The Impact of a Globalising Market on Future European Gas Supply and Pricing: the Importance of Asian Demand and North American Supply

Howard V Rogers

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Preface

Over the past five years it has become a commonplace observation that regional gas markets are increasingly influenced by developments in different parts of the world. The shale gas revolution in North America, economic recession in Europe, the Arab Spring and the Fukushima nuclear accident in Japan provide examples of events which have had impacts on gas supply, demand and pricing far beyond their immediate geographical regions. This increasing "connectedness" between natural gas markets is often said to have created a "global gas market", but much depends on how that term is defined. Certainly the stage of development of international gas trade cannot be compared with the global oil market. But increasing "globalisation" - the fact that European gas stakeholders need to pay increasing attention to what is happening in both North America and Asia - marks a new phase in natural gas development which our research needs to take into account.

In his previous studies, Howard Rogers developed a model and a methodology which show the interaction of gas markets on a global scale. This study uses that model to analyse different scenarios of North American gas supply, and Asian gas demand over the next 15 years, showing how these could create fundamentally different outcomes for European supply, demand and pricing. This highlights the relative parochialism of much European gas commentary which, over the past decade, has concentrated on security issues relatively narrowly defined as dependence on Russian gas supplies. The study also examines the impact on Russian gas supply and pricing to Europe of different scenario outcomes in North America and Asia, showing that Gazprom also may need to make uncomfortable choices between volume and pricing of European exports over the next decade.

The innovative aspect of this research is that it shows that in a globalising gas market, Europeans need to pay as much attention to what is happening in gas markets elsewhere in the world, as they do to their own supply, demand and pricing dynamics.

Jonathan Stern
January 2012

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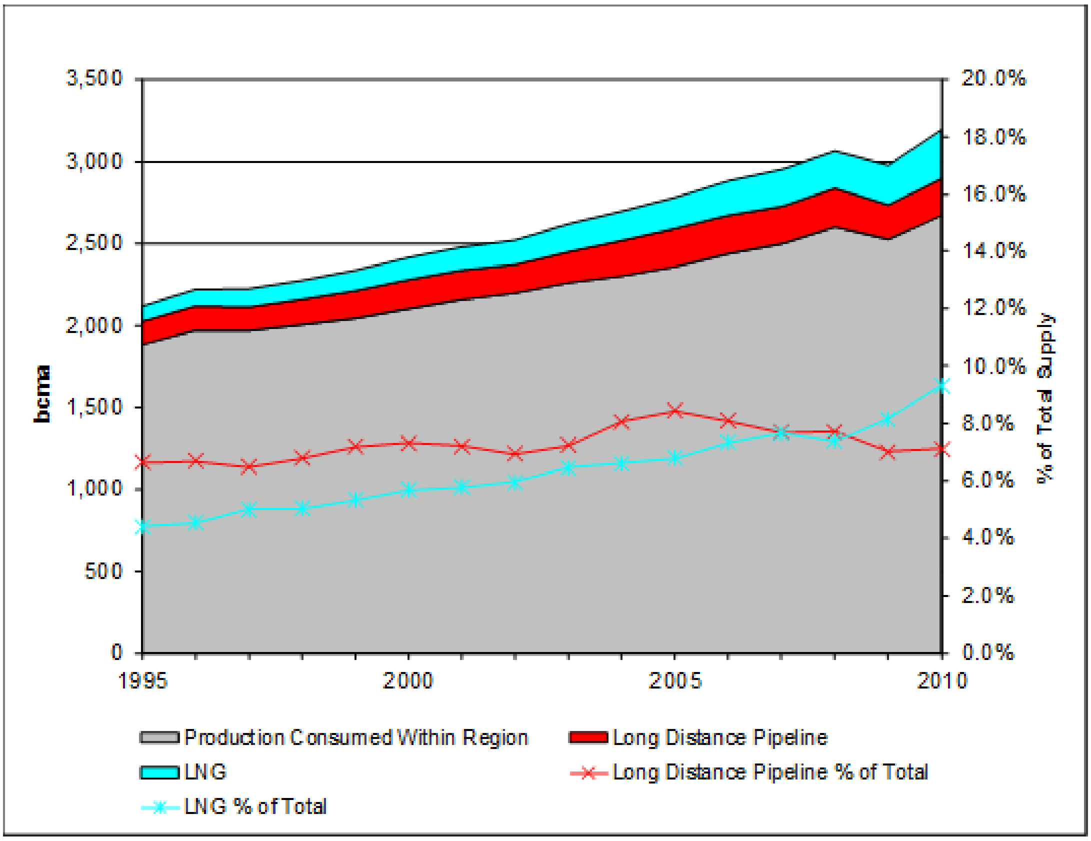
Introduction

Given its relatively high cost of transportation and storage when compared with higher 'energy per unit of volume' fuels such as oil, it is not surprising that historically natural gas production has tended to grow to supply nearby national and adjacent regional markets. Accordingly each regional market has developed its own approach to natural gas price formation. Broadly half of global gas consumption is priced either on the basis of gas on gas competition or by reference to oil or oil products prices; most of the remainder is 'state regulated', often at levels significantly below those prevailing in the markets of Europe and North America[1].

Figure 1: Global Gas Supply Channels 1995–2010



Source: BP Statistical Review of World Energy 2011, own analysis

As growing regional gas market demand outpaced the availability of indigenous and proximate supplies, the growth of 'long distance' gas, (trade-flows of pipeline gas and LNG), became established[2]. This is defined as LNG and pipeline gas which crosses regional and/or economic trading bloc gas market boundaries[3]. Figure 1 shows the segmentation of total

[1] ' Wholesale Gas Price Formation - A global review of drivers and regional trends', IGU, June 2011, http://www.igu.org/igu-publications-2010/IGU%20Gas%20Price%20Report%20June%202011.pdf

[2] Gas demand in the power generation sector was bolstered from around 1990 onwards by the widespread adoption of the Combined Cycle Gas Turbine.

[3] Where contiguous markets share the same broad market regulatory framework with a view to encouraging bi-directional gas trade-flows, their cross-border trade is excluded from this segmentation.

global gas supply in this manner. Long distance gas is classified as all LNG (blue) and pipeline trade-flows from Russia, North Africa, Iran and Azerbaijan into Europe and pipeline flows within Asia and South America (red) [4]. In the period 1995-2010 both grew, with LNG on a continuous trajectory. The economic recession resulted in a fall in global gas consumption and pipeline trade-flows in 2009, however LNG consumption increased markedly over 2008 levels in both 2009 and 2010.

The main regional markets receiving (or having the potential to receive) long-distance gas are **North America** (US, Canada and Mexico), **Europe** and the main **LNG importing countries of Asia** (Japan, South Korea, Taiwan, China and India[5]). Given the differing mechanisms of price formation and contractual supply arrangements in each region, the intriguing question arises as to "what would happen if one were to 'connect them together' with long distance gas?" This is not a hypothetical question. The challenge to Europe's oil-indexed gas contract paradigm, catalysed by the co-incidence of the depressed demand in 2009 and rapid growth of flexible LNG supply, is an on-going case study which in 2011 escalated to legal arbitration between three major players.[6]

This paper examines the present interaction between disparate regional market pricing structures facilitated by flexible LNG and how this may develop in the future. The assessment is based upon data available in 4th quarter 2011, however three particular areas of high future uncertainty require a scenario approach to be taken, giving rise to a matrix of cases. These relate to the future pace of demand for natural gas (and LNG) in the growing Asian economies, the prospects for US domestic production (including the possibility of North American LNG exports) and the degree of slippage of non-North American LNG projects. These are examined quantitatively with the aid of a system balance model to explore the logic and causality of the system as distinct from an attempt to predict the future.

In examining these scenario modelled outcomes the impact on regional prices and their linkage or de-linkage is assessed as are the differing fortunes of key suppliers (such as suppliers of long distance pipeline supplies to Europe) and their possible responses.

The paper concludes with a summary of the scenario findings and of the scale of the impact which future Asian demand and US production uncertainty could have on the connected global natural system, (particularly on Europe), due to the associated change in direction and size of LNG trade-flows.

To begin to explore these issues we need to first understand how gas pricing is formulated in each of the key gas consuming regions (North America, Europe and Asia) and the nature and degree of flexibility of pipeline gas and LNG.

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[4] Note that this excludes pipeline flows between European national markets.

[5] Thailand has recently joined the group of Asian importing countries. Its future LNG imports will be accounted for in global balances but commentary will focus on the existing Asian importers.

[6] Gazprom, E.ON and RWE: 'E.ON and Gazprom in gas price deadlock, Petroleum Economist, 2nd August 2011, http://www.petroleum-economist.com/Article/2877261/EOn-and-Gazprom-in-gas-price-deadlock.html; also Stern & Rogers, pp. 28,29

1. Regional Price Formation: North America, Europe and Asia

North America

Gas prices in the US are in the first instance driven by gas on gas competition and are discoverable at the many regional trading hubs. The best known is Henry Hub (HH) which is generally viewed as the reference point for North American natural gas prices. Prices at the other regional hubs differ[7] due to transportation costs and the supply-demand balance dynamics caused by the disparate location of demand relative to production centres. The US has 'porous' gas trade borders with Canada and Mexico, hence gas prices in both are influenced by the US market[8]. Due to the potential for inter-fuel competition in the power generation sector, gas prices can at times be influenced by the price of residual fuel oil, however this has rarely been a factor since 2006. Competition with coal in the power sector provides a 'soft floor' for US gas prices - a variable fuel switching price band due to the very significant geographical variation in coal prices between inland and coastal locations and the differing regulatory structures of power generating regions[9]. In the expectation that the US would require significant LNG imports some 160 bcma of LNG regasification[10] capacity was built in the mid to late 2000s (see Appendix, Table 7). With the dramatic growth in US shale gas production, regasification utilisation rates in 2011 remained low however, and several industry groupings are actively considering converting some of these facilities to be capable of exporting as well as importing LNG.

Europe[11]

In contrast to the UK market, which became liberalised in the mid 1990s, Continental Europe began the 2000s with a market structure dominated by long-term oil indexed contracts for pipeline and LNG imports and also for its domestic production. Pipeline gas purchased under long term contracts from Russia and North Africa is priced according to formulae which include six to nine month rolling averages of gasoil and fuel oil prices. These pricing terms are subject to periodic review (typically every three years) and may be amended through negotiation. The buyer commits to purchase, at a minimum, the 'Take or Pay' level (TOP) within a contract year running from October to September of the following calendar year. The take or pay level is typically 85% of the Annual Contract Quantity (ACQ).

During the 2000s the European Union enacted a series of legislative packages with the aim of creating a more competitive and liberalised gas market structure and stimulating more widespread gas on gas competition in Continental Europe. This has been a slow and tortuous

[7] Commonly referred to as 'basis differentials' in the US and Canada.
[8] See Rogers 2010.
[9] The incentive to choose the most economical fuel for power generation varies between regions due to the power market regulatory framework.
[10] The Americas Waterborne LNG Report, Waterborne Energy, Inc., 14th October 2011
[11] As defined for the purpose of modelling in this paper Europe includes: Austria, Belgium, Bulgaria, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania Luxembourg, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, UK.

process, however the demand reduction caused by the 2008 and 2009 economic recession, coinciding with a rapid growth in LNG supply from Qatar and other suppliers, has resulted in more vigorous activity in the nascent gas trading hubs of Northern Europe[12] and a growing challenge to the oil-indexed paradigm for gas pricing. A midstream utility buyer of gas in Continental Europe can choose whether or not its requirements for gas above the oil-indexed contract TOP level can be met by optional additional oil-indexed contract gas, or purchased at a trading hub (much of which physically originated from the UK market via the UK – Belgium Interconnector pipeline). The scope for arbitrage between 'spot gas' and oil-indexed contract gas can be summarised for two cases where:

The spot gas price is lower than the oil-indexed gas price: In this situation, midstream gas companies, trading at the hubs, will buy up more spot gas and buy less oil-indexed gas. This will have the effect of pulling more gas out of the UK and causing the UK gas price to rise. Buyers with long term contracts will thus reduce their nominations – effectively taking gas 'out of the system' as it is left in the gas field upstream. This process repeats itself until either:

- **the spot gas price has risen to equal the continental oil-indexed price; or,**
- **the supply of oil-indexed gas has been reduced to its take-or-pay level and the process of arbitrage can proceed no further (without infringing the terms of the supply contract).**

The spot gas price is higher than the oil-indexed gas price: In this situation, midstream gas companies, trading at the hubs will buy less spot gas and buy more oil-indexed gas. This will have the effect of pulling less gas out of the UK (and could send gas which was oil-indexed into the UK), causing the price to fall. Buyers under long term contracts will increase their nominations - effectively bringing extra gas 'into the system' through higher upstream production. This process repeats itself until either:

- **The spot gas price has fallen to equal the continental oil-indexed price; or,**
- **The supply of oil-indexed gas has been increased to its annual contract quantity (ACQ) level and the process of arbitrage can proceed no further.**

Figure 2 shows the UK price and the Continental oil-indexed price for the period 2001 to 2011 with periods of convergence due to the arbitrage mechanism described above.

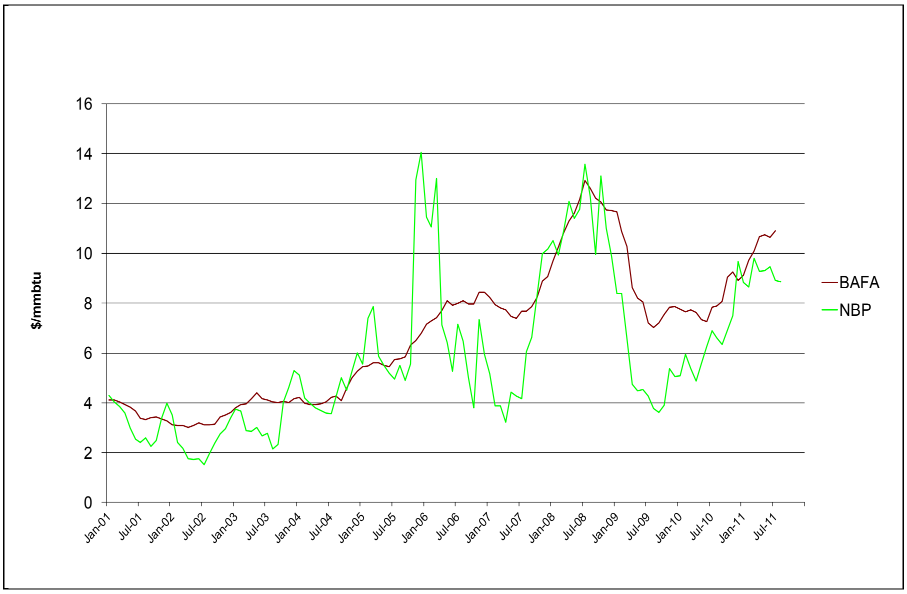
Asian LNG Markets

The majority of LNG trade flows in Asia are sold under long-term contracts with price linked to a time-averaged value of crude oil. Some contracts contain price ceilings and floors or an 'S' curve which moderates the more extreme oil price impacts on the LNG price. Asian importers also purchase spot LNG cargoes to supplement contracted supplies. Unlike the situation with European pipeline gas contracts, there is no explicit provision in Asian LNG contracts for a periodic price review. Each contract pricing formula is in effect 'frozen' for the lifetime of the contract – a 'snapshot' of the negotiated view of buyer and seller as to how

[12] See Heather, OIES (Forthcoming)

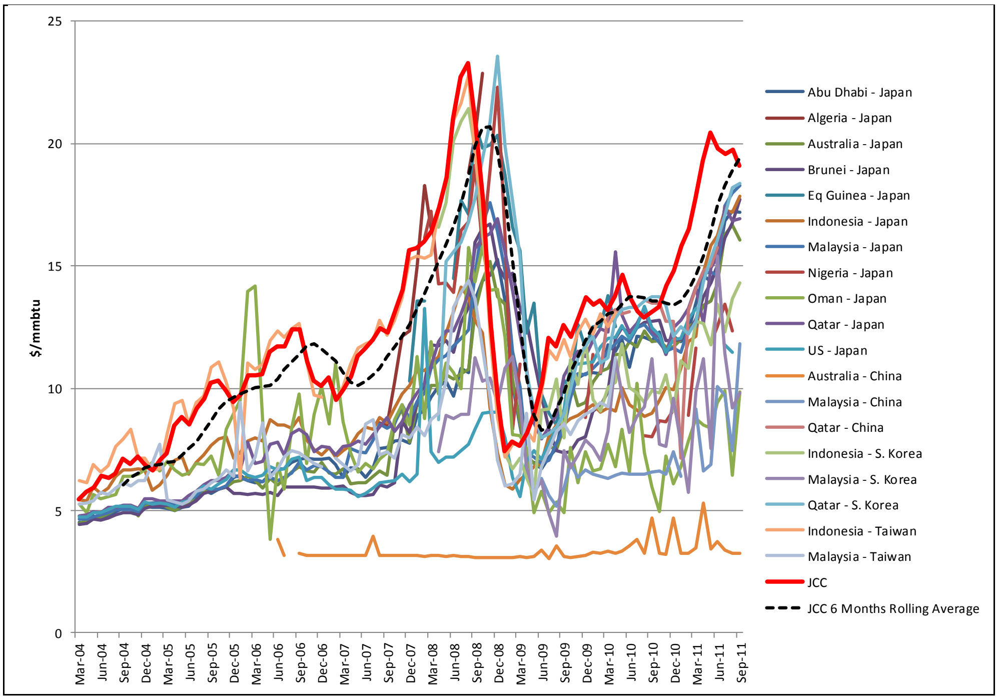
the future LNG price should respond to oil price changes. Over time this has led to a very wide range of contract prices. Figure 3 shows the price of LNG between various supplier countries and Asian LNG importers. Each line represents the bundle of contracts which sum to the particular supplier – importer LNG trade-flow; the picture at an individual contract level would show an even wider range.

Figure 2: UK (NBP) and European Oil-Indexed Price (BAFA) January 2001–August 2011



Source: Platts, BAFA

Figure 3: Asian LNG Prices January 2004–September 2011



Source: Argus Global LNG

The bold red line is the Japanese Customs Cleared (JCC, sometimes referred to as the Japanese Crude Cocktail) crude oil price to which LNG contract prices are related formulaically with a rolling average of several months. In 2004 contract prices were reasonably bounded but in 2011 the spread is from $4/mmbtu to $18/mmbtu[13]. It is also worth noting that more recent contracts have been negotiated at or close to JCC parity, albeit on what (from Figure 3) appears to be a six month time-averaged basis.

Recent Asian LNG spot prices have been identified (on an individual cargo basis) by ICIS Heren[14] since September 2010. These are shown in Figure 4 (low, average and high) together with NBP, JCC and a 6 month rolling average of JCC. Whilst between September 2010 and April 2011 there appeared to be a relationship between NBP and the average Asian LNG spot price, the gap between these price series has since widened. It might be expected that Asian LNG spot prices, in a tightening market could seek a JCC-level price, on the following rationale:

- If spot cargoes are substituting for LNG quantities in the Asian market contract supply 'downward tolerance[15]' band, the contract price would provide a benchmark price to which Asian spot LNG prices would rise through arbitrage.
- In Japan and Korea both LNG and crude oil are power sector fuels (although some gas from LNG is also supplied to non-generation final users). While we might expect fuel switching to provide the basis for a spot LNG price band, in practice short-term price - driven fuel switching is not a noticeable feature in these markets.
- From the foregoing it might be expected that a tightening market could see Asian spot market prices rising to a level similar to the 'lagged JCC' plot in Figure 3. In 4Q 2011 this seemed to be happening. Figure 4 suggests that for the period September 2010 to March 2011, the benchmark for Asian spot LNG cargoes was the UK gas price (NBP)[16]plus a margin which presumably reflects a distance-related shipping cost. After March 2011 the Asian Spot price started to rise closer to the lagged JCC plot.

If this trend continues one might expect further diversions of flexible LNG away from Europe and towards Asian LNG importing markets, further raising NBP and other European traded hub prices. When European hub prices reach European pipeline gas oil-indexed gas price levels one might expect European hub prices to remain in line with these such oil-indexed prices as higher pipeline contract nominations replace LNG volumes diverted to Asia. The continuation of cargo diversions to Asia may be sufficient to bring Asian LNG prices down from the JCC-lagged price level to re-establish the previous equilibrium with the 'NBP plus transport differential' relationship. We return to a discussion of these dynamics in the scenario outcome discussion.

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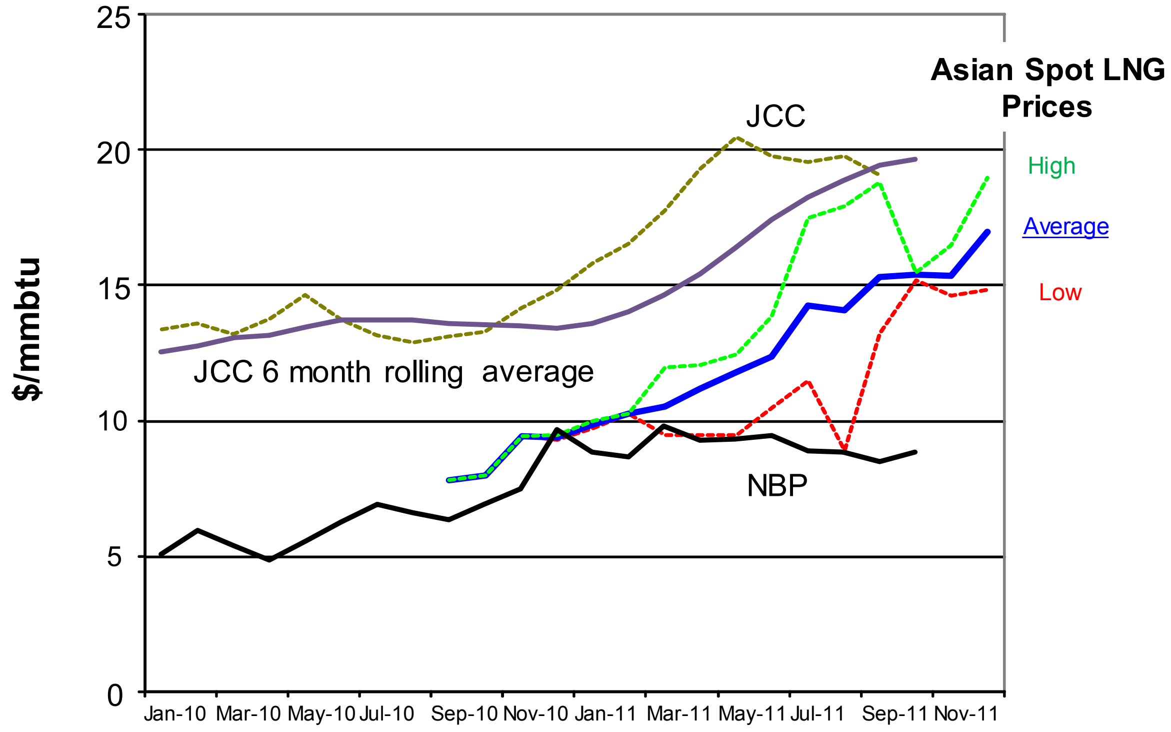
[13]Note that this data also contains spot cargoes which introduce a degree of deviation from a smooth time series relationship. See Argus Global LNG, Volume VII, Issue 11. pp. 17, 18 and historical issues

[14] ICIS Heren Global LNG Markets, 18th November 2011, pp. 6 – 10.

[15] Downward tolerance is analogous to the difference between Annual Contract Quantity and Take-or-Pay level in European oil indexed gas pipeline contracts.

[16] NBP stands for National Balancing Point, the UK gas 'virtual' trading hub.

Figure 4: Asian Spot LNG Prices January 2010–December 2011

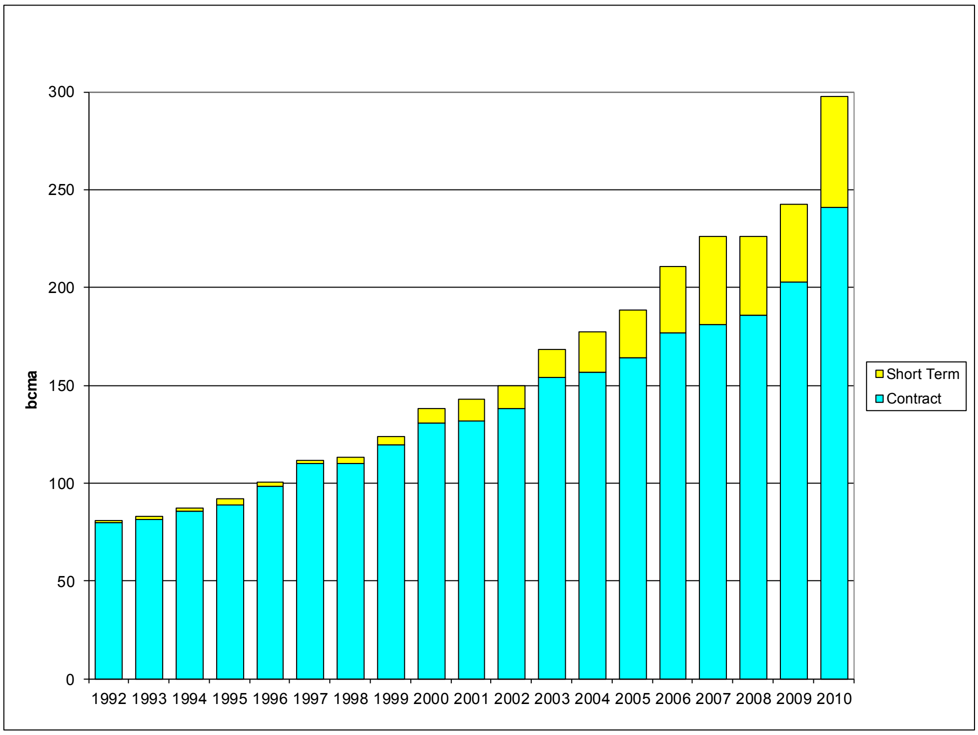


Sources: ICIS-Heren, Argus Global LNG, Platts

2. The Flexibility of LNG

In order to consider how the regional markets of North America, Europe and the Asian LNG importing markets might behave when 'connected together' let us first examine the flexibility of LNG supply. The majority of LNG is sold under long term contracts, however the trend has been towards more flexible arrangements. Figure 5 shows total global LNG supply under long term contracts (blue) and short term sales[17] (yellow). In 2010, short term sales accounted for 18% in 2008 and 19% in 2010.

Figure 5: Long and Short Term LNG sales 1992–2010



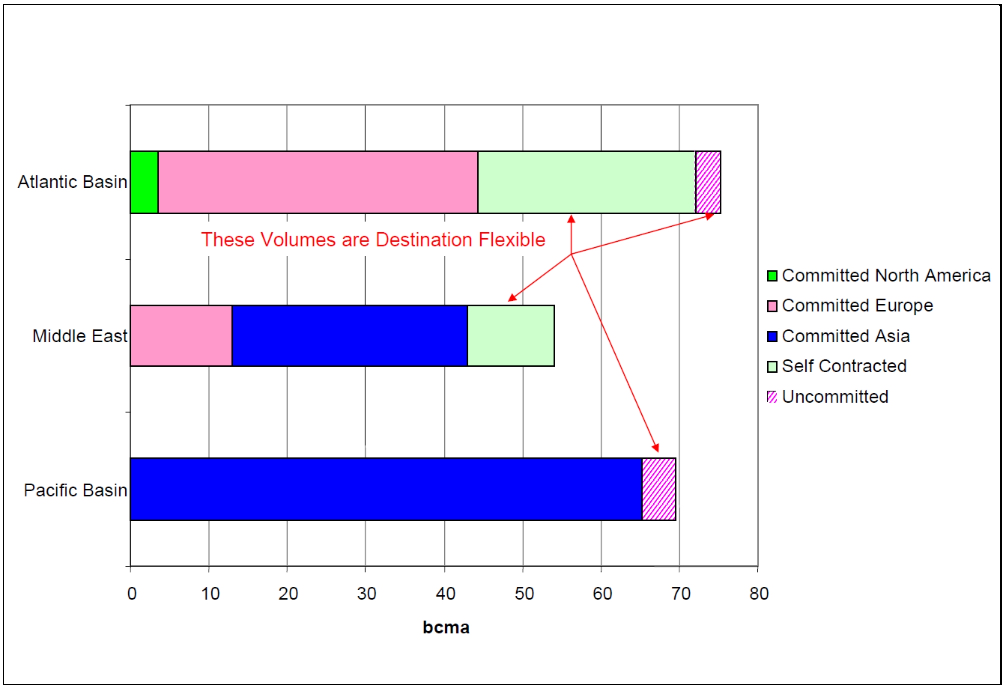
Source: BP Statistical Review of World Energy, GIIGNL

Figure 6 provides a view of which categories of LNG had flexibility potential in 2008. Flexible LNG represents some 23% of total volumes shown. In addition to the short term sales, or 'flexible LNG' shown in Figure 6, and the view of flexible volumes in Figure 5 additional optionality has been negotiated into 'Committed' European LNG purchase contracts such that some cargoes may be diverted to markets offering higher prices.

Noting the foregoing discussion of flexible diversions of LNG from Europe to the fast growing LNG import markets of Asia, this shift is confirmed by recent monthly data on LNG deliveries. Figure 7 shows, from April 2011, this movement of LNG volumes away from Europe and towards Asia.

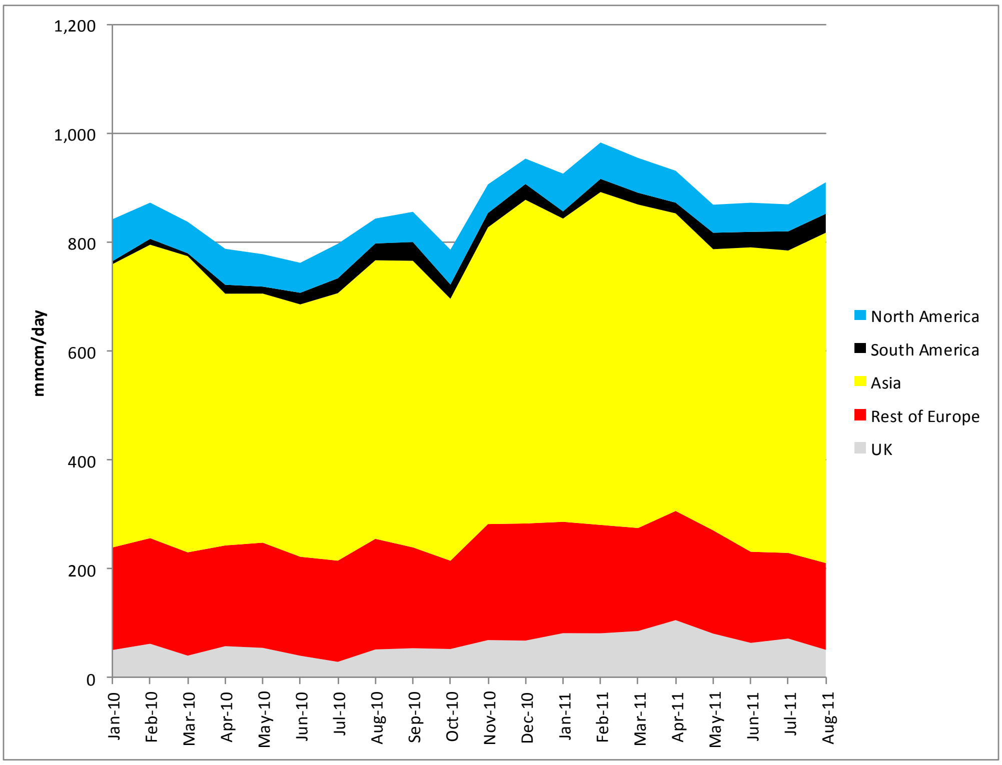
[17] 'The LNG Industry 2010, GIIGNL, http://www.giignl.org/fileadmin/user_upload/pdf/A_PUBLIC_INFORMATION/Publications/GNL_2010.pdf

Figure 6: LNG Supply by Region of Origin – 2008 Showing Uncommitted or Self Contracted Volumes



Source: Jensen 2009, slide 26

Figure 7: Monthly Global LNG Consumption by Region: January 2010–August 2011

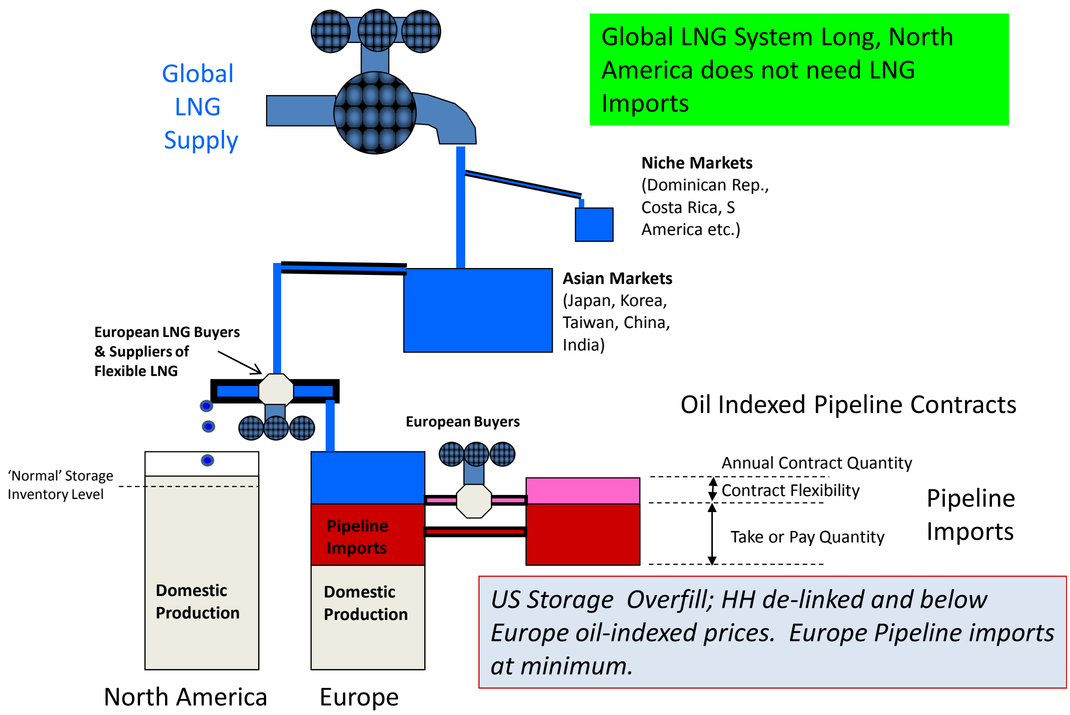


Source: Waterborne LNG: Americas Report 16th September2011, Asian Report 17th September 2011 and European Report 23rd Spetember2011

3. Connecting the Markets Together – The Situation in 2011

The schematic in Figure 8 is a depiction of the gas markets of North America, Europe and the Asian LNG Importing markets in 2011.

Figure 8: System Dynamics 2011[18]



Global LNG supply is represented by the tap at the top of the diagram. The Asian markets are assumed to take whatever LNG they require to meet their demand (Japan, Korea and Taiwan having no other sources of natural gas)[19]. The remaining LNG is available for Europe and North America. At the moment however, due to the growth of shale gas production in the US, North America only takes minimal quantities of LNG. Europe is thus absorbing the balance by virtue of its ability to reduce pipeline imports of oil-indexed gas to Take or Pay levels. What we have in this situation at the end of 2011 is:

- North America as an isolated, self-sufficient gas market with prices in the range $3.50/mmbtu to $4.50/mmbtu.
- A 'hybrid' European market with traded hub spot prices at $8/mmbtu to $10/mmbtu and oil indexed contract prices at $11/mmbtu to $13/mmbtu, with buyers trying to

[18] For a more comprehensive explanation of the system dynamics, please see Rogers 2010, Chapter 2, pp. 42 – 59.

[19] For completeness also shown are the new and niche LNG markets of South America, Kuwait and Dubai, Thailand, the Dominican Republic and Puerto Rico.

satisfy their contract TOP commitments whilst maximising purchases of cheaper spot gas.

- Asia with a range of LNG contract prices from \$4/mmbtu to \$17/mmbtu with supply supplemented by spot cargoes at prices around \$15/mmbtu, at times (though not continuously) linked to European hub spot prices with a transport margin and premium.

A graphical representation of the geography of 2011 inter- regional gas price linkages is shown in Figure 9.

Figure 9: Global Gas Price Linkages - 2011

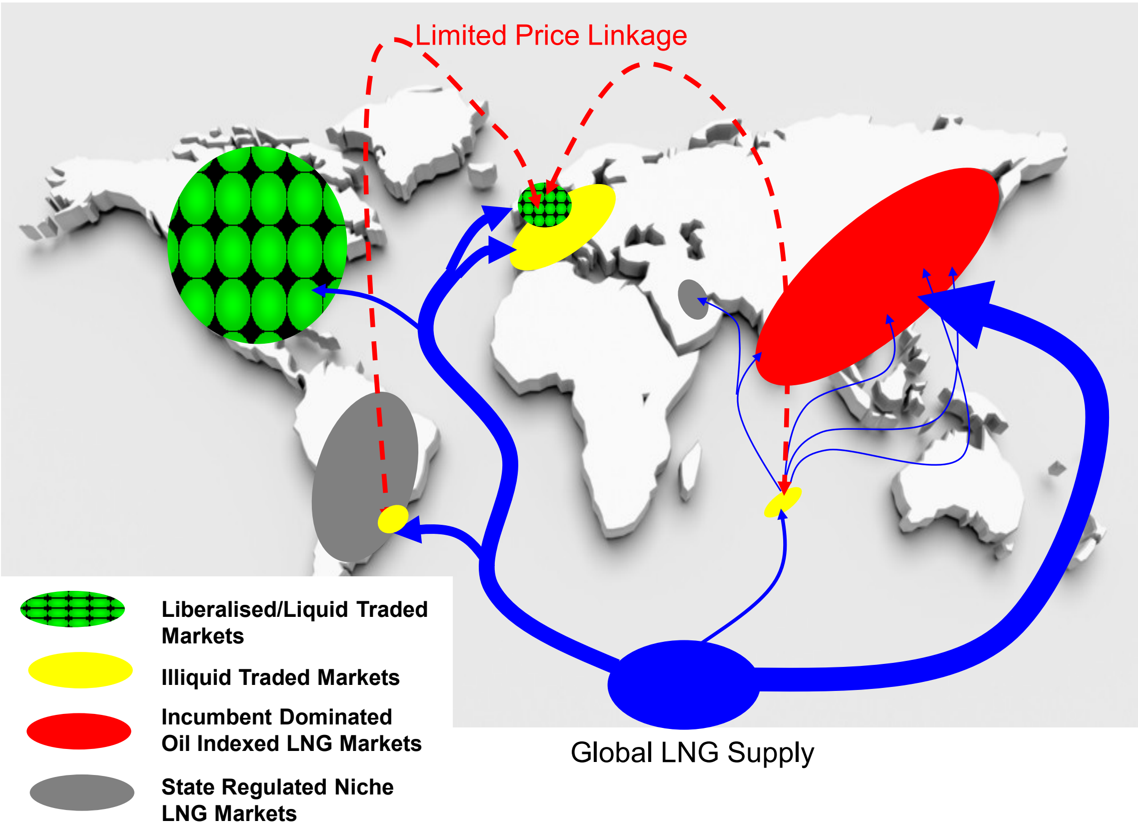


Figure 9 shows (schematically) the global LNG supply in deep blue, flowing to the liquid liberalised markets of North America (minor flows), Europe (with North West Europe shown as a liquid market, surrounded by a less liquid hinterland), and a large flow of contracted LNG to the 'incumbent dominated' LNG importing markets of Japan, Korea, Taiwan, China and India. Also depicted are the illiquid LNG spot markets of Asia and, notionally, South America. The red dashed lines indicate a tenuous or intermittent link between these LNG spot markets and European hub prices (see Figure 4).

4. Future Scenarios in the 2015 to 2025 Period

4.1 Introduction

Given trends which are apparent in 2011, the key uncertainties which will fundamentally shape the future price linkages between regions in the period to 2025 are:

- Future natural gas demand growth (and associated LNG import needs) of China, India, Japan South Korea and Taiwan.
- The future trajectory of US shale gas production and the extent to which North America becomes an LNG exporter, or indeed under a pessimistic assessment, a significant importer.

These are examined in four scenarios combining low and high Asian demand with low and high US production cases.

Other key assumptions also explored in this section are the likely timings and supply profile of new non-North American LNG projects, the potential for higher future Russia – Europe pipeline exports and Russia's future export dynamics in a world where oil-indexed contracts survive or alternatively where they transition to a hub-based price formation paradigm.

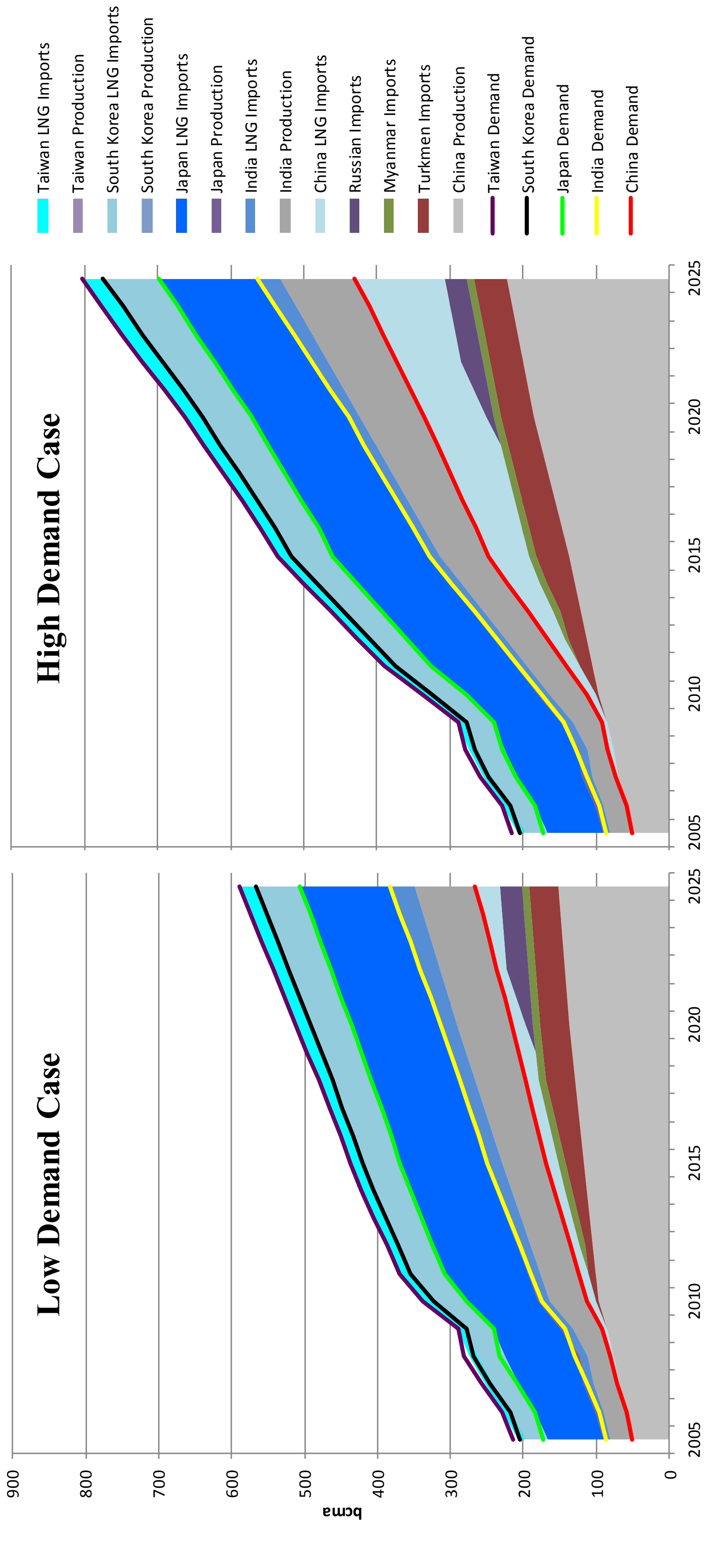
4.2 Asian Demand Assumptions

The uncertainty in Asian natural gas and LNG import demand has already become apparent. In 2009 consumption of natural gas in Japan, Korea, Taiwan, China and India was 3.5% above 2008 levels (LNG imports were 3.9 % lower). In 2010 however actual gas consumption was a staggering 18.1% up on 2009 and LNG imports also increased by corresponding levels. This had a direct consequence on the volumes of LNG available for Atlantic Basin markets. In the first quarter of 2011 LNG imports into these Asian markets were 11% greater than during the same period in 2010, even prior to any major increase in Japanese LNG imports due to the Fukushima incident. China and India are relative newcomers to the group of Asian LNG importers. Both have domestic production and, in the case of China, current and potential future pipeline gas import supplies. Both countries have high economic growth rates and a low share of gas in the primary energy mix[20]. Future gas demand (and the balance of LNG in the mix) is highly uncertain.

Asian Demand Assumptions are shown in Figures 10 for Low and High Demand Cases. A more detailed discussion of key supply assumptions is contained in the Appendix.

[20] In 2010, 10.6% for India, 4.0% for China, Source: BP 2011, Primary Energy by Fuel Page.

Figure 10: Asian Supply and Demand Assumptions – Low and High Demand Cases

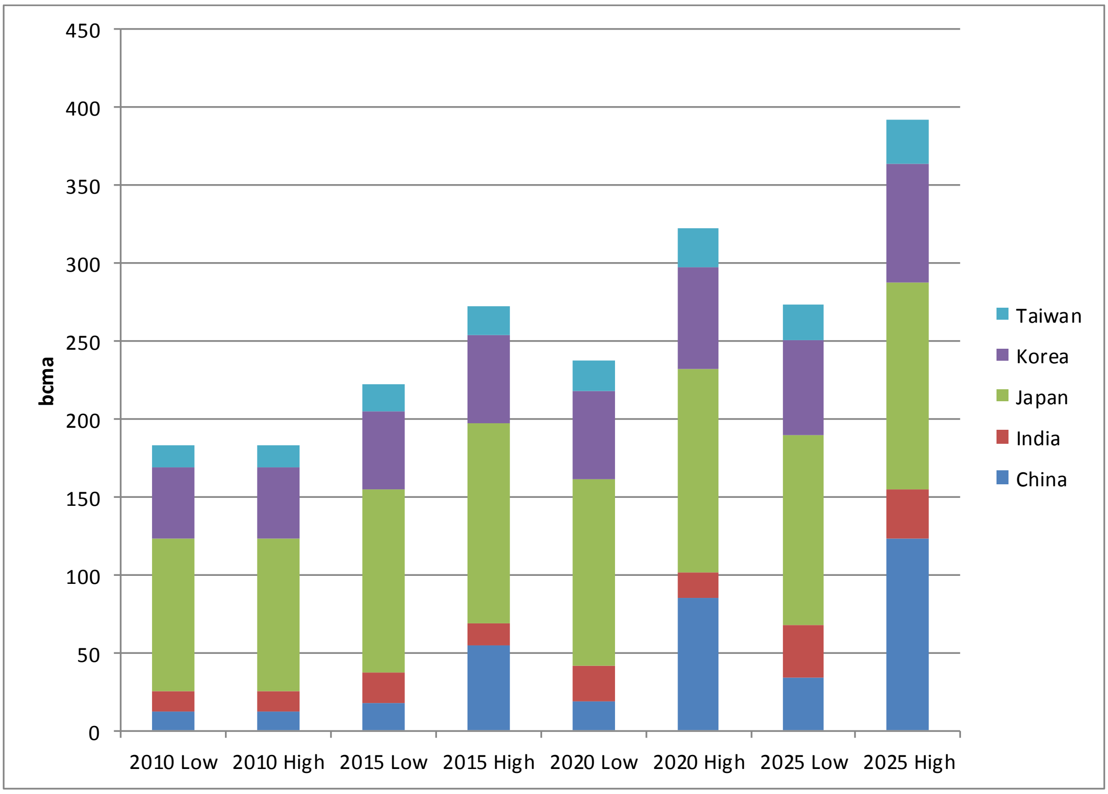


Source: IEA, Waterborne LNG, BP Statistical Review of World Energy, own analysis

The demand and production assumptions for China, India and Japan in the Low Demand case correspond to those contained in the IEA's World Energy Outlook 2010 New Policies Scenario[21], in which natural gas demand growth is moderated by the more widespread adoption of renewables and nuclear power generation and the reduction in fossil fuel subsidies. Chinese pipeline import levels and timing assumptions are detailed in the Appendix. Demand growth for China, India, Japan, South Korea and Taiwan in the period 2010 to 2025 in aggregate is 3.9%/year, with LNG imports growing from a 2010 level of 183 bcm to 280 bcma by 2025. Japanese demand reflects the anticipated increase in LNG requirements as a consequence of the Fukushima incident, assumed to be 15 bcma to 2014 trending down to 11 bcma thereafter.[22]

In the High Demand Case, the demand and production assumptions for China, India and Japan correspond to those contained in the IEA's 'Are We Entering a Golden Era of Gas' report.[23] Demand figures for Korea and Taiwan have been increased by a notional 25% over the Low Demand Case.

Figure 11: Future Asian LNG Import Volumes, Low and High Demand Cases



Source: Waterborne LNG, own analysis

Figure 11 compares Asian LNG imports between these cases. Two important conclusions flow from this data:

[21] IEA 2010: World Energy Outlook, pp. 182, 191
[22] Presentation at 6th Annual LNG World Conference, Perth, 5 – 7th September 2011 by Oliver Matcshke, Total E&P Indonesia, slide 4.
[23] IEA 2011, pp. 23, 27

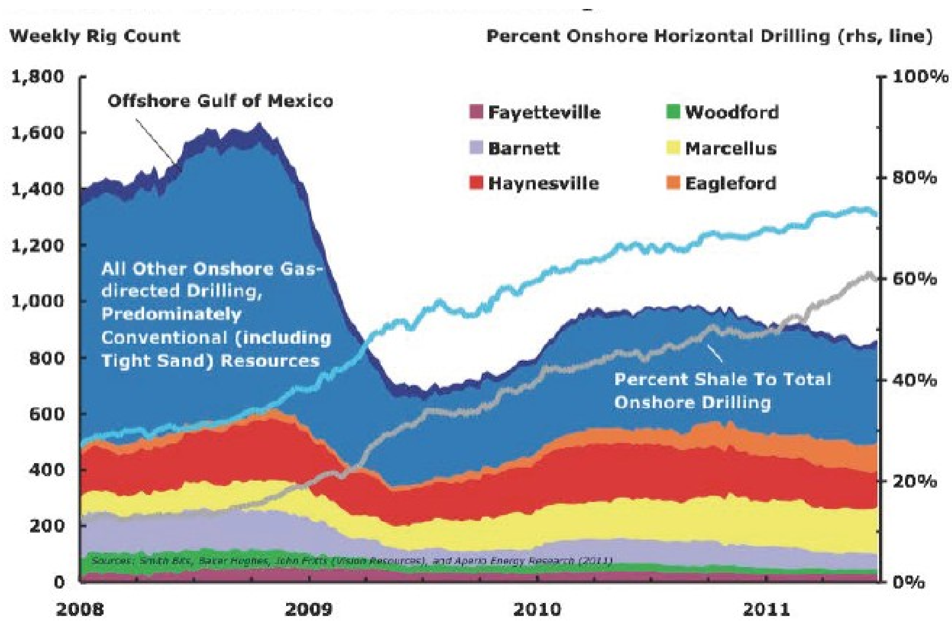
- By far the largest change between cases is the increase in China's LNG import volumes.
- Even in the High Demand Case, China and India's assumed LNG import volumes are less than projected regasification capacity until 2015, i.e. there is ample time to construct future additional capacity if required.

4.3 US Production and Future US & Canadian LNG Export Assumptions

The much discussed 'shale revolution' in the US transformed its domestic natural gas outlook from one of steady decline (at an annual rate of 2.1% between 2001 and 2005) to one of strong growth. Between 2006 and 2010, US domestic production grew at an annual rate of 3.4%. 2010 US production was 611 bcm compared with the 2006 level of 524 bcm.

Some observers question the sustainability of future shale gas production growth. They view the production costs claimed by shale operators as optimistically low and have produced analysis[24] which demonstrates that, on average, US shale gas requires a Henry Hub price of around $6.50/mmbtu to remunerate the full cost base, including lease acquisition costs, overheads, direct costs, taxes and return on capital. The current momentum of shale production growth at Henry Hub prices in the $3.50 to $4.50/mmbtu range is claimed to be due to price hedging using a (usually) bullish forward curve, sale of additional equity by shale developers and money-forward economics[25] which justify drilling leases whose acquisition investment is a 'sunk cost' and where such leases will be forfeited if drilling is not undertaken before a fixed expiry date.

Figure 12: US Natural Gas Rig Count – Shale versus other Categories 2008–11



Source: Arthur E Berman

[24] Foss 2011

[25] This refers to economic decision-making where only future costs and revenues are considered.

While the assessment of shale gas 'in place' in the US's extensive plays is rarely disputed, the future cost of production and well decline trajectory are challenged. Well production performance has been observed to vary significantly (and unpredictably) across play geography and within one or two years, drilling activity tends to focus on the discovered 'sweet spots' which may account for only 10 to 20% of the play area. Even within the sweet spot areas performance varies between wells. Shale gas production also declines with time to a far greater degree than conventional gas wells. Since the fall in US natural gas prices which accompanied the 2008 – 2009 economic recession, natural gas drilling has shifted markedly towards shale gas prospects. This is shown dramatically in Figure 12. The blue area represents the weekly rig count for non-shale natural gas and the coloured areas the weekly rig count on the labelled shale plays. The blue line shows the percentage of total natural gas drilling which is horizontal drilling versus and the grey line the percentage of total onshore natural gas drilling which is for shale.

After a review of all the major US shale plays, ex-Amoco geologist Arthur Berman[26] concludes starkly that (in mid 2011):

- 30% to 40% of US gas production is from wells that began production in the last 12 months.
- Despite the large new production volumes from shale, US supply has no 'depth' and is therefore insecure.
- If [shale gas] drilling slows, supply will plummet.

Maintaining US domestic production requires the continuation of intensive shale drilling activity to avoid a decline. This is only possible in the long run if shale gas wells remunerate investment. If the breakeven price for shale in general is $6.50[27] this was clearly not the case in 2011.

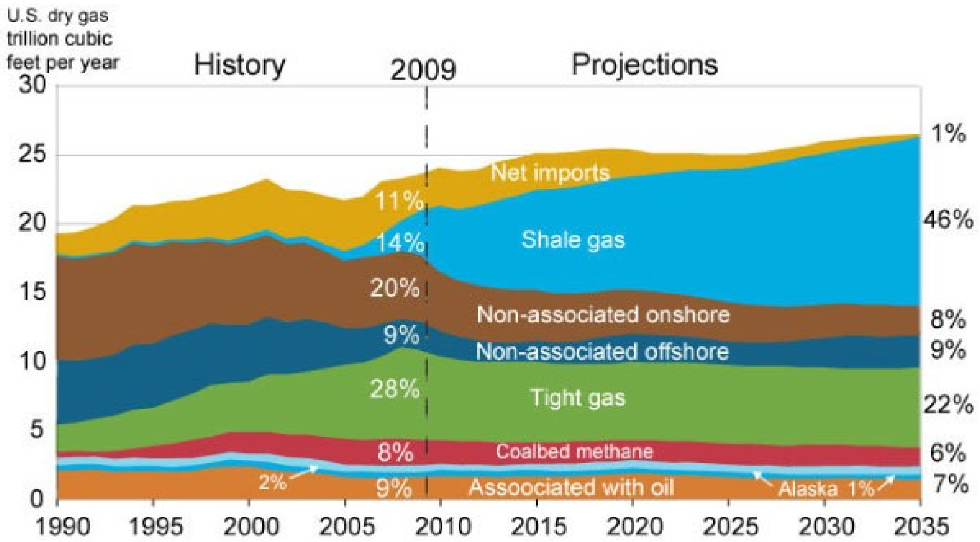
In the 'opposite corner' we have shale enthusiasts who regard this newly emerging resource as having strong future growth potential. Figure 13 shows the EIA's view of past and future US natural gas supply. Shale's contribution rises from 14% of US requirements in 2009 to 46% by 2035, virtually eliminating net imports by that date (currently a combination of Canadian pipeline gas and relatively small LNG volumes)

In the early 2000s, in the expectation of the US becoming a major LNG importer, numerous LNG regasification facilities were built on the US Gulf coast, and Eastern seaboard, in aggregate some 160 bmca of capacity[28]. Now, in the anticipation of domestic production in excess of US domestic requirements there are several projects to add liquefaction facilities to some of these installations and so enable them to export LNG . There is also the potential for

[26] Berman and Presentation 'Shale Gas The Eye of the Storm', Arthur E Berman, July 2011. http://www.artberman.com/presentations/Berman_Shale%20Gas--The%20Eye%20of%20the%20Storm%2020%20July%202011_OPT.pdf
[27] The presence of liquid co-production reduces the breakeven price, however the 'marginal' dry shale gas is clearly economically questionable at 2011 Henry Hub gas prices.
[28] See Appendix Table 6. The North America total is 184 bcma.

LNG export schemes from the Canadian west coast. The status of these US and Canadian projects is shown in Table 1.

Figure 13: US Natural Gas Supply to 2035



Source: EIA, Annual Energy Outlook 2011

The total of capacity of these 9 projects is 134 bcma – which, for context, represents 44% of total global LNG supply in 2010. Just how many of these will come to fruition is uncertain, however they represent a potentially major new LNG supply source which could have significant implications for future LNG market dynamics.

Table 1: US and Canadian LNG Export Projects

Terminal/Project - US	Commercial partners	Capacity (bcma)	DoE Status	FERC Status	Possible Start-up
Sabine Pass	Cheniere	22	Approved	Under Review	2015
Freeport	Freeport LNG, Macquerie	12.5	Approval Expected 2011	Under Review	2016
Lake Charles	Southern Union, BG	19.3	Approved	Not Yet Applied	2016+
Cameron	Sempra	24	Not Yet Applied	Not Yet Applied	2016+
Cove Point	Dominion	11	Not Yet Applied	Not Yet Applied	2016+
Jordan Cove	Jordan Cove Energy, First Chicago	12	Not Yet Applied	Not Yet Applied	2016+
	Sub-total	***100.8***			
Terminal/Project - Canada	**Commercial partners**	**Capacity (bcma)**	**Environmental Approval**	**Other Approvals**	**Possible Start-up**
Kitimat	Apache, EOG Resources	6.9	Approved	Underway	2015
BC LNG	LNG Partners, Haisla First Nation	2.5	Not Yet Applied	Not Yet Applied	2016+
Prince Rupert	Shell	13.8	Not Yet Applied	Not Yet Applied	2016+
Petronas	Petronas	10.2	Not Yet Applied	Not Yet Applied	2016+
	Sub-total	***33.4***			
	Total US & Canada	**134.2**			

Source: The Americas Waterborne LNG Report 14th October 2011, P. 12, Andy Flower, OIES

An initial assessment of these US LNG export schemes indicates that the tolling-fee equivalent cost of the liquefaction facility would be around $2/mmbtu[29]. Shipping (assuming Europe as the destination market) would cost some $1/mbbtu[30] and the regasification fee would be around $0.5/mmbtu at current rates, making a total of $3.50/mmbtu. LNG export projects could therefore be expected to be economically attractive if the spread between US gas prices and those of the destination market is $3.50/mmbtu or greater. As Table 1 shows, the earliest expected start-up of these projects is 2015. A continued positive outlook for future shale gas growth could result in several projects being built.

Conversely, if US shale gas prospects dim as a 'higher than billed' cost base finally slows the momentum of the shale operators, we might expect US domestic production to plateau and possibly decline and the US begin to utilise its existing regasification facilities to import significant volumes of LNG.

US Production: High and Low Cases

In line with the foregoing discussion of the 'optimistic' and 'pessimistic' polarised view of future US shale gas production levels and hence total US domestic production trajectory, hypothetical views of US production were prepared in order to model the scenarios described above and explore potential future price linkages and are shown in Figure 14 over a range of Henry Hub prices.

These hypothetical production-price trajectories will be used below in the modelling of the global LNG-connected system.

4.4 European Pipeline Imports, Russian Gas Production Potential and its Response to Market Developments

In order to stay within the bounds of realism with our modelling results, it is important to review the status, production potential and future disposition of Russia as the largest source of pipeline gas supply to Europe.

James Henderson makes the case that the non-Gazprom Russian upstream companies, by developing already discovered gas reserves, have the potential to contribute significantly more to Russia's gas production base than is currently the case[31]. Table 2 shows his assessment of the potential production levels from this set of IOC's and Russian upstream companies.

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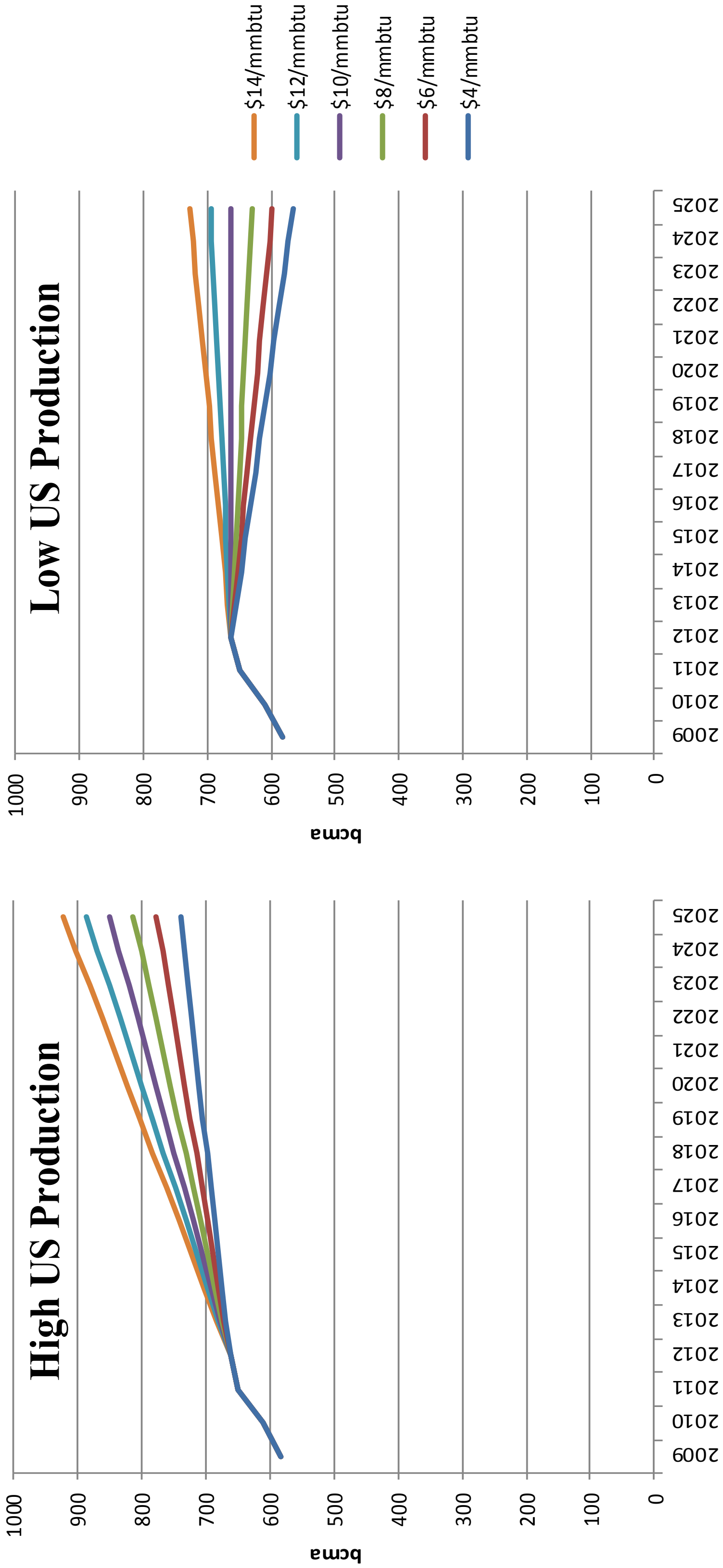
[29] Source: 'Cheniere to Export LNG in 2015' MLP Hindsight, 29th October 2011, http://mlpguy.com/archives/919

[30] Average shipping cost differential between UK and US Gulf taken from table in 'The European Waterborne LNG Report', Volume 7, Week 44, 3rd November 2011, P. 18

[31] Henderson 2010

Figure 14: Hypothetical High and Low US Production Paths for a Range of Henry Hub Prices



Source: EIA and IEA for historical data, hypothetical assumption for future

Table 2: Estimate of Possible non-Gazprom Supply (bcma)

	2009	2015	2020	2025
To Russia and Europe	114	237	300	327
To East	16	19	26	33
Other LNG			9	16
Total	**131**	**256**	**336**	**376**

Source: Henderson 2010 Page 239, Figure 9.1

We will now compare these estimates with the call on non-Gazprom producers as depicted in the 2009 Russian Energy Strategy to 2030.[32]

Table 3: Estimated Total Potential Russian Pipeline Exports to Europe

	2013 -2015		2020-2022		2030	
	low	high	low	high	low	high
Russian Gas Production	684	744	801	835	885	940
Central Asia Imports	66	70	69	70	70	71
Total Supply	**750**	**814**	**870**	**905**	**955**	**1011**
Domestic Russian Consumption	478	519	539	564	605	641
CIS Exports to CIS	88	90	87	92	78	92
Exports to Asia	24	36	55	55	70	75
Exports to Europe	159	169	190	195	201	201
Total Consumption plus Exports	**749**	**814**	**871**	**906**	**954**	**1009**
Russian Production Sourced:						
Gazprom Production	547	595	601	626	646	686
Non-Gazprom Production	137	149	200	209	239	254
Total	**684**	**744**	**801**	**835**	**885**	**940**
Additional Non Gazprom Supply potentially available for Europe	*100*	*88*	*100*	*91*	*88*	*73*
Estimated Total Potential Exports to Europe	**259**	**257**	**290**	**286**	**289**	**274**

Source: Non-Gazprom Gas Producers in Russia, James Henderson, NG45, OIES, 2011, P. 24, Table 2.1

In Table 3 the italicised row shows the additional potential for Russian gas production by non-Gazprom producers comparing the 'To Russia and Europe' row in Table 2 with the 'Non Gazprom Production' row in Figure 3 for comparable time periods.[33]

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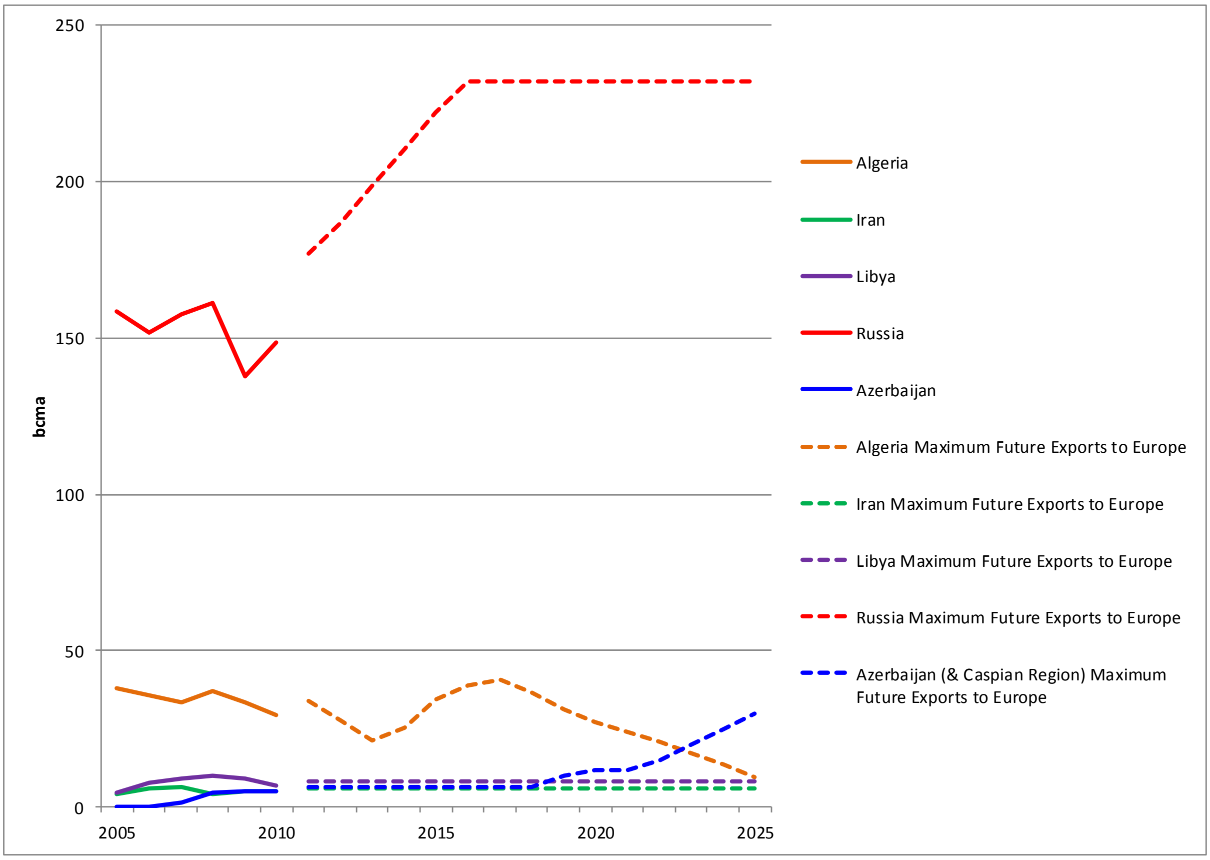
[32] *Henderson 2010, Page 24, Table 2.1 based on 'Energy Strategy of Russia for the Period up to 2030', Ministry of Energy of the Russian Federation, November 2009, pp. 133 – 152,* http://www.energystrategy.ru/projects/docs/ES-2030_(Eng).pdf

Figure 15 shows the future modelling assumptions for maximum pipeline import levels from the various sources of European imports. Note that the post 2015 assumed availability from Russia, at 230 bcma is well below the range of 260 to 280 derived in Table 3.

Figure 15: European Pipeline Imports, Historical Actual Imports to 2010 and Future Assumed Maximum Import Availability



Source: IEA Monthly Data, Darbouche[34]*, own analysis*

Having established the very considerable headroom on future Russian supplies of gas to Europe[35] we now turn to the very topical issue of the framework under which this gas will be sold and the likely future Russian response to changing market circumstances.

A Continuation of European Oil Indexation: In this possible future it is assumed that negotiations and/or arbitrations do not result in a transition away from long term contracts with oil indexation as the means of price formation. In Europe this allows the continuation of arbitrage between un-contracted gas whose price is determined primarily by the forces of supply and demand, and contracted gas whose price is determined by a formula in the long term contract with reference to time-averaged values of gasoil and fuel oil. The annual Take or Pay level represents the minimum contract year quantity that contract buyers are obliged to

[33] Note it has been assumed that non-Gazprom production potential for Russia and Europe on 2030 is at the same level as 2025 in Table 2.

[34] Source: Darbouche 2011, P.40, Figure 1.12

[35] Note that with the commissioning of the Nord Stream Phase 1 pipeline in 2011 to be followed by Phase 2 in 2012 it is unlikely that imports of pipeline gas to Europe will be limited by pipeline capacity.

take. When European demand results in a need to import above the Take or Pay level there is a scope for arbitrage which will tend to lead to a periodic price convergence between hub prices and oil indexed contract prices. This dynamic also however has a bearing on the regional disposition of flexible LNG, depending on the price levels in competing markets.

A Transition to Hub Based Pricing: This would represent a more benign future for European midstream buyers of long term contract gas who, in 2011, are caught in the invidious position of buying supplies at oil-indexed prices and selling to customers who demand a hub-based price. However from a supply/demand and even price level (as opposed to price formation) viewpoint, this could very well result in similar dynamics.

The chain of causality producing the similar dynamics could be as follows:

- Russian long term contracts switch from oil indexation to hub indexation either as a consequence of arbitration or negotiation.
- Because the volume of gas (nominated by the buyer) has the potential to influence hub prices, the seller will insist upon the right to buy a portion of the contract quantity on the trading hubs and deliver it as part of the contractual volume (thus reducing the physical volume of gas moved down its supply chain from its upstream fields).
- Such activity requires the seller to establish an in-house supply and trading capability. Once established, and if hub markets are sufficiently liquid, there is no financial benefit to selling gas under a long term contract; the seller will achieve the same price by selling directly on the trading hubs.
- Whether by purchasing gas at the hubs and re-delivering it to the buyer as part of the contract quantity, or by directly selling gas at the hubs, the upstream seller achieves a position of market power with which he is able to maintain hub prices by managing physical supply.

Thus the seller is faced with the dilemma of choosing an appropriate market price level to maintain through supply management. If this price is too high it will encourage LNG diversions away from lower priced regional markets in the short term and encourage the development of competing new supplies in the longer term.

If we assume that the seller in this commercial context has a strategy of maintaining a target price level but with a minimum export level to Europe, the dynamics, in terms of supply-demand modelling and arbitrage within the global system are in most respects the same as a commercial context where oil indexation survives.[36]

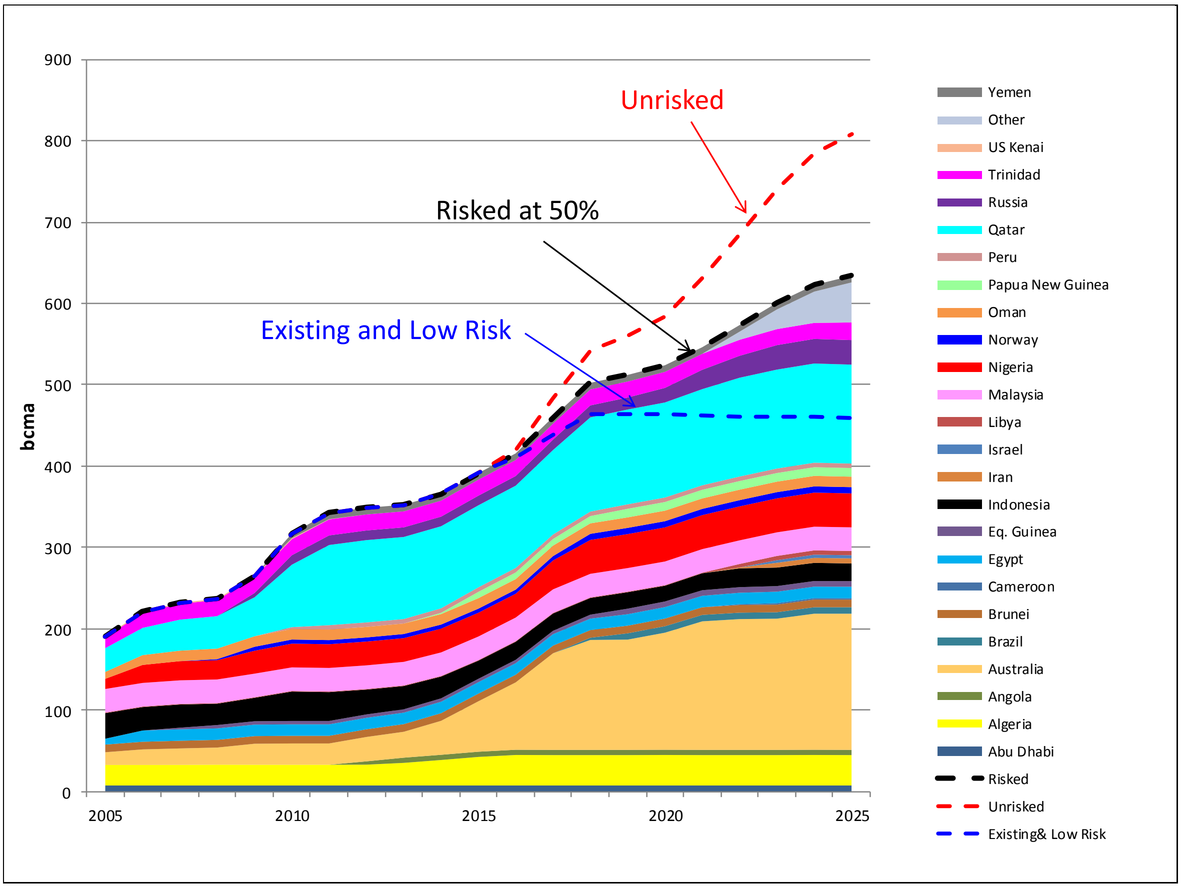
These dynamics will become evident in the modelled scenario outcomes.

[36] The key difference, although not germane to this analysis, is that the transition to hub-based pricing would relieve the exposure faced by European midstream utilities to the difference between upstream oil-indexed contract prices and hub-based end-user customer price levels.

4.5 Future LNG Assumptions (excluding future North American projects)

Given the significant Financial Investment Decision (FID) delays and project slippages observed in the implementation of the projects comprising the 2005 - 2010 LNG supply wave, it is prudent to exercise a degree of caution in assessing the supply growth from the long list of projects which are mooted to come on-stream in the 2015 to 2025 timeframe. A simple but effective approach is to apply a probability factor to those projects which have not yet achieved FID. Applying a probability factor of 50% to future projects which carry a degree of uncertainty produces the outlook for global LNG supply shown in Figure 16[37].

Figure 16: Risked View of Global LNG Supply (excluding new North American projects)



Source: *Sources: Based on methodology by D Ledesma, OIES, data from Waterborne LNG, other industry reports and own analysis*

The area where slippage concerns are highest is Australia (buff coloured area in Figure 16) where the number of projects expected to proceed in parallel might exceed the capacity of the specialised liquefaction contracting industry and Australia's ability to attract sufficient skilled and experienced personnel in light of its restrictive labour laws.

Having described the context of the Asian LNG demand and US production uncertainties and other key assumptions, we can now explore how price linkages might be transmitted between

[37] See Rogers 2011 pp. 25 – 27 for a more detailed explanation of the methodology.

regions through flexible LNG. The system has been modelled on four scenarios which reflect the two key uncertainties discussed above:

- High Asian Demand, Low US Domestic Production.
- Low Asian Demand, Low US Domestic Production.
- High Asian Demand, High US Domestic Production.
- Low Asian Demand, High US Domestic Production.

The order in which these cases are presented has been chosen for ease of explanation of system dynamics.

4.6 Other Modelling Assumptions

In addition to Asian demand, US production, future non-North American LNG and European pipeline gas availability, the following key variables were defined through reference to third party estimates and the Author's own assessment:

- North American Natural Gas Demand
- Canada and Mexico production
- European domestic production
- European demand
- New LNG market demand

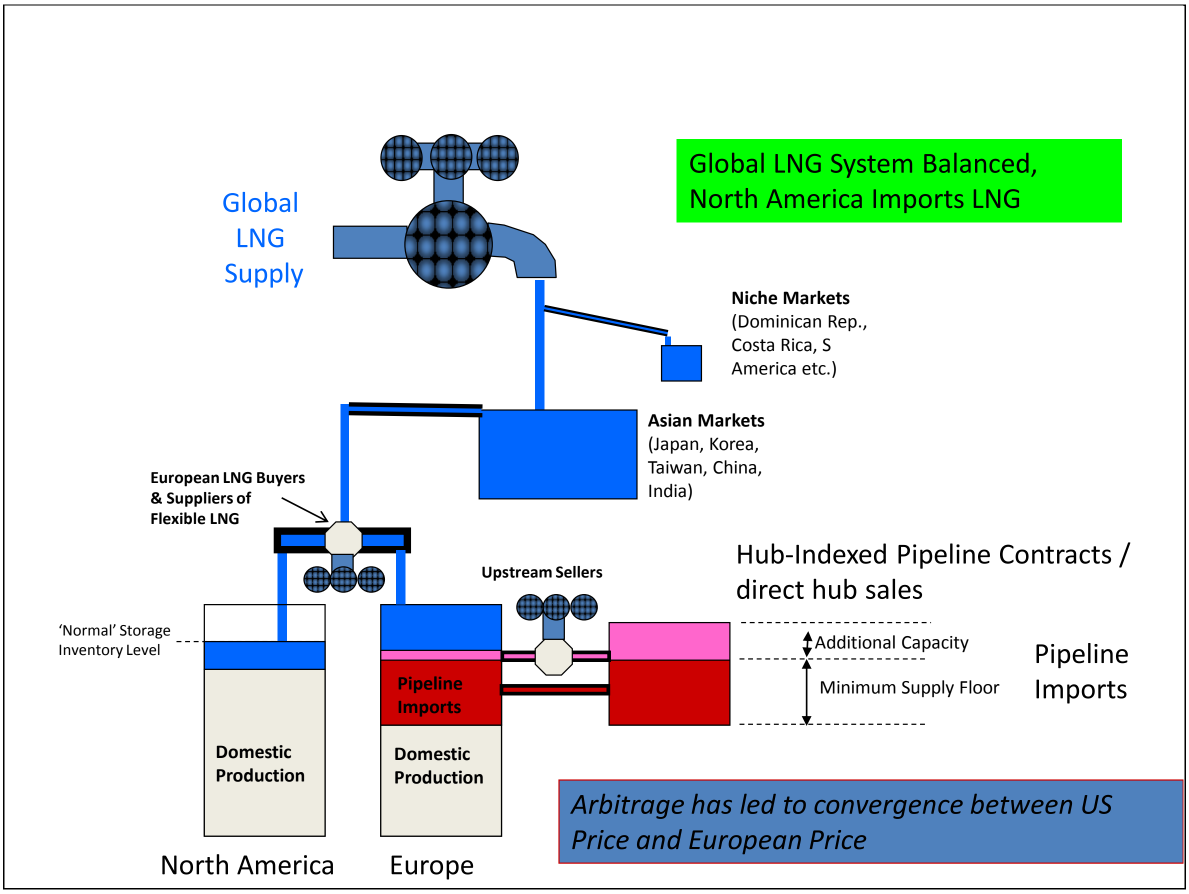
The assumed future trajectories for these variables are set out and discussed in the Appendix.

5. Scenario Modelling

5.1 Dynamics of the Low US Domestic Production Scenarios

In **the Low US Domestic Production Scenarios,** represented in Figure 17, future declining US production has resulted in North America becoming a significant LNG importer. LNG supply which remains after Asia and niche market requirements is available for Europe and North America. Arbitrage of flexible LNG will create a linkage between European and North American gas prices[38]. It has been assumed that Europe has transitioned away from oil-indexed contracts to hub-indexed contracts and/or direct upstream sales. Upstream suppliers of pipeline gas to Europe are expected to maintain a 'target price' – but with the consequence that the higher this price is, the more attractive it makes the diversion of flexible LNG away from North America and towards Europe. Equilibrium is reached when US prices (labelled as 'Henry Hub') are equal to European hub prices plus a spread which represents the differential LNG shipping cost between Europe and North America.

Figure 17: System Schematic for the Low US Domestic Production Scenarios



The increase in Henry Hub prices brought about through arbitrage would in turn increase US shale drilling activity (with a lag) as more play areas became economically viable (as depicted in Figure 14). While stressing the hypothetical representation of these future US

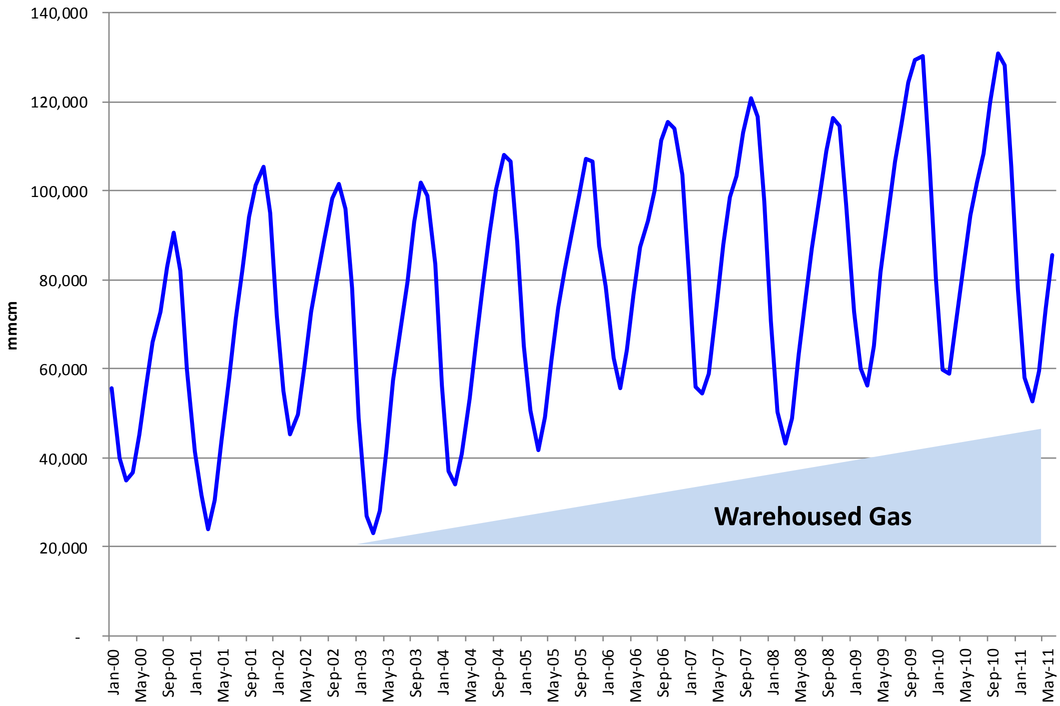
[38] See Rogers 2010, Chapter 2, pp. 40 - 59

production curves at various prices, they do allow us to explore the likely dynamics of such a scenario.

Again at a hypothetical level we can define a relationship between US and Canadian storage inventory levels and gas price. More specifically the relationship between end month storage inventory divided by a 5 year historical average and price is used to represent the observed tendency of US gas prices to respond to relative storage levels as an indicator of supply surplus or deficit.

As Figure 18 illustrates however, since the onset of the shale gas growth phase in the US, the North American market has been 'warehousing' gas, i.e. new storage capacity has been built to accommodate surplus supply whilst the minimum working gas inventory (typically in the month of March) has been rising to levels unlikely to be needed to meet severe winters. In deriving the gas inventory index for future months, the average monthly inventory for the period 2000 to 2004 was used.

Figure 18: End Month Storage Working Gas Inventory – US & Canada 2000–11



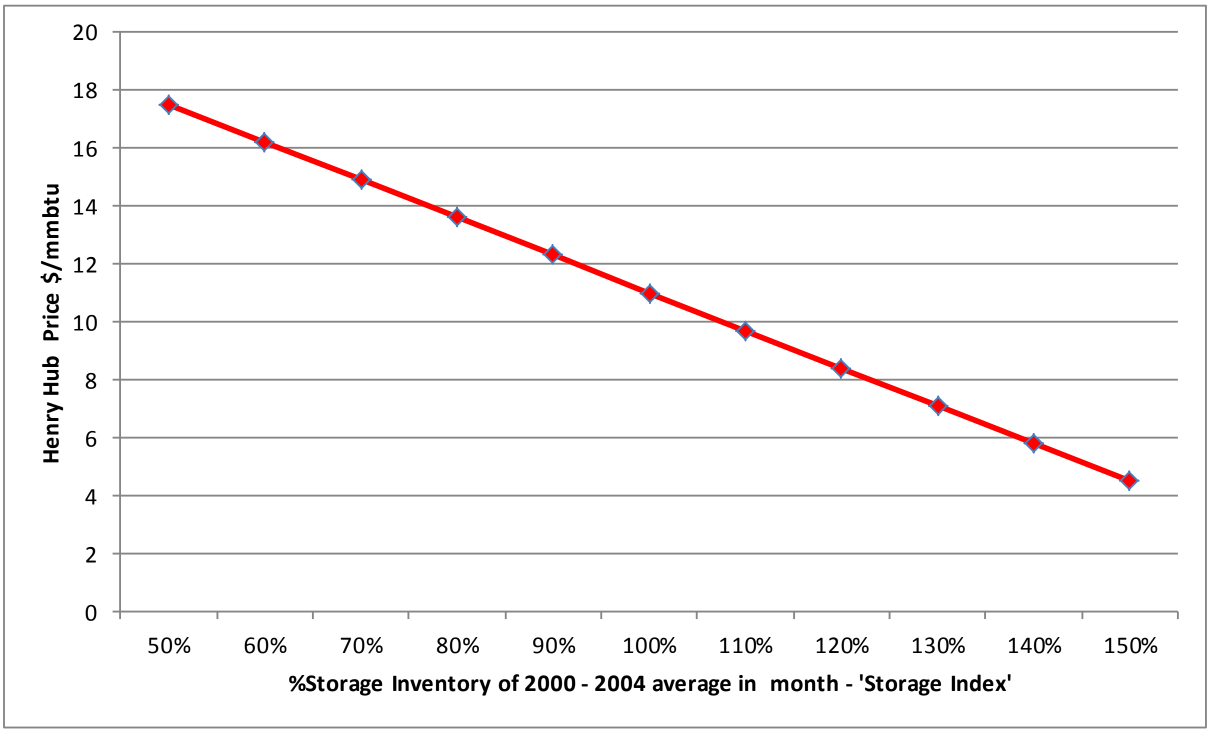
Source: EIA, Canadian Gas Association

For the purposes of modelling it is assumed that the North West Europe price is maintained at \$10/mmbtu by sellers controlling pipeline supplies into the European traded market. (For reference, based on historical relationships this would correspond to an oil-indexed contract price at \$80/bbl Brent crude oil and a continuation of the current relationship between gasoil and fuel oil prices with Brent). While this price level has been chosen for illustrative purposes it is broadly in line with an underlying cost of supply of $8/mmbtu for new European supply from LNG and long-distance pipeline imports[39]. (For comparison, the gas price corresponding to $100/bbl Brent would be $12.50/mmbtu).

Assuming a differential transport cost between the US and Europe of $1/mmbtu results in a Henry Hub price at arbitrage equilibrium of $11/mmbtu. The hypothetical relationship between storage index[40] and Henry Hub price is shown in Figure 19. This presumes that the North American market reaches equilibrium at a storage inventory index of 100% when Henry Hub prices are such that LNG arbitrage with Europe has caused price convergence taking into account incremental shipping costs.

Asian LNG contract price (for contracts signed post 2007) is assumed to be equal to JCC (with a six month lag), which at $80/bbl would be $13.80/mmbtu. The Asian spot LNG price is nominally assumed to be NBP plus $2.50/mmbtu.

Figure 19: Hypothetical Relationship between US & Canadian Storage Inventory Index and Henry Hub Price



Source: Hypothetical assumption

The feedback-loop between Henry Hub prices and future US production is completed by the following modelling linkage:

- The average annual Henry Hub price in year n, is defined based on the hypothetical relationship with the average storage index for year n, as represented in Figure 19.

[39] see IEA 2009, P 482, with allowance for FSU export taxes at 30%.

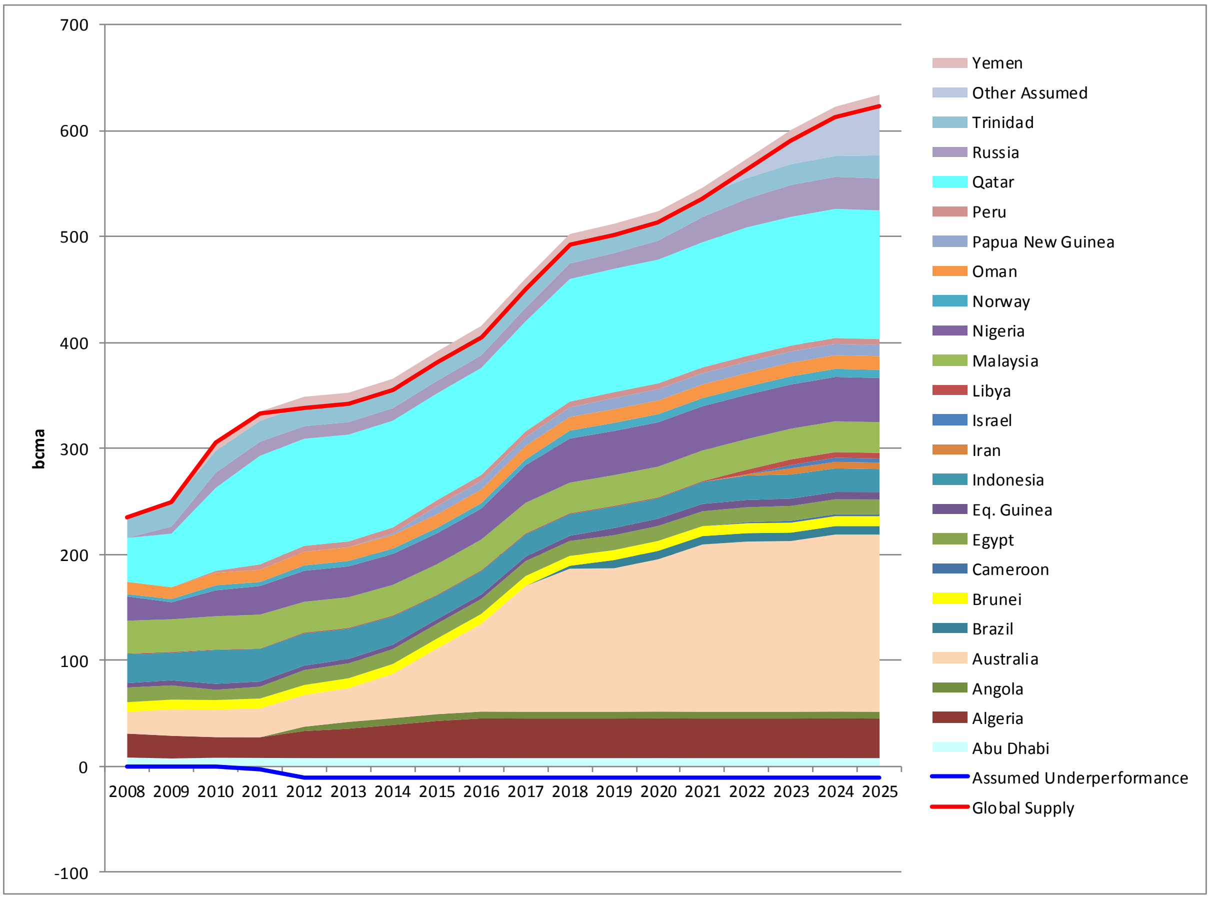
[40] The Storage Index is the modelled end-month US and Canadian working gas storage inventory divided by the average for that month for the period 2000 to 2004.[Hope I've got this right – see above.]

- US production in year n+1 is determined from the hypothetical relationship in Figure 14. The one year lag is used to approximate the investment lead time response to changed price signals.
- The degree of year to year changes in US production level was constrained to plus or minus 3.5% in order to further recognise inertia in the system, this being the observed growth rate from 2006 to 2010.

For both Low US Domestic Production Scenarios the global LNG supply is shown in Figure 20, which is derived by applying a 50% probability to future projects which have not yet achieved FID and whose ultimate timing is uncertain. Note that potential US and Canadian projects are not included in this outlook.

Data up to August 2011 is actual reported supply. From September 2011 to 2025 an assumed 10 bcma of 'underperformance' relative to that predicted from a monthly model is included, based on performance over the 2005 to 2010 period.

Figure 20: Global LNG Supply 2008–25 (Low US Production)



Sources: Based on methodology by D Ledesma, data from Waterborne LNG, other industry reports and own analysis

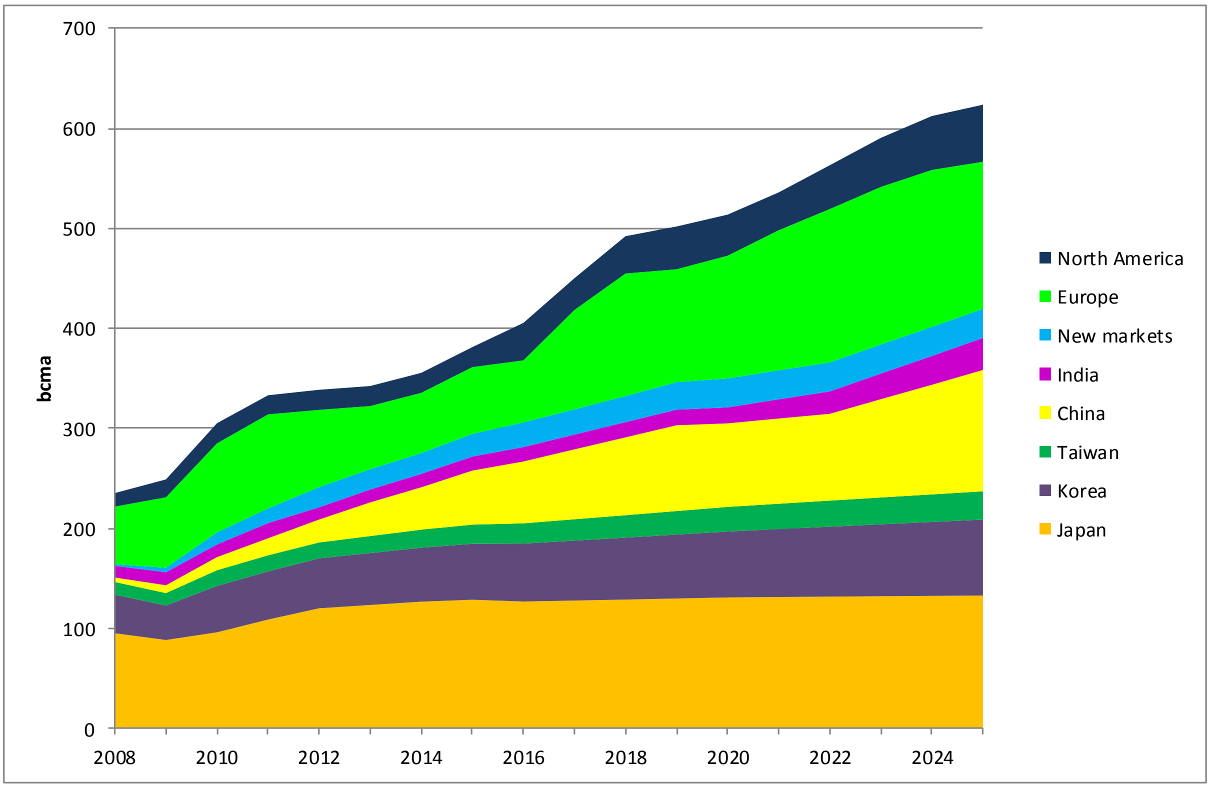
5.2 High Asian Demand, Low US Domestic Production Scenario Results

Overview of the scenario

As might be expected from the title, this is a scenario in which North America, in the face of flagging domestic production, again becomes an LNG importer progressively through the modelled period. In order to secure supplies it must compete with Europe and hence US domestic prices would have to rise from 2011 levels to achieve this.

Figure 21 shows where global LNG is consumed on this scenario. Data to August 2011 is as reported by Waterborne LNG[41]; future consumption is modelled. As to be expected, the dominant trend is the rising level of imports to Japan, Korea, Taiwan, China and India. The rationale for this demand build-up is provided in Figure 10. Europe's LNG imports are constrained in the 2012 to 2016 period as a consequence of the slowdown in global LNG supply growth but expand significantly thereafter.

Figure 21: Global LNG Disposition 2008–25



Source: Waterborne LNG (historical data), own analysis

European Balances and Pipeline Imports

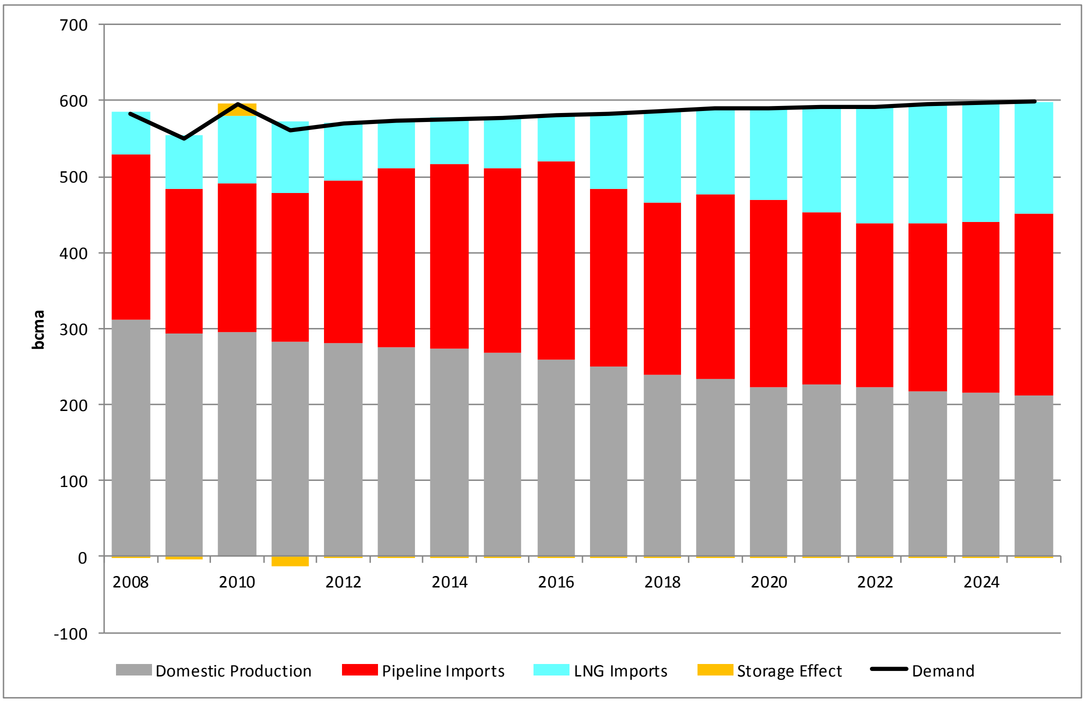
The European supply and demand balance for this scenario is shown in Figure 22. While European demand is assumed to grow only modestly over the period, domestic production continues its long term decline to 2020 when it is assumed to be partially arrested by the

[41] The Waterborne LNG Americas, European and Asia Reports, 16th September 2011, 23rd September 2011 and 17th September 2011 respectively.

growth of shale gas production.[42] Pipeline imports increase in the 2012 to 2016 period due to Asian competition for slowly growing global LNG supplies. After 2016 LNG imports increase as global LNG supply growth gathers momentum.

The historical and modelled future contribution of European pipeline imports from its various suppliers is shown in Figure 23. The major contribution of Russia in the pipeline supply mix is noted; both historically and until 2025.

Figure 22: European Supply and Demand Balance 2008–25



Sources: IEA, Waterborne LNG for historical data to mid 2011, own analysis post mid 2011

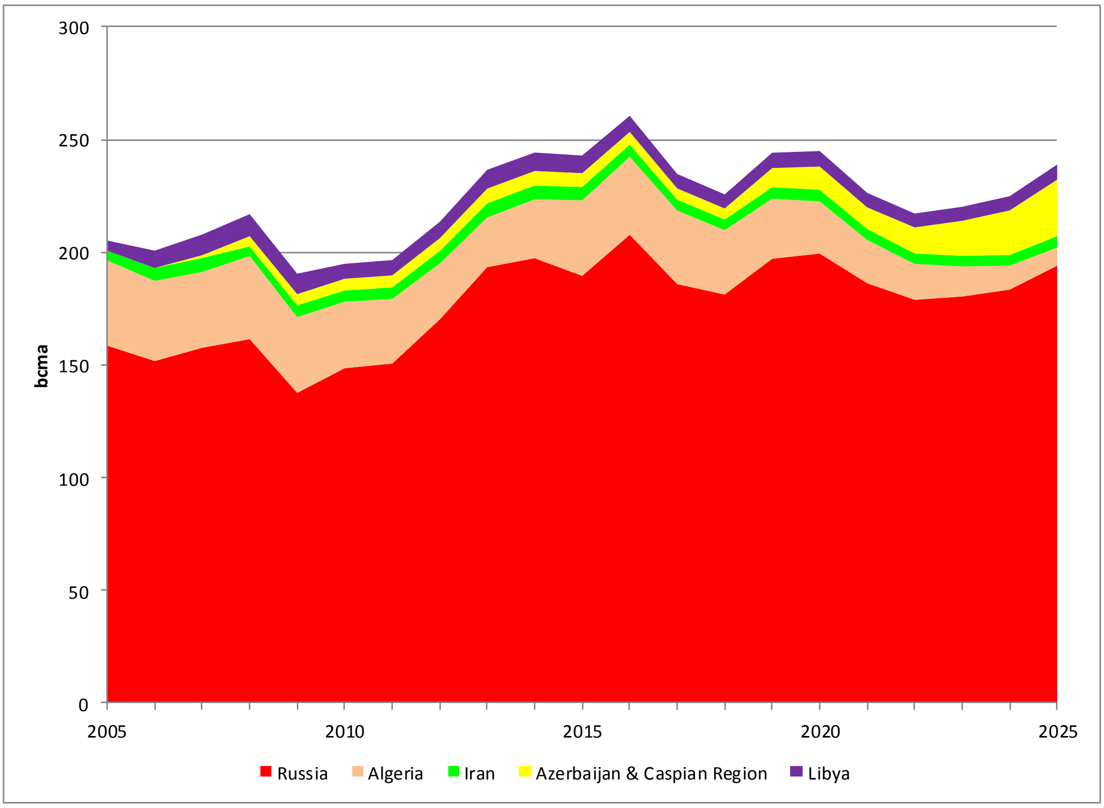
Figure 24 compares the modelled Russian pipeline imports into Europe with:

- The estimate of production capacity discussed and shown in Figure 15; and,
- A possible 'minimum European export level' which Russia might expect to wish to defend in a post oil-indexed contract world.

Note that the supply floor level is broadly equivalent to the estimated aggregate contract Take or Pay level for 2011. In this scenario it is evident that imports are comfortably above this floor but below the estimate of production capacity. Of particular note is the rapid rise in Russian supply to Europe in the 2012 to 2014 period. The implications of this are discussed in the Scenario Critique section.

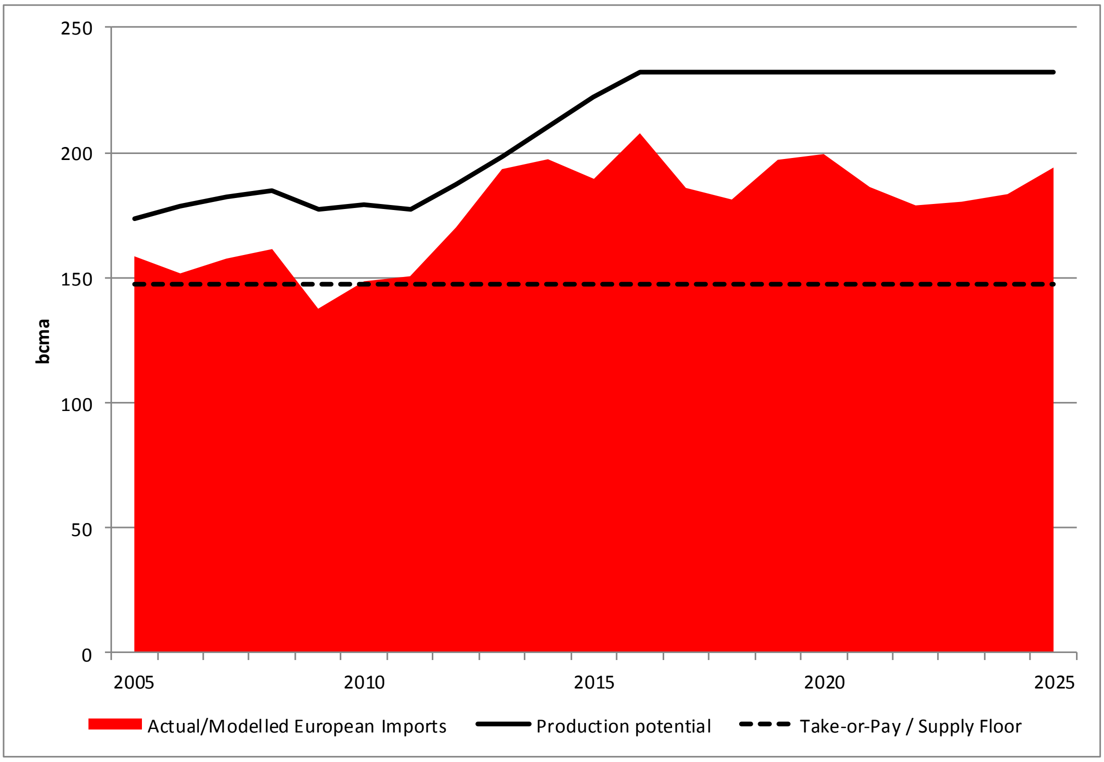
[42] See Appendix for assumptions on future European production.

Figure 23: European Pipeline Imports 2005–25



Sources: IEA and Cedigaz historical data to mid 2011, own analysis post mid 2011

Figure 24: Russian Pipeline Supply to Europe 2005–25

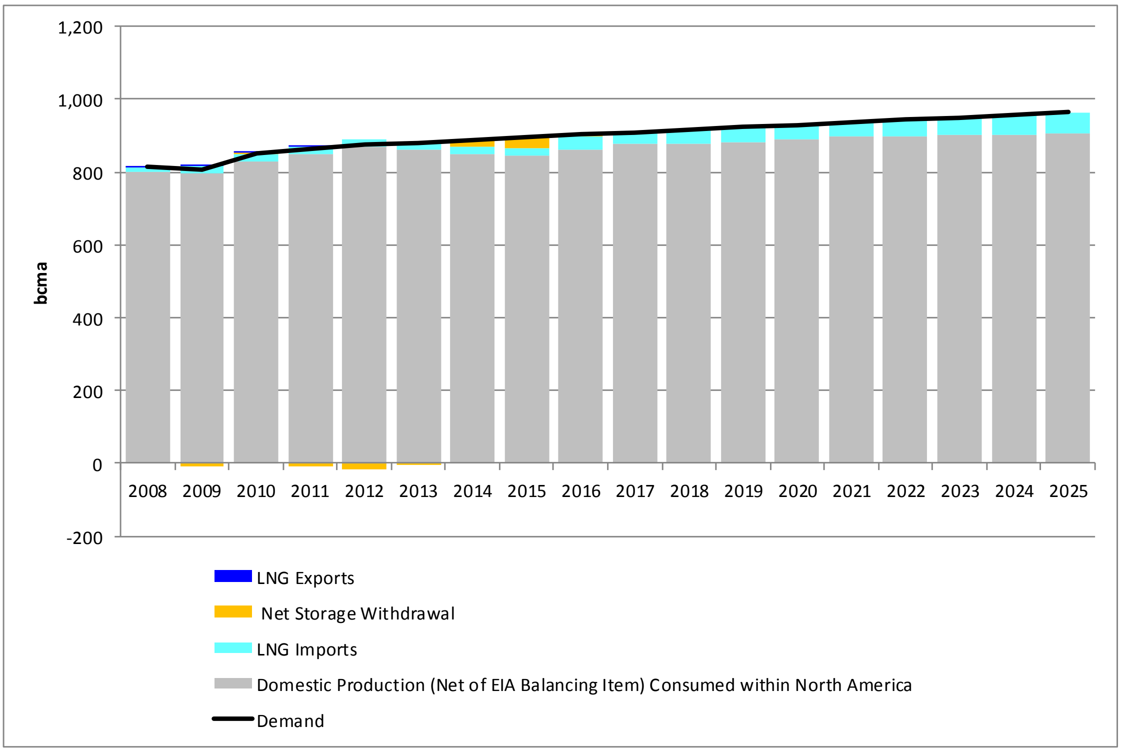


Sources: IEA and Cedigaz historical data to mid 2011, own analysis post mid 2011

North American Balances, LNG imports and Storage

Figure 25 shows the supply and demand balance for North America. The slow growth of LNG imports post 2015 is noted. Also from the chart the continued storage inventory build in 2012 and 2013 is seen (below the axis) which is reversed in 2014 and 2015.

Figure 25: North America Supply and Demand Balance 2008–25

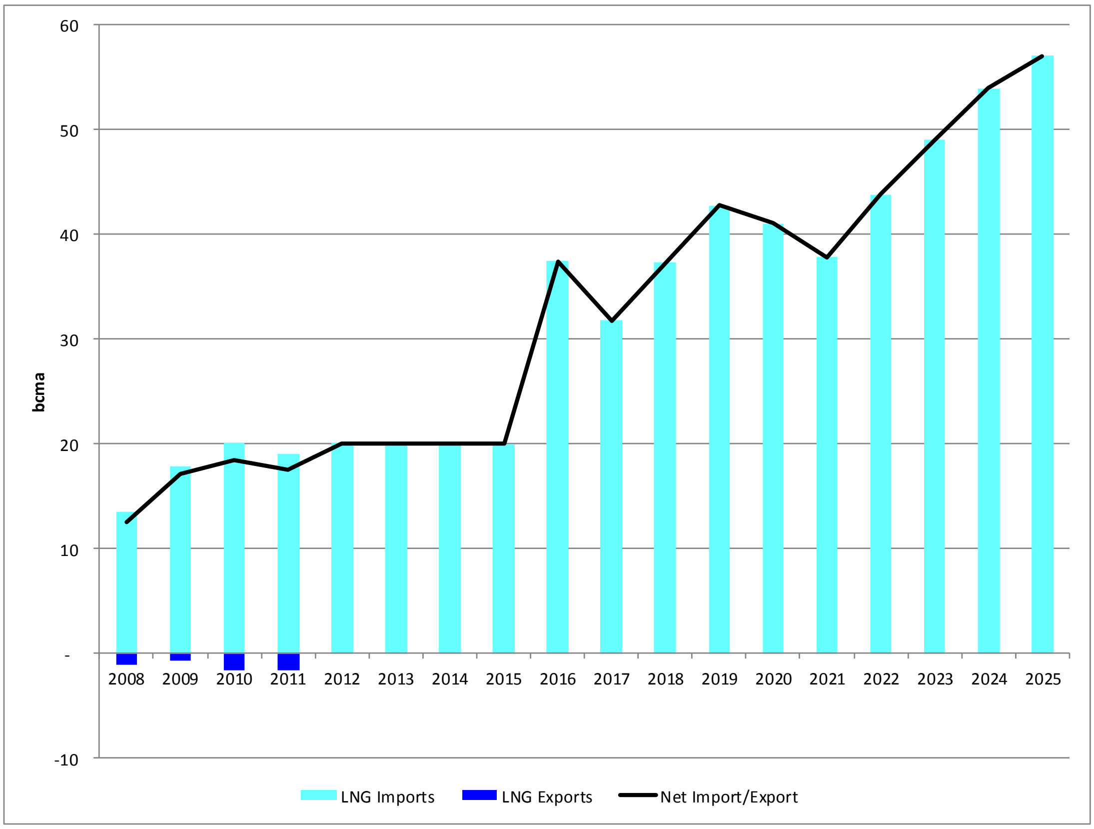


Sources: EIA, IEA and Waterborne LNG historical data, own analysis post mid 2011

Figure 26 shows the annual build up in North American LNG imports. Prior to 2015 it is assumed that the low import levels of the 2009 to 2011 period continue as a 'minimum'. From 2015, import levels climb, reaching 57 bcma by 2025. For completeness the minor export volumes from Kenai and historical LNG re-exports are shown in dark blue below the axis.

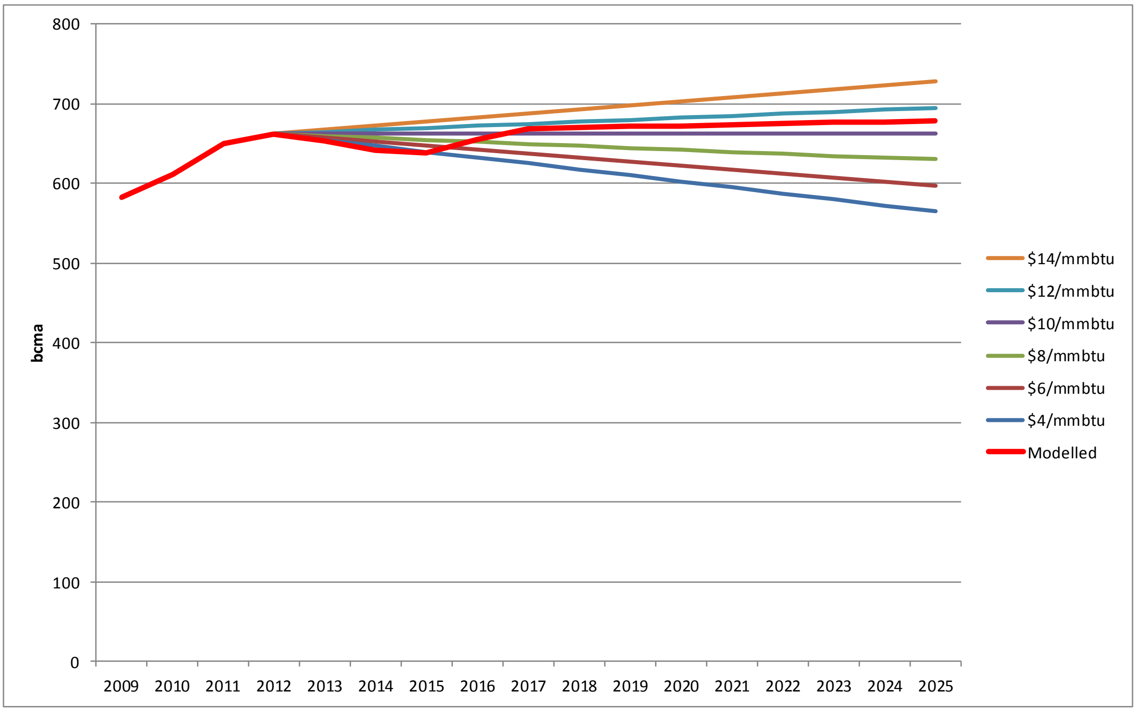
In line with the methodology discussed and depicted in Figure 14, Figure 27 shows the modelled US production level (red line) which is a consequence of the need for LNG imports to supplement domestic production, and hence the transmission of price via LNG arbitrage.

Figure 26: North American LNG Imports and Exports 2008–25



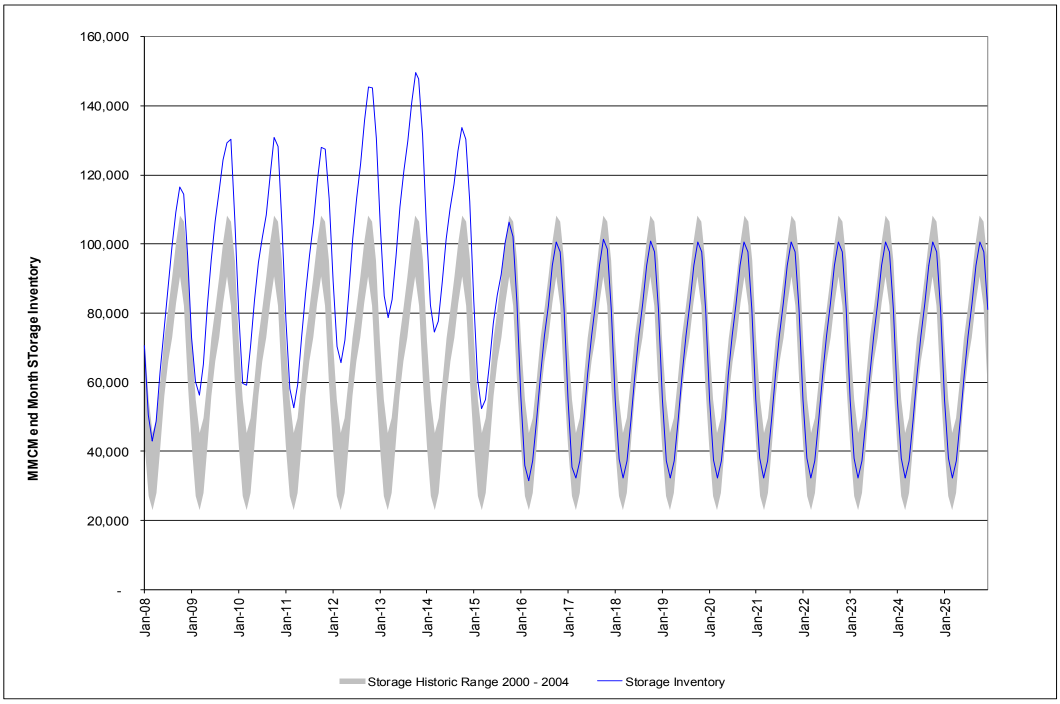
Sources: Waterborne LNG historical data, own analysis post mid 2011

Figure 27: US Production Modelled Path 2009–25



Source: EIA (historical), own analysis

Figure 28: US and Canadian Aggregate end-month Storage Inventory 2008–25



Source: EIA & Canadian Gas Producers Association (historical data), own analysis

This is further elaborated in Figure 28 which shows the end month US and Canada aggregate storage inventory. As US production falls post 2012 (in line with the assumptions in Figure 27), North American gas is withdrawn from storage until a level corresponding to the 2000 to 2004 monthly average is achieved. At this point Henry Hub price equals European hub price plus an assumed incremental $1/mmbtu LNG transportation cost.

Scenario Results Critique and Pricing Trends

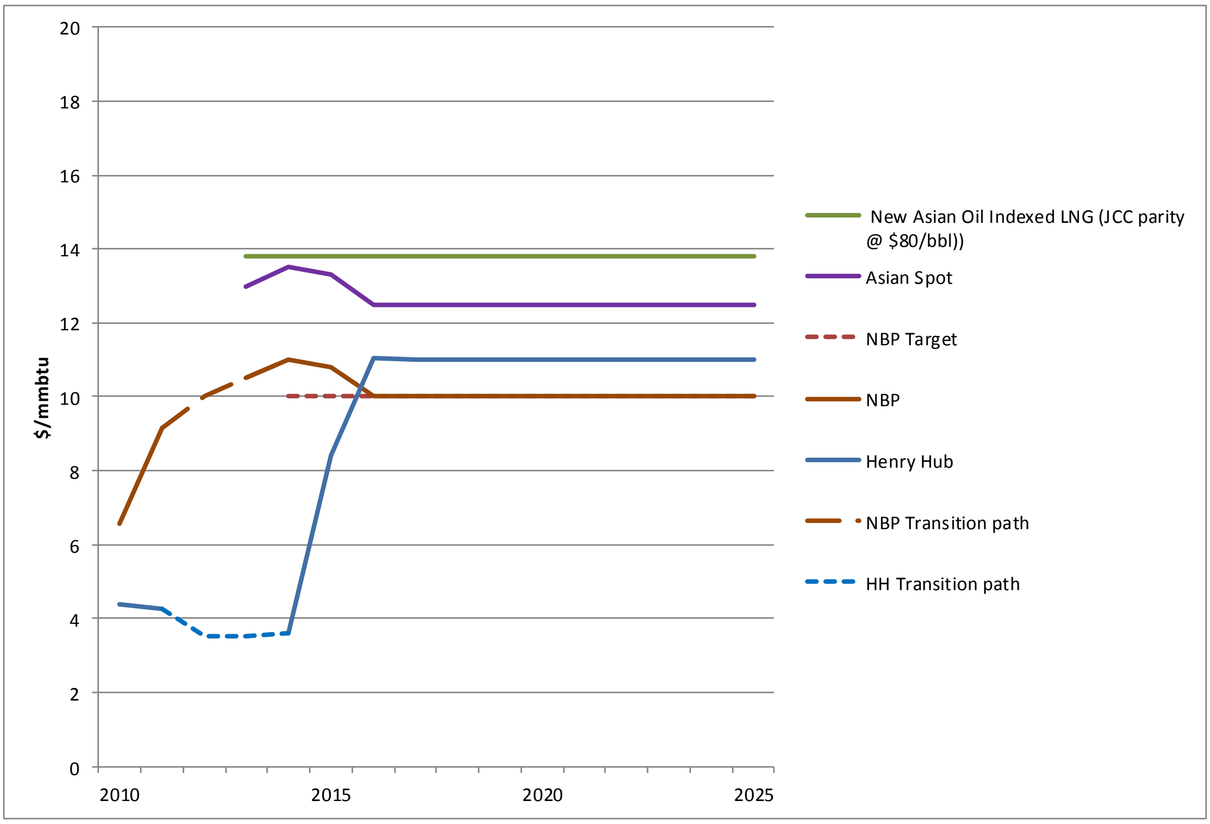
Accepting the 'input' assumptions upon which it is based, the modelled outcome of this scenario is broadly feasible in terms of the supply and demand balances of the three regions considered. Whether Europe transitions away from long term oil-indexed contracts or not, the modelling results show pipeline import levels between 2012 and 2025 comfortably above the 2011 Take or Pay level, which might set the target minimum Europe export volume in the future for Russia in particular.

If oil indexation remains, it is by no means certain that the position of midstream buyers of pipeline oil indexed gas would remain tenable. Although the scenario results suggest the scope for general convergence between oil-indexed long term contract prices and hub prices in Europe, even relatively short episodes where oil-indexed prices exceed hub prices would result in financial losses for these players, whose end user customers have, in the 2010 to 2011 period successfully demanded and received hub-based price tariffs. The seasonal pattern of arbitrage-induced convergence (shown in Figure 2) would suggest that such year-round convergence is likely to be the case.

Figure 29 shows the regional price trends implied from modelling this scenario. We have assumed, for illustrative purposes, that oil prices would be \$80/bbl, which sets the assumption for new Asian JCC parity LNG contract prices at \$13.80/mmbtu. On the basis of current oil products price relationships and the historical correlation between BAFA oil-indexed prices, we would also expect Russia (and other pipeline suppliers to Europe) to strive to manage supply volumes to achieve a European hub price which corresponds to \$80/bbl crude; i.e. \$10/mmbtu.

The most significant price shift in this scenario is the rise in Henry Hub from 2011 price levels of \$3.50 to \$4.50/mmbtu to a level of some \$11/mmbtu as North America makes the transition from a minimalist LNG importer to requiring significant LNG imports to supplement domestic production in order to meet demand. In reality this would have a moderating impact on North American natural gas demand, particularly in the power and industrial sectors, (beyond the scope of this analysis), although it is unlikely this would delay the price rise by more than a year or so.

Figure 29: Regional Scenario Gas Price Trends 2010–25



Sources: BP Statistical review of World Energy (historial data), own analysis

As previously noted, this scenario-modelled outcome represents a world where Russia is clearly above its nominal 'minimum European export floor' and hence has the ability to maintain European hub prices at a desired level. We also noted that the 2012 to 2014 period could see exceptionally high levels of Russian pipeline supply to Europe relative to the estimated supply availability. To reflect this it has been assumed that the result is a tight supply situation in Europe which exacerbates competition for flexible/spot LNG with Asia. In this period Figure 29 shows Asian LNG Spot prices converging on JCC causing an increase in NBP ($2.50 lower than Asian Spot prices due to assumed transport cost differentials). After 2014 additional supply availability from Russia to Europe and new LNG projects coming on stream ease this situation; NBP reverts to its target price level and Asian LNG spot prices fall back to $2.50/mmbtu above NBP (the assumed transport price differential).

At first hand it might be assumed that only a market with excess supply is likely to provide the environment in which Asian LNG spot market might develop and achieve liquidity, this scenario raises an interesting alternative to this view. With Europe relying to a great degree on pipeline imports and less on LNG, this scenario represents a long-term shift of flexible LNG supplies away from Europe and towards Asia. If these volumes remain 'flexible', i.e. are not converted into volumes sold under medium or even long-term oil indexed contract flows, then the Asian LNG spot market could develop depth and liquidity. Given recent precedent however, it is likely that at least some flexible LNG would be converted to oil-indexed medium term contract volumes.[43]

5.3 Low Asian Demand, Low US Domestic Production Scenario Results

Overview of the scenario

In this scenario, North America still faces the prospect of flagging domestic production, and becomes a significant LNG importer progressively through the modelled period. In order to secure supplies it must compete with Europe and hence US domestic prices would have to rise from 2011 levels to achieve this. The difference in this scenario is the more moderate level of Asian gas (and hence LNG) demand growth, as shown in Figure 10.

Figure 30 shows where global LNG is consumed on this scenario. The key changes compared with the previous scenario are the lower LNG consumption levels in Asia and a corresponding increase in Europe.

European Balances and Pipeline Imports

The European supply and demand balance for this scenario is shown in Figure 31. Pipeline imports still increase in the 2012 to 2016 period due to Asian competition for slowly growing global supply, however by 2017 LNG imports equal pipeline imports and outpace them for the rest of the period to 2025. The contribution of European pipeline imports from its various suppliers is shown in Figure 32 which shows the dramatic aggregate decline post 2015.

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43 For an example of this phenomenon see 'Qatargas signals more LNG diversions on PETRONAS deal',ICIS Heren, 25th July 2011, http://www.icis.com/heren/articles/2011/07/25/9479745/qatargas-signals-more-lng-diversions-on-petronas-deal.html

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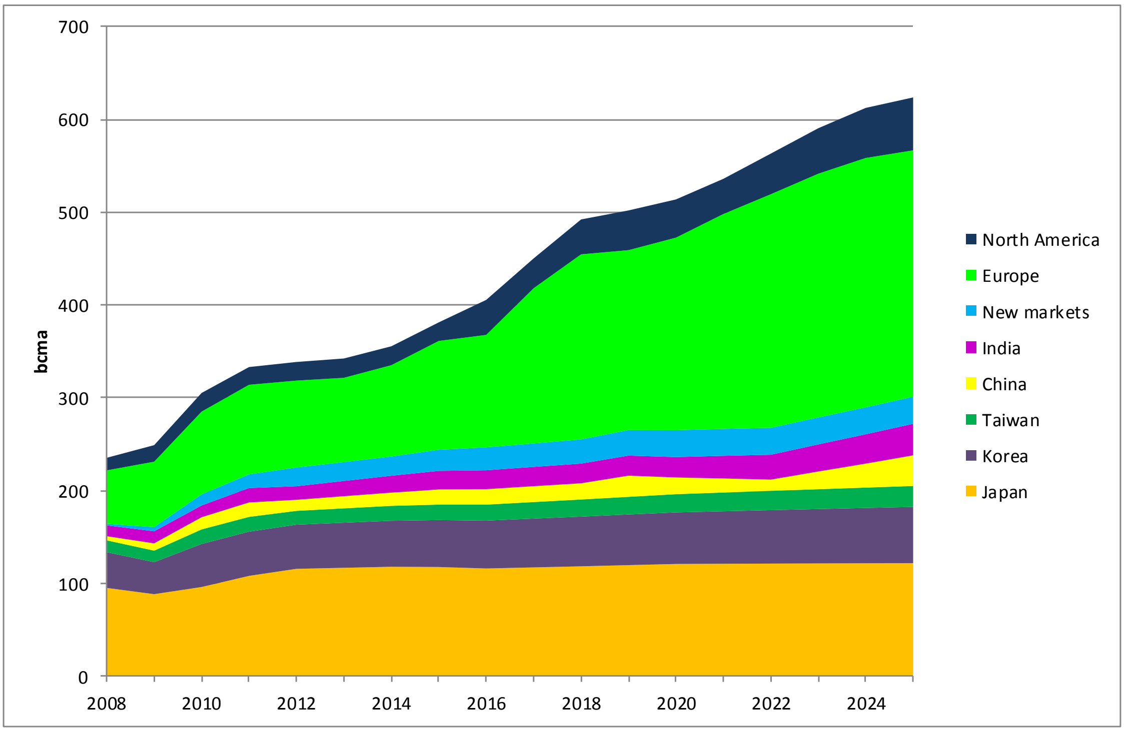
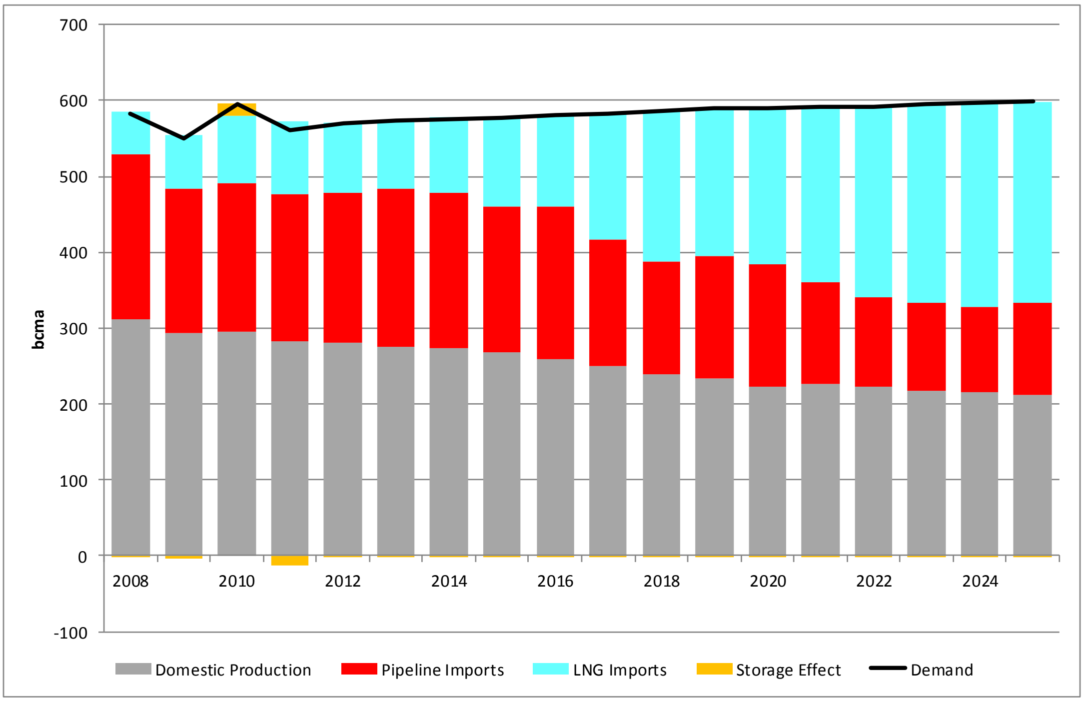
Figure 30: Global LNG Disposition 2008–25



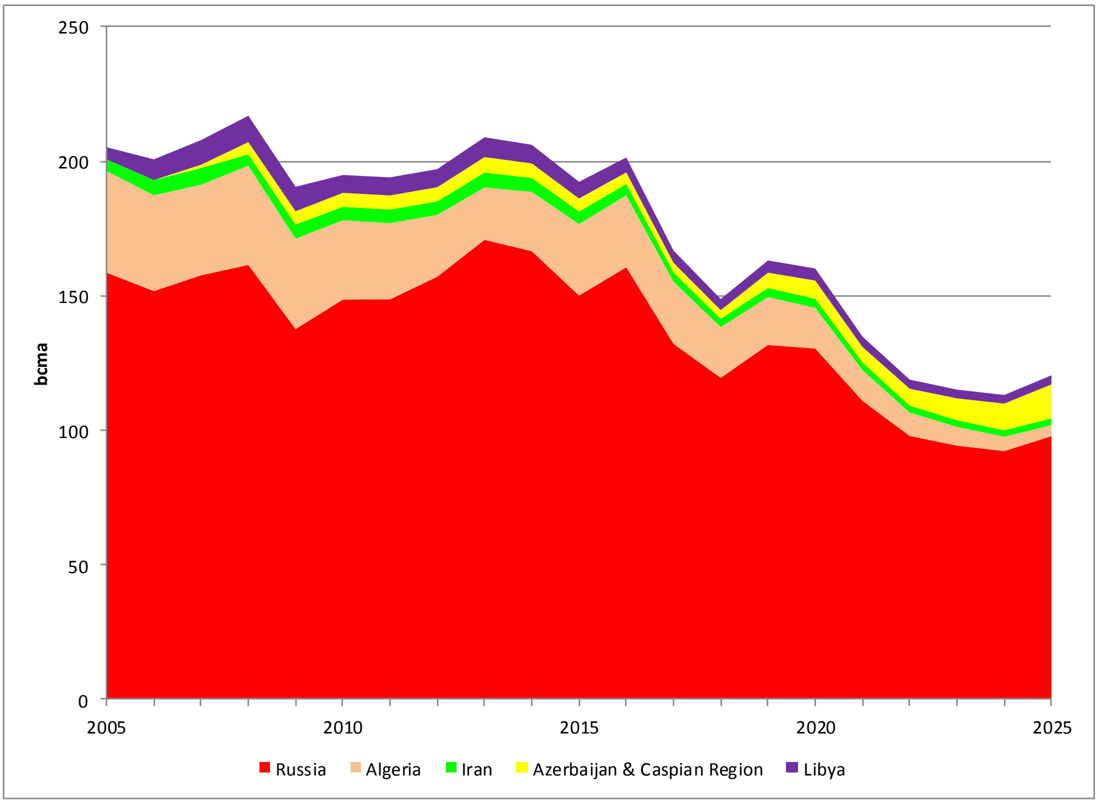
Source: Waterborne LNG (historical data), own analysis.

Figure 31: European Supply and Demand Balance 2008–25



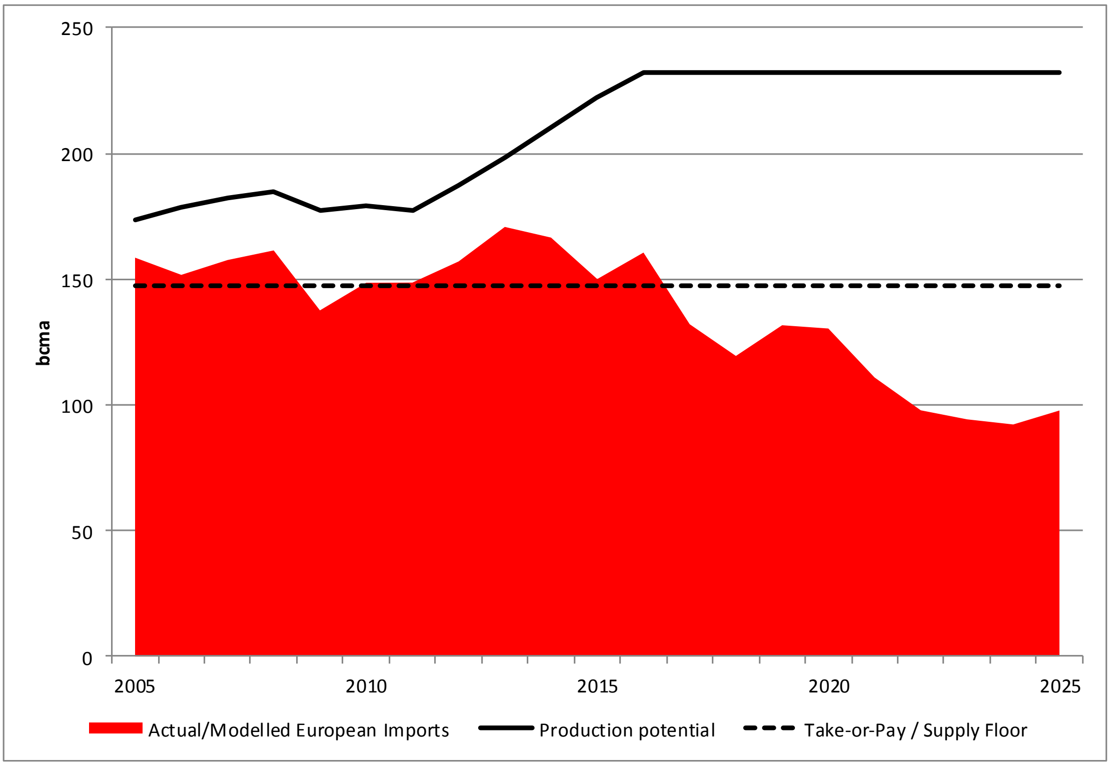
Sources: IEA, Waterborne LNG for historical data to mid 2011, own analysis post mid 2011

Figure 32: European Pipeline Imports 2005–25



Sources: IEA and Cedigaz historical data to mid 2011, own analysis post mid 2011

Figure 33: Russian Pipeline Supply to Europe 2005–25



Sources: IEA and Cedigaz historical data to mid 2011, own analysis post mid 2011

Figure 33 compares the modelled Russian pipeline imports into Europe with production potential and Take or Pay levels. While Russian pipeline imports recover to comfortably above the 2011 Take-or-Pay/long term minimum European export level in 2012 and 2013, they fall below this level and remain at very low levels from 2016 onwards.

North American Balances, LNG imports and Storage

The supply and demand balance for North America and the modelled outcome for LNG imports are unchanged from the previous scenario. The same is true for US production and US and Canadian Storage inventory trends. While the price trend is the same as that for the previous scenario (Figure 29), it provides an interesting context in which to discuss the situation of Russia in this scenario.

Scenario Critique, Further Development and Pricing Trends

The build up to the position of 'plentiful supply' in this scenario is masked by the 2012 – 2013 increased call on Russian gas due to still strong Asian demand in the context of a slowdown in global LNG supply growth. At the heart of this scenario is a marked slowdown in Asian demand evident by 2015 which, in the face of earlier evidence of deteriorating US production performance, does not immediately slow the pace of global LNG supply investment.

The dilemma for Russia is highlighted in the following depiction of its challenges whether or not Europe has made the transition away from oil-indexed pipeline gas contracts.

- In a post oil-indexed pipeline contract world Russia might be hoping to maintain hub prices at the (assumed) level of $10/mmbtu by managing pipeline gas supply to Europe within the range bounded by the 2011 Take or Pay level of around 150 bcma and its production capacity (230 bcma from 2016). The wholesale diversion of LNG volumes to Europe[44] in this scenario creates the situation where the maintenance of $10/mmbtu requires Russian imports to fall well below this minimum supply floor. The alternative path would be to maintain supply at the minimum European export level and effectively enter a 'price war' with competing LNG supplies. This would result in a lowering of European hub prices and North American prices as LNG cargoes sought the highest net-back in an over-supplied market. Given the low variable operating costs of an LNG supply chain it is unlikely that LNG production would be significantly curtailed.
- In a world where European pipeline imports under oil-indexed contracts continued, this scenario would represent a reprise of the 2009 situation where buyers were obligated to purchase Russian gas (at take or pay levels) at oil-indexed prices and sell to a customer base unwilling and not obliged to accept this price level. The spread between hub prices and oil indexed prices would again threaten the viability of midstream utilities and would be unsustainable.

[44] Diversions to Europe from Asia would arise from buyers exercising downward tolerance under their contracts and, in extremis, buyers seeking to minimise their losses under their take or pay obligations by selling contracted gas on trading hubs.

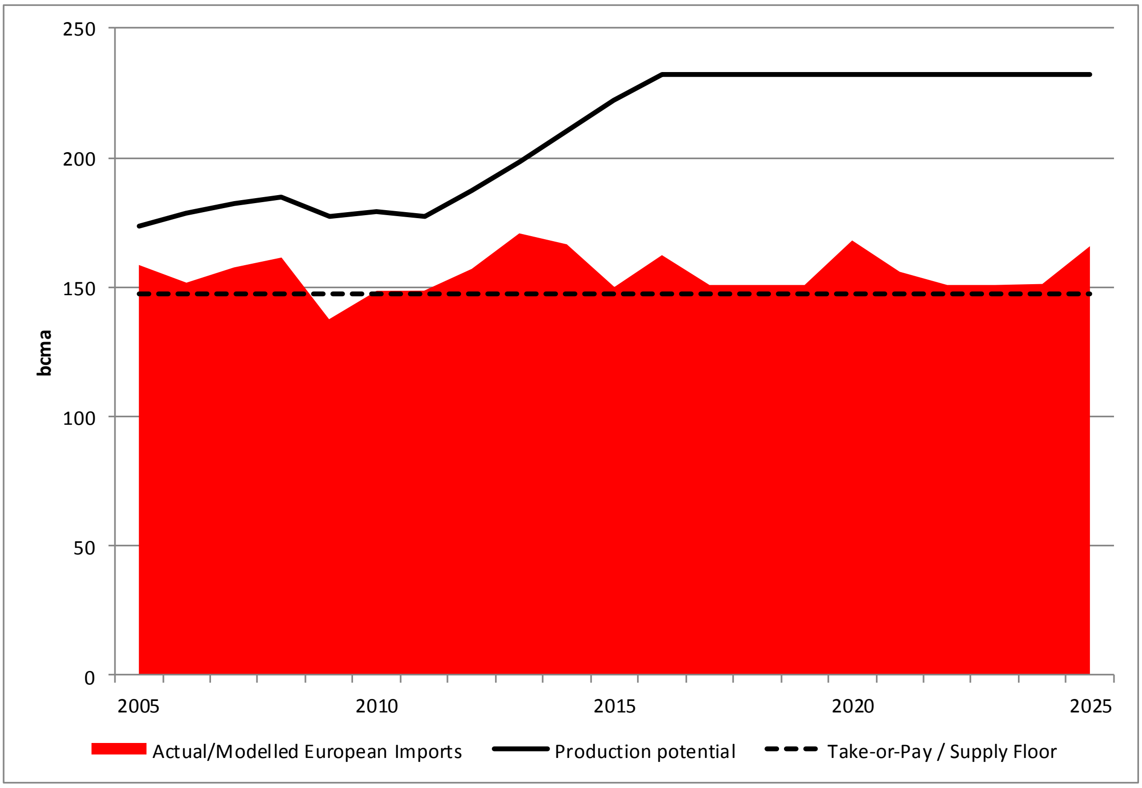
At present most observers might assign this scenario a low probability of occurrence, however the debate on the sustainability of US shale production growth in 2011 is unresolved. Also the ability of Asia to continue its rapid economic (and hence gas demand) growth in the face of apparent economic stagnation in the OECD countries, and questions over China's ability to manage a soft landing vis a vis its internal debt-funded asset inflation challenges, at the very least require us to consider this scenario as a possible outcome.

To explore these issues further the scenario was developed to incorporate two second order effects:

- An assumed deferment of some future LNG supply projects (a probability of 40% rather than 50% was assumed for future uncertain projects).
- A minimum European export level of 190 bcma was defended by pipeline gas suppliers to Europe (150 bcma for Russia).

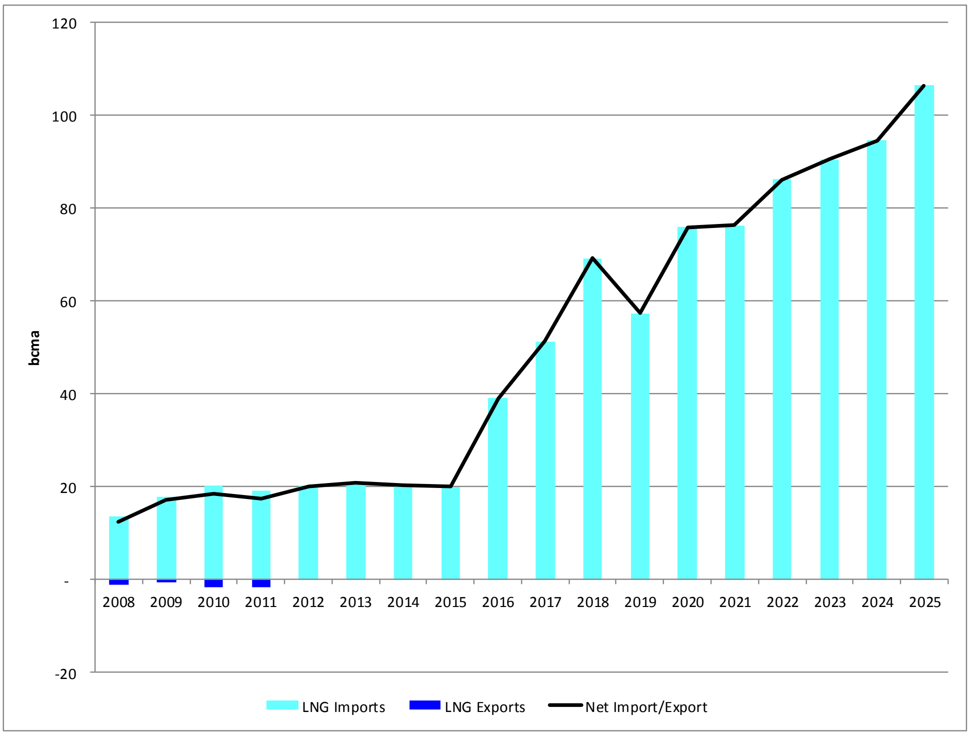
The resulting outcome for Russian pipeline supply to Europe is shown in Figure 34. Clearly with European Pipeline suppliers holding to a minimum European export level 'excess LNG supply' is diverted to the North American market where is has an impact on storage inventory and hence price and domestic production. Figure 35 shows the future path of North American LNG imports under these assumptions, reaching 105 bcma by 2025.

Figure 34: Russian Pipeline Supply to Europe 2005–25



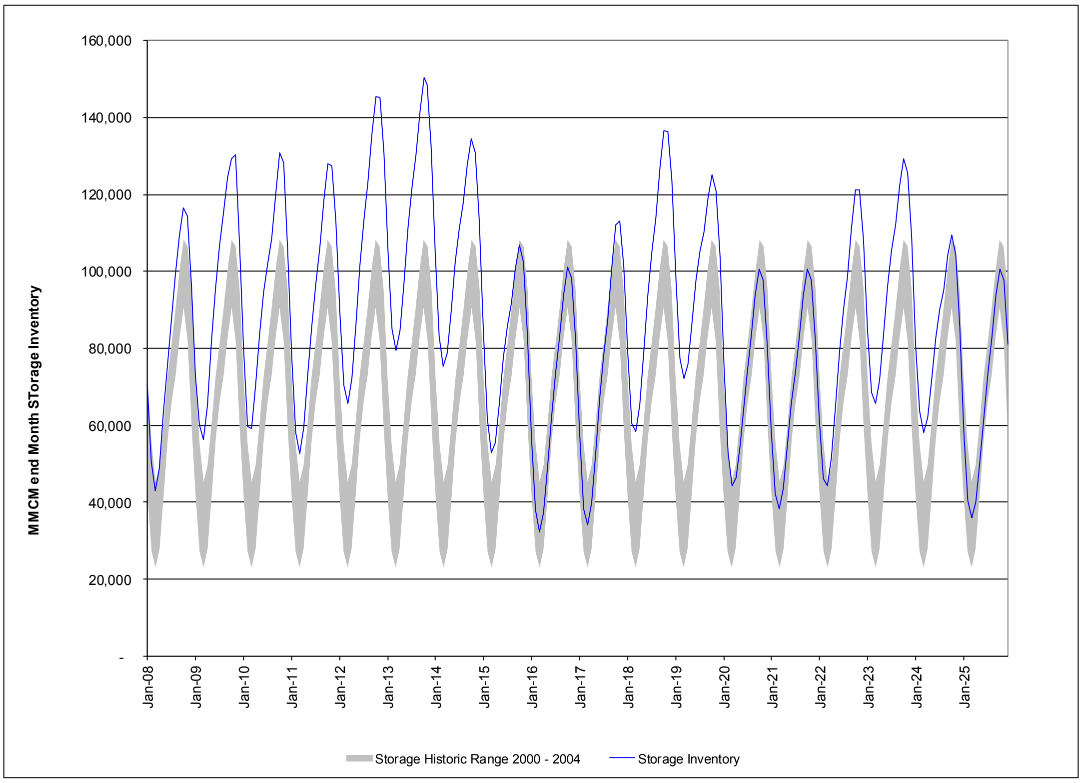
Sources: IEA and Cedigaz historical data to mid 2011, own analysis post mid 2011

Figure 35: North American LNG Imports and Exports 2008–25



Sources: Waterborne LNG historial data, own analysis post mid 2011

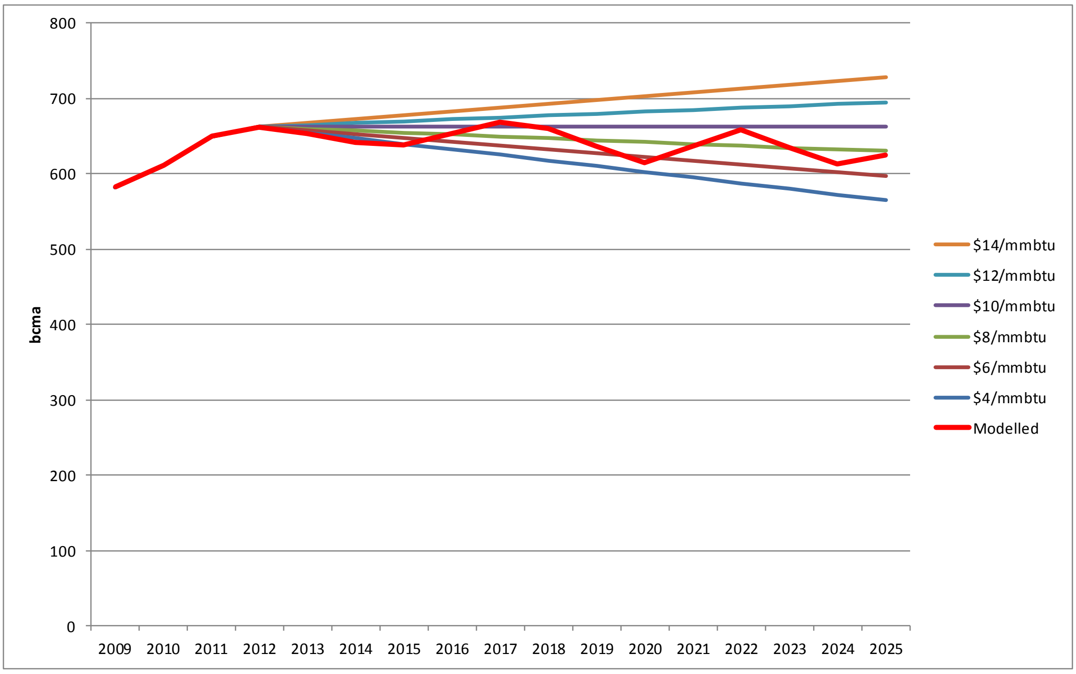
Figure 36: US and Canadian Aggregate end-month Storage Inventory 2008–25



Source: EIA & Canadian Gas Producers Association (historical data), own analysis

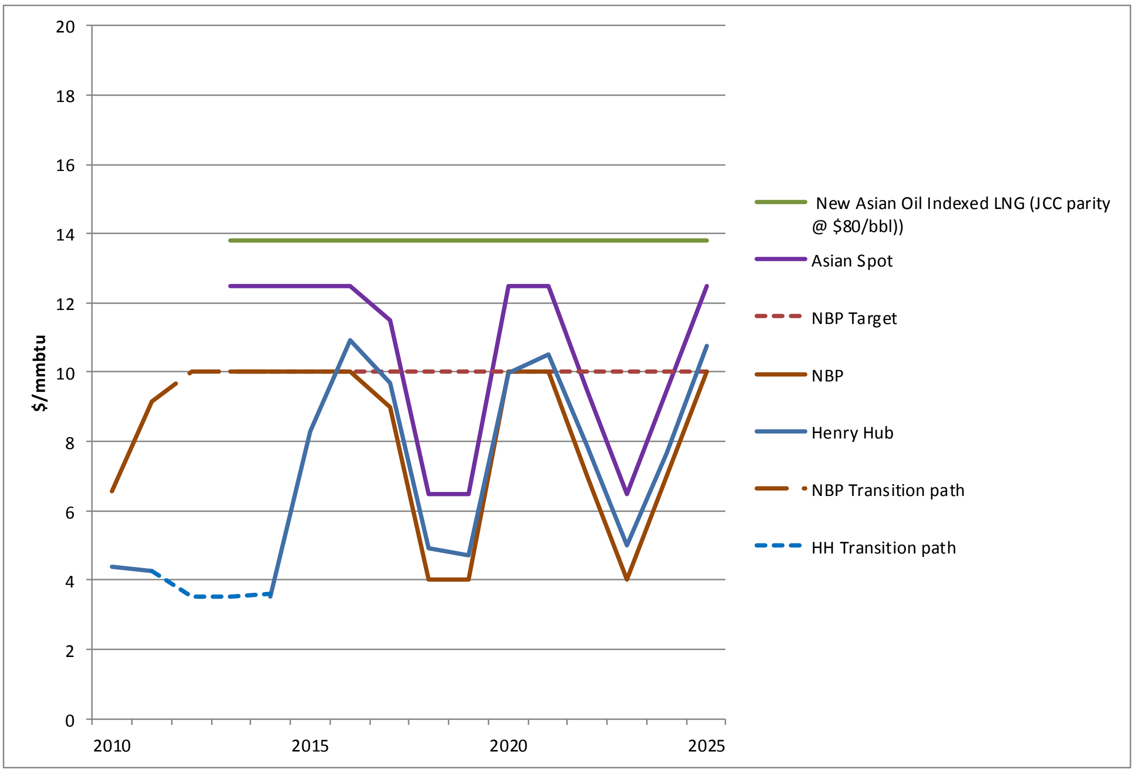
Figure 36 shows the impact on North American storage inventory with notable high working gas inventory periods in 2018 and 2019 and again in 2022 and 2023.

Figure 37: US Production Modelled Path 2009–25



Source: EIA (historical), own analysis

Figure 38: Regional Scenario Gas Price Trends 2010–25



Sources: BP Statistical review of World Energy (historical data), own analysis

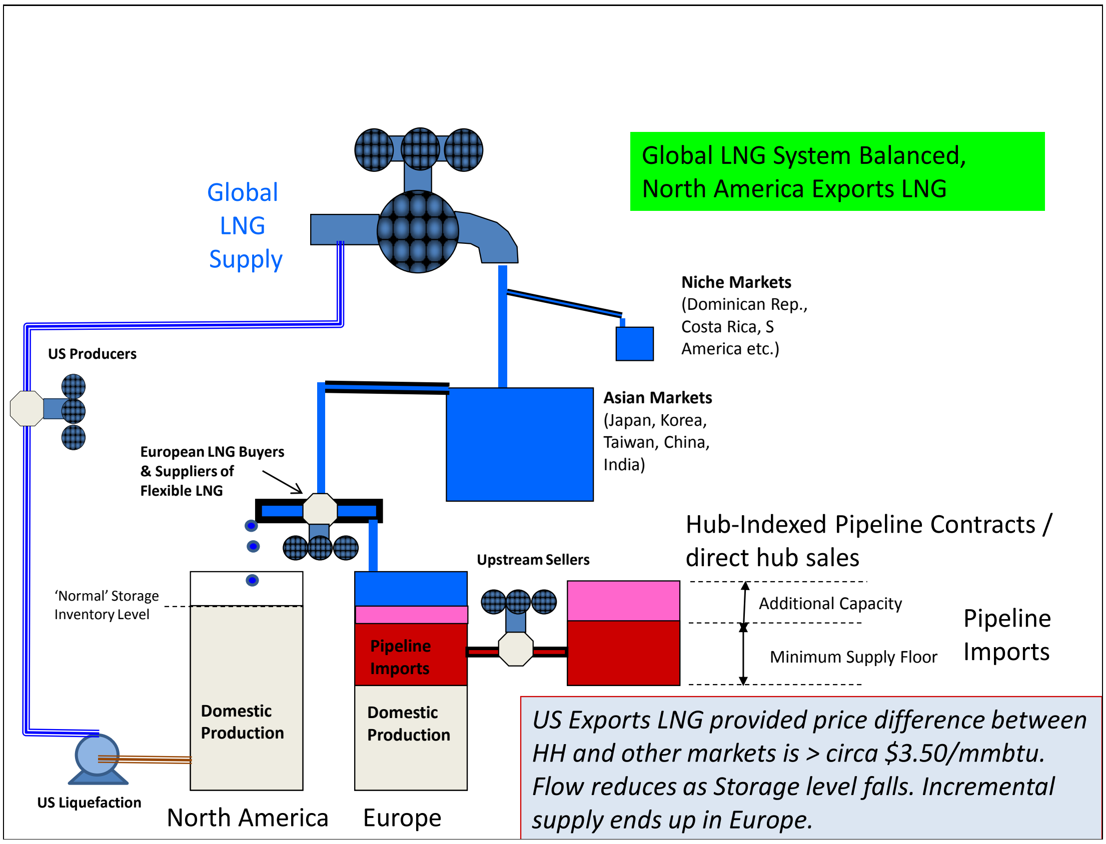
Figure 37 shows the impact of LNG imports, the variation in storage inventory and Henry Hub price on production levels. The resulting pricing trends for this scenario are shown in Figure 38. The consequence of suppliers of pipeline gas to Europe maintaining their minimum European export level at the expense of price is an overspill of 'excess LNG' to North America, where it depresses price. LNG arbitrage would ensure that both European traded hubs and Asian LNG spot prices tracked Henry Hub (with differentials due to shipping costs).

The impact on Asian LNG spot prices of this modified scenario produces a wide spread compared with JCC-priced contracted LNG. As the durations of the two periods of high spreads are relatively short it is unlikely they would cause a wholesale shift away from long term JCC-linked contracts in the Asian market.

5.4 Dynamics of the High US Domestic Production Scenarios

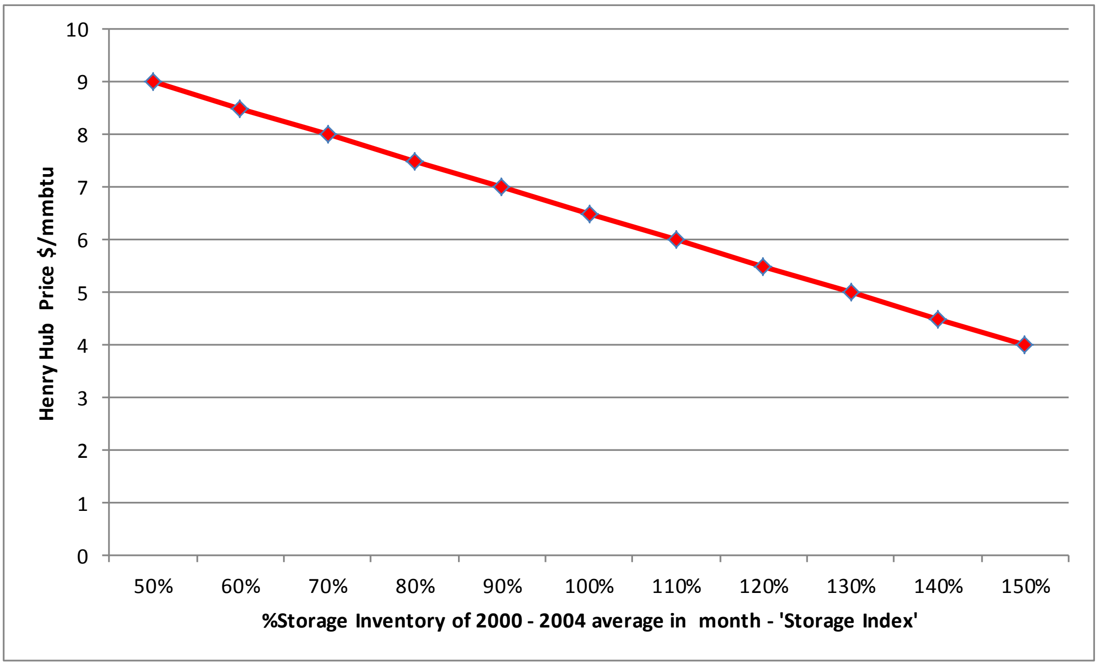
In this scenario the global system is represented in Figure 39. Continuing strong shale growth has led to the construction of LNG export capacity from the US and Canada which adds to the global supply of LNG. If this additional supply does not lead to a change in the timings of future LNG projects elsewhere then incrementally these additional volumes will end up in the Atlantic basin[45].

Figure 39: System Schematic for the High US Domestic Production Scenarios



[45] It is also assumed that that demand for natural gas in Asia and Europe is unchanged by these additional LNG volumes.

Figure 40: Hypothetical Relationship between US & Canadian Storage Inventory Index and Henry Hub Price



Source: Hypothetical assumption

It has been assumed that Europe has transitioned away from oil-indexed contracts to hub-indexed contracts and/or direct upstream sales. Upstream sellers of pipeline gas to Europe are expected to maintain a 'target price' – but with the consequence that the higher this price is, the more attractive it makes the diversion of flexible LNG towards Europe.

Equilibrium is reached when US prices (labelled as 'Henry Hub') are equal to European hub prices less a spread which represents the cost of tolling through the North American LNG export facilities, the LNG shipping costs and the destination market regasification fee. In aggregate this spread is estimated at $3.50/mmbtu[46].

Any increase in Henry Hub prices brought about through arbitrage in this system would in turn increase US shale drilling activity (with a lag) as more play areas became economically viable (as depicted in Figure 14). Again at a hypothetical level we can define a relationship between US and Canadian storage inventory levels and price in these High US production cases.

In this scenario, for the period after North American LNG exports commence, it is assumed that a monthly storage index of 100% corresponds to the Henry Hub price at which arbitrage based on North American LNG exports achieves an equilibrium between North America and Europe with Henry Hub prices $3.50 below those of Europe. This assumed relationship is shown in Figure 40.

[46] Note that even if some of these volumes are targeted at the Asian spot market, the global LNG balance will ultimately result in the North American – European spread being the primary concern.

As in the Low US Production cases, the feedback-loop between Henry Hub prices and future US production is completed by the following modelling linkage:

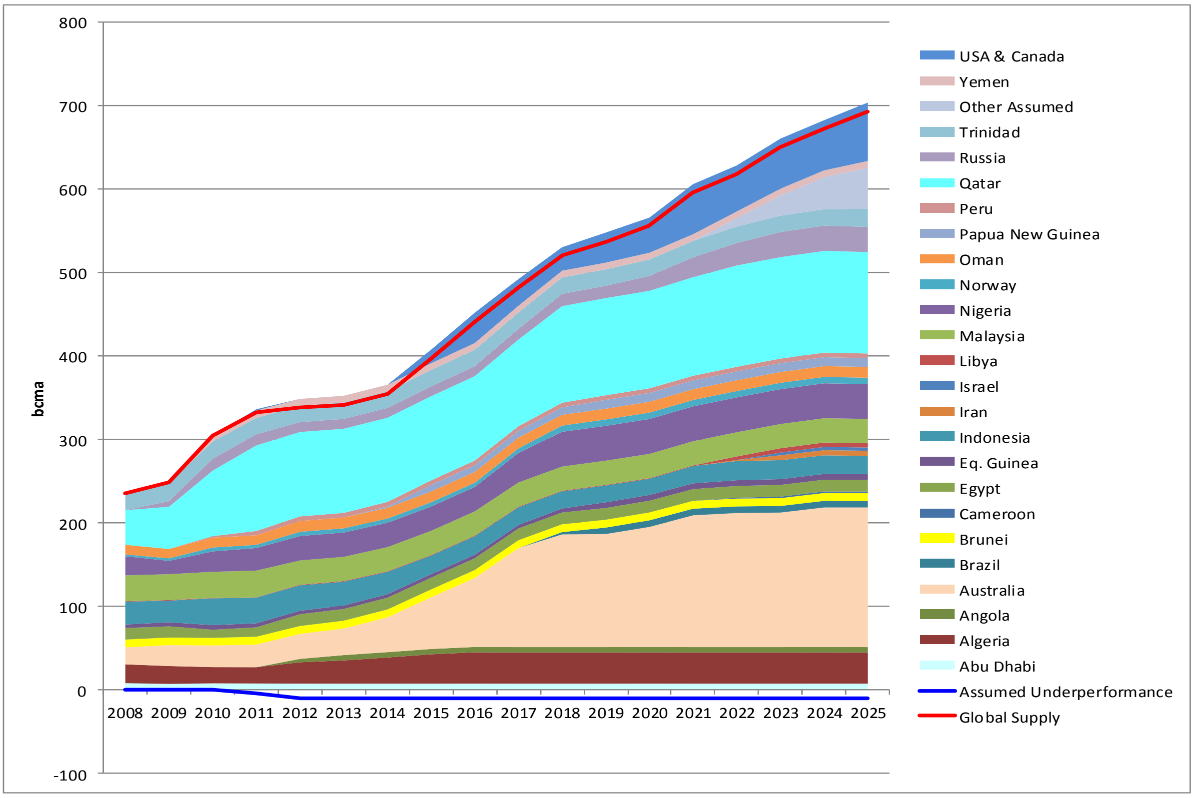
- The average annual Henry Hub price in year n, is defined based on the hypothetical relationship with the average storage index for year n – as represented in Figure 40.
- US production in year n+1 is determined from the hypothetical relationship in Figure 14. The one year lag is used to recognise the investment time lag to changed price signals.
- The degree of year to year changes in US production level was constrained to plus or minus 3.5% in order to further recognise inertia in the system, this being the observed growth rate from 2006 to 2010.

5.5 High Asian Demand, High US Domestic Production Scenario Results

Overview of the scenario

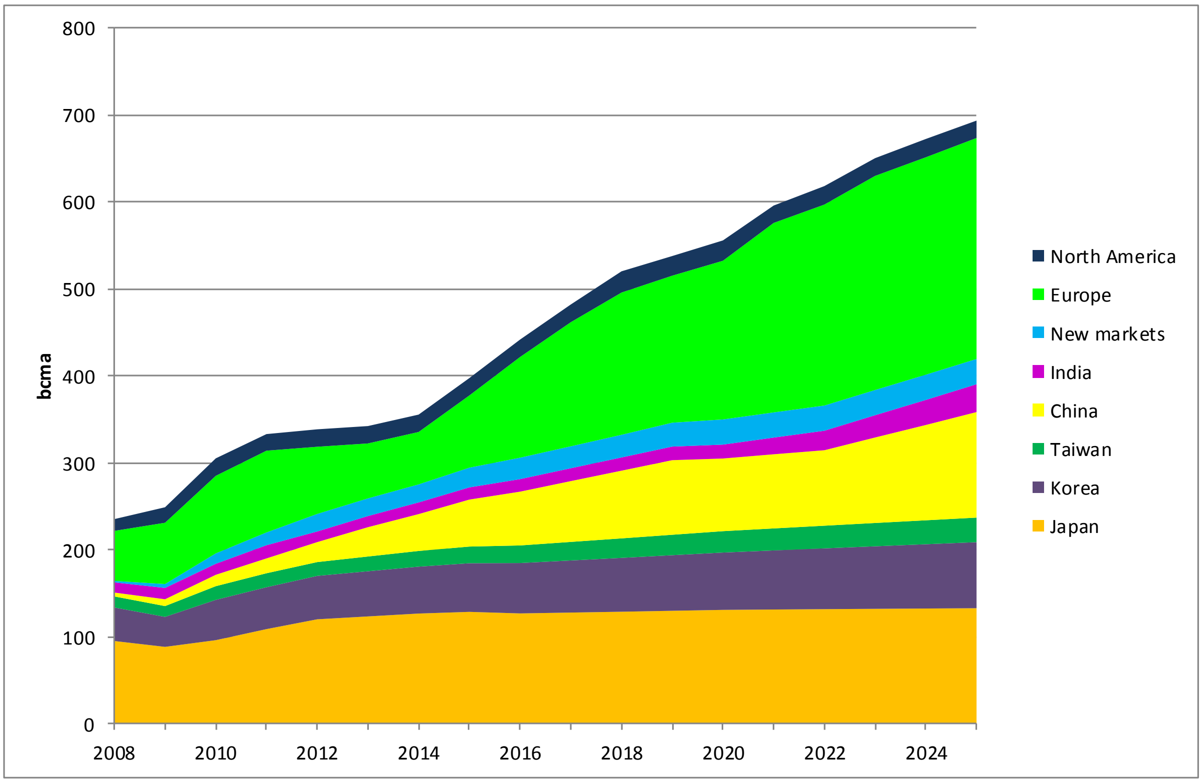
This is a scenario in which North America production continues its post 2005 – 2010 growth trajectory due to continued, successful shale gas development. Of the LNG export projects shown in Table 1, up to 70 bcma of export capacity is assumed to become operational. Figure 41 places the North American export supply in a global context, taking supply by 2025 up to 695 bcma.

Figure 41: Global LNG Supply 2008–25 (High US Production)



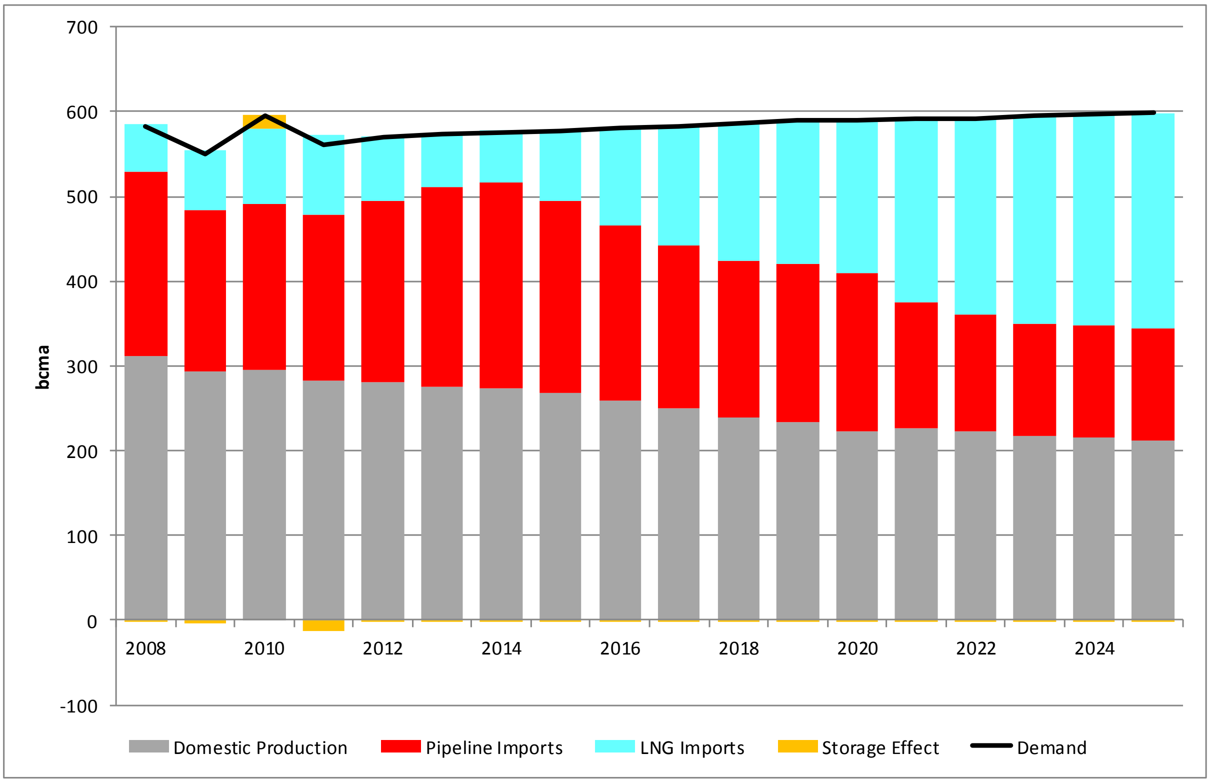
Sources: Based on methodology by D Ledesma, data from Waterborne LNG, other industry reports and own analysis

Figure 42: Global LNG Disposition 2008–25



Source: Waterborne LNG (historical data), own analysis

Figure 43: European Supply and Demand Balance 2008–25



Sources: IEA, Waterborne LNG for historical data to mid 2011, own analysis post mid 2011

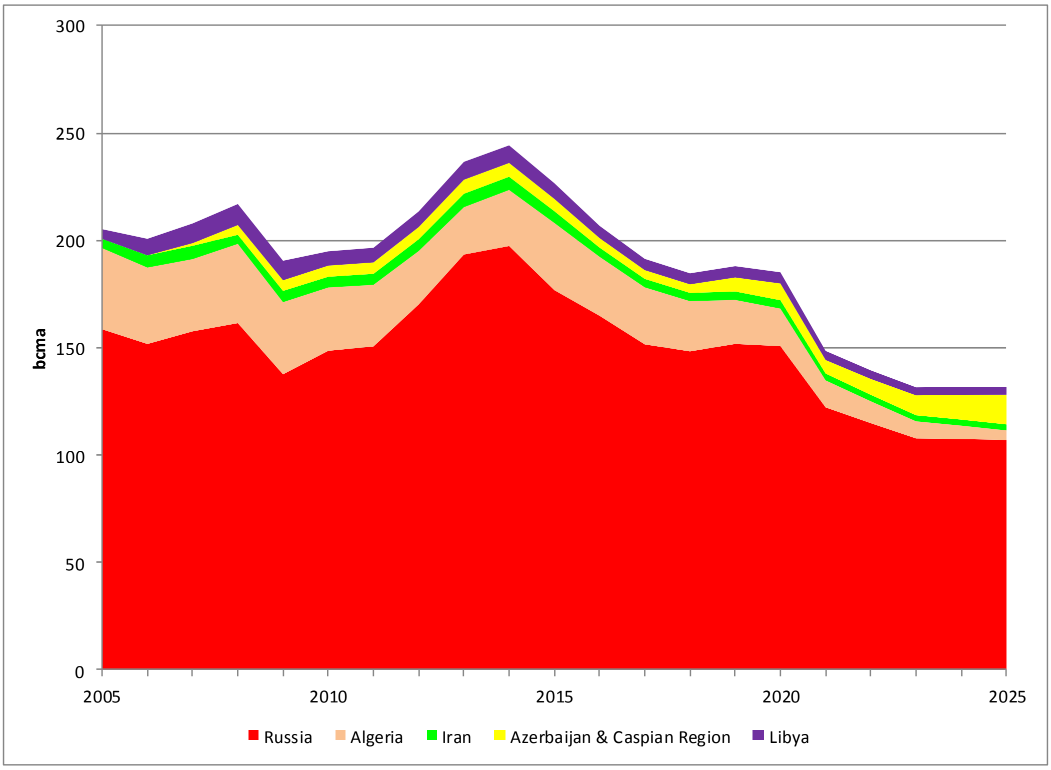
Figure 42 shows where global LNG is consumed in this scenario. With Asian LNG demand assumed the same as in the 'High Asian Demand, Low US Domestic Production Scenario' the additional supply from North America, incrementally, results in higher European LNG imports. North American imports are assumed to continue at 2009 – 2011 levels into Mexico and regions of Canada and the US where pipeline gas is not available.

The European supply and demand balance for this scenario is shown in Figure 43. Pipeline imports increase in the 2012 to 2014 period due to Asian competition for slowly growing global LNG supplies. After 2014 LNG imports grow as global supply gathers momentum and North American LNG exports are assumed to commence.

European Balances and Pipeline Imports

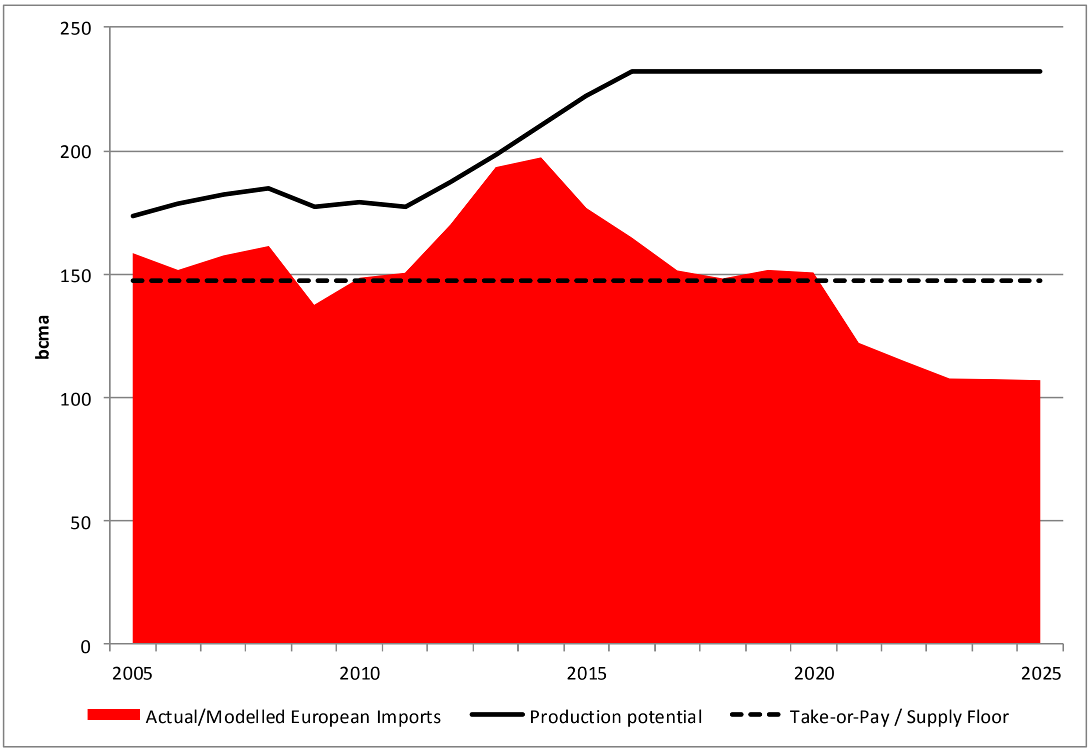
The historical and modelled future contribution of European pipeline imports from its various suppliers is shown in Figure 44. The level of European imports reaches a peak in 2014 and then declines dramatically, stabilising only in 2023. Figure 45 shows the outcome for Russian pipeline imports into Europe. While falling from 2014 onwards, they stay at or above the take-or-pay/minimum European export level until 2020, falling substantially below this level thereafter.

Figure 44: European Pipeline Imports 2005–25



Sources: IEA and Cedigaz historical data to mid 2011, own analysis post mid 2011

Figure 45: Russian Pipeline Supply to Europe 2005–25



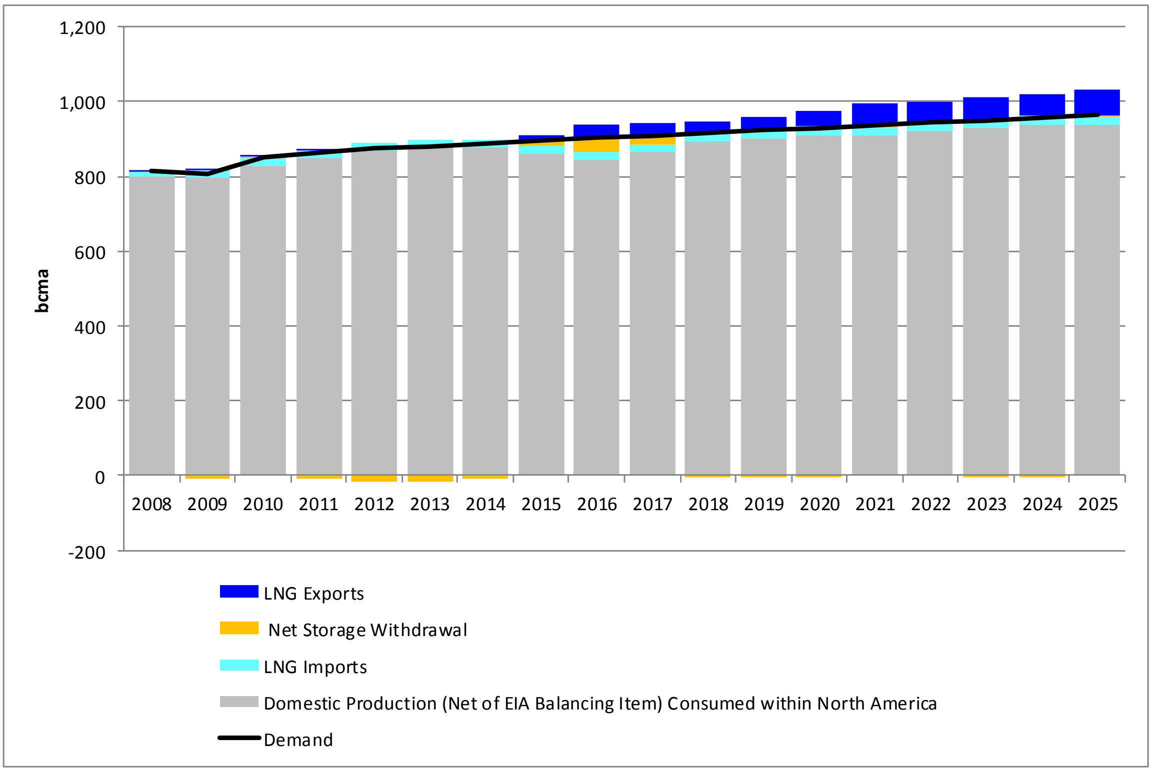
Sources: IEA and Cedigaz historical data to mid 2011, own analysis post mid 2011

North American Balances, LNG imports and Storage

Figure 46 shows the supply and demand balance for North America. LNG exports are shown starting in 2015, building up through the period to 2025. The storage inventory build from 2012 to 2014 is noted (below the axis) which is reversed in 2015 to 2017 once LNG exports commence.

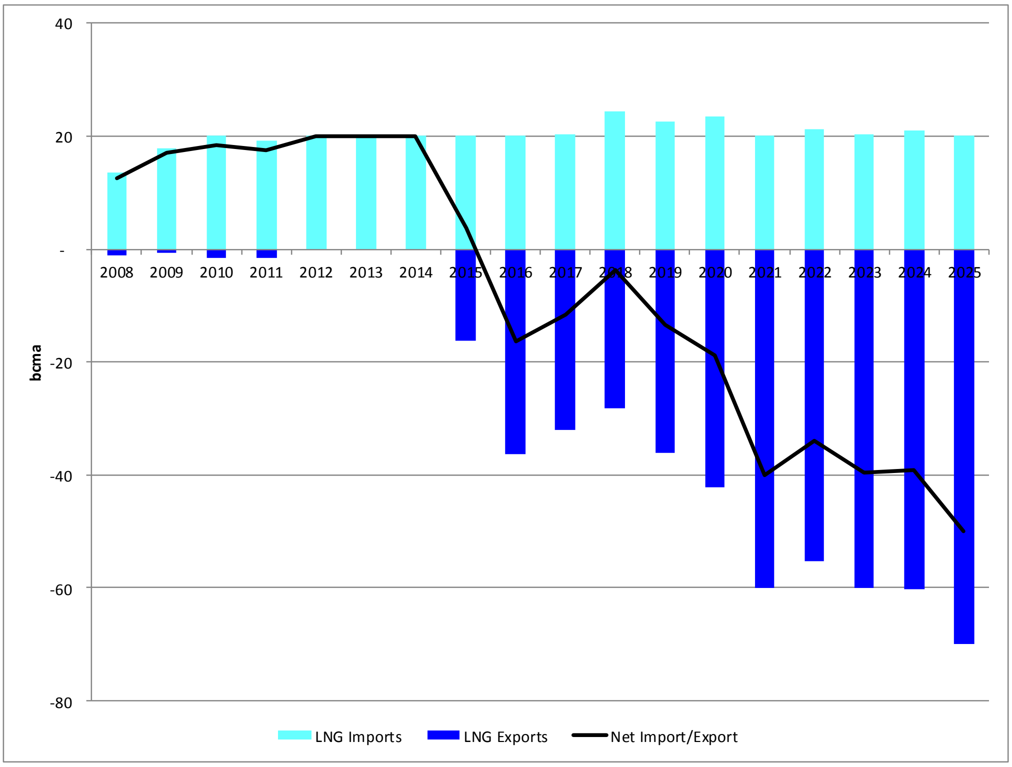
Figure 47 shows the annual build up in North American LNG exports. LNG exports in the 2015 to 2017 period are, at the margin, supplied by drawing down on excess storage inventory. This acts to increase the Henry Hub price and in turn incentivises increased production levels. The increase in production levels in turn provides a sustainable additional supply for LNG export over and above North American consumption requirements. By 2025 North American exports reach 70 bcma which, after deducting LNG imports, yields a net 50 bcma LNG export balance.

Figure 46: North America Supply and Demand Balance 2008–25



Sources: EIA, IEA and Waterborne LNG historical data, own analysis post mid 2011

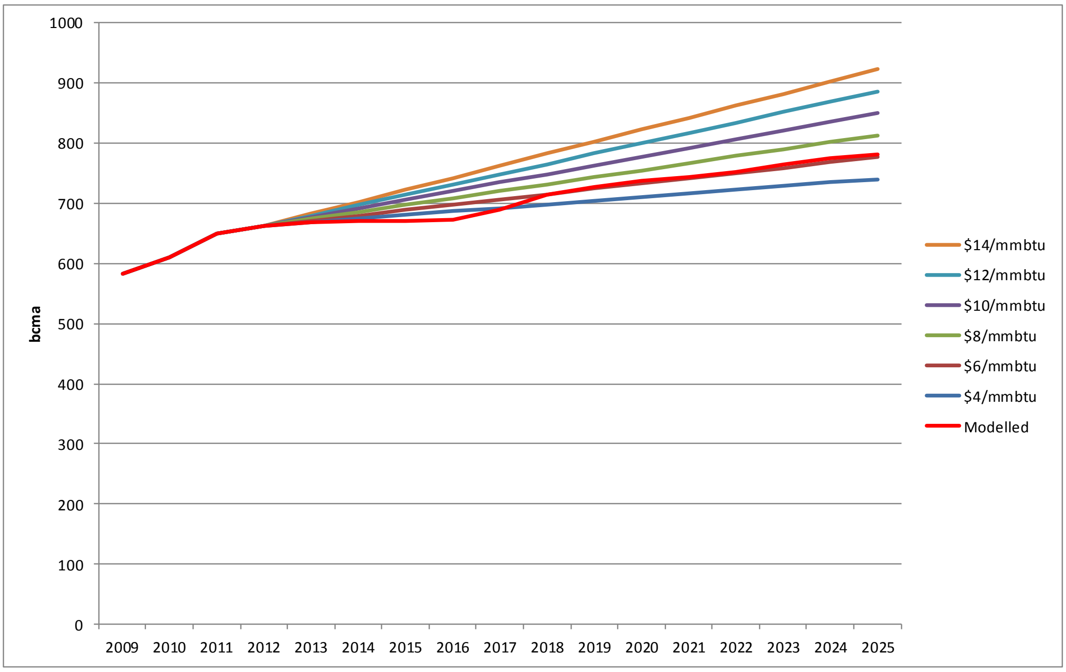
Figure 47: North American LNG Imports and Exports 2008–25



Sources: Waterborne LNG historical data, own analysis post mid 2011

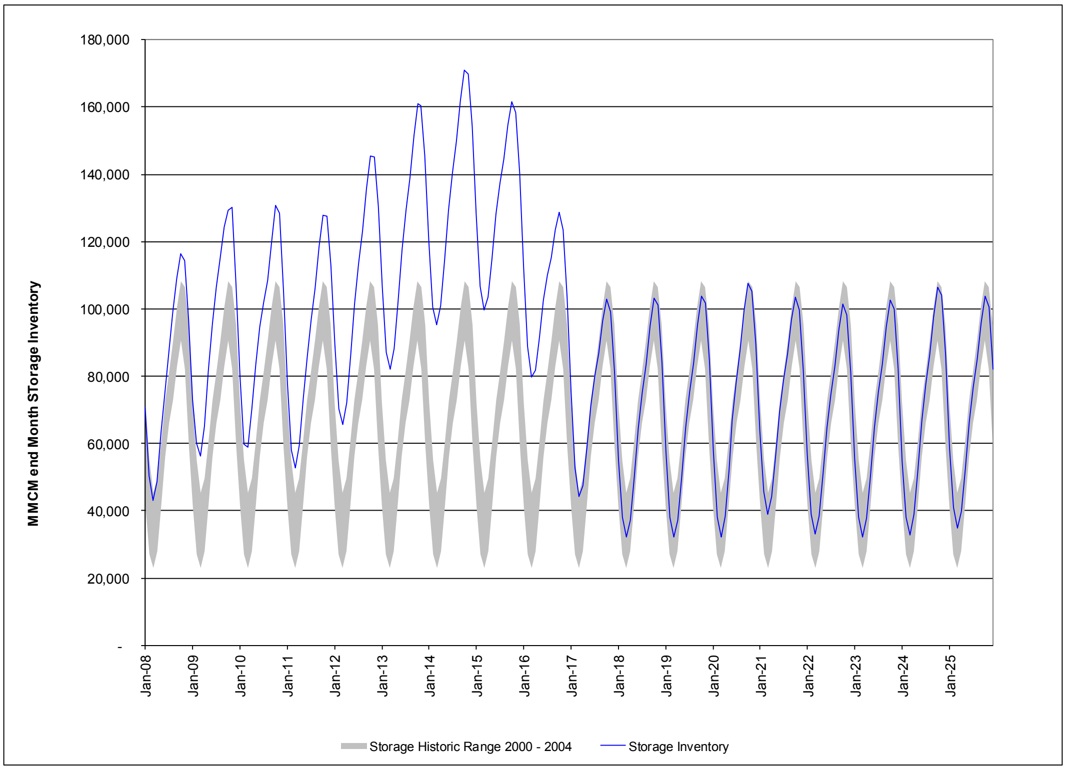
Figure 48 shows the trajectory of US production (red) in line with the hypothetical price – production relationship.

Figure 48: US Production Modelled Path 2009–25



Source: EIA (historical), own analysis

Figure 49: US and Canadian Aggregate end-month Storage Inventory 2008–25



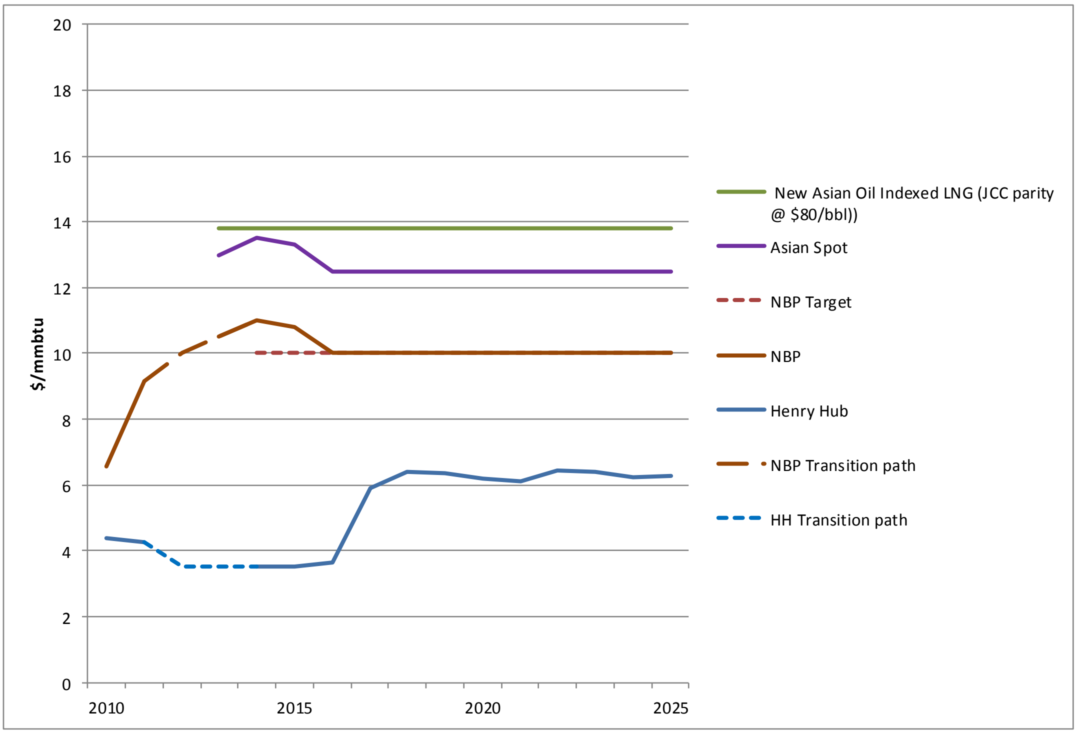
Source: EIA & Canadian Gas Producers Association (historical data), own analysis

Figure 49 shows the end month US and Canada aggregate storage inventory. In the period 2012 to 2015 (before LNG exports commence) production continues to outstrip North America demand and hence storage inventory continues to grow[47]. Once LNG export projects come on-stream storage inventory is reduced. By 2018 storage levels are in line with 2000 to 2004 averages and the inventory surplus has been cleared.

Figure 50 shows the regional price trends implied from modelling this scenario. By 2017 Henry Hub has risen to a level of \$6.50/mmbtu; i.e. the volume of LNG exports is such that the equilibrium spread of \$3.50 between Henry Hub and European Hub prices has been reached. Prior to 2015 Henry Hub price levels on this graph have been constrained by an assumed price floor of \$3.50/mmbtu. In light of the potential for severe storage inventory build, threatening to overwhelm available capacity, it is very possible that prices could be lower than this level, causing some production shut-in prior to the start-up of LNG export facilities.

As noted in the High Asian Demand, Low US Production scenario, there is a potential tight European supply situation in the 2012 to 2014 period due to very high levels of Russian pipeline supply to Europe relative to the estimated supply availability. This is likely to exacerbate completion for spot and flexible LNG between Europe and Asia. This is illustrated in Figure 50.

Figure 50: Regional Scenario Gas Price Trends



Sources: BP Statistical review of World Energy (historical data), own analysis

[47] It is likely that storage inventory in Figure 50 would exceed storage physical volumes in 2013–15. This would likely result in a temporary shut-in of some production in anticipation of LNG export schemes becoming operational.

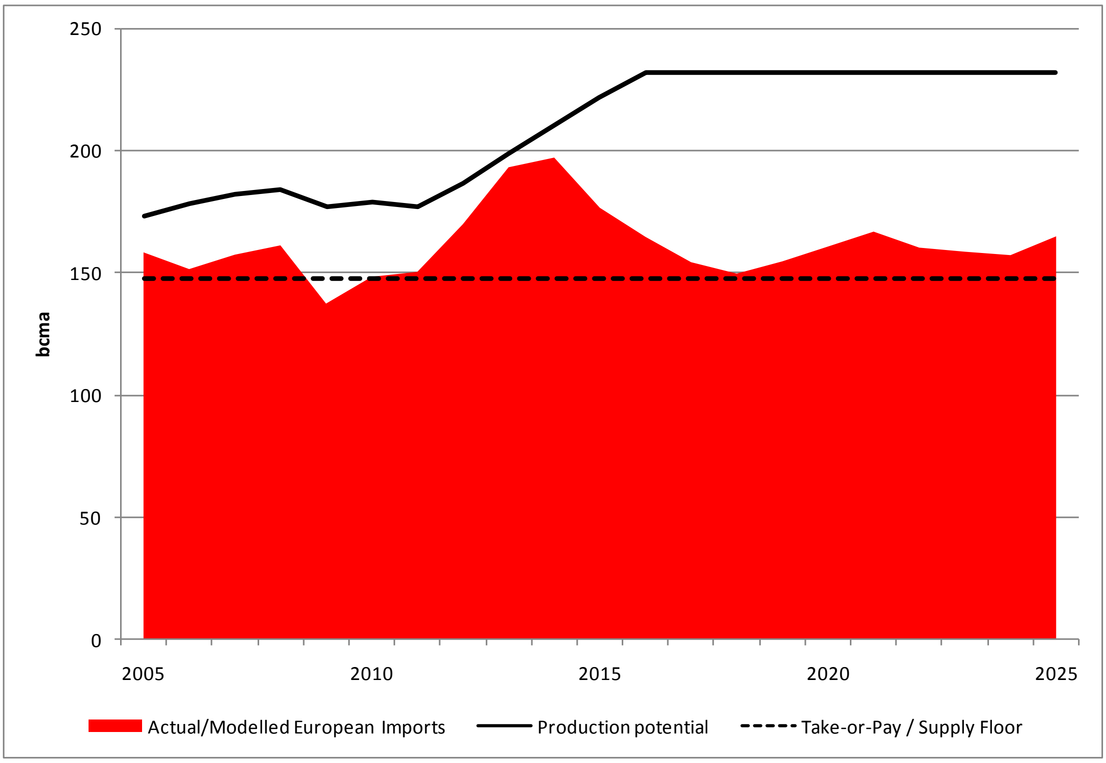
Scenario Critique, Further Development and modified Pricing Trends

This scenario is one of radically 'changing fortunes' for suppliers of pipeline gas to Europe. The addition of growing volumes of North American LNG to the global supply pool from 2015 onwards steadily reduces the supply of pipeline gas to Europe in a world where these exporters are balancing supply to maintain a target European hub price.

The results of modelling the situation where this 'price maintenance' policy is changed to one of maintaining a minimum European export level (at the expense of price) are discussed with the aid of selected graphics.

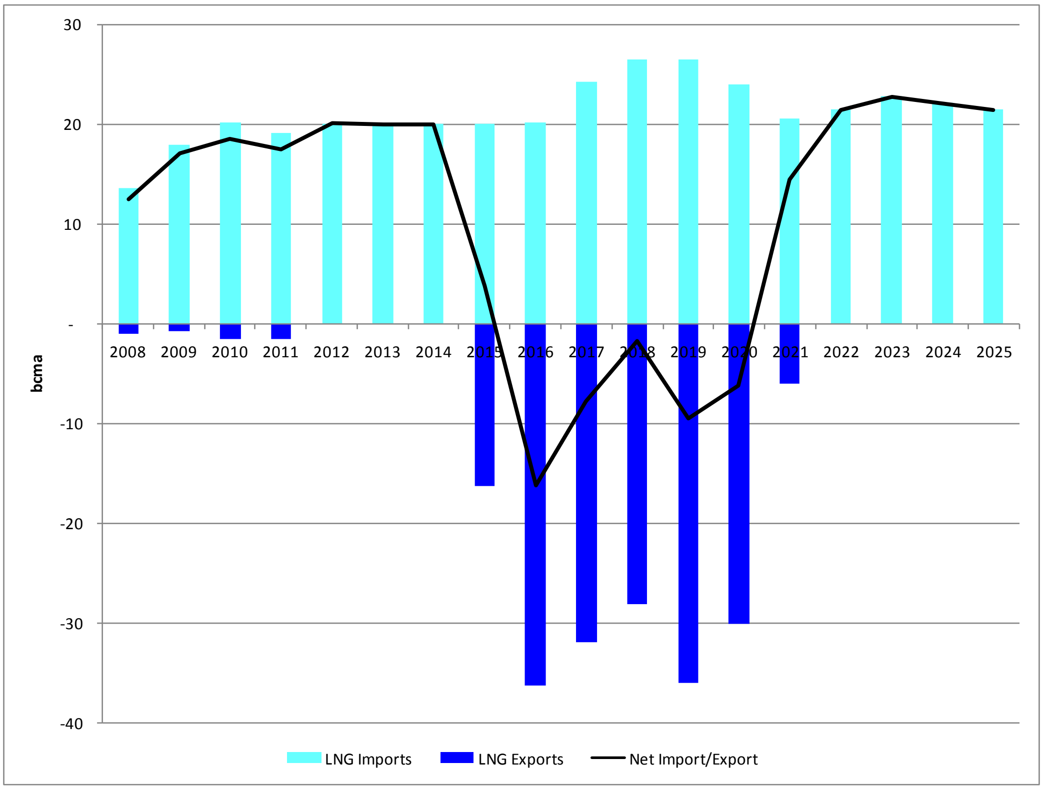
Figure 51 shows the impact on Russia's supply of pipeline gas to Europe of maintaining minimum European export volume. Figure 52 shows the impact on North American LNG imports and exports caused by this change of stance by Europe's pipeline suppliers. With Russia and other pipeline suppliers to Europe determined to maintain a minimum European export volume, this results in an oversupply of gas on European hubs and destroys the \$3.50/mmbtu spread required to maintain North American LNG export economics. In this modelled outcome there are no North American LNG exports post 2020.

Figure 51: Russian Pipeline Supply to Europe 2005–25



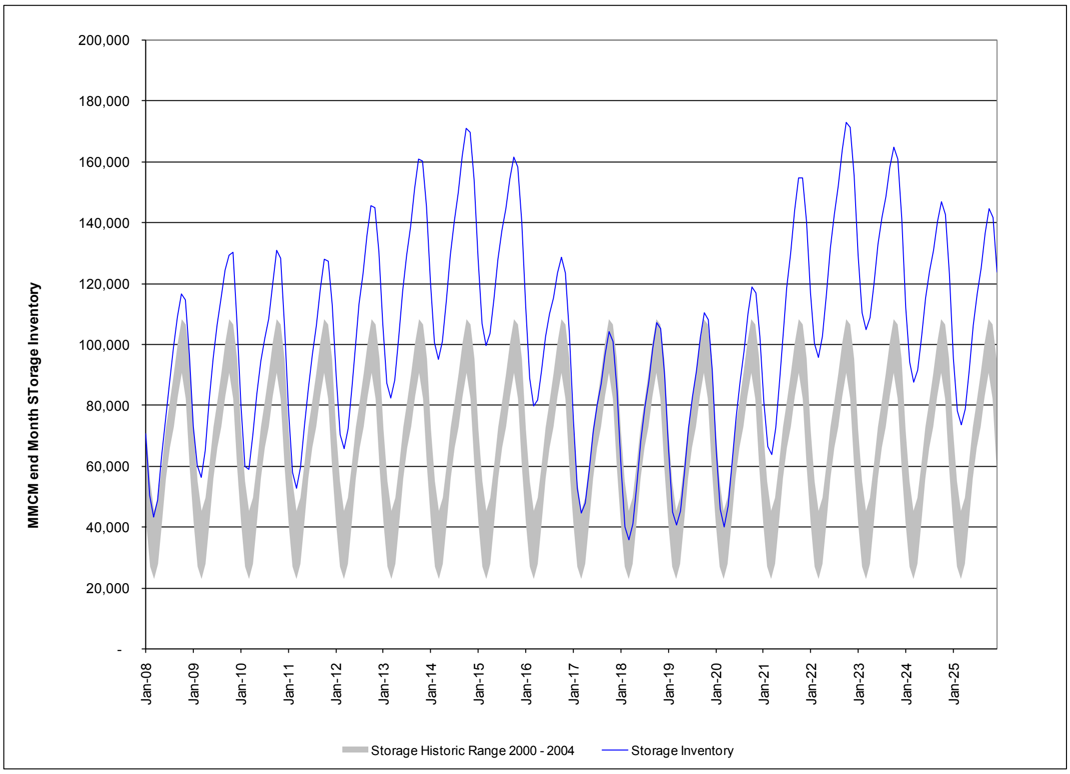
Sources: IEA and Cedigaz historical data to mid 2011, own analysis post mid 2011

Figure 52: North American LNG Imports and Exports 2008–25



Sources: Waterborne LNG historical data, own analysis post mid 2011

Figure 53: US and Canadian Aggregate end-month Storage Inventory 2008–25

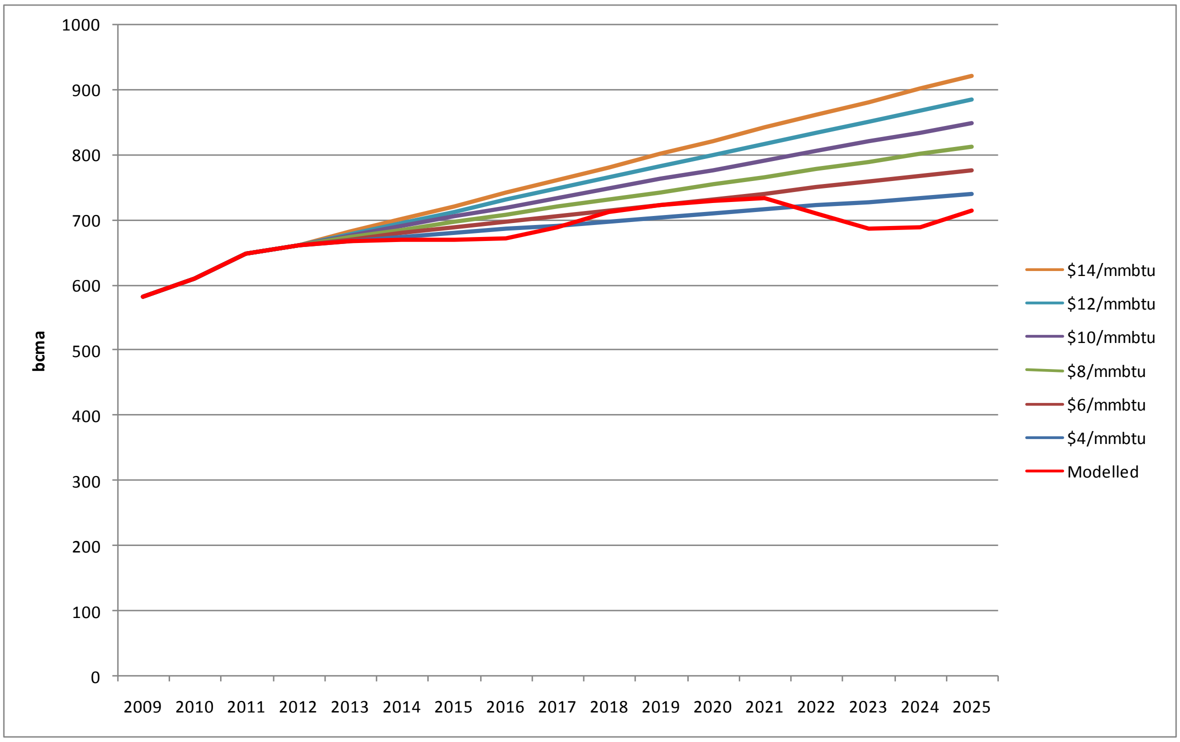


Source: EIA & Canadian Gas Producers Association (historical data), own analysis

Figure 53 shows the impact on North American Storage Inventory. Exports of LNG in the 2015 to 2020 period resulted in a reduction of 'excess' storage inventory however this builds up again from 2020 onwards as North American LNG exports are curtailed.

Figure 54 shows the modelled US production path for this scenario. The lack of North American LNG exports post 2020 depresses price and production in that period.

Figure 54: US Production Modelled Path 2009–25

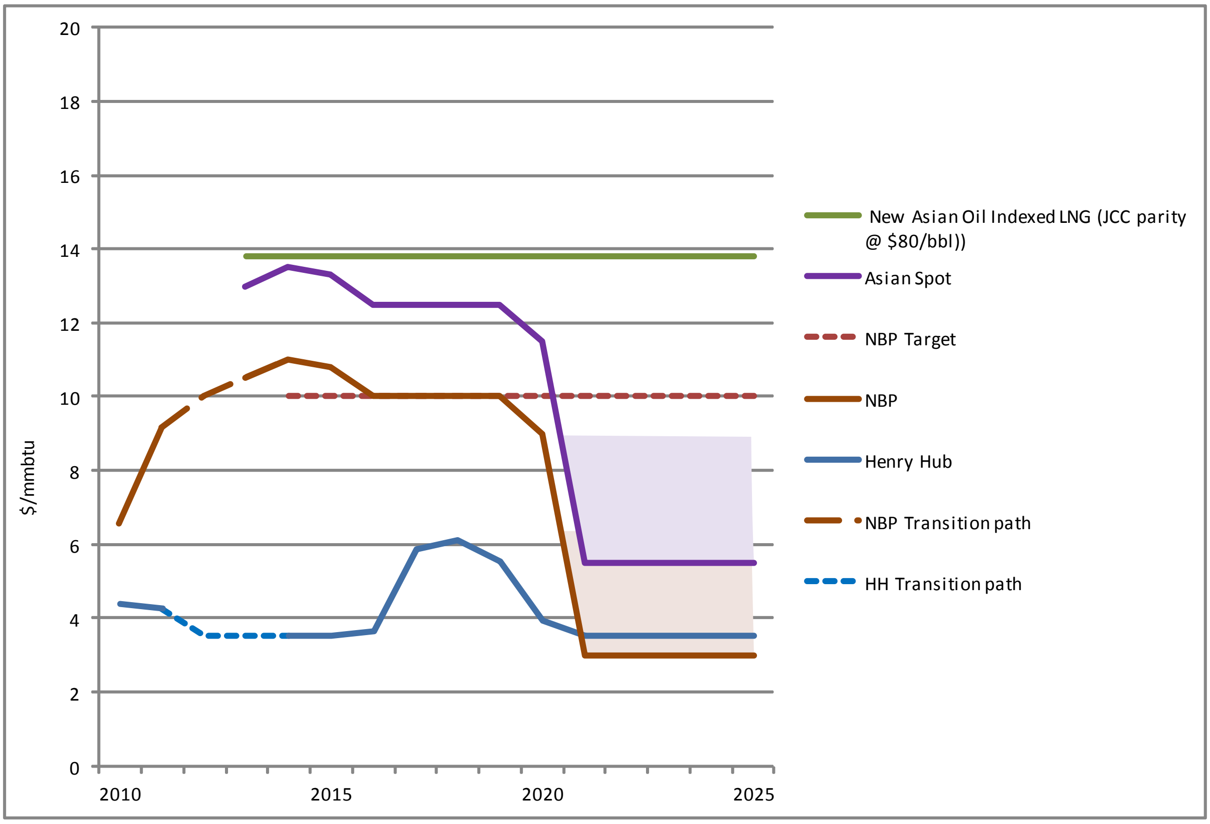


Source: EIA (historical), own analysis

Figure 55 shows the significant drop in Henry Hub, NBP and Asian spot LNG prices post 2020 due to the higher flows of pipeline gas into Europe in that period. The uncertainty range (shaded) for NBP is that in which European prices provide the incentive neither for flexible LNG diversions to North America nor for LNG exports from North America. If Russia manages to keep European hub prices within this band it would be able to maintain its minimum European export volume. It is assumed that Asian LNG spot prices follow NBP with a $2.50/mmbtu margin. The disparity between these prices and JCC-linked Asian LNG contract prices post 2020 might be sufficient to tempt some Asian LNG buyers to consider an alternative to this pricing mechanism for contracted supply post 2020.

The period of low hub prices from 2020 onwards would also serve to stimulate higher gas demand in Europe. Based on historical observations this would occur in the very short term through switching from coal to gas in the power sector (although this would be muted if coal-fired generation capacity had been reduced by this time due to CO_2 abatement policies). Increased space heating demand through lower prices would also be tempered through energy efficiency and insulation measures enforced in the 2010 to 2020 period. Industrial demand increases would be expected to have longer lead-times. While demand responses were not modelled it is considered that, in a European context, it is unlikely that they would significantly negate the price dynamics depicted here. Demand increases due to lower prices in Asia might be more significant but that would depend on the speed and extent to which LNG imports on a hub pricing basis gained precedence over oil-indexed LNG contracts.

Figure 55: Regional Scenario Gas Price Trends 2010–25



Sources: BP Statistical review of World Energy (historical data), own analysis

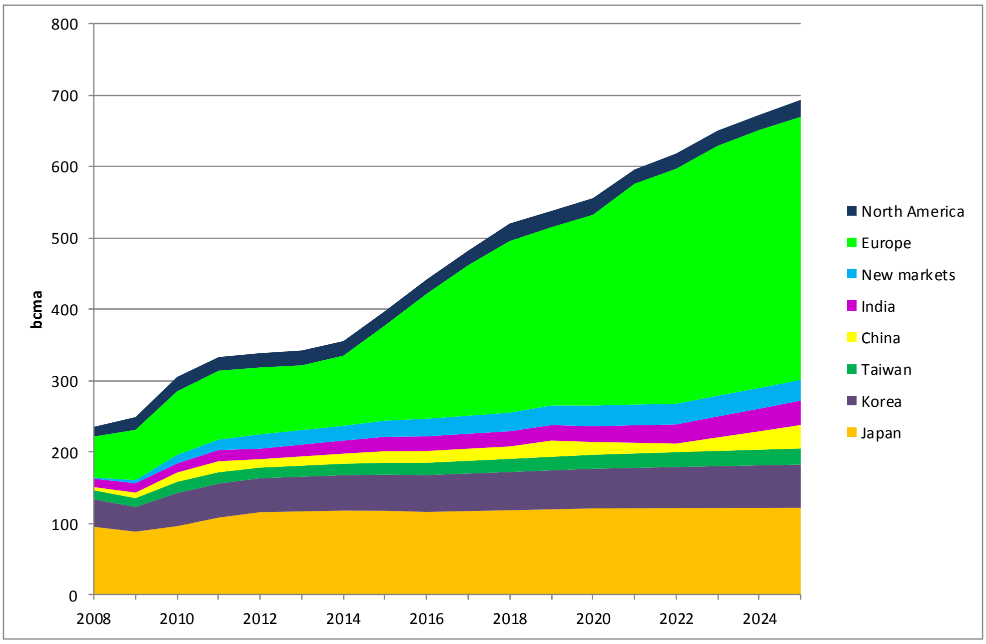
5.6 Low Asian Demand, High US Domestic Production Scenario Results

Overview of the scenario

In this scenario we combine the high US future production assumptions with the lower view of future Asian demand for natural gas (and LNG). As might be expected this produces an extremely challenging situation for European pipeline gas suppliers. For consistency we have assumed the global LNG supply position (including North American LNG exports) is identical to the previous scenario. Initially we assume that suppliers of pipeline gas to Europe manage supply to maintain a target price.

Figure 56 shows where global LNG is consumed in this scenario. Given the lower Asian demand, this scenario shows Europe taking a very significant and growing share of LNG post 2014.

Figure 56: Global LNG Disposition 2008–25

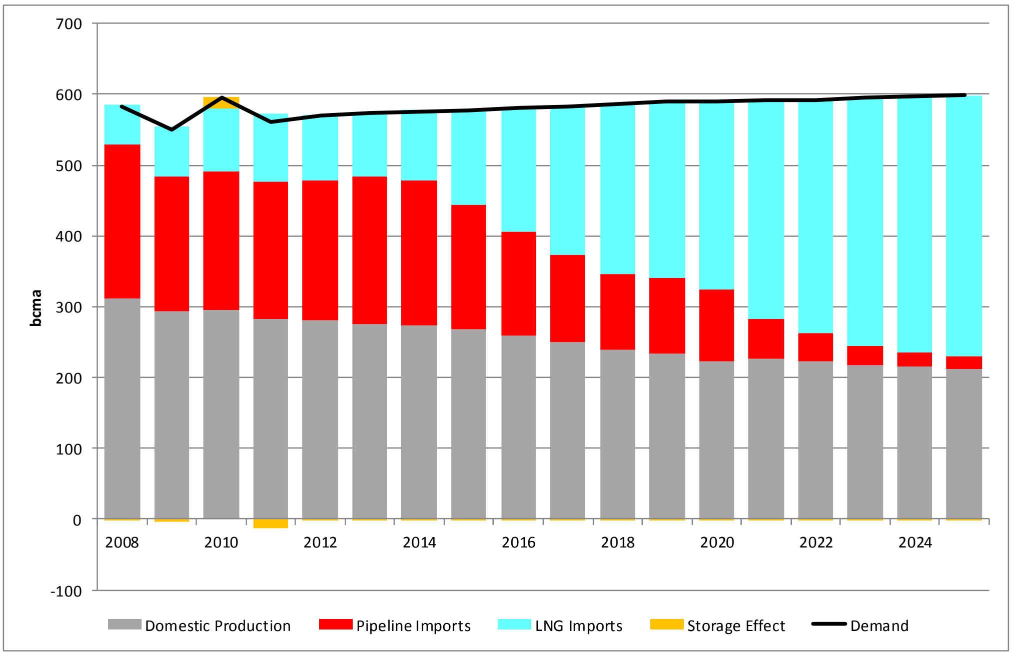


Source: Waterborne LNG (historical data), own analysis

European Balances and Pipeline Imports

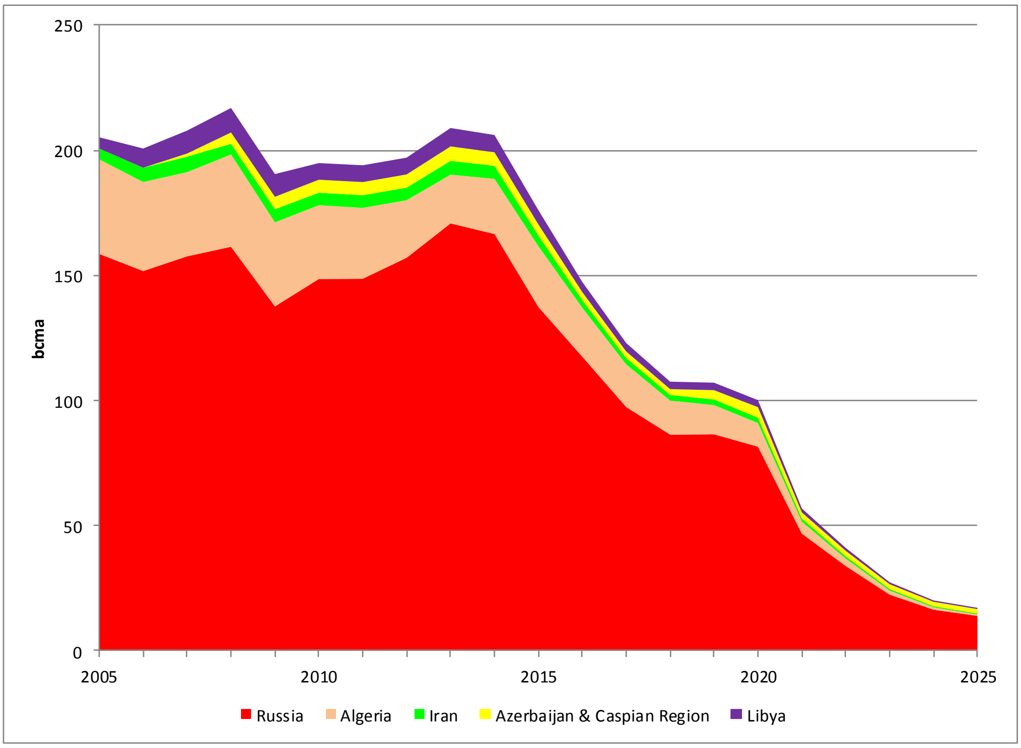
The European supply and demand balance for this scenario is shown in Figure 57. Pipeline imports increase slightly in the 2012 to 2013 period due to Asian competition for slowly growing global LNG supplies. After 2013 LNG imports grow as global LNG supply gathers momentum and North American LNG exports are assumed to commence in 2015.

Figure 57: European Supply and Demand Balance 2008–25



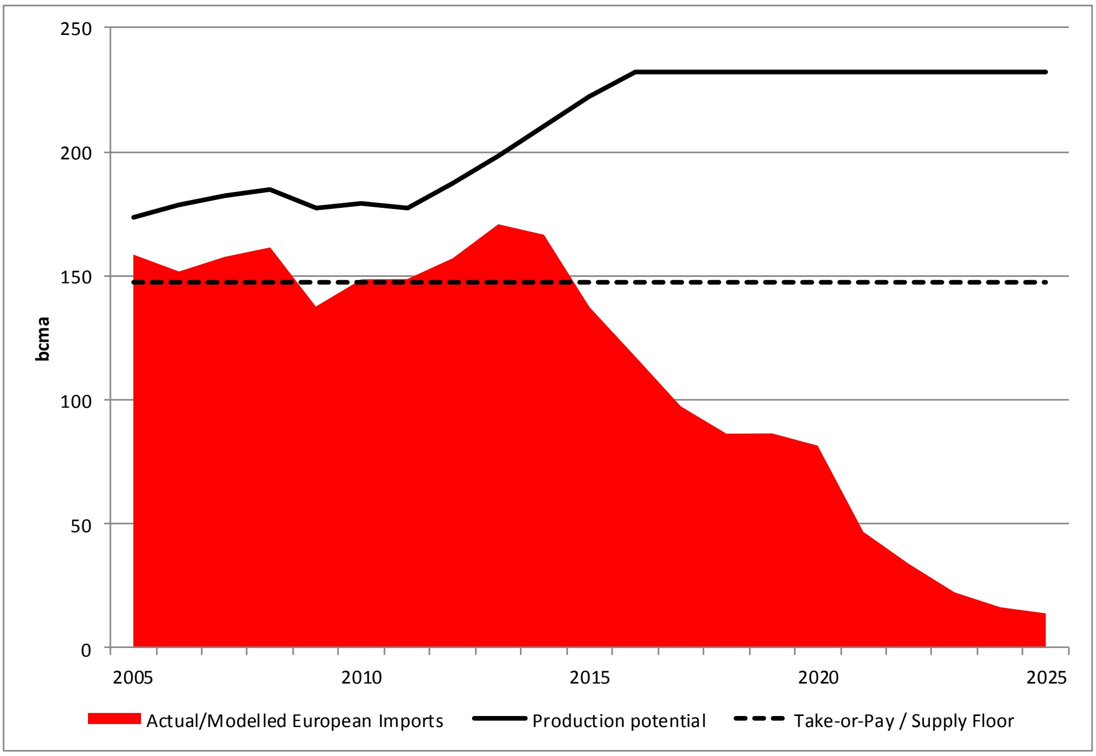
Sources: IEA, Waterborne LNG for historical data to mid 2011, own analysis post mid 2011

Figure 58: European Pipeline Imports 2005–25



Sources: IEA and Cedigaz historical data to mid 2011, own analysis post mid 2011

Figure 59: Russian Pipeline Supply to Europe 2005–25



Sources: IEA and Cedigaz historical data to mid 2011, own analysis post mid 2011

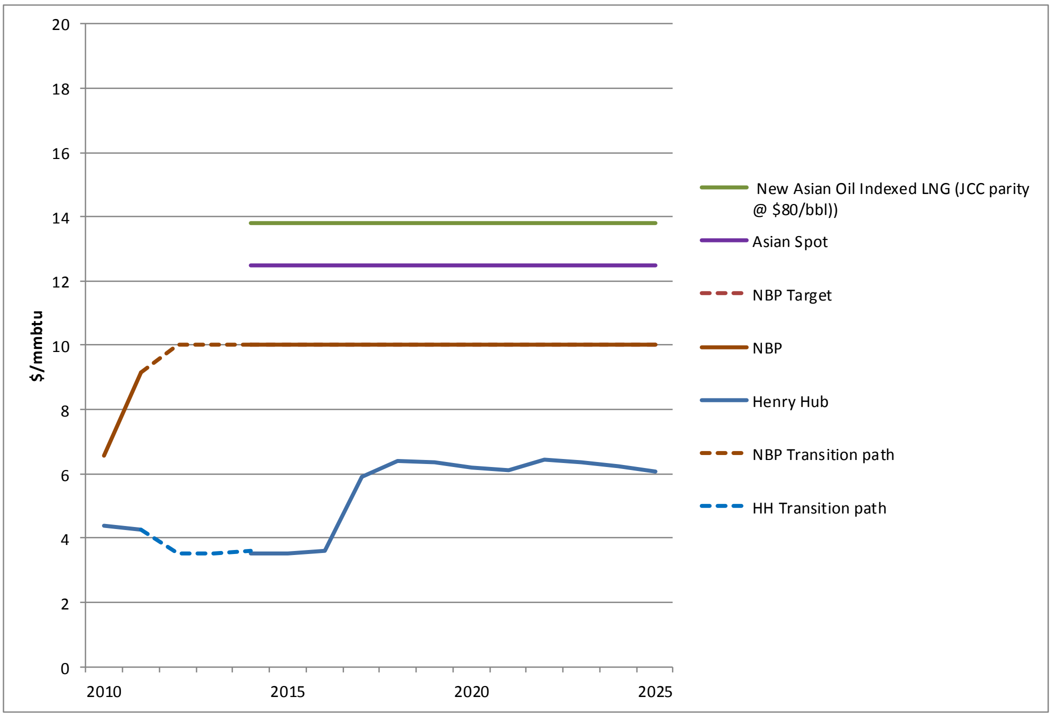
The historical and modelled future contribution of European pipeline imports from its various suppliers is shown in Figure 58. The level of European imports reaches a peak in 2013 and then declines precipitously. Figure 59 shows the outcome for Russian pipeline imports into Europe which also show a very marked decline from 2014 onwards.

North American Balances, LNG Imports and Storage

The supply and demand balance for North America is unchanged from the previous scenario (Figure 46) as is the assumed annual build up in North American LNG exports and the trajectory of US production and US and Canada storage inventories (Figures 47, 48 and 49).

Figure 60 shows the regional price trends assumed and implied from modelling this scenario. By 2017 Henry Hub has risen to a level of \$6.50/mmbtu; i.e. the volume of LNG exports is such that the equilibrium spread of \$3.50/mmbtu between Henry Hub and European Hub prices has been reached. Prior to 2015, Henry Hub price levels have been constrained by an assumed price floor of \$3.50/mmbtu. In light of the potential for severe storage inventory build, threatening to overwhelm available capacity, it is very possible that prices could be lower than this level, causing some temporary production shut-in prior to the start-up of LNG export facilities.

Figure 60: Regional Scenario Gas Price Trends 2010–25



Sources: BP Statistical review of World Energy (historical data), own analysis.

Scenario Critique and Development

For suppliers of pipeline gas to Europe this is indeed a ‘disaster scenario’ if its early trends are not identified and non-North American LNG projects are not cancelled or deferred. Even with a zero probability applied to future uncertain non-North American LNG projects, European pipeline suppliers would see European imports at around 83% of the minimum European export volume between 2016 and 2023, assuming the same pattern of North American LNG exports as shown in Figure 47. Of all the scenarios modelled and discussed here, this is the one with least scope for adaptive accommodation.

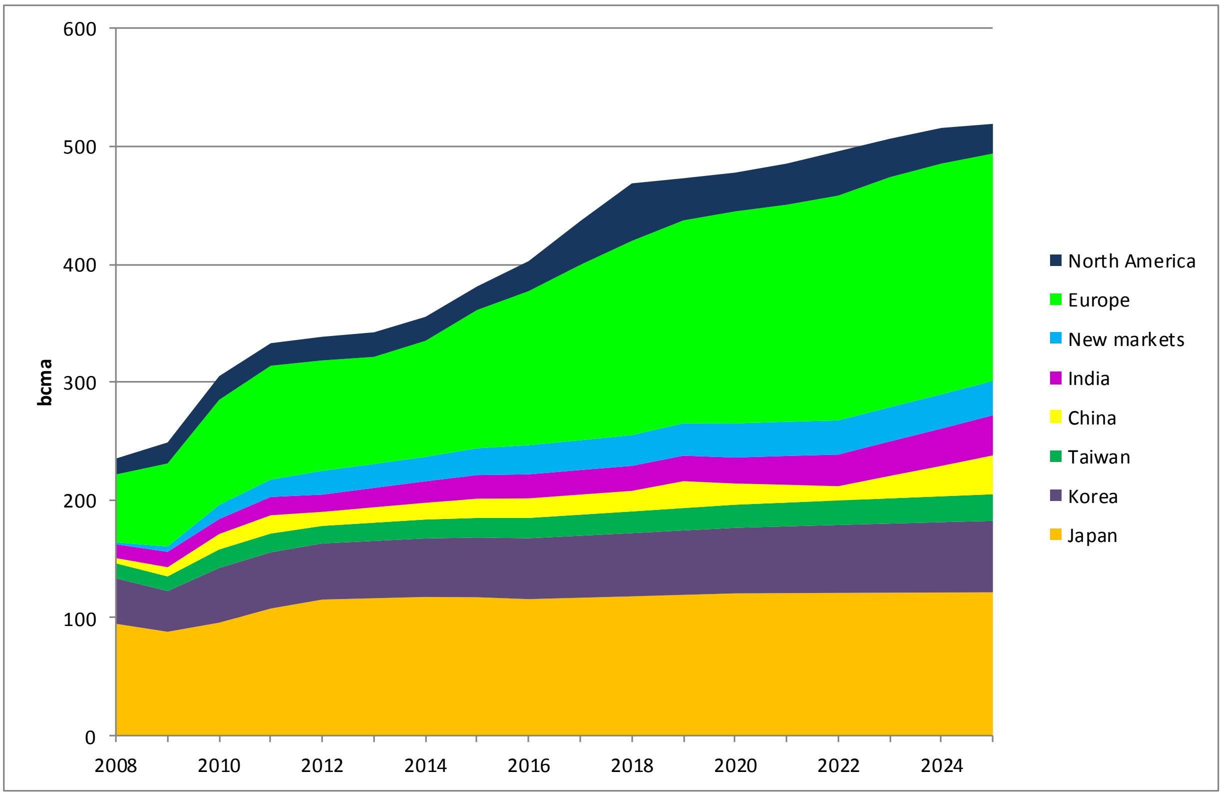
In this scenario maintaining a minimum export volume for pipeline supplies to Europe would clearly lead to an over-supplied LNG market. This scenario represents the most fertile ground for the development of a deep and liquid Asian LNG spot market, albeit subject to overcoming the current preference for JCC-linked pricing.

As an illustration of the scale of the market imbalance which would follow from this action, the scenario outcome was re-modelled based on the following assumptions:

- European pipeline gas suppliers maintain their minimum European export level.
- A 20% probability was applied to the future uncertain non-North American LNG projects.

Figure 61 shows the resulting global LNG supply and where it is consumed with significant supply to Europe and also some growth in imports to North America.

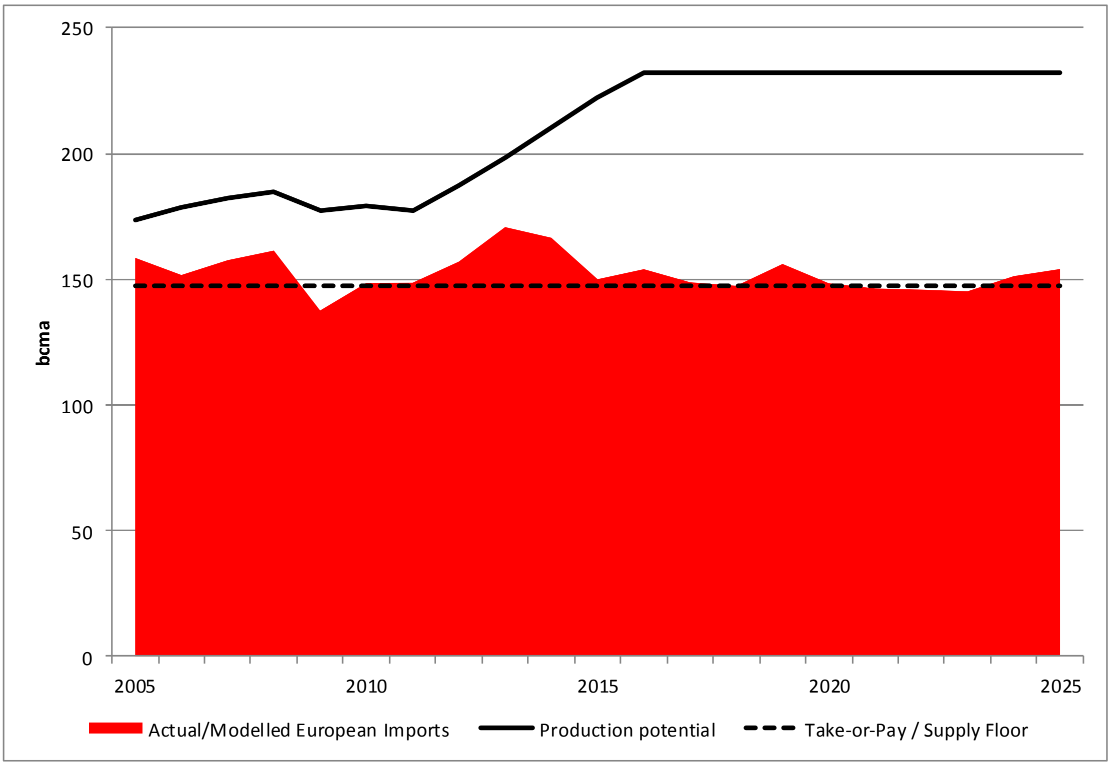
Figure 61: Global LNG Disposition 2008–25



Source: Waterborne LNG (historical data), own analysis

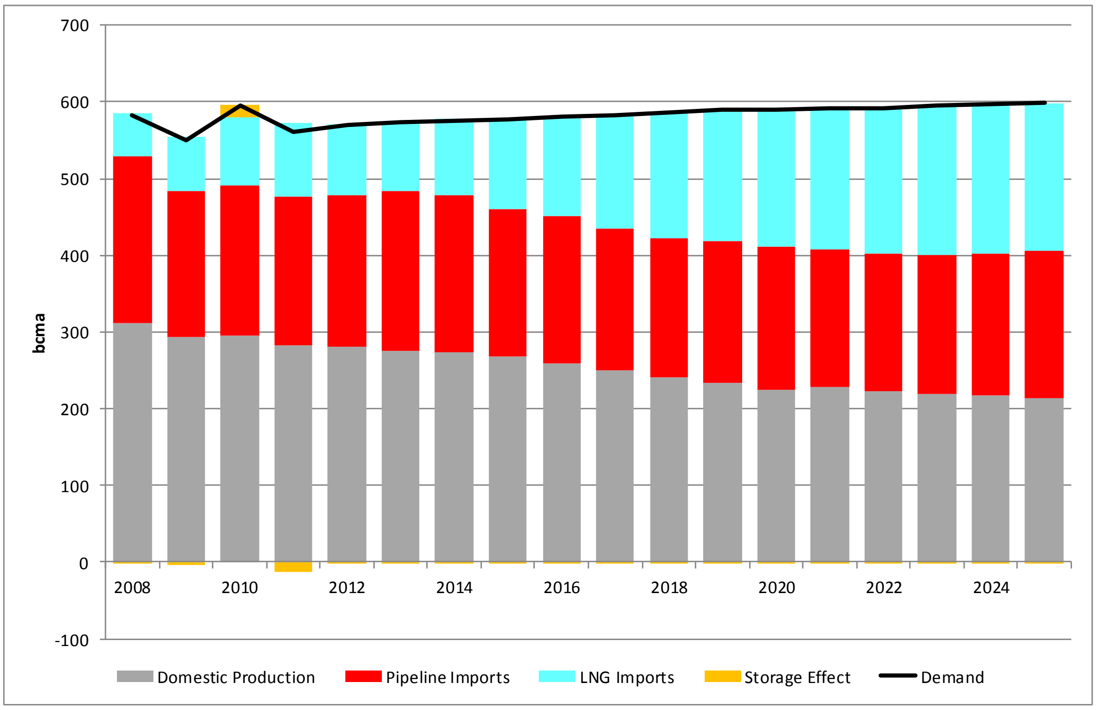
Figure 62 shows the level of Russian pipeline supplies to Europe at the minimum export level of around 150 bcma.

Figure 62: Russian Pipeline Supply to Europe 2005–25



Sources: IEA and Cedigaz historical data to mid 2011, own analysis post mid 2011

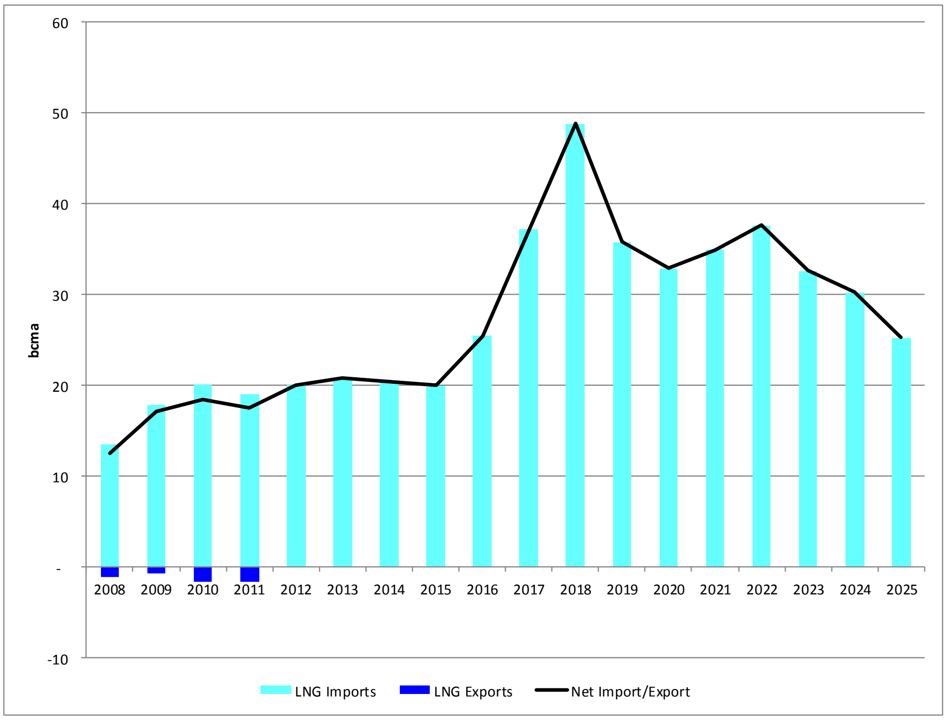
Figure 63: European Supply and Demand Balance 2008–25



Sources: IEA, Waterborne LNG for historical data to mid 2011, own analysis post mid 2011

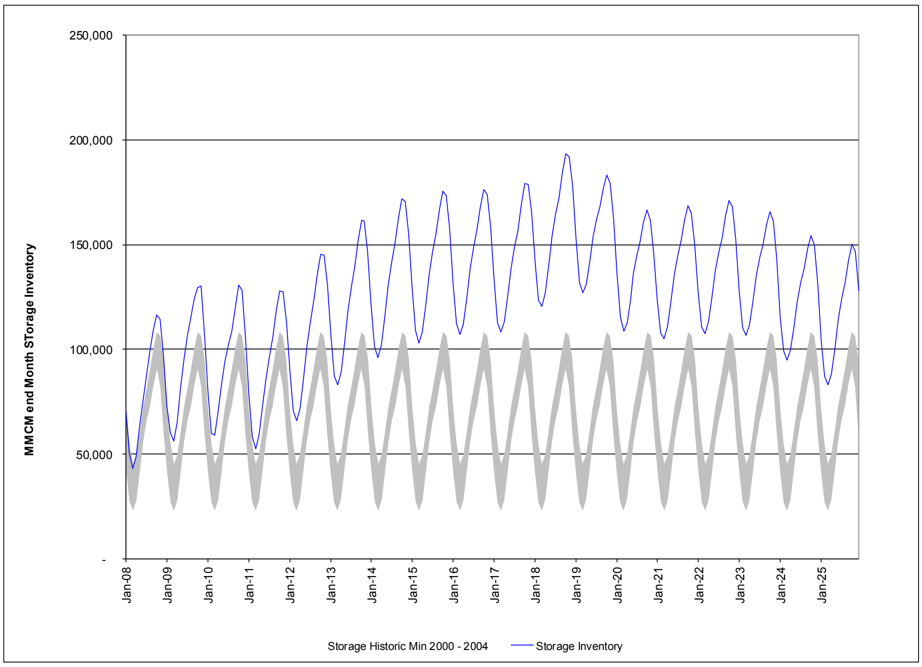
Figure 63 shows the European balance with LNG imports growing to equal pipeline imports by 2025. Figure 64 shows the North American LNG import position, with import levels between 25 bcma and 50 bcma post 2015. This is excess LNG 'over spilling' into the North American markets.

Figure 64: North American LNG Imports and Exports 2008–25



Sources: Waterborne LNG historical data, own analysis post mid 2011

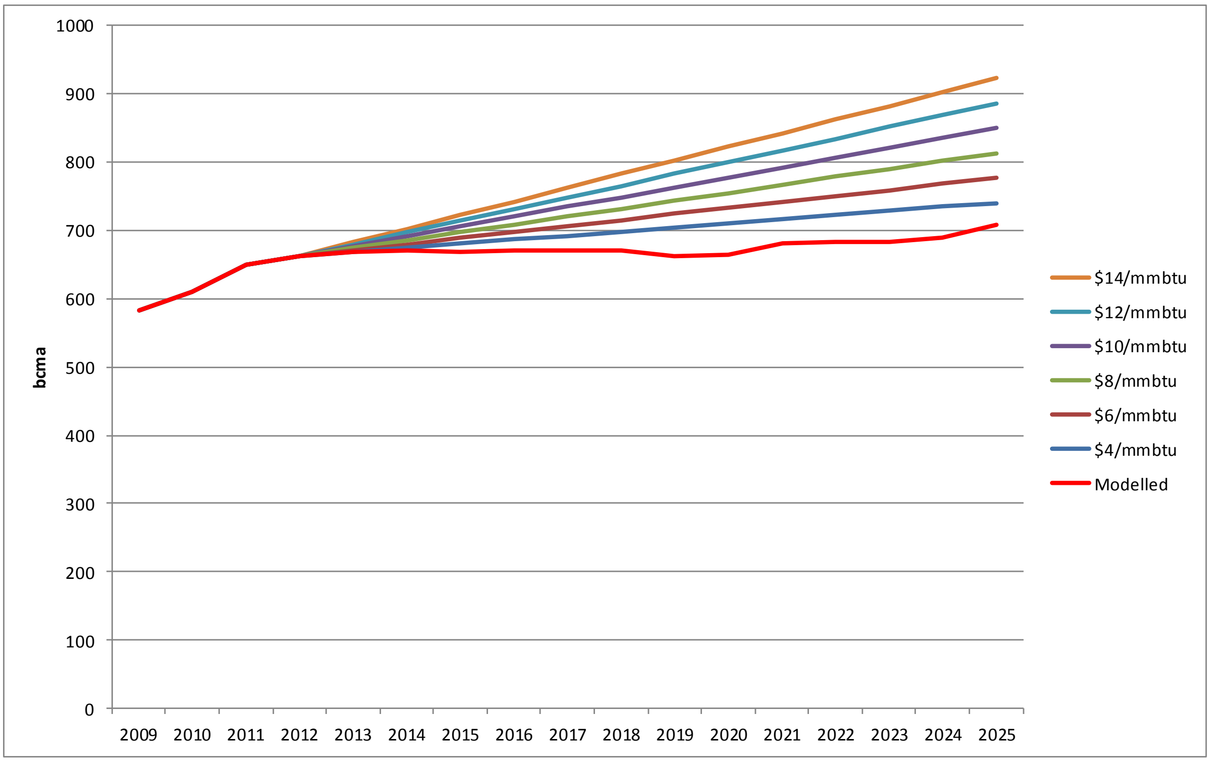
Figure 65: US and Canadian Aggregate end-month Storage Inventory 2008–25



Source: EIA & Canadian Gas Producers Association (historical data), own analysis

The modelled storage inventory position for North America is shown in Figure 65. These levels exceed the likely physical limits of storage in the period to 2025 which suggests that even the depressed levels of US production shown in Figure 66 would be unlikely to be realised.

Figure 66: US Production Modelled Path 2009–25

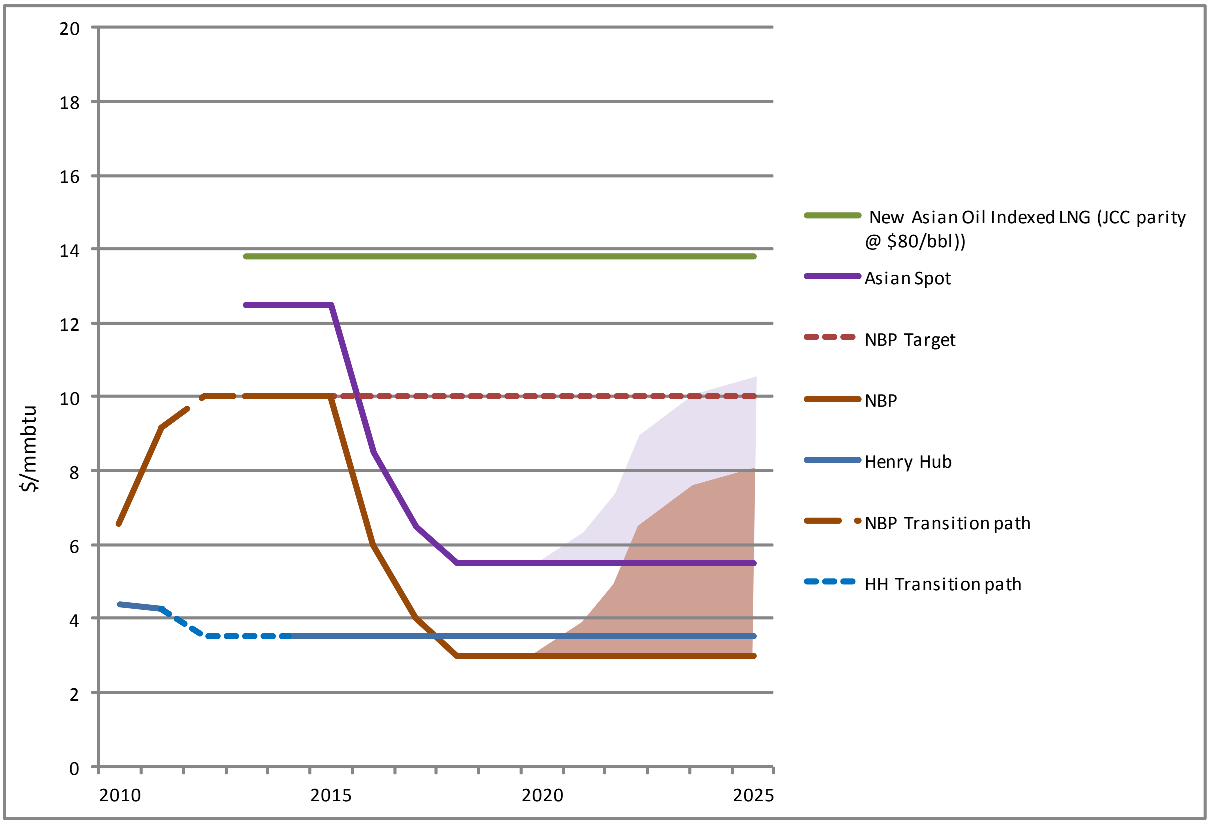


Source: EIA (historical), own analysis

Figure 67 shows the potential price trends in this scenario with Henry Hub at its assumed $3.50/mmbtu price floor and NBP and Asian spot price falling in line. Whether such low price levels are sustainable to 2025 and beyond is doubtful. If the price required to remunerate investment of new supplies is around $8/mmbtu for Europe, then it is likely that such a recovery would occur around 2020, (in order to allow new supply projects to proceed). Clearly at such reduced price levels there is the likelihood that demand would be stimulated, however as noted above this would be most significant in Asia but only if JCC were to be eclipsed by spot pricing for significant volumes of LNG supply.

Even at these more sustainable levels, there would be a significant gap between an Asian LNG spot price (related to NBP) of $10.50/mmbtu and the $13.80/mmbtu assumed $80/bbl JCC level. This would act as a significant incentive for contract LNG buyers to move away from JCC as the contract price formation reference price.

Figure 67: Regional Scenario Gas Price Trends 2010–25



Sources: BP Statistical review of World Energy (historical data), own analysis

6. Key Findings from the Scenario Analysis

The findings from the scenario modelled outcomes are summarised in Table 4 (Low US Production Outcomes) and Table 5 (High US Production Outcomes).

Table 4: Summary of Findings for the Low US Production Outcomes

Low US Production Scenarios

- With High Asian Demand:
  - Russia comfortably above today's Take or Pay level to 2025.
  - US prices rise to above NBP around 2015 (to attract LNG imports)
  - Possible peak in NBP and Asian LNG spot prices 2012 – 2015 due to high call on Russian pipeline supply.
- With Low Asian Demand:
  - To maintain hub prices, Russia shuts in exports to below 2011 ToP levels, or
  - Maintaining 2011 ToP levels results in periodic low European and US hub prices and Asian LNG spot prices, even if some future LNG projects are deferred.

In the **Low US production, High Asian Demand** case, the need to attract LNG imports to North America requires Henry Hub to rise to at least NBP levels to offer an equivalent netback. Beyond 2016 Henry Hub, NBP and Asian Spot LNG prices are linked. North America thus experiences a significant price increase from 2011 levels. Asian spot prices remain linked to NBP apart from a period of market tightness prior to 2015, when they move towards JCC contract LNG prices, influencing NBP accordingly. European pipeline suppliers are able to maintain European hub prices while keeping flows above the minimum European export level. This case sees high regional price linkage but prices are maintained by the market power of European pipeline suppliers rather than by gas on gas price competition.

In the **Low US production, Low Asian Demand** case, the attempt to maintain a target NBP price level by European pipeline suppliers results in their flows falling below the minimum European export level from 2016. In this modelled outcome Henry Hub, NBP and Asian Spot LNG prices are linked beyond 2016. This case sees high regional price linkage but prices are maintained by the market power of European pipeline suppliers (albeit at the cost of declining supply post 2016) rather than by gas on gas price competition.

In the case where European pipeline suppliers enforce a minimum European export volume policy post 2016, and assuming a deferral of some future non-North American LNG projects (a probability factor of 40% as opposed to 50% applied), the result was a higher level of LNG imports to the US. Henry Hub, NBP and Asian LNG spot prices are linked post 2016 but alternating periods of market tension and excess supply in the Atlantic markets (caused in part by the US production response) creates a volatile path for prices.

Table 5: Summary of Findings for the High US Production Outcomes

High US Production Scenarios

- **With High Asian Demand:**
  - North America exports LNG, rising to 70 bcma by 2025. Henry Hub rises to $3.50 below European hub price levels.
  - To maintain European hub prices, Russian exports to Europe fall below 2011 ToP levels post 2020.
  - If Russia maintains exports at 2011 ToP levels, European, US and Asian LNG spot prices fall post 2020 and North American LNG exports stop, US prices depressed.
- **With Low Asian Demand:**
  - To maintain hub prices, Russia shuts in exports below 2011 ToP level from 2015, or
  - Maintaining 2011 ToP level results in low European, US and Asian LNG spot prices from 2015 onwards. Significant threat to JCC Asian LNG contract pricing. No incentive to start North American LNG exports, US prices depressed.

In Table 5, in the **High US production, High Asian Demand** case, the attempt to maintain a target NBP price level by European pipeline suppliers results in their flows falling below the minimum export level from 2020. With North American LNG exports commencing in 2015, by 2017 North America has reduced its storage inventory surplus and Henry Hub has risen to a level which is $3.50/mmbtu below NBP. In this modelled outcome Henry Hub, NBP and Asian Spot LNG prices are linked beyond 2017. This case sees high regional price linkage but prices are maintained by the market power of European pipeline suppliers (albeit at the cost of declining supply post 2020) rather than by gas on gas price competition.

In the case where European pipeline suppliers maintain their minimum export level from 2020 onwards, the impact is to create an LNG oversupply situation and a reduction in European hub prices. North American LNG exports cease in 2021 and storage inventory increases, pushing down Henry Hub price levels. NBP falls to within a range between $1/mmbtu below Henry Hub to $3.50/mmbtu above Henry Hub, thus leaving North America with no economic incentive to either export or import LNG. Henry Hub is briefly linked to NBP while North America exports LNG, but beyond 2021 the situation is volatile and the linkage more tenuous. Asian spot prices remain linked to NBP apart from a period of market tightness prior to 2015 when they move towards JCC contract LNG prices, influencing NBP accordingly.

In the **High US production, Low Asian Demand** case, the attempt to maintain a target NBP price level by European pipeline suppliers results in their flows falling rapidly to around 10% of minimum export level by 2025. In this outcome, North America exports LNG and Henry Hub becomes linked to NBP albeit $3.50 below it, thus Henry Hub, NBP and Asian Spot LNG prices are linked from 2017.

In the case where European pipeline suppliers enforce a minimum export level policy, and assuming a deferral of some future non-North American LNG projects (a probability factor of 20% as opposed to 50% applied), the result was to remove any incentive to export LNG from North America. As a consequence of the excess supply situation, Henry Hub falls to its assumed floor of $3.50/mmbtu. LNG arbitrage, in an oversupplied market, would cause NBP to fall to around this Henry Hub price level, taking Asian LNG spot prices down accordingly. It is unlikely that such low price levels could exist indefinitely as these prices are below the long run marginal cost of supply for Europe.

In summary, the scenario outcomes modelled above pose significant risks to various supply-side players, namely:

- **European pipeline suppliers:** Maintaining a target price at a European supply above a minimum export level (broadly equivalent to the estimated 2011 aggregate Take-or-Pay level), is only possible in the High Asian Demand cases. However, in the High Asian Demand, High US production case, maintaining a target price would cause supplies to fall below this level from 2020 onwards due to the impact of North American LNG exports.
- **North American LNG Exporters:** For North American LNG exports to be a viable long term venture, a combination of High Asian Demand and a policy of maintaining European hub (NBP) target price at the expense of volume on the part of European pipeline suppliers is desirable. The Low Asian Demand and High US Production case where NBP is maintained by a drastic reduction in European pipeline supplies might not be viewed as a secure investment scenario by North American LNG exporters as this relies on Russia's future supply/pricing strategy.
- **US upstream gas producers:** The combination of Low Asian Demand and High US production where European pipeline suppliers maintain a minimum export level is not an attractive environment for upstream producers as it perpetuates the problems observed in 2011 of supply-driven inventory surpluses and low prices. This is an intensely competitive environment.

7. Summary and Conclusions

The physical linkage of the UK and Continental gas markets by the Bacton - Zeebrugge interconnector in 1998 and the observed general connection between UK traded prices and European oil-indexed contract prices through arbitrage was the first step in an evolutionary process in which regional gas markets might in time become more closely linked, both by physical gas supply and in terms of price through arbitrage.

In the late 2000s we observed flexible LNG volumes growing but the expected linkage of North America and Europe did not come about due to US shale gas production growth and consequent minimal LNG requirements in North America, although the observed close correlation between NBP and Henry Hub in the period May 2009 to April 2010 arguably anticipated such a linkage.

At end 2011 we observed arbitrage between Europe and Asia for flexible LNG. The short-lived equilibrium of European hub prices (determined by supply and demand) providing a basis for Asian spot LNG prices (with a transport premium) appeared to change. By the end of 2011 Asian spot LNG prices were closer to the six month average JCC price[48]. If North West European supply-demand balances tighten, competition for LNG with Asia could result in NBP and some European hub prices rising accordingly. When NBP reaches European oil-indexed price levels it should then stabilise as the call on Russian and other pipeline suppliers is increased. This would mark an interesting precedent: the linkage of an LNG traded market with an onshore gas traded market, with arbitrage to pipeline oil-indexed contract prices.

What follows from this is subject to numerous uncertainties:

- Will Europe make the transition away from oil-indexed pipeline contracts to hub-indexed price formation; and if so will suppliers of pipeline gas use their market power to maintain hub prices at a ‘target’ level?
- Will US production, through a continuation of intensive shale gas development, follow something like the ‘high case’ trajectory put forward as a hypothesis in this paper?
- Will North American LNG exports commence around 2015 and if so at what scale, or alternatively in a more constrained US production future, will North America revert to a future of significant LNG imports?
- Will Asian LNG importing markets continue their current high demand growth trend or will this be moderated? In either case what will be the call on LNG supplies from countries such as India and China which have conventional and unconventional domestic production growth potential and pipeline import options?
- What will be the degree of schedule slippage on current and future LNG projects and will some be deferred if Asian demand growth slows?

[48] Which appears to provide a reference level to which the more recent long term Asian LNG contract prices are linked.

- Will the Asian LNG importers move away from JCC-related pricing for new LNG contracts in the event that flexible LNG supplies remain available in significant volumes and the Asian LNG spot market gains depth and liquidity?

Such uncertainties undermine attempts to produce a unified view of what the future might hold for the global system discussed in this paper. What is more enlightening is to explore the outcome of scenarios which have been defined by combining cases of contrasting future US production and Asian natural gas demand in a post European oil-indexed contract world.

In the **Low US production, High Asian Demand** case, the need to attract future LNG imports to North America requires US prices to rise to at least European hub levels. Beyond 2016 Henry Hub, NBP and Asian Spot LNG prices are linked, with US prices experiencing a significant increase from 2011 levels. European pipeline suppliers (chiefly Russia) are able to sustain European hub prices while keeping flows above the minimum European export level. This case sees a high level of regional price linkage but prices are maintained by the market power of European pipeline suppliers rather than by gas on gas price competition.

In the **Low US production, Low Asian Demand** case, the attempt to maintain a target NBP price level by European pipeline suppliers results in their flows falling below the assumed minimum European export level from 2016. In this modelled outcome Henry Hub, NBP and Asian Spot LNG prices are linked beyond 2016. This case sees a high level of regional price linkage, but prices are maintained by the market power of European pipeline suppliers (albeit at the cost of declining supply post 2016).

In the event that European pipeline suppliers enforce a minimum European export volume policy post 2016, and assuming a deferral of some future non-North American LNG projects, this resulted in a higher level of LNG imports to the US. Henry Hub, NBP and Asian LNG spot prices are linked post 2016 but alternating periods of market tension and excess supply in the Atlantic markets (caused in part by the US production response) create a volatile path for prices with periods of low prices.

In the **High US production, High Asian Demand** case, the attempt to maintain a target NBP price level by European pipeline suppliers results in their flows falling below the minimum export level from 2020. With North American LNG exports commencing in 2015, by 2017 North America has reduced its storage inventory surplus and Henry Hub rises to a level which is \$3.50/mmbtu below NBP. In this modelled outcome Henry Hub, NBP and Asian Spot LNG prices are linked beyond 2017. This case sees a high degree of regional price linkage but prices are maintained by the market power of European pipeline suppliers (albeit at the cost of declining supply post 2020).

In the event that European pipeline suppliers maintain their minimum export level from 2020 onwards, the impact is to create an LNG oversupply situation and a reduction in European hub prices. North American LNG exports cease in 2021 and storage inventory increases, pushing down Henry Hub price levels. NBP falls within a range between \$1/mmbtu below

Henry Hub to $3.50/mmbtu above Henry Hub, thus leaving North America with no economic incentive to either export or import LNG.

In the **High US production, Low Asian Demand** case, the attempt to maintain a target NBP price level by European pipeline suppliers results in their flows falling rapidly to around 10% of minimum export level by 2025. In this outcome, North America exports LNG and Henry Hub becomes linked to NBP albeit $3.50 below it, post 2017.

In the event that European pipeline suppliers enforce a minimum export level policy, and assuming a significant deferral of some future non-North American LNG projects, the result is to remove any incentive to export LNG from North America. As a consequence of the excess supply situation, Henry Hub falls to its assumed floor of $3.50/mmbtu. LNG arbitrage, in an oversupplied market, would cause NBP to fall to around this Henry Hub price level, taking Asian LNG spot prices down accordingly. It is unlikely that such low price levels could exist indefinitely as these prices are below the long run marginal cost of supply for Europe. In this eventuality it is unlikely that JCC would survive as the basis for future Asian LNG long-term contracts.

The scenarios modelled and described in this paper were constructed to examine the potential state of the key regional gas markets and how they might behave when ‘connected together’ over a range of some of the key unknowns listed above. The findings from this analysis proved to be more challenging and thought provoking than expected at the outset. Although the scale of uncertainty of future Asian demand and US production is evidently significant, there is still a tendency to compartmentalise the ‘gas world’ into rigid regional settings which is a significant barrier to comprehending and anticipating the consequences of regional imbalances on the global system.

From a European perspective an important conclusion of this paper is that, whilst to date much of the focus on European gas supply security has tended to focus on the availability of Russian pipeline supply and related transit issues, in the future the path of Asian demand and US production might be equally important, in particular for pricing.

Furthermore, in the face of emerging trends in Asian demand and US production the response of other gas exporters is of paramount importance. These include the price versus volume strategic positioning of pipeline gas exporters to Europe (who can respond in a matter of days) and the deferral of non-North American LNG projects (whose investment lead-time is typically 4 to 5 years).

The body of this analysis has assumed that Europe undergoes a transition away from oil-indexed pipeline gas contracts towards a mixture of hub-indexed contracts and direct sales of upstream gas to hubs by around 2015. However, the consequence of Europe retaining oil-indexed pricing in long term contracts has been noted. Even if a relatively balanced market between 2012 and 2015 reduces the spread between European hub prices and oil-indexed prices, three of the scenarios modelled here would see a resumption of wide and prolonged differentials between price levels for these two distinctly different price formation structures. Such a spread would widen dramatically from 2015 for both Low Asian Demand scenarios and from 2020 for the High US production, High Asian Demand scenario. If oil indexation persisted, it is unlikely that European midstream utilities could financially survive the price spreads in these modelled scenario outcomes.

Turning to issues previously alluded to but not explicitly addressed in the analytical section of this paper:

Mid-case US production: It is possible that future US production will follow a path between the two described above. This is where production grows slightly slower than demand such that North America does not require additional LNG imports but Henry Hub rises such that the price differential to Europe is less than that required to justify LNG export schemes. Such a course represents a 'dead-zone' in which price arbitrage does not take place. The point here is that, should production break out of this 'dead-zone', then arbitrage would quickly establish price linkage to other regions.

US Policy Limiting LNG Export Volumes: The prospect of LNG exports growing (as modelled in this paper) to a level some \$3.50/mmbtu below European hub prices might be viewed with alarm by US authorities who have become attuned to Henry Hub prices of \$4.00/mmbtu or less. This would especially be the case were it perceived that such European hub price levels would be managed by adjusting the level of Russian gas exports to Europe. A limit on the approved level of US LNG exports could (in the High US production case) have the effect of continuing the 2011 situation in the US where production is constrained by a combination of low prices and 'warehousing' gas by building ever greater underground storage capacity, pending the possible growth in future demand for gas in the power and possibly transportation sectors.

Asian JCC Contract Prices: At present it does not appear likely that Asian LNG buyers will move to rely on an index of LNG spot price as a means by which long term contracts are priced, let alone rely on the nascent Asian LNG spot market to source long term supply needs. This however is an area to monitor since it cannot be ruled out on an economically rational basis, depending on the changing view of LNG supply and demand fundamentals.

North American Exports to Asia: the analysis in this paper is based on the premise that North American LNG exports enter the global supply pool such that, all other things being equal, at the margin they add to the volume of LNG available for Europe. Whilst it is quite possible that west coast Canadian projects might wish to sell LNG to Asian markets under JCC-indexed contracts this implies that either:

- Such Canadian projects will displace volumes from other LNG projects (existing or prospective) in which case the net additional supply will be available for Europe; or,
- Other non-North American LNG projects will be deferred or cancelled and removed from the supply pool considered in this analysis.

The key consideration here is whether such Canadian projects are producing from stranded plays (in terms of lack of infrastructure connections to the North American transmission grid) or whether such future exports would reduce supply to the North American market. If they remain isolated from transmission networks, then they have no impact on North American markets. However, if they connect to transmission networks then significant levels of Canadian LNG exports could exert upward pressure on North American gas prices, and ultimately threaten the viability of such projects.

The analysis in this paper has highlighted the significant potential for connectivity and price linkage between regions, while recognising the different paths this might take given the not inconsiderable uncertainties around future regional supply and demand fundamentals. It has also illuminated the role played and challenges faced by some key players, particularly Russia as the largest supplier of pipeline gas to Europe and the potential market power it could, in certain scenarios exert, not just on European prices but also those of North America and Asian LNG.

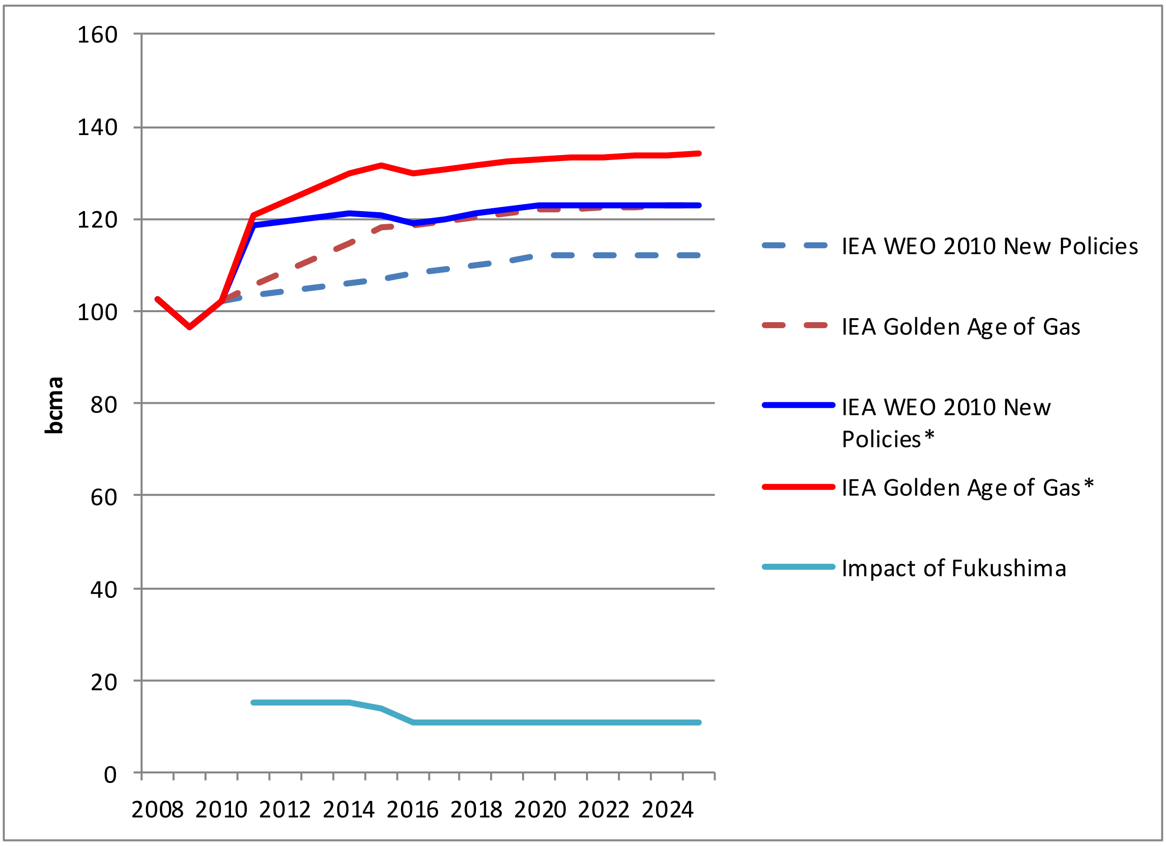
Appendix – Other Key Assumptions

A.1 Asian Supply and Demand Assumptions

The supply and demand outlook for the key Asian LNG importing countries of Japan, South Korea, Taiwan, China and India for the 'Low Demand' and 'High Demand' cases was based on the IEA 'New Policies Scenario[49]' and 'Golden Age of Gas Scenario' respectively[50]. Key assumptions by country are discussed below. In all cases the difference between future demand and the sum of supply sources discussed below is assumed to be met by LNG imports.

Japan: Natural Gas Demand

Figure 68: Assumed Japanese Natural Gas Demand to 2025



Sources: IEA WEO 2010, IEA 2011, Total Indonesia

*Note * denotes where the estimated incremental demand due to the Fukushima incident has been added to the IEA scenario data.*

[49] IEA 2010, pp. 182, 191
[50] IEA 2011, pp. 23, 27

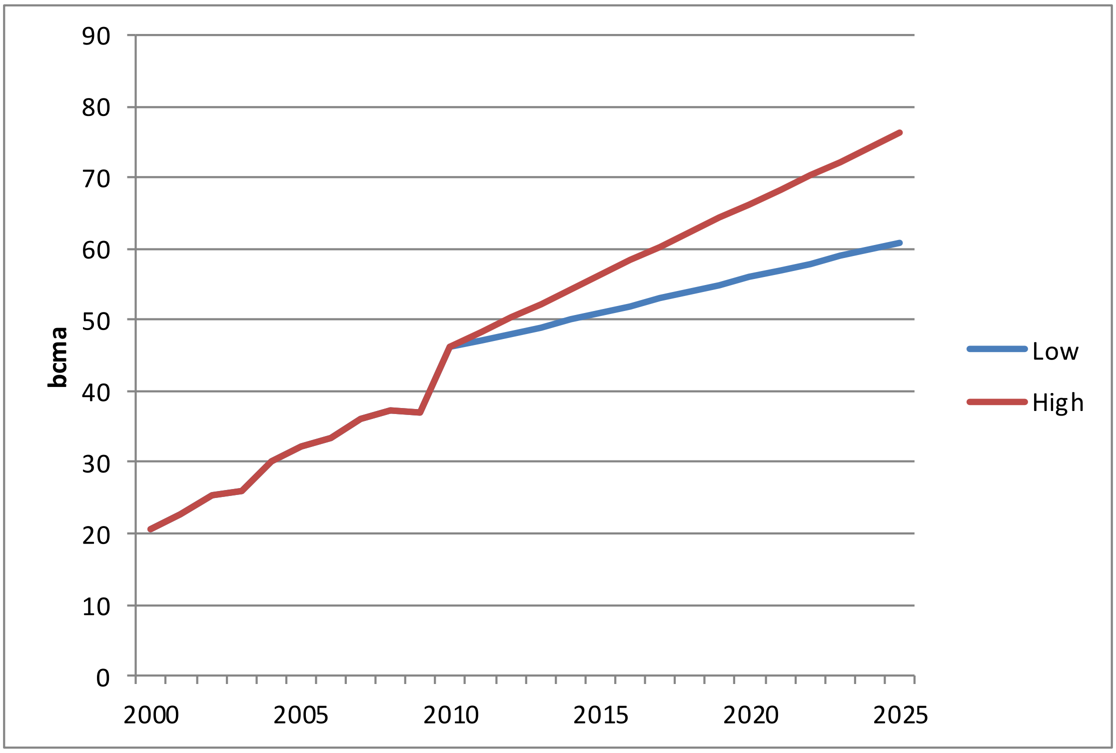
Domestic production

The IEA in its monthly natural gas data service reports domestic production for Japan which for 2010 was 4 bcm. It is assumed that this declines steadily to a 2025 level of 1.5 bcma.

South Korea: Natural Gas Demand

The IEA does not include specific data for South Korea demand in its scenarios. Figure 69 shows historical data for the period 2000 to 2010 from the IEA Monthly Natural Gas data service[51]. The High scenario assumes a growth trend broadly in line with historical demand growth. The Low scenario assumes a moderation in growth.

Figure 69: Assumed South Korean Natural Gas Demand to 2025



Source: IEA Monthly Natural Gas Service

Domestic Production

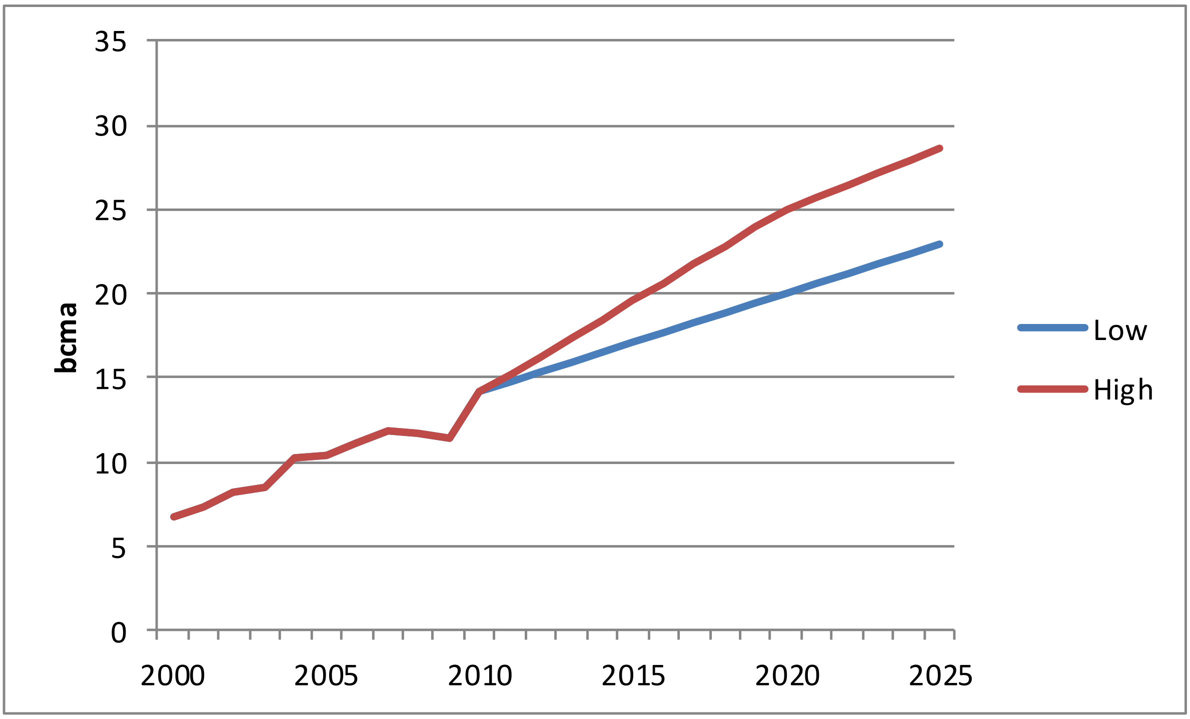
Based on 2010 IEA data, domestic production for South Korea was assumed to continue at 0.6 bcma to 2025.

Taiwan: Natural Gas Demand

Due to the lack of specific data on Taiwan in the IEA Scenarios, a similar approach was adopted to that for South Korea. This is shown in Figure 70.

[51] Note that data for the first half of 2011 supports a 2011 demand of around 50 bcm for South Korea.

Figure 70: Assumed Taiwanese Natural Gas Demand to 2025

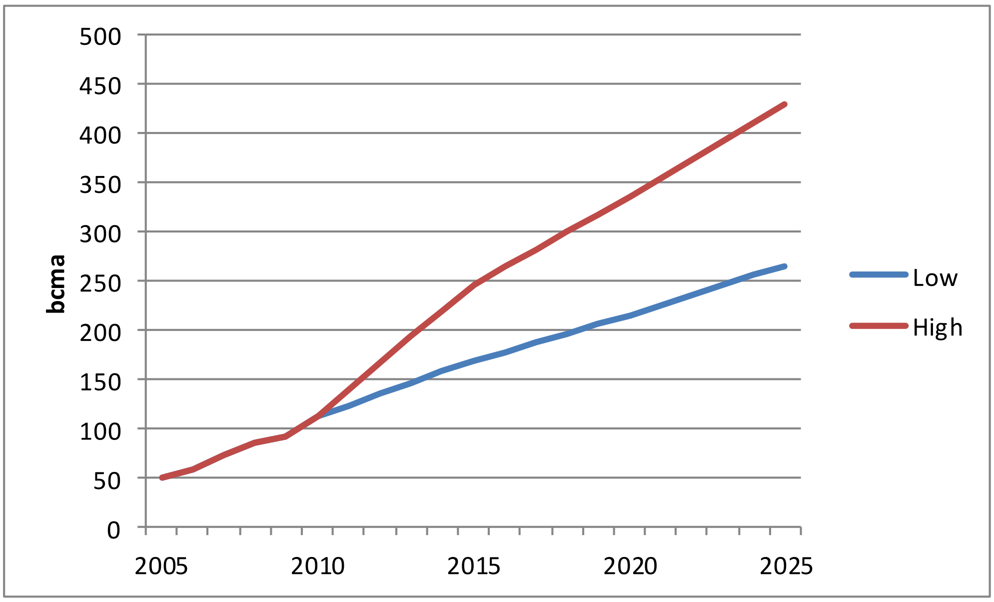


Source: IEA Monthly Natural Gas Service

China: Natural Gas Demand

Natural gas demand for the High and Low IEA scenarios used is shown in Figure 71.

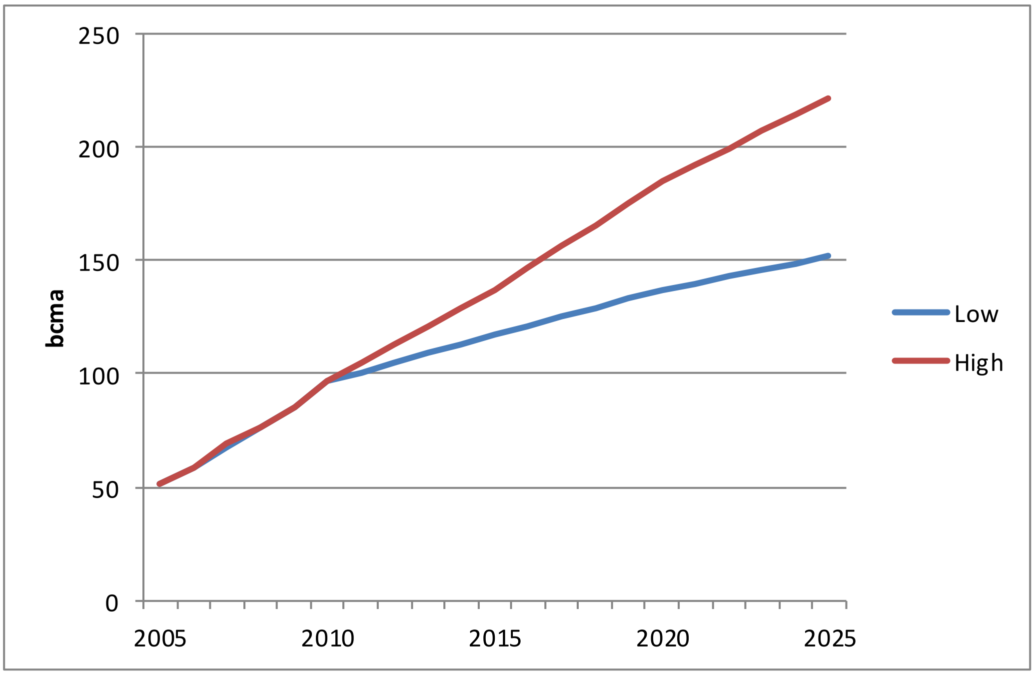
Figure 71: Chinese Natural Gas Demand Assumptions to 2025



Source: BP Statistical Review, IEA WEO 2010, IEA 2011

Domestic Production

Figure 72: Chinese Natural Gas Domestic Production Assumptions to 2025



Source: BP Statistical Review, IEA WEO 2010, IEA 2011

Chinese domestic natural gas production for the Low and High Scenarios is taken from the respective IEA scenarios and shown in Figure 72.

Pipeline Imports

Turkmenistan – China: the pipeline from Turkmenistan to China became operational in December 2009 and flowed 3.55 bcm in 2010[52]. Volumes are expected to build to 40 bcma with the potential to reach 60 bcma with further investment[53]

Myanmar – China: The 12 bcma pipeline from Myanmar is expected to be completed in time for first gas in 2013[54].

Russia – China: Gas imports from Russia have been the subject of intense though intermittent discussions and negotiations with still some distance between the parties on price and the directly connected issue of source (East Siberia or West Siberian fields)[55]. It has been assumed that such imports commence in 2020. Table 6 shows the specific assumptions made on Chinese pipeline imports by Scenario.

[52] BP 2011, Gas Pipeline Trade sheet.
[53] Henderson 2011, pp. 14,15
[54] Henderson 2011, p 18
[55] See Henderson 2011

Table 6: Future Chinese Pipeline Imports Assumed by Scenario (bcma)

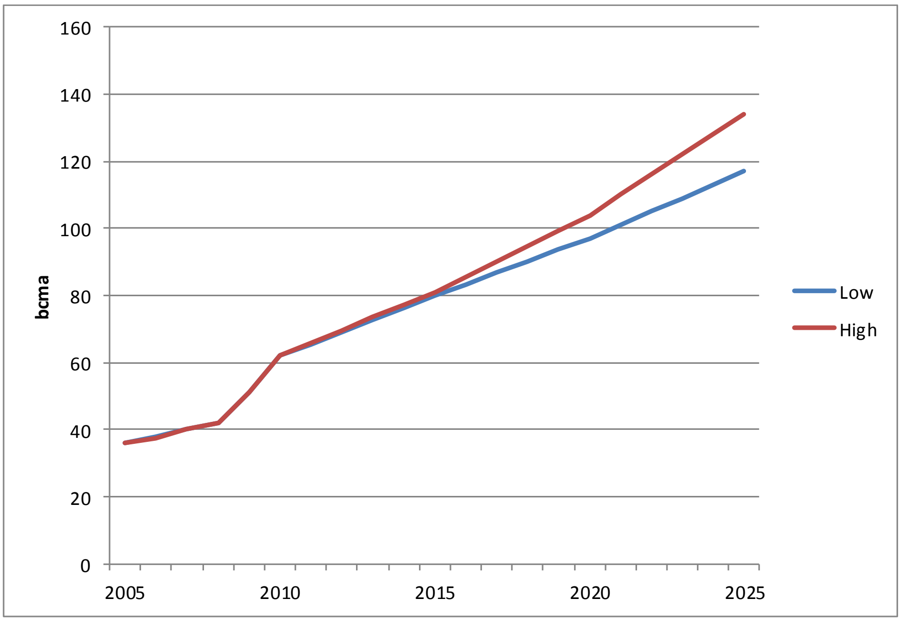
	2010	2015	2020	2025
Low Scenario				
Turkmenistan - China	4	25	40	40
Myanmar - China		10	10	10
Russia - China			10	30
Total Pipeline imports	**4**	**35**	**60**	**80**
High Scenario				
Turkmenistan - China	4	45	45	45
Myanmar - China		10	10	10
Russia - China			10	30
Total Pipeline imports	**4**	**55**	**65**	**85**

Source: Estimates based broadly on Henderson 2011

India: Natural Gas Demand

Natural gas demand for the High and Low IEA scenarios used is shown in Figure 73.

Figure 73: Indian Natural Gas Demand Assumptions to 2025

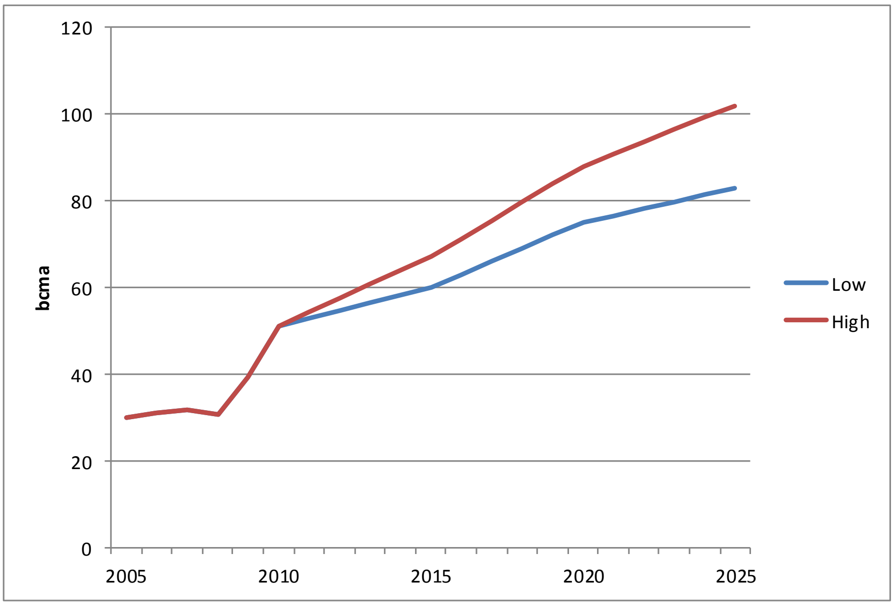


Source: BP Statistical Review, IEA WEO 2010, IEA 2011

Domestic Production

Indian domestic natural gas production for the Low and High Scenarios is taken from the respective IEA scenarios and shown in Figure 74.

Figure 74: Indian Natural Gas Domestic Production Assumptions to 2025



Source: BP Statistical Review, IEA WEO 2010, IEA 2011

A.2 North American Regasification Capacity

Table 7 shows the base-load re-gasification terminal send-out capacity for existing (2011) North American terminals.

Table 7: North American Regasification Terminal Send-Out Capacity (bcma)

	Terminal	Capacity (bcma)
US	Everett	7.2
	Lake Charles	18.6
	Cove Point	14.5
	Elba Island	9.3
	Golden Pass	20.7
	Cameron	17.1
	Sabine Pass	41.3
	Freeport	15.5
	Gulf LNG	13.4
	Sub-Total	**157.6**
Canada	Canaport	10.3
Mexico	Altamira	5.2
	Costa Azul	10.3
	Total North America	**183.5**

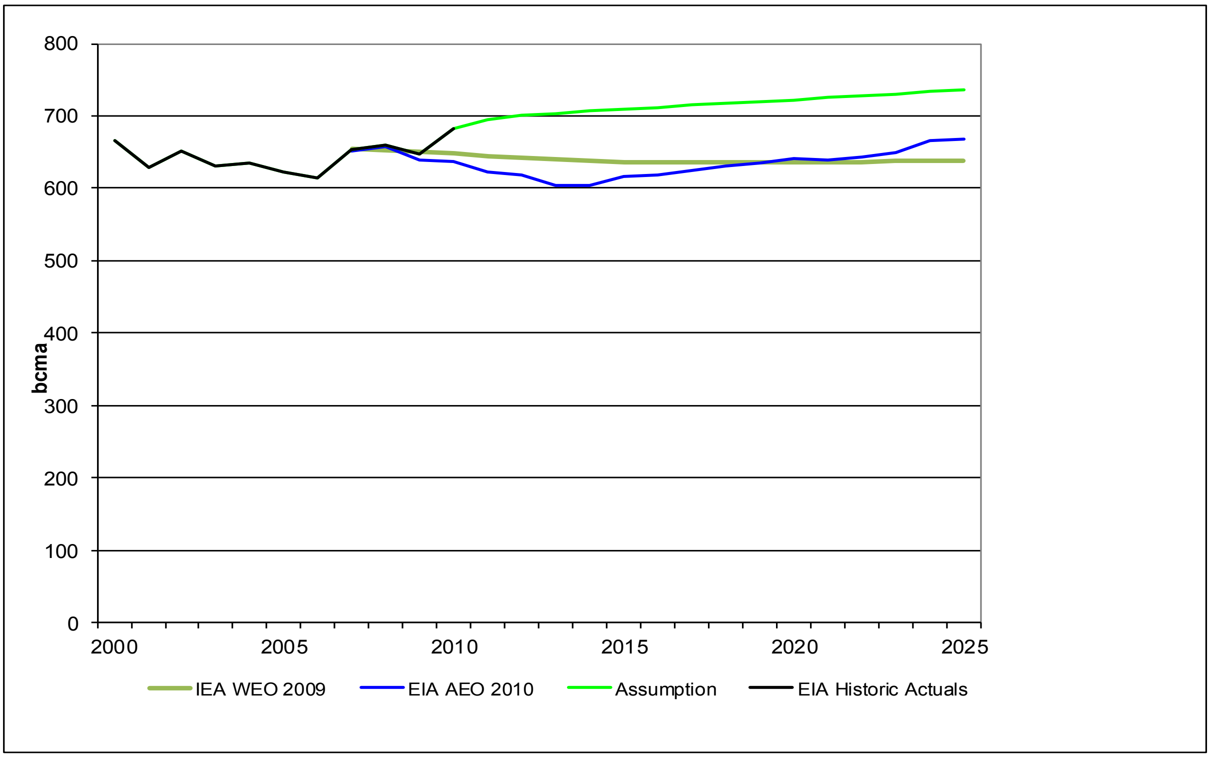
Source: The Americas Waterborne LNG Report, Waterborne Energy, Inc., 14th October 2011

A.3 North American Natural Gas Demand

USA

Figure 75 shows historical demand to 2010 and that assumed in this analysis to 2025 compared with data from the IEA World Energy Outlook 2009 and the EIA AEO 2010 Case. The EIA actual demand for 2010 represents a departure from the IEA forecasts due to the growth in power sector demand. The assumed future demand case is based on continued strong power sector gas demand.

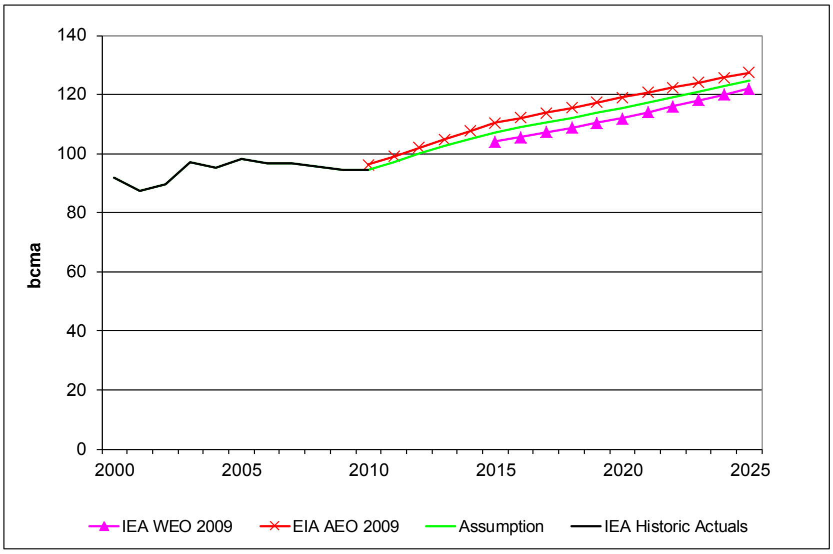
Figure 75: US Natural Gas Demand Assumptions 2000–25



Source: EIA, IEA

Canada

Figure 76: Canadian Natural Gas Demand Assumptions 2000–25



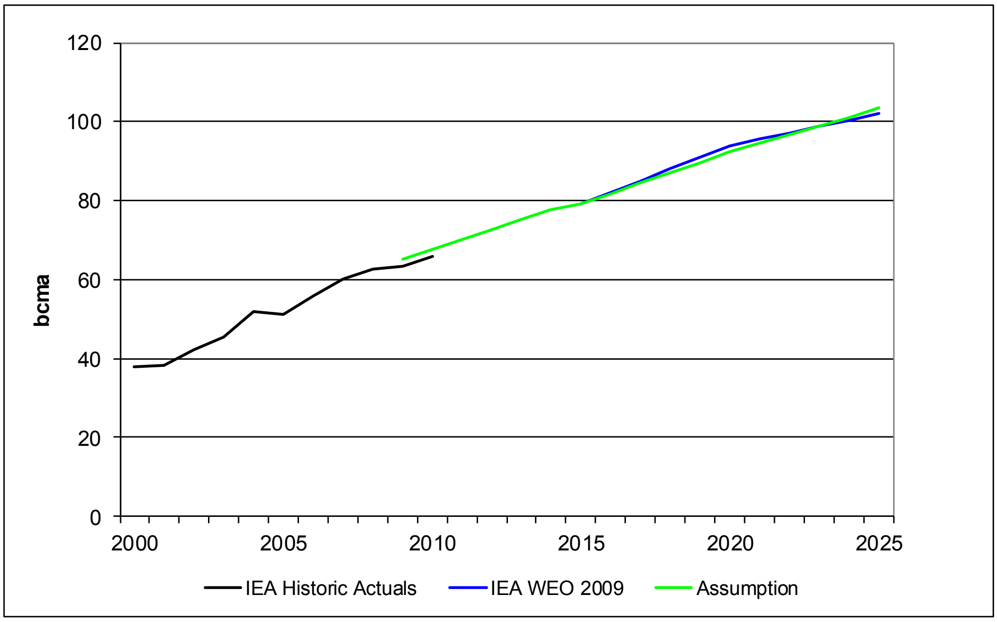
Source: IEA, EIA

Figure 76 shows historical demand to 2010 and that assumed to 2025 compared with data from the IEA World Energy Outlook 2009 and the EIA AEO 2009 Case. The future demand assumption for the analysis in this paper is shown to trend within these projections.

Mexico

Figure 78 shows the assumed future natural gas demand in Mexico which closely follows the IEA 2009 Reference Case.

Figure 77: Mexican Natural Gas Demand Assumptions 2000–25



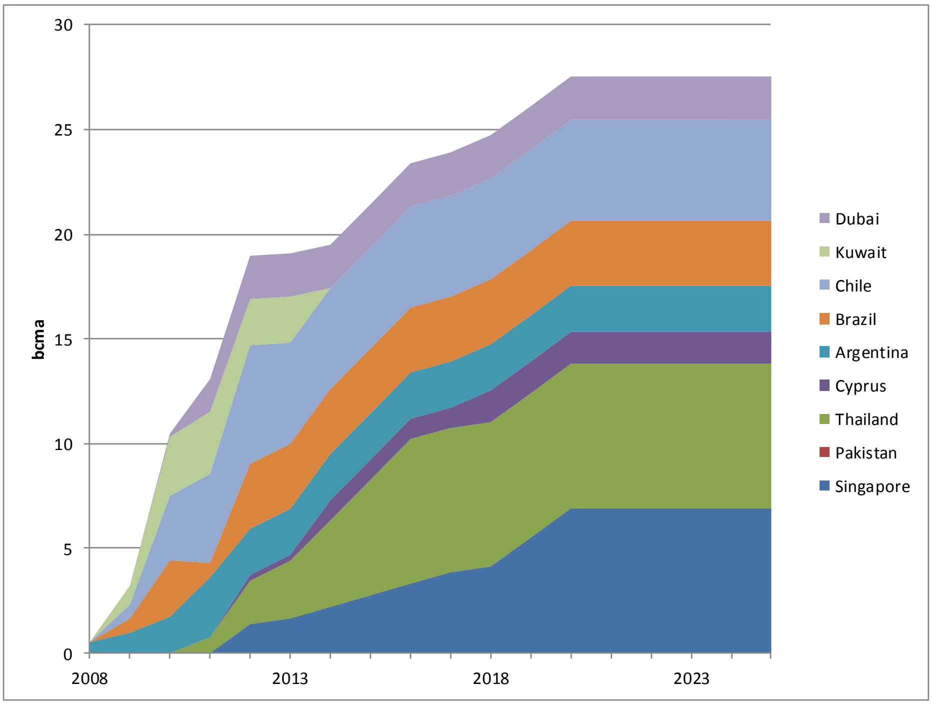
Source: IEA

A.3 New LNG Markets

Since 2008 Argentina, Brazil, Chile, Kuwait, Dubai and Thailand have become LNG importers. Other countries may follow including Singapore and Pakistan. Since the discovery of significant gas resources offshore Israel the likelihood of Cyprus becoming an LNG importer may have reduced, depending on whether it is selected as the location for the liquefaction plant associated with these discoveries.

Past and future import levels for these countries are shown in Figure 78. As many are seasonal importers, there is significant uncertainty around projections of future import levels, however these account for a relatively small percentage of global LNG supply (around 5% in 2020).

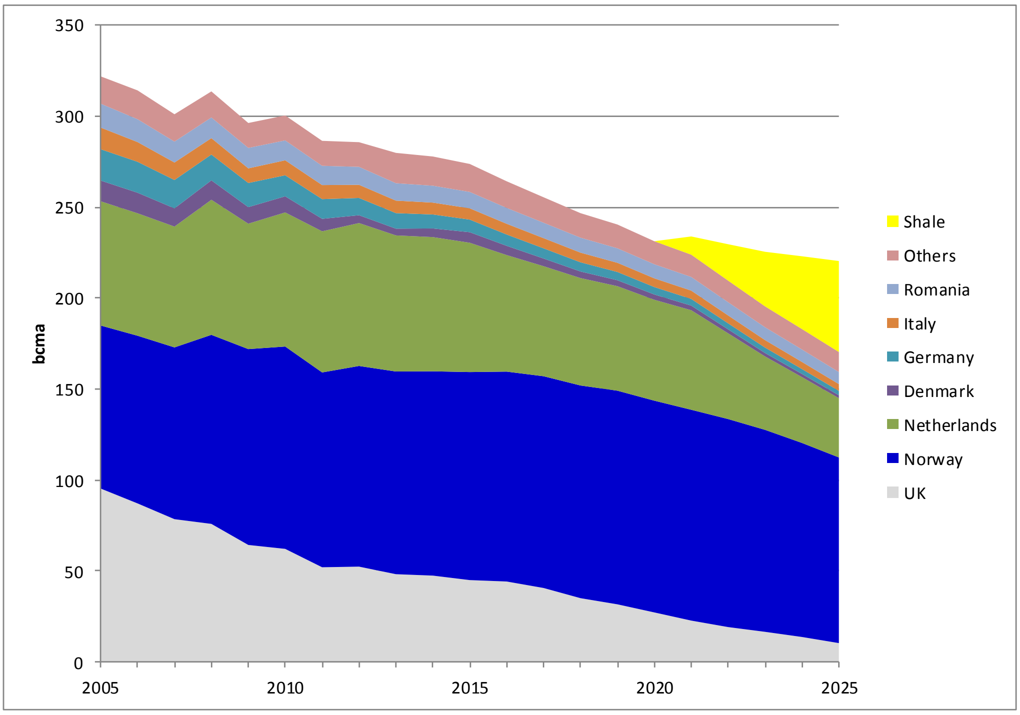
Figure 78: New LNG Market Assumed LNG Imports 2008–25



Source: Waterborne LNG (historical data)

A.4 European Domestic Production

Figure 79: European Domestic Production 2005–25



Sources: IEA, WoodMackenzie, National Grid, Dutch Ministry of Foreign Affairs, Energi Styrelsen, Norwegian Ministry of Petroleum and Energy, own analysis

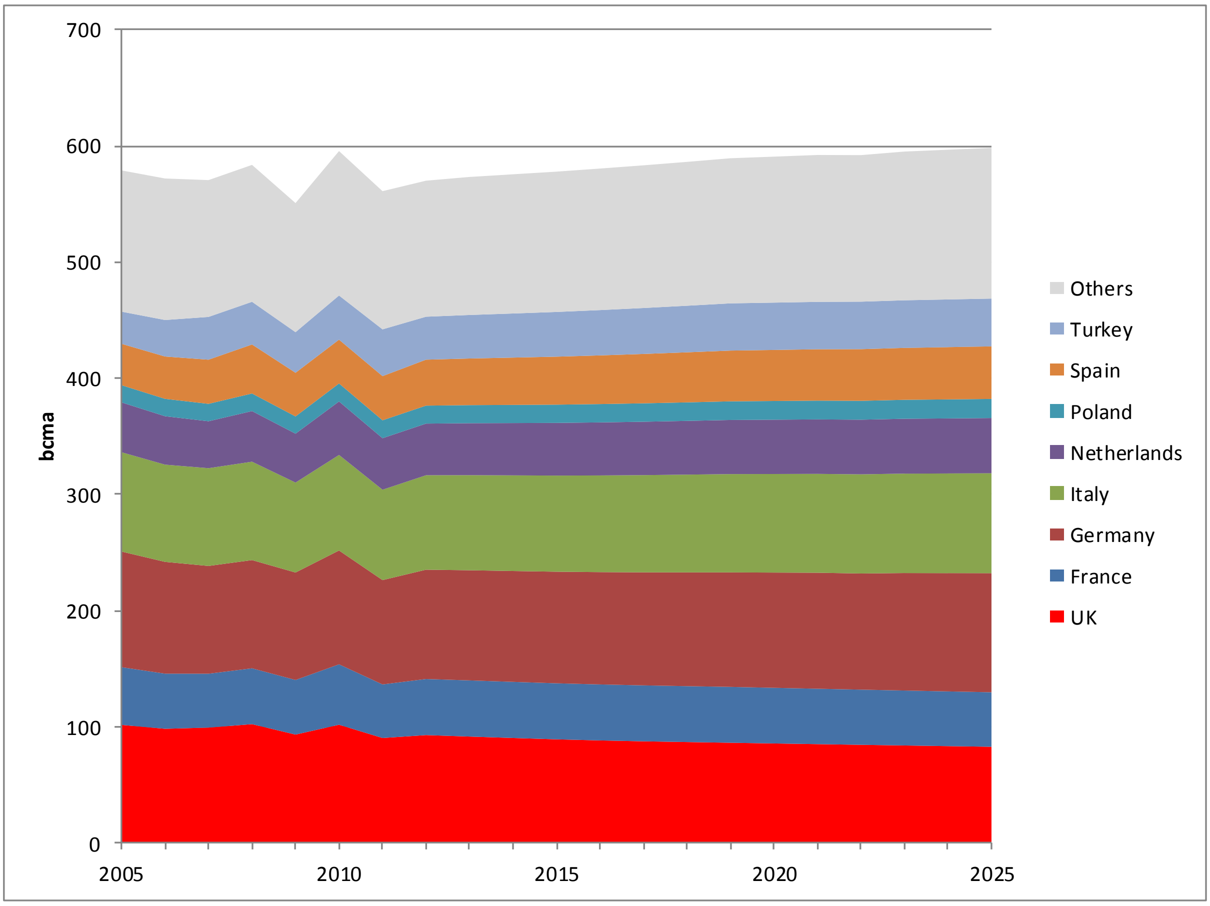
Figure 79 shows the historical and assumed future production in the European region[56]. For the major producing countries future forecasts were based on the sources listed below Figure 80. The minor producers were assumed to continue to experience decline rates in line with those observed in the 2005 to 2010 period.

Shale gas is assumed to make a contribution to Europe's production from 2020[57]. As shown in Figure 79 (yellow) it is assumed to grow to 50 bcma by 2025. It is noted however that this would not reverse the long-term decline in European domestic production.

[56] Countries with identified domestic gas production: Austria, Bulgaria, Croatia, Czech Republic, Denmark, France, Germany, Hungary, Ireland, Italy, Netherlands, Norway, Poland, Romania, Serbia, Slovakia, Turkey, UK
[57] Gény 2010

European Gas Demand[58]

Figure 80: European Demand 2005–25



Source: IEA, Eurostat, own analysis

A view of future European gas demand was developed at a country level by assembling annual data by sector, and aggregate IEA or Eurostat[59] annual demand data to 2010. A judgement was made for the likely long term demand trend, post-recession, based on previous sector trends but adopting a conservative approach. For the UK efficiencies in the domestic space heating sector result in a decline in demand (see Rogers 2011 page 85).

Of note is the reduction in demand in 2009 caused by the economic recession, the strong recovery in 2010, largely due to severe winter weather and the assumed slow demand growth trend for the remainder of the period.

[58]As defined for the purpose of modelling in this paper Europe includes: Austria, Belgium, Bulgaria, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania Luxembourg, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, UK

[59]IEA data used for all countries except Bulgaria, Croatia, Estonia, Latvia, Lithuania, Romania, Slovenia, for which Eurostat data used.

Glossary

Annual Contract Quantity (ACQ): The quantity that, under a gas contract, a buyer has the right to nominate and the seller the obligation to deliver.

Bacton-Zeebrugge Interconnector: see IUK

BAFA: The German Federal Office of Economics and Export Control website which reports natural gas production, imports, exports and storage inventory changes: http://www.bafa.de/bafa/en/index.html

Bcm: one billion cubic metres.

Bcma: one billion cubic metres per annum.

BP 2011: BP Statistical Review of World Energy 2011

CCGT - Combined Cycle Gas Turbine: a gas-fired power generation plant which has a high pressure gas turbine cycle and a steam cycle.

Conventional Gas: Natural gas produced from an underground reservoir other than shale gas, tight gas or coal bed methane.

FID: Final Investment Decision: usually in the context of a gas project, this is the joint decision on the part of the investment companies and any state entities to proceed with the full development of a project through to commercial operation.

Fuel Oil: the heaviest commercial fuel that can be obtained from crude oil, heavier than gasoline and naphtha.

Gas oil: refined petroleum fraction corresponding to diesel.

Gas Storage: The storage of natural gas in either underground structures such as depleted oil or gas reservoirs, salt caverns or aquifers, or alternatively as LNG either in storage tanks at regasification terminals or LNG Peak Shaving facilities.

Henry Hub: Henry Hub is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX). It is a point on the natural gas pipeline system in Erath, Louisiana where it interconnects with nine interstate and four intrastate pipelines. Spot and future prices set at Henry Hub are denominated in \$/mmbtu (millions of British thermal units) and are generally seen to be the primary price set for the North American natural gas market.

Hub: the location, physical or virtual, where a traded market for gas is established.

IUK: the shorthand name for the Bacton (UK) to Zeebrugge (Belgium) bi-directional gas pipeline. Import capacity 25.5 bcma, export capacity 20 bcma.

JCC: The Japan Customs-cleared Crude (JCC) is the average price of customs-cleared crude oil imports into Japan (formerly the average of the top twenty crude oils by volume) as reported in customs statistics; nicknamed the "Japanese Crude Cocktail". It is a commonly used index in long term LNG contracts in Japan, Korea and Taiwan.

LNG: Natural Gas which has been cooled to minus 162 degrees Centigrade where it exists in a liquid state at atmospheric pressure and can be transported in specially designed ocean going tankers.

Mmcm/day: Million cubic metres per day.

Mmbtu: Million British thermal units

Mmcm; million cubic metres

NBP: the UK's National Balancing Point: a virtual point (hub) in the National Transmission System where gas trades are deemed to occur. It is also used as shorthand for the UK spot gas price.

OECD: An international organisation (The Organisation for Economic Co-operation and Development) whose aim is to promote policies that will improve the economic and social well-being of people around the world. The OECD provides a forum in which governments can work together to share experiences and seek solutions to common problems.

Oil-Indexed Gas Prices: gas prices within long term contracts which are determined by formulae containing rolling averages of crude oil or defined oil product prices.

Liquefaction Plant: A large scale processing plant in which natural gas is cryogenically cooled to minus 162° centigrade where it becomes a liquid at atmospheric pressure.

Regasification: The process of reinstating LNG to a gaseous state for injection into a distribution system for end-user consumption. A regasification terminal comprises an unloading jetty, insulated storage tanks and a heat exchanger to re-convert the LNG to a gas.

Rig Count: the number of rotary rigs which are actively drilling on a given date. These are essentially working on exploration or development wells and represent the activity level of new production capacity development.

Shale Gas: natural gas formed in fine-grained shale rock (called gas shales) with low permeability in which gas has been adsorbed by clay particles or is held within minute pores and micro fractures.

Spot price: the price of gas determined through trading – i.e. determined by supply and demand and/or gas on gas competition. Usually referred to as 'prompt' rather than futures prices.

Storage Inventory: the quantity of working gas volume in storage. Working gas is distinct from ‘cushion gas’ which is needed to maintain pressure in the store and is only withdrawn from storage when a storage site is decommissioned.

Take or Pay (TOP): sometimes called the ‘minimum bill’, this is the quantity of gas which, during a gas contract year, customers are obliged to pay for regardless of whether they physically take it for resale or not.

Tight Gas: natural gas formed in sandstone or carbonate (called tight gas sands) with low permeability which prevents the gas from flowing naturally.

Working Gas: see Storage Inventory

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Waterborne LNG: Waterborne LNG is a subscription service providing US, European and Asian reports data and commentary on LNG cargo movements. Data is reported at an individual tanker level and summarised by month. In this way the complete global supplier-importer matrix can be assembled at a monthly level. Data is available back to January 2004.