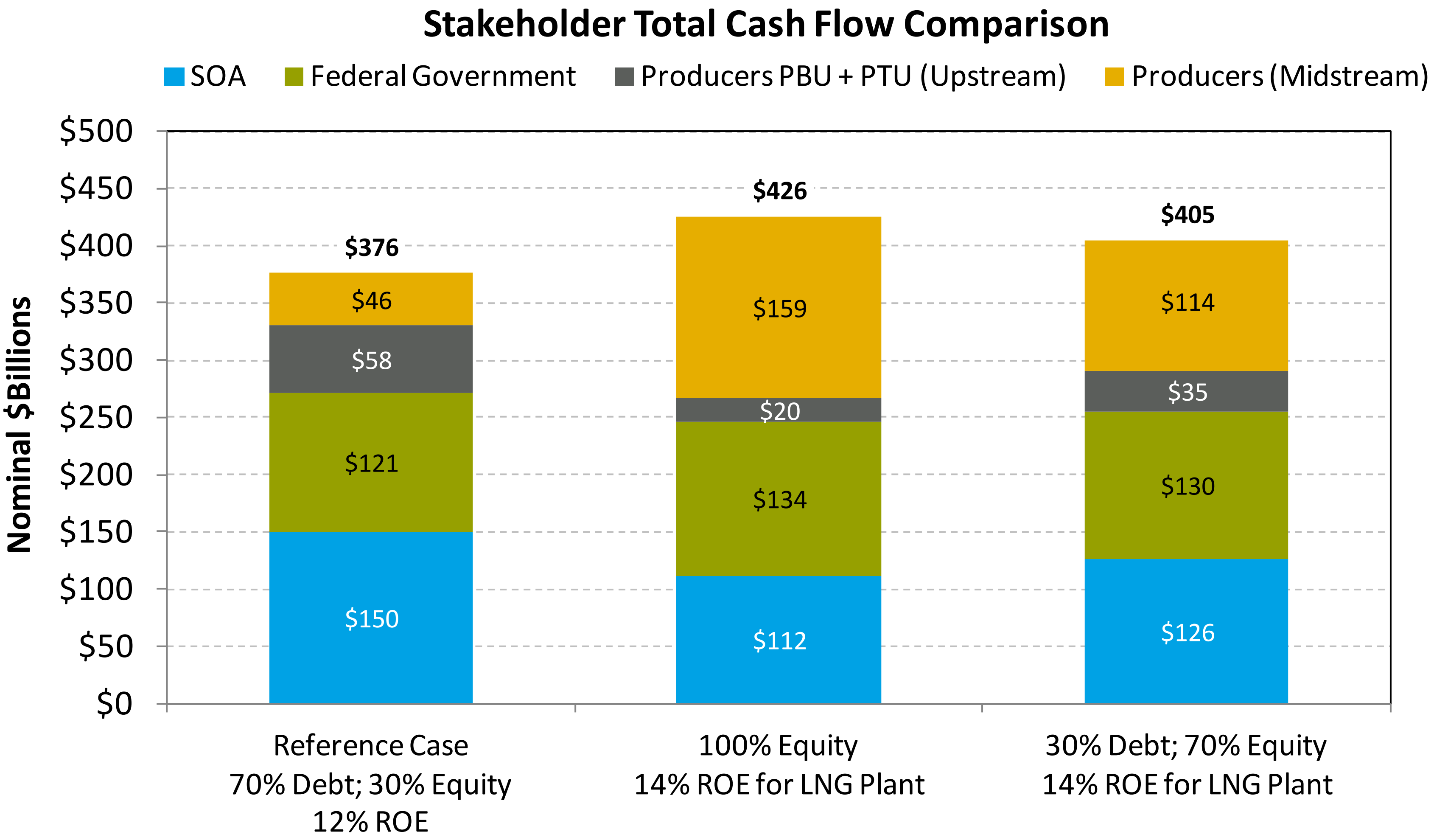
COMMERCIAL STRUCTURE OF AKLNG PROJECT COULD DRIVE MISALIGNMENT BETWEEN THE STATE AND PRODUCERS

- **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**

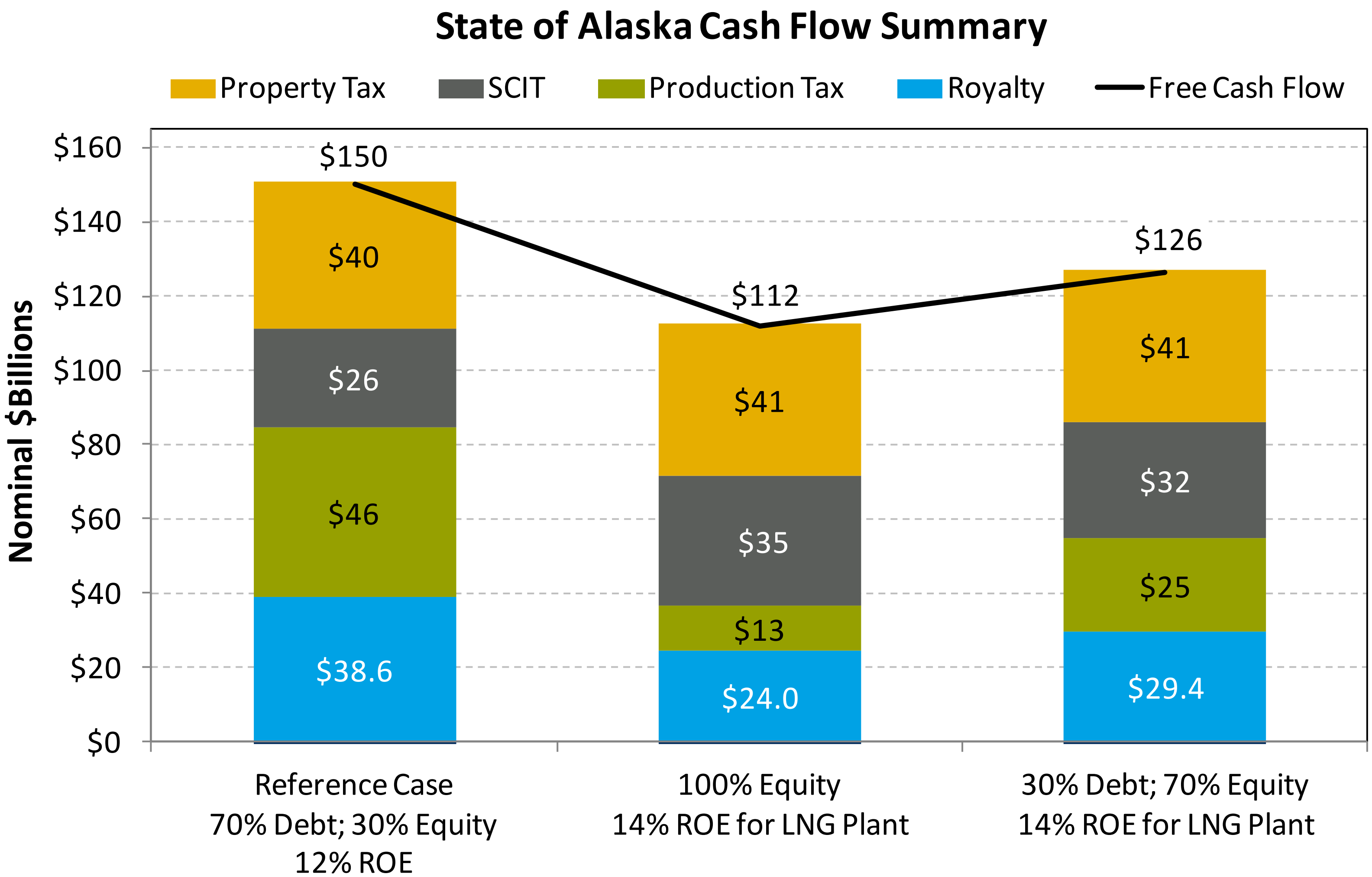
EQUITY-RICH FINANCING STRUCTURE DRIVES A HIGH TARIFF FOR LNG PLANT



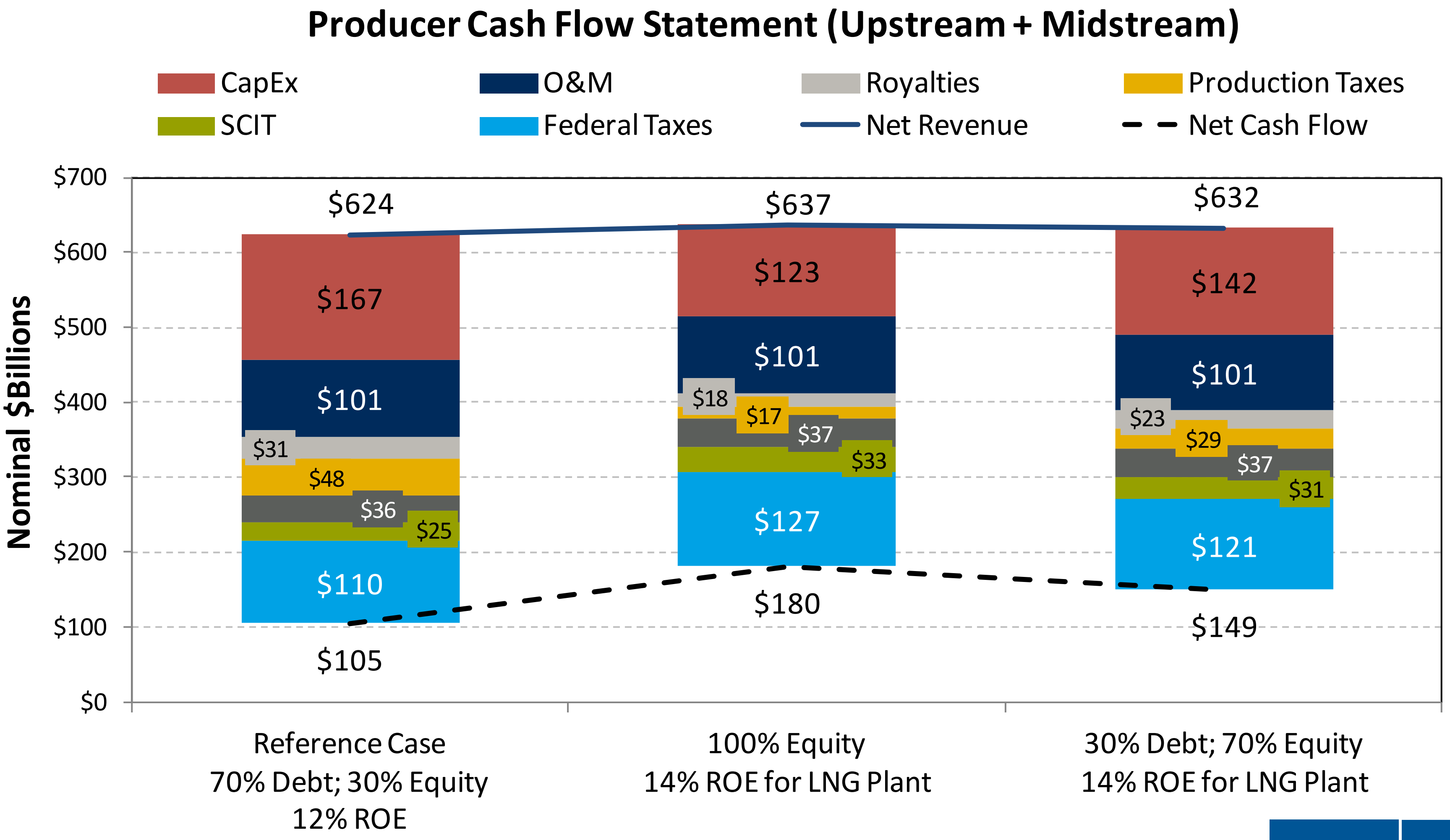
PRODUCERS GAIN NET CASH FLOWS THROUGH THEIR MIDSTREAM COMPONENTS AT THE EXPENSE OF THE STATE



STATE COULD POTENTIALLY LOSE BILLIONS OF DOLLARS OF VALUE FROM AKLNG PROJECT THROUGH MISALIGNMENT



PRODUCERS COULD GAIN TOTAL CASH FLOWS WITH MORE EQUITY AND HIGHER ROE FOR THE LNG PLANT



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

- **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

CONTENTS

- AKLNG Project Overview
- LNG Markets
- Supply Chain Elements
- Fiscal Framework
  - **Overview of International Fiscal Systems**
  - Fiscal Incentives
  - Royalty in Kind vs. Royalty in Value
- Risk Allocation & Commercial Structure

QUESTIONS TO ANSWER BY ITEM AND COVERAGE IN THIS REPORT

	Questions to answer	**Covered in this report through**
3. Fiscal Framework	• What fiscal structures exist outside of Alaska with respect to the ownership stake of host countries?	• A list and description of fiscal structures currently being used in the market • Tables with specific examples of agreements between governments and LNG projects with respect to the tax structure, royalty system, and incentives
	• What are the risks and opportunities associated with these structures?	• Explain the criteria that drive the selection of fiscal structures
	• What incentives are appropriate? – When should they happen? – How should their value to the project – be measured? – What commensurate actions by each of the parties are appropriate?	• List all of the "levers" Alaska could pull and explain the benefits and costs they could bring to the state • Analyze the net benefits to the state assuming a given level of incentives

A SUCCESSFUL FISCAL SYSTEM BALANCES THE INTERESTS OF THE HOST GOVERNMENT AND THE CONTRACTOR

A well-designed fiscal system

Host government

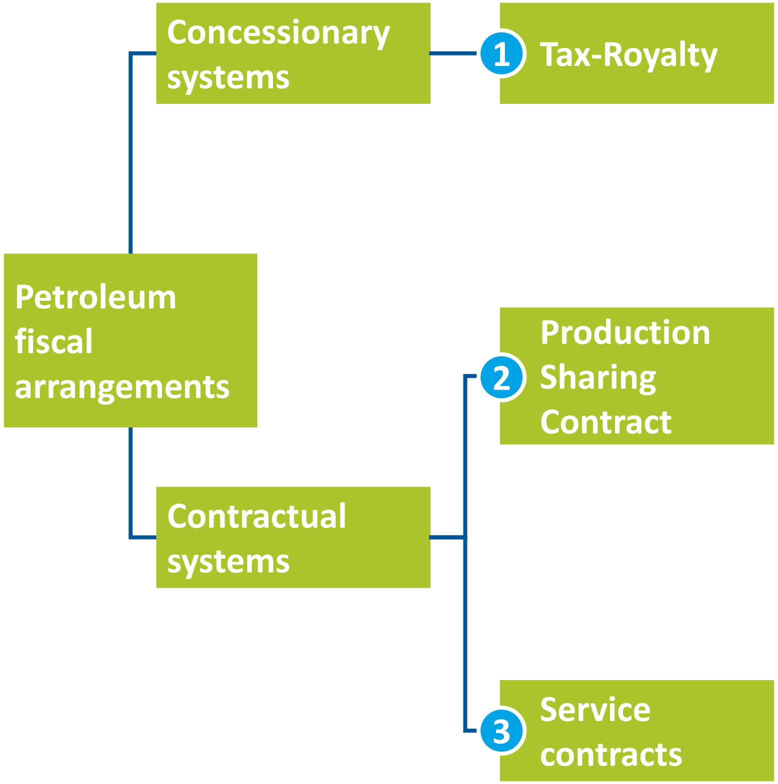
- Is **predictable** with **stable revenues**
- **Provides exposure to 'upside'** (i.e. higher revenues at higher prices)
- Is flexible over the long time periods
- **Encourages development of resources** by allowing investors a reasonable chance to earn a sufficiently **attractive return**
- Promotes **alignment** between **stakeholders**
- Encourages **optimal** and **efficient** development
- Is **competitive** with other governments
- Has **low administration costs**

Contractor

- Is **transparent, stable** and offers **"certainty"**
- Minimizes the **upfront loading of investment** or payments
- Provides an **attractive return** on oil and gas investments over the full project life
- Enables **repatriation of proceeds** to the parent company

SOURCE: Team Analysis

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



- Petroleum fiscal arrangements
  - Concessionary systems
    - ① Tax-Royalty
  - Contractual systems
    - ② Production Sharing Contract
    - ③ Service contracts

Fiscal system	Simple description	Examples
① Tax-Royalty	• 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.	• U.K. • U.S. • Norway • Australia • Russia • Canada
② Production Sharing Contract	• Title to hydrocarbons resides with host government • Production in kind is shared between the contractor and the government at the export point – A basic PSC has royalty, cost oil, profit oil and taxes	• Nigeria • Angola • Russia • Algeria • Kazakhstan • Indonesia • Qatar
③ Service contracts	• Title to hydrocarbons resides with host government • The contractor is reimbursed and paid a fee, typically in cash. These are rare and unpopular	• Iran • Iraq • Mexico • Ecuador • Russia

SOURCE: Team Analysis

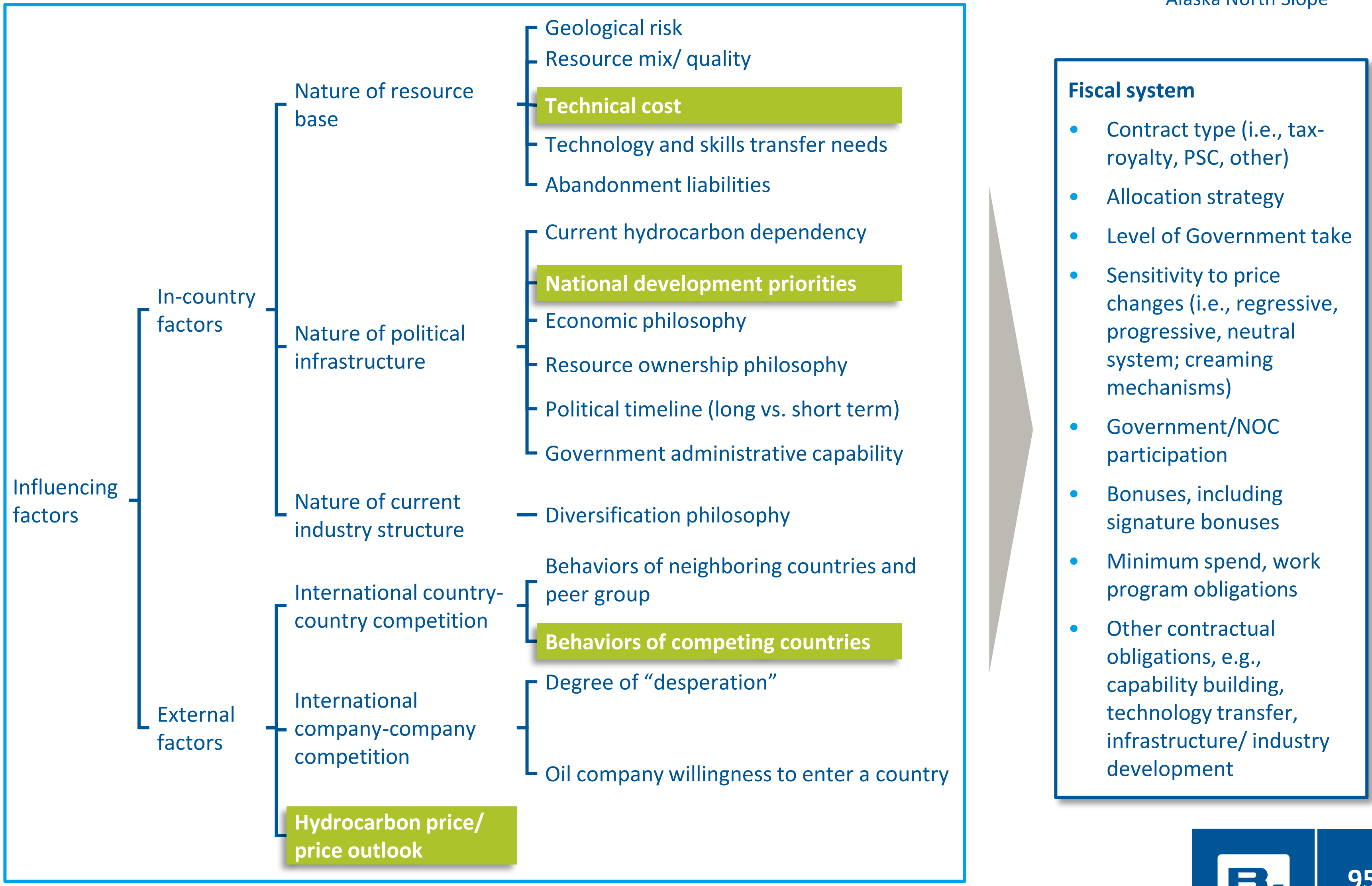
SUMMARY OF KEY DIFFERENCES AMONG FISCAL SYSTEMS

	① Tax royalty	② Production sharing contract	③ Service contracts
Reserves ownership	• **Concession holder** has title to reserves at the wellhead	• **Government** retains title but Contractor entitled to share at Export Point	• **Government** retains title to reserves
Costs	• **Concession holders bear** exploration, development and production costs • **Costs repaid from** project **net revenue** – Opex in-year – Capex following DD&A schedule – Costs audited by taxing authority	• **Contractor bears** exploration, development and production costs • **Costs repaid from** share of production (‘cost oil’) – Opex in-year – Capex following DD&A schedule – Costs audited to ensure compliance with PSC	• **Contractor bears** most **costs** • Contractor supplies operating staff, and recovers costs according to **agreed compensation scheme** – Compensation can be $/bbl – Can include some incentives – **Little/no upside**
Govern-ment revenue	• Concession holder pays **royalties** to the Government • **Post-royalty net income** less ‘deductions’ is **taxed**	• Contractor pays **royalties** and remaining oil or gas **‘profit oil’,** is shared according to an agreed ratio. Contractor also pays **taxes**.	• **Government retains** all **revenue** and **pays all costs**, including compensation to Contractor

SOURCE: Petroleum Economist; literature search; Team Analysis

MANY FACTORS DRIVE THE SELECTION OF FISCAL SYSTEMS

🟩 High importance for Alaska North Slope



- Influencing factors
  - In-country factors
    - Nature of resource base
      - Geological risk
      - Resource mix/ quality
      - **Technical cost**
      - Technology and skills transfer needs
      - Abandonment liabilities
    - Nature of political infrastructure
      - Current hydrocarbon dependency
      - **National development priorities**
      - Economic philosophy
      - Resource ownership philosophy
      - Political timeline (long vs. short term)
      - Government administrative capability
    - Nature of current industry structure
      - Diversification philosophy
  - External factors
    - International country-country competition
      - Behaviors of neighboring countries and peer group
      - **Behaviors of competing countries**
    - International company-company competition
      - Degree of "desperation"
      - Oil company willingness to enter a country
    - **Hydrocarbon price/ price outlook**

Fiscal system

- Contract type (i.e., tax-royalty, PSC, other)
- Allocation strategy
- Level of Government take
- Sensitivity to price changes (i.e., regressive, progressive, neutral system; creaming mechanisms)
- Government/NOC participation
- Bonuses, including signature bonuses
- Minimum spend, work program obligations
- Other contractual obligations, e.g., capability building, technology transfer, infrastructure/ industry development

SOURCE: Team Analysis

OIL & GAS FISCAL TERMS: OVERVIEW

Term	Definition
Government take	Government share of **economic profits** (total full-cycle gross revenues less total costs), typically expressed as a percentage. Total government share of production or gross cash flow from royalties, taxes, bonuses, profit oil etc. There is diverse terminology used but the most common is: Government Take = Government Cash Flow/Gross Project Cash Flow (or it may be based on *discounted* cash flow).
ERR	**Effective royalty rate** – The minimum share of revenues (or production) the gvt. will receive in any accounting period from either royalties and/or its (guaranteed) share of profit oil.
Lifting Entitlement	Physical and legal possession of crude oil (or gas). For an IOC ordinarily consists of two components under a PSC: **cost oil** and **profit oil**. Under a royalty/tax system it consists of total production (at the wellhead) less royalty oil. Often corresponds to barrels 'booked'.
Savings Index	The savings index represents the percentage share of profits that goes to the IOC if it manages to save a dollar. It represents the incentive to keep costs down.
Ringfencing	The term 'ringfence' means that all costs associated with a 'cost center' must stay within the ring fence and cannot be 'consolidated' with other projects for tax calculation or production sharing purposes.

These metrics do not capture such non-financial incentives as stabilization or international arbitration provisions

SOURCE: Team Analysis

OTHER INDICATIVE LNG FISCAL JURISDICTIONS

SOURCE: Team Analysis

OVERVIEW OF SELECTED INDICATIVE LNG PROJECTS

		Major partners	Startup – actual/ proposed	Plant Capacity, Mtpa	Total capital cost/Mtpa
① **Gorgon LNG**		- Chevron (47%)[1] - Shell (25%) - Exxon (25%)	2016	15	US$1.3 bn
② **Snøhvit LNG**		- Statoil (36.79%) - Petoro (30%) - Total E&P (18.4%) - GDF Suez E&P (12%) - RWE Dea (2.81%)	2008	4.2	US$1.4 bn
③ **Yemen LNG**		- Total (39.62%) - Hunt Oil (17.22%) - Yemen LNG (16.73%) - SK Gas (9.55%) - Korea Gas (8.88%)	2009	6.7	US$0.7 bn

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[1] Operator of project

SOURCE: Company websites, press releases, presentations; trade press

OVERVIEW OF SELECTED INDICATIVE LNG PROJECTS

		Major partners	Startup – actual/ proposed	Plant Capacity, Mtpa	Total capital cost/Mtpa
④ Equatorial Guinea		• Marathon (60%) • SONAGAS G.E. S.A. (25%) • Mitsui & Co. (8.5%) • Marubeni Gas Development (6.5%)	2007	3.7	US$0.4 bn
⑤ Indonesia - Tangguh		• BP (37.16%) • CNOOC Muturi & Wiriagar Overseas (13.9%) • Nippon (12.23%) • KG Bereau/KG Wiriagar (10%)	2009	7.6	US$0.7 bn
⑥ Papua New Guinea - Hides		• ExxonMobil (33.2%) • Oil Search (29%) • National Petroleum Company of PNG • Santos (13.5%) • AGL Energy (3.6%)	2014	6.9	US$2.8 bn

SOURCE: Company websites, press releases, presentations; trade press

EXAMPLE 1: AUSTRALIA FEDERAL LNG ROYALTY AND PROFIT SHARE SYSTEM

Australia Overview

Regime

Concession system

- **Offshore:** Fields in Commonwealth waters (3 nautical miles offshore) pay **Petroleum Resource Rent Tax (PRRT)**
- **Onshore:** Fields onshore or inshore fall under State jurisdiction and pay state royalties as well as PRRT

Royalty

- Fields in Commonwealth water subject to PRRT pay no royalties
- Fields under State jurisdiction pay 10-12.5% fixed percentage of the wellhead value
  - Assessed monthly month
  - Wellhead value = revenue – excise payment – downstream costs to bring petroleum to point of sale

Taxes

- Fields in Commonwealth waters pay a profits-based tax of **40% (PRRT)** and then a **federal tax of 30%** of gross income less allowable deductions
- Fields under State jurisdiction also pay PRRT and federal tax of 30% of gross income less allowable deductions
- Carbon tax of A$23/tonne for all producers

Incentives

- **LNG sector pays only a portion of carbon tax**
- Frontier region exploration uplift allowance available

Government Take

Government Take					Effective Royalty Rate	Lifting Entitlement	Savings Index
	Downside	Mid-range	Upside	Marginal			
Undiscounted	35%	45%	53%	57%	0%	100%	70¢
Discounted 10%	58%	65%	56%	57%			70¢

SOURCE: Daniel Johnston & Co.

EXAMPLE 1: AUSTRALIA FEDERAL LNG ROYALTY AND PROFIT SHARE SYSTEM (CONTINUED)

	Australia Federal LNG
Depreciation	• E&D expenses; Dev **8 yr SLD**; Facilities **20% DB**
Ringfencing	• **Offshore exploration costs** are deductible from **PRRT** company wide
Other	• **15%** Withholding

SOURCE: Daniel Johnston & Co.

EXAMPLE 2: SNØHVIT LNG – CONCESSIONARY SYSTEM

	Norway Overview	Norway LNG
Regime	• Concession	• Concession
Royalty	• None payable for fields approved after 1 Jan 1986 • Royalty was phased out for all fields (those approved prior to 1986) from March 2000	• None payable
Taxes	• 28% **Corporate Income Tax (CIT)** • + 50% **Special Petroleum Tax (SPT)** not deductible against **CIT** • **78% effective tax rate** • **NOK 0.48 (8¢)** per liter of oil or per standard cubic meter of gas	• All taxes payable • CO_2 and NO_x taxes payable
Incentives	• Capital expenditure uplift of 30% over four years introduced in 2005 — Recent proposal to change to 22% uplift • Exploration costs may be expensed and written off immediately or alternatively can be capitalized and written off over a number of years	• Special depreciation rate over 3 years instead of 6 years

SOURCE: Team Analysis

EXAMPLE 2: SNØHVIT LNG – CONCESSIONARY SYSTEM (CONTINUED)

Norway Snøhvit LNG

	Government Take					Effective Royalty Rate	Lifting Entitlement	Savings Index
		Downside	Mid-range	Upside	Marginal			
Government Take	Undiscounted	73%	75%	76%	76%	0%	100%	15¢
	Discounted 10%	100+%	87%	82%	82%			42¢

Depreciation

- Development costs 3-year SLD beginning in year of investment
- Losses carried forward with interest (legal rate)

Ringfencing

- Not in upstream sector
- The tax system is **company based**, not field based. Companies can deduct all costs and are taxed on a **net profit basis**
- Unused exploration costs can qualify for a cash refund

Other

- Partners: **Statoil (36.79%) (operator)**, Petoro (30%), Total E&P Norge (18.40%), GDF SUEZ E&P Norge (12%) and RWE Dea Norge (2.81%)
- **Government Participation: 0-30% Petoro** (state owned)
  - Not ‘carried’ i.e. heads up” or “straight up” from day one
- Rentals: Exploration license **NOK 65,000/year + 33,000** per seismic survey
  - No fees for areas ‘with activity’

SOURCE: Daniel Johnston & Co.

EXAMPLE 3: YEMEN LNG ROYALTY AND PROFIT SHARE SYSTEM

	Yemen Upstream	Yemen LNG
Regime	• **Production sharing contract (PSC)**	• LNG is a concession agreement and operates under a PSC with an over-riding royalty
Royalty	• Rates **for oil** varies **3-10% up to 100,000 BOE/d**, **fixed at 10%** for production **>100,000 BOE/d** • Non-associated **gas** pays royalties **same way as oil** • **Associated gas** is **property of state** and pays no royalties	• Plant liquids royalty paid at 10% • LNG royalty paid at 2-10% of transfer pricing depending on year of production (escalating by year)
Taxes	• Income tax payable at **35%** • Taxes paid in full by government on behalf of contractor from share of profit oil/gas	• Income tax payable at 35% • Taxes paid in full by government on behalf of contractor from share of profit oil/gas
Incentives	• **Cost Recovery: 50-70% of revenue** after royalty • Taxes, bonuses, royalties and financing costs are not recoverable from cost oil	• 50% of revenues after royalty • Taxes, bonuses, royalties and financing costs are not recoverable from cost oil

SOURCE: Team Analysis

EXAMPLE 3: YEMEN – LNG ROYALTY AND PROFIT SHARE SYSTEM (CONTINUED)

Yemen LNG

		Government Take				Effective Royalty Rate	Lifting Entitlement	Savings Index
		Downside	Mid-range	Upside	Marginal			
Government Take	Undiscounted	53%	60%	66%	89%	14+%	66%	0¢
	Discounted 10%	100+%	71%	69%	86%			40¢

Depreciation

- 8 yr SLD

Ringfencing

- N/A

Other

Revenues/Expenses	Government Share
<1.00	25%
1.00-1.25	30%
1.25-1.66	35%
1.66-2.00	50%
2.00-2.25	55%
2.25-2.75	70%
>2.75	90%

SOURCE: Daniel Johnston & Co.

EXAMPLE 3: YEMEN – LNG ROYALTY AND PROFIT SHARE SYSTEM (CONTINUED)

	Yemen LNG
Other	• **Government participation: Yemen Gas Company** – ultimately **16.73%** • **Bonuses: $30 MM** paid by **Total** at various stages in the project • Partners: In 1995, **Total** was chosen as the Project Leader. Total owns **39.62%**, state-owned Yemen Gas Co. (16.73%), Hunt Oil Co. (17.22%), SK Energy (9.55%), Korea Gas Corp. (6%), Hyundai Corp. (5.88%), and the Yemen General Authority for Social Security and Pensions (GASSP) owns (5%) • Social, Medical, Training: $1.5 Million/y • Profit share: — LNG: **Profit share** according to a scale of **R factors** (ratio of cumulative revenues to expenses)

SOURCE: Daniel Johnston & Co.

EXAMPLE 4: EQUATORIAL GUINEA – ALBA LNG ROYALTY AND PROFIT SHARE SYSTEM

Equatorial Guinea Alba LNG

Regime

- Production Sharing Contract — Wiriagar, Barau and Muturi

Royalty

- 10% for oil
- 10% for gas
- 10.75% for condensate

Taxes

- **25%**

Incentives

- N/A

Government Take

Government Take					Effective Royalty Rate	Lifting Entitlement	Savings Index
	Downside	Mid-range	Upside	Marginal			
Undiscounted	41%	39%	38%	36%	10%	87%	71¢
Discounted 10%	82%	52%	48%	37%			70¢

Depreciation

- **Exploration costs** expensed – **Capital costs 4 yr SLD** for cost recovery

SOURCE: Daniel Johnston & Co.

EXAMPLE 4: EQUATORIAL GUINEA – ALBA LNG ROYALTY AND PROFIT SHARE SYSTEM (CONTINUED)

	Equatorial Guinea Alba LNG
Ringfencing	• Yes for cost recovery; no for tax purposes
Other	• Rentals: $1.00/hectare/year • **Government participation: 3%** Sub-Area A • Contractor to supply (free) gas feedstock for 20 MW power plant • Training fee: $220,000/year • **Bonuses:** Signature **$1.0 Million** (not recoverable but tax creditable) — First Production: **$1.0 Million**; **$2.0 Million**@20 MBOPD; **$5.0 MM** @ 50 Million BOE/d • Cost Recovery Limit: 90% for oil; 80% for gas • DMO: If requested, a portion of **net crude oil** at market prices • Government Share of Profit Oil: “Net Crude Oil” **5%**

SOURCE: Daniel Johnston & Co.

EXAMPLE 5: INDONESIA – PSC TANGGUH LNG ROYALTY AND PROFIT SHARE SYSTEM

Indonesia PSC Tangguh

Regime

- Production Sharing Contract

Royalty

- None

Taxes

- **48% effective tax rate**, resulting from 35% income tax and 20% withholding tax
- **27%** investment credit
- Transfer of rights: **5%** for **exploration rights**; **7%** for **exploitation rights**

Incentives

- N/A

Government Take

Government Take					Effective Royalty Rate	Lifting Entitlement	Savings Index
	Downside	Mid-range	Upside	Marginal			
Undiscounted	60%	60%	61%	61%	4%	83%	36¢
Discounted 10%	100+%	84%	73%	62%			52¢

Depreciation for C/R & Tax

- Oil **25% declining balance** written off in year 5
- Gas **10% declining balance** with balance written off in year 8

Ringfencing

- Each license ringfenced

SOURCE: Daniel Johnston & Co.

EXAMPLE 5: INDONESIA – PSC TANGGUH LNG ROYALTY AND PROFIT SHARE SYSTEM (CONTINUED)

	Indonesia PSC Tangguh
Other	• **Cost Recovery: 86.64%** limit because of 1st Tranche Petroleum of **15.36%** • **Profit Gas Split: 23.077% / 76.923%** (in favor of **contractor**) — After the extension dates, **contractor** profit oil and gas **shares drop** by about **4%** — **Government take increases** by about **2%** • DMO: For first 60 months production from a field, contractor receives **24.28%** of market price for **25%** of "share oil." After that, starting in Q4 2013, **contractor receives market price** • **Government participation:** None

SOURCE: Daniel Johnston & Co.

FISCAL TERMS SUMMARY

Country	Royalty	C/R Limit[1]	ERR[2]	Savings Index[3]	Ringfence[3]
Australia Offshore	0%	-	0%	70%	No
Equatorial Guinea	10% Gas; 10.75% Cond.	90% Oil 80% Gas	10%	71%	Yes for C/R No for Tax
Indonesia Tangguh	0%	84.6%	4%	36%	Yes
Malaysia Bintulu	10.5%	60%	25%	18%	Yes
Norway	0%	-	0%	24%	No
PNG	2%	-	2%	54%	Partial; Effectively Yes
Qatar EGU	0%	40%	48%	17%	Yes
Russia Sakhalin II	6%	-	6%	59%	Yes
Yemen	2% - 8 yrs 4% - 4 yrs 6% - 4 yrs 8% - 3 yrs 10% - after	50%	14+%		
Alaska	12.5%	-	12.5%	60%	No

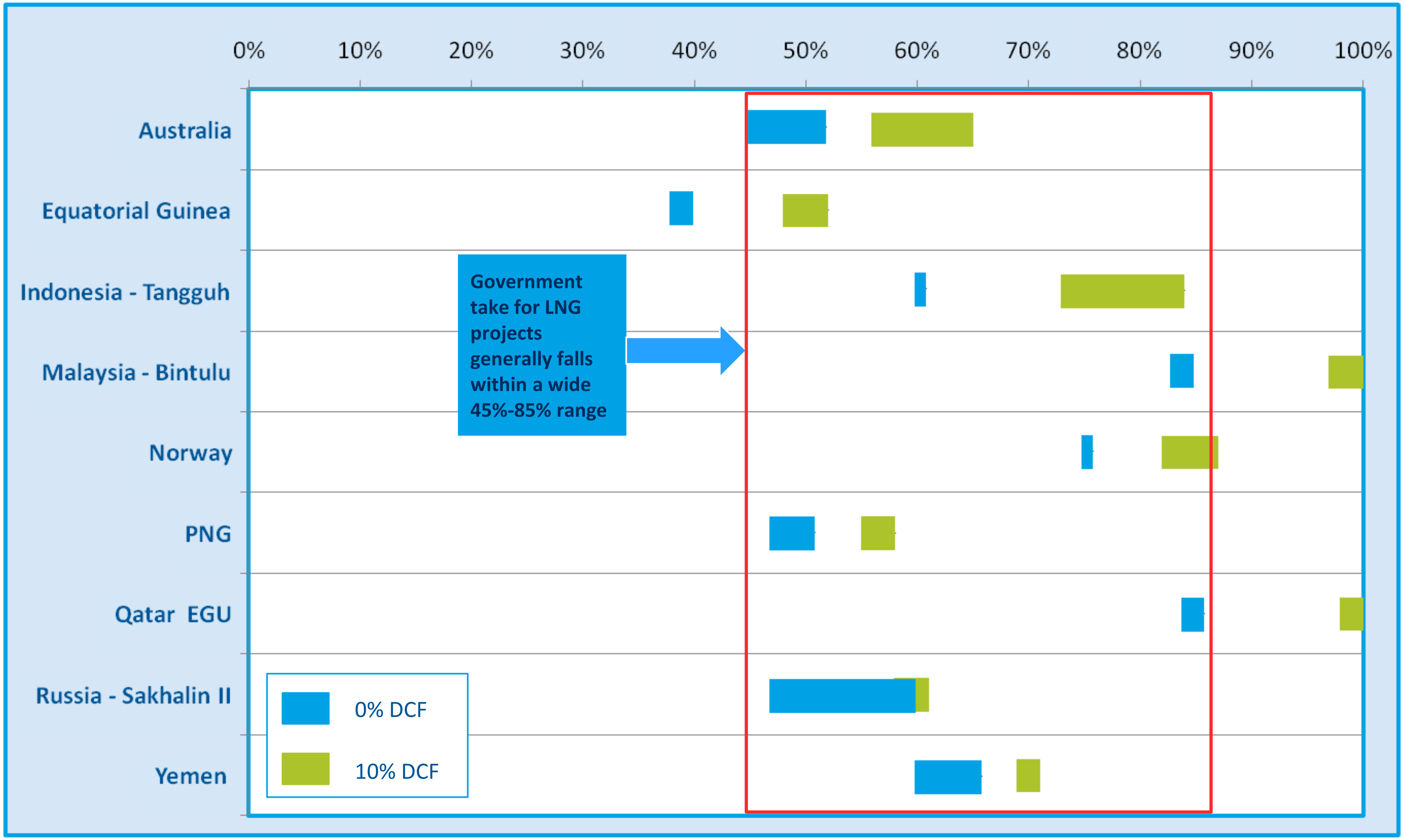
[1] Cost Recovery Limit
[2] Effective Royalty Rate
[3] See glossary

FISCAL TERMS SUMMARY

Country	Government Profit Oil Split	Corporate Income Tax
Australia Offshore	PRRT 40% (Based on ROR Trigger)	30% (36% pre-2009)
Equatorial Guinea	5%	25%
Indonesia Tangguh	23.1%	48% (35 + 20%)
Malaysia Bintulu	< 60 BCF 50/50% > 60 BCF 70/30%	40%
Norway	SPT 50%	28%
PNG	ROR APT < 17.5% 7.5% > 17.5% 10%	30%
Qatar EGU	Approximately 80-82% Combination of production-based and R factor-based sliding scale	35%
Russia Sakhalin II	ROR Gvt. Share > 17.5% 10% 17.5 – 24% 50% > 24% 70%	32%
Yemen	R Factor Gvt. Share <1.00 25% >2.75 90%	25%
Alaska[1]	No P/O Split; Production Tax of 35%	35% Federal; Circa 4% (effective rate)

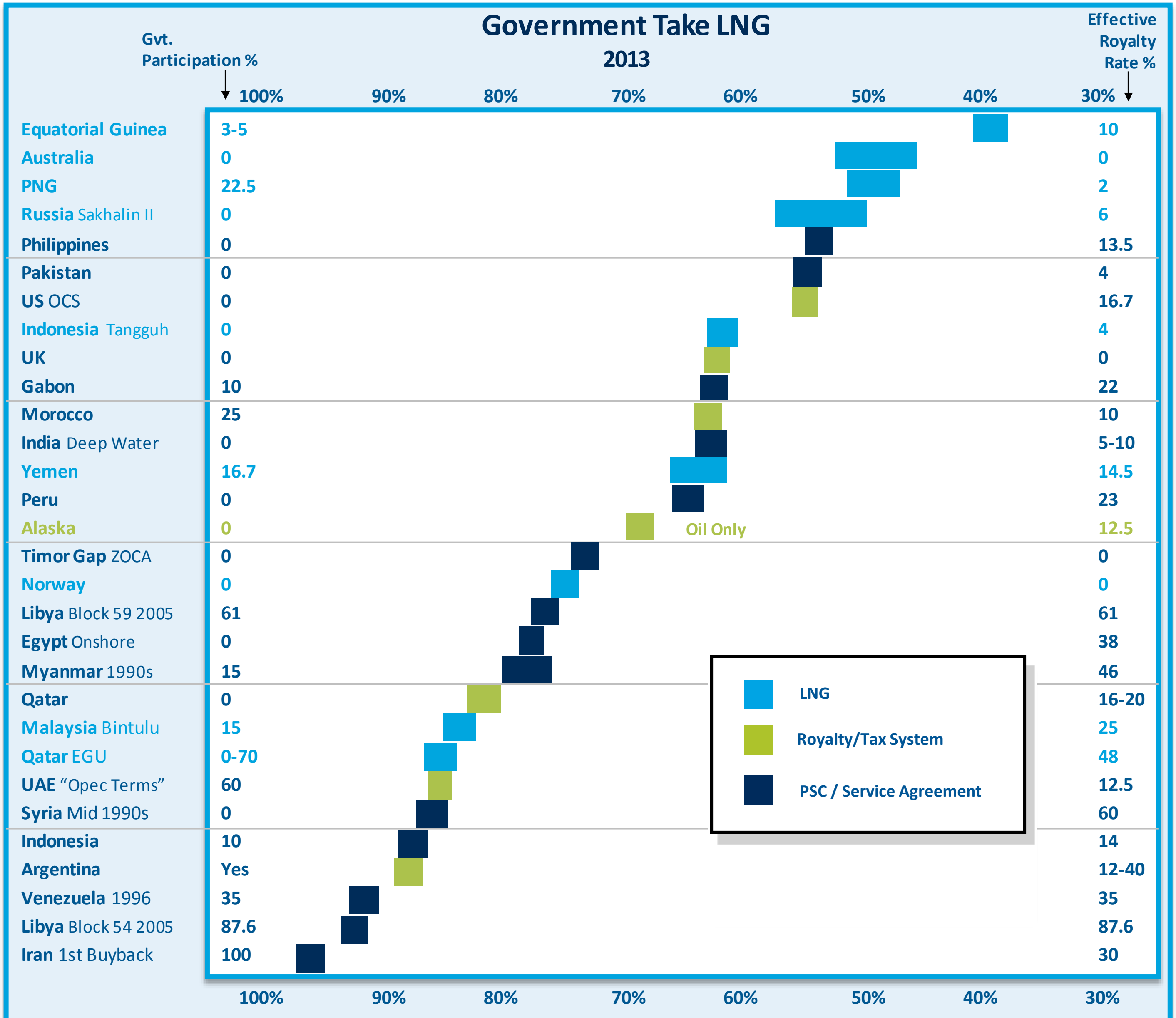
[1] MAPA

GOVERNMENT TAKE SUMMARY



Government take for LNG projects generally falls within a wide 45%-85% range

GOVERNMENT TAKE ON LNG PROJECTS, BY COUNTRY


Government Take LNG
2013

Daniel Johnston & Co., Inc. © 1994-2013

SUMMARY: INTERNATIONAL FISCALS

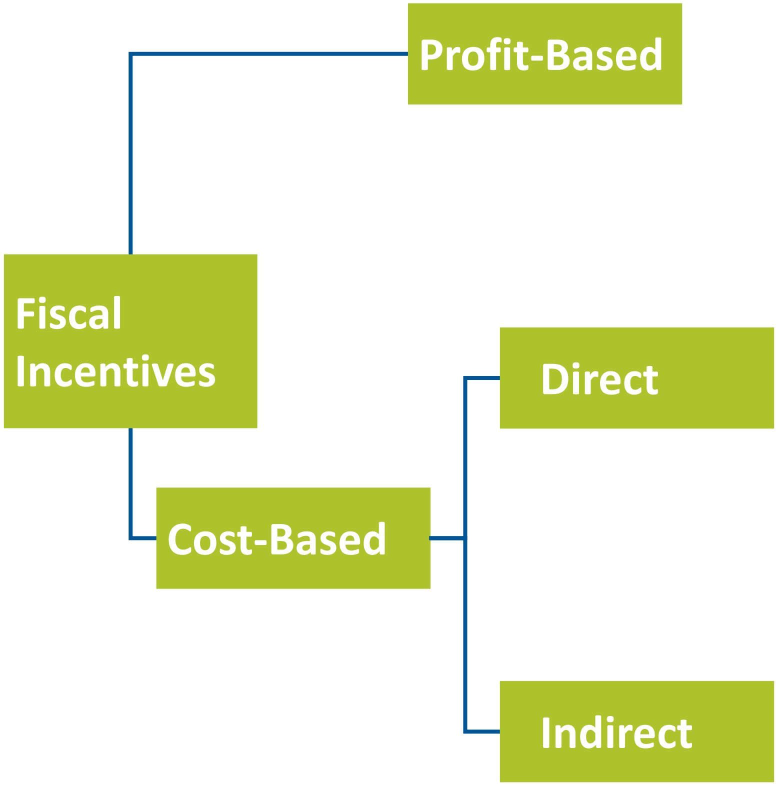
1 A successful fiscal system balances the interests of the host government and the contractor/producer

2 LNG projects have either concessionary or contractual fiscal systems

3 The range of government take for LNG projects generally lies between 45% and 80%

CONTENTS

KEY FISCAL INCENTIVES IN USE AROUND THE WORLD



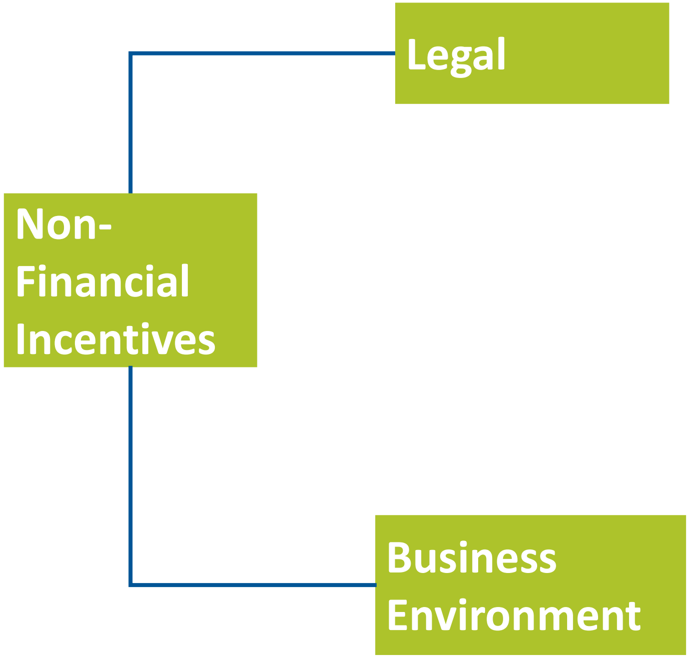
Fiscal Incentives

- **Profit-Based**
- **Cost-Based**
  - **Direct**
  - **Indirect**

	Simple description	Examples
Profit-Based	Royalty Reductions Tax or Royalty Holidays Progressive Fiscal Structures Depletion Allowances (rare) Frontier Incentives	India Indonesia USA Israel
Direct	Interest Cost Recovery Investment Uplifts/Allowances Tax Credits Exploration Subsidies Providing Infrastructure Providing low-interest financing	Indonesia Angola Algeria Nigeria Norway
Indirect	Reduced or Eliminated Ringfencing Government W.I. Participation Accelerated or 100% Depreciation Greater 'Reserves Entitlement'	Norway US, UK AU, NZ

SOURCE: Team Analysis

KEY NON-FISCAL INCENTIVES IN USE AROUND THE WORLD



Simple description

Non-Financial Incentives

Legal

- Stabilizing Provisions
- Dispute Resolution (International Arbitration)
- Reasonable Rights of Assignment

Business Environment

- Reasonable (non-hostile) Audits
- Reasonable ‘Permitting’ Processes
- Stable Business Environment

SOURCE: Team Analysis

STABILIZING PROVISIONS

Term	Definition
Freezing Clauses	• These clauses prohibit the host state from changing its laws after the effective date of the specific investment contract (generally not very effective nor sustainable).
Equilibrium Clauses	• These clauses stipulate that if there is a change in laws detrimental to the IOC a corresponding adjustment to some mechanism over which the NOC has control will reestablish the original economic balance that existed on the effective date.
Taxes in lieu	• These arrangements dictate that all taxes and royalties be paid by the NOC out of the NOC share of profit oil. Thus if there is a change to taxes or royalties it is handled by the NOC and does not effect the IOC. These are considered to be some of the more stable arrangements that exist

SOURCE: Daniel Johnston

SLIDING SCALES (ALSO KNOWN AS CREAMING)

A Production-based

- Daily production rates (tranches)
- Cumulative production rates

B R-factors

- Standalone
- In combination with production-based systems
- In combination with price tranches

C Rate of return-based systems

- Sometimes called “World-Bank Model” or “Resource Rent Taxes”
- Standalone

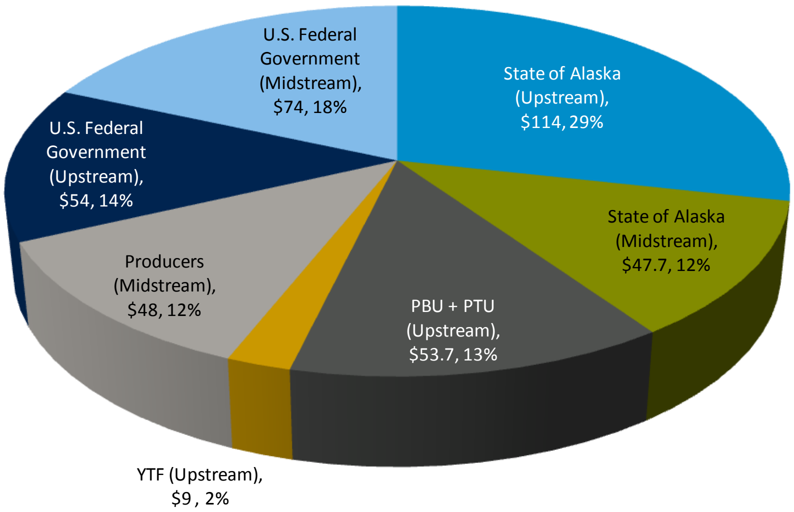
D Price-based scales

- Sometimes called “Windfall Profits Taxes,” such as ACES

SOURCE: Daniel Johnston

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

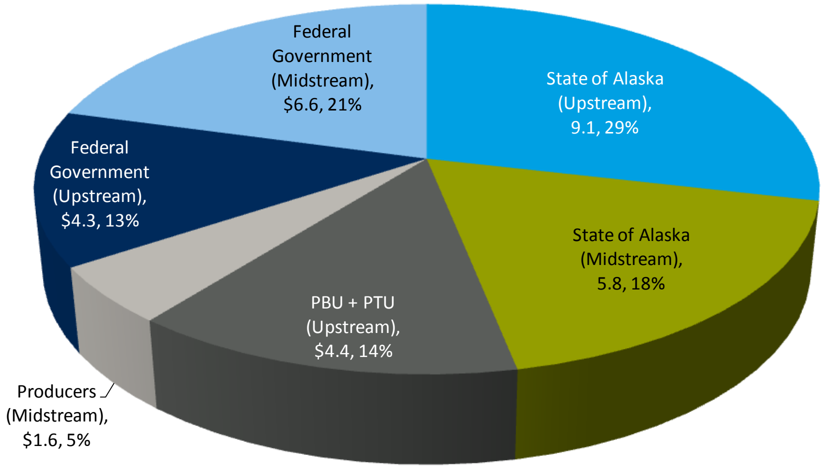
Gasline Impact Total Cash Flow by Stakeholder (Billions)



$328 Billion in Total Cash Flow

72% Government Share

Gasline Impact NPV$_{10}$ 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

COMPETITIVE GOVERNMENT TAKE AND PROJECT RETURNS ARE GENERALLY NEEDED FOR A SUCCESSFUL PROJECT

Royalty/Tax Type	Rate	Degree of Progressivity[1]
Royalty	~12.5%	Regressive
Property Tax	2%	Regressive
Production Tax (with per barrel deduction)	35%	Moderately progressive
State Income Tax	9.4%	Neutral
Federal Income Tax	35%	Neutral

- **The current Alaska structure is regressive/neutral**
- **Government Take ranges from 70% to 80% (including the U.S. Federal government share)**
- **Estimated IRRs for the Project Sponsors is ~15% under baseline assumptions**

---

[1] Regressive: system where a high proportion of the government revenue receipt is taken prior to full cost recovery on the project
Progressive: system where a high proportion of the government revenue is tied to project profitability

ALASKA'S OPTIONS AND CONSIDERATIONS

	Overview	Commentary
Alaska's R/T Regime	**Royalty/Tax (Concession) system** • It is unlikely that any advantage could be gained by changing the basic existing (R/T) fiscal/contractual framework in Alaska.	• Suitable fiscal terms can replicate any perceived benefits of a PSC arrangement within a R/T structure
Royalties	• Royalties, property taxes are 'Front-end-loaded' i.e. regressive – Any reduction in rates is expected to be welcomed by the Producers – Generally, royalties or royalty equivalent elements for LNG projects around the world are low	• Some reduction is expected to be required. • Total elimination is difficult to justify. • Some revenue 'guarantee' is politically and intuitively healthy
Taxes	• Government Take in Alaska is fairly high for a challenging LNG project, although within the range of government take for the LNG projects reviewed.	• Some tax relief/reduction may be required • Federal Tax of 35% appears to be simply a boundary condition
Other	• Equity Participation is an option that is very dynamic with respect to added risks to the State while being common worldwide	• Equity participation in large projects is generally viewed favorably by project sponsors
Incentives	• **The main challenges for Alaska are based on the long lead time and the high cost. It may be best to focus incentives in these areas.**	• Cost relief can be included as incentives although it may be hard for AK to control costs or timing

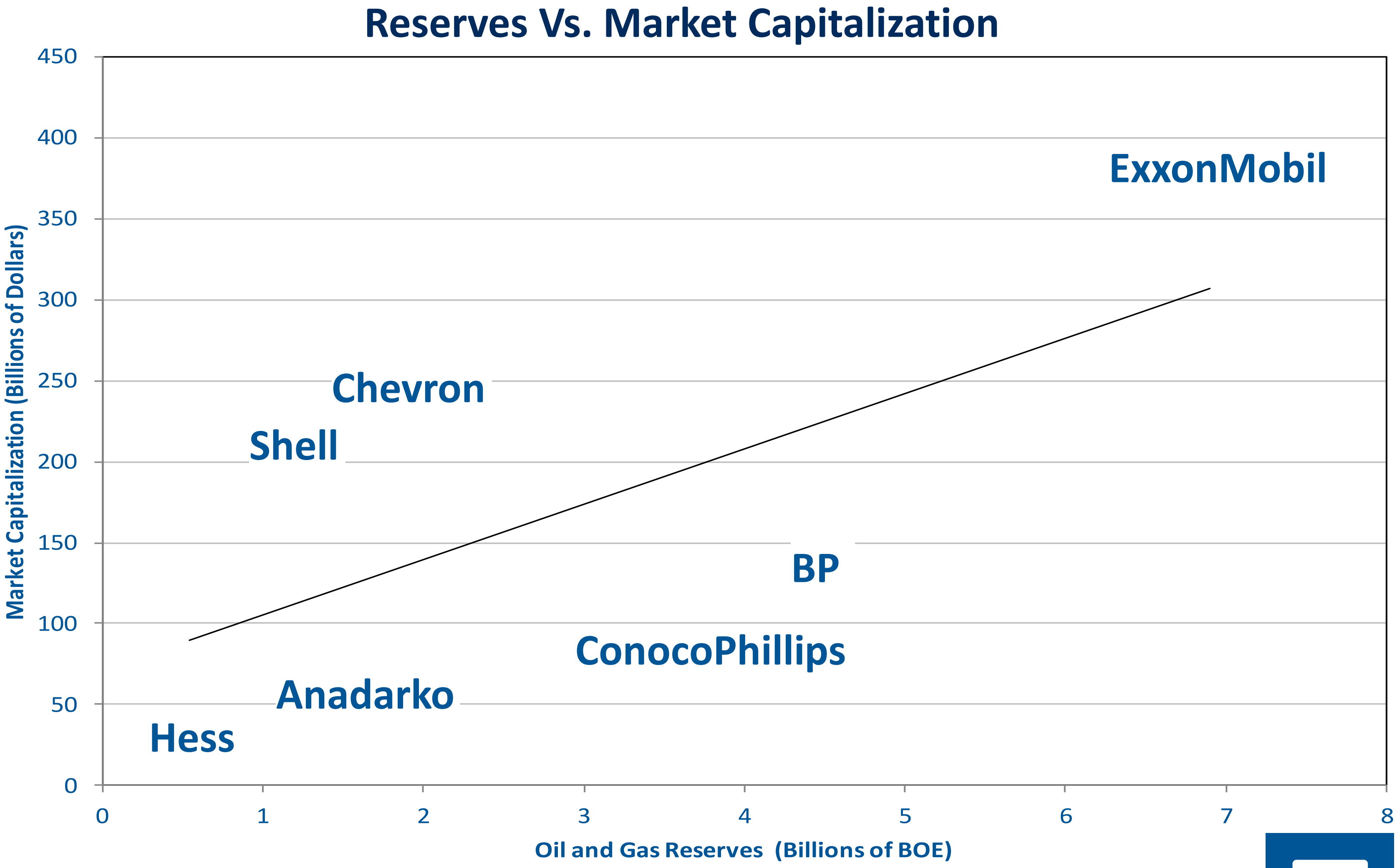
SOURCE: Team Analysis

STATE CAN EXAMINE SEVERAL OTHER LEVERS AS PART OF A FULL FISCAL DEAL FOR NORTH SLOPE

	Examples of fiscal levers	Description/comments
Commercial constructs	Ring fencing	A development or block is ‘ring fenced’ if for tax purposes costs incurred cannot be deducted against revenue from other operations.
	Tax holidays	Exclusion for tax for a given period of time
	Depreciation uplift	Mechanism that allows the Contractor to depreciate more (in total money of the day) than actual Capex. This offsets loss of time value of money and incentivizes the Contractor to invest capital
	Domestic market obligations (DMO)	DMO require the Contractors to sell a portion of production from a project into the domestic market at a certain price (typically below market rate). Some countries such as Kazakhstan can call on DMO in emergencies usually pro-rata
Bonuses	Signature bonuses	Signature bonuses for acquiring the rights to explore or develop a resource is the most common way to award rights competitively Signature bonuses in some countries raises significant government revenues
	Production bonuses	Commonly used at certain project milestones, e.g., payment when a project has delivered a specific cumulative production or production rate or at Commerciality, startup, payout, etc.
Fees	Training fees License fees	A number of recent contracts tie to economic or social development, including training, skill building and infrastructure development - common
Special taxes	Special Petroleum Tax Petroleum Revenue Tax Repatriation Tax Withholding Taxes	Governments often institute special taxes for upstream operations In some cases upstream projects are exempt from general taxes, e.g., VAT, import taxes etc.
Abandonment provisions	Abandonment provisions	Some countries provide tax relief for decommissioning, e.g., the U.K. (there is speculation that tax laws could change as this becomes a burden on governments; large scale decommissioning is yet to take place) Other countries require funds to be set aside for decommissioning at the end of the projects life but these funds as they are set aside are cost recoverable and/or tax deductible

SOURCE: Team Analysis

DESIGNING STATE PARTICIPATION TO ALLOW PRODUCERS TO BOOK THE HIGHEST LEVEL OF RESERVES CAN BE A STRONG INCENTIVE



SOURCE: Ernst & Young, Team Research

DESIGNING STATE PARTICIPATION TO ALLOW PRODUCERS TO BOOK THE HIGHEST LEVEL OF RESERVES CAN BE A STRONG INCENTIVE

- In a concessionary system, the reserves that can be booked by the contractor depend on whether royalty is taken in value or in kind
- If royalty and/or taxes are taken in value, then the Contractor may book the total applicable reserves.
- If royalty and/or taxes are taken in kind, then the State would get to book the reserves corresponding to its royalty and tax share
- Given this difference in how booking of reserves could occur for the AKLNG Project, any arrangements that allow producers to book more reserves as an incentive should be carefully considered

FISCAL LEVERS CAN RESULT IN VARIOUS BENEFITS WHICH CAN BE TESTED VIA IMPACT ON PROJECT PROFITABILITY

Sample levers

- Governments have multiple fiscal levers, e.g.,
  - Replace royalty with profits-based tax
  - Accelerated depreciation
  - Capital allowance (Deduct more than 100% of capex)
  - Tax credits
  - Enhance lifting entitlement
  - Direct capital contributions

Benefits

- Results are:
  - **Lower Government Take**
  - **Defer Government Take**
  - **Reduce cost exposure – increases IOC IRR**
  - **Reduce IOC Risk**

Testing impact

- Effect:
  - **Internal Rate of Return**
  - **Break-even prices**
  - **NPV**
  - **Government take**
- Will help determine level of impact in attracting new investment

SOURCE: Team Analysis

NON-FISCAL LEVERS CAN RESULT IN VARIOUS BENEFITS WHICH ARE DIFFICULT TO TEST

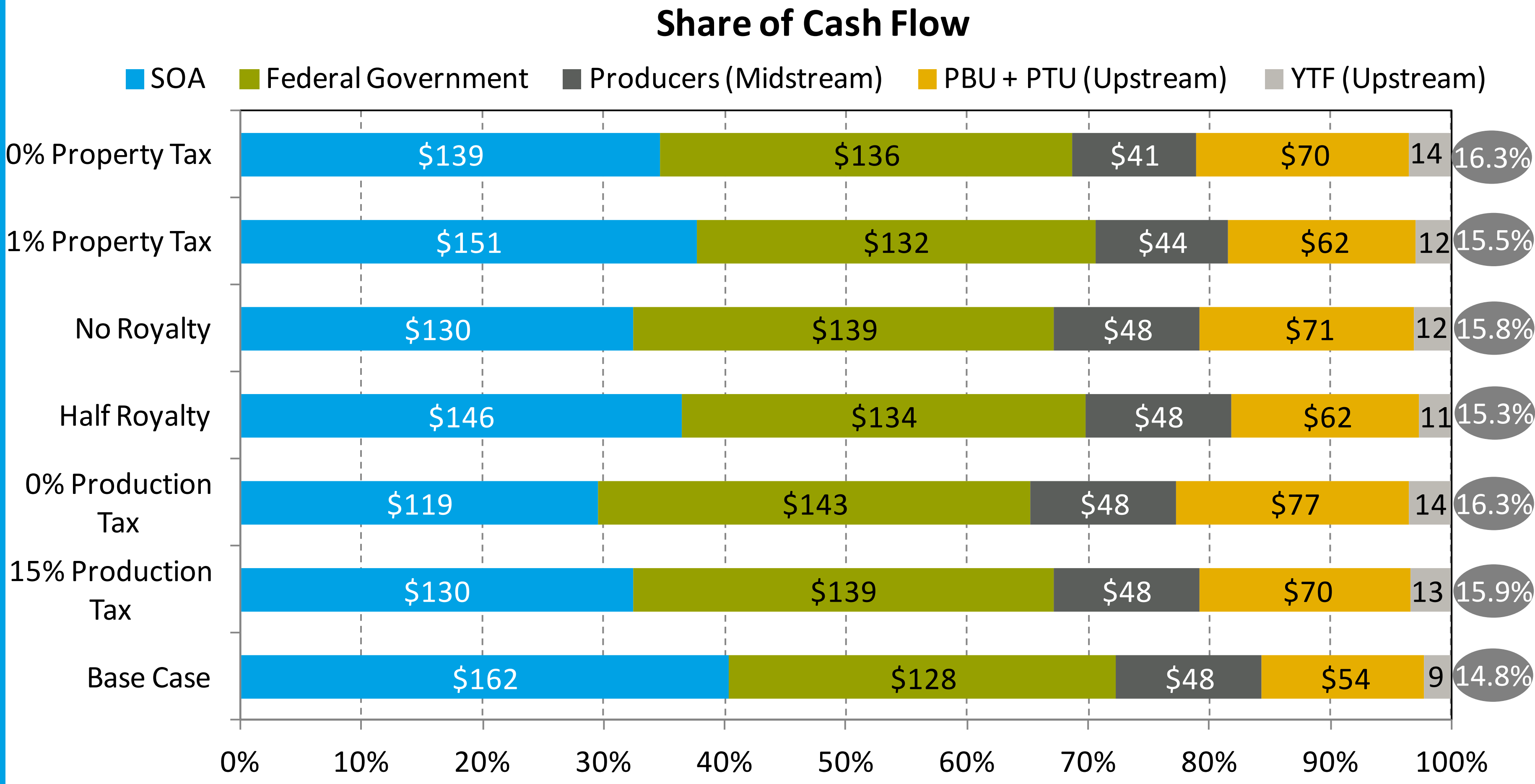
Sample levers	Benefits	Testing impact
• Governments have various options: – Stabilizing provisions – Intl. arbitration dispute resolution – Increase IOC lifting entitlement (for booking barrels)	• Results are: – **Reduce IOC Risk** – **Enhance IOC comfort/confidence** – **IOCs should be more willing to invest**	• Effect is difficult to see with financial metrics

SOURCE: Team Analysis

IMPACT OF FISCAL LEVERS ON AKLNG PROJECT ECONOMICS UNDER DIFFERENT PRICE AND CAPEX MARKET CONDITIONS

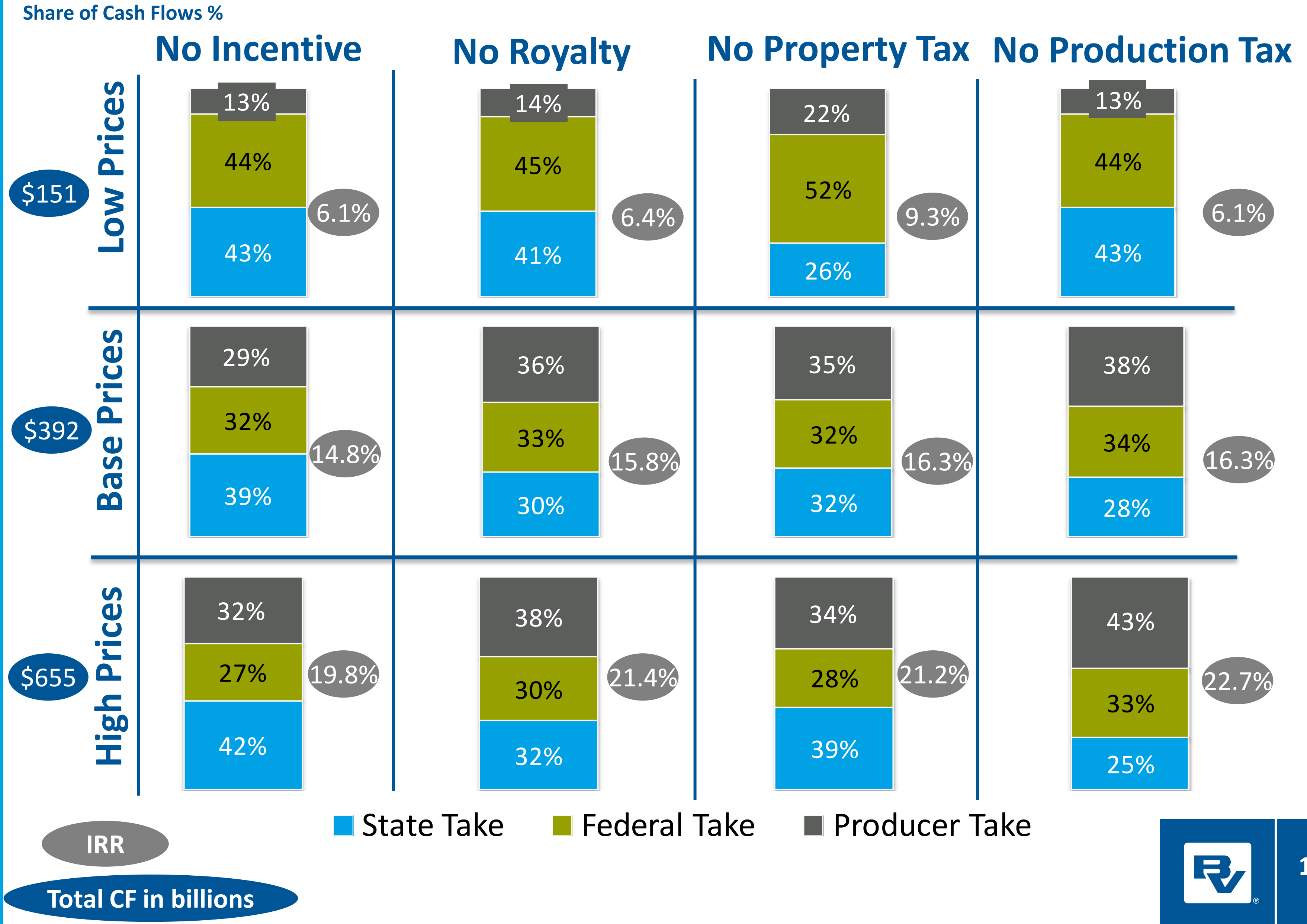
- **In order to understand the magnitude of the potential impact of reducing royalty, production tax and property tax on Producer IRRs and government take from the AKLNG project, this analysis examines the upper bound condition of eliminating each of these fiscal components under different market conditions**
- **Price Sensitivity**
  - The analysis examines the impact of royalty, production tax and property tax levers under high and low price scenarios
- **Capex**
  - High CapEx – This scenario shows the impact of applying a fiscal incentive as the midstream CapEx is increased to the high end of the capital cost estimate ~$54 billion
  - Low CapEx – This scenario shows the impact of applying a fiscal incentive as the midstream CapEx is increased to the high end of the capital cost estimate ~$39 billion

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

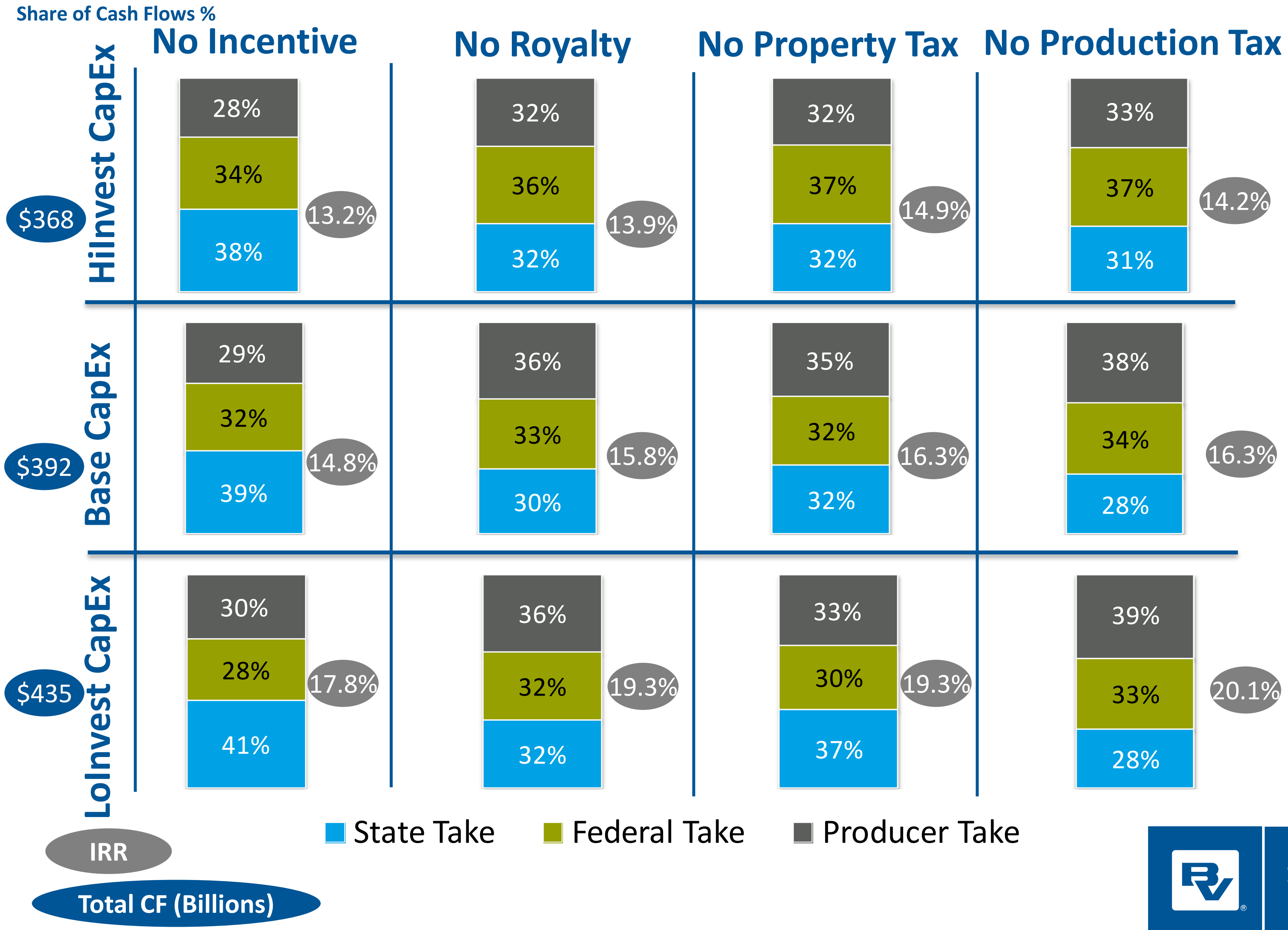


% Producer (Upstream + Midstream) IRR

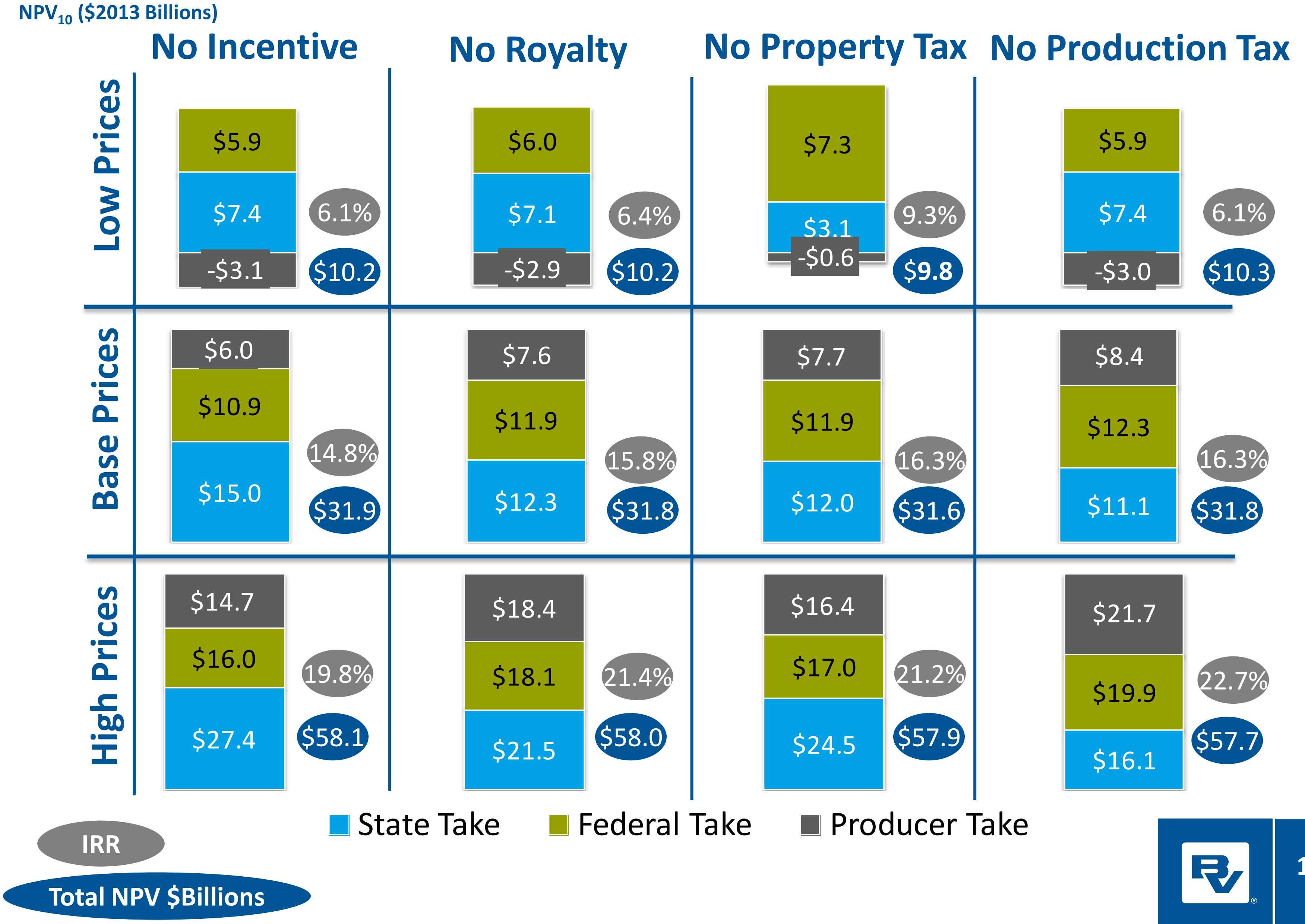
IMPACT OF FISCAL LEVERS UNDER DIFFERENT PRICE AND CAPEX MARKET CONDITIONS - SHARE OF CASH FLOWS – PRICE SENSITIVITY



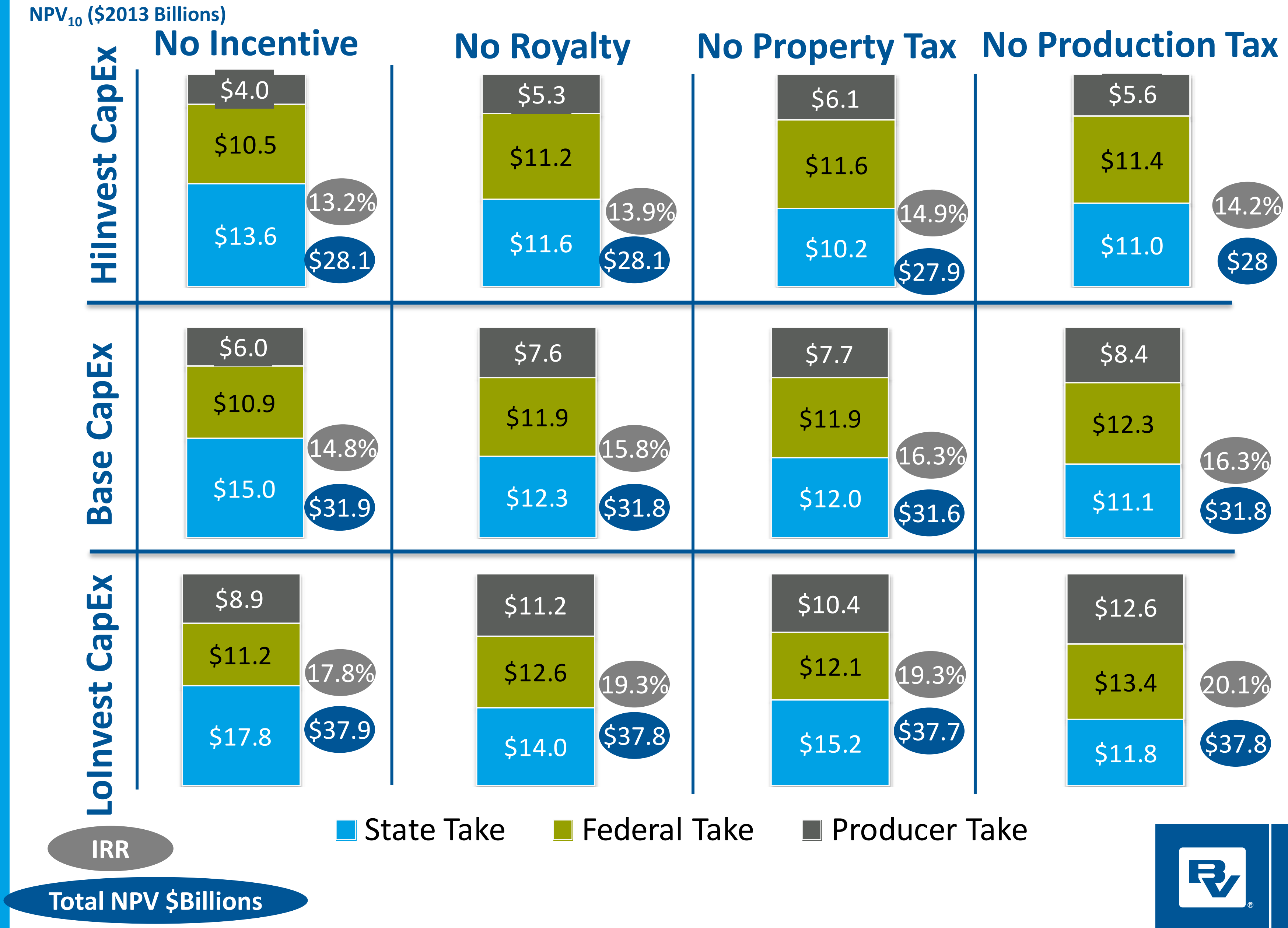
IMPACT OF FISCAL LEVERS UNDER DIFFERENT PRICE AND CAPEX MARKET CONDITIONS - SHARE OF CASH FLOWS– MIDSTREAM CAPEX



IMPACT OF FISCAL LEVERS UNDER DIFFERENT PRICE AND CAPEX MARKET CONDITIONS - NPV$_{10}$ – PRICE SENSITIVITY



IMPACT OF FISCAL LEVERS UNDER DIFFERENT PRICE AND CAPEX MARKET CONDITIONS - NPV$_{10}$ — MIDSTREAM CAPEX



IMPACT OF FISCAL LEVERS ON AKLNG PROJECT ECONOMICS UNDER DIFFERENT PRICE AND CAPEX MARKET CONDITIONS

- 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

CONTENTS

ROYALTIES ARE ONE OF A NUMBER OF MECHANISMS USED WITHIN FISCAL SYSTEMS

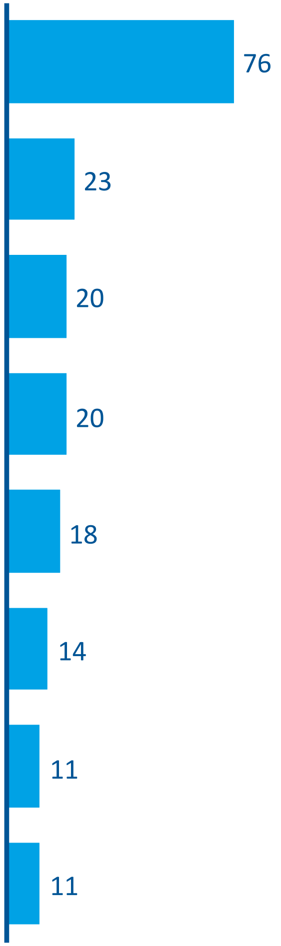
Mechanism	Pros and cons (from the contractor's point of view)
Royalty	• Simple to administer • Is (normally) a fixed % of revenue (not profit) and can be an increasing burden at low oil prices (i.e., it is a regressive mechanism)
Taxes	• Usually fairly simple to administer • Progressive mechanisms link government take directly to asset profitability
Cost oil	• Typically costs/budgets have to be approved by the NOC. However, like tax deductions in R/T systems, costs with PSCs can (and should) be audited
Profit oil	• Similar to 'taxable income' in R/T systems in all respects except profit oil is denominated in barrels—not dollars
Creaming mechanisms	• There are 3 main families: Production-based, R-factor-based and rate-of-return-based (ROR) systems • Most mechanisms are fairly straightforward – depending on design characteristics – However, rate of return-based systems and some 'R-factor'-based system can experience unintended consequences and misalignment between stakeholders. The greatest concern is "opportunistic" and "strategic" gold plating – Sliding scales based on volumes rather than revenues or profits are insensitive to changes in cost or commodity prices
Signature bonuses	• An upfront payment (or tax or commitment to infrastructure) that is not linked to the project's success or profitability. The payment immediately becomes a sunk cost. Extremely regressive and unpopular.

SOURCE: Team Analysis

FEW LARGE LNG EXPORTERS APPLY ROYALTIES; WHEN APPLICABLE THEY ARE PAID IN CASH

	Royalties upstream	LNG
Qatar	No royalties paid	Royalties paid (% undisclosed)
Malaysia	10% of gross revenue and payable in cash Measured and valued at sales point	No royalties paid
Australia	Royalty of 10-12.5% on wellhead value paid by onshore/inshore fields Paid in cash	Royalties only paid on upstream project if onshore/ inshore field
Nigeria	No royalties paid on gas in Concession regime No fiscal terms for gas in PSC regimes	No royalties paid
Indonesia	Paid in the form of FTP (First Tranche Petroleum) where first 15.36% of prod. shared between contractor and gov.	No royalty/FTP paid
Trinidad & Tobago	No royalties paid	No royalties paid
Algeria	5.5-23% depending on production and location Payment in kind can be requested by national agency Alnaft	N/A
Russia	Royalties paid in the form of MET (Minerals Extraction Tax) Associated gas exempt from MET Non-associated gas pays a fixed rate	LNG royalty paid at 2-10% of market pricing depending on year of production (Concession)

2012 LNG export
Mtpa



SOURCE: BP Statistical Review of World Energy 2013; Team Analysis

VERY FEW COUNTRIES CURRENTLY ALLOW ROYALTY IN KIND

🟩 **Relevant for gas**

	Royalties
🟩 **Algeria**	• Payment in kind can be requested by national agency Alnaft
Cameroon	• Paid in cash or in kind or a combination
Chad	• Royalties in PSC oil contracts are paid in kind • Payment details for offshore gas not provided by onshore gas royalties paid in kind
Gabon	• Companies can pay royalties and tax in kind
Thailand	• Paid in cash or in kind • Royalties paid in kind are at a higher rate of 14.28% of gross revenue compared to 12.5% if paid in cash
🟩 **Mozambique**	• Paid in cash or in kind
🟩 **Myanmar**	• Paid in cash or in kind
United States[1]	• Paid in cash or in kind in some States • Private land royalties can also be paid in kind

[1] Alaska, California, Colorado, Louisiana, Oklahoma, Pennsylvania, Texas; Payments in kind abolished at Federal level
Production and demand are shown at overall level

SOURCE: Team Analysis; EIA

ROYALTY IN KIND

Royalty In-Kind

Advantages

- Attractive to producers
- Reduces valuation disputes
- Reduces commercial uncertainty for project
- Provides the State with better market insight

Disadvantages

- Exposes State to various additional risks
- Requires modifications to current legislation and authority
- Requires marketing expertise
- Credit requirements for shipper agreements

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

SOURCE: Team Analysis

ROYALTY IN VALUE

Royalty In-Value

Advantages

- Status quo, familiarity
- No direct firm capacity commitments
- RIV auditing and management capabilities currently exist

Disadvantages

- 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

SOURCE: Team Analysis

EQUITY INVESTMENT

Equity Investment

Advantages

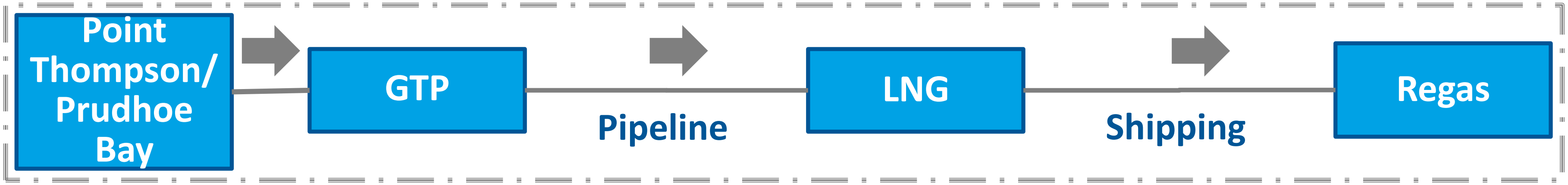
- Higher transparency of supply chain from GTP through LNG
- Potentially attractive investment opportunity for SOA
- Provides path to ensure TPA
- Preserves path for expansion rights
- Attractive to the producers for SOA to have skin in the game - alignment
- Reduces commercial uncertainty for project

Disadvantages

- Significant investment ($10 - $15 billion)
- Management team required for JV
- Increases SOA exposure to project becoming uneconomic
- Disputes on royalty valuation and allowances could remain

SOURCE: Team Analysis

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**
Risk Profile	•Volume •Price	•Volume •Price •Capex (GTP) •Operational risk (GTP) •CO_2 disposal & gas quality •Balancing/scheduling •Credit risk (GTP) •Force majeure	•Volume •Price •Capex (GTP+P) •Operational risk (GTP+P) •CO_2 disposal & gas quality •Balancing/scheduling •Credit risk (GTP+P) •Force majeure	•Volume •Price •Capex (GTP+P+LNG) •Operational risk (GTP+P+LNG) •CO_2 disposal & gas quality •Balancing/scheduling •Credit risk (GTP+P+LNG) •Force majeure	•Volume •Price •Capex (GTP+P+LNG+S) •Operational risk (GTP+P+LNG+S) •CO_2 disposal & gas quality •Balancing/scheduling •Credit risk (GTP+P+LNG+S) •Force majeure
Rewards:	**Inlet GTP**	**Inlet Pipeline**	**Inlet LNG**	**FOB**	**DES**
Reward Amt	15% JCC – S – LNG – P – GTP – RP	15% JCC – S – LNG – P – RP	15% JCC – S – LNG – RP	15% JCC – S – RP	15% JCC
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

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	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
Marketing Costs	No marketing costs, but audit costs	Marketing costs
Credit Costs	Credit cost borne by Producers	Borne by State

GTP AND UPSTREAM FIELD COST DEDUCTIONS COULD CREATE MINOR DIFFERENCES BETWEEN RIK AND RIV

- **Under RIV, currently, the State allows only PBU to deduct its GTP costs as well as an upstream field cost deduction while calculating royalty dues**
- **It is as yet undefined whether upstream field cost allowances would be applicable to other fields under RIV and under RIK**
- Value difference could occur between RIK and RIV depending on whether differences are introduced in how GTP costs and FCA are treated under RIK and RIV
  - Not expected to be significant value drivers for royalty influencing the decision between RIK and RIV

HIGHER OF PROVISION PROVIDES PRICE PROTECTION FOR THE STATE UNDER RIV

- **Under current higher of provisions, each of the three producers would be required to pay royalties on the higher of its own value or the average of the value achieved by the other two producers**
- **Estimated to provide approximately 3% uplift in royalty value**
  - Analysis assumes three markets – Japan, Korea, Taiwan, China and India with different market price expectation
  - Further, assumes that each of three producers has a different mix of sales contracts with these three markets which creates a range of sales prices achieved by the producers

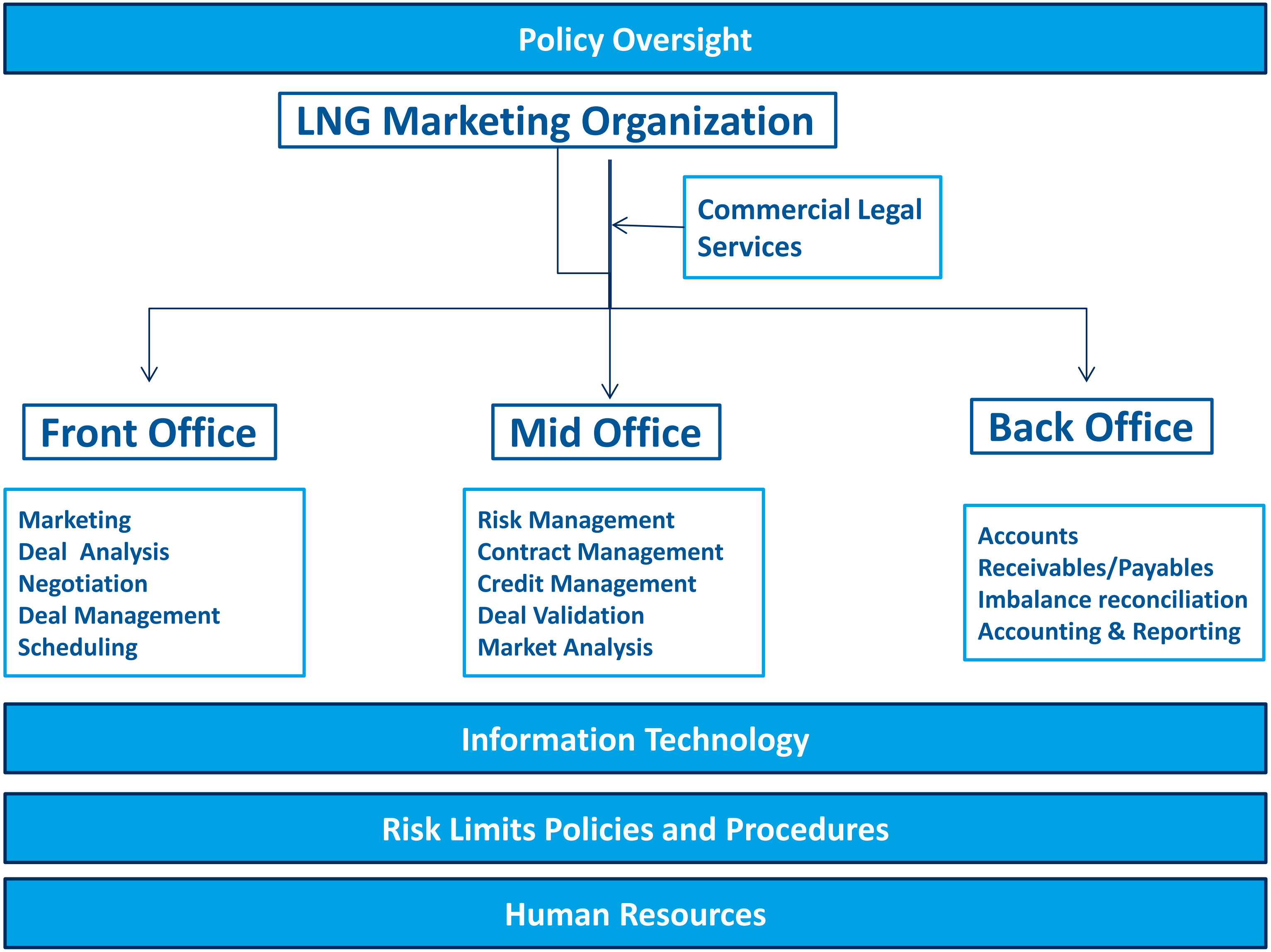
PRICE DISCOUNT FROM RISK PREMIUM IS EXPECTED TO BE THE BIGGEST DRIVER OF DIFFERENCES BETWEEN RIK AND RIV

- **The State is expected to suffer a discount in the sales price it achieves driven by its relative lack of:**
  - Experience and historical transaction relationships
  - Access to diverse supply portfolio
- **As the State moves its sales point further upstream, its risk exposure is lower but consecutively, so is its reward – higher risk premium when moving down the supply chain**
- **Analysis examined the impact of a discount to LNG sales price of the LNG multiplier in the 1% to 3% range in order to examine the boundaries of the impact of sales price discount that would be borne by the State**

MARKETING AND CREDIT COSTS PRESENT OTHER FINITE COSTS FOR RIK

- **State would need to set up a marketing organization to monetize its LNG share**
  - 30-40 employees at $150-200K/year salary each
  - Systems and other support functions
  - Office space, utilities, etc.
  - Conservatively estimated to ramp up to $10 - $15 Million annually for initial 5 years and then $7 - $10 Million annually
- **Credit costs are related to making long-term firm capacity commitments on the GTP, pipeline, LNG plant and marine facilities**
  - Total commitments are estimated to be in the range of $4MM a day (or $1.5B a year or $45B over 30 years)
  - A line of credit could be prohibitively expensive and the State may need to provide the equivalent of a parent guarantee

LNG MARKETING IS FACILITATED BY A MARKETING ORGANIZATION – DIFFICULT AND EXPENSIVE TO CREATE IN ALASKA



Policy Oversight

LNG Marketing Organization

Commercial Legal Services

Front Office

- Marketing
- Deal Analysis
- Negotiation
- Deal Management
- Scheduling

Mid Office

- Risk Management
- Contract Management
- Credit Management
- Deal Validation
- Market Analysis

Back Office

- Accounts
- Receivables/Payables
- Imbalance reconciliation
- Accounting & Reporting

Information Technology

Risk Limits Policies and Procedures

Human Resources

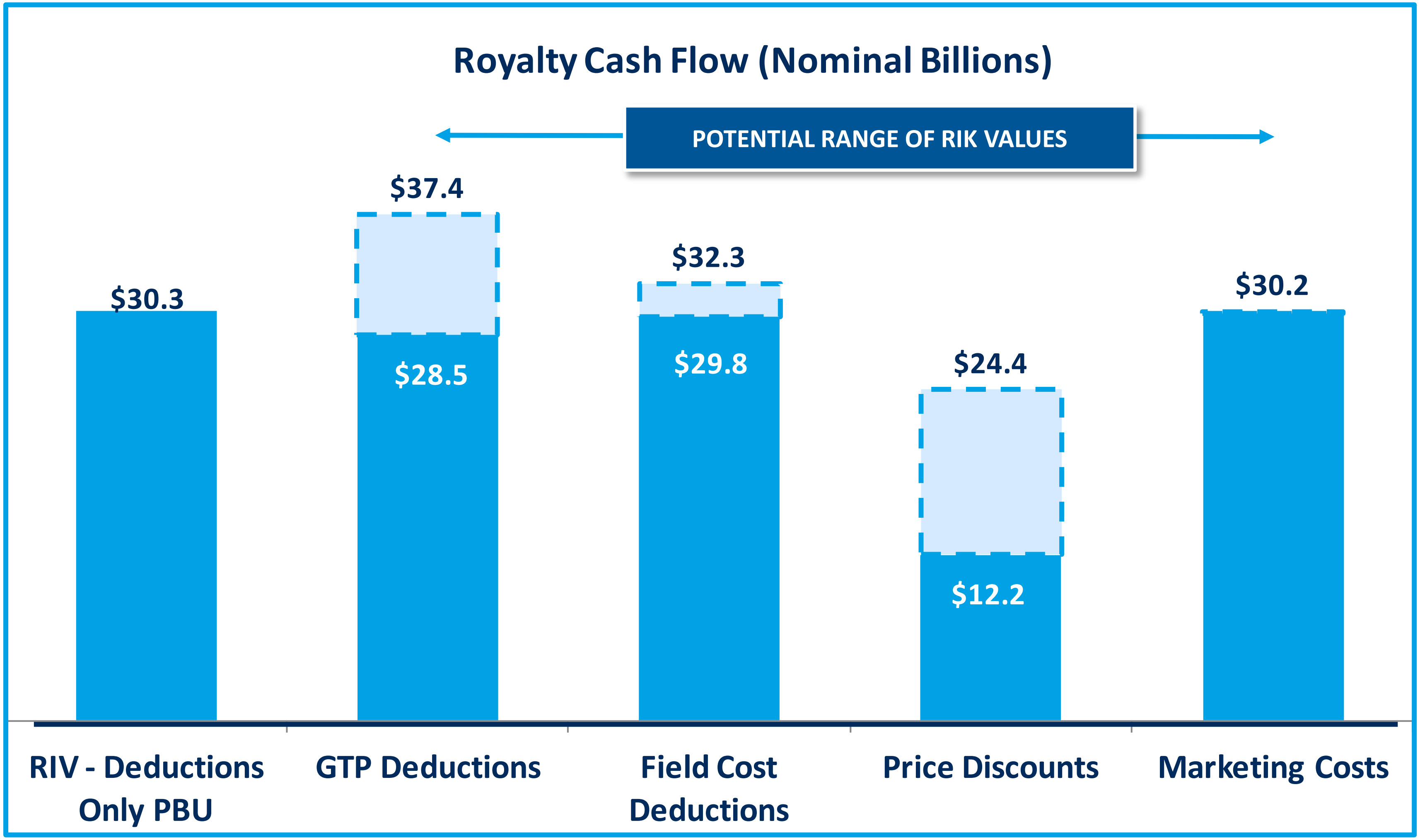
SOA'S LNG MARKETING CAPABILITIES WOULD NEED SIGNIFICANT ENHANCEMENT TO BECOME COMMERCIALLY VIABLE

ILLUSTRATIVE

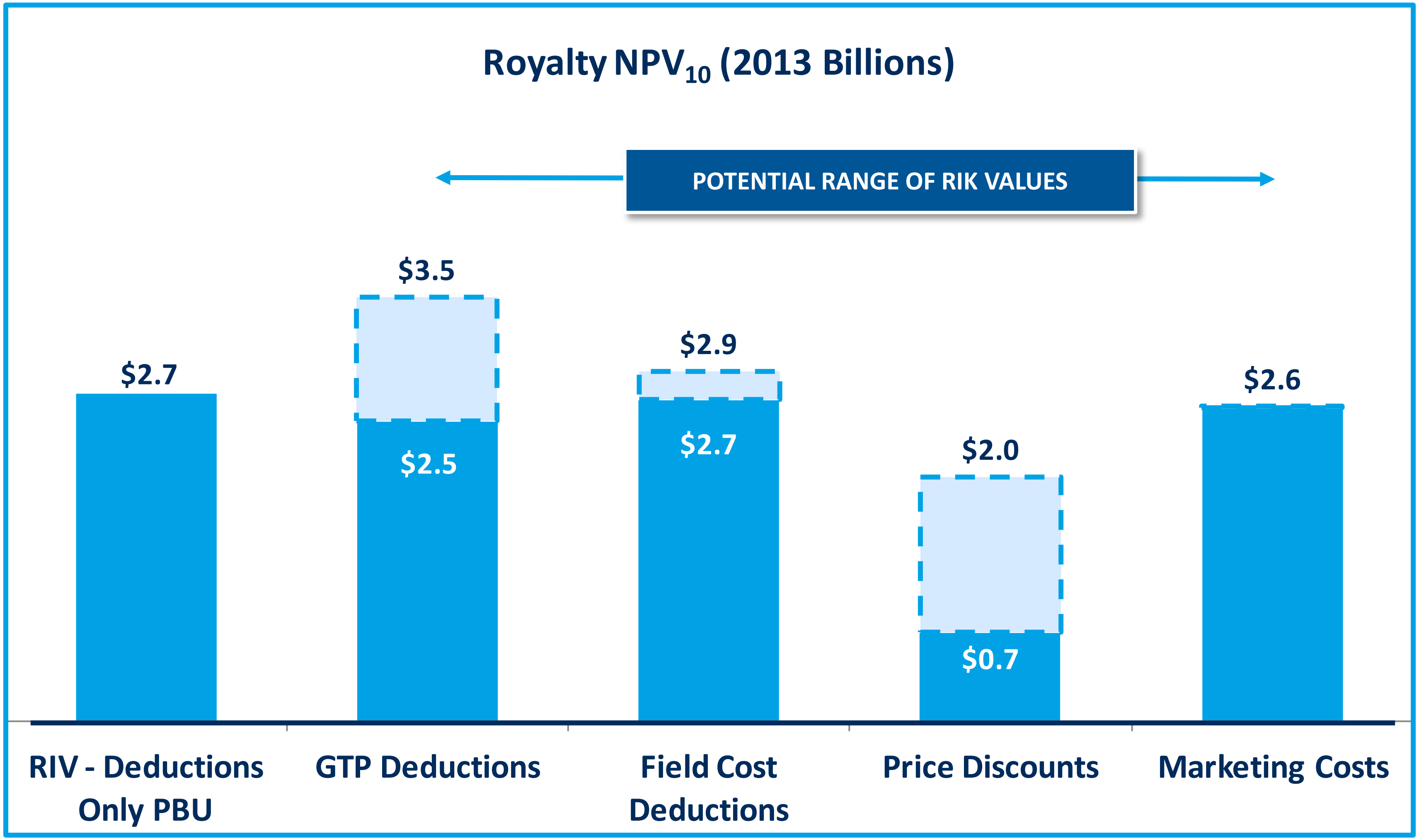
SOA RIK Capabilities Plot

Producers are expected to charge SOA for these costs, even if they assume these responsibilities related to the State's royalty gas

UNDER BASE ASSUMPTIONS, TAKING RIK COULD LEAD THE STATE TO LOSE UP TO 60% OF ITS ROYALTY VALUE RELATIVE TO RIV



NPV LOSSES TO THE STATE FROM GOING RIV COULD BE AS MUCH AS 75% OF VALUE RELATIVE TO RIV



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

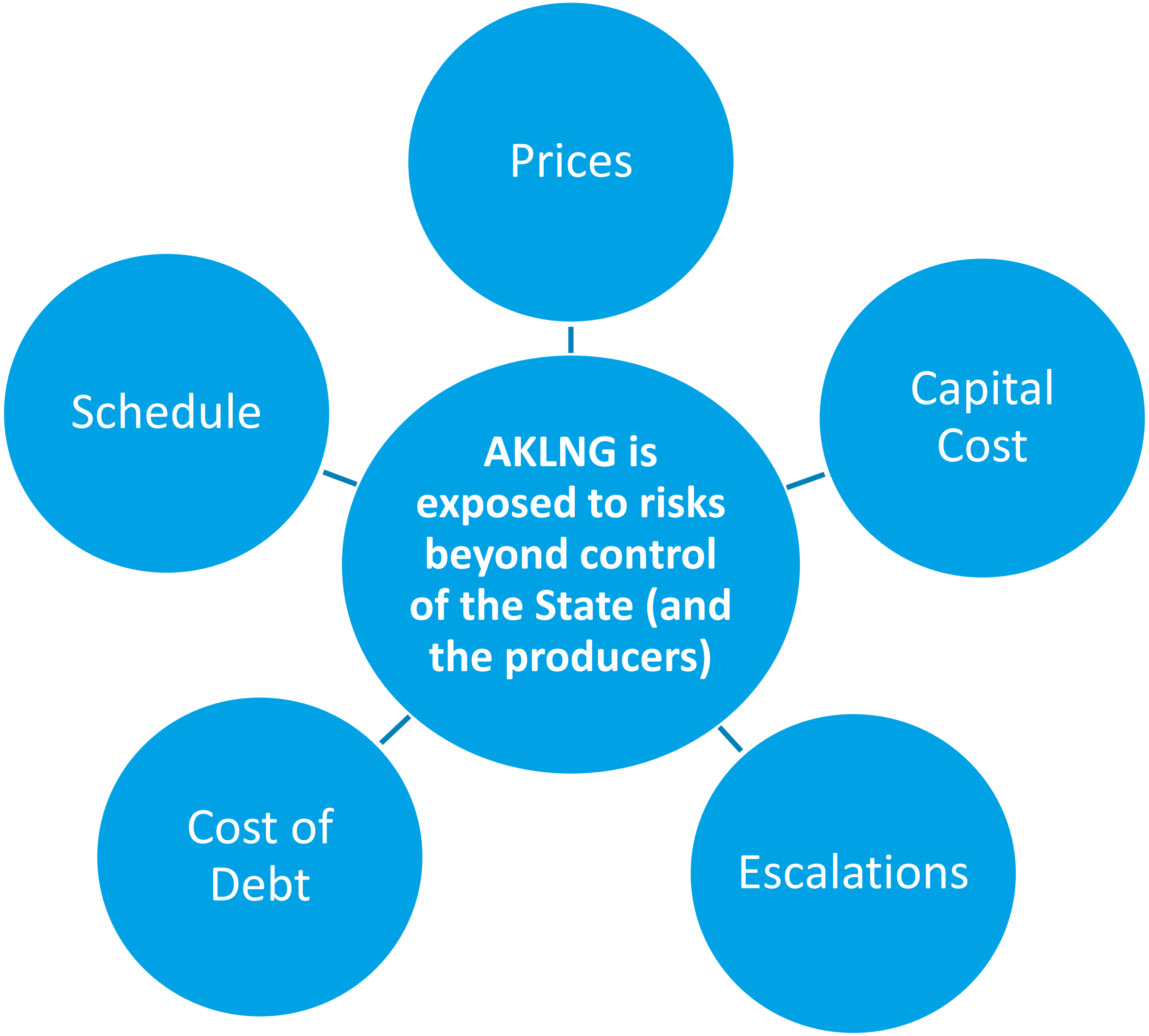
CONTENTS

QUESTIONS TO ANSWER BY ITEM AND COVERAGE IN THIS REPORT

	Questions to answer	Covered in this report through
4. Risk allocation	• Guidance regarding the financial, equity participation, or other tradeoffs as risk is transferred from one party to another, including transparency of full supply chain across parties	• Case studies of risk allocation and mitigation approaches across stakeholders across regions (e.g. Middle East, Africa, Australia) • Assessment of implications for Alaska

SOURCE: Team discussion

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



Prices

Schedule

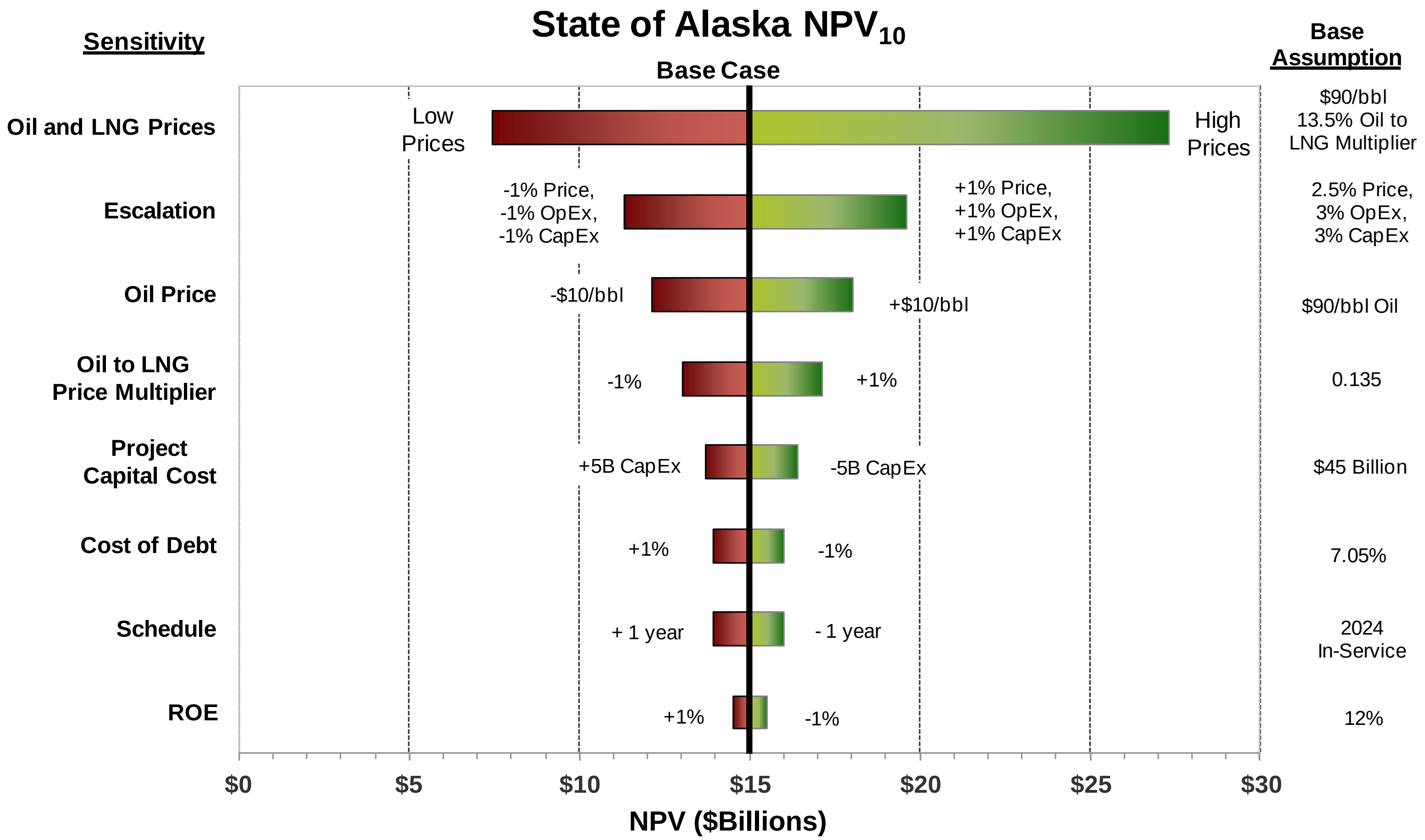
Capital Cost

AKLNG is exposed to risks beyond control of the State (and the producers)

Cost of Debt

Escalations

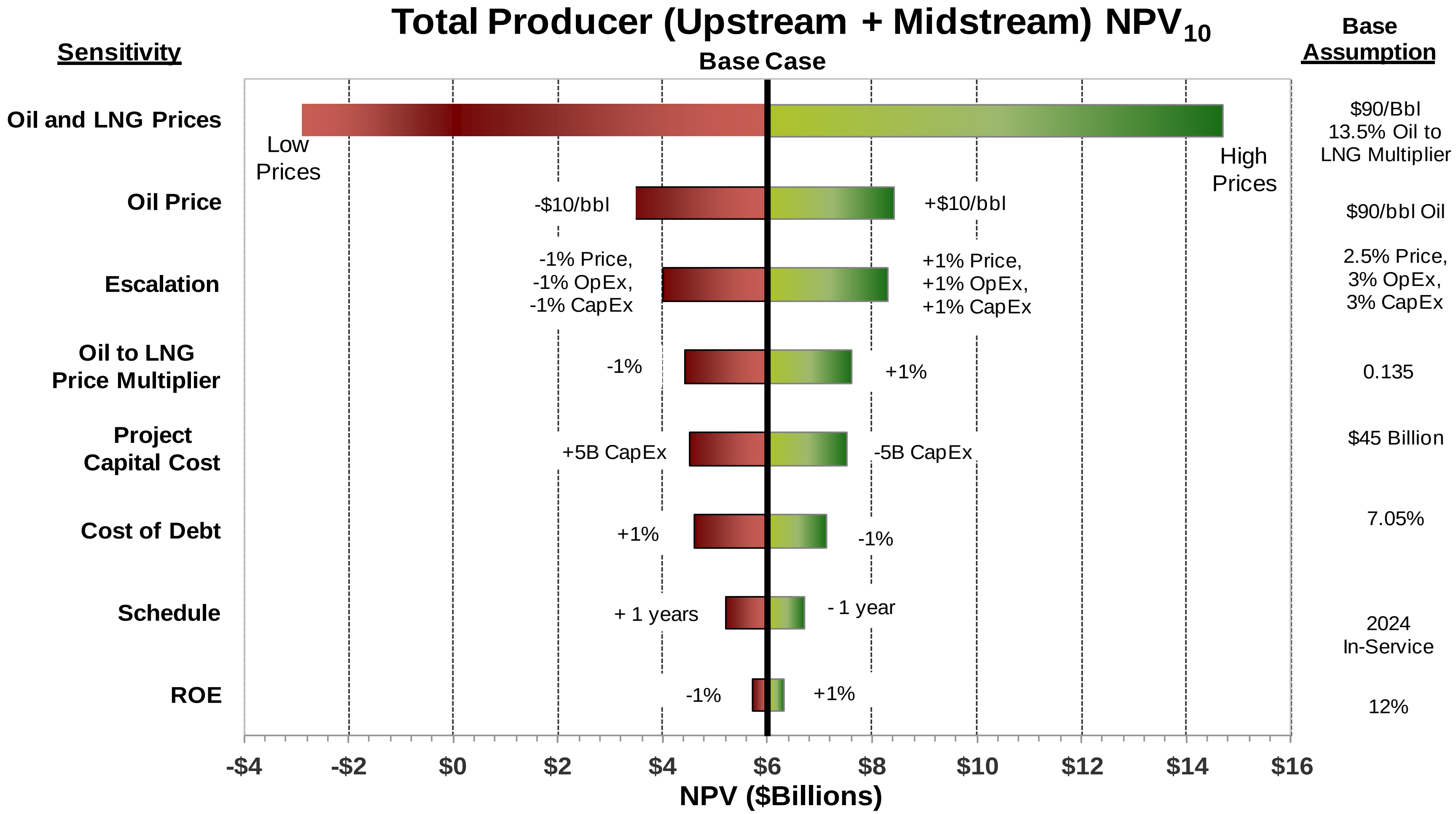
PRICE AND CAPITAL COST RELATED UNCERTAINTIES EMERGE AS THE KEY FACTORS DRIVING THE PROJECT ECONOMICS FOR SOA



[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

SIMILARLY, PRICE AND CAPITAL COST RELATED UNCERTAINTIES DRIVE THE PROJECT ECONOMICS FOR THE PRODUCERS



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[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: SUMMARY

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
  - **End user participation**: Several projects have equity stake of end buyers providing ensured-market for corresponding equity volumes

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**

SOURCE: Team Analysis

CASE EXAMPLE FOR RISK ALLOCATION– SNØHVIT

Background

- Snøhvit field discovered in 1984
- Complex and high cost deepwater development
- First liquefaction terminal in Europe
- GDF Suez bought into project in 2001 to secure equity gas supply

	Upstream	Transport to liquefaction plant	Liquefaction
Equity owners	Statoil (operator)[1]: 36.8% Petroro (Norwegian State)[1]: 30% Total: 18.4% GDF Suez: 12% RWE Dea: 2.8%		
Project cost	[US$8bn]		
Reserves/ Capacity	0.7 Tcf reserves, 4.3 Mtpa capacity		
Project structure	Fully integrated project with a single operator and equal equity shares at stage of the supply chain		
LNG sales	Total and GDF take their equity share of production in kind. Remaining export capacity was sold to Statoil and Iberdrola		

[1] The Norwegian government owns 67% of Statoil and 100% of Petoro

SOURCE: Team Analysis

CASE EXAMPLE FOR RISK ALLOCATION – ANGOLA LNG

Background

- Uses associated gas which was previously flared
- Project was proposed by Chevron to Sonangol in 1997
- Operators of nearby deepwater fields (BP, Exxon, Total) joined the project
- ENI bought out Exxon in 2007

	Upstream	Transport to liquefaction plant	Liquefaction
Equity owners	Associated gas supplied from fields operated by Chevron, BP, ExxonMobil, Total, Eni	Sonangol (joint –operator): 22.8% Chevron (joint –operator): 36.4% Total: 13.6% BP: 13.6% Eni: 13.6%	
Project cost	NA	[~US$10 bn]	
Reserves/ Capacity	10 Tcf gas	5.2 Mtpa	
Project structure	Integrated transport and liquefaction project, jointly led by Sonangol and Chevron. Gas supply is contracted from multiple local producers (who have few alternative markets)		
LNG sales	LNG is jointly marketed by Angola LNG. Capacity was originally destined for US but is now being traded on a spot basis. ALNG may sign long term contracts in future		

SOURCE: Team Analysis

CASE EXAMPLE FOR RISK ALLOCATION – PERU LNG

Background

- Camisea Gas Project - discovery in 1986 by Shell
- First natural gas liquefaction plant in South America
- Start-up in June 2010

	Upstream	Transport to liquefaction plant	Liquefaction
Equity owners	Pluspetrol (operator): 26% Hunt Oil: 36% SK Corporation: 18% Sonatrach: 10% Techint: 10%	Tecgas (operator) 23.4% Pluspetrol: 22.2% Hunt Oil: 22.2% SK Corporation: 11.1% Sonatrach: 11.1 Tractebel: 8.0% Graña y Montero: 2.0%	Hunt Oil (operator): 50% SK Corporation: 20% Shell: 20% Marubeni: 10%
Project cost	[~US$1 bn]	[~US$1 bn]	[~US$3.8 bn]
Reserves/ Capacity	14 Tcf gas + 480 MMboe NGLs	0.45 Bcfd	4.45 Mtpa

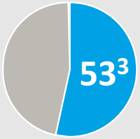
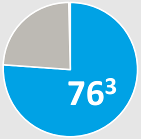
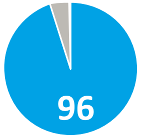
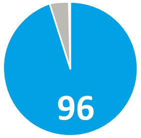
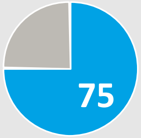
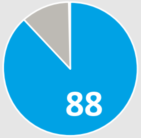
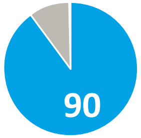
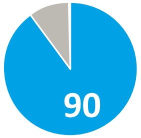
Project structure	Separate operator and ownership structure for each stage of supply chain
LNG sales	Repsol contracted for 100% of off-take volume with 90% sold onward to Mexico. Shell has acquired Repsol’s stake and offtake capacity

SOURCE: Team Analysis

CASES OF RISK MITIGATION APPROACHES ACROSS PROJECTS – SUMMARY

		Project	Startup	
Examples of securing demand via	**Pre-FID commitments**	Gorgon LNG	2015	**Up to 96% of supply is locked in contracts before final investment decision**
		APLNG	2015	
		Wheatstone	2016	
		Gladstone	2015	
	End user participation	Tangguh	Jul 2009	**Often more than equity volumes are delivered to these end-buyers**
		Sakhalin II	Mar 2009	
		EG LNG	May 2007	
		APLNG	2015	
Examples of State participation	**Governments participation**	Snøhvit	Oct 2007	**Governments participate through NOCs**
		Sakhalin II	Mar 2009	
		Yemen LNG	Nov 2009	
		Angola LNG	Jul 2013	

PRE-FID: LNG PROJECTS SECURE MAJORITY OF VOLUMES IN LONG TERM COMMITMENTS PRIOR TO FID

Project	Operator	Total capex USD/BLN[1]	LNG capacity MTPA	Percent of LNG sold prior to FID	Percent of LNG sold till date	FID Date	Years FID to first gas[2]
Wheatstone	Chevron	29	8.9			Sep-11	5
APLNG	Origin/ Conoco-Phillips	23	9.0[4]			Jul-11	4
Gorgon LNG	Chevron	52	15			Sep-09	5
Gladstone LNG	Santos	16	7.8			Jan-11	4

[1] Latest estimates - Includes capex for liquefaction terminal and gas field development

[2] Based on estimation of startup dates

[3] Includes 9.5% equity participation from Tokyo Electric (8%) and Kyushu Electric (1.5%)

[4] First 4.5MTPA train sanctioned in July 2011 with 96% sold. Second 4.5MTPA train sanctioned Jul 2012 also with 96% sold

END USER PARTICIPATION: IN SEVERAL OF THESE PROJECTS, IT IS COMMON FOR END BUYERS TO HAVE EQUITY STAKE

🟩 End Buyer

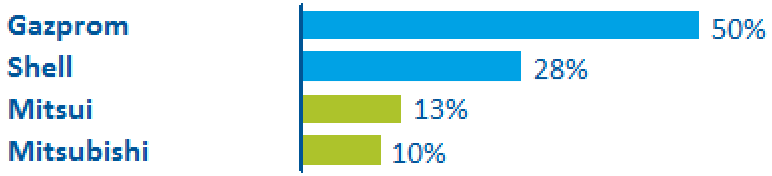
Partners | **Equity share, %** | **Comments**

Tanguuh LNG

Japanese buyers signed contracts & took equity in Indonesian project Tanguuh

- **Nippon & INPEX** are Japanese oil companies while Mitsubishi is a Japanese trading company supplying LNG to Japan

Sakhalin II



- The project is contracted in two ways – direct buyers and Gazprom-Shell. Shell volumes are split evenly between Shell and Gazprom and marketed separately

APLNG

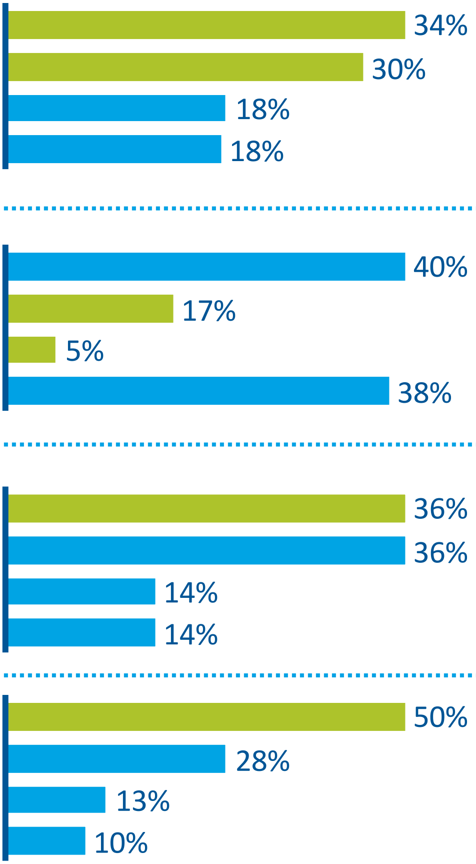
- **Sinopec** signed a contract with APLNG and also took a **15% stake** in the project enabling project FID

Often more than equity volumes are delivered to these end-buyers

SOURCE: Company websites; press releases; presentations; trade press

AKLNG STATE PARTICIPATION: WHERE STATE PARTICIPATION EXISTS, IT IS USUALLY THROUGH NOCs

🟩 Government involvement



	Partners	Equity share, %	Comments
Snøhvit LNG	**Statoil**	🟩 34%	- **Petoro, is wholly owned** by the state of **Norway** - **Norwegian State** is the **largest shareholder** in **Statoil**, with a direct ownership interest of 67%
	Petoro	🟩 30%	
	Total	18%	
	Others	18%	
Yemen LNG	**Total**	40%	- **Yemen gas** is owned by **Yemeni Government and Shell**
	Yemen Gas	🟩 17%	
	GasSP (Yemen)	🟩 5%	
	Others	38%	
Angola LNG	**Sonangol**	🟩 36%	- **Sonangol** is the National Oil Company of Angolan government
	Chevron	36%	
	Total	14%	
	BP	14%	
Sakhalin II	**Gazprom**	🟩 50%	- **Russian Federation** is the majority holder in **Gazprom (50.002%)**
	Shell	28%	
	Mitsui	13%	
	Mitsubishi	10%	

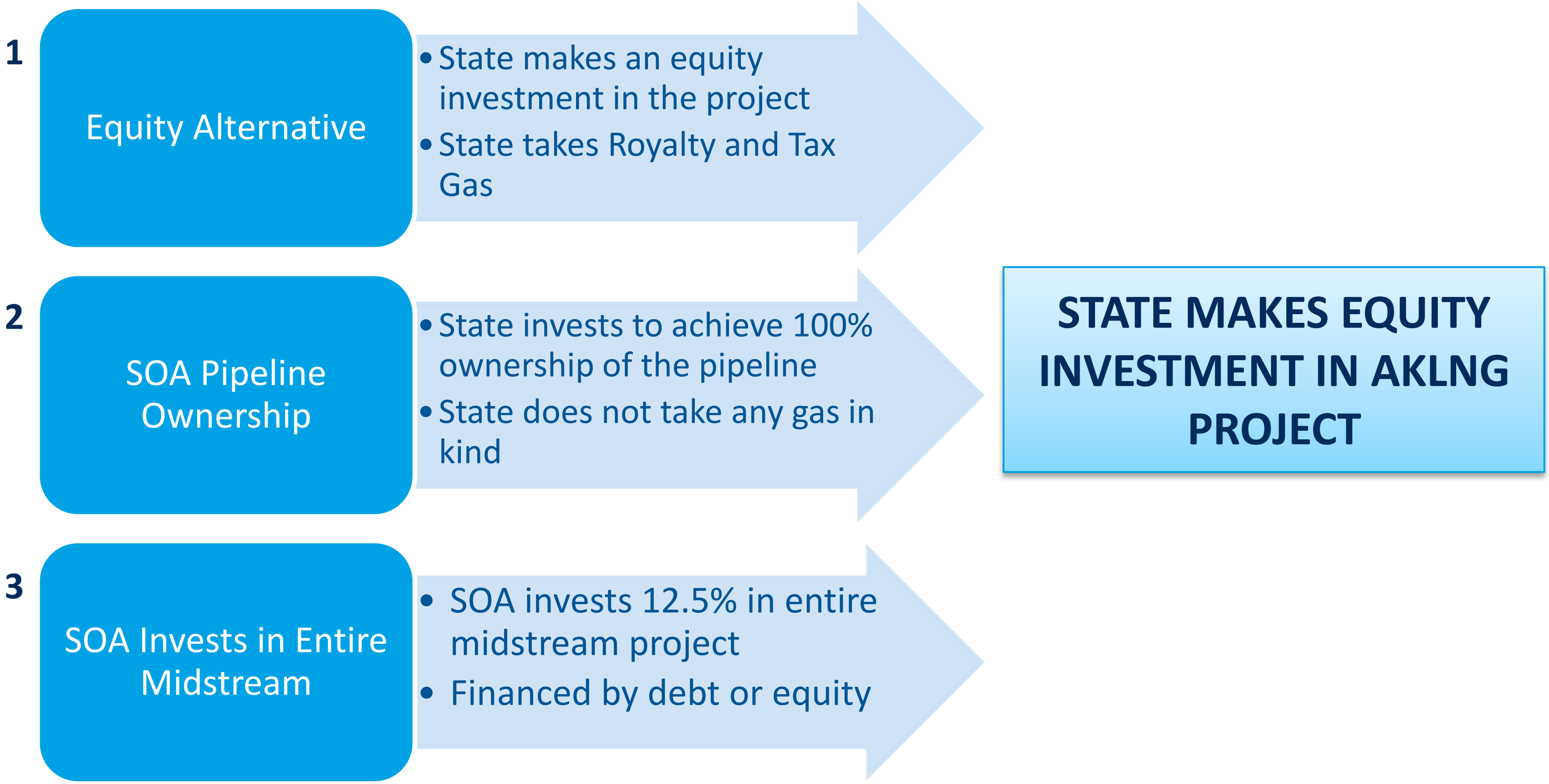
SOURCE: Company websites; press releases; presentations; trade press

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

THERE ARE VARIOUS ALTERNATIVES FOR THE STATE TO PARTICIPATE WITH AN EQUITY INVESTMENT IN THE AKLNG PROJECT

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



1 **Equity Alternative**

- State makes an equity investment in the project
- State takes Royalty and Tax Gas

2 **SOA Pipeline Ownership**

- State invests to achieve 100% ownership of the pipeline
- State does not take any gas in kind

3 **SOA Invests in Entire Midstream**

- SOA invests 12.5% in entire midstream project
- Financed by debt or equity

STATE MAKES EQUITY INVESTMENT IN AKLNG PROJECT

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

- **Equity Alternative**
  - In this alternative, the State would make an equity investment across the midstream and receive 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%

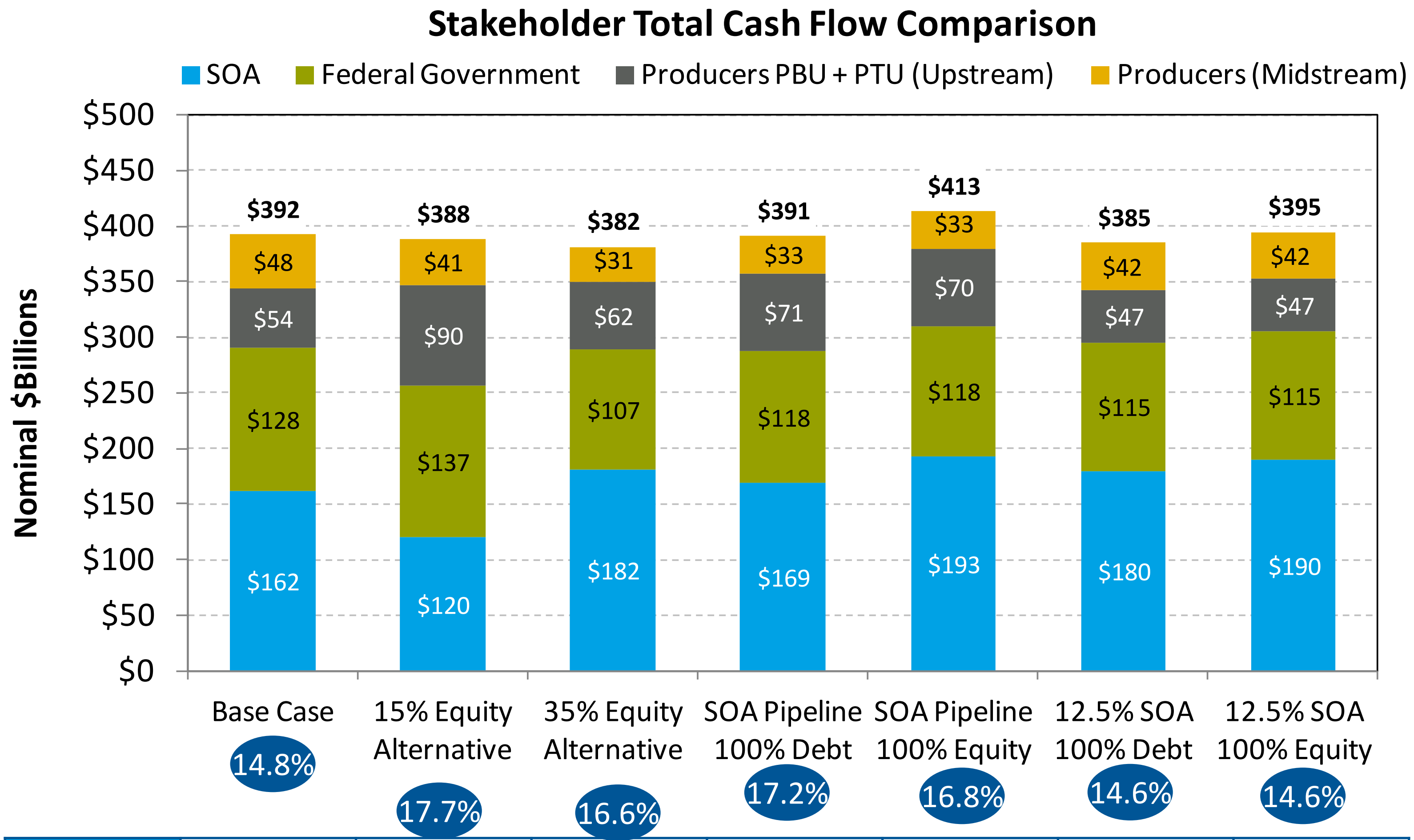
ALTERNATIVES FOR THE STATE TO PARTICIPATE WITH AN EQUITY INVESTMENT IN THE AKLNG PROJECT – STATE PIPELINE OWNERSHIP

- 100% State Ownership of Pipeline
  - In this alternative, the State would invest 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

ALTERNATIVES FOR THE STATE TO PARTICIPATE WITH AN EQUITY INVESTMENT IN THE AKLNG PROJECT – 12.5% EQUITY INVESTMENT IN MIDSTREAM

- 12.5% State Ownership of Midstream
  - In this alternative, the State would invest 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

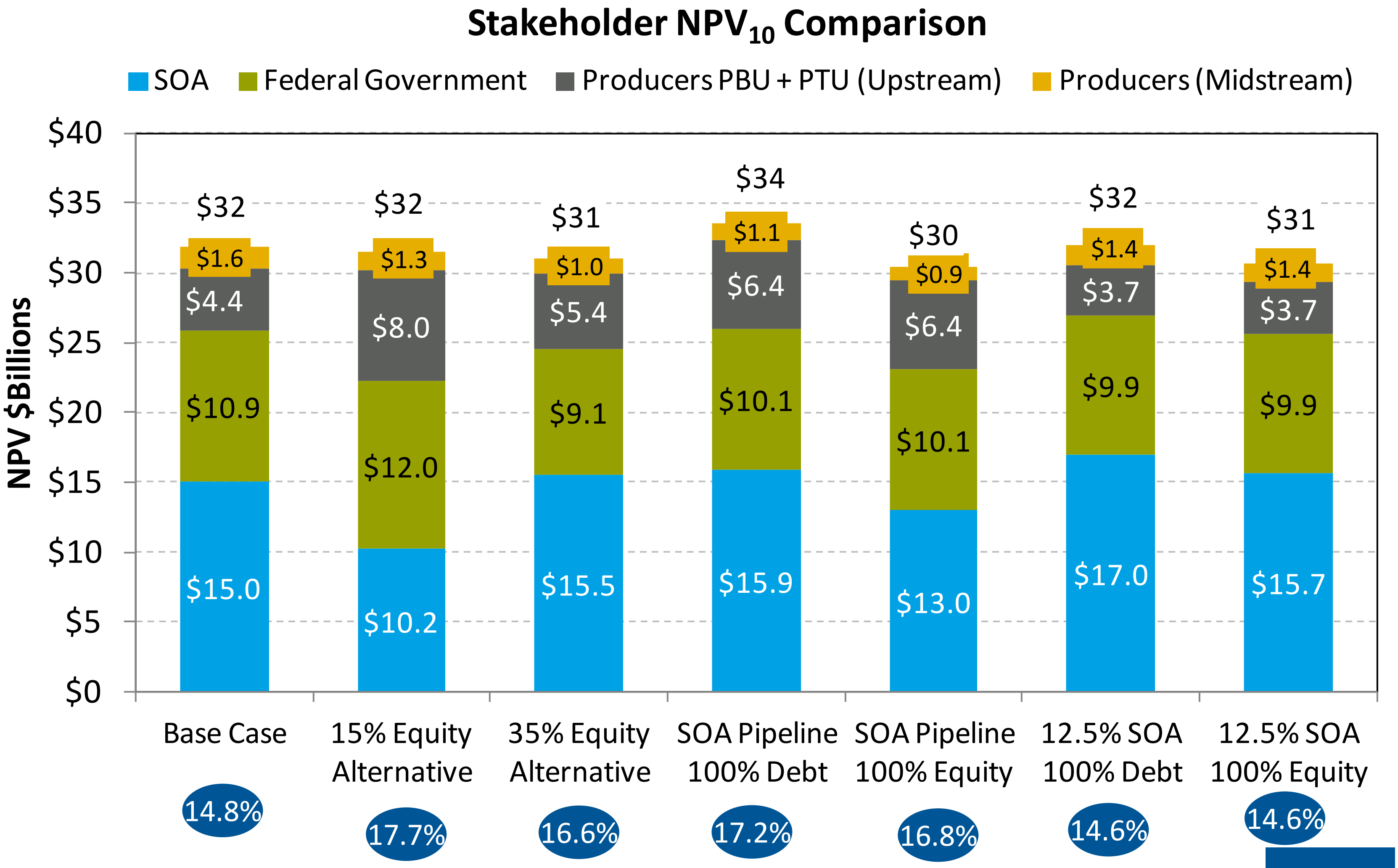
STATE EQUITY PARTICIPATION CHANGES DISTRIBUTION OF CASH FLOW FOR STAKEHOLDERS


Stakeholder Total Cash Flow Comparison

Govt. Take	**74%**	**66%**	**76%**	**73%**	**75%**	**77%**	**77%**

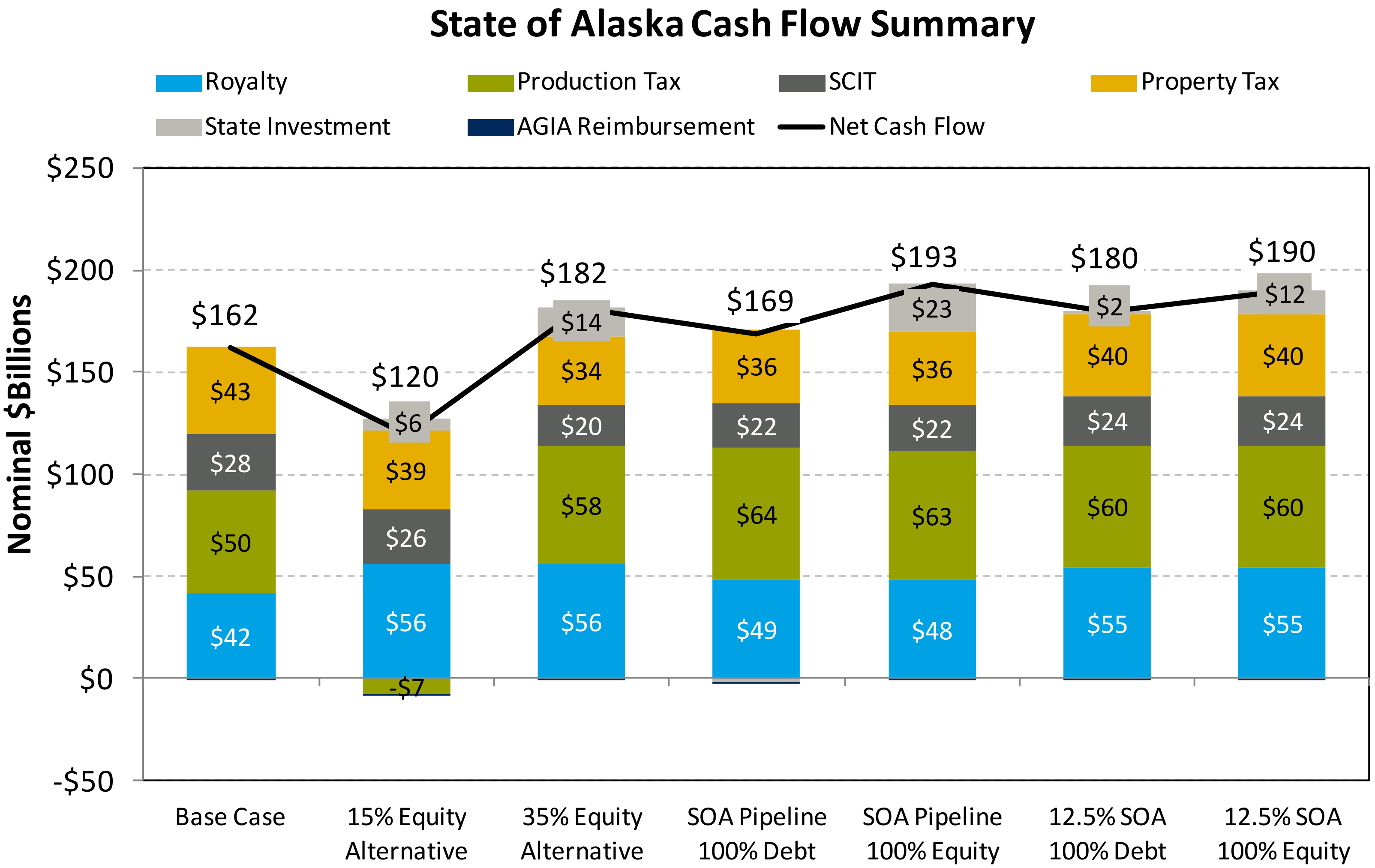
% **Producer (Upstream + Midstream) IRR**

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

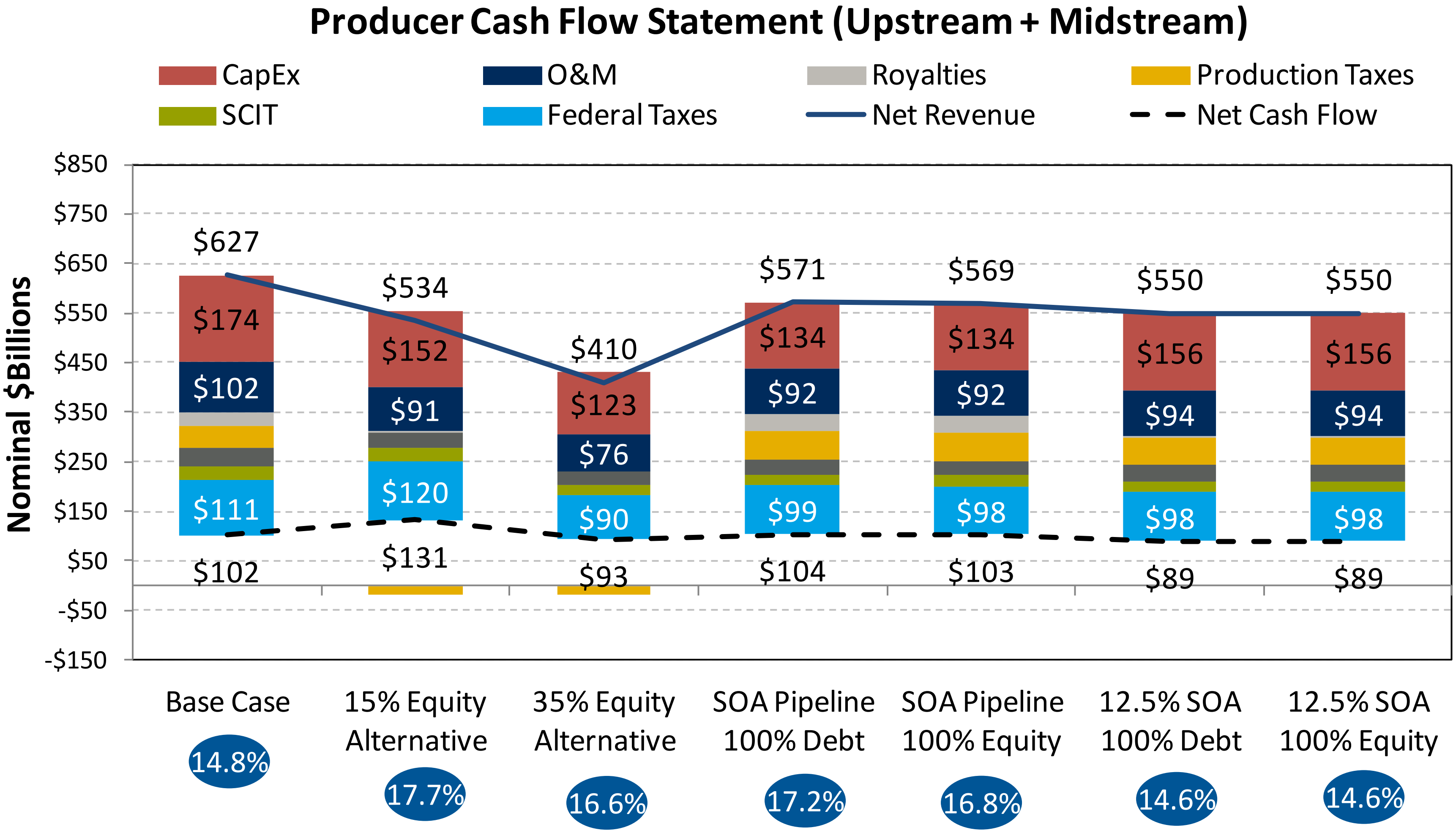


% Producer (Upstream + Midstream) IRR

STATE'S CASH FLOW PROFILE CHANGES WITH EQUITY INVESTMENT, DRIVEN BY LEVEL AND NATURE OF INVESTMENT



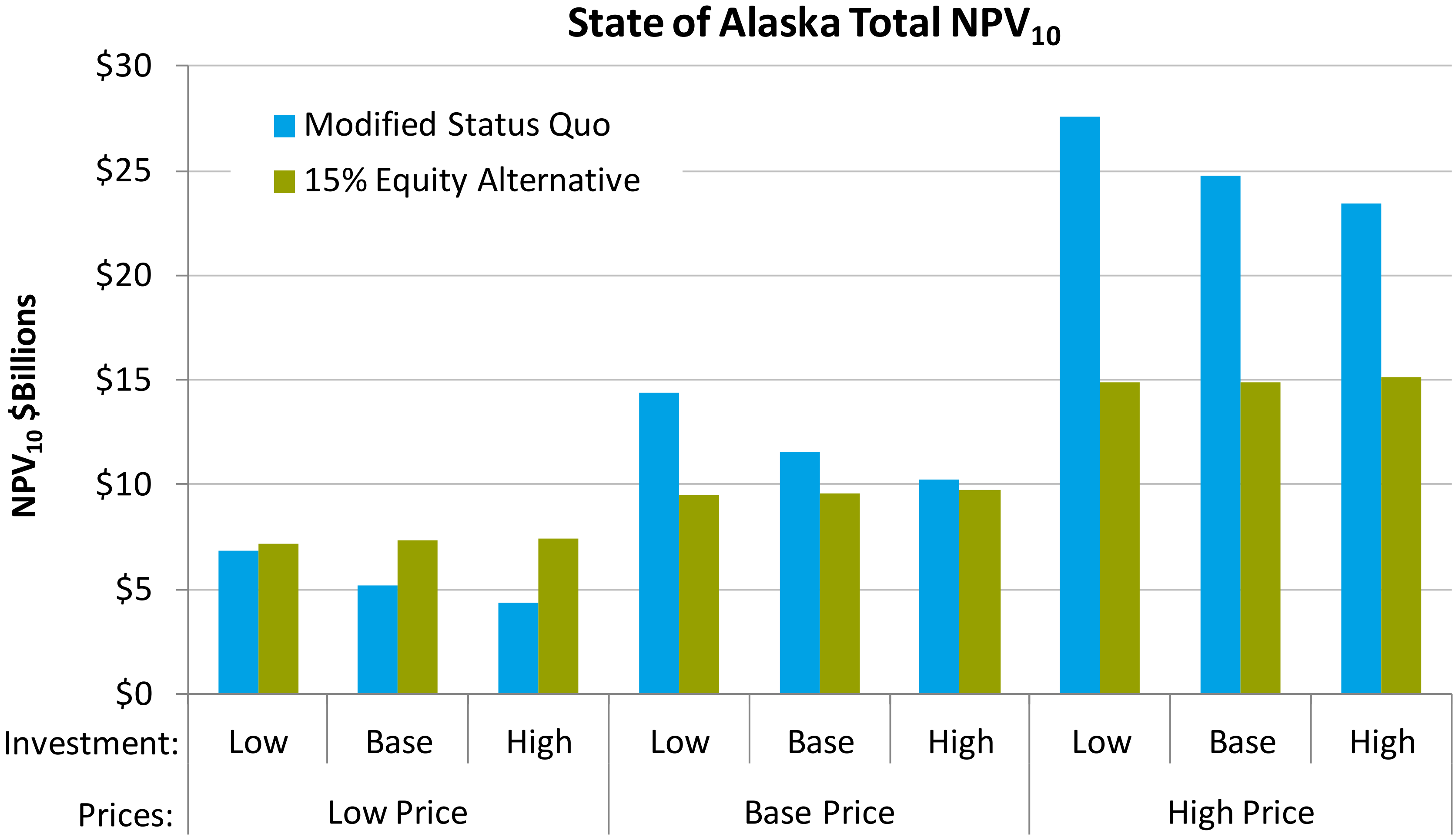
STATE EQUITY PARTICIPATION WITH STATE GAS SHARE ALLOWS PRODUCERS TO INCREASE THEIR RETURN ON THE AKLNG PROJECT


Producer Cash Flow Statement (Upstream + Midstream)

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

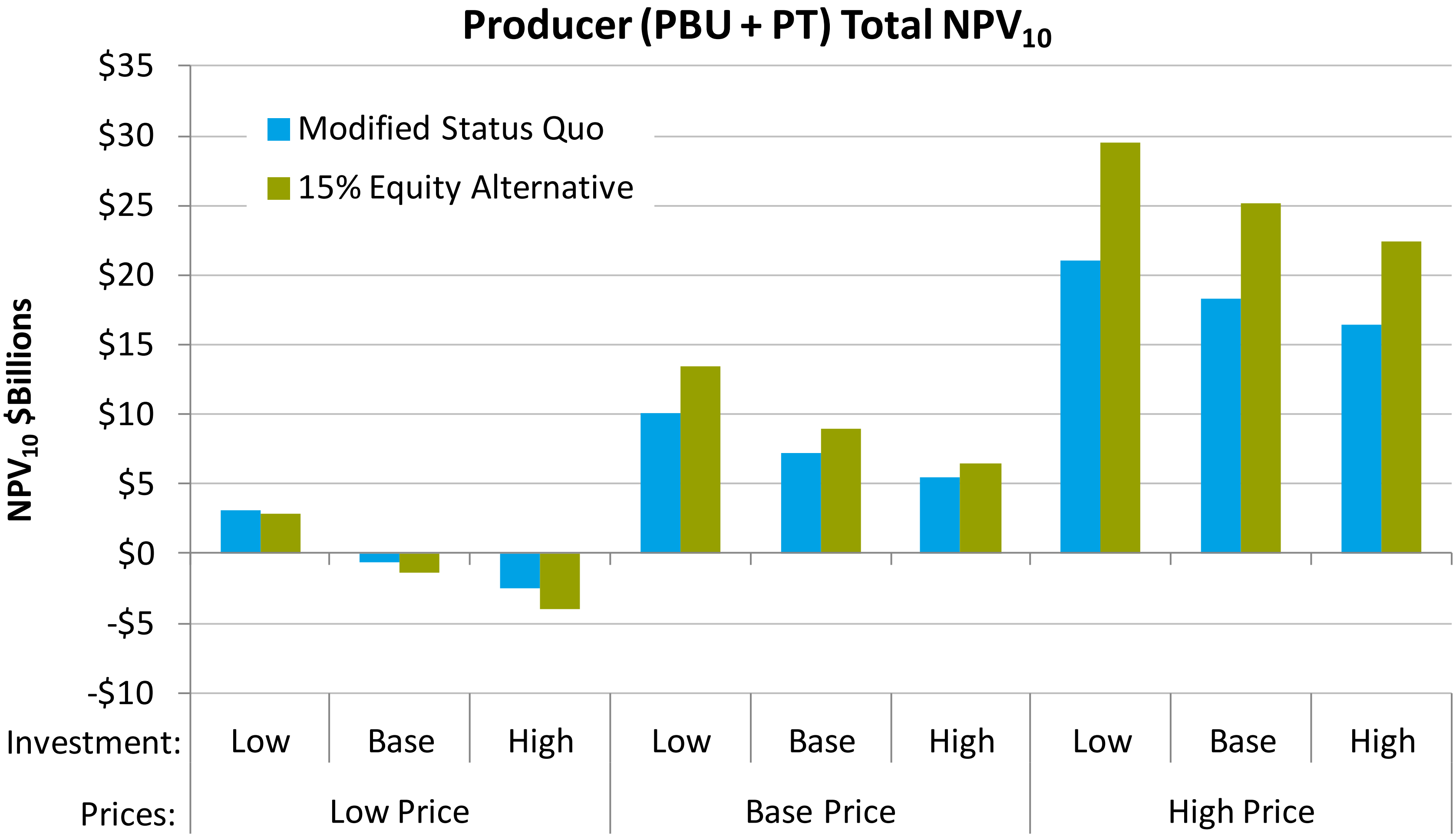
- Scenarios examining a range of capital costs and market prices were assessed to understand whether the equity alternative provides positive economic value to the State relative to status quo under each of the scenarios
- 15% and 35% state equity participation levels in combination with equivalent royalty 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

15% SOA EQUITY PARTICIPATION – SOA NPV_{10}



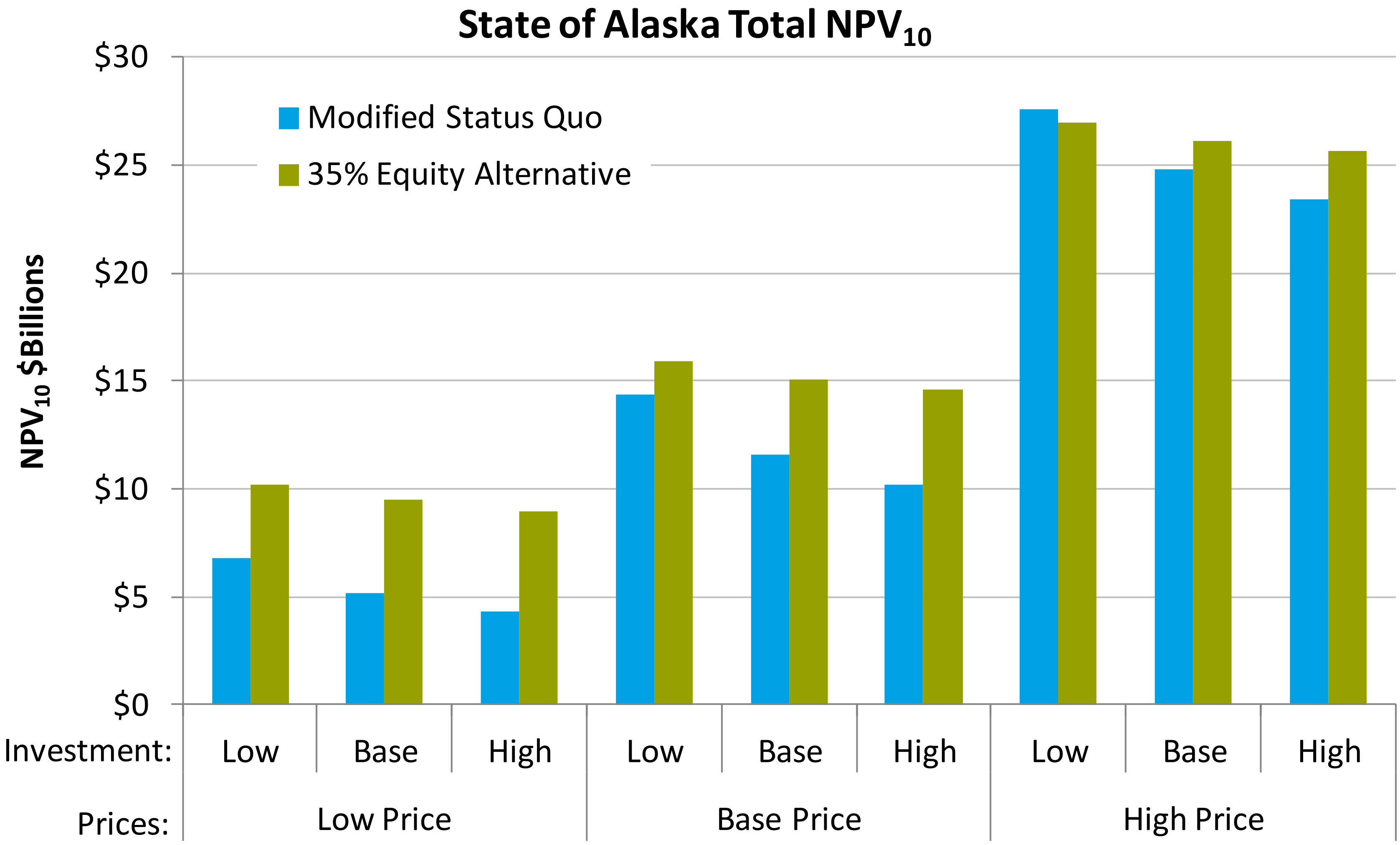
15% equity participation does not provide positive economics to the State under base and high price scenarios

15% SOA EQUITY PARTICIPATION – PRODUCER NPV_{10}



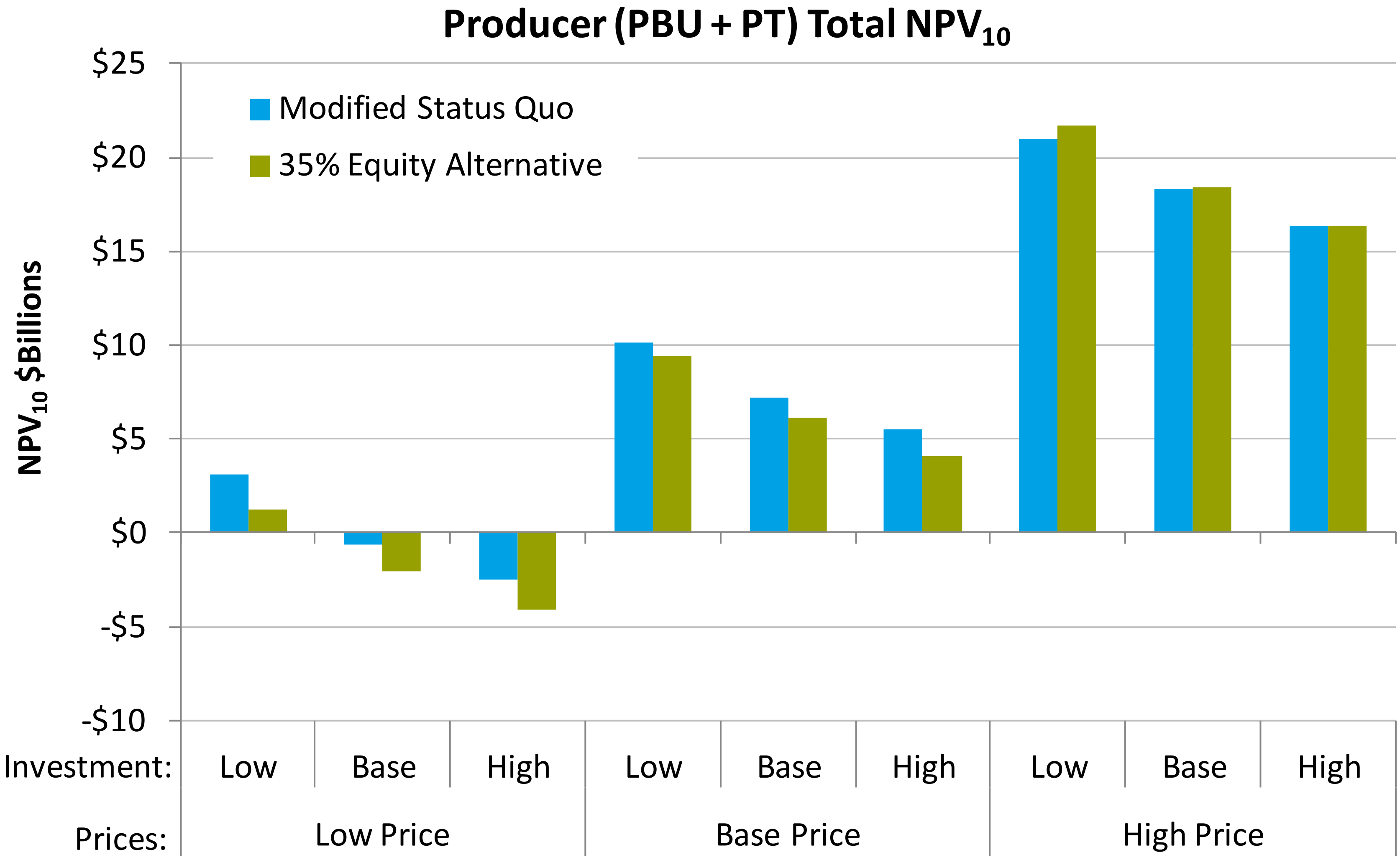
At low prices the project is not economic for the Producers for either scenario

35% SOA EQUITY PARTICIPATION – SOA NPV$_{10}$



35% State equity participation provides positive economics for the State across most scenarios

35% SOA EQUITY PARTICIPATION – PRODUCER (PBU + PT) NPV$_{10}$

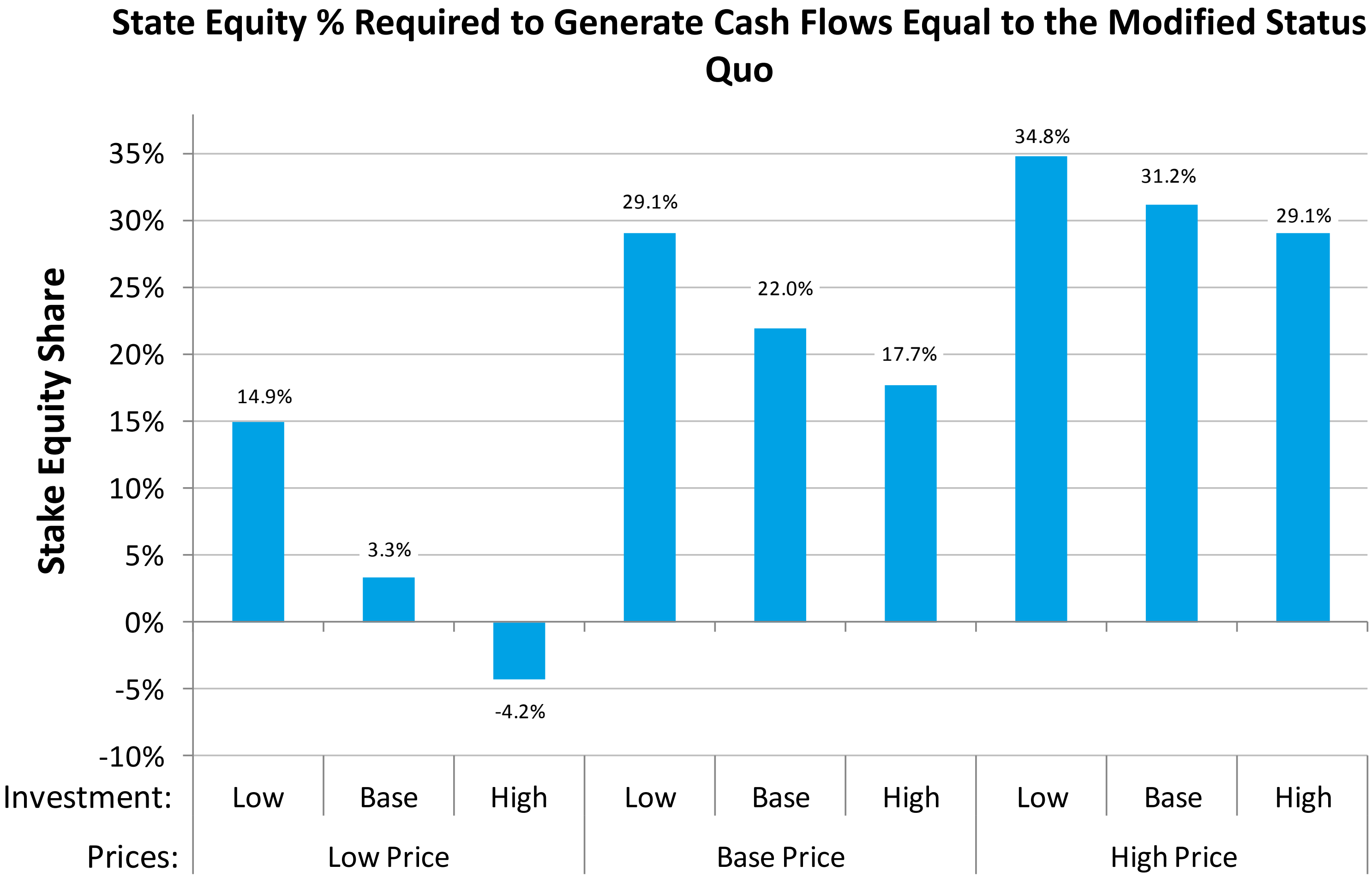


Producers economics with the equity alternative is close to modified status quo with a State 35% equity stake

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

- 15% SOA equity participation generally does not see positive economics for the State relative to Status quo due to a decrease in overall take by the State
  - Equity participation provides a dampening effect for the State wherein both the upside and downside under low price scenarios are less with equity participation than under modified status quo
- A 35% State equity participation indicates positive economic benefits for the State across 8 of 9 scenarios examined
- In order to get an indication of the level of equity investment that would be appropriate for the State, we estimated the level of state equity participation that would make the State’s cash flows and NPV10 equal to what it would in modified status quo for each of the capital cost and price scenarios

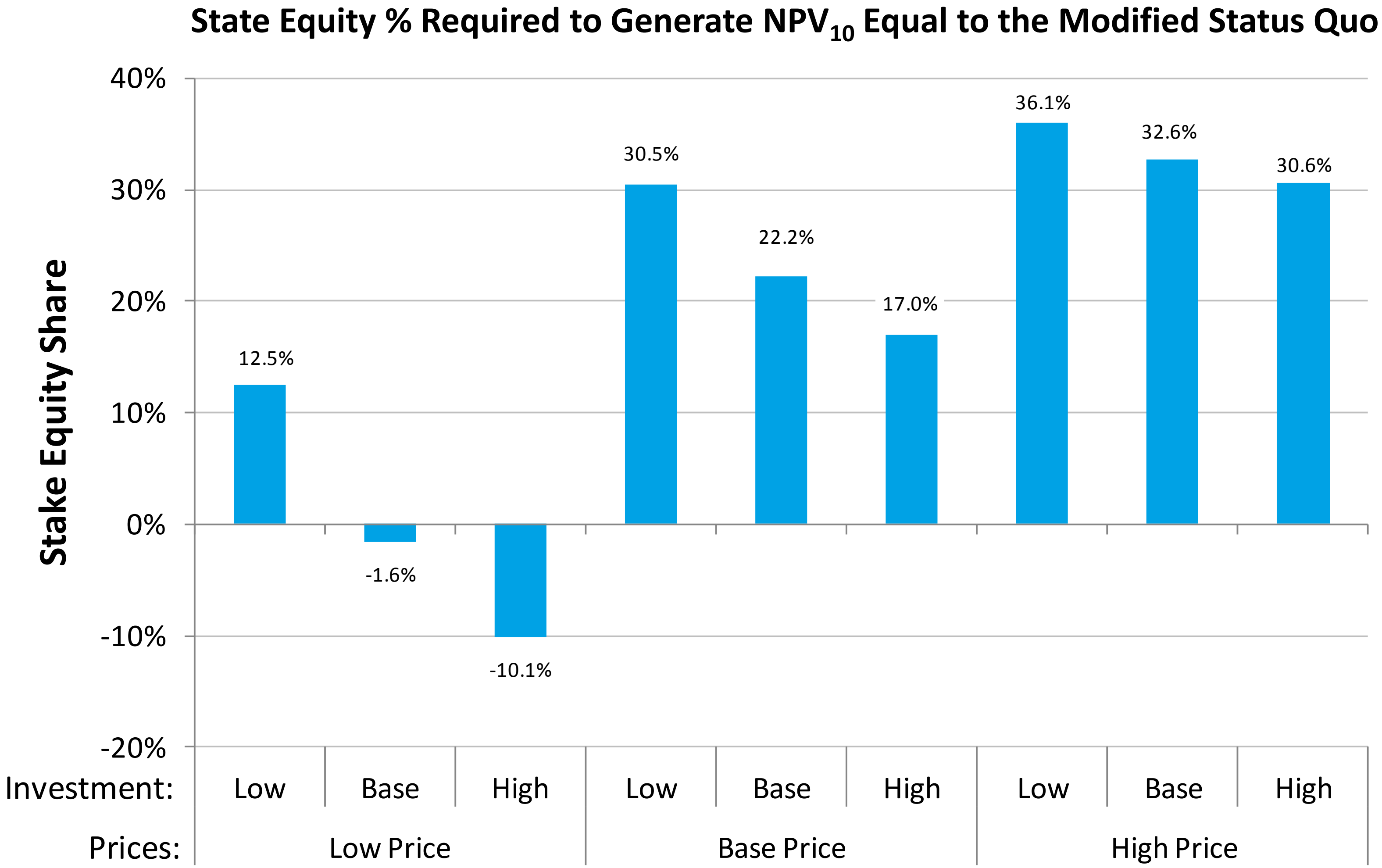
THE LEVEL OF STATE EQUITY INVESTMENT REQUIRED TO EQUAL TOTAL STATE CASH FLOWS UNDER STATUS QUO VARIES WITH MARKET CONDITIONS



Prices	Investment	State Equity Share
Low Price	Low	14.9%
Low Price	Base	3.3%
Low Price	High	-4.2%
Base Price	Low	29.1%
Base Price	Base	22.0%
Base Price	High	17.7%
High Price	Low	34.8%
High Price	Base	31.2%
High Price	High	29.1%

State equity participation between 20% and 30% offers cash flows at or above the modified status quo levels for the State

THE LEVEL OF STATE EQUITY INVESTMENT REQUIRED TO EQUAL TOTAL STATE NPV_{10} UNDER STATUS QUO VARIES WITH MARKET CONDITIONS



State equity participation between 20% and 30% offers NPV_{10} at or above the modified status quo levels for the State

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

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

- **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	✓ All Structures • Might be limits on tolling structure
Position on management committee	✓		• Integrated
Participation through secondees on GTP, Pipeline and LNG plant teams	✓		• Integrated
Undivided joint interest approach “pipe within a pipe”		✓	• Integrated
Expansion rights to be negotiated within context of JVA		✓	• 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