Alaskan LNG Exports Competitiveness Study

Alaska Gasline Port Authority (AGPA)

Final Report

July 27, 2011

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Background

As part of its interest in promoting a large volume pipeline from the North Slope to a 2.7 bcfd liquefaction facility in Valdez (and a lateral to serve south central Alaskan demand), AGPA has contracted Wood Mackenzie to evaluate the economic competitiveness of Alaskan LNG exports relative to other proposed liquefactions projects at various stages of development.

With oil prices hovering today around $100 per barrel, and expected to remain at or around that level for an extended period of time, the Alaskan LNG export opportunity appears today to make economic sense. Typical Asian oil-indexed LNG pricing delivers product to regasification terminals at over $15 per mmBtu. On the other hand, Lower-48 and Canadian natural gas, if exported as LNG, could potentially be delivered to Asia at or around a cost of $10 per mmBtu, subject to various assumptions and costs.

The purpose of this report is to help AGPA to develop an informed perspective as to the overall economic attractiveness of the proposed Valdez LNG export facility.

Please note all future values throughout this study are given in nominal terms.

Agenda

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Agenda

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From an economic perspective, Alaskan LNG exports are competitive, viable across scenarios, and could generate between $220 and $419 billion for Alaska*

- The numbers generally “work” for Alaskan LNG exports when the global oil price is north of $75/bbl oil and Asian firm contract pricing reflects a 13%(+) oil indexation** (indexation for firm contracts today is approximately 14.85%)
- Alaskan LNG exports have a delivered cost structure below $10/MMBtu. Given a range of infrastructure cost scenarios, oil prices projected utilizing Woodmac’s April 2011 NAGS price outlook or the NYMEX forward strip, and LNG - oil indexation pricing to Asia of 13 – 16%, Alaskan LNG could be priced DES between $18.00 - $46.00/MMBtu through 2050.
- Proposed Alaskan LNG exports have a substantial cost advantage relative to possible competing LNG supply projects
- Alaskan LNG would use assets that are producing gas for re-injection (essentially limited to gathering, transport and processing costs)
- Most competing Australian projects and proposed NA LNG exports yet to secure Final Investment Decision (FID) are expected to deliver LNG to Asia at costs of $10 - $12/MMBtu under current gas price assumptions
- Assuming start-up in 2021 and a project life of 30 years, royalties (12.5%) and state taxes (starting at 25% post-royalties) could yield a total of between $220 and $419 billion*
- Royalties (12.5%) and state taxes (starting at 25% post-royalties) could yield $2.4 to $24 billion per year.
- While we do not address them, there are a number of commercial challenges associated with all liquefaction projects
- Economics are important, but commercial issues such as the scale of value chain requirements (pipes, storage, etc.), buyer risk tolerance, financing arrangements, etc. are critical

Taking all into account – basis, shipping, capital requirements – Alaska LNG export facilities can deliver LNG to Asia less expensively than US Lower 48 or Canada and competitively vis-à-vis traditional Australian LNG sources

*Total undiscounted taxes and royalties values utilize nominal figures (2.4% inflation), 14.85% indexation, and avg. recourse rate of $4.18. Assuming a nominal discount rate of 5%, the NPV of taxes and royalties is between $65 and 124 billion.

**Oil indexation price example: With an oil price of $100/bbl, “oil indexation” of 14.85% yields a gas price of $14.85/MMBtu

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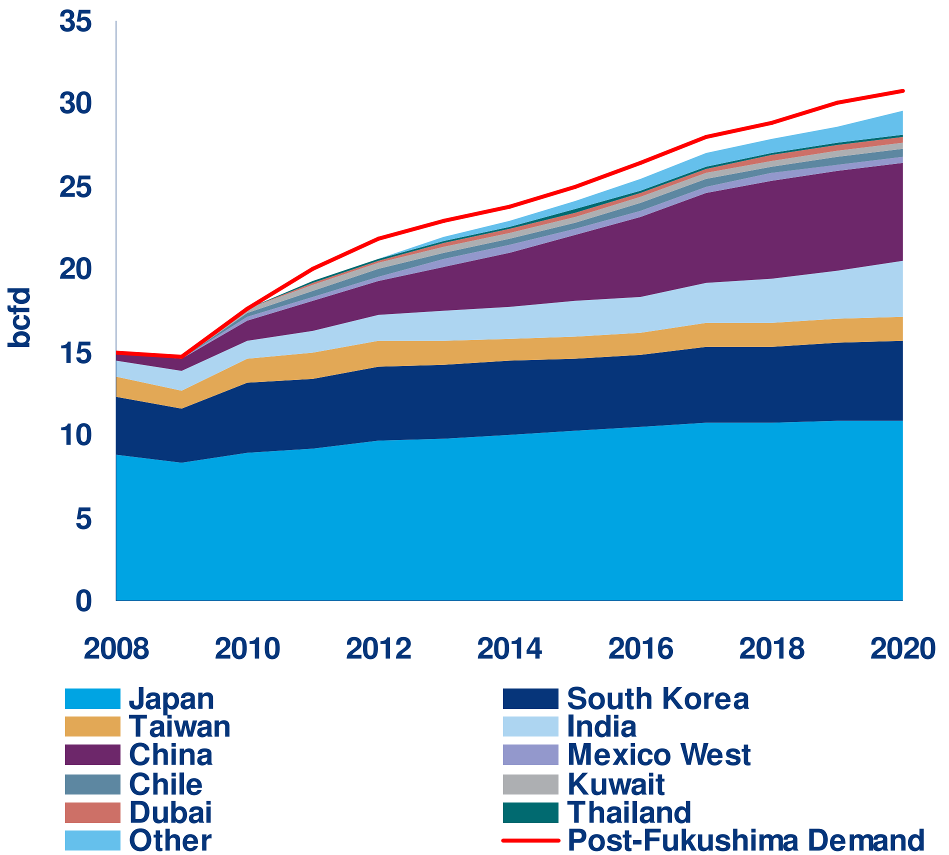
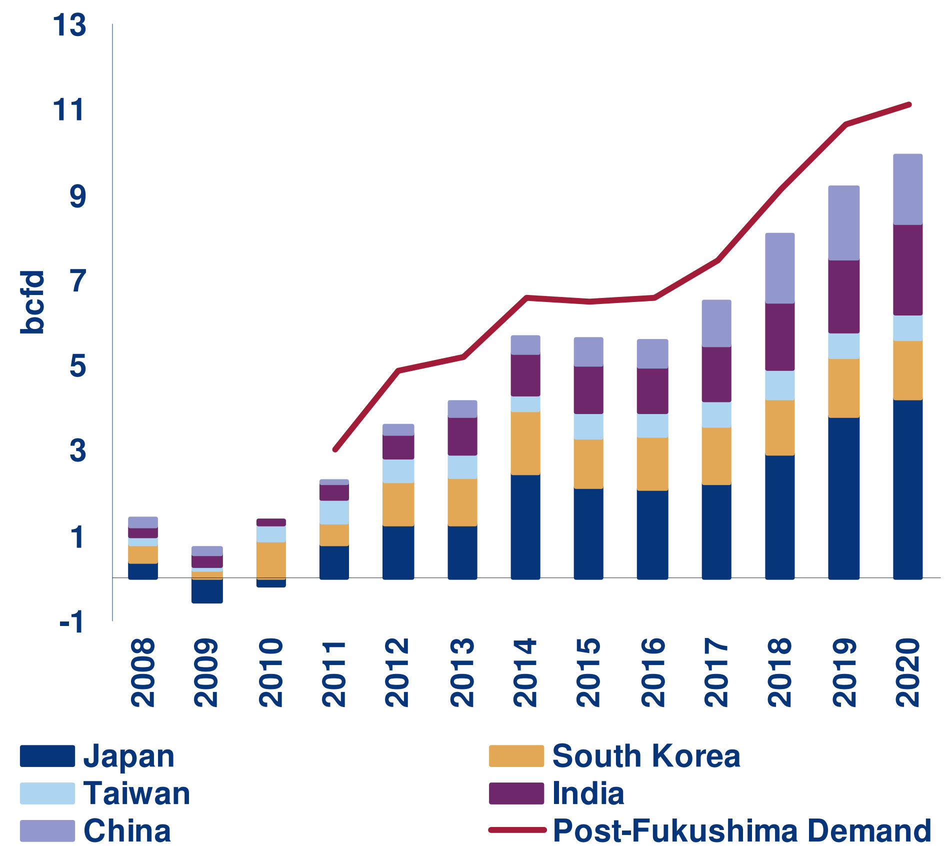
China is a key driver of Pacific LNG demand growth, but traditional JKT (Japan, Korea, Taiwan) markets still account for most uncontracted demand

Pacific/ME LNG Demand



Uncontracted Demand, Selected Countries



Source: Wood Mackenzie LNG Tool, Feb'11, Global Gas Service H1 '11

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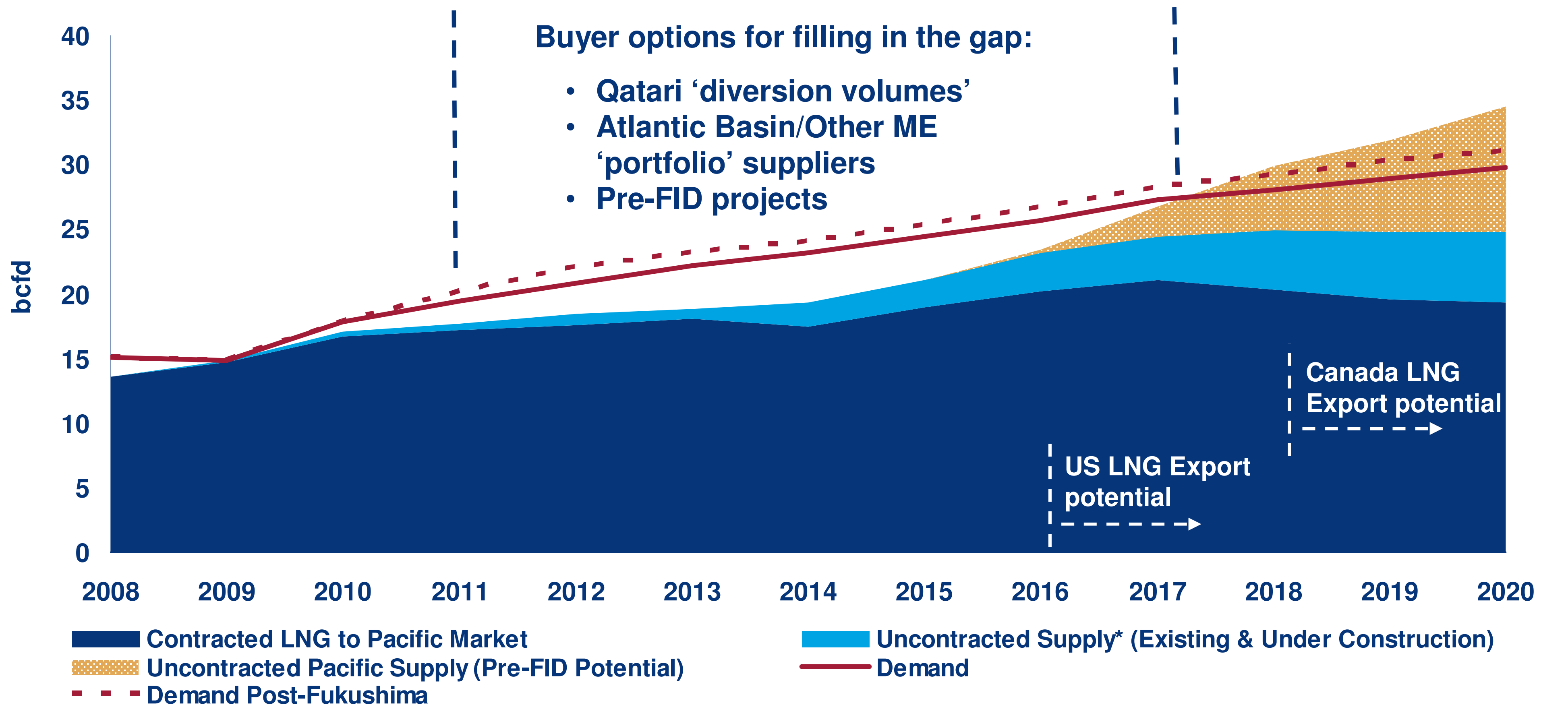
The Pacific Basin market is short of proximate LNG and a number of projects will compete for long-term supply requirements (including Alaska LNG)

Pacific/ME Basin LNG supply vs demand

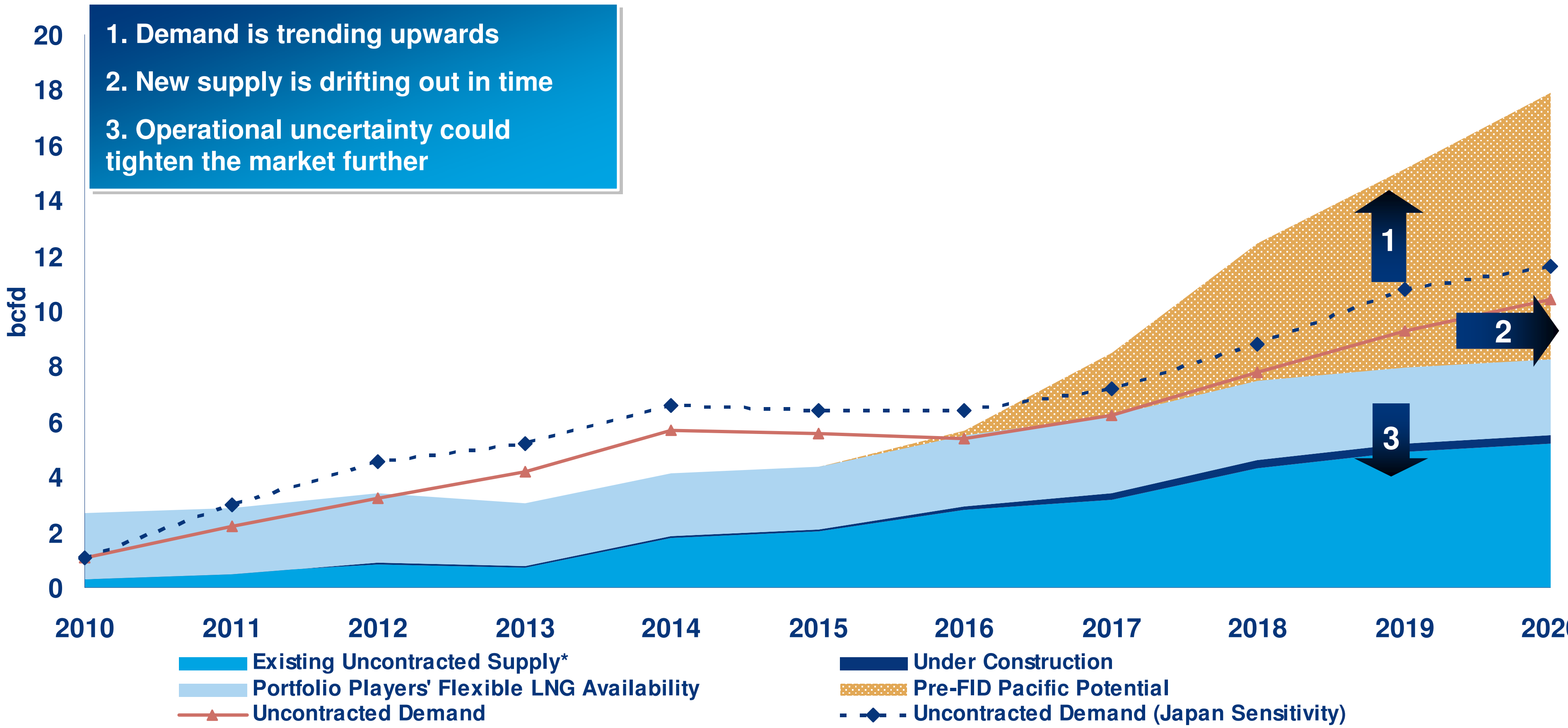


*Includes uncontracted supply from Pacific Basin and Middle East supply projects, but excluding 'flexible' Qatari volumes that are 'allocated' to the Atlantic Basin

Source: Wood Mackenzie LNG Tool, Feb'11, Global Gas Service H1 '11

There is insufficient Atlantic portfolio LNG to bridge the gap and the market is tighter than it appears (since Fukushima) supporting current LNG prices

Pacific Basin uncontracted LNG supply vs demand, including portfolio supplies



*Includes uncontracted supply from Pacific Basin and Middle East supply projects, but excluding 'flexible' Qatari volumes that are 'allocated' to the Atlantic Basin

Source: Wood Mackenzie LNG Tool, Feb'11, Global Gas Service H1 '11

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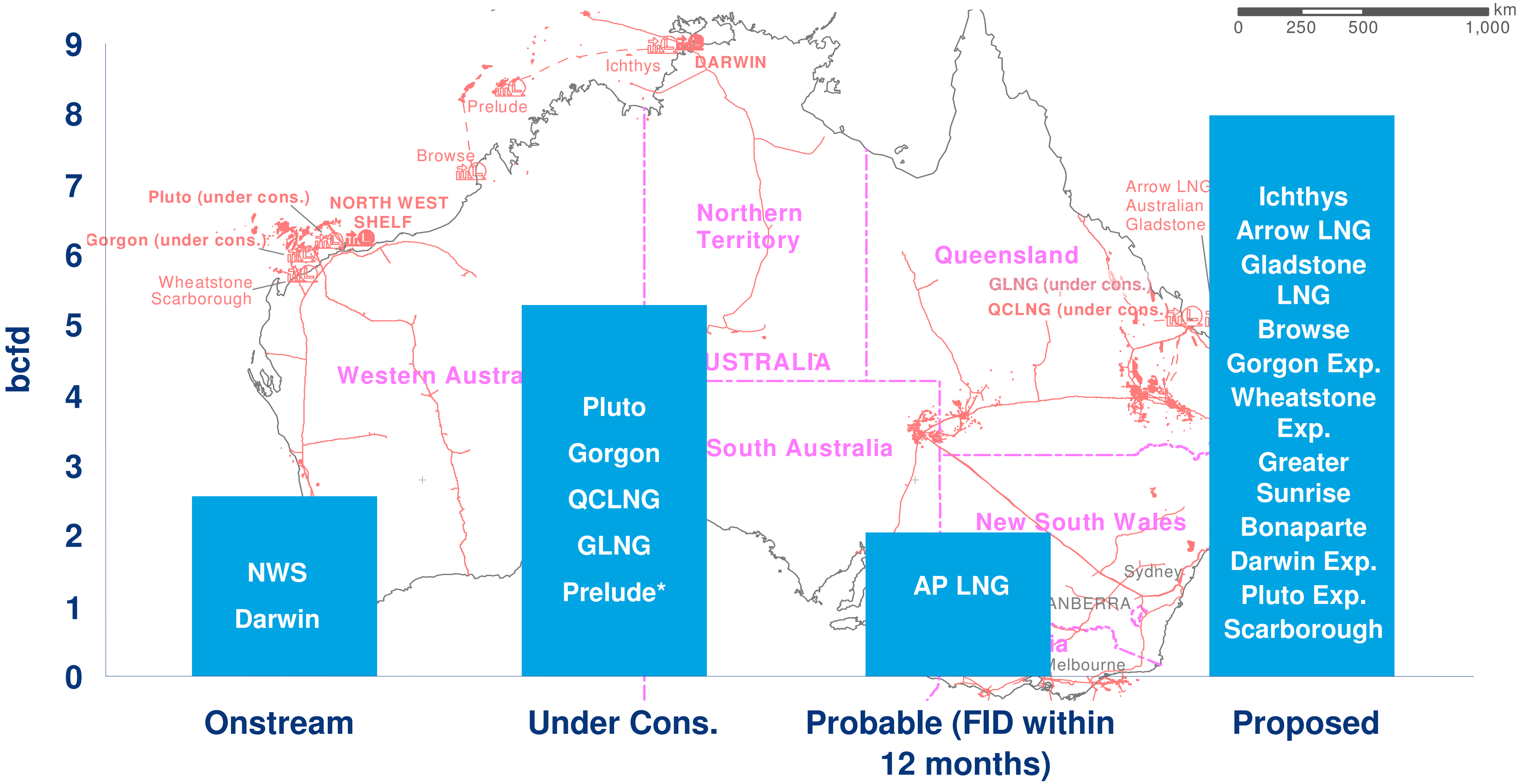
Australia will help fill the Pacific supply gap with over 7 bcfd of capacity on-stream or currently under construction…

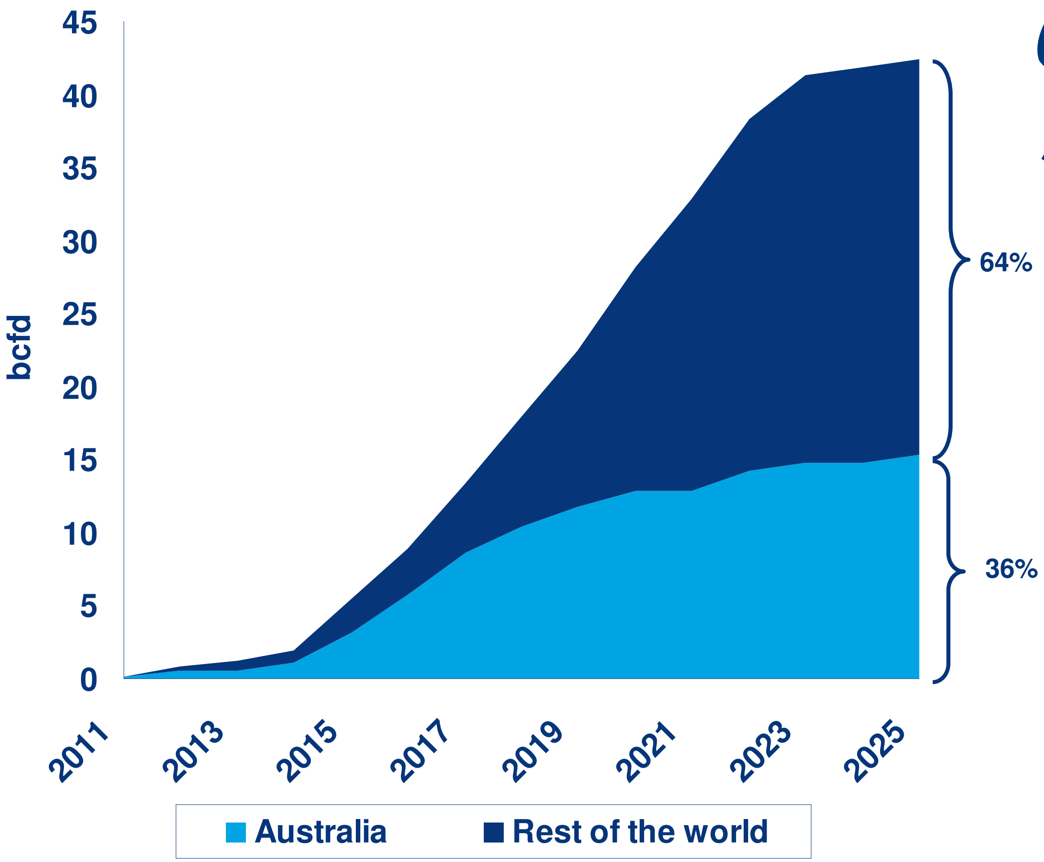


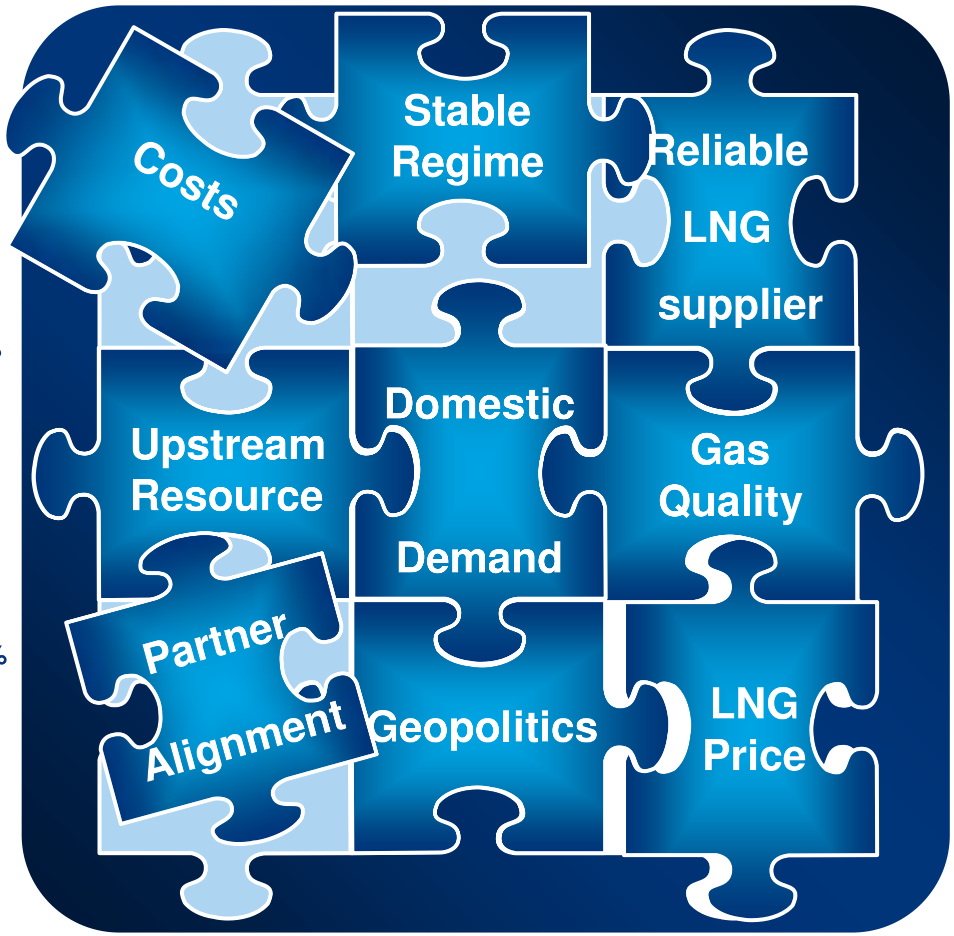
* Prelude took FID in mid May

Source: Wood Mackenzie. As of May 2011.

…and continues to dominate the global outlook for new LNG supply due to its large gas resource base and attractive investment climate

'Potential' LNG supply*: Australia and the rest of the world





*Includes under construction, probable and proposed LNG capacity globally

Source: Wood Mackenzie LNG Tool

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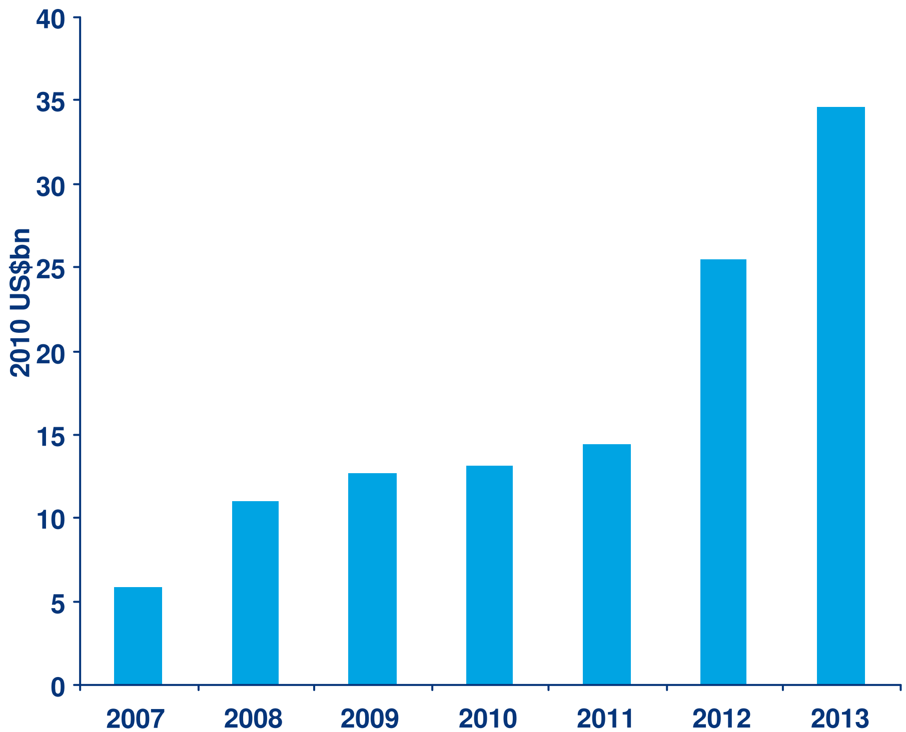
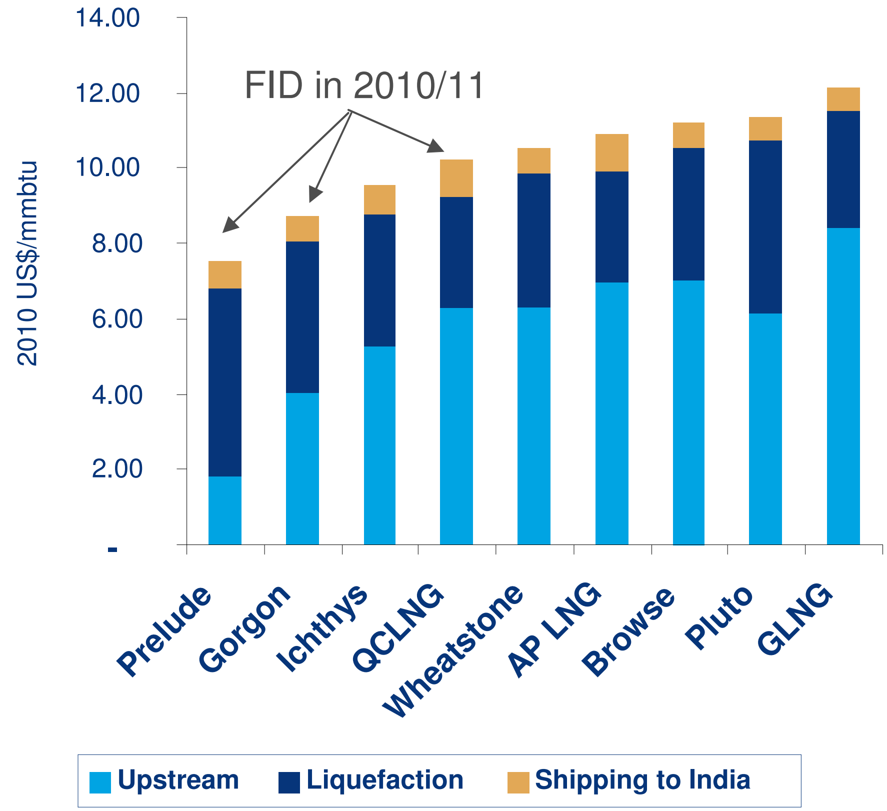
But rising costs are putting pressure on Australian project economics… Which sponsors are best placed to mitigate against cost over-runs and delays?

Australian oil and gas upstream and liquefaction capital expenditure



DES cost stacks for Australian LNG projects (base Capex)*



** The analysis is taken from the February 2011 LNG Service Insight: 'Might Rising Costs In Australia Propel North America LNG Exports'.*

Source: Wood Mackenzie CAT, LNG GEM, LNG Tool

There may be headroom for a few North American LNG export projects

Douglas Channel Energy Partnership project is a proposed 0.9 mtpa barge facility near Kitimat

AGPA is promoting a potential "All Alaska" pipeline and liquefaction project from Valdez

Dominion has announced plans to add export capacity at the Cove Point regas facility

Kitimat LNG is a proposed 5 mtpa facility (Apache/EOG/EnCana) fed with shale gas from Horn River / Montney

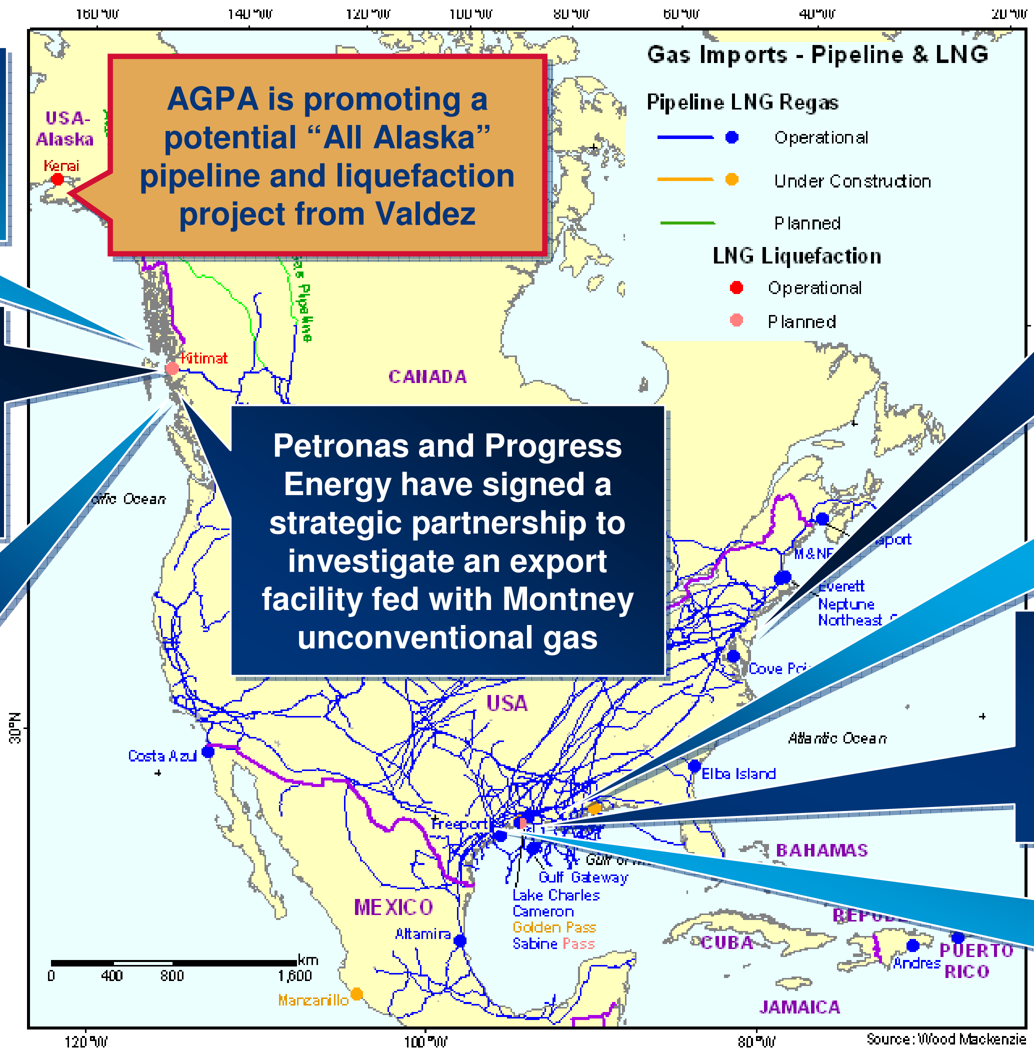
Petronas and Progress Energy have signed a strategic partnership to investigate an export facility fed with Montney unconventional gas

BG and Southern Union have announced plans to add 2 bcfd of export capacity at the Lake Charles regas facility

Cheniere is proposing to add 1.0 bcfd of export capacity at the existing Sabine Pass LNG regas facility and has signed 6 non-binding MOUs for capacity

Shell/Mitsubishi (with PetroChina, KOGAS and several Japanese utilities) and Nexen/LNG Japan are reportedly considering similar schemes in the BC area

Macquarie/Freeport are proposing to add 1.4 bcfd of export capacity at the existing Freeport LNG regas facility



Source: Wood Mackenzie

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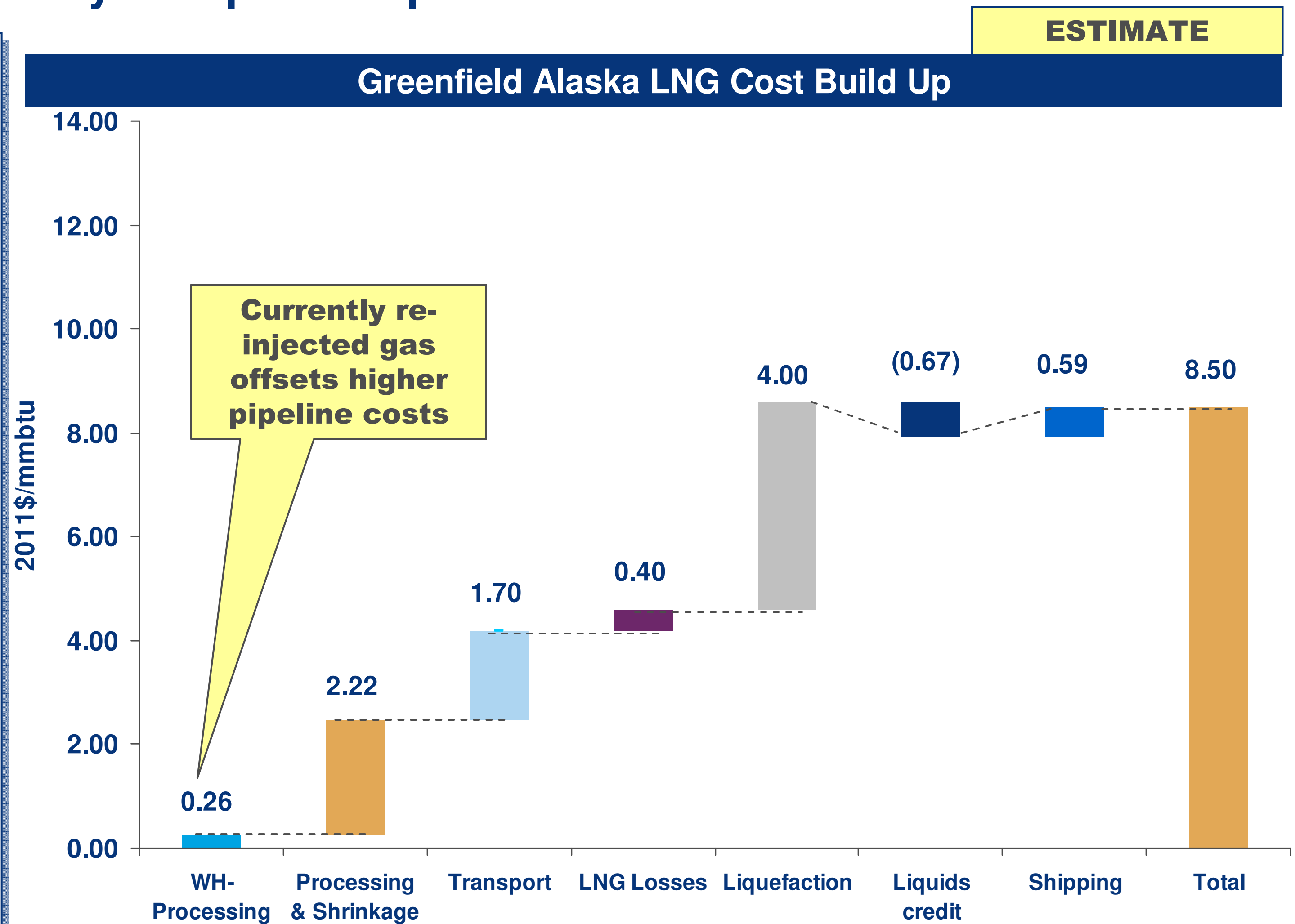
Strategy with substance

Access to currently re-injected gas upstream puts the Alaska LNG liquefaction project in an economically competitive position relative to others…

Key Assumptions

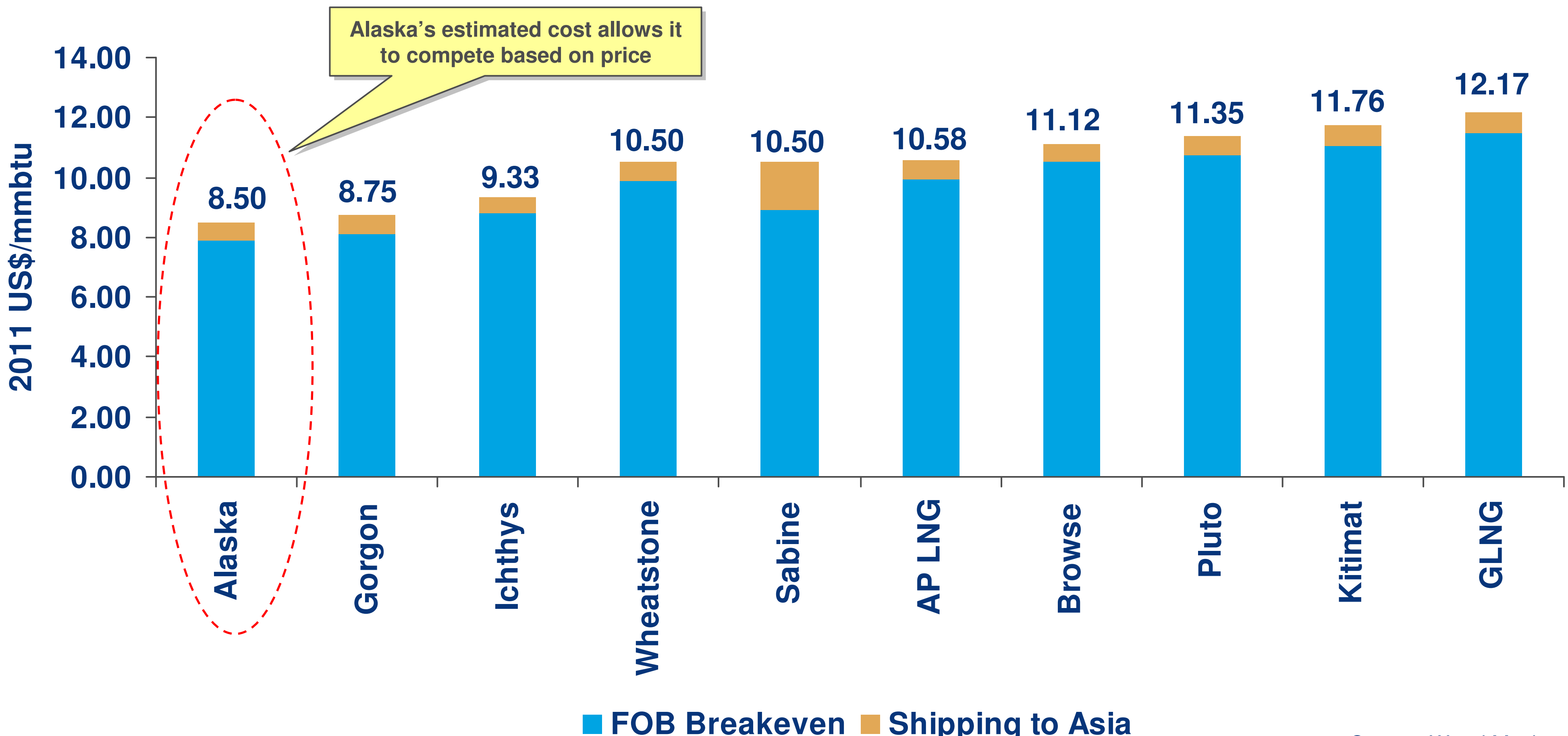
- All data from "Transcanada XOM Alaska Pipeline Project Open Season Notice, 2010, Valdez LNG Case" except below items:
- Liquefaction:
  - CapEx: $1,200/ton; est. rate covers CapEx, Opex, 12% nom. ROE.
  - Alaska LNG losses 9.65%
- Shipping Assumptions:
  - Ship: 155,000 m³
  - CapEx/ship: $200 million
  - OpEx: $15,000/day; 2.33% annual escalation
  - 8% ROE after tax
- LNG Processing Losses: estimated from AGIA NPV Report, Fig. 7.2
- Liquids credit determined using $80/bbl netback price for LPG and volumes provided by AGPA (88,000 MMBtu/d; ~20,000 bpd)



Source: Wood Mackenzie

…and it competes favorably with both proposed Australian and other North American export facilities which have yet to reach FID

DES Cost Stack Comparison



Source: Wood Mackenzie

Two pricing norms have emerged in recent long-term Pacific Basin deals

Conventional LNG

- Most recent deals are understood to have been priced at 14.85% JCC, with additional deals for pre-FID projects being negotiated at the same level
- Qatar is now also understood to be willing to accept 14.85% JCC as a price from ‘established’ Asian buyers
- Some evidence that buyers are seeking high s-curves in new deals in light of the current high oil price outlook

Coalbed Methane (CBM) LNG

- Recent deals are understood to feature s-curves, reflecting the fact that CBM LNG is a harder sale than conventional LNG
  - Primary slope of ~14.5% JCC between the kink points
  - Slopes of ~12% above and below the kink-points
- Market rumours indicate that APLNG has gone beneath these levels
  - But exact pricing terms remain uncertain
- Lower (s-curve) prices, combined with non-price concessions (see next slide) are essential in order to sell CBM LNG into a market with limited appetite for the product

Oil indexation will technically remain the standard in long-term gas contracting but additional mechanisms will be required to ensure that pricing remains within the relevant pricing boundaries

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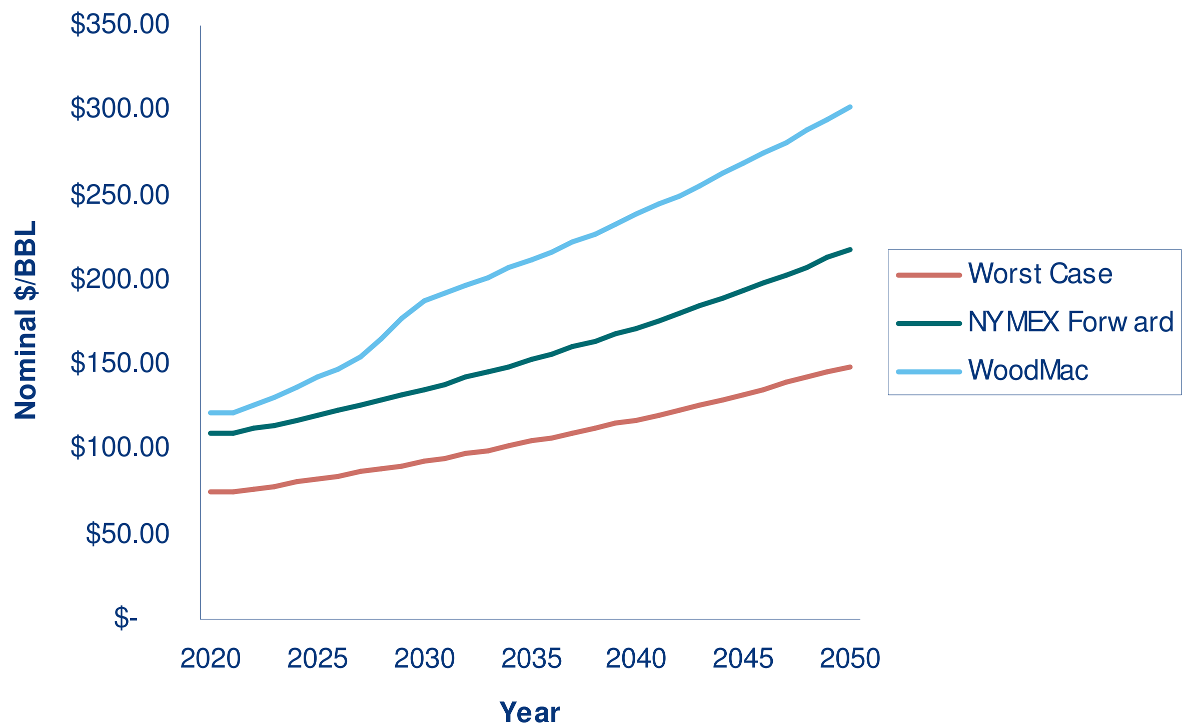
We evaluated Alaskan LNG export economics based upon two primary long-term crude oil pricing scenarios

- The extended forward NYMEX strip from July 5, 2011 is treated as a base case
- Combining the NYMEX strip scenario with a second scenario utilizing Woodmac's April 2011 NAGS price outlook, we establish the range of likely NPVs
- In a final test, we evaluated a "worst case" scenario of an inflation adjusted oil price of $75 / bbl throughout the projection period
- Oil prices and oil price scenarios are viewed as fully disconnected from North American natural gas prices

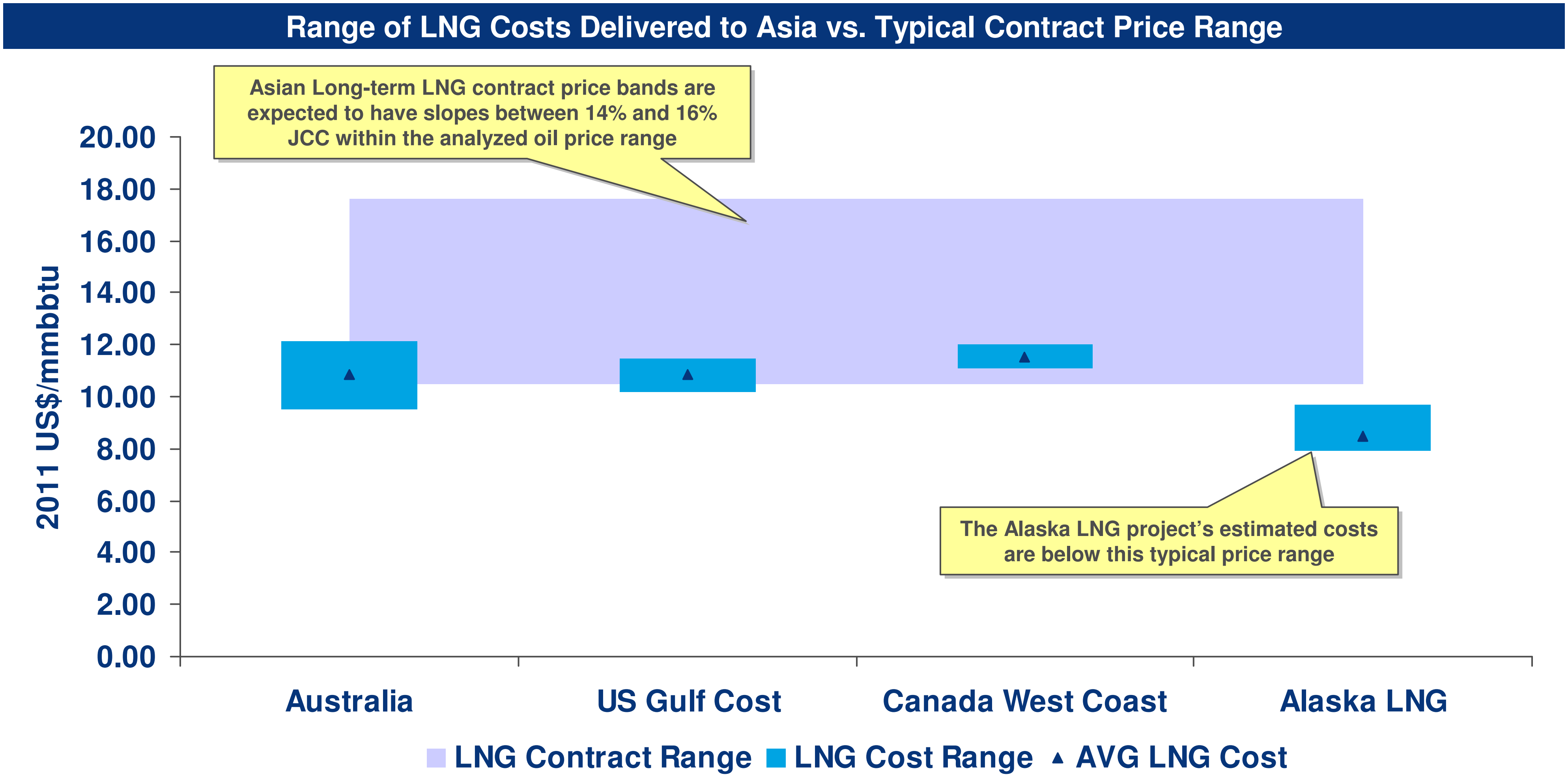
WTI Oil Nominal Prices



NYMEX forward strip data from July 5, 2011; Woodmac data from April 2011 NAGS outlook; all prices nominal

Source: CME.COM and Wood Mackenzie

The Alaska LNG export project's estimated cost is below typical LNG contract prices…



Players who win LNG contracts first win the race to FID

…The NYMEX strip scenario (base case) yields annual tax and royalty revenues of $2 to 16 billion to the state, for a total of $220 billion over the 30-year life of the project*

- Model at right depicts the NYMEX strip base case utilizing Woodmac's 2.4% inflation rate beyond NYMEX projected years.
- Producer net income of $178 billion

Model	2021	2022	2023	2024	2025
Nominal WTI oil price	$ 109.56	$ 112.19	$ 114.88	$ 117.64	$ 120.46
Asia DES Price	16.86	17.26	17.68	18.10	18.54
Less Infl adj. Shipping Rate / MMBtu	0.59	0.60	0.62	0.63	0.65
Less Pipe Transportation (will not vary significantly)	4.18	4.18	4.18	4.18	4.18
Less Liquefaction	4.00	4.00	4.00	4.00	4.00
= Wellhead Net Back Value / MMBtu	8.09	8.48	8.88	9.29	9.71
Daily production in millions of MMBtu	2.7	2.7	2.7	2.7	2.7
Annual production in millions of MMBtu	986	986	986	986	986
Taxes and Royalties					
Alaska 12.5% share of production in MMBtu	123	123	123	123	123
Alaska royalty = 12.5% share * Netback Value	997	1,045	1,094	1,145	1,196
Remaining gas Taxable under ACES in MMBtu	862	862	862	862	862
Tax Rate to $5 / MMBtu	0.25	0.25	0.25	0.25	0.25
Tax Rate between $5 and 15.42 / MMBtu	0.324	0.334	0.343	0.353	0.363
Tax Rate beyond 15.42 / MMBtu	0.324	0.334	0.343	0.353	0.363
Total ACES Taxes	2,263	2,440	2,629	2,829	3,041
Total Royalties and Taxes	**2,386**	**2,564**	**2,752**	**2,952**	**3,164**
Sum of Royalties and Taxes	**220,101**				
Period (years from 2011)	10	11	12	13	14
Discount Factor	0.61	0.58	0.56	0.53	0.51
PV of Taxes and Royalties ($MMs)	1,465	1,499	1,532	1,565	1,598
NPV Taxes and Royalties 2021 - 2050 ($MMs)	$ 65,021				
Producer					
Revenues = 87.5% share * netback value ($MMs)	6,979	7,315	7,660	8,013	8,375
Less ACES Taxes	2,263	2,440	2,629	2,829	3,041
Post-tax netback to producer	4,716	4,875	5,031	5,184	5,334
Sum Producer Netback	**178,278**				
Period	10	11	12	13	14
Discount Factor	0.39	0.35	0.32	0.29	0.26
PV	1,818	1,709	1,603	1,502	1,405
Producer NPV 2021 - 2050 ($MMs)	$ 22,576				

Players who win LNG contracts first win the race to FID

*NYMEX strip to 2018 then 2.4% inflation;14.85% indexation, avg. recourse rate $4.18 assumed to be flat (annual increases in operational costs would be incrementally small). Model uses nominal figures and nominal discount rate. Assuming 5% nominal discount rate, NPV of taxes and royalties amounts to $65 billion.

…The Woodmac scenario yields annual tax and royalty revenues of $3 to 24 billion to the state, for a total of $419 billion over the 30-year life of the project*

- Model at right depicts the Woodmac scenario, which uses the NAGS April 2011 oil price forecast through 2030, followed by the 2030 price projected to 2050 using Woodmac's long-term inflation rate of 2.4% (oil prices shown in nominal terms)
- Producer net income of $187 billion

Model	2021	2022	2023	2024	2025
Nominal WTI oil price	$ 121.97	$ 125.75	$ 130.99	$ 136.40	$ 141.96
Asia DES Price	18.70	19.28	20.07	20.89	21.73
Less Infl adj. Shipping Rate / MMBtu	0.59	0.60	0.62	0.63	0.65
Less Pipe Transportation (will not vary significantly)	4.18	4.18	4.18	4.18	4.18
Less Liquefaction	4.00	4.00	4.00	4.00	4.00
= Wellhead Net Back Value / MMBtu	9.93	10.49	11.27	12.08	12.90
Daily production in millions of MMBtu	2.7	2.7	2.7	2.7	2.7
Annual production in millions of MMBtu	986	986	986	986	986
Taxes and Royalties					
Alaska 12.5% share of production in MMBtu	123	123	123	123	123
Alaska royalty = 12.5% share * Netback Value	1,224	1,293	1,389	1,488	1,589
Remaining gas Taxable under ACES in MMBtu	862	862	862	862	862
Tax Rate if below $5 / MMBtu	0.25	0.25	0.25	0.25	0.25
Tax Rate if between $5 and 15.42 / MMBtu	0.368	0.382	0.401	0.420	0.440
Tax Rate if beyond 15.42 / MMBtu	0.368	0.382	0.401	0.420	0.440
Total ACES Taxes	3,155	3,455	3,893	4,371	4,891
Total Royalties and Taxes	**3,278**	**3,579**	**4,016**	**4,495**	**5,014**
Sum of Royalties and Taxes	**419,101**				
Period (years from 2011)	10	11	12	13	14
Discount Factor	0.61	0.58	0.56	0.53	0.51
PV of Taxes and Royalties ($MMs)	2,013	2,092	2,236	2,384	2,532
NPV Taxes and Royalties 2021 - 2050 ($MMs)	$ 124,030				
Producer					
Revenues = 87.5% share * netback value ($MMs)	8,565	9,049	9,720	10,413	11,125
Less ACES Taxes	3,155	3,455	3,893	4,371	4,891
Post-tax netback to producer	5,410	5,594	5,827	6,041	6,234
Sum Producer Netback	**187,551**				
Period	10	11	12	13	14
Discount Factor	0.39	0.35	0.32	0.29	0.26
PV	2,086	1,961	1,857	1,750	1,642
Producer NPV 2021 - 2050 ($MMs)	$ 24,126				

Players who win LNG contracts first win the race to FID

*WM NAGS price outlook to 2030 then 2.4% inflation; 14.85% indexation, avg. recourse rate $4.18 assumed to be flat (annual increases in operational costs would be incrementally small). Model uses nominal figures and nominal discount rate. Assuming 5% nominal discount rate, NPV of taxes and royalties amounts to $124 billion.

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…The "worst case" scenario yields annual tax and royalty revenues of $0.4 to 6 billion to the state, for a total of $75 billion over the 30-year life of the project*

- Model at right depicts the "worst case scenario in which prices are held flat at an inflation adjusted price of $75/bbl
- Producer net income of $131 billion

Model	2021	2022	2023	2024	2025
Nominal WTI oil price	$ 75.00	$ 76.80	$ 78.64	$ 80.53	$ 82.46
Asia DES Price	10.34	12.01	12.30	12.59	12.89
Less Infl adj. Shipping Rate / MMBtu	0.59	0.60	0.62	0.63	0.65
Less Pipe Transportation (will not vary significantly)	4.18	4.18	4.18	4.18	4.18
Less Liquefaction	4.00	4.00	4.00	4.00	4.00
= Wellhead Net Back Value / MMBtu	1.57	3.23	3.50	3.78	4.07
Daily production in millions of MMBtu	2.7	2.7	2.7	2.7	2.7
Annual production in millions of MMBtu	986	986	986	986	986
Taxes and Royalties					
Alaska 12.5% share of production in MMBtu	123	123	123	123	123
Alaska royalty = 12.5% share * Netback Value	194	398	431	466	501
Remaining gas Taxable under ACES in MMBtu	862	862	862	862	862
Tax Rate to $5 / MMBtu	0.25	0.25	0.25	0.25	0.25
Tax Rate between $5 and 15.42 / MMBtu	0.168	0.207	0.214	0.221	0.228
Tax Rate beyond 15.42 / MMBtu	0.168	0.207	0.214	0.221	0.228
Total ACES Taxes	228	577	646	720	799
Total Royalties and Taxes	**351**	**701**	**769**	**843**	**922**
Sum of Royalties and Taxes	**74,939**				
Period (years from 2011)	10	11	12	13	14
Discount Factor	0.61	0.58	0.56	0.53	0.51
PV of Taxes and Royalties ($MMs)	215	410	428	447	466
NPV Taxes and Royalties 2021 - 2050 ($MMs)	$ 21,617				
Producer					
Revenues = 87.5% share * netback value ($MMs)	1,357	2,784	3,020	3,261	3,509
Less ACES Taxes	228	577	646	720	799
Post-tax netback to producer	1,129	2,206	2,373	2,541	2,710
Sum Producer Netback	**131,018**				
Period	10	11	12	13	14
Discount Factor	0.39	0.35	0.32	0.29	0.26
PV	435	773	756	736	714
Producer NPV 2021 - 2050 ($MMs)	$ 13,217				

Players who win LNG contracts first win the race to FID

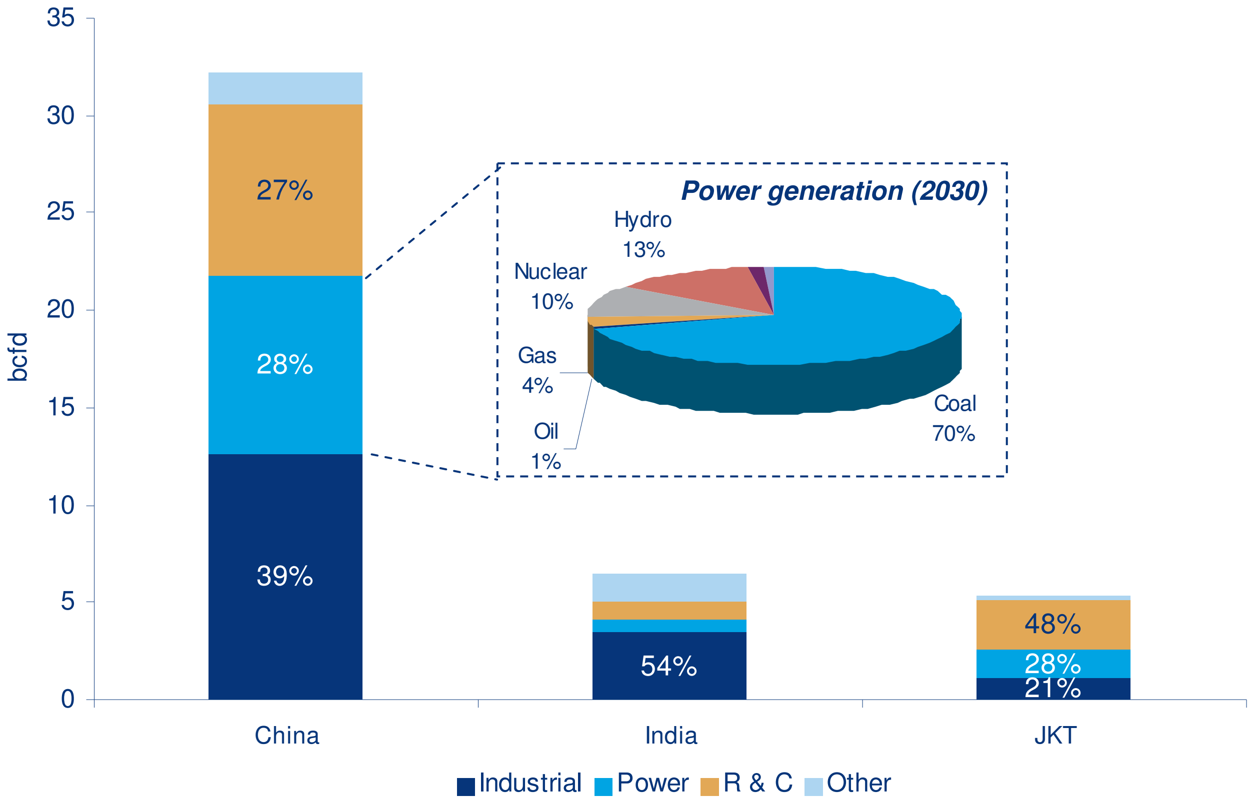
2.4% inflation, 14.85% indexation, avg. recourse rate $4.18 assumed to be flat (annual increases in operational costs would be incrementally small). Model uses nominal figures and nominal discount rate. Assuming 5% nominal discount rate, NPV of taxes and royalties amounts to $22 billion.

Agenda

LNG Pricing Perspectives

Gas price ceilings differ by region – in Asia, the price ceiling is increasingly based on displacing oil products in the R/C/I sectors

Asia gas demand growth 2010 - 2030

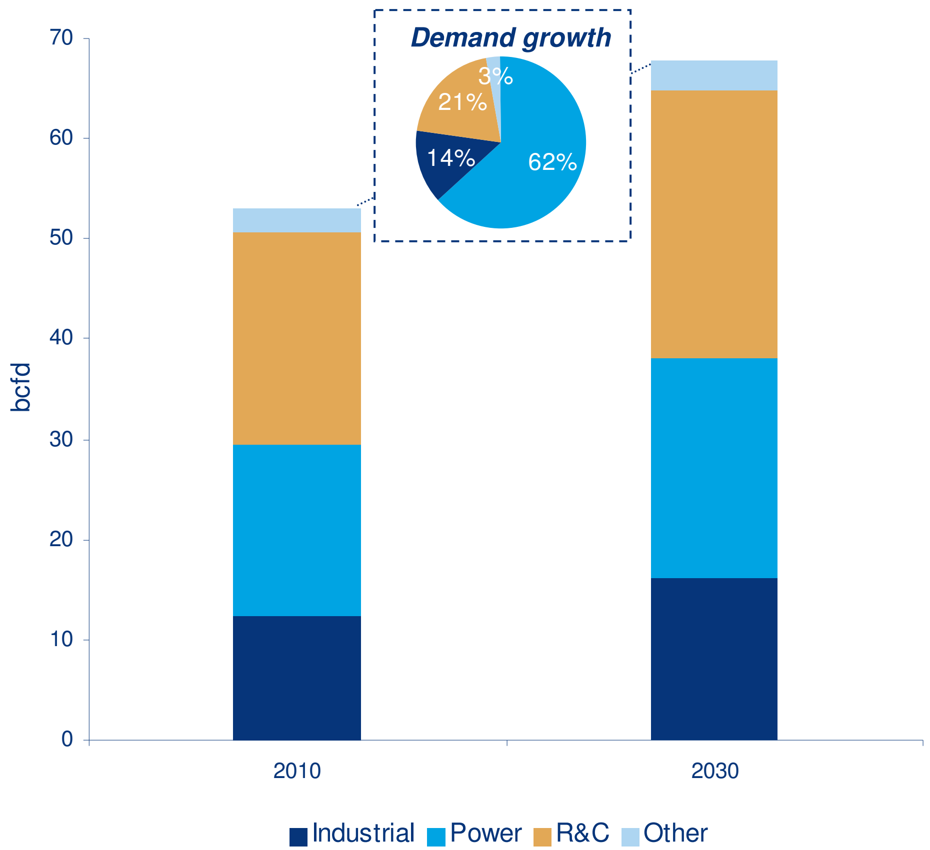


- Historically, the desire for fuel diversity and need for security of supply (primarily in Japan) drove relatively high regional gas prices
- Moving forward, Wood Mackenzie sees oil substitution in the R&C and Industrial sectors in China and India as the primary force behind maintaining premium pricing in the Asian market
- It is however expected that in JKT a premium will continue to be paid for security of supply

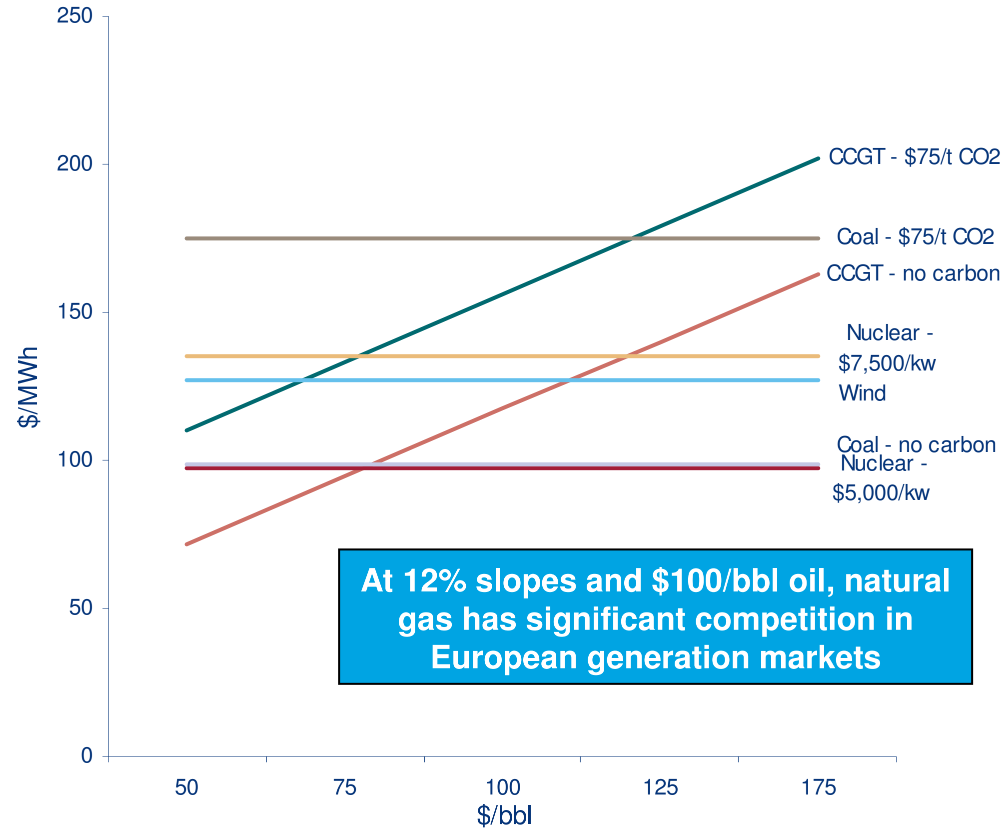
Source: Wood Mackenzie Global Gas Tool, H2 2010

While in Europe the gas price ceiling is "soft" and influenced by the economics of alternative forms of power generation

Europe gas demand

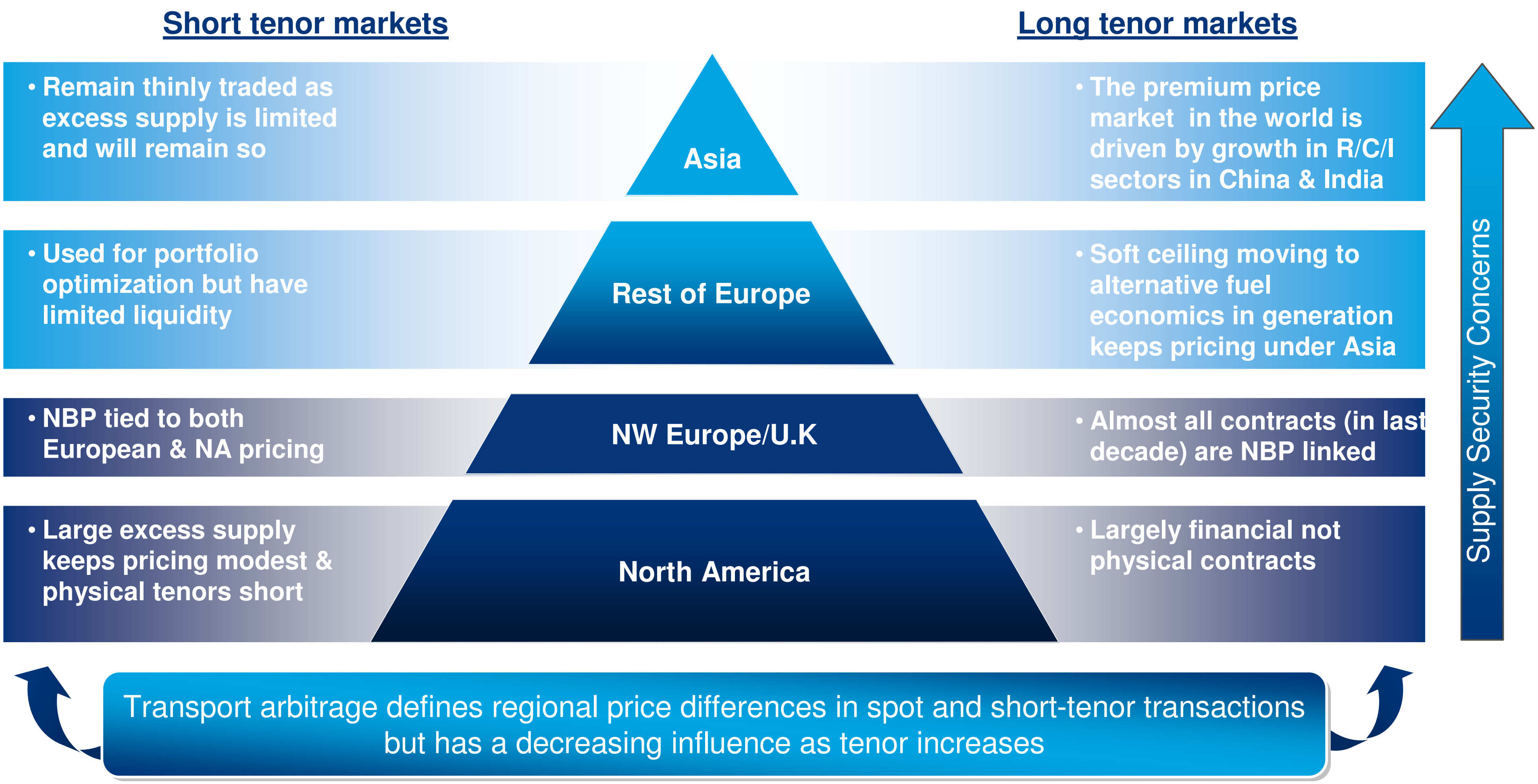


Europe power generation screening curve



Note: 12% discount rate, no taxes, levelized capital cost, Gas fired CCGT: LNG costs at 12% slope plus $0.8/mmbtu combined shipping and regas. $1,200/kw, 25 years useful life. 6,900 Btu/KWh, LHV heat rate, 92.5% utilization, 1135 lbs/MWh of CO2 emissions; Coal: $3,750/kW, 30 years useful life. $4.25/mmbtu delivered, $9,275 btu/kWh heat rate, 92.5% utilization. 2250 lbs/MWh CO2 emissions; Nuclear: 30 years useful life, 92.5% utilization. No subsidies; Wind: $1,800/kw, 20 years useful life, 27.5% utilization, $25/MWh grid access. No subsidies

Ultimately the markets develop a relative hierarchy by geography and tenor



Long-tenor gas contracts will remain oil-indexed in geographies that lack liquid, reliable gas indices as an alternative

Requirements for Gas-Indexed Term Deals

- **A reputable index must exist that is deep and difficult, if not impossible, to manipulate; e.g.:**
  - North America (HH et al)
  - The UK (NBP) and NW Europe
  - *Not the Rest of Europe, not Asia*
- **The index must reflect floor and ceiling economics in the market in which it is used; that is, to gain widespread acceptance the index must serve a real economic purpose to buyers and sellers**
  - HH makes obvious sense in NA (just as NBP does in the UK) as the index is related to actual development costs and alternative fuel economics
  - But would there be significant demand for HH-indexed gas in Asia where the floor is oil or fixed price linked and the ceiling is oil linked?

Rationale Behind Oil-Indexed Deals

- **Historical comfort: sellers are largely long oil price risk and don't mind more; sellers have done similar deals for years**
- **Oil indices are deep and solid; manipulation risk is relatively low**
- **Agency risk: no one has ever lost their job for doing an oil-indexed deal. Buyers, particularly certain Asian buyers, do not generally seek innovation in LNG contract pricing terms**
- **For the most part, oil indexation does what it is supposed to do**
  - For buyers with oil product alternatives, oil indexation at slopes less than oil-equivalent prices locks in economics

But many of those “oil-indexed” deals will remain so in name only

“Oil indexation” is just the beginning . . .

- **In reality “oil parity” indexation would appear to meet both buyer and seller needs only within a limited range of oil prices**
  - Development costs for LNG in Asia of around $9-$10/mmBtu FOB suggest the need for floors around $60/bbl at 14.85% slopes
  - In Europe, even at more modest slopes (e.g., 12%) as oil prices rise above roughly $100/bbl other generation sources are increasingly advantaged

. . . but not the end

- **As a result, a variety of mechanisms have and will continue to emerge and evolve to shape the risk profile of the typical “oil indexed” contract; e.g.:**
  - Different slopes or constants
  - S-curves, even extreme examples, that better match the economic market reality of floor costs and ceiling alternative pricing
  - A variety of contract re-openers predicated on certain oil prices or other triggers

Oil indexation will technically remain the standard in long-term gas contracting but additional mechanisms will be required to ensure that pricing remains within the relevant pricing boundaries

Assumptions used in the tax and revenue discount model

Assumptions		
Production	2.7	Bcf/d
Conversion	0.000001	
Shipping	$ 0.59	
Asia DES Price calculated as % of WTI:	14.85%	
Base Case: 14.85% of real 2011 price		
WM Price Case: April 2011 NAGS Price Outlook		
NYMEX Forward Curve Case:		
Transportation Cost Scenarios:		
Low Negotiated	$ 2.25	
High Negotiated	$ 2.92	
Low Recourse	$ 3.64	
High Recourse	$ 4.72	
Average Recourse	$ 4.18	
Liquefaction	$ 4.00	
Base Royalty on Net Back Value	12.5%	
Taxable under ACES Law	87.5%	
Base ACES Royalty	25%	
Incremental tax for each $ beyond 5	2.4%	
Incremental tax for each $ beyond 50% tax	0.6%	
State of Alaska Nominal Discount Rate	5%	
WoodMac LT Inflation Rate Forecast	2.4%	
Producer Nominal Discount Rate	10%	

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