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Global
Equity Research

Global LNG Sector—Update

The Credit Suisse Connections Series leverages our exceptional breadth of macro and micro research to deliver incisive cross-sector and cross-border thematic insights for our clients.

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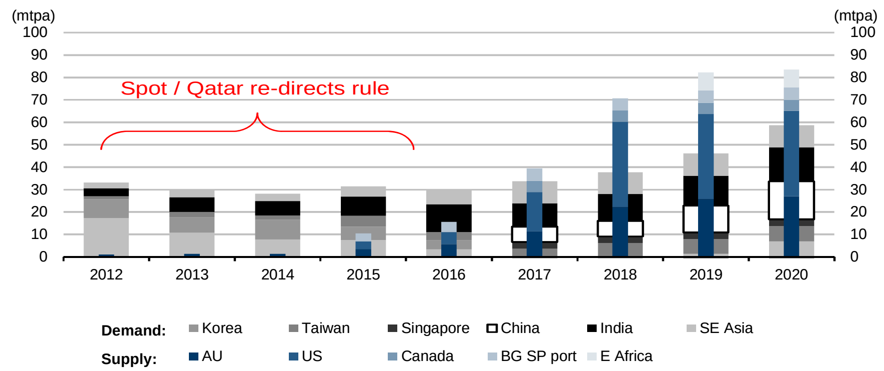
Connections Series

Tighter then looser

Spot prices remain strong in 2012: Qatar redirections, NA LNG, East Africa and Asian brown-field expansions set to fight for 2018+ demand window.

Figure 1: **APAC un-contracted demand/supply: 2012–20E**



Source: Credit Suisse estimates

- **Supply—sanction season nearly over, for now.** In AU the Ichthys was project sanctioned, with APLNG close behind. In the US Cheniere's Sabine Pass was sold out and a slew of projects is lined up for export approval, but political headwinds are mounting, unlike Canada where the Kitimat project was approved. In East Africa Mozambique still needs an LNG developer and BG and Ophir get 'market ready' in Tanzania.
- **Demand—robust going forward.** We increase Japan's 2012 demand to 87 MTpa, requiring 20% as spot supply to make up for the contract shortfall. In China we increase our long-term forecast to reflect a taste for equity-linked off-take, but still remain demand bears. In Europe Qatar re-directions to APAC have led to demand weakness while in LatAm and the Middle East demand continues to grow.
- **Future contracts/pricing—we do not buy price convergence yet.** Short-term APAC prices should remain very robust due to supply shortfall. In the medium to longer term we believe projects with strong marketing propositions should trade increased supply flexibility for the continued strong crude price linkage, leaving less compelling projects to compete for price-sensitive buyers.
- **Qatar, Inpex and BG all well positioned**. Inpex now moves onto Abadi; BG benefits in the near term from sales to Asia and in the longer term with Sabine Pass; and Tanzania (along with Ophir) is rapidly building momentum.

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Credit Suisse Global Energy Research Team

Figure 2: **Credit Suisse Global Energy Research Team**

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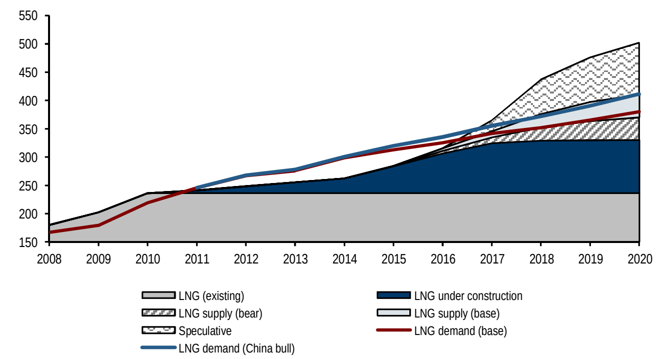
We would like to acknowledge the contribution from the entire Credit Suisse global Oil & Gas team and from the European Utilities team to this report.

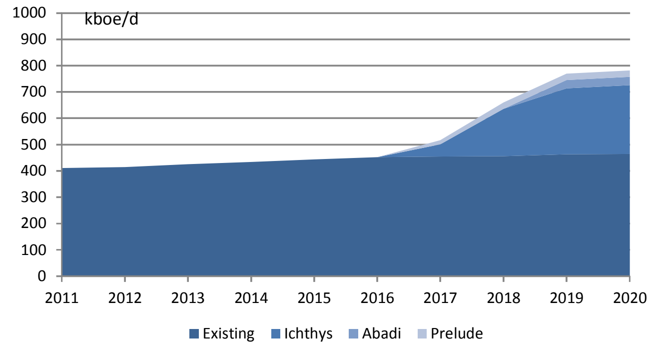
Focus charts and tables

Figure 3: Global LNG demand versus potential supply *(in mpta)*



NB: China bull demand case assumes that 30% of additional gas demand is met by LNG. Source: Credit Suisse estimates

Figure 4: Inpex—production effect of Ichthys, Abadi and Prelude



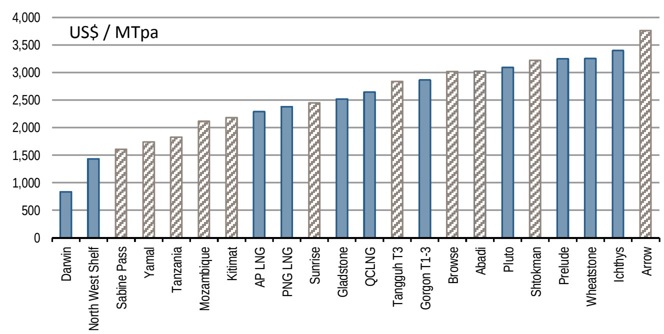
Source: Credit Suisse estimates

Figure 5: Key APAC marketing considerations for US LNG projects

Cheniere Sabine Pass	Yes	No	No	No	Yes	18	Brown
Cheniere SP expansion	?	?	No	No	Yes	9	Brown
Cheniere Corpus Christi	Yes	No	No	No	Yes	13.5	Green
BG Lake Charles	No	Yes	Yes	Yes	likely	15	Brown
BG Sabine Pass	No	Yes	Yes	Yes	likely	5.5	Brown
Conoco Freeport	No	Yes	If 'portfolio'	If 'portfolio'	likely	10	Brown
Dominion Cove Point	Yes	?	No	No	Yes	7.8	Brown
Sempra Cameron	Yes	?	No	No	likely	12	Brown
Cheniere Sabine Pass	Yes	No	No	No	Yes	18	Brown

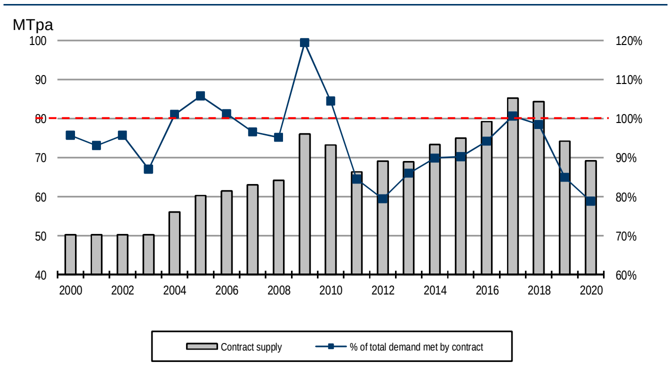
Source: Credit Suisse estimates.

Figure 6: Global LNG cost curve—East Africa and North America well positioned



Source: Company data, Credit Suisse estimates

Figure 7: Japan—Demand covered by long term contracts: 2000-20E



Source: Credit Suisse estimates

Figure 8: CS Japan LNG landed price forecast 2012–15E

	2012E	2013E	2014E	2015E
Brent—US$/bbl	125	132.5	135	95
JCC—US$/bbl	122.5	129.9	132.3	93.1
Average correlation	75%	76%	77%	77%
Price in US$ / boe—FOB basis	91.9	98.7	101.9	71.7
Price in US$ / mmbtu—FOB basis	17.0	18.2	18.8	13.3
Price in US$/mmbtu—DES basis	**18.0**	**19.2**	**19.8**	**14.3**

Source: Credit Suisse estimates

Tighter then looser

Spot prices remain strong in 2012: Qatar redirections, NA LNG, East Africa and Asian brown-field expansions set to fight for 2018+ demand window.

Supply: Sanction frenzy largely complete

Australia largely sanctioned for now, focus moves to NA & East Africa

In Australia Inpex sanctioned Ichthys, farmed into Prelude (and farmed down a 30% stake in Abadi) and Origin gets ready to sanction APLNG as a two-train project. Qatar secured 5 MTpa of long-term contracts to Korea and Taiwan, and in North America Cheniere all but sold out its four-train Sabine Pass facility. In Canada Kitimat received approval to export and is presumably aggressively marketing in APAC. In Mozambique the entry of a credible LNG developer remains uncertain as Shell and PTTEP bid for Cove while in Tanzania BG and Ophir are now ‘market ready’ to target first gas in 2018. In the US non-FTA approvals appear a victim of the political process, awaiting the Presidential election in November.

Demand: Robust as Japan hesitates on nuclear

Demand strength continues, supported by nuclear concerns in core LNG countries

We increase our 2012 Japan LNG demand forecast to 87 MTpa suggesting the entire 20% of Japan’s 2012 LNG requirements will have to be met from non-contract sales. With the Qatar, Yemeni and Brunei deals Korea looks set to limp through its near-term shortfall. Taiwan is reasonably well supplied to 2015 but will need to contract for the latter part of the decade. We continue to be demand bears in China, but now include placeholder 10MTpa demand post 2017 for supplies linked to material equity purchases. In India we step up our forecast reflecting capacity additions and an assumed lower spot price in the latter part of the decade. Plans for new regas in South East Asia abound, but the recent change of plans in Indonesia demonstrates the mercurial nature of this demand. In Europe Qatar redirections to Asia softens demand, while demand in LatAm, specifically Argentina, looks set to grow, presuming sellers are willing to supply.

Contracting: We do not buy price convergence yet

Supply reliability will lessen the effect of US HH-based pricing in Asia

In the short term, the dramatic supply shortfall in APAC should support highly correlated contract prices, with spot pricing pacing and occasionally exceeding contract prices. The question is how much more short-term supply can Qatar convert into long-term contracts. In the medium term (2017–18) un-contracted supply exceeds un-contracted demand, and that demand is largely from new markets and price-sensitive buyers. We expect supply projects with strong marketing propositions to wait to sell into the Japan un-contracted window in 2019–20, offering improved flexibility condition for buyers to sustain the significant crude price correlation, and the new price sensitive demand segment to the supply projects with less compelling marketing propositions in low-cost geographies. Our price forecast therefore continues to assume that the Asian LNG price premium prevails through the end of the decade.

Inpex and BG all well positioned

Inpex and BG stand out as having well-positioned LNG portfolios

Inpex now has two sanctioned LNG projects under construction (Ichthys and Prelude) and are building momentum in its third project—Abadi. BG benefits in the near term from portfolio cargo allocations to Asia and in the longer term with Sabine Pass in its portfolio, and Tanzania (along with Ophir) rapidly building momentum. Origin’s APLNG seems set to be sanctioned (take the Final Investment Decision) shortly, with Chevron’s Train 4 at Gorgon likely to start marketing, along with Exxon’s PNG LNG T3 and BP’s Tangguh T3.

What's changed in our global LNG model?

- **We see a tighter LNG balance in 2012** (about 5–6 MTpa) due to our upward revision to Japanese LNG demand, and delays to start-ups at Pluto and Angola LNG. On the other hand, 2013 should be less tight than we had previously expected due to a lower LNG demand forecast in Europe given a weaker economic outlook. We continue to expect the **LNG supply deficit to peak in 2014–15** at 36 MTpa in 2014 and 29 MTpa in 2015.
- We expect the **LNG market to remain tight for one year longer** than previously. We now see global LNG supply/demand returning to **balance only in 2017** instead of 2016 as we have delayed some project start-ups (particularly in Australia) and increased our APAC LNG demand forecasts.
- Longer term, we see an **even longer list of potential (speculative) LNG projects** which could further loosen the market in 2019–20—if they come on stream. We now see 280–85 MTpa of potential supply projects by 2020E versus 260 MTpa previously, with most of the additions coming from the US and East Africa. On paper, this is more than enough to cover about 135 mpta of LNG demand growth.

As we wrote in our November 2011 Global Gas note, the supply side is responding to current market tightness and price signals—ultimately the LNG supply cycle will turn. But with gas market growth still constrained by affordability, the question is what projects will make the cut.

Key assumptions

Figure 9: LNG projects start-ups, 2012–25E (nameplate capacity in MTpa)

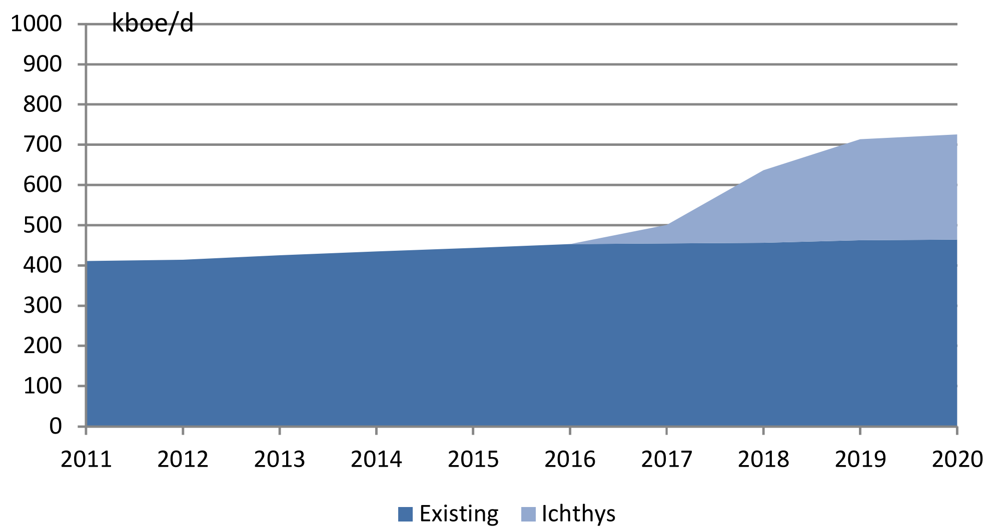
Country	Project	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Status
Construction & Possible																
Australia	Pluto LNG	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	Const.
Angola	Angola LNG	2.6	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	Const.
Algeria	Skikda expansion		3.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.4	Const.
PNG	PNG LNG			2.0	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	Const.
Algeria	Arzew GL3-Z				3.5	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	Const.
Australia	Gorgon LNG T1-3				7.5	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	Const.
Australia	QC LNG				4.0	7.0	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	Const.
Australia	Gladstone LNG				2.0	5.9	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	Const.
Indonesia	DS LNG				2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	Const.
Australia	AP LNG (Origin)					2.2	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	Const.
Australia	Ichthys LNG					4.2	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	Const.
US	Sabine Pass Export					7.0	9.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	Poss.
Canada	Kitimat LNG					4.0	5.0	5.0	5.0	7.5	10.0	10.0	10.0	10.0	10.0	Poss.
Australia	Pluto LNG T2						2.2	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	Poss.
Australia	Prelude FLNG						3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	Const.
Australia	Wheatstone						4.5	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	Const.
Australia	AP LNG (Origin) T2						2.2	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	Poss.
Australia	QCLNG Train 3						4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	Poss.
Russia	Yamal LNG							10.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	Poss.
Australia	Gorgon LNG T4							5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	Poss.
Indonesia	Tangguh T3								3.8	3.8	3.8	3.8	3.8	3.8	3.8	Poss.
Nigeria	Brass LNG								2.5	10.0	10.0	10.0	10.0	10.0	10.0	Poss.
Tanzania	Tanzania LNG								8.0	8.0	8.0	8.0	8.0	8.0	8.0	Poss.
Mozambique	Mozambique LNG								4.0	8.0	8.0	13.0	18.0	18.0	18.0	Poss.
Total Construction + Possible		**5.5**	**13.0**	**16.0**	**39.6**	**72.5**	**102.2**	**135.1**	**158.4**	**172.4**	**174.8**	**179.8**	**184.8**	**184.8**	**184.8**	
of which in Construction		**5.5**	**13.0**	**16.0**	**39.6**	**61.5**	**79.6**	**84.0**	**84.0**	**84.0**	**83.9**	**83.9**	**83.9**	**83.9**	**83.9**	
of which Possible						**11.0**	**22.6**	**51.1**	**74.4**	**88.4**	**90.9**	**95.9**	**100.9**	**100.9**	**100.9**	
Speculative																
Russia	Shtokman (Ph 1)						3.3	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	Spec.
US	Freeport Export						2.4	7.2	10.0	10.0	10.0	10.0	10.0	10.0	10.0	Spec.
US	Cameron						12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	Spec.
Brazil	Santos FLNG						3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	Spec.
PNG	PNG LNG T3						1.7	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	Spec.
Eq Guinea	EG LNG T 2							4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	Spec.
Australia	Pluto LNG T3							4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	Spec.
Norway	Snøhvit T2							4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	Spec.
US	Lake Charles							7.5	15.0	15.0	15.0	15.0	15.0	15.0	15.0	Spec.
US	Cove Point							2.5	7.8	7.8	7.8	7.8	7.8	7.8	7.8	Spec.
US	Corpus Christi							13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	Spec.
Indonesia	Abadi FLNG								2.5	2.5	2.5	2.5	2.5	2.5	2.5	Spec.
Russia	Sakhalin 2 T3								2.5	5.0	5.0	5.0	5.0	5.0	5.0	Spec.
Canada	Shell LNG Canada									2.5	12.0	12.0	12.0	12.0	12.0	Spec.
Australia	Sunrise LNG									4.3	4.3	4.3	4.3	4.3	4.3	Spec.
Australia	Wheatstone T3									4.5	4.5	4.5	4.5	4.5	4.5	Spec.
Iran	Iran LNG									5.3	10.5	10.5	10.5	10.5	10.5	Spec.
Nigeria	NLNG Train 7										6.0	8.4	8.4	8.4	8.4	Spec.
Angola	Angola LNG T2										2.5	5.0	5.0	5.0	5.0	Spec.
Australia	Browse										2.0	3.5	6.0	7.5	7.9	Spec.
Nigeria	Olokola											5.0	5.0	5.0	5.0	Spec.
Australia	Scarborough											3.0	6.0	6.0	6.0	Spec.
Australia	Bonaparte											2.0	2.0	2.0	2.0	Spec.
Iraq	Shell											2.0	4.5	4.5	4.5	Spec.
PNG	InterOil LNG											2.0	4.0	4.0	8.0	Spec.
Australia	Fisherman's L.												0.8	1.5	1.5	Spec.
Australia	Arrow												4.0	8.0	8.0	Spec.
US	Alaska Valdez												10.0	20.0	20.0	Spec.
Total Speculative							**22.3**	**69.4**	**90.0**	**109.0**	**134.2**	**154.6**	**179.4**	**195.6**	**200.0**	
Total additions		**5.5**	**13.0**	**16.0**	**39.6**	**72.5**	**124.5**	**204.5**	**248.4**	**281.4**	**309.0**	**334.4**	**364.2**	**380.4**	**384.8**	

Source: Company data, Credit Suisse estimates

Supply update

A very busy time for supply projects worldwide. In Australia Inpex sanctioned Ichthys, farmed into Prelude (and farmed down a 30% stake in Abadi), and Origin gets ready to sanction APLNG as a two-train project, with buyers and now funding in place. Qatar signed 5 MTpa of long-term contracts to Korea and Taiwan—redirecting from lower value markets. In North America Cheniere all but sold out its four-train Sabine Pass facility, and a slew of projects is lining up for non-FTA sales approval but the political headwinds are beginning to blow. In Canada Kitimat received approval to export and is presumably aggressively marketing in APAC. In Mozambique the entry of a credible LNG developer remains uncertain as Shell and PTTEP bid for Cove while in Tanzania BG and Ophir are now 'market ready' to target first gas in 2018.

Figure 10: **Inpex: Effect of Ichthys on production**

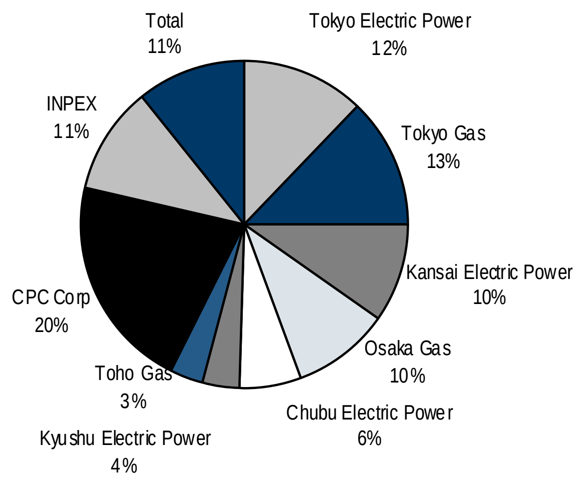


Source: Credit Suisse estimates

Ichthys sanctions two trains—approved space for four more…

Inpex Ichthys—Project 'Narnia' no more: We have long been believers in the Ichthys project (harshly dubbed project 'Narnia' by some, frustrated by the time frame required to commercialise LNG projects) which announced its Project Sanction (Final Investment Decision – 'FID') in early January. The project targets first gas in 2017 with an announced capex of US$34 bn (for a two-train, 8.4 MTpa capacity), with TEPCO and Tokyo Gas each off-taking 1.05 MTpa , Kansai and Osaka Gas each off-taking 0.8 MTpa, and Chubu Electric, Kyushu Electric and Toho Gas also participating. With prospectivity in the Browse basin and the gas infrastructure in place we believe Ichthys will have the potential to expand over time, building a world-scale LNG facility.

Figure 11: **Inpex—Ichthys' long-term customer base**

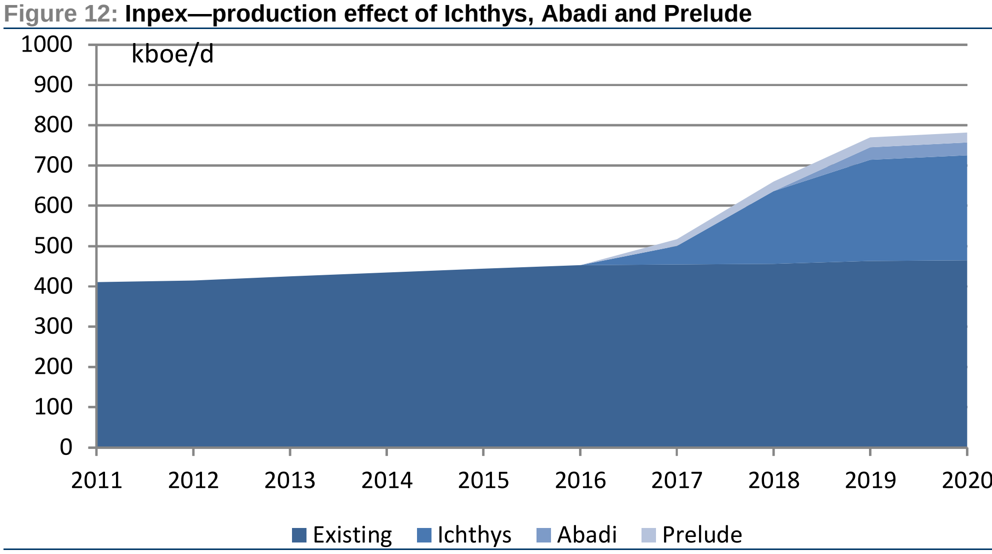


Source: Company data

Inpex's Adabi project also beginning to gain momentum

Inpex Abadi—farm-down to Shell increases PoS of commercialisation: Inpex also moved its second significant green field LNG project Abadi further towards commercialisation—farming out a 30% stake to Shell. Shell paid US$850 mn for the 30% stake—suggesting Inpex's remaining 60% stake is worth US$1.9 bn at this stage of the project development. The current proposal is for an FLNG development; however, we would not be surprised to see an upgrade in the development plan over the remainder of 2012 looking at FLNG as a phase I development followed shortly thereafter with a two-train onshore expansion to drive project economics. With CS forecasting up to four trains of un-contracted LNG demand in Japan by 2020 Abadi will increase its presence in the LNG development ladder as it moves towards FEED and then FID in the next few years.

Figure 12: **Inpex—production effect of Ichthys, Abadi and Prelude**

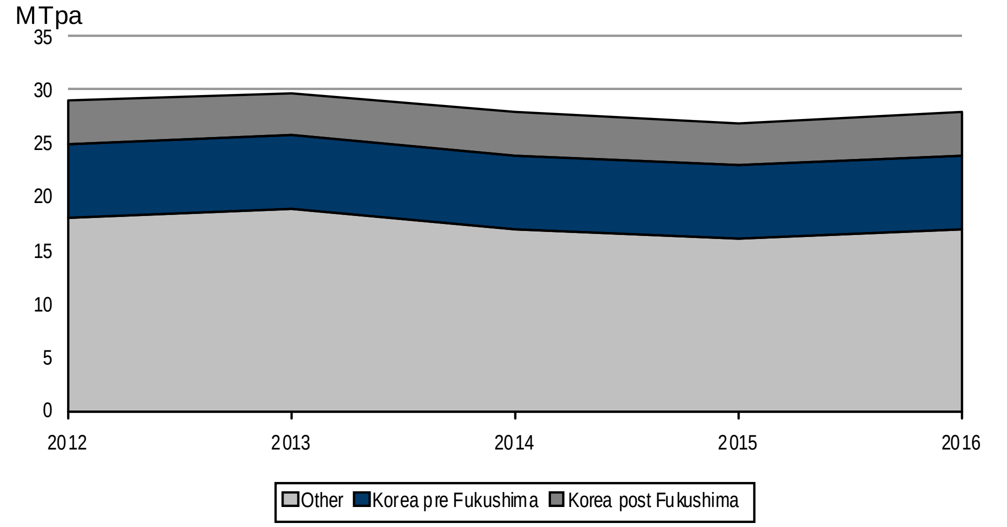


Source: Credit Suisse estimates

Shell farms into Abadi… then Inpex farms into Prelude

Shell/Inpex Prelude: Unitisation—better late than never: Prelude is an incredibly proximal structure to Ichthys; however, the resources were not unitised and as a result (and possibly reflective of RDS' desire to commercialise FLNG as a concept) Prelude is being developed as a standalone project. Inpex announced recently that it has farmed in to Prelude, taking a 17.5% stake. The consideration was not announced but we would not be surprised if it were a similar amount to the price RDS had paid for its stake in Abadi. In essence this is akin to a delayed unitisation—but shows that Inpex has translated green-field risk (the Abadi sell-down) into brown-field investment (Prelude). With this deal Inpex is now involved in Bontang, Darwin, Ichthys, Abadi and Prelude LNG projects and is moving up the LNG developers league table. Shortly after the deal with Inpex, Shell sold a 10% stake in Prelude to Kogas and 5% to CPC of Taiwan. Shell now has a 67.5% interest in Prelude, down from 100%—the proceeds will be recycled into other LNG projects e.g. Abadi and most importantly East Africa post the Cove deal.

Figure 13: Korea: Qatar contract volumes, pre- and post- Fukushima

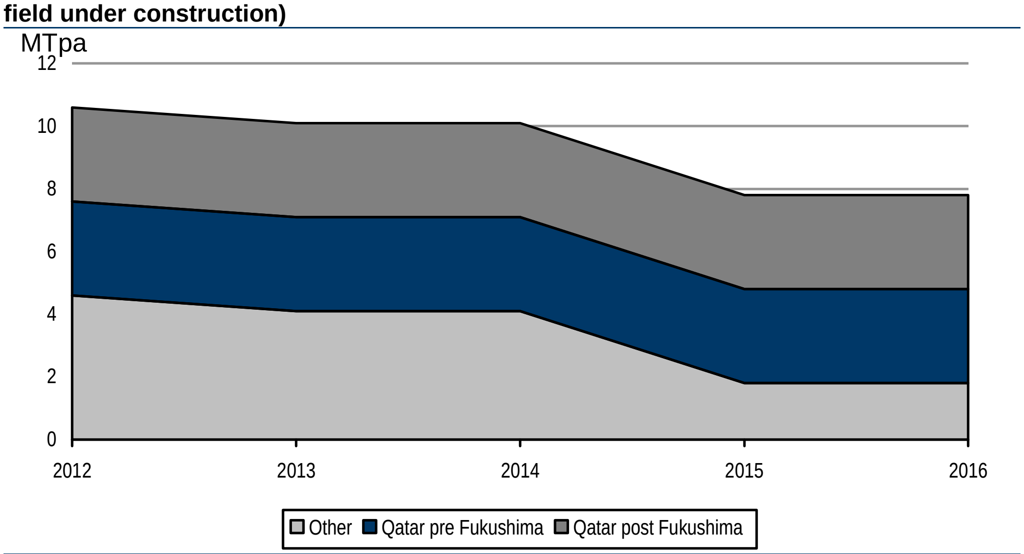


Source: Credit Suisse estimates

Kogas buys near-term supply security from Qatar

Qatar signs a '4 into 2' MTpa deal with Kogas: With a crippling near-term shortfall in contract LNG supplies Kogas recently announced a long-term deal for 2 MTpa from RasGas, with an incremental 2 MTpa up to 2016—essentially a '4 to 2' deal. With other adjustment this still leaves Korea short by 8 MTpa in 2012 and 2013, rising to 10 MTpa in 2014 before falling back in the latter part of the decade. While the price is not yet known we would expect the deal to be in the 85-90% correlation to crude range for the long-term supply (possibly in the 80% range for the incremental 2 MTpa in the inner years of the supply).

Figure 14: Taiwan: Contracted LNG supply—pre and post Fukushima (excludes green field under construction)

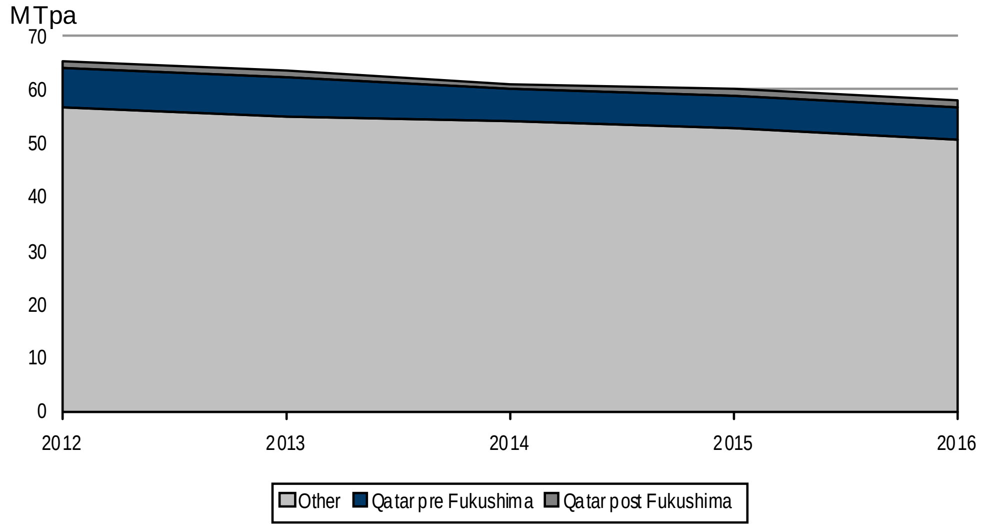


Source: Credit Suisse estimates

As does Taiwan…

Qatar—A '3 into 1.5' MTpa deal with CPC in Taiwan: CPC in Taiwan signed a similar deal with RasGas II, talking 3 MTpa until 2016, falling to 1.5 MT for a further 15 years. This takes the pressure from 2012, 2013 and 2014 but still does not deal with material contract shortfalls for 2015 forward (6+ MTpa).

Figure 15: **Japan: Segmented contract supply—pre and post Fukushima (excludes green-field under construction)**



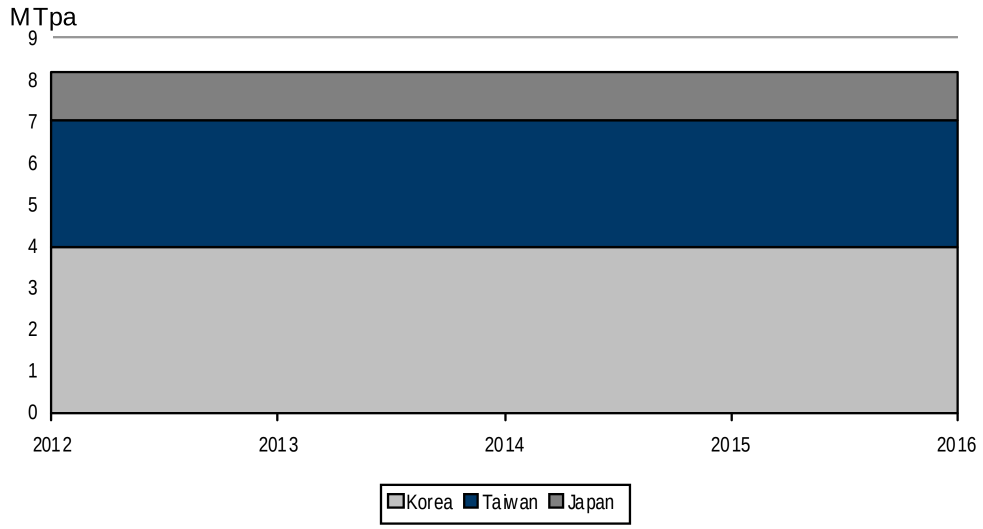
Source: Credit Suisse estimates

Qatar—1.2 MTpa sold into Japan, thus far: Qatar has signed a 10-year 1 MTpa deal with Tokyo Electric, starting in 2012, which follows up a 0.2 MTpa deal with Chubu Electric/Shizuoka gas (starting in 2016, for six years).

Japan still holding out from committing to material supplies from Qatar

We expect more long-term deals from Qatar into Japan: Expecting further deals to be announced in 2012, we would not be surprised to see a further 2-6 MTpa signed under long-term supply arrangements (10+ years) with Japanese buyers, with a high likelihood of 'top up' near-term supplies a la recent announcements in Korea and Taiwan.

Figure 16: **Qatar medium / long-term sales post Fukushima**

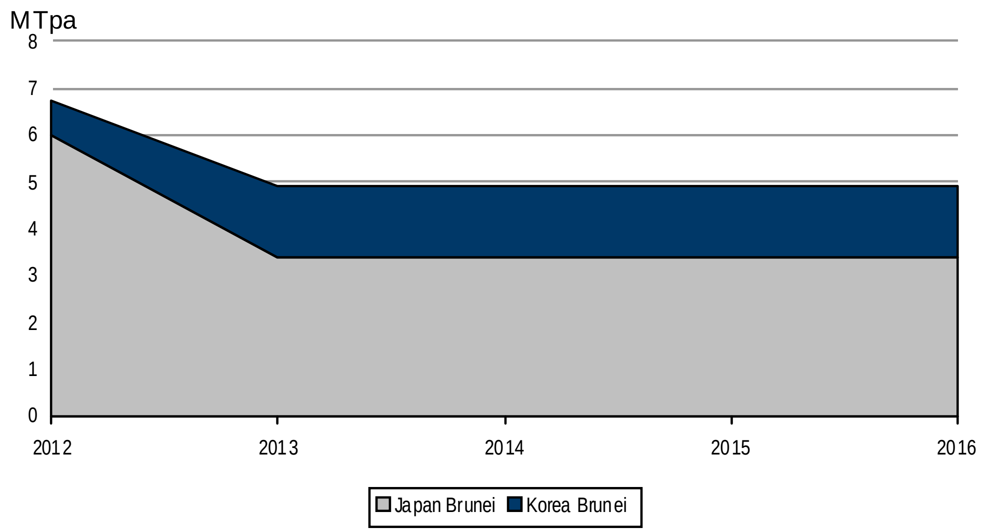


Source: Credit Suisse estimates

Qatar: Converted 9 MTpa into 2012—2016 contract sales: Qatar has done a reasonable job of leveraging its unique advantage of scale divertible avails into medium/long-term sales—re-diverting 9 MTpa in the 2012-16 period—with a long-term (10+ years) 5 MTpa conversion, again at prices assumed to be in the 80-90% correlation to crude oil range.

Qatar slowly converting its near-term supply advantage into long-term sales

Figure 17: **Korea/Japan Brunei contract off-take: 2012-16**



Source: Credit Suisse estimates

Brunei Japan's loss is Korea's (marginal) gain: Kogas extended and expanded its Brunei off-take, stepping up from 0.7-1.5 MTpa from 2013, for a further 10 years. Japanese buyers (TEPCO, Tokyo and Osaka Gas) also extended Brunei supply for a further 10 years (to 2023) but reduced the annual off-take from 6 MTpa to 3.5 MTpa.

Brunei signs up another 10 years but allocates away from Japan

US LNG

Cheniere Sabine Pass—from two to four trains, and sold out: Cheniere accelerated in 1Q12, effectively selling out its four-train liquefaction project with four anchor buyers—BG (5.5 MTpa (0.72 Bcf/d) - which will be used as portfolio gas) GNF (3.5 MTpa / 0.46 Bcf/d), GAIL in India (3.5 MTpa / 0.46 Bcf/d) and Kogas (3.5 MTpa / 0.46 Bcf/d) —leaving 2 MTpa / 0.26 Bcf/d for spot/short-term direct sales. All of the deals are priced off Henry Hub (HH) with a 15% uplift in gas sourcing and a liquefaction charge ranging between US$2.25/mcf and US$3/mcf where 10-15% of that charge is subject to an inflation-related escalation. In mid-April Cheniere announced that it had hired eight banks to arrange US$4 bn in debt financing. The project has also received a green light from the FERC (Federal Energy Regulatory Commission), the final regulatory approval needed to start construction of the project. Cheniere still needs to find around US$4 bn in financing to build the facility, having secured US$6 bn of financing so far out of a US$10 bn capex estimate for the first 16 MTpa phase.

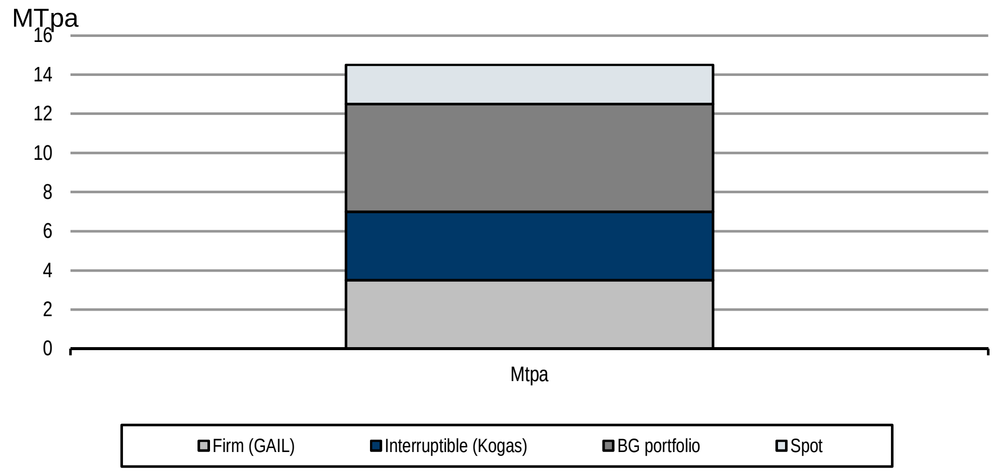
Cheniere certainly displayed execution capability as it sold out Sabine Pass

Figure 18: **Cheniere: Sabine Pass—off-take distribution**

MTpa	2014	2015	2016	2017	2018	2019	2020
BG		3.5	3.5	3.5	3.5	3.5	3.5
BG additional			1.0	2.0	2.0	2.0	2.0
Gas Natural		3.5	3.5	3.5	3.5	3.5	3.5
Kogas				3.5	3.5	3.5	3.5
GAIL				3.5	3.5	3.5	3.5
reserved for spot sales		0.0	1.0	2.0	2.0	2.0	2.0
Capacity		7.0	9.0	18.0	18.0	18.0	18.0

Source: Company data

Figure 19: **Cheniere: Sabine Pass avails potential delivery into Asia**



Source: Credit Suisse estimates

Sabine Pass: 3-15 MTpa could end up in Asia

GAIL's off-take is a firm take or pay contract, whereas Kogas' contract is understood to be interruptible where the Korean utility would pay a 'suspension fee' (presumably reflective of the liquefaction charge). BG has effectively increased its portfolio pool with its deal at Sabine Pass—we suspect a reasonable proportion will be sold under term contracts where the interruptible element that BG enjoys with Cheniere is passed onto Asian utility buyers, in return for pricing formulas related to JCC (Japanese Crude Cocktail) rather than HH-based pricing. We assume 2 MTpa is un-contracted and available for sale in Asia from 2017; this is the amount Cheniere has 'held back' from contract sales to participate in the spot market.

Cheniere Sabine Pass expansion requires Chevron / Total's concurrence: Cheniere is understood to have been considering expanding its liquefaction capacity at Sabine Pass—adding a further two trains—presumably another 9 MTpa / 1.18 Bcf/d, but this would require approval from its anchor re-gasification customers, Chevron and Total (both committed to 1 Bcf/d off-take). We assume that both the super majors would look to be involved should they decide to acquiesce, and with extensive exposure to the Asian LNG price premium they would look to 'control' price pollution from low-cost US-sourced LNG. We count this as speculative rather than market ready at this stage.

Cheniere Corpus Christi—targeting 2013 approvals: Cheniere is beginning to focus on its second LNG liquefaction project at Corpus Christi Bay, with a further three trains or 13.5 MTpa / 1.77 Bcf/d of liquefaction capacity. This would be a green-field development (unlike the brownfield retro-fit at Sabine Pass). Cheniere is currently targeting FERC approval in September 2013 and first gas in 4Q 2018. As with the Sabine Pass expansion we currently treat Corpus Christi as speculative rather than market ready, but given Cheniere's recent history of accelerating projects will monitor developments carefully.

US: brownfield conversions a key advantage over green-fields: BG has indicated that cost savings on a brownfield LNG facility built on a regasification site could be as much as 50%. A liquefaction facility built alongside a regas terminal would be able to utilise land, tanks, process equipment, jetties and utilities. Our US research team assumes that the four-train 16 MTpa / 2.09 Bcf/d Sabine Pass facility would cost US$10 bn capex or US$625 mn per MTpa. We are sceptical about the feasibility of green-field US LNG exports given the rising number of competing brownfield projects with immediate cost and regulatory advantages.

Freeport—Conoco now in change? Freeport LNG is being developed by Conoco in Texas. The project is a 10 MTpa / 1.31 Bcf/d liquefaction facility on an existing regas terminal—targeting FERC approval in 4Q 2012. Media reports suggest GAIL and Freeport are in advanced discussions for a 2 MTpa / 0.26 Bcf/d off-take; however, it is not clear that Macquarie will be involved in the marketing of the project. If Conoco leads the marketing of the project we assume it would be more conscious of the Asian LNG price premium which it enjoys in its existing Asian LNG ventures including Darwin LNG and APLNG which has just concluded agreements to sell the majority of the two-train capacity to Sinopec. We carry Freeport as market ready for sales to Asia.

BG may link equity molecules to Lake Charles supply to Asia

Lake Charles—equity gas could be a differentiator: BG and its partner Southern Union received approval for LNG exports from Lake Charles to FTA countries in July 2011. The export licence is for up to 15 MTpa (or 1.97 bcf/d) for 25 years. The takeover of BG's partner Southern Union by Energy Transfer Equity (ETE) announced in June 2011 slightly delayed the design and permitting process, but the project is now back on track. BG expects to get non-FTA approval by year-end, allowing them to start marketing the gas to China and India, among others. The partners filed approval from FERC in early April 2012, and expect Lake Charles to be sanctioned in 2014 with first LNG in 2018. Interestingly, Lake Charles now appears to have moved ahead of QCLNG Train 3 in BG's timeline of future LNG options. We believe that BG is very keen to progress Lake Charles as the company will need big capital-intensive projects in 2016+ to absorb all the free cash flow generated by Brazil and Australia. BG has said it could either provide its own equity gas from its Haynesville acreage into the plant or buy third-party gas, similar to Sabine Pass. We believe Asian LNG buyers (particularly Japanese) would prefer the LNG seller to also own the equity gas, as this is seen as reducing delivery/country risk. We assume BG will market the LNG from Lake Charles to customers from its "global LNG portfolio" on oil-linked prices, thereby capturing the spread between HH and oil, again, similar to Sabine Pass. With the potential to link US-sourced molecules plus the advantage of portfolio marketing we count Lake Charles as 'market ready' at this stage.

Cove Point starts discussions with Tokyo Gas / Sumitomo for a pure liquefaction service

Dominion Cove Point: The Maryland-based regas facility received a DoE approval on 7 October 2011 to export up to 8 MTpa / 1.05 Bcf/d to FTA countries and then filed an application for the same capacity to also be exported to further 8 MTpa to non-FTA countries. Dominion signed an initial agreement (to then negotiate a Terminal Service Agreement) with Sumitomo/Tokyo Gas. The scope is different from the Cheniere Sabine Pass deal in that Tokyo Gas / Sumitomo will be responsible for sourcing feedstock gas for the liquefaction capacity. Dominion expects to start construction in 2014 and exports in 2017.

Cameron LNG—Japanese trading participation but where will the gas come from?

Sempra-Cameron: Becoming a Japanese Trading Co enclave? A three-train, 12 MTpa / 1.57 Bcf/d facility is envisaged, using Cameron LNG's existing facility, with the brownfield conversion capex forecast at US$6 bn. Mitsubishi and Mitsui are understood to have signed an interim off-take agreement for 4 MTpa / 0.52 Bcf/d each. Thus far Cameron LNG has approval for sales to FTA countries only, but has applied for FERC approval to sell to non-FTA countries and aims to take project FID in 2013. What is unclear with the Mitsui/Mitsubishi agreements is who will source the gas and what are the price and flexibility terms; however, our initial soundings suggest Sempra is looking at simply being a merchant liquefaction supplier, hence possibly only seeking a tolling fee, leaving the Japanese trading firms with both the opportunity to buy at HH, but also the requirement to source to the satisfaction of Japanese buyers (assuming the trading houses intend to target sales into Japan). Following the Japanese deals Sempra then announced a deal with GDF Suez, also for 4 MTpa hence selling out the 12 MTpa facility. We carry Cameron LNG as speculative, awaiting clarity on gas sourcing, and non-FTA sales approval.

Figure 20: **CS' view of market ready and speculative US LNG to target APAC**

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Market ready / near to market ready									
Sabine Pass phase 1	0	0	0	0	1	2	2	2	2
BG Sabine Pass sourced				3.5	4.5	5.5	5.5	5.5	5.5
BG Lake Charles	0	0	0	0	0	0	15	15	15
Conoco Freeport LNG	0	0	0	0	0	10	10	10	10
Cove Point	0	0	0	0	0	0	7.8	7.8	7.8
Sempra / Mitsubishi/ Mitsui/ GDF Suez Cameron	0	0	0	0	0	12	12	12	12
Total	*0*	*0*	*0*	*3.5*	*5.5*	*17.5*	*40.3*	*40.3*	*40.3*
speculative									
Sabine Pass expansion						9	9	9	9
Cheniere Corpus Christi	0	0	0	0	0	0	13.5	13.5	13.5
Total (market ready + speculative)	0	0	0	3.5	5.5	26.5	62.8	62.8	62.8

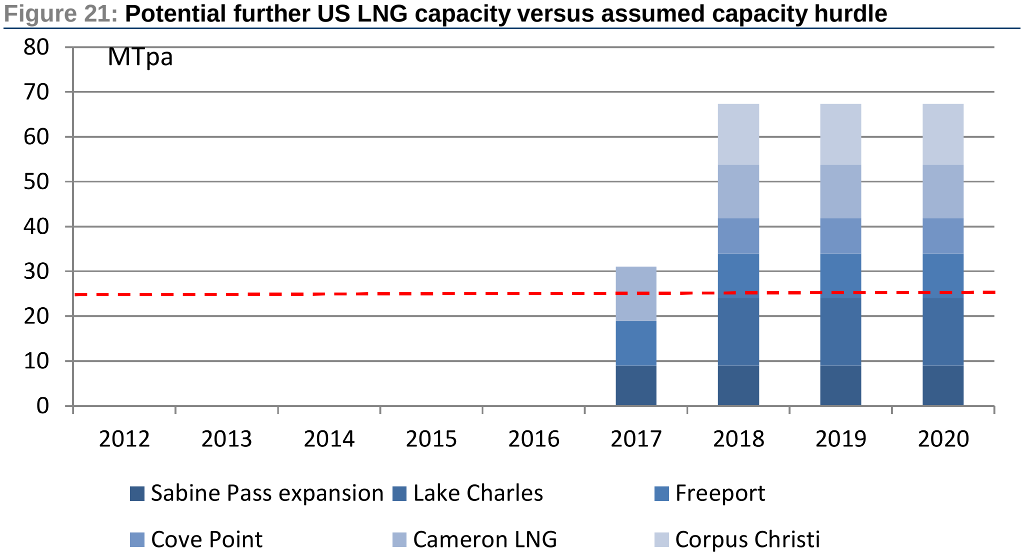
Source: Credit Suisse estimates

Political headwinds regarding US LNG exports beginning to mount?

How much LNG will the US really allow to be exported? In the recent EIA study a 6 Bcf/d hurdle (46 MTpa) was used when identifying the effect on domestic US gas prices. The result was an assumed increase of US$0.52/mmbtu against the EIA reference case. Since the report political opposition to scale LNG exports appears to be mounting, Congressman Markey (D-Mass) has proposed a bill to stop any further exports of US gas (the bill is subtly named, Keep American Natural Gas Here Act). We would expect manufacturers of chemicals, fertilisers, agriculture, etc., all of which benefit from a low-cost feedstock, to be particularly worried about what an increase in domestic prices of LNG exports may bring.

DoE not exactly putting out positive vibes…: In late March, the DoE delayed a decision on non-FTA exports, pending the completion of a second report assessing the impact of exports on the US economy. The DoE (Deputy Assistant Secretary Christopher Smith) reportedly stated that the government would be reluctant to withdraw or modify previously granted authorisations, except in the event of extraordinary circumstances. This second report (from a private contractor) was scheduled to be released at the end of 1Q12 but has now been pushed back until late summer, and appears that it may run into 'election season' as the US prepares for the Presidential elections in November.

Figure 21: **Potential further US LNG capacity versus assumed capacity hurdle**



Source: Credit Suisse estimates

We assume a further 25 MTpa / 3.27 Bcf/d *could* be (non-FTA) approved in the US: We look back to the great regas race in the early 2000s where more than 60 regas terminals were proposed, but in the end less than five were constructed. Given the building political backlash to gas exports and the lack of maturity of a number of the project proposals we assume the 6 Bcf/d ceiling is set, suggesting a further 25 MTpa could be approved following Cheniere's Sabine Pass project.

Figure 22: **Key APAC marketing considerations for US LNG projects**

	HH price link	JCC price link	Avoid US political risk	'Portfolio' / reserves certainty	Interruptable	Capacity (MTpa)	Brown/ greenfield
Cheniere Sabine Pass	Yes	No	No	No	Yes	18	Brown field
Cheniere SP expansion	?	?	No	No	Yes	9	Brown field
Cheniere Corpus Christi	Yes	No	No	No	Yes	13.5	Green field
BG Lake Charles	No	Yes	Yes	Yes	likely	15	Brown field
BG Sabine Pass	No	Yes	Yes	Yes	likely	5.5	Brown field
Conoco Freeport	No	Yes	If 'portfolio'	If 'portfolio'	likely	10	Brown field
Dominion Cove Point	Yes	?	No	No	Yes	7.8	Brown field
Sempra Cameron	Yes	?	No	No	likely	12	Brown field

** NB: Cheniere Sabine Pass phase 1 has already been almost entirely sold (16 MTpa out of 18 MTpa) and only 2 MTpa is left to be marketed. Sempra / Cameron has signed initial agreements for its full capacity, and Cove Point has signed an initial agreement for 2.3 of its 7.8 MTpa.*
Source: Credit Suisse estimates.

Alaskan LNG proposal gathering momentum, but post 2020: While Kenai LNG, the US's only LNG export plant, now permanently shut down due to feed-gas depletion, another Alaskan LNG project is emerging. Operator Exxon and partners BP and Conoco are in the early stages of studying LNG exports from the North Slope, seen as a more commercial alternative to pipeline exports to Canada and on to the Lower 48 given depressed North American gas prices. Unlike in the Lower 48, exports are actively being pushed by authorities (notably by Governor Sean Parnell) as the gas would otherwise be stranded with no natural market. In early April TransCanada submitted a request to the US state of Alaska for permission to build a gas pipeline from Alaska's North Slope to the port of Valdez, where a liquefaction plant would be built (with Conoco as the likely liquefaction lead). In a mid-2011 study, WoodMac estimated an Alaskan LNG FOB cost of between US$8/mcf and US$10/mcf before transportation costs to Asia, making it marginally more competitive against greenfield Australian LNG projects (with FOB break-evens of US$11-14/mcf) and even against Western Canadian projects (e.g. Kitimat with an estimated FOB breakeven of US$11/mcf). We would not expect Alaskan LNG to start up before the next decade (2022 at the earliest). However, Alaska LNG will be in direct competition with other LNG projects for customers around the middle of this decade.

Is Alaska going to get a second wind for LNG supply to Asia?Alaska North Slope being considered for LNG exports

Marketing proposals from the yet-to-be-sanctioned US projects may vary greatly: Cheniere clearly demonstrated a focus on achieving an adequate return to its liquefaction rather than capturing the Asian market premium—leaving value for aggregators like BG and end users like GAIL and Kogas. For the developers of further LNG facilities their existing exposure to the Asian LNG premium will likely be a primary motivator, hence a reticence to repeat the pricing precedent set by Cheniere. For those developers CS expects a marketing strategy built around the value of increased flexibility (interruptible) will be stressed rather than a HH linkage. This would be relevant for BG and Conoco; however, for Cheniere's Corpus Christi and Dominion's Cove Point we assume the developers will offer HH linkage a la Sabine Pass sale made thus far.

Don't assume all US LNG projects will be marketed on the back of HH pricing…

US-sourced LNG is 'lean', which brings challenges to N Asian LNG buyers: Japan and Korea are designed to accept rich (i.e. higher High Heating Value's or HHV) whereas gas in the US open access pipeline system is lean. The issue is that to meet the send out specification N Asian buyers may need to spike lean LNG with LPG to meet the send out spec. In small quantities those LNG buyers can deal with this issue by effectively blending rich LNG—but if US-sourced LNG became a mainstream supplier this can become a material issue for some Asian LNG buyers.

Japanese City gas has a mandated calorific value of 45–46MJ/m3: With some exceptions, the gas supplied by Japan's major city gas vendors has a mandated calorific value of around 45–46 megajoules per cubic meter. Gas-burning equipment, especially industrial gas burners, are designed to suit this calorific value. Any divergence can result in non-optimal combustion, with less-than-ideal results.

Japanese mandated send-out rates exceed US 'lean' gas specs

LPG's CO2 emissions 19% higher than those for LNG: It is cause for some concern that an increase in LPG consumption would bring about growth in CO2 emissions. According to the Japan LP Gas Association, LPG emits 59g of CO2 per megajoule of energy produced, 19% higher than the equivalent figure of 49.5g for LNG. While LPG is considered more environmentally friendly than either coal (90.6g CO2) or crude oil (68.6g), the comparison with LNG is not so favorable.

Lowering send-out rates another option: We mentioned that combustion of fuels with non-optimal send-out rates can deliver less-than-ideal results. In reality, this only applies to industrial applications where temperatures must be strictly controlled. Providing the city gas used is of the 13A specification, there is no such concern with residential gas appliances. A comparison of the 13A standard with current send-out rates suggests that there is scope for the major city gas suppliers to lower calorific values by another 2MJ or so. Lowering send-out rates would likely become a realistic option if city gas companies were to start utilising large volumes of lean LNG.

Japan could consider lowering the send-out rates, if lean LNG becomes a major supply component

Canada LNG

Kitimat: 5-10 MTpa (0.65–1.3 Bcf/d)—still seeking Asian Premium: First train gas is guided for 2015. It would appear that historical Heads of Agreements reached with Kogas and GNF have fallen away, so we update our un-contracted supply assumption to reflect the full 5 MTpa. We continue to believe that Kitimat will not offer a NA gas hub price to Asian buyer with Apache already involved in the Wheatstone LNG project, recently sanctioned at a circa 85% correlation to JCC. Unlike its US competitors we believe that the Kitimat partners (EnCana, Apache and EOG) can offer physical reserves confidence, a crucial difference in our opinion. Recent media speculation suggests that Kitimat may offer equity in the facility as another marketing 'plus'. The project now guides for project sanction at the end of 2012, hence is marketing actively at this point. In late April the project gained a further fillip, with an approval to increase the size of the Pacific Trails pipeline from 36 inches to 42 inches, increasing confidence in the ability to supply the second phase 10 MTpa capacity.

Canada: More palatable politics and increased reserve certainty vs. the US?

Figure 23: **Canada—possible marketing attributes for Asian buyers**

	NA gas hub link	JCC price link	Avoid US political risk	'Portfolio' / reserves certainty	Interruptible
Kitimat	No	Yes	Yes	Yes	Unclear
Shell Facility	No	Yes	Yes	Yes	Likely

Source: Credit Suisse estimates

Shell liquefaction facility also on the drawing board in Kitimat: Shell bought a marine terminal near Kitimat BC with a view to developing an LNG liquefaction point. Shell has 40% of the project (dubbed "LNG Canada"), and is partnering with CNPC / PetroChina, Kogas and Mitsubishi, each with a 20% stake. For PetroChina, Canada-sourced LNG makes sense if it has equity participation in the upstream. Following the failure to close the EnCana Cutback Ridge farm-in PetroChina and Shell announced a farm-in of Shell's Groundbirch shale play—in British Columbia. With Kogas already positioning itself in the upstream with its farm-in to EnCana plays in Horn River this provides an alternative to Kitimat LNG as a liquefaction point for equity gas to move to South Korea. Shell will clearly not look to pollute the Asian price premium and will likely offer flexibility / interrupt ability as the key value-add from its facility (along with linkage to molecules and lower political supply risk versus the US). Shell aims for first LNG around the end of the decade. Thus far we have not included any volumes from the two-train, 12 MTpa / 1.57 Bcf/d facility by 2020 as un-contracted supply, as the project is not market ready at this time.

BC LNG—also licensed for small scale exports: In February BC LNG Export Co-operative LLC was awarded a 20-year LNG export license, for 36 mn tonnes, with an annual maximum of 1.8 MTpa / 0.24 Bcf/d. BC LNG is a partnership between Haisla Nation and LNG Partners. Interestingly gas supply to the liquefaction point is proposed to be met by 16 upstream producers in Canada under a bidding system. With no off-take agreements and the gas supply plan we carry 1.8 MTpa as speculative from 2016 (versus the advertised 2013/14).

Figure 24: **Canada: Market ready / speculative avails—MTpa**

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Market ready / near market ready									
Kitimat	0	0	0	0	0	5	5	5	5
Total	*0*	*0*	*0*	*0*	*0*	*5*	*5*	*5*	*5*
Speculative									
Shell LNG Canada									5
LNG Partners / First Nation					1.8	1.8	1.8	1.8	1.8
Total possible + Speculative	*0*	*0*	*0*	*0*	*1.8*	*6.8*	*6.8*	*6.8*	*11.8*

Source: Credit Suisse estimates

East Africa—a new LNG province

Mozambique—lots of gas, but no natural LNG lead, as yet

Mozambique—where's the leader? Eni has found nearly 40tcf or recoverable gas in Area 4 (47-52tcf of gas in place, recovery factors between 65% and 85%) versus Anadarko's >30tcf of recoverable gas in Area 1. Although each company already has enough gas for at least four LNG trains, both companies are still drilling to increase their resource estimates (another three wells in Eni's Area 4 drilled in 2012). We understand Eni's and APC's desire to prove up more gas to understand the geology better and determine the lowest-cost reservoirs to produce from in the long term, but we suspect that another big motivation for Eni and APC is to gain the upper hand during unitisation (i.e. getting a higher stake in the joint block/project). Unitisation talks between Eni and APC have now started, and Eni expects the process to be completed by the end of 2012.

Eni is prioritising a joint development of the two blocks, but is also separately considering Floating LNG as an option for early monetisation of gas resources located solely within Area 4. This could indicate that the Mozambican government is keen to get cash up-front and putting pressure on operators to sanction early, using leverage such as Capital Gains Tax or domestic gas sales requirements. Unlike in Tanzania, partners have not signed gas sales commercialisation agreement or domestic sales clauses with the government, which could delay the project's timeline.

Uncertainty about operatorship and final ownership has risen further following Shell's bid and PTTEP's counter-bid for Cove. If Shell does not prevail, Cove Eni would seem the "natural" operator of the project as it has more experience in LNG than APC—even if some observers doubted Eni's ability to carry out a large-scale LNG development in a country lacking any oil and gas track record. Should Shell prevail it would logically follow by bids for part of APC's 36.5% stake in Area 1 and/or Bharat Petroleum and Videocon's 10% stake, which would eventually put the world's largest LNG marketer among majors in direct competition with Eni for operatorship. Eni is publicly saying it is happy to welcome Shell into the partnership (the two firms have worked together in other projects e.g. Nigeria LNG), but relations could become more tense once Shell has reached a material stake in Area 1.

Mozambique probably 12+ months away from being 'market ready'

In a nutshell, with no clear partner alignment and another eight months at least before unitisation, the Mozambique LNG project is not yet marketable at this time. Kogas's presence in Eni's Area 4 (10% stake) could help to secure at least some LNG sales. Kogas could also be a candidate for the 20% stake that Eni will farm out in late 2012/early 2013 after the current drilling campaign. FID is targeted for 2013 and first gas for 2018—we assume FID in 2014 and start-up in the second half of 2019.

Figure 25: **East Africa: Market ready and speculative avails (for sale in Asia)**

MTpa	2014	2015	2016	2017	2018	2019	2020
Market ready / near market ready							
Tanzania (BG / Ophir)	0	0	0	0	0	8	8
Speculative							
Mozambique	0	0	0	0	0	5	10
Total possible + Speculative	**0**	**0**	**0**	**0**	**0**	**13**	**18**

Source: Credit Suisse estimates

We assume BG / Ophir's project is now 'market ready'

Tanzania—ticking the boxes in short succession: BG's (60%) and Ophir Energy's (40%) recent Mzia-1 discovery has taken gas resources to c.10 Tcf, enough gas for a two-train LNG project. The presence of Statoil in neighbouring Block 2 (between BG's blocks 1 and 3) with 5 Tcf of gas-in-place further increases the project's chances of going ahead. Another one to two wells will be drilled this year in Tanzania to try to get to 20 Tcf. Ophir expects its BG-partnered acreage to hold about 40 tcf of un-risked gas resources, with significant further upside potential if basin-floor stratigraphic play from Area 1 and Area 4 in Mozambique extends into its Block 1 in Tanzania. This would be important for Tanzania gas story as each basin-floor play well could add about 10 Tcf of gas, similar to the ones drilled in Mozambique. Ophir/BG recently shot 3D seismic over this area and the initial seismic results are expected by September, with wells expected late this year or early 2013 to test this play (if encouraging). This will not only prove gas resources quickly, but also reduce overall development costs.

We see fewer issues of partner alignment in Tanzania than in Mozambique, given BG's considerable lead over runner-up Statoil with respect to gas commercialisation agreements, compared to Mozambique's much closer race between Eni and Anadarko/Shell (neither of which has gas commercialisation agreements) and uncertainty over final ownership and operatorship. BG's pedigree as one of the world's most credible LNG developers and Tanzania's presence in BG's LNG capacity projections add further weight to the project. BG is already looking at possible sites on the Tanzanian coast for an LNG development. Having crossed the resource threshold for a two-train LNG project, we would expect BG to start marketing the LNG in the very near future, as they can market from their global "LNG portfolio". We note that Ophir is becoming an increasingly attractive take-out candidate for an LNG buyer with a desire to own equity gas. Ophir has already said it does not want to participate in an LNG development in Tanzania and will look to monetise the assets, likely in 2013.

We do not see significant issues on domestic gas sales, despite the growing political pressure in Tanzania to use offshore gas discoveries for domestic purposes before exports are considered. Tanzania's existing power infrastructure is already working flat out and gas-fired power generation (around 50% of current power generation sources) is seen as a solution to reduce electricity shortages. We do not expect this to be a show-stopper for BG/Ophir as their commercial terms specify that only 10% of the gas will be sold domestically.

We assume the BG/Ophir project is "market ready" by the summer for sales into Asia, and assume the project is a two-train, 8 MTpa facility (though further gas resources could expand the project's size).

What Asian buyers want in East Africa: Buyers would like a differentiated price i.e. not JCC, confidence on operators ability to commercialise projects in a new LNG geography, partner cohesion, low-country risk and importantly equity. At this time the Mozambique protagonists lack a credible LNG 'lead' and partner alignment (focused on proving up gas pre unitisation rather than building a marketable platform) while in Tanzania with recent exploration success the BG/Ophir project has a (very) credible operator, partner alignment, enough gas to start pre marketing and with BG's global portfolio presumably a way to give comfort on country risk in Tanzania. We will argue in the next section that being 'market ready' in the next 6–12 months will be crucial for project success in the late decade demand window. We assume a two-train 8 MTpa facility (or more) is market ready in Tanzania from the start of the second half of 2012, including this as competing for un-contracted demand from 2018–19, and await clarity on unitisation/LNG lead in Mozambique before adding potential supply from this country.

Figure 26: **East African LNG: Key drivers for Asian buyers**

	Non JCC price formula	Reserves confidence	Credible LNG 'lead'	Partner alignment	Country risk mitigation	Equity
Mozambique	Not known	Yes	?	No	No	Not known
Tanzania	Not known	Yes	Yes	Yes	Yes	Not known

Source: Credit Suisse estimates

Australia and Papua New Guinea

APLNG train 2—FID imminent

Capacity: 4.5 MTpa, brownfield expansion (Curtis Island, Queensland), First LNG 2017

ORG.AX and COP look set to announce FID on its second LNG train on Curtis Island in Queensland. Project sanction was reached on train 1 in July 2011, with expectations train 2 would be approved by the middle of 2012. The JV has already sold most of the off-take from train 2 to Sinopec (3.3 MTpa) and Kansai Electric (1 MTpa), with government approvals of the gas sales to China the major hurdle remaining. ORG.AX is still mulling its funding options for train 2 (expected to cost A$6 bn, versus A$14 bn for train 1), with further equity sell-down in the project being contemplated. We carry 0.4 MTpa from 2018 as market ready, with the remainder of the two trains already sold.

Browse LNG—James Price Point or North West Shelf backfill?

Browse—standalone or backfill gas for the North West Shelf project?

Capacity: 12 MTpa, green-field site at James Price Point (Western Australia), First LNG target 2018.

The Browse JV (comprising WPL.AX, RDS, CVX, BP and BHP) find itself moving towards a delayed decision on a James Price Point development for Browse. The project reserves were recently increased to 14.4 Tcf and 417 mmbbl of condensate, which in theory will be developed for a 12 MTpa (3 x 4 MTpa trains) at a green-field site in Western Australia. The JV has a commitment with the state and federal governments in Australia to be ready to take a final investment decision on a James Price Point development by the middle of 2013. But with very similar ownership structure between North West Shelf and the Browse JV, and NWS (16.7 MTpa capacity) forecast to shortfall on gas deliverability in 2021, most of the Browse JV partners would prefer to see Browse gas kept to back-fill NWS. We suspect we'll know more about the preferred Browse development pathway in 2H12, as detailed downstream cost estimates are due before the middle of the year. Also imminent is WPL selling down its 46% equity stake in Browse to one or more LNG customers, but the question remains: What sort of LNG development do these players believe they are buying into?

PNG LNG train 3—drilling success increases confidence in gas volumes to underpin third LNG train

PNG LNG Train 3 IRR > 35%...

Capacity: 3.3 MTpa, brownfield expansion (Papua New Guinea), first LNG target 2017

The PNG LNG project has been optimised for three LNG trains. The first two LNG trains are now more than halfway through the construction phase, with first LNG targeted for 2014. The overinvestment in trains 1 and 2 means the cost of train 3 construction is expected to be A$3.5-5 bn, significantly less than the A$8 bn/train for the first two LNG trains. The combination of low capex, high liquids content and attractive PNG fiscal terms means the IRR of train 3 is over 35%. The JV requires a minimum of 2.5 Tcf of proved gas resources to underpin train 3 and has an aggressive drilling campaign underway this year to reach that target by early 2013. The XOM-led JV recently announced the P'nyang South appraisal well had identified a vertical gas column of at least 380 metres, with seismic data indicating potential for over 650 metres. We believe this is approximately 50% more than pre-drill expectations, and we expect this gas field could contain 3-4 tcf of recoverable gas. Further drilling at Trapia (exploration well) and two Hides appraisal wells should see the JV comfortably exceed the minimum resource target. Train 3 FEED and LNG marketing is expected in 2013, with FID by late 2013/early 2014.

Gorgon Train 4—Strong marketing profile and weakening phase 1 economics support a Train 4 expansion.

Capacity: 5 MTpa, brownfield expansion on Barrow Island (Western Australia), first LNG target 2019

There is considerable speculation around cost overruns at Gorgon development, due to the environmental constraint put on the construction process (quarantine requirements onto Barrow Island add a time constraint). There is plenty of gas for Gorgon 4 (and Gorgon 5), and with Chevrons strong marketing footprint in Japan we would not be surprised to see an active Train 4 marketing programme to commence in 2H 2012 targeting FID in 2014 and first LNG in 2018.

Wheatstone Train 3—CVX driving further expansion

Wheatstone Train 3—after Gorgon Train 4?

Capacity: 4.5 MTpa, brownfield expansion in Western Australia, first LNG target 2020

The continued exploration success by CVX points to future expansion at Wheatstone, where the development footprint has enough room to eventually produce 25 MTpa. CVX has been quite aggressive in stating its ambitions to expand, after beating WPL.AX to attract APA/Kufpec gas to join the first two LNG trains. CVX may look to bring in third party gas (Equus (HES) or Scarborough (XOM/BHP)). Logical development timing for Wheatstone 3 is after Gorgon 4 train volumes are sold.

Pluto train 2—WPL to review gas position 2H12

Pluto expansion—the gas conundrum continues

Capacity: 4.3 MTpa, brownfield expansion (Western Australia), first LNG target 2017

The entire investment thesis behind Pluto train 1 was that further gas volumes would be found or aggregated and additional LNG trains constructed, leveraging off the Pluto 1 infrastructure. To date WPL.AX has been unsuccessful in proving up sufficient resources to underpin a second LNG train on its own. Exploration continues with a further three gas exploration wells to be drilled shortly, but WPL.AX plans to update the market on its equity position with respect to Pluto expansion in 2H12. We believe that WPL.AX has a strong preference to develop Pluto 2 on its own, but if it has no clear line of sight on sufficient equity gas volumes for train 2 it may opt to bring in other resource owners (the HES-led Equus gas project and the XOM-led Scarborough gas are the logical parties to supply gas to Pluto expansion).

QCLNG Train 3—taking longer

BG's QCLNG—expansion seems a way off at this point

Capacity: 4.3 MTpa, brownfield expansion (Queensland), first LNG target 2017

BG continues to drill to prove up enough gas for a third train at Queensland Curtis LNG (QCLNG). Its gross 2P reserves of 9.9 Tcf are just enough to cover requirements for the first two LNG trains (8.5 MTpa capacity). In short, we do not expect BG to be able to sanction a third train before the end of 2012 or early 2013 at the earliest.

BG has three or four options to prove up the >5 tcf of 2P gas reserves it needs to sanction a third train: (1) Surat coal-bed methane exploration and appraisal drilling; (2) Bowen basin, north of the Surat basin, where BG acquired acreage through the Sunshine and Pure Energy deals. BG estimates risked resources at 4.7 tcf and will do further testing and run a pilot in 2012. We understand that some parts of the Bowen basin have lower coal permeability than the Surat, leading to higher production costs. BG is also exploring Bowen deep gas sands (4 km depth) with two exploration wells planned in 2012; (3) Shale gas opportunities in the Cooper basin, 700 km west of the Surat/Bowen. This would present infrastructure access issues and would be a longer-term play—economics of extraction in the Cooper are uncertain and expected to be high at this stage.

Tangguh train 3—heading for FID in 2015

BP getting after a Tangguh expansion: domgas rather than reserves may be the challenge

Capacity 3.8 MTpa, brownfield expansion (Indonesia), first LNG target 2018.

BP is working towards the construction of a third LNG train at Tangguh in Indonesia after 2011 drilling confirmed an additional 5 tcf of reserves. The size of the train is expected to be 3.8 MTpa (similar to the first two LNG trains), with FID slated for 2013 and first LNG in 2018. The Indonesian government has indicated it will request 50% of the LNG be sold to domestic power utilities company PT PLN, leaving 1.9 MTpa available for export. The Indonesian government is keen to see additional trains built at Tangguh; however, it can also ask BP to allocate gas to petrochemical and/or fertiliser plants. We include Tangguh T3 as “possible” supply in our global gas model, starting in 2019.

Other Australian LNG options

Plus another 38 MTpa+ of less defined projects around Australasia

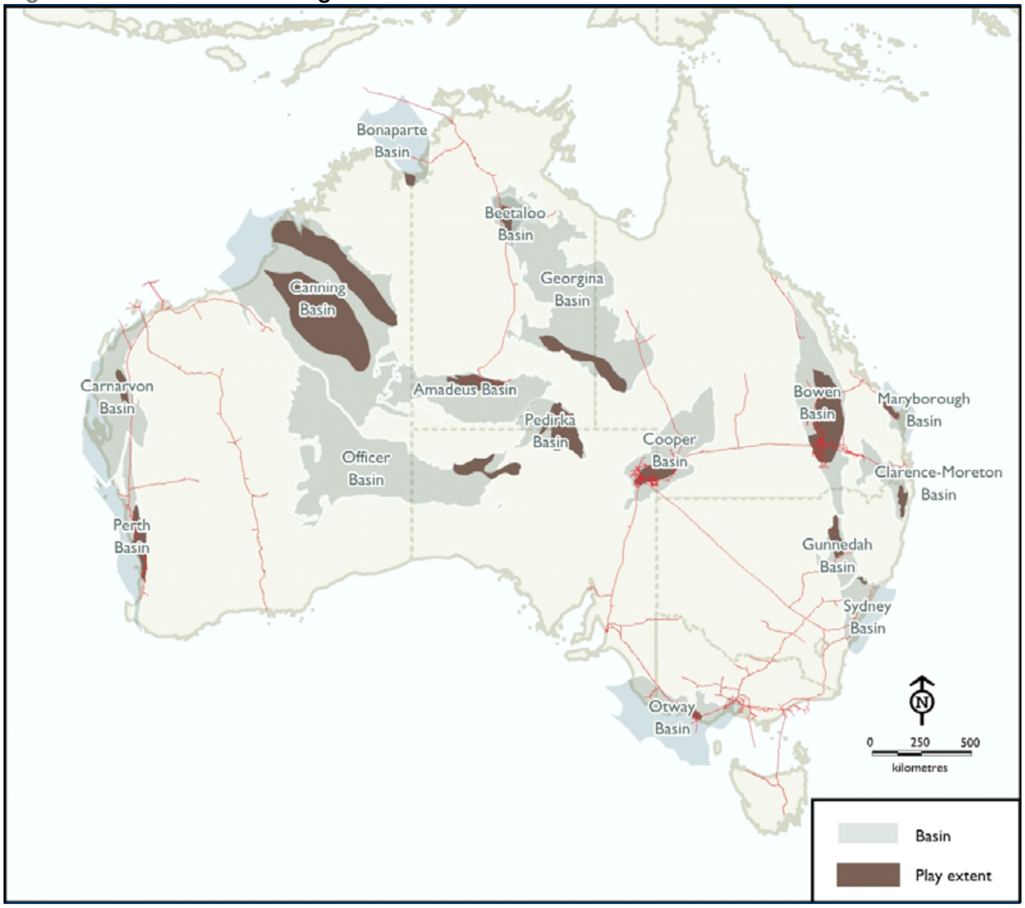
There’s at least a further 38 MTpa of potential LNG supply not discussed above: The challenges to move these projects forward vary, from misalignment with government (e.g. Sunrise), “further delineation required” projects (HES-led Equus project, XOM-led Scarborough, COP-led Poseidon and GDF Suez-led Bonaparte FLNG), the “we have the technology, but not the gas” projects (Fisherman’s Landing), “we’ll get there when we get there” projects (Gorgon 5 and APLNG 3) and the “is it real?” category (InterOil’s PNG LNG ambitions).

Australian shale gas potential for LNG

And then there’s shale gas in Australia as well…

There is a growing interest in Australia’s vast shale (and tight) gas resources, with an EIA report in 2010 concluding Australia has the fourth largest shale resources globally of over 400 tcf. Very little exploration and appraisal activity has been undertaken to date so the economics of gas extraction are unknown; however, at least 20 wells targeting shale gas will be drilled in 2012, with the majority of these fracture stimulated. To date most interest has surrounded the Cooper Basin in central Australia and the Canning Basin in Western Australia (Figure 27). The Cooper Basin has a data set of shale information already available thanks to more than 1,000 conventional wells having been drilled historically, and the area has some existing gas processing and transport infrastructure available. The shales in the Canning Basin are thought to contain some degree of liquids, though how much and whether the technical characteristics of the shale will result in commercial extraction is still unknown. The size of the prize is attracting the interest of majors, and we have already seen companies such as BG Group, HES, COP and Mitsubishi farm into various shale basins. There is a long way to go to understand the economics of shale gas extraction in Australia, but success would mean additional gas volumes available for LNG export. As the cost of shale gas extraction is expected to be relatively high (due to Australia’s high cost environment and remote location of these shale basins), the most likely scenario for shale gas into LNG is as back-fill behind conventional gas supplies, or as part of brownfield expansion supplies. Key players in shale gas in Australia include STO.AX, BPT.AX, SXY.AX, DLS.AX (Cooper Basin), AWE.AX, NWE.AX (Perth Basin) as well as BRU.AX and NSE.AX (Canning Basin).

Figure 27: **Australian shale gas basins**



Source: MBA Petroleum Consultants, Shale Gas Atlas of Australia 2011

Other supply points

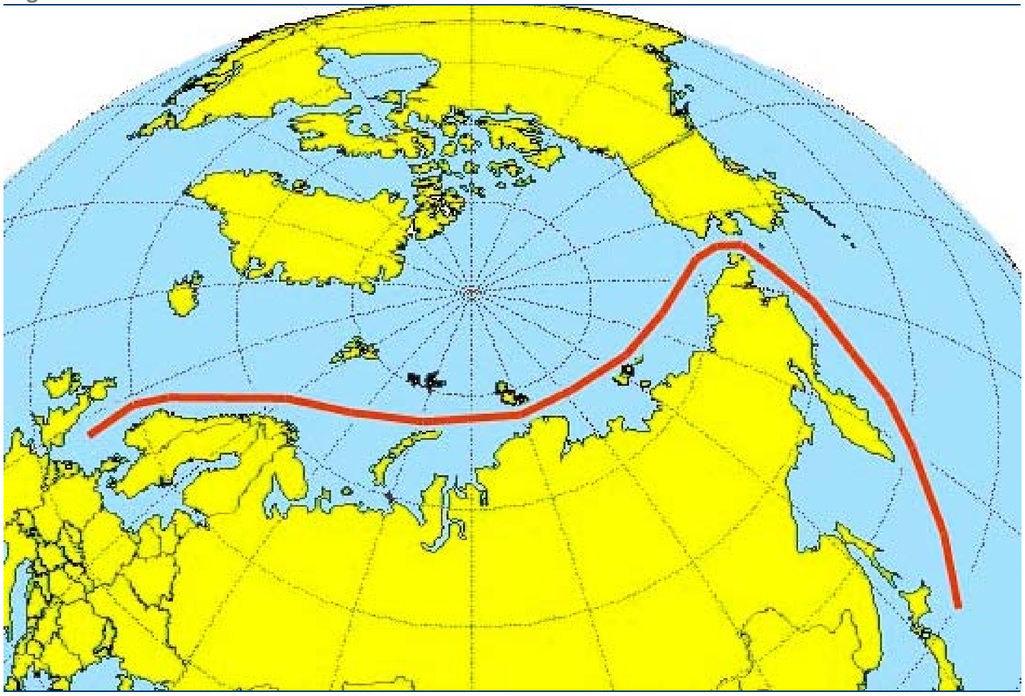
Supply update in Russia

Yamal LNG: Ambitious project export plan

Capacity 5-15 MTpa, green-field, first LNG target late 2016

Novatek, the project's operator and a 51% stake owner of Yamal LNG is confident that the first train of 5 MTpa should come on stream as early as in the end of 2016 followed by two more trains in 2017 which would bring the total capacity to 15 MTpa. The project has received unprecedented support from the Russian government who agreed to grant 12-year tax breaks on export duty and Mineral Extraction Tax. On top of this the government undertook to build the port infrastructure which is the most difficult part of the project as the shallow sea bed does not allow to use LNG vessels of Q-max class at the moment. The government has already placed orders for six ice-breakers, designed to ensure transportation of LNG in winter months. The project targets 40% of initial sales in Asia (the remainder in Europe), but delivery certainty may be a marketing issue in Asia, given the plan to travel along the Northern Sea Route using ice-breakers. Novatek is looking to bring in additional partners into Yamal LNG alongside Total (20% stake)—names that have been mentioned include Qatar Petroleum, a consortium of Indian companies (ONGC, Petronet and GAIL), France's EDF and (oddly enough) Gazprom.

Figure 28: **Northern Sea Route**



Source: www.gospodarkamorska.pl

Yamal LNG: Will Asia buy the shipping route via the Northern Sea Route?

Last year Novatek received four more licences for 1.2 tcm of P2 gas (or 42tcf) in the same area as South Tambey field (the reserve base of Yamal LNG project). This potentially may enable Novatek to add two more trains at a later stage increasing overall capacity of Yamal LNG to 25 MTpa. Very recently Novatek signed an agreement with Gazprom which has a few big gas fields in the same area and is interested in tying up with Novatek to use Yamal LNG infrastructure once it is developed. We expect FID on Yamal LNG to be taken by the end of 3Q this year. We include a three-train Yamal LNG project in our global model with a potential start-up in 2018 and full production in 2019.

Shtokman LNG—mired in politics

Capacity 7.5 MTpa, green-field, first LNG target 2017

Despite the fortunes of Yamal LNG, Shtokman's partners recently announced another delay to FID. Potential tax breaks remain the stumbling block. The Russian government recently confirmed its reluctance to consider any tax breaks before the project's FID is taken. The project's participants on the contrary noted that without the certainty on the tax situation it is not possible to take FID. This tug of war should, in our view, continue through this year. We therefore expect further delays with the project and no news on FID at least till the end of 2012. We do not include Shtokman in our base case LNG supply forecasts, and classify it as "speculative".

Sakhalin II expansion—not enough gas

Sakhalin II—likely needs more gas to expand

Capacity 5 MTpa, brownfield expansion, first LNG target 2017–18

Gazprom and its partners are interested in increasing LNG production at Sakhalin II, Russia's only LNG exporting scheme with 9.6 MTpa of capacity. The partners are studying plans to build a US$5-7 bn third train at Sakhalin, but we understand there is not yet enough gas at Lunskoye to fill a train, so the partners would have to buy third-party gas (e.g. from Gazprom's Sakhalin 3 or Exxon's Sakhalin 1, where Exxon has enough gas but is unwilling to sell to Gazprom at domestic prices). In addition, Gazprom is also considering another LNG project, in neighbouring Vladivostok, which would compete with Sakhalin II T3 for feedstock. Given the prevailing uncertainty, we do not include Sakhalin II T3 in our base case LNG supply forecasts.

Other supply updates—Atlantic Basin

Brass LNG back on the table

Nigeria: Brass LNG getting headlines again

Capacity 10 MTpa, green-field (Nigeria), first LNG target 2017

After years in the doldrums, Brass LNG has made a comeback in the last one to two years, boosted by President Goodluck Jonathan's support for the project which would be located in his home state of Bayelsa. The plant—one of the few proposed LNG projects in the Atlantic Basin—is expected to have 10 MTpa of capacity from two trains with cost estimates ranging from US$8-18 bn (with the upper end sounding more realistic). Nigeria produces 22 MTpa of capacity from six trains at NLNG. The Nigerian government is keen to maintain the country's market share in LNG, set to fall from 8% in 2011 down to 5% by 2020 assuming no production expansion. NNPC's president suggested in February that FID on Brass could be taken in 2Q12; however, we believe FID is more likely to be taken at the end of 2012 or early 2013. The consortium is understood to have been marketing the gas aggressively to Asian buyers with a view to securing at least 80% of sales before FID. Current partners are NNPC (49%), Eni, Total and Conoco (17% each). NNPC has said it will sell 7% to Japanese utilities (Sumitomo and Sojitz: 4% and Itochu: 3%); however, it will only be able to close the sale until after FID approval (the more normal route would be to sign an initial equity sales agreement conditional on FID, with a drop dead date). We currently carry Brass as a "possible" project in our global gas model with a start-up in 2019 and full production in 2020. Recent media speculation suggests Conoco is considering exiting via the sale of its share in Brass LNG (not the most auspicious of signposts for the project, if true).

Meanwhile, NNPC is aiming for an FID at NLNG's long-delayed Train 7 in 2Q13—an ambitious target in our view given competition that NNPC's foreign partners are either involved in Brass too (Eni, Total) and are likely to prioritise Brass over NLNG, or focusing on LNG projects elsewhere (Shell). We continue to carry NLNG T7 as a "speculative" project in our LNG database (i.e. not included in our base case).

Norway: Snøhvit LNG expansion

Statoil's troubled LNG child—Snøhvit considering an expansion

Capacity 4.3 MTpa, brownfield expansion (Norway), first LNG target 2018–19

Statoil is aiming to add a 4.3 MTpa second train at its Snøhvit LNG facility. The decision whether to go for a T2 vs. a pipeline vs. a T1 lifetime extension is scheduled to be made in mid-2012. The amount of available gas for an expansion has risen following Statoil's recent Skrugard/Havis discoveries in the Barents Sea, some 100 km north of Snøhvit. Eni's nearby Goliat field could also provide gas to Snøhvit. Statoil targets a final investment decision in late 2013 with a start-up in 2018 at the earliest. Snøhvit Train 1 has been operating at sub-optimal rates ever since its start-up in 2008, but Statoil says it has learned from its experience as an operator and hopes that Train 2 could proceed more smoothly. The extra LNG would be targeted at Asian markets rather than Europe—indeed if Statoil wanted to target Europe, it would more likely build a 1,000 km pipeline to Norway and Europe. We expect marketing in Asia to be challenging given the operational challenges associated with T1, with Asian buyers placing a premium at delivery reliability Statoil operates and owns 36.8% of Snøhvit, Petoro 30%, Total 18.4%, GDF Suez 12% and RWE 2.8%. We currently carry Snøhvit T2 as "speculative" in our model.

Equitorial Guinea thinking about T2—but need gas…Ophir is busy drilling…

Equatorial Guinea Train 2—long-term option

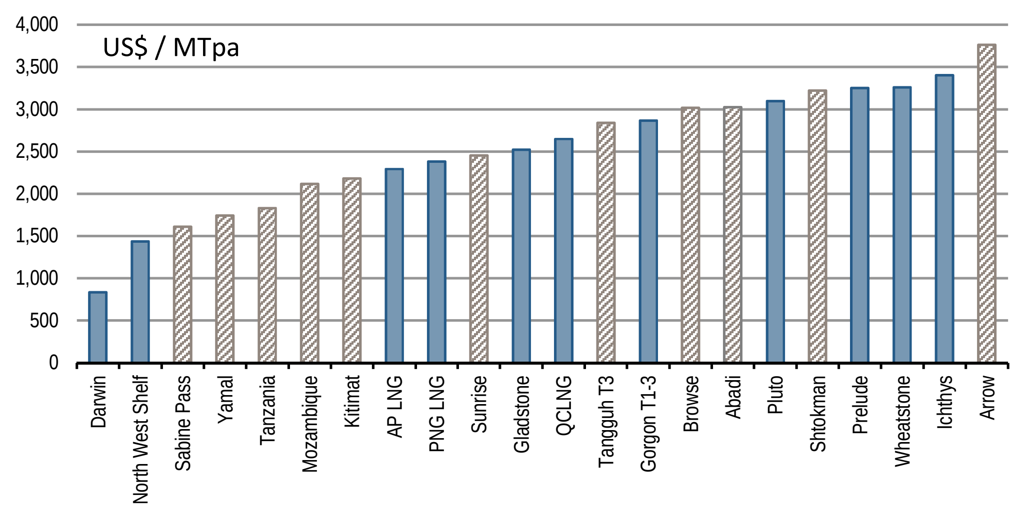
Capacity 4.4 MTpa, brownfield expansion (Equatorial Guinea), first LNG target 2017–18

The EG LNG consortium is aiming to build a US$4 bn second train at the EG plant on Bioko Island, using much of the existing infrastructure from the first train. The two main issues are (1) insufficient feedgas (only ~3 tcf so far vs. 5 tcf required) and (2) a lack of alignment between partners in EG LNG 1 and 2. Train 1 shareholders include Marathon Oil (60%), Sonagas, the national gas company of Equatorial Guinea (25%), Mitsui (8.5%) and Marubeni (6.5%), with 100% of the sales going to BG. A Memorandum of Understanding (MoU) signed in April 2011 envisages that participants of T1 will fund and operate T2, but it also gives the upstream partners the right to sell their respective gas entitlements as LNG at international market prices. Feedstock for Train 2 is expected to come from associated gas from Blocks I, O (operated by Noble Energy) and R (operated by Ophir), all located in Equatorial Guinea (to avoid cross-border issues). LNG would be marketed to Europe, Asia and South America. There is an aspirational FID target of 2013 but we think FID in 2014 followed by start-up in 2018 is more realistic. Ophir will drill three wells in Block R this year. We do not include EG LNG T2 in our global LNG supply model given the high degree of uncertainty (WoodMac assumes start-up in 2020).

Global LNG cost curve

We see East Africa and North American LNG projects are better-positioned than greenfield Australian projects from a cost-to-supply perspective in the race to secure off-take from LNG buyers and get to FID, with unit costs of US$1,500-2,200/tonne versus over US$2,500/t for greenfield Australian LNG, but caution that the cost-plus model has thus far not prevailed in the LNG industry.

Figure 29: **Global LNG cost curve—East Africa and North America well-positioned**
Total capital costs ($/tpa) until plateau—grey bars are pre-FID projects, blue are post-FID



Source: Company data, Credit Suisse estimates. NB: Only capex until first LNG.

Figure 30: LNG projects start-ups, 2012–25E (nameplate capacity in Mtpa)

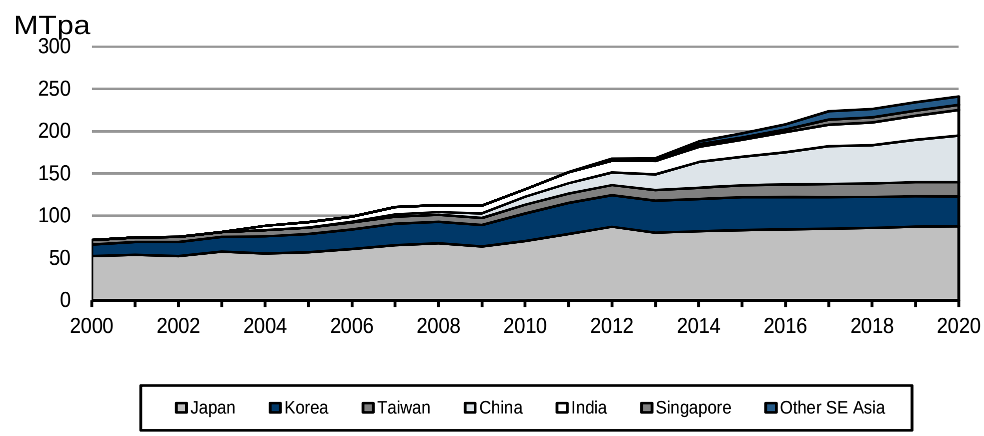
Country	Project	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Status
Construction & Possible																
Australia	Pluto LNG	2.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	Const.
Angola	Angola LNG	2.6	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	Const.
Algeria	Skikda expansion		3.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.4	Const.
PNG	PNG LNG			2.0	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	Const.
Algeria	Arzew GL3-Z				3.5	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	Const.
Australia	Gorgon LNG T1-3				7.5	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	Const.
Australia	QC LNG				4.0	7.0	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	Const.
Australia	Gladstone LNG				2.0	5.9	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	Const.
Indonesia	DS LNG				2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	Const.
Australia	AP LNG (Origin)					2.2	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	Const.
Australia	Ichthys LNG					4.2	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	Const.
US	Sabine Pass Export					7.0	9.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	Poss.
Canada	Kitimat LNG					4.0	5.0	5.0	5.0	7.5	10.0	10.0	10.0	10.0	10.0	Poss.
Australia	Pluto LNG T2						2.2	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	Poss.
Australia	Prelude FLNG						3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	Const.
Australia	Wheatstone						4.5	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	Const.
Australia	AP LNG (Origin) T2						2.2	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	Poss.
Australia	QCLNG Train 3						4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	Poss.
Russia	Yamal LNG							10.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	Poss.
Australia	Gorgon LNG T4							5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	Poss.
Indonesia	Tangguh T3								3.8	3.8	3.8	3.8	3.8	3.8	3.8	Poss.
Nigeria	Brass LNG								2.5	10.0	10.0	10.0	10.0	10.0	10.0	Poss.
Tanzania	Tanzania LNG								8.0	8.0	8.0	8.0	8.0	8.0	8.0	Poss.
Mozambique	Mozambique LNG								4.0	8.0	8.0	13.0	18.0	18.0	18.0	Poss.
Total Construction + Possible		**5.5**	**13.0**	**16.0**	**39.6**	**72.5**	**102.2**	**135.1**	**158.4**	**172.4**	**174.8**	**179.8**	**184.8**	**184.8**	**184.8**	
of which in Construction		**5.5**	**13.0**	**16.0**	**39.6**	**61.5**	**79.6**	**84.0**	**84.0**	**84.0**	**83.9**	**83.9**	**83.9**	**83.9**	**83.9**	
of which Possible						**11.0**	**22.6**	**51.1**	**74.4**	**88.4**	**90.9**	**95.9**	**100.9**	**100.9**	**100.9**	
Speculative																
Russia	Shtokman (Ph 1)						3.3	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	Spec.
US	Freeport Export						2.4	7.2	10.0	10.0	10.0	10.0	10.0	10.0	10.0	Spec.
US	Cameron						12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	Spec.
Brazil	Santos FLNG						3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	Spec.
PNG	PNG LNG T3						1.7	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	Spec.
Eq Guinea	EG LNG T 2							4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	Spec.
Australia	Pluto LNG T3							4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	Spec.
Norway	Snøhvit T2							4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	Spec.
US	Lake Charles							7.5	15.0	15.0	15.0	15.0	15.0	15.0	15.0	Spec.
US	Cove Point							2.5	7.8	7.8	7.8	7.8	7.8	7.8	7.8	Spec.
US	Corpus Christi							13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	Spec.
Indonesia	Abadi FLNG								2.5	2.5	2.5	2.5	2.5	2.5	2.5	Spec.
Russia	Sakhalin 2 T3								2.5	5.0	5.0	5.0	5.0	5.0	5.0	Spec.
Canada	Shell LNG Canada									2.5	12.0	12.0	12.0	12.0	12.0	Spec.
Australia	Sunrise LNG									4.3	4.3	4.3	4.3	4.3	4.3	Spec.
Australia	Wheatstone T3									4.5	4.5	4.5	4.5	4.5	4.5	Spec.
Iran	Iran LNG									5.3	10.5	10.5	10.5	10.5	10.5	Spec.
Nigeria	NLNG Train 7										6.0	8.4	8.4	8.4	8.4	Spec.
Angola	Angola LNG T2										2.5	5.0	5.0	5.0	5.0	Spec.
Australia	Browse										2.0	3.5	6.0	7.5	7.9	Spec.
Nigeria	Olokola											5.0	5.0	5.0	5.0	Spec.
Australia	Scarborough											3.0	6.0	6.0	6.0	Spec.
Australia	Bonaparte											2.0	2.0	2.0	2.0	Spec.
Iraq	Shell											2.0	4.5	4.5	4.5	Spec.
PNG	InterOil LNG											2.0	4.0	4.0	8.0	Spec.
Australia	Fisherman's L.												0.8	1.5	1.5	Spec.
Australia	Arrow												4.0	8.0	8.0	Spec.
US	Alaska Valdez												10.0	20.0	20.0	Spec.
Total Speculative							**22.3**	**69.4**	**90.0**	**109.0**	**134.2**	**154.6**	**179.4**	**195.6**	**200.0**	
Total additions		**5.5**	**13.0**	**16.0**	**39.6**	**72.5**	**124.5**	**204.5**	**248.4**	**281.4**	**309.0**	**334.4**	**364.2**	**380.4**	**384.8**	

Source: Company data, Credit Suisse estimates

Demand update

Japan between a rock and a hard place: Japanese nuclear re-starts have faltered and we increase our 2012 Japan LNG demand forecast to 87 MTpa (+10 MTpa YoY, +17 MTpa 2012 vs. 2010). Unlike both Korea and Taiwan which are committed to 7 MTpa post Fukushima to meet near-term demand, Japan is still not blinking. We forecast the entire 20% of Japan's 2012 LNG requirements will have to be met from non-contract sales. With the Qatar deal, plus additional Yemeni supplies and as Brunei Korea looks set to limp through its near-term shortfall, Taiwan is reasonably well supplied through 2015 but will need to contract for the latter part of the decade. We continue to be incremental demand bears in China, but include placeholder 10 MTpa demand post 2017 for supplies linked to material equity purchases (a la APLNG). In India we step up our forecast, to 20 MTpa in 2015 and 30 MTpa by 2020, assuming high spot prices will curtail capacity usage until the second half of the decade, when lower crude prices drive a lower absolute spot price environment. Plans for new country regas in South East Asia abound, but the recent change of plans in Indonesia demonstrates the mercurial nature of this demand. In Europe Qatar redirections to Asia softens demand, waiting for Angola and Algeria while demand in LatAm, specifically Argentina, looks set to grow, but the question arises as to whether political actions spook spot cargoes arriving.

Figure 31: **CS: APAC geographically segmented LNG demand 2000–20E**

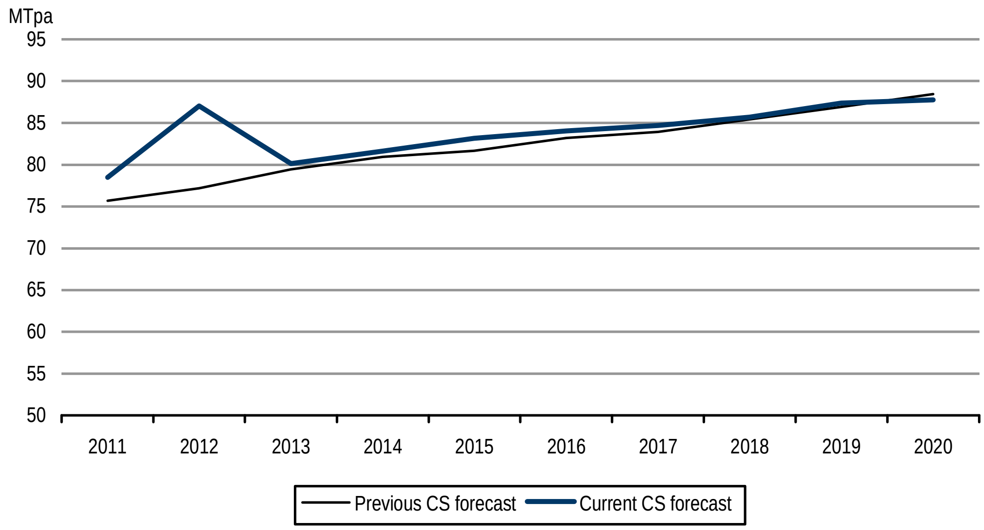


Source: Credit Suisse estimates

Japan—87 MTpa in 2012, as nuke re-starts stall

Japan—we adjust our base case LNG forecast: 2011 saw total LNG imported at 78.5 MTpa vs. long-term contracts of 66 MTpa, and 8.5 MTpa higher YoY. Given the inertia around nuclear re-starts in the near term we adjust our 2012 LNG demand forecast up to 87 Mtpa, an increase of 10 MT versus our previous forecast. With re-starts of some of the newer nuclear facilities in 2013 we forecast LNG demand in that year to be 80 Mtpa, then raising to 83 MTpa by 2015 and to 88 MTpa by 2020.

Figure 32: **CS old versus new Japan LNG demand forecast 2011–20E**

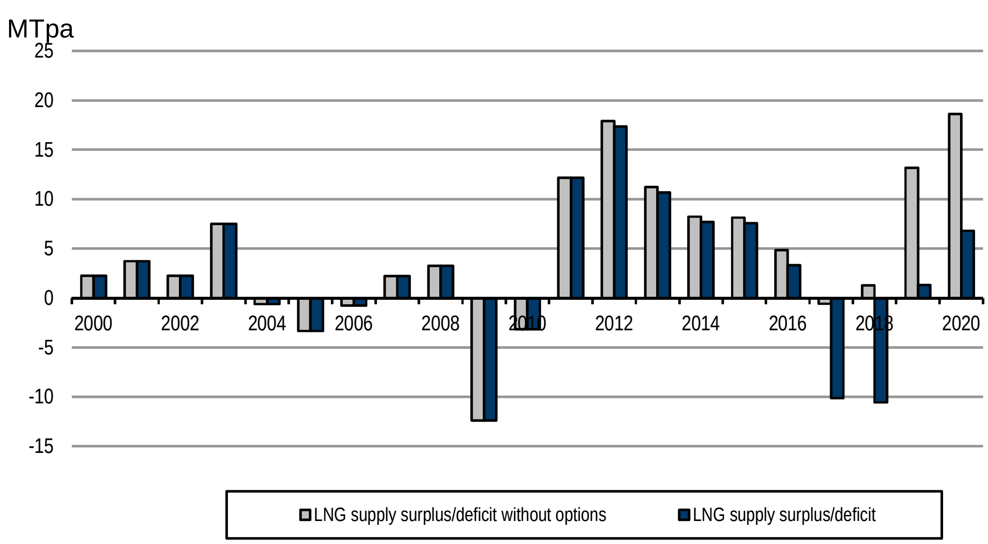


Source: Credit Suisse estimates

Japanese un-contracted demand: 2012 is a hump year: Given the on-going domestic inertia around the nuclear re-start issue our increase in LNG demand in 2012 leads to a hump year for un-contracted demand this year (some 18 MT—6 MT more than in 2011). This represents entire 21% of total demand, a new record for Japan. Our forecasts suggest that un-contracted demand falls to zero by 2017 (Ichthys's first gas plus Brunei extension plus 1.2 MTpa from Qatar) before the demand window re-opening to nearly 15 MTpa in 2019 and 20 MTpa of four trains by 2020.

21% of 2012 demand will have to come from non-contracted sources

Figure 33: **Japan—CS forecast un-contracted LNG demand 2000–20E**

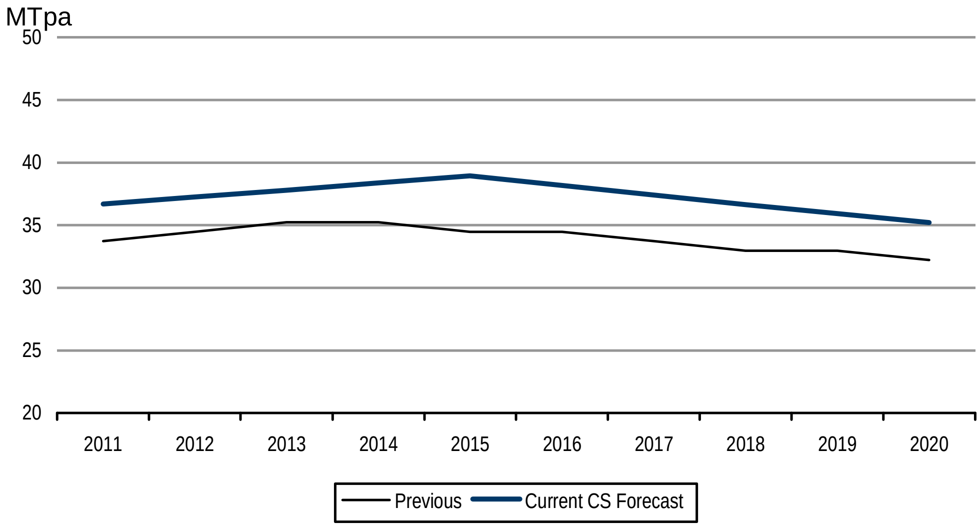


Source: Credit Suisse estimates

Korea—also showed significantly stronger growth in 2011 recording full-year demand of 36.7 MTpa, an increase of 4.1 MTpa YoY and a full 3 MTpa above our previous forecast. We adjust our forecast to reflect 1.5% pa growth until 2015, and a 2% pa decline thereafter.

Demand also stronger in Korea in 2011 than expected

Figure 34: **Korea: CS forecast LNG demand 2011–20E**

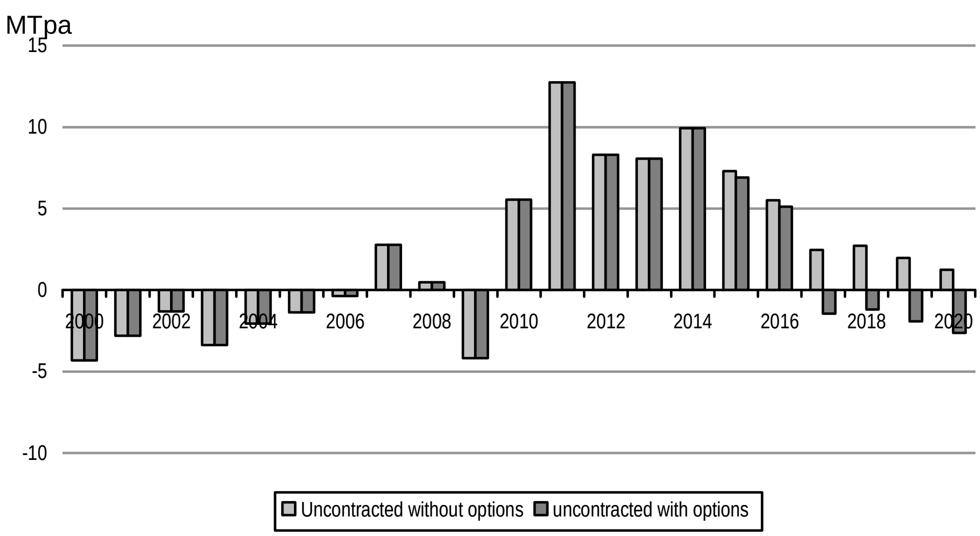


Source: Credit Suisse estimates

Korea un-contracted demand still front end loaded

Korea still needs 5-10 MTpa for the next five years: Despite the 4 MTpa deal with Rasgas to 2016, 1 MTpa additional from Yemen for the next two years and an increased extension of the Brunei contract, Korea still requires 5-10 MTpa above its current contracted amount for the next five years. This falls in the latter part of the decade as demand growth stalls and the Cheniere deal starts to supply. 2012 appears slightly less stressful for Kogas with 84% of demand contracted for—versus 71% in 2011—with un-contracted demand declining through the remainder of the decade, moving above 90% by 2015. Our base numbers assume Korea stays on course for nuclear expansions in the latter part of the decade, but a political shift to the Democratic United Party (DUP) would put this assumption at challenge. The April elections left the ruling party in place, but by a far diminished majority vs. the DUP.

Figure 35: **Korea—un-contracted LNG demand 2000–20E**

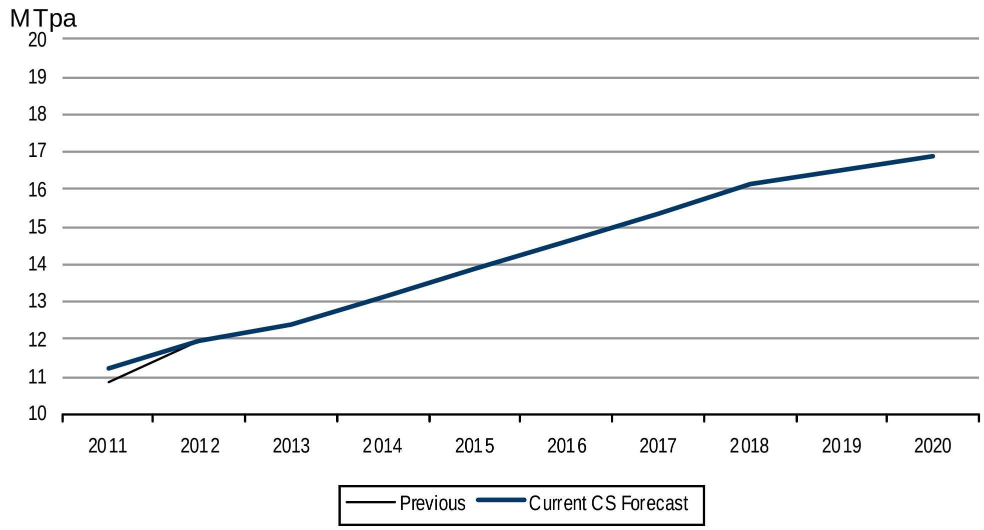


Source: Credit Suisse estimates

New seller/new buyer in Korea? Korea Midland Power Company (Part of KEPCO) has reportedly signed a 0.4 MTpa final contract with Vitol for supply between 2015 and 2024. The LNG is scheduled to be received at POSCO's LNG terminal. With a lack of clarity of Vitol's supply point we reflect this deal as an 'option' in our Korea demand-supply balance.

Taiwan—demand profile largely unchanged: We adjust the 2011 actual, which came in 0.5 MT higher than our previous forecast but leave 2012 forward unchanged, already reflective of ongoing nuclear challenges.

Figure 36: **Taiwan: CS' previous and current LNG demand forecasts 2011-20E**

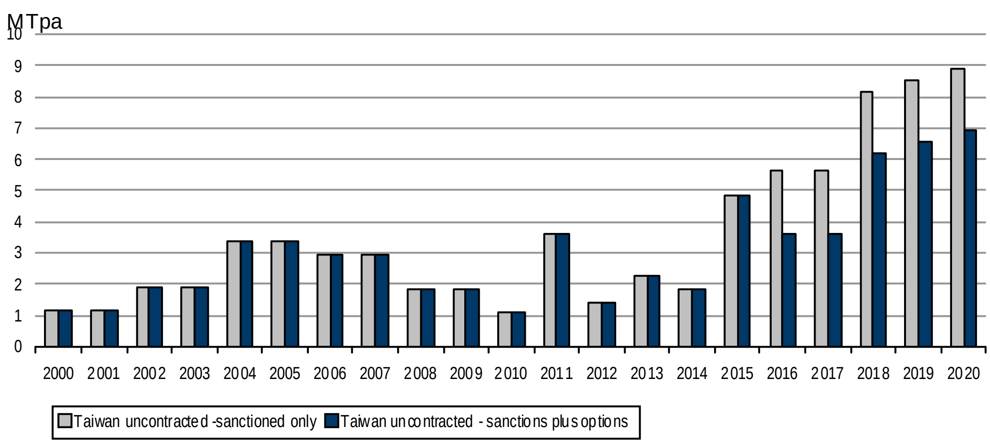


Source: Credit Suisse estimates

Recent deals leave Taiwan largely contract supplied to 2015: As a result of the 3 MTpa deal with Rasgas (falling to 1.5 MTpa in 2016) Taiwan is largely contract supplied to the middle of the decade—running a 1–2 MTpa deficit until 2015. For the second half of the decade Taiwan will need one to two trains of new contracts, as long as demand growth eventuates as per our forecast.

Post the Qatar deal Taiwan is reasonably well supplied up to 2014

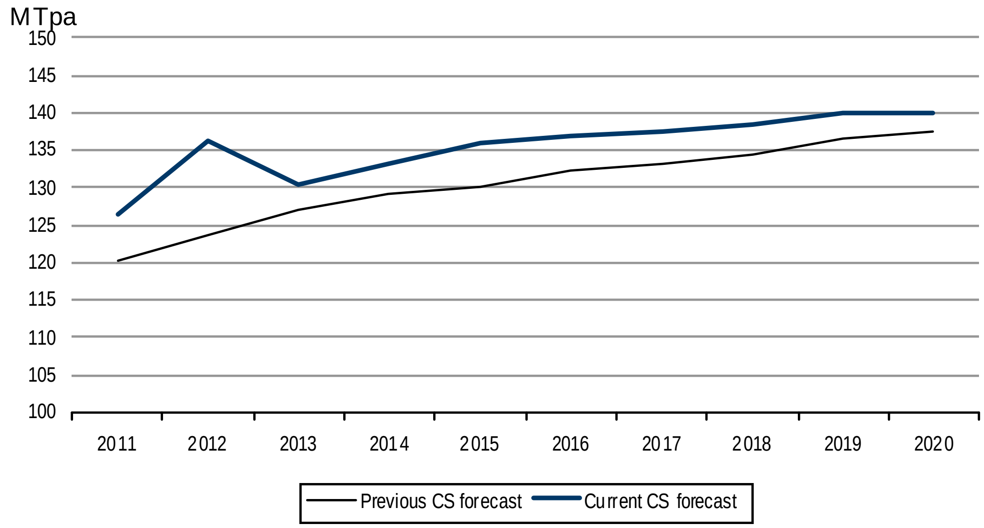
Figure 37: **Taiwan: CS forecast un-contracted LNG demand 2000-20E**



Source: Credit Suisse estimates

N Asia 'Big 3': Japan 2012 shortfall is the major change: Aggregating the big 3 N Asia buyers the main change to our previous forecast is the recognition of significantly larger demand in 2012 in Japan, with higher starting points in 2011 for both Japan and Korea; however, in outer years the total demand forecast has only risen 2–5 MTpa.

Figure 38: **Japan/Korea/Taiwan: Previous & current CS LNG demand forecast 2011–20E**

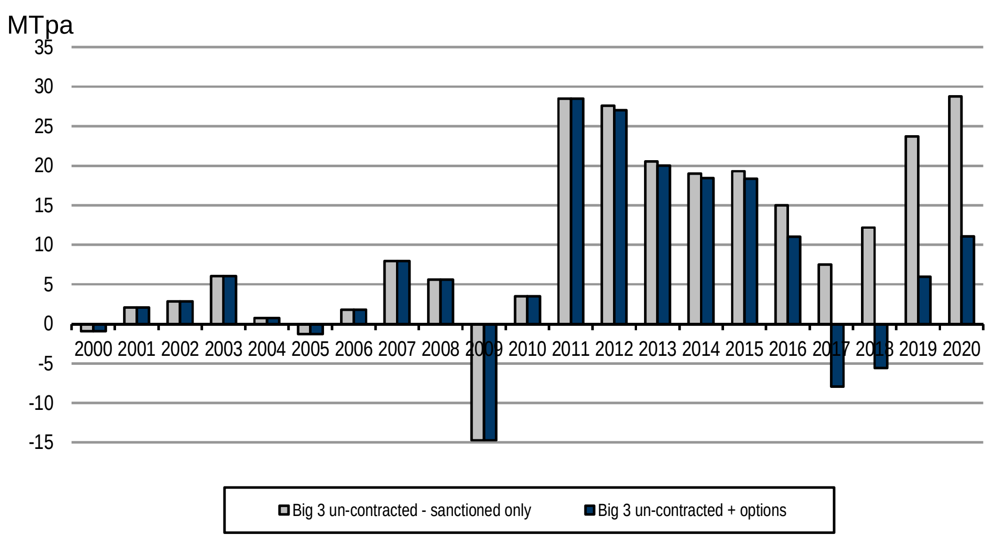


Source: Credit Suisse estimates

N Asia big 3: 30 MT shortfall in 2012, falling to 20 MT into mid-decade: Taking N Asia as a whole the near-term shortfall is nearly 30 MT this year, as high as last year, clearly signalling ongoing spot price strength.

Traditional N Asian buyers (plural) still require 20 MTpa to 2015

Figure 39: **N Asia big 3 un-contracted demand 2000-20E**

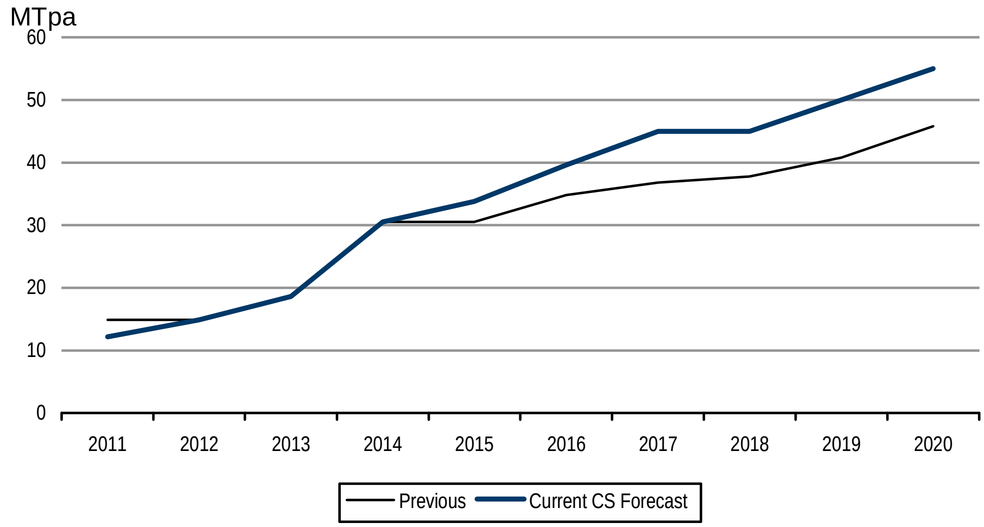


Source: Credit Suisse estimates

China—we remain LNG demand bears for China going forward: As laid out in CS' Global Gas report, *From tight to loose*, in November last year we continue to believe China is focused on understanding its domestic unconventional gas opportunity, from both an input cost and energy security perspective. As a result we believe further LNG purchases will be marginal over the next 24 months as the shale 'adventure' builds pace. We lift our previous forecast by broadly 10 MTpa from 2017, or two trains, building demand space in the anticipation that one or more of the Chinese entities take equity in a project/projects. Our logic remains that China would buy significantly more LNG at lower LNG prices, and that 'equity' LNG offers that opportunity—the challenge is finding LNG projects that will offer scale equity participation for LNG off-takers.

We remain cautious of incremental Chinese LNG demand going forward

Figure 40: **China: CS previous vs. current LNG demand forecast**

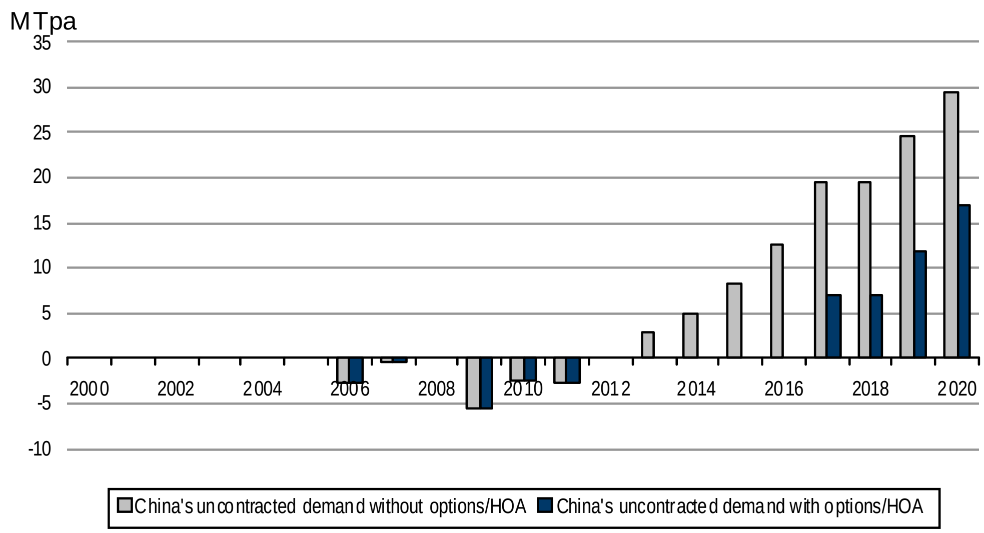


Source: Credit Suisse estimates

We expect further Chinese LNG purchases to need to be linked to significant equity participation

Un-contracted demand—marginal pre 2017, once APLNG take FID: We expect, with Sinopec's decision to increase its commitment to 7.6 MTpa with APLNG, the project to be sanctioned in the very near future. This un-contracted demand would be marginal until 2017 when the increase in demand described in the previous paragraph creates a two-train un-contracted gap which we suspect will be met by further equity participation in LNG projects, possibly in Canada (CNOOC / Kitimat and or PetroChina / Shell Kitimat project), or East Africa.

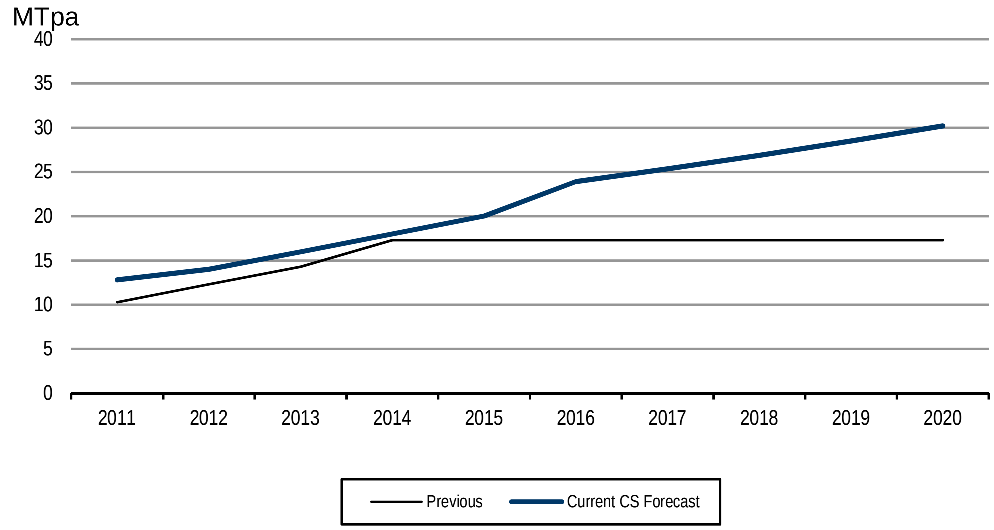
Figure 41: **China—un-contracted demand forecast 2000-20E**



Source: Credit Suisse estimates

India—significant tweak to long-term demand: India recorded 12.8 MTpa LNG demand in 2011—2.5 MTpa higher than our previous forecast. We reflect this, but continue to use our expectation of receiving capacity as the leading indicator of actual demand in India. Our forecast is broadly unchanged to 2015 taking into account regas constraints and our assumption of high crude oil, contract and spot LNG prices in Asia. With CS forecasting crude correcting to US$90/bbl (2012 $) in 2015, we expect a greater degree of spot cargo affordability in the latter part of the decade in India—driving the change to our forecast.

Figure 42: India: CS previous and current LNG demand forecast 2011-20E



Source: Credit Suisse estimates

More LNG terminals: Several upgrades/new terminals have been announced in India post the success of Petronet and the disappointments at D6. Shell, at Hazira, is looking to debottleneck to 5 MTpa from the current 3 MTpa over the next two to three years. Petronet's Kochi terminal is also expected to increase to 5 MTpa (from the initial 2.5 MTpa) around 2015/16, while the Dahej terminal is expected to increase to 15 MTpa by 2015 from the 12.5 MTpa it is likely to be by end-2013. If GAIL proceeds with the construction of the breakwater, the Dabhol terminal can also add c.3 MTpa of capacity by 2015/16.

On the Indian East Coast, Petronet has announced initial approvals for a new 5 MTpa terminal, while GAIL and GDF have announced a 3.5 MTpa FSRU implementation by 2014.

GSPC's 5 MTpa Mundra LNG project remains stuck as does Indian Oil's proposed Ennore terminal. Swan Energy is awaiting environmental clearances for a 3 MTpa FSRU at Pipavav as well.

Figure 43: India LNG import capacity plans

Company	Location	Proposed capacity addition (MTpa)	Likely commissioning	Likelihood
Petronet LNG	Kochi	2.5	2013	High
Petronet LNG	Dahej	1.0	2014	High
Petronet LNG	Dahej	2.5	2015	High
Petronet LNG	Kochi	2.5	2015/16	High
Petronet LNG	Gangavaram	5.0	2016/17	Medium
Shell	Hazria	1.5	2014/15	Medium
GAIL	Dabhol	1.5	2012	High
GAIL	Dabhol	3.5	2016	Medium
GAIL (FSRU)	East Coast	3.5	2014	Medium
Sub total		**23.5**		
GSPC	Mundra	5.0		Low
Swan Energy	Pipavav	3.0		Low
IOC	Ennore	5.0		Low
Sub total		**13.0**		

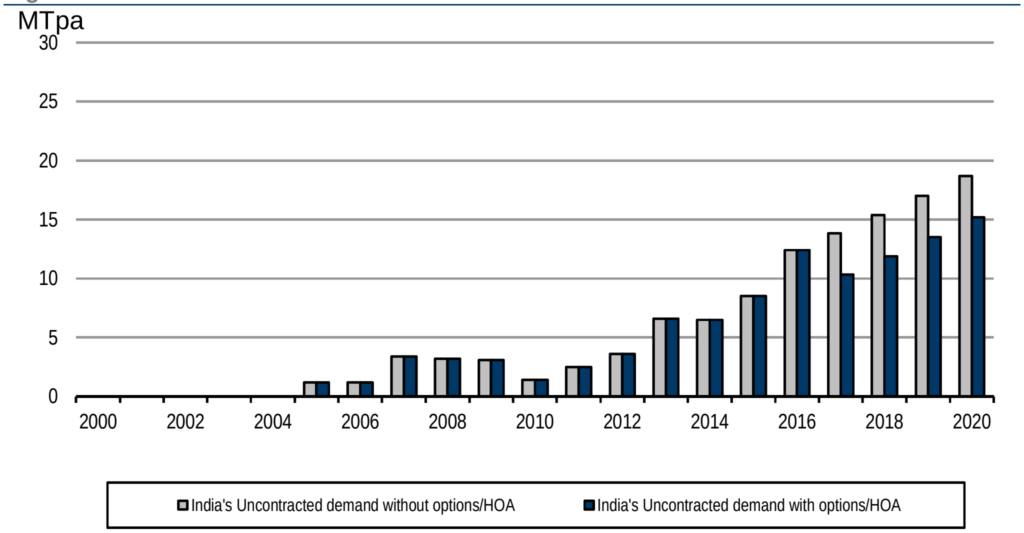
Source: Company data, Credit Suisse estimates

We count 10 MTpa of relatively firm LNG import capacity adds in India over the next four years. A large portion of this is likely to operate on spot volumes in the short term. A combination of (1) increased competition among import terminals, (2) a potential decline in

LNG contract prices and (3) improving domestic gas production may force some of these terminals to lock in customers and supply through long-term contracts.

India has met demand with short-term supply historically: Since LNG imports began in 2005 India has imported 1-3 MTpa on a non-contract basis. We reflect the Sabine Pass deal as an option prior to formal project sanction, but expect it to go forward. If it does then India needs to contract circa 2 MTpa from 2017 forward, and 5 MTpa pre 2017 i.e. it may consider, a la Korea and Taiwan a front loaded supply contract, from Qatar.

Figure 44: **India: Un-contracted LNG demand 2000-20E**

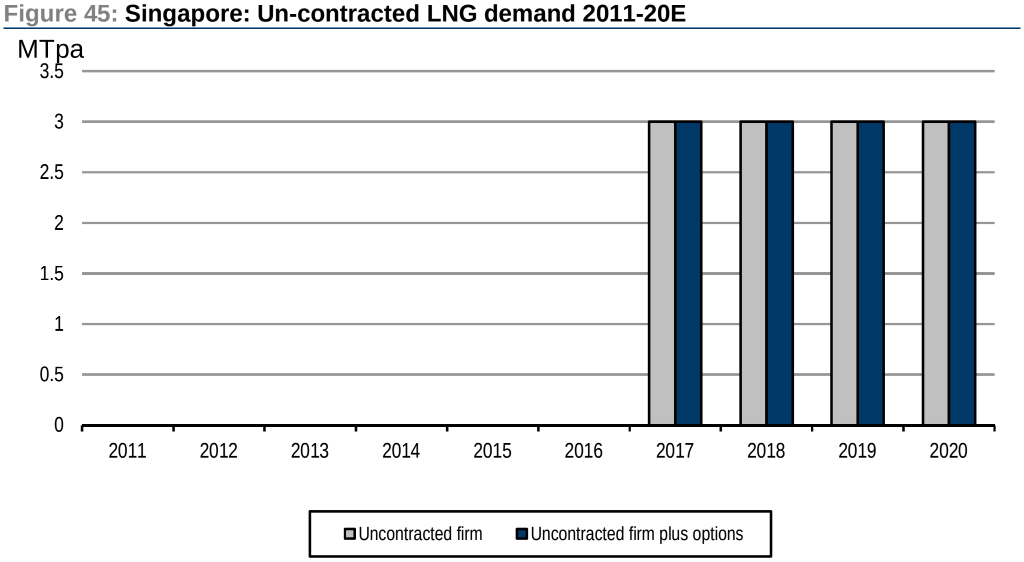


Source: Credit Suisse estimates

Singapore—2017 3 MTpa un-contracted demand to compete for: Singapore is actively considering the expansion of its LNG facilities currently being constructed to receive gas next year. This will be an attractive opportunity for LNG sellers capable of meeting the 2017 (CS est.) supply window.

Singapore: likely looking for another 3 MTpa—supply reliability will be key

Figure 45: **Singapore: Un-contracted LNG demand 2011-20E**



Source: Credit Suisse estimates

Other SE Asia—no progress on firm supply contracts thus far: We largely leave our un-risked and risked demand assumptions in place for the numerous regas projects in Malaysia, Thailand, Vietnam (changed from 2.1 MTpa to 1 MTpa on updated information), Bangladesh, Indonesia and the Philippines. These are clearly opportunity markets for LNG supply projects, but with no LNG history, no infrastructure and challenged end-user prices we continue to consider these projects as less attractive to LNG sellers vs. established markets.

Indonesia: Government review throws the projects back up the air

In Indonesia a broad-based review of LNG regas plans has halted the development of the Semarang terminal in Central Java, given a conditional green light to the conversion of the Arun LNG liquefaction facility and the relocation of Belawan terminal to Lampung in South Sumatra. However, final approvals for this significant change in plans is still pending. We carry 4.5 MTpa as onshore regas proposed capacity from 2016, with a placeholder 4 MTpa as temporary floating regas capacity (2 MTpa from 2013, 4 MTpa from 2015). It is quite possible that the Domestic Market Obligation (DMO) for suppliers to the Bontang facility, along with the proposed T3 at Tangguh and DS LNG may have to make up for 25% of total LNG production available to meet domestic off-take into these terminals.

Malaysia: Malacca terminal about to start up—already contracted for

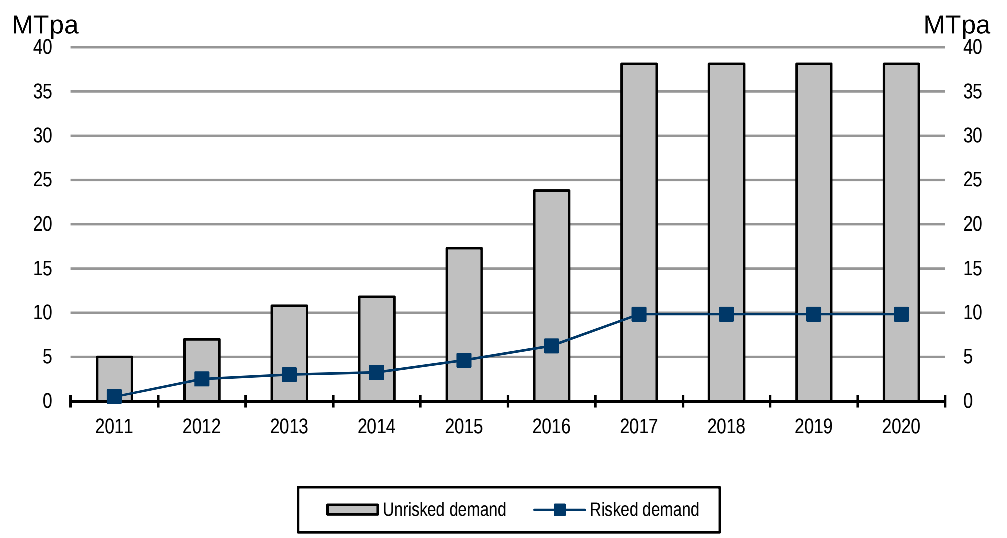
In Malaysia the Malacca terminal is due to start up mid-year 2012, with an operational capacity of 3.8 MTpa and supply contracts to meet that capacity to 2035 (the majority coming from Santos's GLNG green-field under construction in Queensland). We treat this off-take as firm contracted in our model.

Thailand: Putting the terminal in front of the horse…

In Thailand, Map Ta Phut terminal (phase 1) is now operational but, with no long-term supply contracts, it is receiving only spot cargoes (and running with very low utilisation). PTT has indicated plans to expand the terminal from 5 MTpa to 10 MTpa capacity as early as 2015, but we suspect this is less than firm, given the nearer-term challenge to secure long-term contractual supplies for the first phase.

And the rest three projects (Mashal, Pakistan GasPort and Port Qasim) in Pakistan all appear stalled at the moment, with no clear go forward or gas supply. In Bangladesh a 5 MTpa FSRU is proposed to be located south of Chittagong and an MoU is understood to be in place with Qatar Petroleum for 4 MTpa. We use 2014 as a placeholder for the commencement of operations and assume QP will be the supplier (hence recording 1 MTpa un-contracted demand from that year). We continue to reflect three potential regas projects in the Philippines with a gross off-take target of 5.3 MTpa starting in 2017.

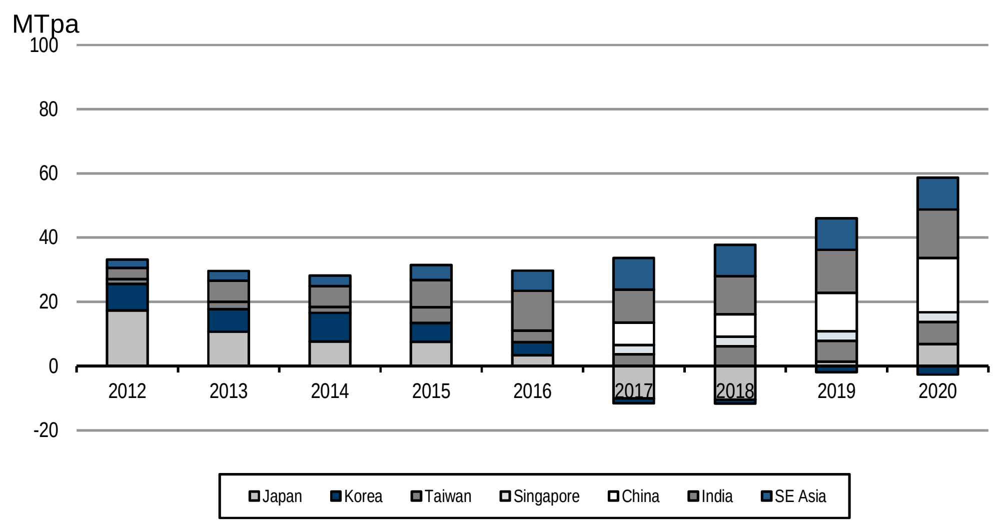
Figure 46: **SE Asia (ex Singapore) un-risked and risked demand**



Source: Credit Suisse estimates

APAC as a whole: N Asia in the near term—Japan at the end of the decade: Demand in the near term (2012-16) continues to be dominated by the traditional N Asian buyers, with Japan increasingly exposed as it struggles to re-start its nuclear fleet. For Korea we see little un-contracted demand in the latter part of the decade, whereas for Taiwan the near-term requirement is largely met. In 2016-17 China may emerge with avails, but in our view this is predicated on its ability to buy into LNG projects thus accessing equity LNG (with significantly lower delivered costs vs. 'headline' LNG). Japan becomes important again in the final two years of the decade, requiring a further four trains of LNG at that time.

Figure 47: **APAC geographical un-contracted demand: 2012-20E**



*Source: Credit Suisse estimates * NB – this represents the un-contracted demand including options*

European LNG demand

European LNG demand is a tricky one to forecast—unlike in the traditional markets of Japan-Korea-Taiwan where LNG imports are equal to the country's gas demand, Europe produces gas domestically and imports piped gas from a variety of sources (Russia, Norway, North Africa, etc.). Therefore, European LNG imports are a function not just of demand, but domestic production (e.g. North Sea outages) and exporters' strategies to maximise revenues (e.g. Gazprom's and Statoil's price/volume policy). Over the past ten years, LNG has gained market share as customers have sought alternatives to Russian imports and domestic production declined. From 2000 to 2010, imports rose 10% p.a. while overall gas demand was up only 1.7% p.a. Going forward, we continue to believe European customers will prioritise LNG over more expensive gas sources since LNG is often priced off UK NBP (cheaper than oil-linked gas from Gazprom or Statoil) and allows for supply diversification away from Russia.

In the long term, we expect Euro gas buyers to lean towards LNG

In the near term, we believe European LNG demand growth could slow as Libya returns, and LNG sellers divert cargoes away from Europe into Asia. Qatar is the only swing supplier of LNG between Europe and Asia. Until recently, it was sending significant amounts of spot LNG to Europe, deliberately "tightening" the APAC market while waiting to secure new long-term contracts in Asia. But Qatar has managed to sign three contracts totalling 8 MTpa with Asian customers this year (Korea, Taiwan and Japan) and has thus started to redirect cargoes away from Europe to Asia. LNG imports to the UK from Qatar are down ~20% in January-February 2012 versus December 2011. While up to 15 MTpa (~2 Bcf/d) of flexible LNG could be directed away from Europe to Asia, we believe only contracted volumes are coming into Europe at the moment.

Short-term Qatar diversions to premium APAC markets will soften EU demand

LNG demand growth from Europe should resume as and when new Atlantic LNG capacity starts up, e.g. from Angola LNG, Algeria (Skikda expansion and Arzew), Yamal (Russia) and Brass (Nigeria), as Europe will be able to compete with Asia thanks to lower transport costs. We currently forecast European LNG demand to grow c.4% p.a. from 2010 to 2020 but there will be a period of slower growth while Asia pulls marginal LNG cargoes.

Other LNG demand

New LNG markets in Latin America and the Middle East should continue to grow, albeit from a small base. These markets made up just 4% of global LNG demand in 2010, and we forecast this to grow to c.8% by 2015. Latam and MidEast LNG imports are already changing trade patterns as demand in these regions is counter-seasonal relative to the northern Hemisphere (MidEast demand is higher in the summer for air conditioning). In the **Middle East**, Kuwait and Dubai started importing LNG in 2009 and 2010, respectively. Other MidEast countries which could join the club of LNG importers in the medium term (2013-14) include Bahrain, Jordan, Abu Dhabi and possibly Israel.

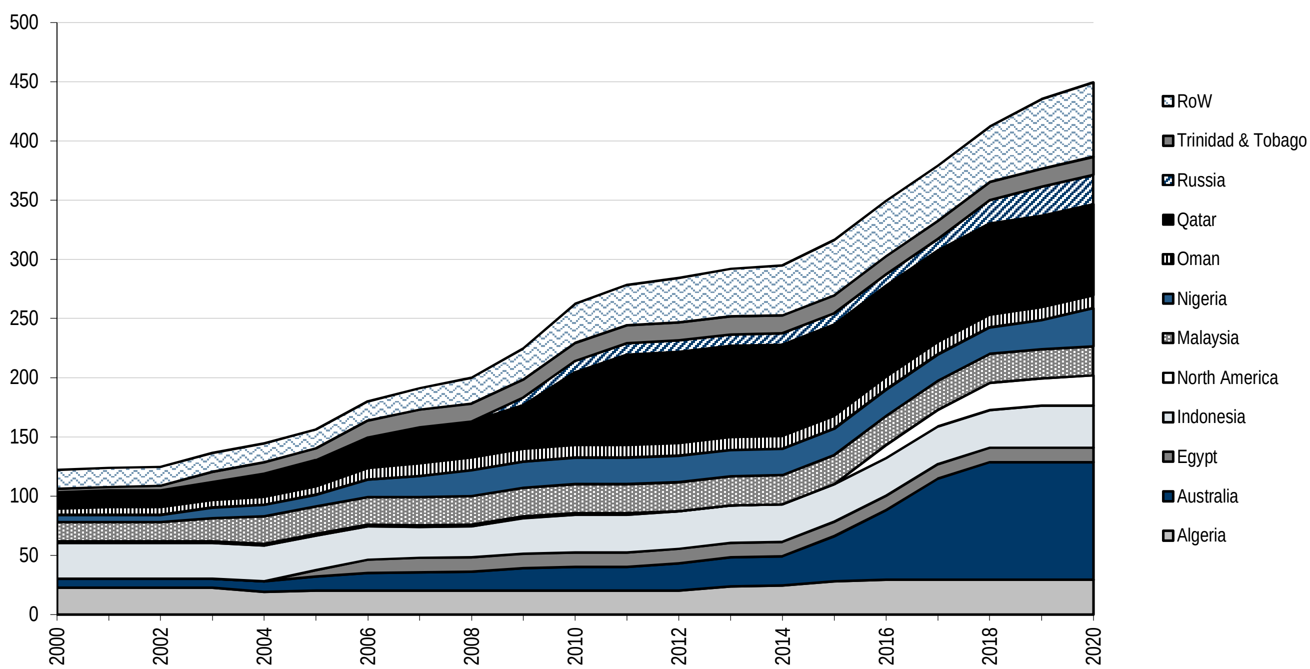
MidEast demand continues to grow as the summer weighted gas shortfall grows

In **Latin America**, we expect **Argentina** to import growing volumes of LNG in 2012 after already doubling imports in 2011 (80 cargoes in 2012 vs. 56 in 2011), as domestic gas demand soars and indigenous production lags. Despite attractive pricing (Argentina is willing to pay Henry Hub + a US$13/mmbtu premium), the question is whether the country will find enough willing LNG sellers after having nationalised YPF in March, spooking international investors. We understand that BG is asking Argentina to pre-pay for the cargoes as additional security post-YPF nationalisation. In 1Q12, Latin America made up almost a quarter of BG's LNG cargo deliveries. **Chile** is aiming to increase LNG imports by expanding the existing Quintero regas terminal and/or building a new floating storage and regasification unit (FSRU). Chile expects to pay around US$14/mmbtu for LNG and aims to reduce LNG import costs by buying LNG from planned US Gulf Coast LNG export projects.

Demand growth in LatAm—but has Argentina spooked sellers?

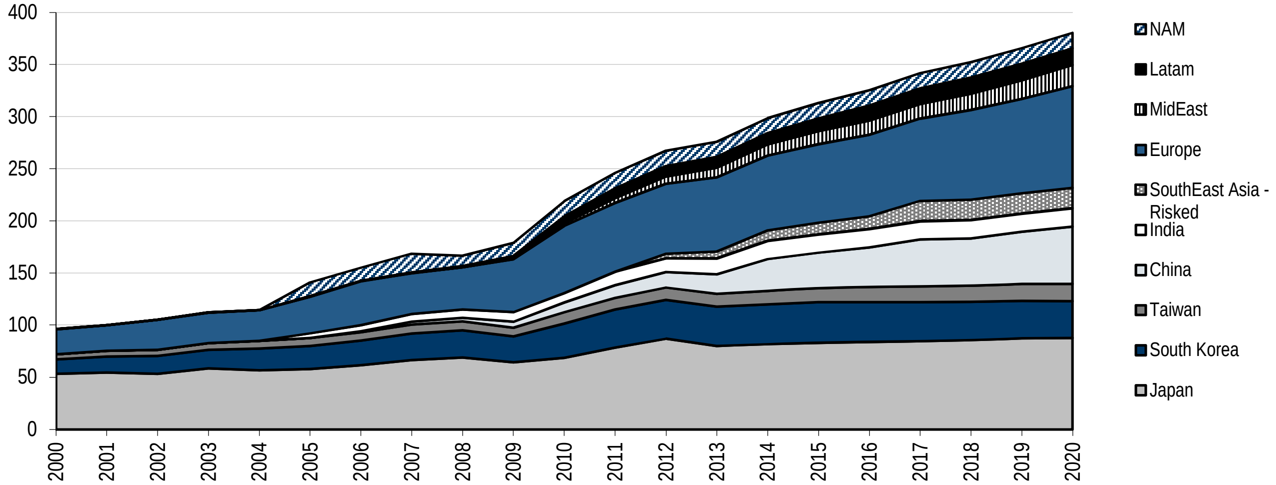
Bringing it all together: Global LNG supply and demand balance

Figure 48: Global LNG supply by country—Credit Suisse base case
Nameplate capacity in MTpa



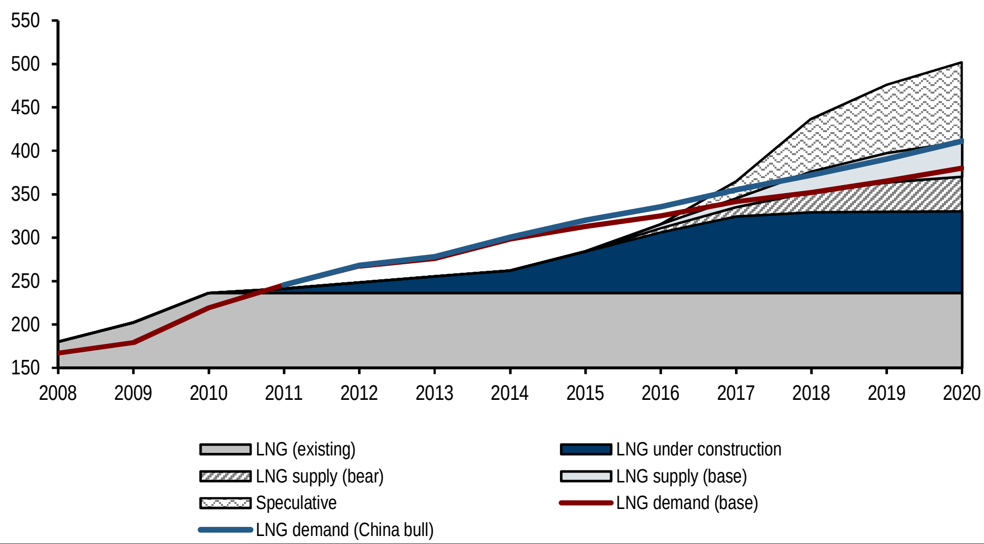
Source: Wood MacKenzie, BP Statistical Review, Credit Suisse estimates

Figure 49: Global LNG demand by country—Credit Suisse base case
in MTpa



Source: BP Statistical Review, Credit Suisse estimates

Figure 50: Global LNG demand vs. potential supply (in MTpa)

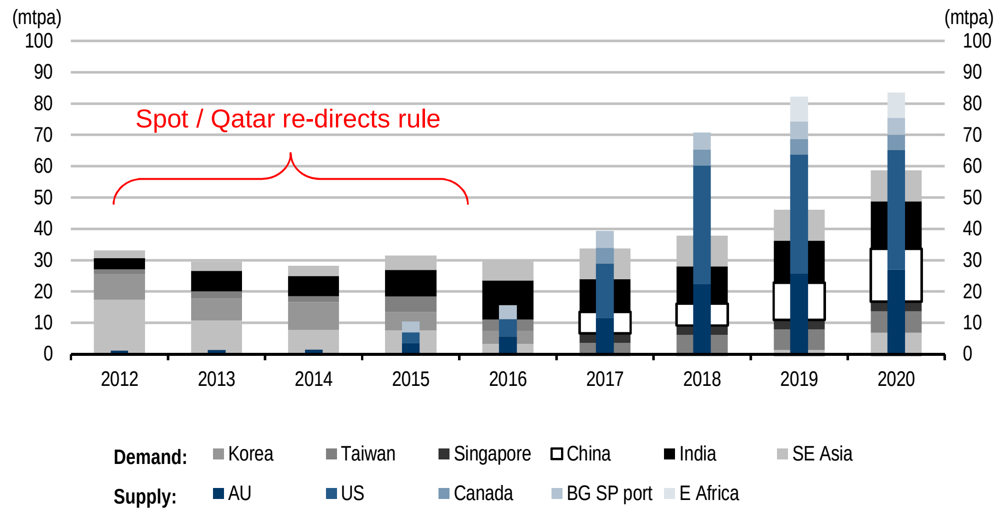


NB: China bull demand case assumes that 30% of additional gas demand is met by LNG
Source: Company data, Credit Suisse estimates.

Contract strategy/price:

Write off the Asian price premium at your peril—In the short term, the dramatic supply shortfall in APAC will support highly correlated contract prices, with spot price moderating and occasionally exceeding contract prices. The question is how much more short-term supply Qatar can convert into long-term contracts. In the medium term (2017-18), un-contracted supply exceeds un-contracted demand, and that demand is largely from new markets and price-sensitive buyers. We expect supply projects with strong marketing propositions will wait to sell into the Japan un-contracted window in 2019–20, trading-improved flexibility conditions for buyers to preserve significant crude price correlation, and the new price-sensitive demand segment to the supply projects with less compelling marketing propositions. Our price forecast therefore continues to predict that the Asian LNG price premium prevails through to the end of the decade.

Figure 51: **APAC un-contracted demand/marketable un-contracted supply 2012-2020E**



Source: Credit Suisse estimates

Security of supply focus and seller concentration has led to crude price linkage for LNG in Asia

Historically, security of supply/delivery has been the most important factor for traditional Asian LNG buyers, driven by an illiquid spot market, pass-through pricing and the need to ensure completely reliable end-user supply. These three factors have supported the highly-correlated crude prices for contract LNG in Asia. The cosy club of LNG developers, super-majors and a few 'specialists' (BG, WPL) have fully embraced the buyer's drivers, enjoying super-normal rent in good times and using crude price linkage to offset soaring unit development costs in recent years. In this section, we examine APAC buyer-drivers in the next phase of LNG procurement.

Figure 52: **CS perception of APAC buyer-drivers**

	Security of supply	**Reserves certainty**	**Price**	**Credible supplier**	**Supply flexibility**	**'Lean' vs. rich gas**	**Buyer equity participation**
Japan	Key	Key	'Nice to have'	Important	Increasingly important	Manageable issue	'Nice to have'
Korea	Important	Important	Important	Somewhat important	Somewhat important	Manageable issue	Important
Taiwan	Important	Important	Important	Somewhat important	Somewhat important	Manageable issue	'Nice to have'
China	Important	Important	Key	Important	Less important	Less important	Important
India	Less important	Less important	Key	Less important	Less important	Less important	'Nice to have'
Singapore	Key	Important	Less important	Important	Less important	Manageable issue	Less important
Other South East Asia	Less important	Less important	Key	Less important	Less important	Less important	Less important

Source: Credit Suisse estimates

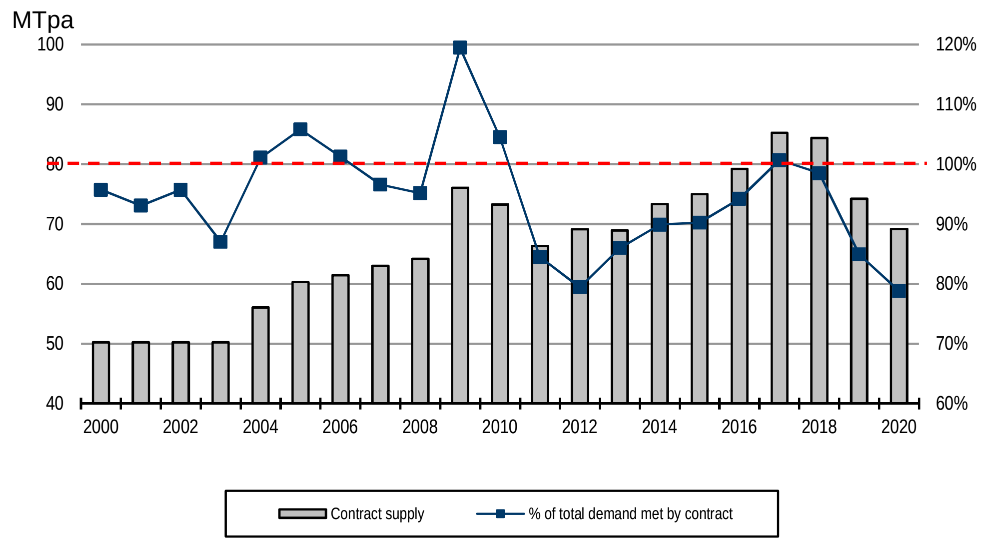
Japan—Will supply security still prevail? We think it will. While there have been recent quotes from METI talking about taking advantage of low cost and increasingly flexible LNG supplies from the US, the reality is that utilities/gas Co's are charged with supply reliability in their operating areas, and we believe they will continue to prioritise this over price. The Japanese buyers also play the long-game, and know that pricing differentials are volatile, remembering that ten years ago, US gas prices were higher than Asian landed-LNG. We therefore expect Japanese buyers to continue to focus on supply security, and expect that in return for continuing a strong crude price linkage look for supplies, to increase the flexibility terms for new LNG contracts starting supply at the end of the decade.

Japan—we think JCC pricing will prevail—but flexibility may increase

Japan: Lots of work to do if contract cover matters—Japan values energy security and the contracting strategy of both utilities and gas distribution companies has reflected this historically, with long-term contract cover in the 90–100% range. However, given the slow re-start of the nuclear fleet, we estimate Japan will need to source 20% of its 2012 LNG requirements from the spot/short-term market. The clear option for Japanese buyers in the short/medium term is the contract with Qatar; however, this brings premium pricing and Qatar is thus far determined to seek long-term contracts.

2012 will be a challenging year for Japan viz. LNG supplies

Figure 53: **Japan—Demand covered by long-term contracts; 2000-2020E**



Source: Credit Suisse estimates

Japan: Two demand-windows need to be addressed— 2012–2016 (pre-Ichthys) and then again the 2019-20 window. What Japanese buyers want to achieve is 'surviving' the first demand window without giving away the un-contracted demand in the second demand window (and of course, Qatar via Qatargas is trying to capture as much of the second demand window at JCC based pricing by helping with the first demand window).

Will the utilities change the model and commit to US LNG? Our view is not materially i.e. the buyers want to be able to sign HH-linked contracts to break the current APAC LNG price premium, but they will be unwilling to risk a significant share of total supply from a supply point that carries both reserves and political risk (reserves risk so far as the liquefaction points will be fed with market-sourced gas rather than reserve-dedicated, a key tenet for Japanese buyers to date). Interestingly, Japanese bureaucrats are talking about the opportunity to source 'low cost, flexible (read—interruptible) LNG from the US as a major shift in Japanese energy policy, but would the Government be willing to accept the fall-out of a future supply interruption? This is why we expect utility/gas distribution buyers to be more cautious in committing to MATERIAL levels of supply from the US.

US brings temptation of HH-linked prices, but long-term supply reliability will remain a question mark

Japan was not an 'early-mover' in the US LNG theme—Thus far, GAIL in India and Kogas in Korea have decided that the supply risk was worth the price benefit; both having committed to 3.5 MTpa from Cheniere (GAIL on a 100% ToP basis; Kogas on a full or partially interruptible basis).

Things to watch out for in Japan in 2012:

(1) **The new Energy Strategy—due in early summer:** We expect a call for 'nuclear ageism', where only the newer nuclear facilities are brought back into service, and new nuclear plans are largely shelved. We also expect a renewed call for expansion in renewable's share in the primary energy mix, which will be laudable, but un-realistic, and a muted increase in gas's share in the mix.

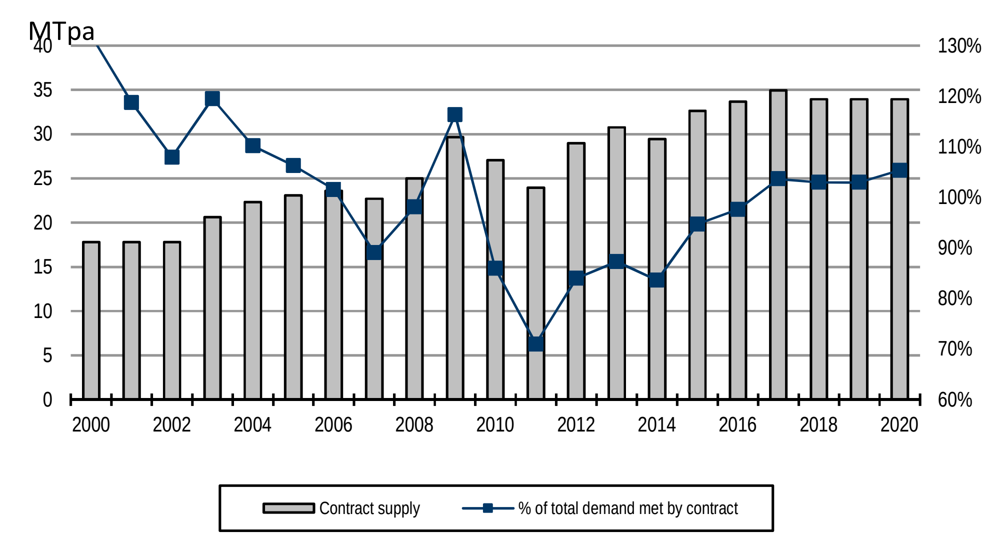
(2) **Qatar signing long-term agreements:** We continue to forecast Qatar achieving circa 9 MTpa of additional LNG contracts. TEPCO signed a ten year 1 MTpa deal starting in 2012, and Shizuoka Gas/Chubu Electric—a symbolic but tiny 0.2 MTpa. We would not be surprised to see more deals announced in 2012; what will be interesting will be whether Japanese buyers buy as a consortium, and if they look to 'step down' contracts in the same way Kogas and CPC in Taiwan did in 2011.

(3) **More (or firmer) US LNG supply contracts?** Tokyo Gas/Sumitomo's deal with Coe Point is material, as is Mitsubishi and Mitsui with Sempra in Cameron. The questions are—whether the non-FTA approval will be given and who will source the gas. It will be interesting to note if we will see a wave of further Japanese commitments to US sources, and the degree of commitment (initial agreements vs. definitive contracts).

Korea—less need to contract post '15 may lead to a wait and see approach to contracting

Korea: Short term gap—long term un-contracted demand already met—With both, Rasgas 4 MTpa (falling to 2 MTpa in 2017) and the Brunei extension/increase, Kogas (and Korea) has removed some of the near-term challenge with LNG supply, but still needs 7–10 MTpa out to 2015, or circa 15% of total demand to the middle of the decade. If our revised demand and supply numbers are directionally correct, the difference with Japan is that Korea appears to have little un-contracted demand in the latter part of the decade, with both Shell's Prelude and Total's Ichthys supply, along with Santos's GLNG and the recent Cheniere/Sabine Pass contract providing supply support in the latter part of the decade. This would suggest Korea likely 'limps' through 2012-13 and 14, using spot/short-term supplies rather than any further significant long-term deals at this stage.

Figure 54: **Korea—contracted demand cover 2000-2020E**

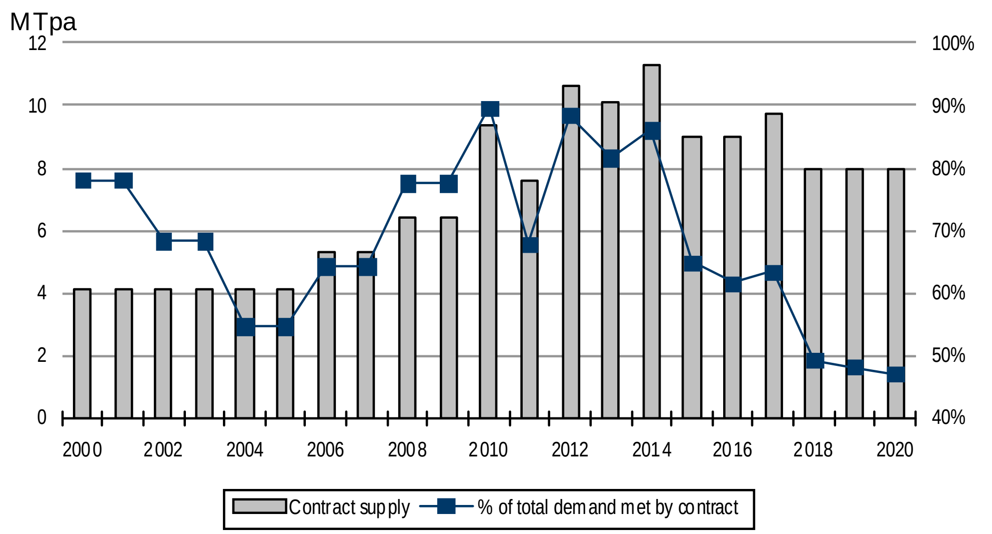


Source: Credit Suisse estimates

Taiwan: Short-term fixed; still a major long-term supply gap—Like Korea, Taiwan acted in 2011, contracting with Qatar for 3 MTpa from 2012 to 2016 (1.5 MTpa thereafter), hence 80-90% of total requirements will be met by long-term contracts to 2014, but the un-contracted demand re-opens in the latter part of the decade, with our model suggesting a 50% spot requirement by 2018 (some 7 MTpa, inclusive of the 2 MTpa option with Shell, generally assumed to be coming from Prelude). The question will be whether Taiwan follows GAIL and Kogas, and looks for HH-based pricing from a Cheniere expansion/new project, bets on East Africa LNG (and which developer it bets on) or waits for Asian-based brownfield expansions. We suspect given historic lethargy around LNG procurement, this won't be decided in 2012.

Taiwan: needs to decide to prioritise price over security – but has time to make the decision

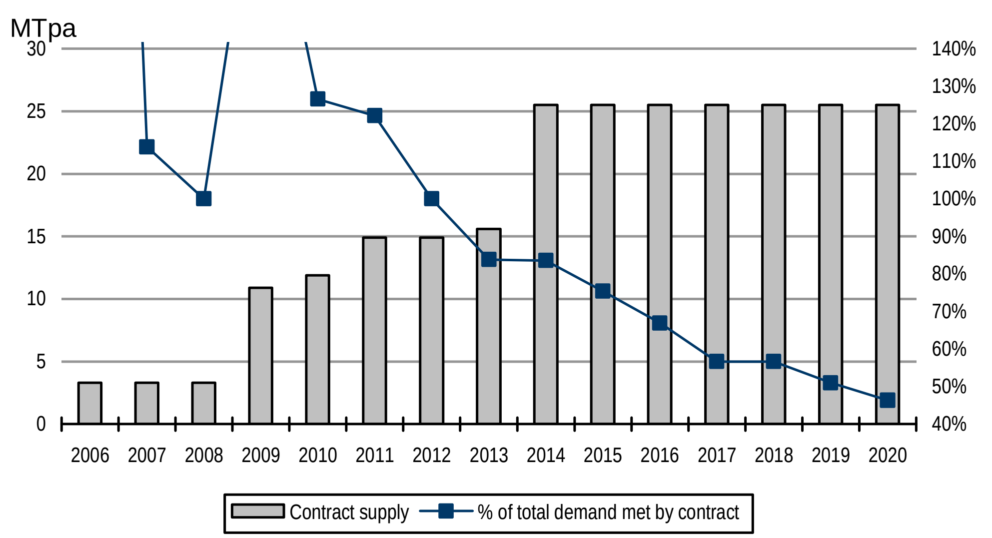
Figure 55: **Taiwan—Percentage of contract cover 2000-20E**



Source: Credit Suisse estimates

China: Broadly covered in the near term—We forecast demand increases 2.7 MT in 2012 over 2011, and that China is covered this year in terms of contract supplies vs. demand. The primary risk to the forecast, in our view, is the potential for a cold winter, driving Chinese SoE's to call in more spot cargoes toward the end of the year.

Figure 56: **China—Percentage of contract cover 2000-20E**



Source: Credit Suisse estimates

China—our un-contracted demand forecast is predicated on equity LNG opportunities: With LNG contract prices in Asia remaining stubbornly highly correlated to (JCC) crude we continue to believe China will continue to focus on, and accelerate its domestic un-conventional gas program. For LNG we continue to balance contracted supply thus far with demand; however in this update we add an additional 10 MTpa, or two LGN trains, of un-contracted demand. This is a placeholder, as we expect China will look for deals / projects that have a significant equity proportion, as long as the equity share of LNG can be directly lifted by the holder. In reality this is a way to reduce the cost of LNG imports and for us increases the attractiveness of the emerging East Africa play for Chinese LNG buyers as cost estimates to produce in East Africa are significantly lower than for example in Australia (please see our Global Gas report 'From tight to loose' published November 2011 for an LNG cost curve).

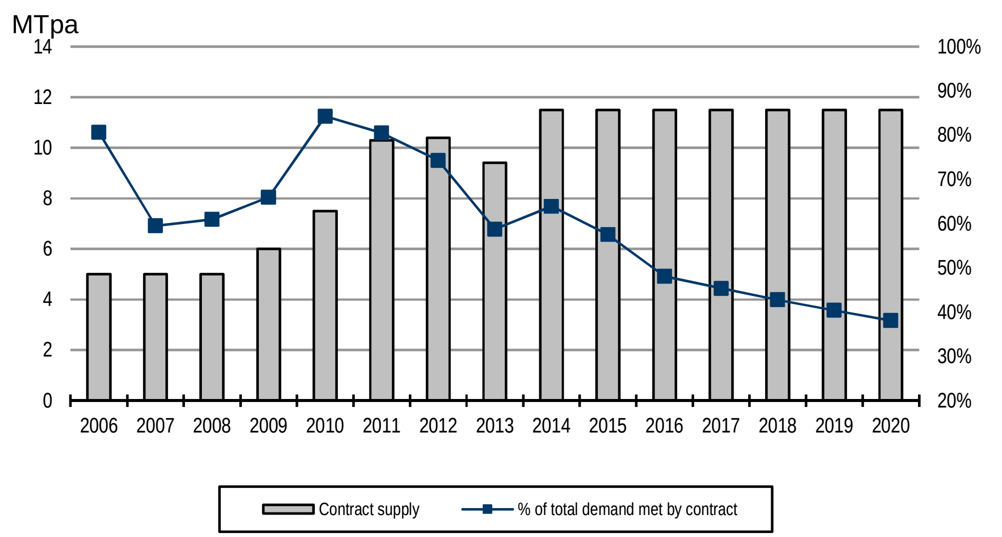
China – will likely focus on equity linked off-take deals – to reduce supply price

India: Reasonable contract cover in the near term—long-term waiting for Cheniere: Our demand-supply balance suggest that India will have an 80% contract cover in 2012, similar to 2011 (which saw a more robust LNG demand than our previous forecast). This drops significantly from 2013 forward, however our analysis of contract does not include the 3.5 MTpa deal recently concluded between GAIL and Cheniere; as long as the Cheniere project takes sanction then India's contract cover would increase to 85%. What will be interesting in the medium term is if there are further Indian buyers willing to replicate GAIL's deal to bring currently lower priced LNG to India to expand demand.

HH linked price likely the driver going forward for incremental Indian LNG contract deals

HH linked price likely the driver going forward for incremental Indian LNG contract deals

Figure 57: **India—contracted supply / % of demand cover**



Source: Credit Suisse estimates

Historically Singapore has depended on Indonesian / Malaysian gas. However, it has decided to introduce LNG far before the current gas pipeline contracts with the other two countries expire. Moreover, it plans to introduce LNG where gas demand exceeds pipeline gas capacity. The reason to build an LNG receiving terminal was the likely desire to reduce dependence on its two neighbours. The contract to supply the first 3 MTpa to Singapore was awarded to BG, which will meet the obligation using portfolio supplies. 2.7 MTpa has thus by far been sold in Singapore to power generators, industrial and commercial users. We expect Singapore to take the decision regarding expansion with a further 2.5 MTpa capacity, creating a 3 MTpa un-contracted demand from 2017 (CS est). We expect Singapore to focus on energy security (the very reason for the introduction of LNG) but to spend time pondering the trade off between security of supply linked to crude prices versus lower supply security linked to US gas prices.

Singapore: energy security at the heart of the Singapore LNG 'experiment'

Other S E Asia: Price driven. Markets looking to introduce LNG suffers from a common problem—gas affordability. This will result in two factors in LNG procurement: (1) buyers will be driven to prioritise price above other supply considerations including supplier credibility, flexibility etc and (2) LNG projects with the strongest marketing proposition will likely prioritise other markets where both the ability to pay, and receive, are perceived to be higher.

Five major supply zones for APAC supply going forward: with very different characteristics

Turning to the differing offerings on the market for APAC LNG buyers to select from. Historically the choices had been more limited with the same super-majors developing new LNG projects around Asia with similar contract expectations regarding confidence / security of supply, price (JCC linked) and flexibility (100% ToP, 10% annual downward flex with a rigorous make up requirement). However, five major supply alternatives currently face APAC buyers, namely:

- **Qatar redirections.** With the near monopoly on near-term supply, Qatar has been focussing on converting the short term decline in Asia into long-term supply contracts. Clearly for this, Qatar seek LNG price formulas that are highly correlated to crude.
- **APAC greenfield.** With the glut of liquefaction build out in the region, comprehensively focused in Australia, buyers are wary of further greenfield exposure at this point.
- **APAC brownfield expansion.** Regional brownfield expansions offer tangible benefits to LNG buyers in terms of faster construction / less risk of capex blow-out delay. The challenges will be two-fold. Will the seller be willing to share the incremental economic advantage of expansion and will the buyer be willing to support 'traditional' APAC LNG pricing (which the brownfield will almost inevitably require to avoid pollution of existing contracts).
- **NA LNG.** Offers the lure of linkage to Henry Hub pricing and more supply flexibility, but brings challenges in terms of gas quality ('lean'), delivery time (at least in the case of US Gulf Coast supplies) and security of supply. These challenges will weigh heavily on APAC LNG buyers.
- **East Africa.** The next big LNG province. For buyers the key differentiator between East African projects will be developer's credibility and a clear understanding of risks involved in various countries and its mitigation. The ability to offer upstream equity will likely be an attractive marketing component for certain APAC buying countries.

Figure 58: **Projects varying marketing offerings—CS view**

	Security of supply	Reserves certainty	Price	Supply flexibility	Credible supplier	'lean' vs. rich gas	Buyer equity participation
Qatar (Qatar Gas/ Ras Gas)	Yes	Yes	JCC	Current APAC conditions	Yes	Rich	No
Cheniere / Sabine Pass	No - US political risk	No	HH link	Yes - potentially interruptible	New to LNG	Lean	No (Cheniere don't own the molecules)
BG from Sabine Pass	Yes - if sold with portfolio fall-back	Yes - on a BG portfolio basis	likely - JCC basis	Yes - potentially interruptible	Yes	Lean	No
Kitimat LNG	Canada = US 'light'	Yes	JCC	?	New to LNG	Lean	Possible
Shell Canada LNG	Canada = US 'light'	likely or via portfolio	V likely JCC	?	Yes	Lean	?
Gorgon Train IV	Yes - AU sourced	Yes	JCC	No - usual Asian 10% flex, 100% ToP	Yes	Rich	Yes but limited
Anadarko Mozambique	Question mark - new gas province	Yes	likely JCC	?	New to LNG	?	Yes
ENI Mozambique	Question mark - new gas province	Yes	likely JCC	?	New to LNG	?	Yes
BG / Ophir Tanzania	Question mark - new gas province	Yes	V likely JCC	?	Yes	?	Probable

Source: Credit Suisse estimates

Will Cheniere sell more LNG to Asia, or is it sold out?

US LNG I—Cheniere was a game changer—one of a kind? The Cheniere Sabine Pass 4 train facility was deftly executed, with a focus on timely commercialisation. Cheniere has no existing investments in Asia and therefore, has no need to protect the Asian price premium. However, as a new LNG player, it does not have any mechanism to ameliorate security risk (from the US) or equity molecules to sell. To expand Sabine Pass, it needs to collaborate with Chevron and Total—existing LNG players in Asia which are very unlikely to allow incremental LNG to flow at HH pricing. Hence if Cheniere wants to sell more LNG at pure HH pricing, then it would require approval of its second proposed liquefaction site—Corpus Christi—but as a greenfield (versus the brownfield conversion at Sabine Pass). Due to a potential of export ceiling in the US, it is far from certain if Cheniere will be offering HH based pricing to Asian buyers again.

BG's purchase from Cheniere will be sold as 'portfolio' gas—unlikely to have HH link

US LNG II—what BG brings to Sabine Pass sourced LNG? BG, with its second purchase from Sabine Pass, has access to 4.8 MTpa at Henry Hub (HH) + 15% + US$2.25 / mmbtu—what it can promise Asian buyers is increased confidence of supply, by backing up SP sourced LNG with its portfolio (in the same way it does at QCLNG). What it is unlikely to do is sell to Asian buyers at HH based price formula. We would not be surprised to see BG SP sourced avails marketed to Asian buyers at Japan Crude Cocktail (JCC) based price formulas, but with the additional benefit of increased flexibility vs. existing Asian sourced LNG projects (passing through some or all of its interruption capacity with Cheniere).

NA LNG developers with interests in Asia disposed to 'protect' the Asian price premium

US LNG III—what motivates the other front runner projects? Other front runner projects are Lake Charles and Freeport LNG, led by BG and Conoco, respectively. In both cases the project developer has existing LNG projects in Asia, and we expect that flexibility rather than a complete link to HH to be the leading marketing tool to sell avails from these projects into Asia. For Dominion's Cove Point, it's still unclear as to what is its marketing strategy for sales to Asian buyers. Sempra has taken significant steps forward recently, announcing merchant liquefaction deals with Mitsubishi, Mitsui and GDF Suez. Clearly the Japanese participants will target sales back into Japan / wider Asia, but will have presumably secured US feed-gas, at which point the big question would be what pricing methodology the traders (hint in the name there…) offer the LNG into APAC.

Canada may be a more compelling supply point for Asian buyers. The key difference, apart from proximity, is the potential to link reserves to supply. Moreover, Asian LNG buyers perceive political stability and less risk of supply interference in Canada vis-à-vis the US. The challenge will be price as greenfields in Canada are increasing the unit liquefaction cost versus regas conversions (for some of the US LNG projects)

Canada = US 'light' with reserves to back up sales – but won't be cheap

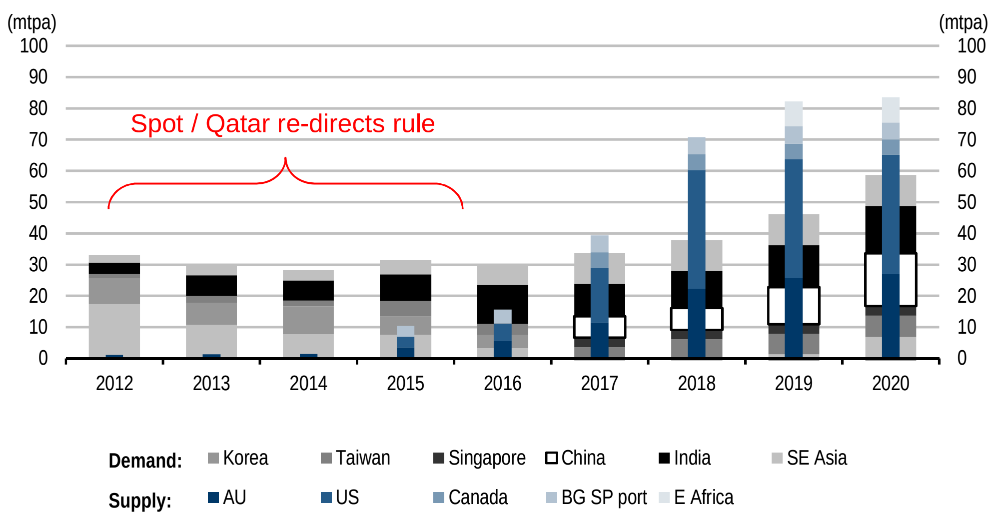
Asian brownfield expansion / extensions—will serve a purpose. With more than 60 MTpa of greenfield liquefaction under construction in Australia alone, and the time and cost challenges it brings, brownfield expansions / extensions will likely be the focus for Asian LNG supply projects competing for APAC LNG contracts for supply in the latter part of the decade. Despite the benefits of expansion (versus greenfield) we do not expect Asian brownfield expansions to offer HH linked pricing—hence the question is how much additional flexibility will they choose / feel compelled to offer to compete with NA LNG projects.

In Asia, the focus will be on brownfield expansions—at Asian price formulas

East Africa: country risk comfort, developer credibility & equity will be the key differentiators: Asian buyers will be potential off-takers from East Africa, but will look for comfort with regard to government alignment / support for the LNG projects, along with confidence that the LNG lead developer has the experience to take a project to 1st gas and beyond in a new LNG geography. Another attraction would be the ability to secure meaningful equity participation, as demonstrated by PTTEP's recent and on-going bid for Cove. To be 'market ready' (i.e. to be taken seriously by LNG buyers) we believe projects in East Africa need to demonstrate alignment with the host government regarding plans to export LNG, have a stable and credible partner group (including an experienced LNG operator), enough gas to fulfil the marketed avails and a credible development plan. While Mozambique appears to have more gas than Tanzania at this point in the exploration phase it lacks a unitised and stable partnership and an experienced operator.

East Africa is attractive to Asia, developer credibility will be key (in the 1st phase at least)

Figure 59: **APAC un-contracted demand / supply: 2012-20**



Source: Credit Suisse estimates

Contracting conclusions:

In the short term (2012–16). Qatar (both Ras and Qatar Gas) will leverage on its short term supply strength to convert more short-term re-directions into long-term supply contracts, retaining a significant (80–90%) correlation to crude (JCC). Spot suppliers to Asia, like BG will also benefit, as spot prices are buoyed by the unusually high non contract requirements in North Asia.

Short term: Contract and spot prices to remain extremely robust for the next 3 years

In the medium term (2017–18). With more potential supply than demand in the medium term and the majority of the demand in our model coming from emerging, price sensitive markets (SE Asia & China / India) 'winners' could come from US HH priced LNG supply (if Cheniere can expand Sabine Pass or accelerate Corpus Christi or possibly supply linked to a significant equity sale (i.e. with the likes of BG / Ophir Tanzania). The 'losers' will be those projects which are not willing or able to offer lower pricing and those quality projects that choose to wait until 2019-20 to secure off-take from credible buyers at acceptable prices, like Chevron's Gorgon T4 expansion.

Medium term: Price sensitive demand 'gap' in '17 – '18, quality projects will likely wait for '19 = '20

In the long term (2019–20). The main fight is for Japan's un-contracted demand—watch Inpex's Abadi project, Chevron's Gorgon T4, the potential for Mitsubishi & Mitsui via Sempra's Hackberry facility, Exxon / Oil Search's PNGLNG T3 & BG Tanzania. Those who are unsuccessful in Japan will be left to compete for price sensitive demand in India and emerging markets where returns will likely be lower and off-take risks higher, and China where upstream equity will be a key un-locker.

Long term: quality LNG projects prevail in North Asia, other projects will have to supply higher risk price sensitive APAC markets

APAC pricing conclusions

Pricing: short term. Contract crude price correlation will remain high with spot prices occasionally higher than contract prices. Feeding in CS' updated Brent crude price forecast suggests a Japan DES (Delivered Ex Ship) average landed price of US$18.0 / mmbtu in 2012, rising to US$19.8 / mmbtu in 2014 before falling back (as our long term crude price does) to US$14.3 / mmbtu in 2015.

At Brent $125 / bbl in '12 expect Japan landed prices of $18 / mmbtu

Figure 60: **CS: Japan LNG landed price forecast 2012 - 2015**

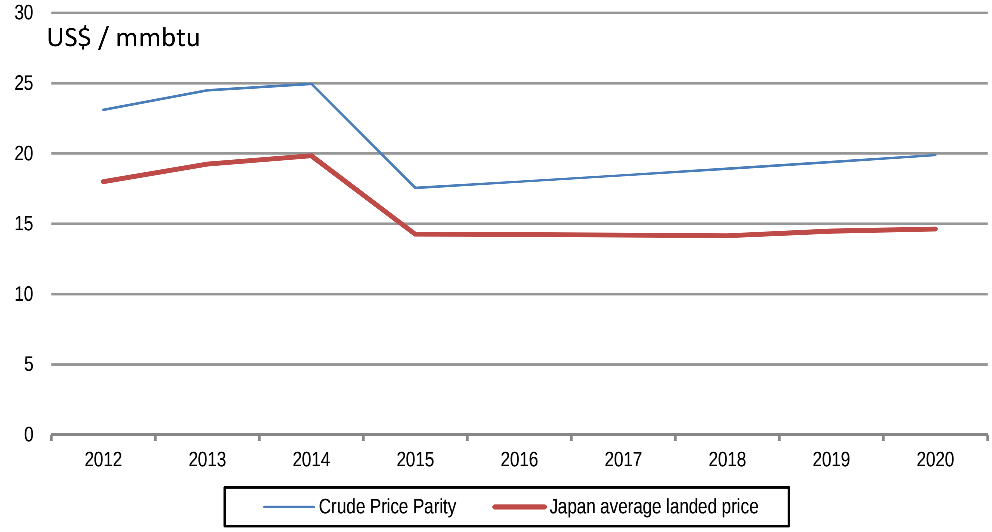
	2012	2013	2014	2015
Brent - US$ / bbl	125	132.5	135	95
JCC - US$ / bbl	122.5	129.85	132.3	93.1
Average correlation	75%	76%	77%	77%
Price in US$ / boe - FOB basis	91.9	98.7	101.9	71.7
Price in US$ / mmbtu - FOB basis	17.0	18.2	18.8	13.3
Price in US$ / mmbtu - DES basis	**18.0**	**19.2**	**19.8**	**14.3**

Source: Credit Suisse estimates

Pricing medium term: Korea will see the first arrival of Cheniere sourced LNG in 2016 /17 representing 10% of total demand in those years. GAIL's 3.5 Mtpa is also from the same source (20% of India's demand at that time). We expect the ultimate US sourced LNG to be at the lower end of market expectations and not all, or even the majority, will be using HH based pricing formulas.

Limited HH linked avails in 2016+ will only moderately soften crude price correlations in APAC

Figure 61: CS: Japan landed LNG price forecast—2012-20



Source: Credit Suisse estimates

Pricing long term. Our view is that the primary markets will continue to favour security of supply over price and instead would like to see increased flexibility conditions in contracts supplying APAC toward the end of the decade. Hence we expect a gradual, but in no way aggressive, softening of the crude price correlation toward the end of the decade. Looking more holistically, the major change in contract terms for supply late in the decade will be significantly increased off-take flexibility.

We still forecast a 70% crude price correlation by 2020 in Japan.

Players

Inpex: Two sanctioned greenfield projects under construction + one seeking FID. Ichthys has been a long journey for Inpex, and the progression to project sanction has taken focus. However, with the farm-in to Prelude, Inpex now has two greenfield projects sanctioned and under construction. We assume Ichthys first gas is late 2016 and Prelude 2017. Behind this the Abadi project took a major step forward with the farm-in of Shell; the FLNG project will likely move into FEED in 2012, targeting FID in 2013 / 14 and 1st gas in 2018 / 19—squarely targeting the re-opening of un-contracted demand in Japan at that time. With significant progress on Ichthys project funding announced recently (US$20 of the 34 billion capex under non-recourse project financing) Inpex has moved from a single LNG project story to a multiple development LNG player.

Woodside: **Pluto LNG online, but future LNG growth is uncertain.** WPL's 4.3 MTpa Pluto LNG project (WPL 90% interest and operator) has finally commenced LNG production—approximately 16 months behind schedule and 25% over budget. The key question for shareholders is: Where does the next layer of growth come from? After years of being told that WPL had three viable LNG projects (Pluto expansion, Browse and Sunrise) in the pipeline, each have since stalled or have question marks hanging over the proposed development option. The hunt for gas for Pluto train 2 has met with minor success, but was insufficient to reach the level required for project sanction; WPL will need to bring in or purchase 3rd party gas if Pluto 2 is to proceed in the next 2-3 years. The WPL-led JV in Browse (WPL 31.3% interest) is continuing to evaluate a standalone 12 MTpa development at James Price Point. However, both CS and the market remain sceptical regarding the viability of this greenfield development. In the best case outcome Browse comes online in 2018/19 timeframe, and the 16.7 MTpa North West Shelf project (some 700 km away) is expected to start short-falling on gas deliverability in 2021. Given the common ownership structure between the two projects we expect Browse gas to eventually backfill North West Shelf. The project with the greatest chance to succeed in the near term is the Sunrise LNG project. New WPL CEO Peter Coleman has spent the past nine months' working to repair its relationship with the East Timorese Government, who has blocked the concept of a Floating LNG development at Sunrise using Shell's FLNG technology; it strongly prefers a land-based LNG project on East Timor. With East Timorese elections due in July, we believe there is a higher chance of a breakthrough in this project later this year, with FID possible in 2014.

Santos: In the construction phase, **but concerns remain around GLNG costs and landowner relations.** STO has a 30% interest in GLNG (16 months into a 4.5 year construction period) and a 13.5% interest in PNG LNG (halfway through a 4.5 year construction period). Key concern amongst shareholders is in the costs of GLNG, which reached project sanction at US$16 bn for 7.8 MTpa output. Though we now estimate the capex is now approximately US$17 bn after FX movement since FID. On a US$/tpa basis GLNG is the least expensive of the three Gladstone LNG projects at US$2,180/tonne. In recent weeks, BG announced its QCLNG capex estimate had increased by 35% to US$21.8 bn and shareholders remain concerned GLNG costs could be heading in the same way. However, with approximately 70% of construction costs in AUD and STO reporting in AUD, it sees itself as having a large natural hedge from FX volatility. With over 6,000 wells needed to be drilled onshore in Queensland for GLNG over the project life, landowners remain concerned regarding the impact upstream activities may have on their rural lifestyle. We expect all LNG proponents in Qld to end up increasing the level of compensation paid significantly in order to appease local landowner concerns. STO is also progressing with the Bonaparte FLNG project, with GDF Suez planning to drill a well in the Petrel/Tern gas fields off the coast of the Northern Territory in the next 18 months, and is adamant it remains on schedule for FID in 2014.

Oil Search: Increasing reserves cover at PNG, train 3 looking more certain. OSH has been very bullish on a third LNG train at its PNG LNG Project. With trains 1 and 2 well into the construction phase and heading for first LNG in 2014, the hunt for train 3 gas reserves is now underway in earnest. The XOM-led JV had early success when the P'nyang South appraisal well (and subsequent sidetrack) found that the field's vertical gas column is likely to extend over 650 metres. We estimate the field contains between 3 and 4 Tcf of gas. Train 3 needs to be underpinned by proven reserves or resources, but the attractive economics of train 3 (given the level of over-investment in trains 1 and 2 infrastructure) means that as little as 2.5 Tcf of gas reserves are needed to proceed with a 3rd LNG train. Current schedule is for additional exploration and appraisal drilling during 2012 before a decision is made on whether to proceed to FEED and LNG marketing for train 3 in 2013. FID is likely in 2014 ahead of first LNG production in 2017/18 timeframe.

BG: Savviest LNG trader, Growth from (mostly) cost-competitive projects. As we highlighted in our Nov. 2011 Global Gas report and company research ("*LNG upside and superior growth to 2020*", 11 Jan 2012), BG is exceptionally well-positioned in the tight LNG market over the next 4-5 years thanks to its flexible LNG portfolio. BG / Ophir's recent Mzia discovery in Tanzania fully de-risks a 2-train LNG project, bringing BG's marketed LNG volumes to its 30 MTpa target by 2020 (from under 13 MTpa currently). BG also has significant exposure to lower-cost US LNG exports with 5.5 MTpa of off-take priced at HH from Cheniere's Sabine Pass, a third of all approved US LNG exports thus far. A green light on its Lake Charles project would be an incremental positive for BG—we don't currently include the project in our forecasts, so its addition would represent upside to our LNG EBIT forecasts and NAV estimates. The only black eye in BG's otherwise faultless LNG strategy is the significant (36%) cost overrun at the QCLNG facility in Queensland announced in May, dampening the project's returns (~12.5% IRR) and making a T3 expansion even more necessary to benefit from economies of scale and boost the project's total IRR.

Shell: Deepest LNG project hopper, On-going LNG portfolio shift. Shell is the largest IOC player in the LNG market with 21 MTpa of current supply. However, it has less flexibility to redirect cargoes to APAC during the 2012-16 period of market tightness than its competitor BG with the bulk of its supply already contracted. Shell easily has the longest list of LNG supply options of any IOC, with 3 projects under construction and 8 additional unsanctioned projects: Mozambique (if they prevail), LNG Canada, Gorgon T4-5, Abadi, Arrow, Sunrise, Browse & Sakhalin expansion. In our view, Shell's recent move for Cove and its land grab in Western Canada signal a desire to diversify away from Australia and enter lower-cost East African and Canadian LNG. This makes sense to us given rising construction costs in Australia, where Shell is involved in eight different projects. We wouldn't be surprised to see Shell reduce exposure to Australian LNG. By exiting its 24% stake in WPL or individual projects (e.g. Wheatstone, Browse). Another key differentiator for Shell is its Floating LNG technology, which could help it to gain access to stranded gas resources in the future—however in the nearer term, execution at Prelude (and later at Abadi) will be watched closely for validation of the technology.

Chevron: Gorgon (Train 4) from the second half of 2012, looking to leverage its marketing reputation and secure North Asian un-contracted demand in 2019/20. CVX also aims to use Wheatstone as a hub for regional third-party gas. HES and others are looking for LNG outlets for their upstream gas resources.

Exxon Mobil: PNG Train 3: Despite unrest and a landslide, XOM has reiterated that PLNG trains 1+2 are on scheduled for a 2014 start-up. We believe XOM will want to make further progress on construction of T1+2 and also conduct further exploration before moving forward with T3. However, this remains a low-cost project and likely source of incremental LNG supply.

Eni: LNG profile raised by Mozambique; FLNG aspirations: Eni is outside the Top five in the LNG business with 11 MTpa of LNG sales (of which some is third-party LNG rather than equity volumes). Prior to Mozambique, Eni's E&P portfolio was seen as underweight LNG versus its larger peers (RDS, TOT, XOM, CVX) – but the Mozambique discoveries have plugged a big hole and give the company a chance to develop a large-scale LNG project. As Eni and Shell both aim for operatorship, it will be interesting to watch the interplay between the companies once Shell has reached a material stake in neighbouring Area 1. Outside Mozambique, Eni plans to boost LNG production at the Bontang facility (Indonesia) by providing additional feedgas from the Sanga Sanga CBM block and the offshore Jangkrik field—we see this as a much more capital-efficient way to raise LNG output than building a greenfield plant. Eni intends to use Floating LNG in Mozambique (as a fast-track concept, 1-2 years before the onshore plant), Indonesia or Ghana, but we are sceptical given its lack of track record in the technology.

Total: Top 3 LNG player, high end of cost curve: We see Total's LNG portfolio as an under-appreciated part of the company. While Total markets 14 MTpa of LNG versus Shell's 21 MTpa, relative to its size, Total has as much LNG exposure as Shell with similar profitability (~15% of upstream production and ~25% of E&P profits). Total has made LNG a centrepiece of its upstream growth strategy, with three projects under construction (Angola, GLNG, Ichthys) and another three under consideration (Yamal, Brass, Shtokman). Total's problem is that its projects tend to be at the top of the cost curve (both in Australia and in Russia), and that it has missed the trend of emerging lower-cost LNG plays in East Africa and North America. We would not rule out a move by Total into either of these geographies, especially if Brass and Shtokman fail, or if cost inflation in Australia proves to be even worse than we already expect. Lately, regular shutdowns at its Yemen LNG plant due to security issues have been a headache.

Ophir: Early mover advantage, Firming up gas resources before cashing out. Ophir not only enjoys an early mover advantage in Tanzania, but also benefits from having BG, the industry's preeminent player in LNG, as a partner and operator of blocks in Tanzania. With 100% exploration drilling success rate in Tanzania, Ophir/BG has proved c10tcf of gross gas resources in their acreage. Ophir expects its BG-partnered acreage to hold c.40 tcf of gross unrisked gas resources, with significant further upside potential if basin-floor stratigraphic play from Mozambique extends into its Block 1 in Tanzania. 2013 drilling plan will be driven by the recently acquired 3D seismic data and, if encouraging, will target this basin-floor play, but the end game for Ophir is to monetise its acreage as it does not want to participate in an LNG development. We view the asset as of strategic importance to the broader industry and expect a monetisation process (partial farm-out or complete exit) to start as early as 1H13. In addition to Tanzania, Ophir has a 80% stake in Block R in Equatorial Guinea that is expected to provide the feedstock gas for a second LNG train. Ophir will drill three wells in Equatorial Guinea in July/August this year to prove up threshold gas volumes. We expect Ophir to initiate a farm-out process in Equatorial Guinea later during the year.

Anadarko: Mozambique

APC and its partners are conducting a pre-FEED study, targeting its Mozambique LNG project sanctioning in 2013 and first production by 2018. The design envisions a two-train LNG system (~750 mmcf/d each) that is expandable up to ten trains. Resource potential could expand dramatically in 2012, with northern step-outs planned including Orca, Atum, Badejo and Golfinho (successful - see below). These target the same tertiary sands that were prospective in Lebarquenjammer. We would expect FID by mid 2013. In addition, there is the possibility of unitisation and/or joint development with ENI, which after success on its Mamba North exploration prospect, sees up to 40 tcf of gas in place its acreage. Unitisation would only take place for APC's Prosperidade Complex, as Golfhino is a separate structure to the north.

Recent events include a successful Barquentine-2 flow test in March at a constrained rate of 90-100 Mmcf/d, implying the well design is capable of handling up to 100-200 Mmcf/d. As mentioned above, APC announced a successful test at Golfhino in May, a 50-mile northern step-out from its existing Prosperidade complex. Based on this success, APC estimates resource potential in the northern area of 7-20 Tcf. This puts total recoverable resource at 24-50 tcf when combined with current estimates of reserves at Prosperidade (17-30 tcf). Monetisation of Mozambique by APC is a distinct possibility. While the company has received transactional interest in its Mozambique assets, it remains inclined to first let the northern exploration play out. Cove's enterprise value is a reasonable marker for the value of Mozambique, as it is its far and away dominant asset. Based on its current EV, the total value for Mozambique is ~US$23 bn with APC's share at ~US$8 bn.

EOG/APA/ECA: Kitimat

APA is the project operator, with a 40% working interest, while EOG and ECA each own a 30% working interest in the Kitimat LNG export facility, which is under development in British Columbia. The plan envisions a Kitimat LNG facility on Bish Cove, 400 miles north of Vancouver, and a proposed 287-mile pipeline that will originate in Summit Lake, British Columbia. The project aims to link significant western Canadian gas reserves to oil-indexed LNG contracts, allowing the project partners to take advantage of high crude oil prices. Sanctioning has been pushed back to at the earliest year-end 2012, following the potential completion of an oil-indexed contract as well as a detailed project estimate.

Companies Mentioned *(Price as of 07 Jun 12)*
Anadarko Petroleum Corp. (APC, $62.16, NEUTRAL, TP $92.00)
Apache Corp. (APA, $83.59, OUTPERFORM, TP $135.00)
BG Group plc (BG.L, 1241 p, OUTPERFORM, TP 1,730.00 p)
BP (BP.L, 407 p, OUTPERFORM, TP 540.00 p)
Cheniere Energy Inc. (LNG, $12.94, RESTRICTED [V])
Chesapeake Energy Corp. (CHK, $18.21, NEUTRAL [V], TP $20.00)
Chevron Corp. (CVX, $99.80, OUTPERFORM, TP $130.00)
China Petroleum & Chemical Corporation - H (0386.HK, HK$6.99, NEUTRAL, TP HK$7.05)
CNOOC Ltd (0883.HK, HK$13.78, OUTPERFORM, TP HK$18.30)
ConocoPhillips (COP, $53.58, NEUTRAL, TP $67.00)
EnCana Corp. (ECA, $20.81, NEUTRAL, TP $19.00)
ENI (ENI.MI, Eu15.98, OUTPERFORM, TP Eu21.00)
EOG Resources (EOG, $94.92, NEUTRAL, TP $126.00)
ExxonMobil Corporation (XOM, $80.18, NEUTRAL, TP $91.00)
Gazprom (GAZP.RTS, $4.55)
INPEX Corporation (1605, ¥454,000, OUTPERFORM, TP ¥840,000, MARKET WEIGHT)
Korea Electric Power (015760.KS, W24,100, OUTPERFORM, TP W28,000)
Korea Gas Corp (036460.KS, W41,800, OUTPERFORM, TP W50,000)
Marathon Oil Corp (MRO, $24.96, NEUTRAL, TP $42.00)
Noble Energy (NBL, $85.45, OUTPERFORM, TP $124.00)
Occidental Petroleum (OXY, $84.57, OUTPERFORM, TP $135.00)
Oil Search (OSH.AX, A$6.63, OUTPERFORM, TP A$8.55)
PetroChina (0857.HK, HK$9.89, OUTPERFORM, TP HK$13.30)
Repsol (REP.MC, Eu12.65, OUTPERFORM, TP Eu19.00)
Royal Dutch Shell plc (RDSa.L, 2032 p, NEUTRAL, TP 2,530.00 p)
Santos Ltd (STO.AX, A$11.97, NEUTRAL, TP A$15.00)
Statoil (STL.OL, NKr137.70, UNDERPERFORM, TP NKr165.00)
Total (TOTF.PA, Eu34.80, NEUTRAL, TP Eu43.50)
Woodside Petroleum (WPL.AX, A$32.77, OUTPERFORM, TP A$40.70)

Disclosure Appendix

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