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Does the Portfolio Business Model Spell the End of Long-Term Oil-Indexed LNG Contracts?

Background and Introduction

The development of the LNG market[1] and the historic role of long-term oil indexed contracts have been discussed and appraised in depth in several OIES publications[2] and in the wider energy literature and conference fora, with strong views on both sides of the argument for retaining oil indexation versus moving to a market-based pricing mechanism. This debate is particularly apposite given LNG's inherent ability for inter-regional price arbitrage and (especially with the growth in destination flexible US LNG export volumes in the next few years) its increasing prominence in global gas trade-flows versus pipeline gas.

The proponents of market or 'hub price' indexation draw attention to the successive 'evolutionary' waves of market liberalisation in North America, the UK and North West Continental Europe where gas markets have, over the last 3 or 4 decades, in line with the tenets of 'Economics 101', adopted pricing references based on the supply and demand for the commodity which is natural gas. Advocates for the continuation of oil indexation draw on historic custom and practice within the gas and LNG industry, particularly with respect to the core Asian markets and the apparent dictates of the banking sector, when non-recourse financing is used for LNG projects. Although the case for oil as a competing fuel to gas in key Asian market consumption sectors is much harder to make than 30 years ago, it is at present difficult to envisage deep liquid traded gas hubs[3] emerging on much less than a ten-year time horizon in Japan, China and elsewhere in Asia. The European experience suggests emphatically that hub prices are lower than oil-product indexed prices more often than not; creating the desire on the part of the buyer for hubs, not for ideological reasons, but merely to secure lower prices.

Rather than extend the terms of the above debate to LNG markets in general, this paper was written with a more pragmatic approach in mind; namely to appraise the trends in supply and demand

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[1] For a comprehensive appraisal of the history and current state of the LNG industry see 'LNG Markets in Transition: The Great Reconfiguration', Ed. Anne-Sophie Corbeau and David Ledesma, OUP, 2016, https://www.oxfordenergy.org/shop/lng-markets-in-transition-the-great-reconfiguration/

[2] See 'The Pricing of Internationally Traded Gas', ed. Jonathan P. Stern, OIES, OUP 2012, https://www.oxfordenergy.org/shop/the-pricing-of-internationally-traded-gas-ed-jonathan-p-stern/, 'Challenges to JCC Pricing in Asian LNG Markets, H. Rogers & J Stern, NG 81, OIES, February 2014, https://www.oxfordenergy.org/publications/challenges-to-jcc-pricing-in-asian-lng-markets/, 'A New Paradigm for Natural Gas Pricing in Asia: A Perspective on Market Value', A. Miyamoto & C. Ishiguro, NG 28, OIES February 2009, https://www.oxfordenergy.org/publications/a-new-paradigm-for-natural-gas-pricing-in-asia-a-perspective-on-market-value-2/

[3] For an appreciation of what qualifies as a deep liquid hub in a European gas context, see 'The evolution of European traded gas hubs', P. Heather, NG 104, OIES, December 2015, https://www.oxfordenergy.org/publications/the-evolution-of-european-traded-gas-hubs/.

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fundamentals, project commercial structures, price formation mechanisms and perhaps most importantly corporate LNG strategies – and so draw empirical conclusions as to the direction of travel.

The possible emergence of a new mood amongst corporate players is exemplified by a statement by Dale Spencer, Chief Economist of BP, on the occasion of the release of the 2017 BP Energy Outlook that: 'The development of a deep and competitive LNG market is likely to cause long-term gas contracts to be increasingly indexed to spot LNG prices' [4].

While the oil-indexation versus hub pricing debate has occupied centre stage at major gas conferences in recent years, the incidence of conversational references to 'LNG portfolio players[5]' and the growth of LNG trading companies have become more frequent. For many observers however, the mechanics of such businesses are shrouded in an aura of mystery, which has become the more irksome as their perceived importance has grown. Added to this is the impression that such players appear to participate, at least at present, in both oil-indexed and hub (or spot) related transactions and as such appear somewhat agnostic on the 'oil versus hubs' pricing debate.

In addition to seeking to dispel some of the mystery surrounding the LNG portfolio business model, this paper addresses the following key questions:

- How have the demographics and LNG business fundamentals changed over time?
- How have LNG contracting arrangements changed in response to this?
- What is meant by the LNG Portfolio/Trading model and how does it work?
- What are the likely future trends in terms of this model and its interaction with the evolution of the LNG business and what does this portend for oil indexation?

The paper charts the evolution of the industry from its early paradigm of long-term fixed destination contracts between sellers who largely own the upstream fields and liquefaction infrastructure and buyers who receive the LNG at import terminals for their domestic market, to new forms of participation, such as:

- Portfolio Players who generally have some investment in upstream fields and liquefaction plant but who also have long term contracts to purchase LNG and who have a range of buyers on long, medium, short and 'spot' terms on oil and hub-price related prices. Portfolio players are mainly the large 'majors' or 'second tier' international upstream oil and gas companies and more rarely the upstream 'independents'.
- LNG Traders generally engage in short term LNG sales and purchases – seeking to make a margin through flexibility without long-term contractual positions or capital intensive underlying upstream asset ownership positions.

LNG Demographics and Fundamentals over Time

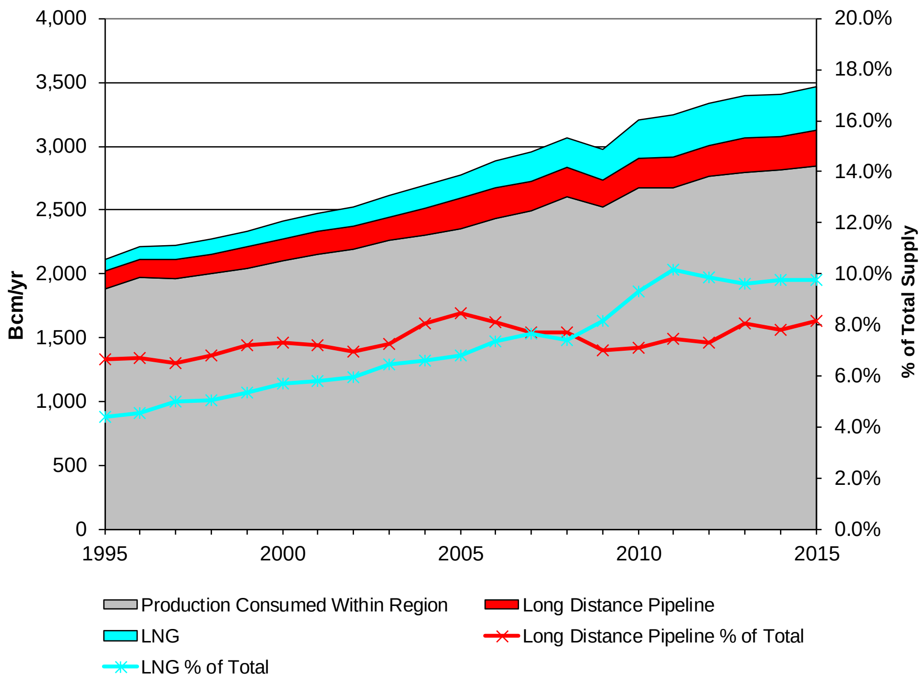
LNG is merely gas which has been cooled to -161 degrees C through cryogenic refrigeration (termed liquefaction) and transported as a liquid to distant markets on specially designed ocean-going tankers. At the receiving import (re-gas) terminal it is initially stored in large insulated tanks and introduced into the transmission system by applying heat to convert it back to natural gas. This is a relatively capital intensive process with the liquefaction, transportation and re-gas stages in aggregate adding some $4 - 7/mmbtu to the upstream break-even price at current cost base levels. Demand for LNG emerged most notably from the 1970s onwards in Japan, South Korea and Taiwan who had no significant alternative natural gas supplies. Since this time, LNG has made the leap from a 'high cost, niche channel' of natural gas supply to one whose share of global gas trade is rising, albeit from modest levels historically (Figure 1). When the expected price achieved in destination markets is sufficient to cover its

[4] 'The effect of LNG growth on global gas markets', http://www.bp.com/en/global/corporate/energy-economics/energy-outlook/lng-and-global-gas-markets.html

[5] The term 'aggregators' is also widely used but in the interests of brevity and accuracy vis a vis the essence of their business model, the term 'portfolio player' will be used throughout this paper.

cost base, LNG benefits from an inherent flexibility denied to pipeline gas and an avoidance of potential pipeline gas 'third country' transit problems.

Figure 1: LNG, Long Distance Pipeline Gas and Regional Production as a Share of Global Gas Consumption



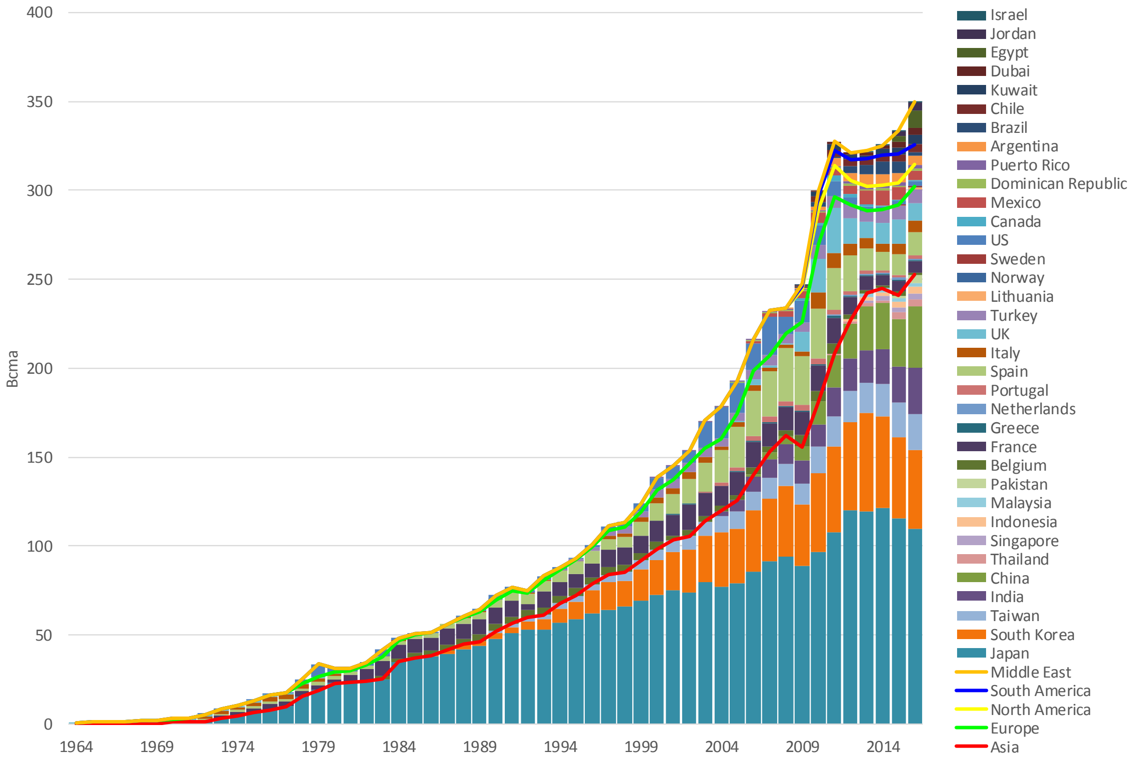
Source: BP Statistical Review of World Energy

Note: Long Distance Pipeline excludes trade-flows between European countries and those of North America i) as these are within relatively homogeneous 'trade blocs' and (ii) to include them would incur significant double-counting due to 're-exports' within these blocs.

In addition to the volume growth of LNG trade-flows, the number of importing countries has expanded dramatically, as shown in Figure 2. The cornerstone of the LNG industry historically has been the practice of contracting the output of liquefaction plants to buyers (traditionally nationally-based midstream utilities who sell gas and power generated from gas and other fuels to end-users) for 25 years or so, for a price directly related to crude oil prices with a minimum 'take or pay' of 90% of Annual Contract Quantity[6]. Such contracts historically had destination constraints (i.e. the buyer did not have the right to re-sell/divert LNG cargoes to third party destinations).

[6] In the LNG Industry this is usually referred to as the Downward Quantity Tolerance.

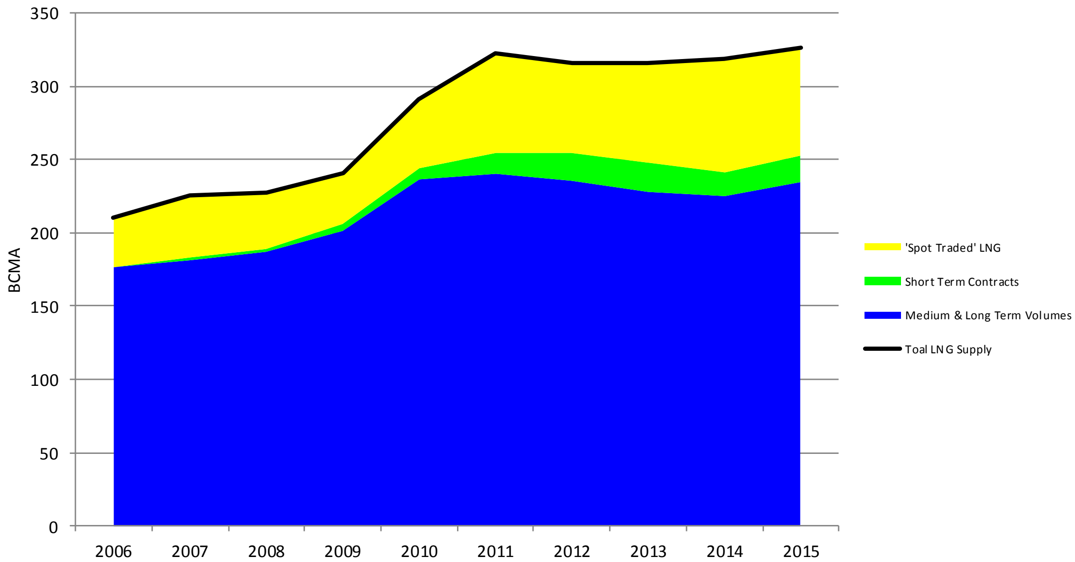
Figure 2: LNG Importing Countries (Grouped by Region) 1964 – 2016



Source: GIIGNL, Platts LNG Service

Over the past 20 years or so, the LNG market has become more flexible. The industry association GIIGNL produces annual statistics on many aspects of the LNG industry, perhaps the most publicised of which is the percentage of LNG sold on short term (four years or less) contracts or 'spot', versus longer term contracts. This is shown in Figure 3. In practical terms the 'spot' sales category includes both individual LNG cargo sales and arrangements for the sale and purchase of multiple cargoes at an agreed price, though usually not on a timescale which is more than a year or so.

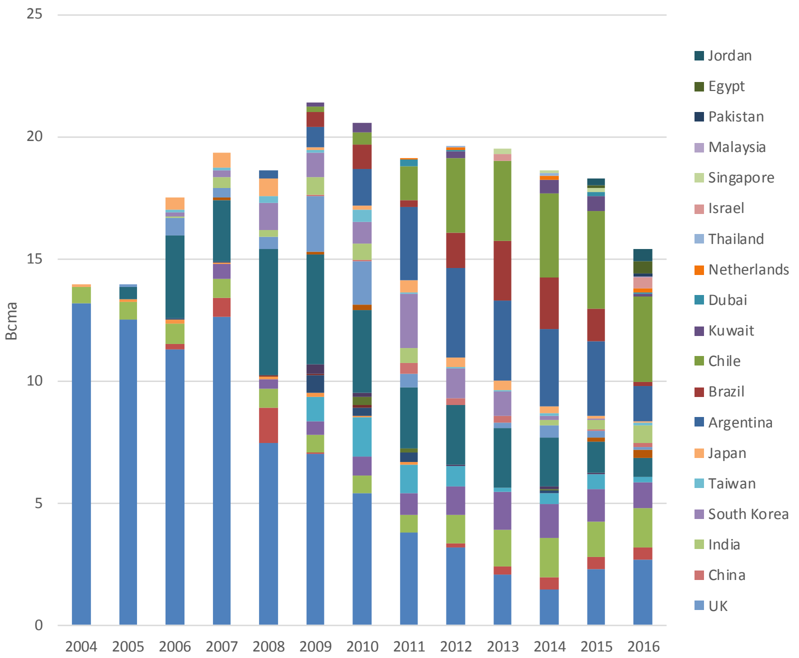
Figure 3: Global LNG Supply by Contract Duration – 2006 - 2015



Source: GIIGNL, Author's Analysis

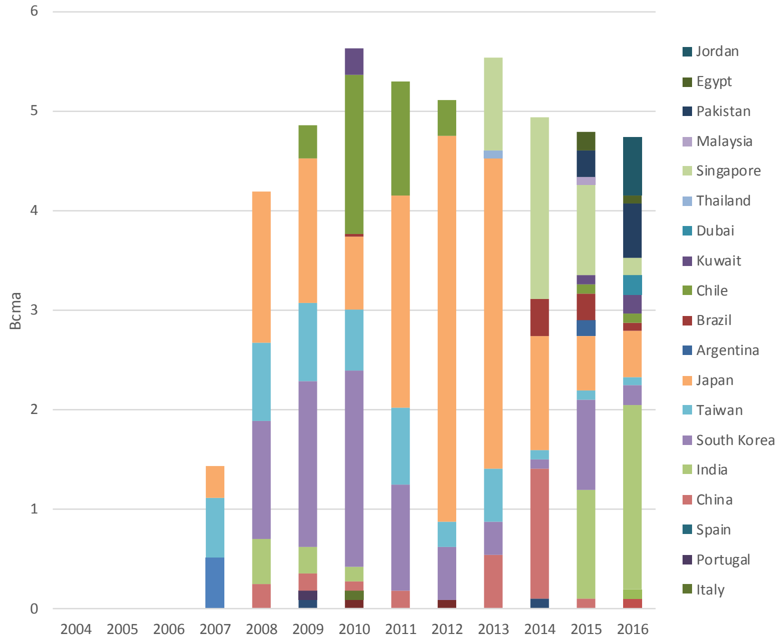
In 2015 Spot and Short-term contracts comprised 22.7% and 5.4% of all volumes sold respectively. It is widely anticipated that this share will increase as (particularly) US LNG export projects come onstream between 2017 and 2020. The growth in LNG volumes which are available for sale outside of a long-term contract is a powerful force for price arbitrage and is key to the business model of portfolio players and traders. Over time the initial buyers of LNG have diversified the range of final sales destinations through trading and short term contracts. Figures 4, 5 and 6 illustrate this diversification over time for Trinidad and Tobago, Equatorial Guinea and Qatar as supplier country examples.

Figure 4: Destination of LNG Cargoes 2004 – 2016 from Trinidad and Tobago



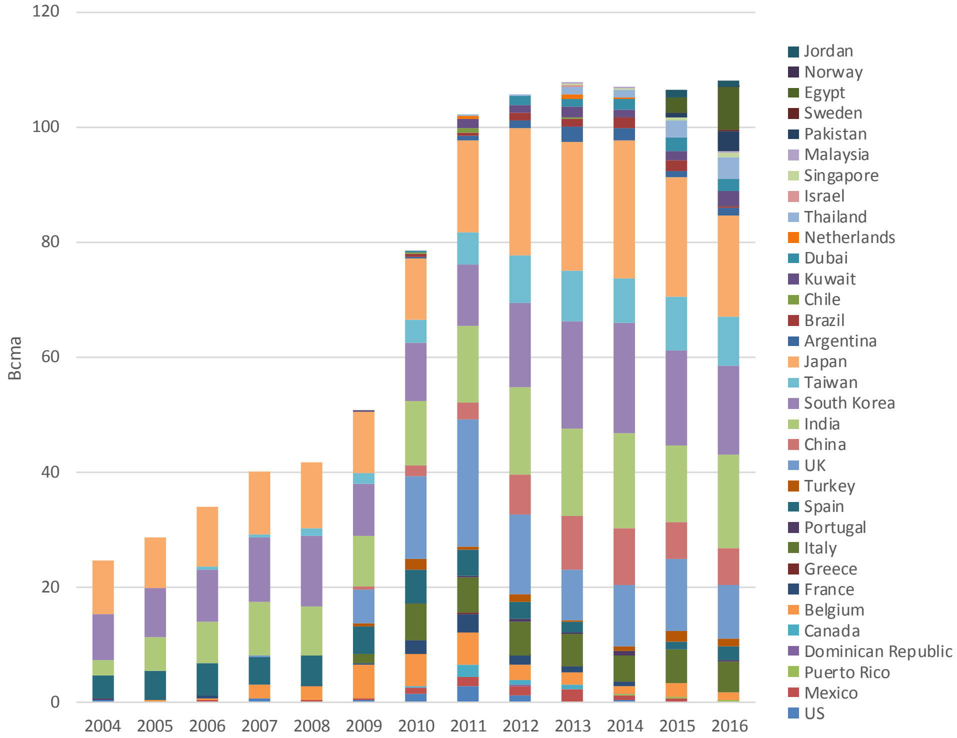
Source: Platts LNG Service

Figure 5: Destination of LNG Cargoes 2004 – 2016 from Equatorial Guinea



Source: Platts LNG Service

Figure 6: Destination of LNG Cargoes 2004 – 2016 from Qatar



Source: Platts LNG Service

Natural Gas and LNG Market Developments

While the Asian importing countries have provided the majority of demand for LNG since the inception of the industry (Figure 2), European imports have been a consistent feature, becoming more significant in the 2000s. North American imports began to exceed 5 bcma[7] in the early 2000s (but then rapidly subsided) with South America and the Middle East LNG imports commencing from the late 2000s. Over the period from 1980 to the present the following market developments directly impacted the LNG industry business model, introducing more flexibility to its original structure:

- **The waves of market liberalisation**, in North America (1980s), the UK (1990s), and North West Europe (2008 onwards) not only reduced the appeal of oil-indexed LNG contractual pricing mechanisms, it rendered them incompatible with the new hub-price related business model of potential LNG buyers in these markets[8]. Only buyers in Mediterranean markets (where, apart from Italy, hub pricing has yet to become the dominant pricing mechanism) could risk signing new LNG long-term oil-linked contracts which would (on the basis of statistical evidence to date) probably be more expensive than European hub pricing most of the time[9].
- **The 'tight' LNG market in the 2006 to 2008 period** caused by the under-performance of Indonesian LNG exports from 2003 onwards; continued rapid growth in Asian LNG demand; the slippage of new LNG supply project start-up dates in the 2005 to 2010 time-frame; and recurring Japanese and South Korean nuclear generation problems requiring the increased usage of gas-

[7] i.e. 5 bcma when converted to natural gas.

[8] See Stern, Jonathan in 'The Pricing of Internationally Traded Gas', Ed. Jonathan Stern, OIES, OUP, 2012, https://www.oxfordenergy.org/shop/the-pricing-of-internationally-traded-gas-ed-jonathan-p-stern/, Chapter 2, pp 46 - 54.

[9] Based on monthly average values for NBP and (oil-indexed) German Border price data from January 2001 to December 2016, German Border price was higher than NBP 77% of the time.

fired generation[10]. The incentive to re-direct LNG cargoes originally destined for Europe (which could be substituted by pipeline gas volumes) provided a sharp incentive for LNG contract counterparties to agree the addition of value sharing diversion clauses in contracts. Once such a flexibility provision was in place there was no reason to remove it.

- **The downward trend in UK and US domestic natural gas production in the early 2000s** was a key signal to develop new LNG supply projects for these markets. This provided part of the incentive for the Qatari LNG expansion, with new re-gas terminals built in Italy, the UK and the USA[11]. The perceived need for future LNG imports into the US in the early 2000s spurred the development of some 200 bcma of US re-gas import capacity. The US shale gas revolution (not anticipated when these projects took FID) by 2008 onwards obviated the need for significant imports of LNG, requiring Qatar and its joint venture partners to seek alternative markets.
- **The divergence in regional price references post 2010** (See Figure 7). For most of the 2000s the key regional gas price markers were relatively closely aligned, (apart from the impacts of Hurricane Katrina in the US and the Rough Storage outage in the UK[12] in winter 2005-2006), until mid-2009. The post financial crisis reduction in gas demand in 2009 resulted in significant falls in Henry Hub, NBP and Asian LNG spot prices (driven by supply-demand forces), while the average Japanese LNG import price (contractually driven by crude oil prices) remained more robust and quickly recovered as oil prices headed north of $100/bbl. With the US becoming a 'gas island' and shale gas production outstripping domestic demand, Henry Hub remained in the range $2/mmbtu to $6/mmbtu. A surprisingly rapid recovery in Asian LNG demand from 2010 was exacerbated by the Fukushima disaster in March 2011 which rapidly tightened the LNG spot market causing the Asian LNG spot price to oscillate around the Japanese oil-indexed average import price. NBP and European hubs gravitated (through arbitrage) towards the Russian oil products-indexed pipeline gas long term contract price but with periods of significant de-linkage to lower levels. The scale of the re-direction of LNG away from Europe towards Asia in this period severed the LNG arbitrage-driven link between Asian LNG spot price and European hub price[13].
- **The emergence, at scale, of US LNG export projects**[14] with a fundamentally different business model than had been previously seen in the LNG industry, which offered significant volumes on a destination-flexible basis. Offtake capacity in the first five projects (currently operational or under construction) was rapidly taken up, mainly by LNG portfolio players. We will return to the impact of this later.
- **The post 2013 softening of Asian LNG demand** (and gas demand in Europe) – led to sharply lower Asian LNG spot prices and European hub prices which can be seen in Figure 7. These price falls pre-dated the collapse of crude oil prices later in 2014 which, through contract price formulae, led to a delayed fall in Japanese average LNG import price.
- Against this more muted (but still uncertain) Asian LNG demand outlook[15], **the prospect of large new LNG supply volumes over the period to 2021** principally from the US and Australia[16] looms

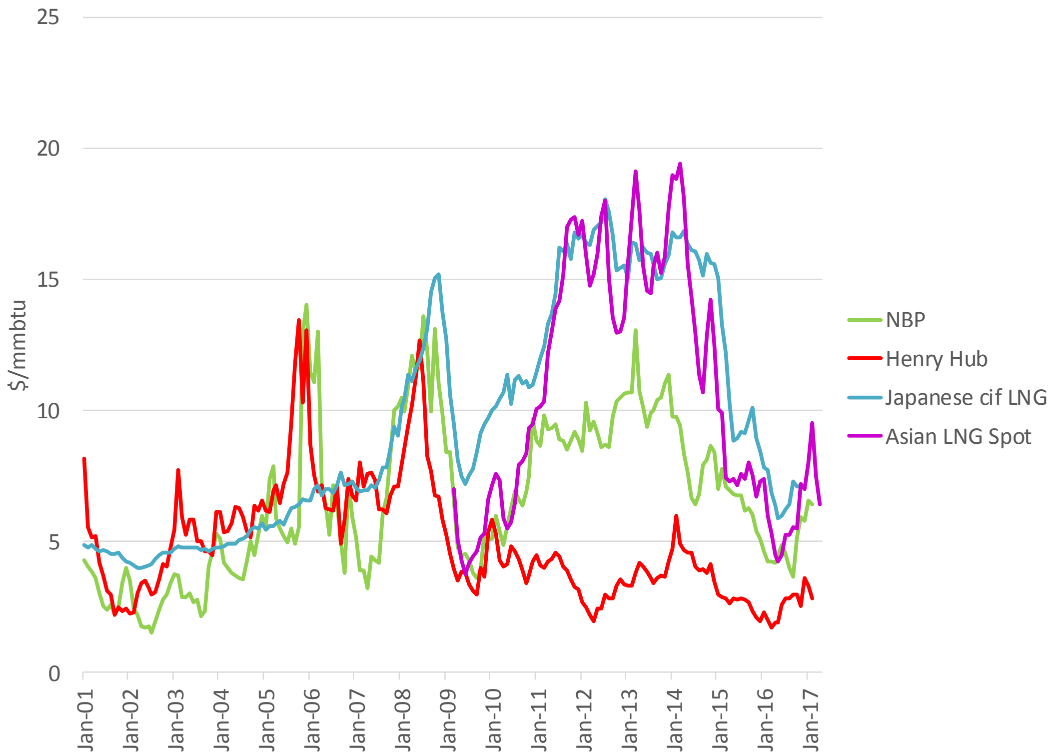
[10] See Rogers, Howard in 'The Pricing of Internationally Traded Gas', Ed. Jonathan Stern, OIES, OUP, 2012, https://www.oxfordenergy.org/shop/the-pricing-of-internationally-traded-gas-ed-jonathan-p-stern/, Chapter 12, pp 384 - 387.
[11] See Flower, Andy, in 'LNG Markets in Transition: The Great Configuration', Ed. Anne-Sophie Corbeau and David Ledesma, OIES 2016, OUP, https://www.oxfordenergy.org/shop/lng-markets-in-transition-the-great-reconfiguration/, Chapter 2, pp76 – 84.
[12] Exacerbated by the aforementioned tight LNG market.
[13] Another dynamic here was the negotiation of diversion flexibility and upside sharing with producers into existing supply contracts in the post Fukushima period which effectively resulted in a growth in gas volumes that are responsive to spot price signals – see later.
[14] Almost all based on adding liquefaction facilities to regas import terminals which had been built in anticipation of significant US LNG imports.
[15] See Rogers, Howard in 'LNG Markets in Transition: The Great Reconfiguration', Ed. Anne-Sophie Corbeau and David Ledesma, OUP, 2016, https://www.oxfordenergy.org/shop/lng-markets-in-transition-the-great-reconfiguration/ Chapter 6, pp 327 – 285.
[16] Also from Russia (Yamal T1 – T3), Indonesia Tangguh T3 and other smaller projects in Malaysia and Indonesia.

large on the horizon. Depending on the (uncertain) trajectory of future Asian LNG demand growth, this is likely to result in a 'glut' of LNG with the direct implication that European hub and Asian LNG spot prices will be lower for its duration[17].

- Possibly 'smarting' from the unprecedented high LNG price levels in Asia in the 2011 to 2014 period (see Figure 7), **Asian LNG buyers stated a strong desire to move away from oil-indexed LNG prices** in new long-term LNG contracts. Indeed the (at present somewhat uncertain) re-start of Japan's nuclear plant, shutdown in the aftermath of Fukushima, could avoid the need for Japan to contract for any new long-term LNG volumes above current legacy portfolio levels.

The above sequential market developments, some driven by unforeseen events, others perhaps more natural evolutionary stepping stones, have introduced flexibility into the relationship between LNG sellers and buyers[18], which once established is difficult to reverse.

Figure 7: Regional Natural Gas Price References 2001 – 2017



Source: Platts, EIA, Argus

LNG Contractual Structure Evolution

The LNG and natural gas market developments described above directly influenced the contractual aspects of the LNG industry. To provide the contextual starting point we will look briefly at the segments of the LNG supply chain and its contractual linkages starting with the upstream field[19].

Upstream gas (and oil) fields, are generally explored for and developed by groups of IOC and NOC co-venturers in an unincorporated joint venture. The group will undertake investment and be

[17] See 'The Forthcoming LNG Supply Wave: A Case of 'Crying Wolf?'', Howard Rogers, OIES, February 2017, https://www.oxfordenergy.org/publications/forthcoming-lng-supply-wave-case-crying-wolf/

[18] For a wider discussion of the development on flexibility in the industry see Corbeau, Anne-Sophie, in 'LNG Markets in Transition: The Great Reconfiguration', Ed. Anne-Sophie Corbeau and David Ledesma, OUP, https://www.oxfordenergy.org/shop/lng-markets-in-transition-the-great-reconfiguration/, 2016, Chapter 9.

[19] For more detail on this subject see Ledesma, David in 'LNG Markets in Transition: The Great Reconfiguration', Ed. Anne-Sophie Corbeau and David Ledesma, OUP, 2016, https://www.oxfordenergy.org/shop/lng-markets-in-transition-the-great-reconfiguration/, Chapter 3

remunerated by a share of the (after-tax) cashflow from this activity either under the terms of a Concession (Tax and Royalty) agreement or a Production Sharing Agreement. One of the co-venturers will act as the Operator and supply skilled resources for oil and gas activities and cash-call other participants for their share of costs (and share out the proceeds of oil and gas sales). The two major exceptions to this structure are a) when the upstream activities are wholly undertaken by an NOC (in which case the state provides all funding and receives all the sales proceeds) or b) where the activity is undertaken as part of an incorporated joint venture. In this situation a separate company is formed to undertake the upstream activities, staffed by secondees from the shareholder companies. This is not a common upstream structure, however it is the form used for some of the Trinidad and Tobago LNG-supplying fields and Qatari LNG projects.

The next segment of the supply chain is the **liquefaction plant**. This is a purpose-built, physically large and capital intensive facility. In the majority of cases historically the liquefaction plant was owned and operated by an incorporated joint venture company. The creation of this 'special purpose entity' (SPE), which could be financed from share-holder equity and loans from banks secured against project performance, at one time had the attractiveness of 'off-balance sheet financing'. However, even prior to the United States Sarbanes-Oxley Act of 2002, this was becoming less attractive to upstream companies, especially the large majors for whom raising balance sheet debt was cheaper, quicker and had less onerous disclosure requirements[20]. The Majors may still at times be required to use SPEs and project financing if it is a political necessity to admit host government entities (e.g. NOCs) and smaller upstream co-venturers into the liquefaction project. In general though it logically follows that, if they were otherwise unconstrained, the major IOCs would prefer to avoid project finance for the liquefaction element of LNG projects.

In terms of the **contractual relationship between upstream gas field projects and liquefaction projects** there are essentially three options[21]:

- A send-or-pay contract between an unincorporated field development joint venture and the liquefaction project entity – either an incorporated or unincorporated joint venture,
- A tolling fee contract between the upstream unincorporated field development joint venture and the liquefaction project entity – either an incorporated or unincorporated joint venture
- An integrated arrangement – whereby these two stages of the LNG supply chain are viewed as essentially one investment project – either as an unincorporated joint venture or (in the case of some of the Qatari projects) an incorporated joint venture company.[22]

The segments of the value chain described above have been the focus of most literature on the LNG industry, however the innovation in the last decade or so has been in the contractual arrangements downstream of the liquefaction plant – the **sales agreements**.

The early template was set by LNG sales to Asian markets. LNG projects (whatever the upstream ownership architecture) sought long term (i.e. 25 year) contracts. The geographic destination was fixed as the buyers' re-gas terminal. The price was linked (in the case of Asia) to the crude price (either international crude price or specifically to the crude import price in Japan[23]) with three or four months' lag. This was not a crude oil price 'equivalent' but was more widely known as the 'slope'- i.e. the extent

[20] See 'BP Amoco (A): Policy Statement on the Use of Project Finance', B. Esty & M. Kane, Harvard Business School, January 2003, xa.yimg.com/kq/groups/23193559/1162016259/name/Case_9_BP

[21] Note that in the case of the Cheniere Sabine Pass project the tolling fee agreement includes a charge for the liquefaction entity to procure gas from the US transmission system (supplied ultimately by upstream unincorporated joint ventures or limited partnerships).

[22] For an illustration of the different structures in the Qatari LNG JVs see: Flower, A. in eds. Fattouh, B. and Stern, J., Natural Gas in the Middle East and North Africa, OUP/OIES: 2011, Chapter 10. (https://www.oxfordenergy.org/shop/natural-gas-markets-in-the-middle-east-and-north-africa/)

[23] The JCC – Officially the price of Japanese Custom Cleared Crude – colloquially referred to as the Japanese Crude Cocktail.

to which the LNG price changes in response to changes in the oil price.[24] The same is believed to be true of Southern European LNG contracts. In Asia some contracts contained floors and ceilings to the relationship with crude price and in more sophisticated contracts 'S' curves to achieve similar results.[25]

As noted above, the spread between Asian LNG spot prices and European LNG contract prices in the late 2000s undermined, through bi-lateral re-negotiation, the destination clauses relating to contracts in Southern Europe – allowing for LNG diversion to achieve higher sales prices.[26] The requirement for the buyers in long term LNG contracts to receive annual contract quantity (ACQ) volumes of LNG on a DES (Destination ex Ship) basis has also been eroded (by the insistence of the buyers) by the more frequent occurrence of the FOB (free on board) norm – i.e. the buyer has the obligation to buy the cargo but is free to sell it in whatever international market it chooses.

Although the oil-indexed long term contract has been the norm for the Asian market, the existence of tolling arrangements[27] (between the upstream producing field grouping and the liquefaction plant), and sales contracts which allowed buyers (whether national utilities or intermediaries) to purchase LNG under long term contract on more of a 'cost plus' basis led to what (from a mid-stream perspective) were viewed as 'cost advantaged' LNG sources. These include Equatorial Guinea (LNG purchased price ex Liquefaction plant based on Henry Hub)[28], Trinidad and Tobago[29] and Qatar[30].

The sales strategy for the LNG from the Qatari trains built in the late 2000s and early 2010s was initially that the US and UK markets would receive each a third of the LNG produced (with the remainder for Asia and other markets). However, the subsequent reduction in US and European hub prices posed an interesting dilemma. Qatari long term contract sales to Asian buyers were concluded on oil-indexed terms, but prospective buyers in the US and North West Europe could not sign such contracts given the risk of unmanageable exposure to hub prices this would create. The Qatari incorporated joint venture shareholders effectively underwrote the liquefaction and upstream investment for these trains and committed to sell the associated LNG volumes for the best price they could using a flexible strategy of market diversification. Small volumes were initially sold in the US market (see Figure 6), and some under a short-term contract at the UK's NBP hub price to Centrica in the UK[31]. The balance appears to be sold on a mix of spot sales and short, medium and long term contracts to a variety of importing countries – on unknown pricing terms. In retrospect the diversification of Qatari volumes as described above can be viewed as a key stage in the development of the portfolio model – albeit at the time this was more likely a forced response to changing market conditions.

The US LNG projects (prior to the fall in crude price, and hence oil-linked LNG contract prices, at the end of 2014) appeared to offer a large new tranche of cost-advantaged LNG for players signing the tolling agreements – typically LNG on an FOB basis at Henry Hub plus 15% (to cover transport and liquefaction energy input) plus a $3.00 to $3.50/mmbtu liquefaction 'tolling fee'. Volumes for the five projects which proceeded to FID were quickly signed up.

We come now to a key distinction concerning sales contracts ex Liquefaction plant, i.e. whether the buyers are:

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[24] For a detailed description of how the slope operates in Asian LNG contracts see: Flower, A. and Liao, J. in ed. Stern, J. The Pricing of Internationally Traded Gas, op.cit., Chapter 11.

[25] For more details on S-curves and how they operate see previous note.

[26] Destination clauses in European gas contracts were declared anti-competitive by EU Competition Authorities in the early 2000s and were required to be taken out of long term gas contracts delivered to European Union countries.

[27] The first Tolling agreement example related to the Bontang liquefaction plant in Indonesia.

[28] See 'Exclusive-How one West African gas deal makes BG Group billions', Reuters Oil Report, July 2012, http://uk.reuters.com/article/bg-equatorial-guinea-lng-idUKL5N0FA1BE20130712

[29] 'Government to Review LNG Agreements', Trinidad and Tobago Guardian, January 2016, http://www.guardian.co.tt/business/2016-01-21/govt-review-lng-agreements

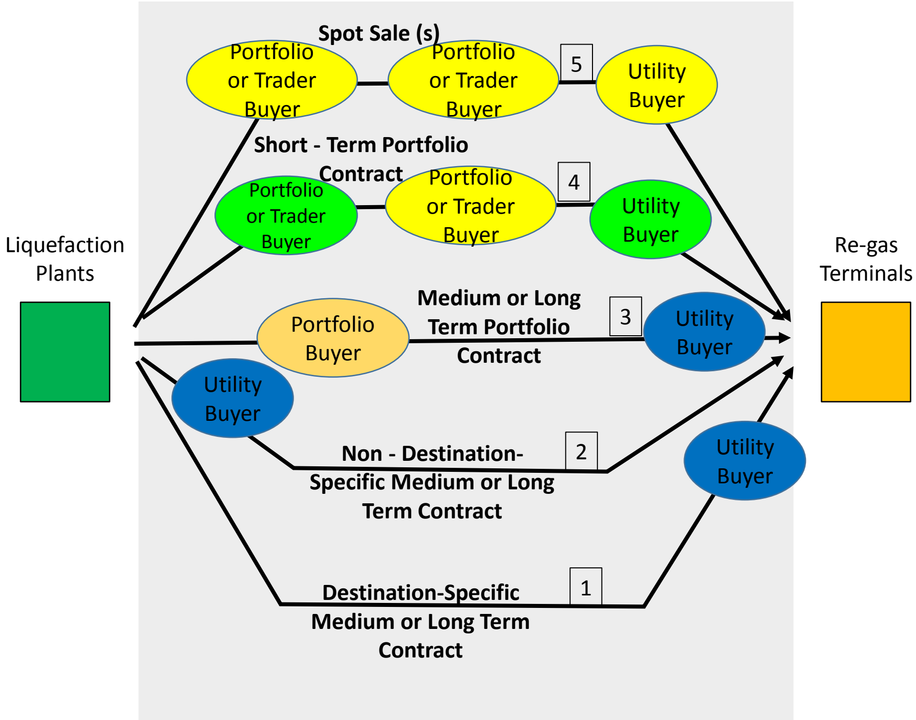
[30] 'The US Shale Gas Revolution and its Impact on Qatar's Position in Gas Markets', Bassam Fattouh, Howard Rogers and Peter Stewart, Columbia Centre on Global Energy Policy, March 2015, http://energypolicy.columbia.edu/sites/default/files/energy/The%20US%20Shale%20Gas%20Revolution%20and%20Its%20Impact%20on%20Qatar's%20Position%20in%20Gas%20Markets_March%202015.pdf, P. 11

[31] There is a 3 mtpa contract in place between Qatar and Centrica (originally 2011 to 2014; extended to 2018)

- Midstream utilities securing LNG supplies under long term contract for sales to (affiliate) power generators or industrial, commercial and commercial end users in their home countries; or,
- Midstream utilities and IOC's committing to buy the output of a liquefaction plant (or in the case of US LNG export facilities, at least commit to the fixed costs of an option to offtake LNG) with the intention to sell this LNG flexibly – i.e. with no fixed destination market in mind.

The situation becomes less clear as we move down the supply chain. In addition to the two cases above, there is now a more complex situation developing where LNG may be re-sold one or more times between the liquefaction plant and re-gas importing terminal – either on an individual spot cargo basis or through a chain of short, mid or long term contracts.

Figure 8: Different Channels to Market



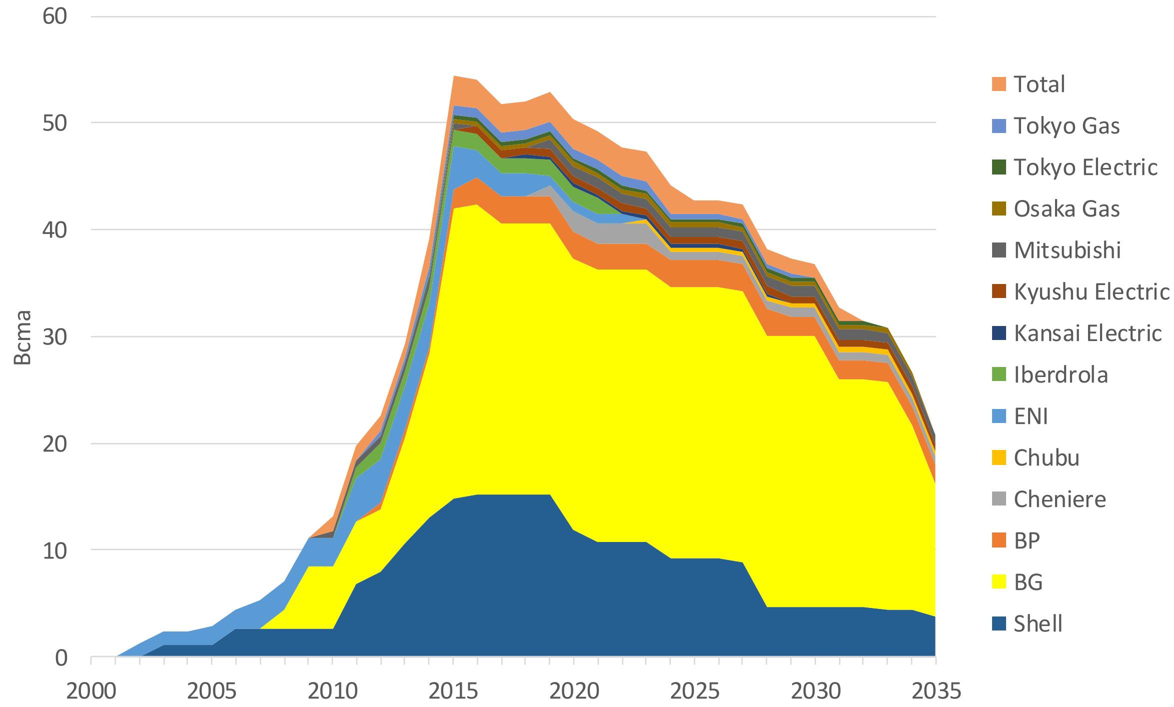
Source: Author

Figure 8 shows a simplified schematic view of different channels to market. Attempting to quantify the volume of LNG in any specific 'channel' is problematic due to the potential for 'double counting' cargo 're-sales'. The matrix of possibilities expands when one takes into account that for 2016 there were 18 active LNG supplier countries and 35 importing countries.

Business Strategy Response – Enter the Portfolio Players and the LNG Traders

Figure 9 shows the volumes under 42 medium and long term contracts identified by GIIGNL explicitly from the portfolios of the sellers listed and a range of buyers. To add further complexity, some of the buyers are also portfolio players. Figure 9 also shows the scale of the combined Shell-BG Group portfolio following the merger in early 2016. The buyers in these long term contracts with Shell – BG are mainly Asian utilities but other portfolio players are also buyers.

Figure 9: Medium and Long Term Portfolio Contracts from Defined Sellers



Source: The LNG Industry, GIIGNL Annual Report, 2016, pp 6 and 11, http://www.giignl.org/publications

Clearly the growth in volumes taken by likely portfolio players from the US LNG projects (at least 40 bcma) and new Australian projects (at least 25 bcma) account for a majority of the volumes in Figure 9, but this does not account for all the BG volumes shown. These probably represent a conversion to medium and long term portfolio contracts of LNG previously sold on a short term or spot basis.

Unfortunately, it is not possible to link the data in Figure 9 either to specific liquefaction projects (source supply) or to the data in Figure 3 (destination sales). Some of the volumes in Figure 9 will be sold to end-user utilities and consumed; some re-sold under medium and long term contracts, short term contracts or spot sales. While it is therefore impossible to derive a quantitative measure of midstream portfolio volumes in terms of total 'delivered and consumed' LNG, clearly this represents a material tranche of supply adding flexibility to tradeflows. A high case estimate of (final delivery) spot and short-term LNG volumes of 43% of total LNG volumes by 2020 is indicative, however, of the scale of transition to flexibility underway[32].

The factors which have catalysed this massive growth in the portfolio and trading model since circa 2000 are:

- The spread between regional gas reference prices between 2009 and 2014 (in the US, Europe and Asia) which provided opportunities for increased profitability, especially for LNG with low ex-liquefaction purchase costs (either due to it being prospectively linked to US Henry Hub prices or on a cost-plus basis[33]).

[32] See Corbeau, Anne-Sophie, in 'LNG Markets in Transition: The Great Reconfiguration', Ed. Anne-Sophie Corbeau and David Ledesma, OUP, https://www.oxfordenergy.org/shop/lng-markets-in-transition-the-great-reconfiguration/, 2016, Chapter 9, P. 538.

[33] Note that prior to the mid 2000s LNG liquefaction plant costs were much lower than those completed later. See 'LNG Plant Cost Escalation', Brian Songhurst, OIES, February 2014, NG83 https://www.oxfordenergy.org/publications/lng-plant-cost-escalation/

- The expanded matrix of LNG exporting and importing countries alluded to above, which introduced individual buyer needs, unforeseen demand spikes and hence price volatility over and above the indicative regional price reference spreads.
- The professed requirement of many Asian utility buyers to move away from oil indexed contracts and their demand for more flexibility in new and existing contracts in terms of destination clauses.
- The proposition that supply and market access optionality combined with the application of advanced trading optimisation and risk management tools can unlock additional value.
- The opportunity to participate as off-takers in the five US LNG projects either recently commissioned or under construction represented a huge opportunity for portfolio players to increase their supply options[34]. As far as can be ascertained, of the 90 bcma or so of liquefaction capacity from the five US LNG export projects, portfolio players took 45 bcma.[35]

Traders such as Trafigura, Vitol, Glencore and Noble are essentially pursuing an 'asset-light' version of the portfolio player business model – essentially securing flexible LNG and creating a web of sales opportunities with lower levels of investment in liquefaction plant or re-gas terminals. The rise in short-term contract and spot volumes since around 2010 (Figure 3) and the consensus outlook of a well-supplied LNG market to 2020 has and will continue to provide a favourable business environment for those players a) able to access LNG for less than full-cycle (or LRMC) cost-reflective prices and b) using relationships with customers established through trading other commodities. Traders have particularly secured trading volume growth through the process in which buyers 'tender' for the purchase of multiple cargoes over a period of months on a competitive price basis.

Understanding the Portfolio/Trading Model[36]

As demonstrated above, the LNG supply chain is subject to interacting physical supply chain elements and degrees of contractual flexibility. From an individual company portfolio perspective, the physical and contractual 'web' created is a complex business to analyse and value, and the decision to invest in a new asset component (or dispose of an existing one) requires an understanding of the impact on the overall company portfolio value. In other words, when it comes to LNG portfolio value the 'whole does not equal the sum of the parts'. Because the portfolio and LNG trading business models are so different to the simple 'point to point' long term contracting historical model, the following staged explanation is set out to help the reader appreciate in the first instance how an individual participant's business is valued and subsequently how it is managed on a day-to day basis.

The three stages to understanding LNG portfolio valuation are set out below:

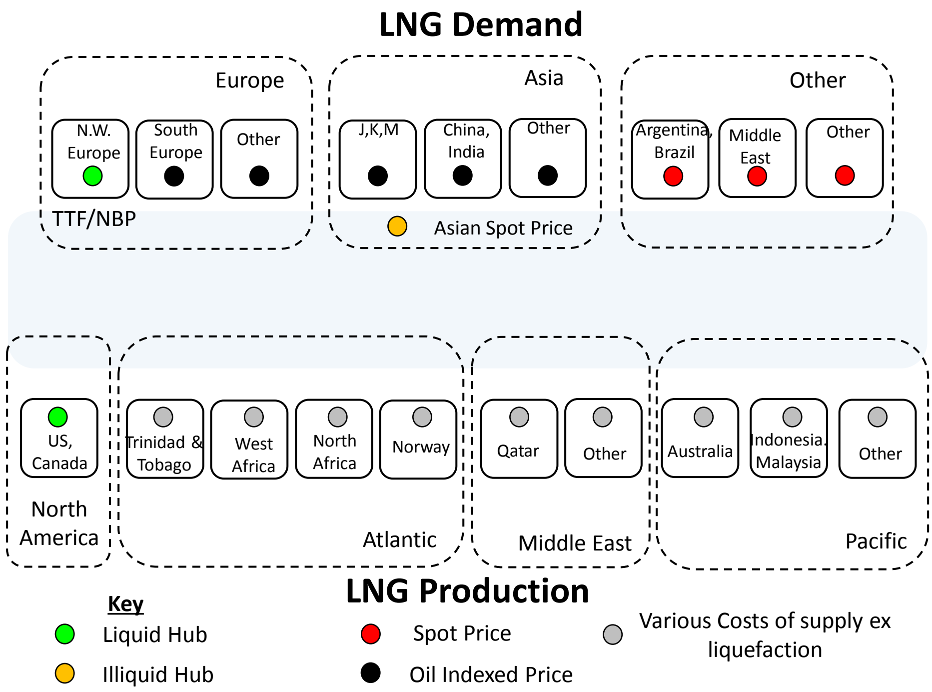
Stage 1: Source to destination analysis: Recognising that price spreads are the key driver of LNG portfolio value this first stage involves a 'nodal' analysis of the value of all supply and destination 'pairings'. Value will be constrained physically by liquefaction plant, shipping and re-gas capacity but also by production cost, supply contract terms and destination price assumptions. In simplistic terms, the profit margin (on a variable cost basis) will be determined by subtracting from the sales revenue (sales volume times expected price at destination) the variable element of any re-gas fees, shipping, liquefaction costs or tolling fees and the cost of feedgas. This is aggregated for all the supply and destination 'pairings'. A full cost version would include fixed costs associated with the above elements.

[34] Although at the time such off-take agreements appeared attractive compared to oil-indexed LNG contracts, this was essentially 'un-hedgeable'. In the subsequent 'LNG glut' outlook the 'extrinsic' value of such contracts – i.e. their flexibility value versus their underlying fixed cost base is becoming increasingly important for global price dynamics.

[35] Based on firm projects in 'Challenges to JCC Pricing in Asian LNG Markets', H. Rogers & Jonathan Stern, NG 81, OIES, February 2014, https://www.oxfordenergy.org/publications/challenges-to-jcc-pricing-in-asian-lng-markets/, Table 5, P. 23, but note that some utilities may also re-sell these volumes

[36] See 'Building LNG Supply Chain Value', Timera Energy September 2012, http://www.timera-energy.com/building-lng-supply-chain-value/, and 'Developing a LNG portfolio valuation capability, October 2012, http://www.timera-energy.com/developing-a-lng-portfolio-valuation-capability/

Figure 10: Nodal view of an LNG portfolio



Source: Timera Energy

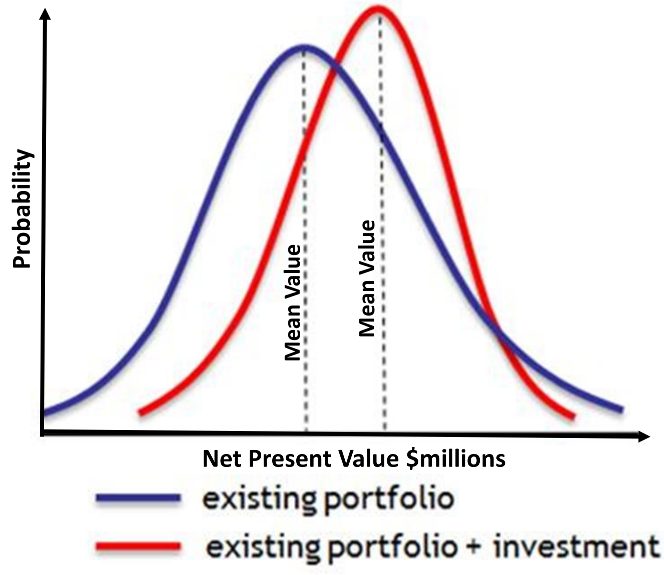
Stage 2: Developing a simple portfolio model: The limitation of the Stage 1 nodal 'source to destination' model is that it lacks the ability to explore alternative market pairings and additional supply options. Stage 2 involves developing a model that optimises LNG portfolio flexibility at current market prices (thus deriving the **intrinsic value** of the portfolio). As well as providing information on asset value, this stage allows the calculation of the cost of specific portfolio constraints (such as limited supply flexibility or shipping capacity).

Stage 3: Developing a full stochastic portfolio model: This stage focusses on capturing the uncertainty around market risk factors and hence allows a better understanding of the **extrinsic value** of portfolio flexibility. Stage 3 involves developing the ability to:

- Simulate the evolution of market prices (e.g. Henry Hub, NBP/TTF, Asian LNG spot price, crude, exchange rates) incorporating views on market fundamentals (e.g. the evolution of hub price correlations and volatility).
- Allow the representation of specific portfolio hedging and optimisation strategies (e.g. hedging portfolio exposures through time).
- Re-optimise portfolio flexibility and adjust hedge positions in response to changes in market prices and exchange rates.

The valuation capability outlined above provides a quantitative assessment of existing portfolio value and risk and specifically the impact of changes in market fundamentals. It also enables the company to quantify the incremental value of structural portfolio changes such as asset investments, changes in contract terms or changes in hedging strategies. Figure 11 shows (illustratively) the valuation of the LNG portfolio (in probabilistic terms) with and without the investment in an additional portfolio asset.

Figure 11: The impact of portfolio value of investing in an additional asset



Source: Timera Energy

The above approach, applied in 'real time' allows portfolio players and traders to monitor their existing LNG network and react to:

- New supply or sales opportunities emerging;
- Anticipated price movements at alternative destinations providing additional value, net of the costs incurred as a consequence of the diversion of LNG cargoes;
- Additional shipping capacity allowing greater ability to reach more remote but perhaps higher priced destination markets;
- The opportunity to swap cargoes for specific destination sales allowing for a reduction in shipping costs.

This 'real-time' modelling of the portfolio is a complex undertaking as it needs to take into account changing physical, pricing and cost factors:

- Variations in the estimated LNG vessel arrival time at the destination port due to weather or other problems. Only when arrival time risk is reduced to an acceptable level can the LNG unloading slot at the destination regas terminal be 'locked in';
- The costs of potential LNG diversion which include regas fees committed to, (if the original destination was a European hub) the placing of an equivalent buy trade for gas to match the previous LNG cargo sell trade, and any increase (or reduction) in shipping costs;
- Changes in destination market prices and associated exchange rates impacting such prices. These will include hub price futures curves, oil and oil product futures prices (in so far as they relate to sales prices related to crude or products).

As might be imagined, the stochastic approach to portfolio valuation, the risked-NPV impact of investments and disposals and the real-time assessment of trading strategies and emerging opportunities require the application of sophisticated mathematical approaches[37]. In general these are based on the Black-Scholes option pricing theory[38] (and subsequent evolutions of this framework). The fundamental attraction of this approach is that it appears to provide the basis on which the value of an option, whose exercise date is at some point in the future, can be quantified based on two critical assumptions; a) that the sales price, while unknown and subject to day to day variation, exhibits 'mean reversion' tendencies[39], and b) that the future volatility of the sales price can be estimated based on recent historic volatility metrics. While this approach provides a convenient analytical valuation framework for LNG trading (and trading in general) the two key criticisms of the approach are that a) rather than 'mean reverting', price movements (particularly in the LNG and gas traded markets), are often skewed by events such as unforeseen supply chain bottlenecks and cold weather high demand events, and b) related to this, price volatility in recent months may be no guide to that in a future period especially where supply is more constrained relative to demand[40]. Despite these shortcomings, the general analytical approach heralded by the Black-Scholes paradigm has been adopted and its imperfections 'buttressed' by informed judgement on key future variables, which is by definition far from fool-proof.

Three important points should be made regarding the LNG portfolio/trading business model:

- Even though they may employ the most gifted applied mathematicians and deploy the most advanced stochastic modelling approaches, there is no guarantee that individual players can place all their LNG cargoes in 'premium' markets. If available flexible supply (in aggregate for all players) exceeds Asian, Middle East, Southern Europe and South American LNG requirements, the balance will be sent to NW Europe for sale at the NBP/TTF hub price.
- In terms of the long-running debate on the relative merits of oil-indexation versus hub prices for natural gas and LNG – the portfolio players/LNG traders are, at heart, agnostic. Their business value is driven by the outlook of the spread between LNG purchase and sales price and how best to take advantage of price volatility while optimising their trading portfolio cost base.
- The approach of the Portfolio players and Traders is a **world away** from the traditional 'A to B' long-term, destination – fixed contract model.

Clearly such a departure from the 'old world' LNG business model would not gain traction if buyers at the end of the 'chain' did not see benefits. These are two-fold:

- Portfolio players and traders, due to their ability to reduce acquisition and transportation cost base through portfolio synergy may be able to offer lower prices to buyers.
- Portfolio players and traders take on the operational and post – strike price cost risk from a buyer's perspective.

The implication of current market conditions for the LNG portfolio model

Notwithstanding the considerable power and sophistication of the LNG portfolio/trading model, the current market environment (see Figure 7) is fundamentally challenging for players who, whatever the price formation basis of their destination market, need to cover the Long Run Marginal Cost of LNG to make a profit. This may be possible for LNG supplies from older plant built before the cost escalation of upstream and liquefaction projects in the late 2000s[41], but for later projects an LNG sales price in the range of $8/mmbtu to $11/mmbtu is necessary. Since mid-2015 (apart from a temporary price spike during winter 2016-2017) such prices have not been attainable in LNG importing markets (other than for those US LNG volumes sold under contract to utilities on the basis of Henry Hub price plus fully built-up supply chain costs).

[37] In the trading business this discipline is often referred to as 'quants'.
[38] See http://www.investopedia.com/university/options-pricing/black-scholes-model.asp
[39] That is, although prices change from day to day, they tend to keep returning to the same general value.
[40] See 'Natural Gas Price Volatility in the UK and North America', S. Alterman, OIES, NG60, February 2012, https://www.oxfordenergy.org/publications/natural-gas-price-volatility-in-the-uk-and-north-america-2/
[41] Or where the co-production of hydrocarbon liquids provides support to project economics.

Apart from attempting to dispose of upstream and liquefaction assets (in a distressed market) or terminate/renege on US project tolling fee agreements, the portfolio players and LNG traders must focus on maximising the margin of sales over variable costs. In extremis this could result in decisions not to offtake US LNG if the variable cost of procuring gas from the US transmission grid, shipping costs and regas costs exceeds the spread between European hub prices or Asian LNG spot prices. In a well- or oversupplied market in the next five years, the 'asset – light' LNG trading model might still prove profitable, especially if traders are able to generate margins by taking 'distressed' cargoes otherwise destined for European hub markets from portfolio players. While the current environment is supportive for the LNG traders, it relies on the availability of LNG which can be purchased from larger players currently unable to recover their full investment costs.

The issue of Asian pricing benchmarks is covered in more depth later in this paper. An important dimension of the current portfolio player/trader business environment, directly related to the current state of regional price evolution, is the need for such players to 'hedge' future positions. For example, LNG sales can be sold into the liquid European hubs up to two years ahead but, if Asian spot prices offer a premium, these can be offset by 'buy trades' to release the cargo for physical sale in Asia (provided that the price premium covers all the costs of balancing the sell position). Essentially this dynamic, in synthesis, can be regarded as a 'put option' for LNG into Europe – with the option cost equalling the operational and transactional costs of not following through with physical LNG delivery. Similarly, LNG sales to Asia by portfolio players and traders concluded on an oil-indexed price (or specific 'slope') can be 'de-risked' or hedged by purchasing crude options at the price prevailing at the time of sale agreement to guard against oil price escalation above the forward curve for the duration of the contract.

The Outlook for the 'Next Wave' of LNG projects

The current soft or 'glut' LNG situation will persist until the market is rebalanced, probably in the early to mid-2020s, depending in large part on the growth rate for LNG demand in Asia which is subject to much uncertainty. In the context of the need for the 'next wave' of LNG projects for the 2020s (after the current hiatus in project FIDs has passed) the key questions are:

- Which projects are likely be 'advantaged' in terms of cost base?
- What are possible evolutionary paths for LNG pricing?
- What is the role of the portfolio players in the next investment wave?

Which projects are likely to be advantaged in terms of cost base?

At present many (but not all[42]) observers of the LNG industry anticipate little need for new liquefaction capacity before the early to mid-2020s. The US is clearly an advantaged location for the 'next wave' of LNG supply projects given high labour force productivity and lower project execution risk characteristics. McKinsey expect North America to dominate the next wave[43] with Africa, Middle East and South East Asia making much smaller contributions to new supply. Notwithstanding its attractions as a liquefaction project location, US LNG projects, to progress to FID, would still require an expectation of an LNG sales price of around Henry Hub plus \$4.5/mmbtu to \$5.5/mmbtu[44]. LNG projects outside North America, will require significant cost reductions from their 2016 estimates and/or the benefit of liquids co-production to compete on break-even pricing with most US projects (especially those involving the conversion of regas facilities to export). Qatar, with its prodigious condensate co-production from the North Field clearly represents a very advantaged location for new LNG projects, however the self-imposed

[42] Both BP and Shell are notably more optimistic on the pace of future LNG demand growth in their respective Energy and LNG 2017 outlooks.
[43] 'Next Wave of LNG capex to fall short of recent highs', Pietro Dalpane, November 2016, Energy Insights by McKinsey, https://www.mckinseyenergyinsights.com/insights/next-wave-of-lng-capex-to-fall-short-of-recent-highs/
[44] This 'spread' between Henry Hub and destination markets to cover the (typically) 15% of Henry Hub for liquefaction fuel consumption, the liquefaction tolling fee/return on capital, shipping costs and regas costs.

moratorium on further development appears to be in place for the duration, although very recent developments suggest that this situation could change[45].

What are possible evolutionary paths for LNG pricing?

Clearly as the market rebalances one would expect the law of supply and demand to be reflected in higher Asian LNG spot prices and, linked by arbitrage, European hub prices. Trying to map out the likely future price formation basis of medium and long term contracts associated with future LNG projects is specific to regional markets. For Europe LNG will be sold at hub prices. Contracts will probably be short to medium term (as the Qatar – Centrica one). However, if hub liquidity is maintained it is questionable whether **contracts with end-user utilities** are necessary as LNG portfolio players and traders can merely sell volumes via hub exchanges or OTC brokers.

As noted in our 2014 paper[46], Asia still presents a dilemma in that buyers are focusing on price level and not price formation. For example, at the Barcelona World LNG Conference in December 2016 it was reported that buyers were looking for a diversification of LNG pricing away from oil. There was no clear preference for an alternative form of indexation other than one which yielded 'lower prices'. In an audience poll the majority of delegates saw hybrid pricing as the preferred solution[47]. Part of this uncertainty is undoubtedly caused by price movements over the past few years. When oil prices were at $100/bbl an LNG contract price based on Henry Hub plus full supply chain costs was very attractive compared to a traditional oil-indexed LNG contract price. With oil at $50/bbl the opposite is the case. In a February 2015 publication[48] Poten & Partners noted that in an environment of lower future demand expectations, portfolio players in effect made volume purchase commitments to upstream suppliers in a market where conventional utility purchasers were harder to find. Where these commitments were priced on an oil-indexed basis the 'slope' ranged from single digits up to 11%. Of the contracts which were wholly or partly linked to one or more hubs in 2015 around two thirds were linked to European hubs and one third to Henry Hub.

JERA Co President Yuji Kakimi, speaking during the Reuters Commodities Summit in Tokyo in October 2015,[49] claimed that the prospect of large US LNG volumes helped push down prices in Asia substantially, as sellers now offer a milder (lower) LNG price slope for oil-linked contracts. He concluded with the statement "We have achieved big success in significantly lowering Asian LNG prices….When oil prices rise, will LNG become more expensive? I don't think such an age will return." Exactly how the goal of lower LNG prices for the long term is to be achieved in practical terms is not spelt out, but would have to either entail a) moving to a different (non-oil related) index or b) constant renegotiation to re-calibrate the 'slope' as the oil price changes.

In his 2016 paper[50] Jonathan Stern noted Japan's firm intention to pursue both power and gas market liberalisation, with the intention of creating a traded gas hub and reference price. However, Kho Hui Meng, Head of Vitol Trading in Asia is less optimistic regarding LNG price benchmarks in the region. "In the energy space, Asian consumers are still price-takers; they don't want to lead the market". The reason for this difficulty, said Mr Kho, is that there is less risk-taking in the Asian markets as compared to the West[51].

However, on a more positive note the Platts JKM swaps hit a new record high in trade liquidity on the Intercontinental Exchange in October, as traders sought to hedge short-term risk amid growing demand

[45] See: http://www.afr.com/markets/commodities/energy/australia-could-lose-lng-export-king-status-after-qatar-lifts-north-moratorium-20170403-gvcymd

[46] 'Challenges to JCC Pricing in Asian LNG Markets', H. Rogers & Jonathan Stern, NG 81, OIES, February 2014, https://www.oxfordenergy.org/publications/challenges-to-jcc-pricing-in-asian-lng-markets/

[47] Conference note from David Ledesma, OIES.

[48] 'LNG in World Markets', Poten & Partners, February 2015, http://www.poten.com/wp-content/uploads/2016/02/Producers-Pass-Buck-to-Portfolio-Players-Opinion.pdf

[49] http://www.reuters.com/article/us-lng-jera-idUSKBN16E2RO

[50] 'The new Japanese LNG strategy: a major step towards hub-based gas pricing in Asia', J. Stern, OIES, June 2016, https://www.oxfordenergy.org/publications/new-japanese-lng-strategy-major-step-towards-hub-based-gas-pricing-asia/

[51] http://www.businesstimes.com.sg/energy-commodities/asian-lng-price-benchmark-might-be-slow-to-take-off-vitol

and rising prices in the Asian LNG spot markets[52]. The JKM swap is a monthly cash-settled futures contract, based on the Platts daily JKM assessment, a daily physical spot market price assessment for LNG delivered to Japan, South Korea, China and Taiwan. A total of 75 companies engage in the assessment of the physical Platts JKM marker, with 25 participants actively trading the JKM swaps through ICE. The JKM swaps contract reflects a standard lot size of 10,000 MMBtu.

Clearly the current oil price of $50/bbl and spot LNG price of $6/mmbtu environment (compared with the 2011 to early 2014 period) is both an uncomfortable one for portfolio players (specifically those who have supplies priced off oil at high slopes or Henry Hub plus tolling fee), and a confusing one for Asian buyers – who would like to see current spot or oil-indexed LNG contract price levels continue, but who similarly are unlikely to create their own price references based on the supply-demand dynamics of their specific market, or at least not for some years.

In advance of the development of an Asian LNG price reference based on deep, liquid trading it is likely that Asian spot prices will see periods of price volatility (price 'spikes') due to weather and possibly nuclear shut-down events, especially as the region is structurally short of underground gas storage. Paradoxically this might be viewed favourably by portfolio players and traders with flexible volumes to take advantage of short-term high price differentials between Europe and Asian LNG markets.

LNG portfolio players and LNG traders are driven by margin optimisation through employing advanced modelling techniques and while they may be 'agnostic' as to the academic arguments for and against hub versus oil-indexation they are keenly aware of how changes in market fundamentals and customer preferences impact portfolio value. A recovery in oil prices ahead of gas-LNG market re-balancing might initially be 'good news' for players with substantial volumes secured with buyers on an oil price slope basis but this would unravel as buyers insist on slope reduction in pursuit of a price level target. At some point it becomes preferable to push for LNG contract prices related to either European hubs or an emerging Asian marker such as the JKM swaps or Singapore Sling.

What is the role of the portfolio players in the next investment wave?

This section examines the comparative advantage of the portfolio players (in particular the majors amongst them) in the next wave of LNG supply project investments in the 2020s.

Although the potential LNG 'glut' period to the early 2020s will not be an easy one for portfolio players, with large sunk costs/commitments difficult to cover through trading margins, paradoxically the 'Majors' amongst them may emerge in a relatively strong position (relative to second tier and independents) for the next LNG supply investment wave in the 2020s. As leading indicators of LNG market rebalance and European hub and Asian LNG spot prices emerge:

- The portfolio players with medium and long term contracts will see improving margins on sales linked to hub or LNG spot prices (oil-indexed sales will not be related to gas market fundamentals).
- All upstream and midstream LNG participants will begin to compete for positions in the next wave of LNG supply – i.e. projects potentially coming onstream in the early to mid-2020s.

In this context, the comparative advantages of the majors amongst the portfolio players compared with the independents and smaller players are:

- Their already well-developed portfolio of LNG supply sources and destination markets – which would allow them to see higher value in new LNG projects (intrinsic and extrinsic value) relative to the stand-alone player.
- Their ability (and preference) to raise debt finance on their balance sheets rather than on a project-specific non-recourse basis (as discussed earlier).

In practical, transactional terms this would translate into the Majors amongst the portfolio players:

[52] http://www.platts.com/latest-news/natural-gas/singapore/platts-jkm-lng-swaps-liquidity-on-exchange-hits-27704862

- taking FID on projects where they are the upstream and liquefaction participants, without long term offtake contracts immediately downstream of the liquefaction plant;
- signing long term contracts for LNG from third party liquefaction projects (or in the case of US LNG projects long term tolling offtake agreements).

In either case the rapid access to lower cost debt and ability to offer better terms for long term offtake (due to portfolio synergy) place them in a stronger position vis a vis the independents. Having secured new supply ex-liquefaction plant, the major portfolio players can then:

- Sell the LNG on whatever price formation basis they can agree with buyers;
- Choose a range of short, medium and long term contracts as well as spot sales to suit their own and buyers' risk preferences, rather than the dictates of banks (which would be the case in non-recourse project financing).

We have already seen examples of the major portfolio players taking large offtake positions on US LNG export projects and BP taking all the supply from the Mozambique Coral LNG Project (conditional on its eventual FID). The next step would be the direct investment in upstream and liquefaction plant by large players without project finance. ExxonMobil and Qatar's Golden Pass project or BP's Mauritania project could provide such examples.

The corollary of the above logic is that, in a world where oil-indexation may be fading and the scale of the next LNG supply wave may be finite and smaller than that of the late 2010s, independents and their banks may require a business model strategic 'reboot'. If non-Majors and energy sector banks do not adapt to this transition they may be 'left on the starting blocks' in the next LNG wave.

Conclusions

In this paper we have reviewed some of the major unforeseen events and evolutionary milestones of the LNG industry in the context of the wider natural gas industry. There are many examples (e.g. the negotiation of diversion rights in European LNG contracts, or the conversion of US regas facilities into export projects due to shale gas) where changes in the business environment drive additional flexibility, which once introduced tend to stick.

In terms of their impact on the LNG business, the waves of liberalisation of the North American, UK and NW European gas markets are possibly the most fundamental 'shocks' to LNG contracts and their price formation. Liquid hubs are the easily accessible markets of last resort for LNG, requiring only re-gas and pipeline access and a trading licence. It is difficult to make the case for retaining anything other than short-term contracts in this market context. The rise of destination-flexible LNG contracts appears to have provided portfolio players with significant volumes of medium and long term contracted sales volumes.

The potential to divert LNG cargoes and earn higher margins became evident probably in the mid-2000s when Asian LNG spot prices were at a premium to those available in Europe. Many IOC players assembled a web (or portfolio) of LNG supply sources and destination market access points. The application of option valuation theory and optimisation through stochastic modelling provided powerful tools to assess the impact of extending the web further through asset acquisition and also to guide real-time trading activity both in terms of profit maximisation and risk management. Portfolio players and the more 'asset-light' LNG trading companies began to focus on risk-weighted intrinsic and extrinsic portfolio value – a paradigm shift from the traditional fixed destination, oil-indexed, long term LNG contract model.

With the expectation of many observers of a period to the early 2020s of LNG supply in excess of demand growth, we are presently seeing something of a hiatus of new project FIDs. New LNG supply will be needed around the middle of the 2020s however. In the interim the industry will witness a period in which many players may be unable to cover fixed costs/generate an attractive return on investment. Portfolio players will focus on maximising revenue to at least cover variable costs – even if this means that US LNG volumes may at times be constrained if spreads between Henry Hub and European hubs are severely compressed.

The LNG price expectation in North West Europe is unequivocally NBP or TTF hub price and in time perhaps other hubs as they develop liquidity and/or are linked by interconnecting pipelines. The prospects for the evolution of Asian LNG market pricing is still unclear. Japan plans to create a trading hub but suitable levels of liquidity on which to base contract prices may be many years away. In the meantime contracts are being progressed on the basis of a mixture of European hubs, Henry Hub and oil indexation, albeit at lower 'slopes'. The lack of clarity caused by Asian buyers wanting lower prices but also wanting to move to a more appropriate price formation mechanism is likely to come to a head if and when oil prices recover ahead of gas and LNG market fundamentals. In this scenario, the prospect of continually renegotiating contract oil-price 'slope' linkages becomes a 'labour of Sisyphus'. Portfolio players will wish to move to a more rational pricing basis, especially because staying with oil indexation increases their risk exposure.

Although the competing embryonic LNG spot price references in Asia (Platts JKM, Singapore Sling, ICIS' East Asia Index) at present suffer from low liquidity as conventionally measured, it is heartening to note the growing liquidity of the JKM Swaps futures contract. If portfolio players' and traders' 'need' for a credible Asian reference price grows in tandem with trading volumes for the JKM swaps or similar product we could see a virtuous circle resulting in sufficient confidence to establish one or more of these as a contract reference price. Alternatively the use of European hubs might suffice with a transport cost adjustment, at least until a bona fide Asian price reference is established.

Although LNG portfolio players may see some lean years until a market rebalancing in the early to mid-2020s the 'majors' amongst them have distinct comparative advantages – both inherent and acquired through experience, which puts them in pole position for the next wave of LNG investment. Their ability to raise financing more cheaply and speedily against their balance sheets puts them at a distinct advantage over a smaller player requiring loans from banks on a non-recourse project basis.

The US with its cost base and lower risk project execution advantages is likely to provide many of the 'next wave' LNG projects and this plays further to the LNG portfolio player majors' skillset. These players will organise their sales strategies – contract length mix and price formation to suit themselves and their buyers – rather than the dictates of the banking community. Unless the mid-tier and independent companies and their banks recognise this change in the LNG business environment and adapt accordingly, they risk being left behind in the next LNG supply wave.