20th March 2014

DECC Gas Pricing Projections 2014

Background

The Department of Energy and Climate Change (DECC) publishes an annual 'Fossil Fuel Price Projections' series, widely used across the UK government for a range of purposes including modeling and appraisal. DECC is currently reviewing its methodology for the 2014 projections and is planning a short external peer review of its gas price projections. South-Court Ltd has been asked to carry out this peer review, and its comments are set out below.

LNG Market

During the period to 2025/2030 the global gas demand is expected to increase, based on a number of assumptions:

- Population growth and rising energy demand as countries develop economically
- New markets for gas and LNG, as purchasers switch from oil to gas as a result of price
- Countries such as China diversifying to gas as new sources of gas supply gives the country confidence to increase its gas use
- Rising demand from countries that seek to reduce carbon emissions to improve air quality
- Gas being used as a fuel of transition from oil and coal to renewables.

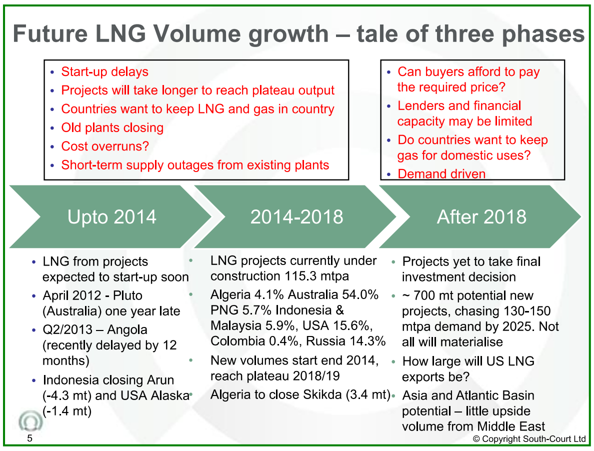
To meet this higher gas demand growth, the movement of gas around the world is expected to rise and LNG is expected to increase faster than pipeline gas, with LNG supply doubling by 2025. At the same time LNG, as a percentage of the global gas trade, is expected to increase from its current level of 10% to ~ 18% by 2030[1]. That said, there are considerable uncertainties in LNG demand and a major question is what will the role of nuclear power generation be in Japan and South Korea? Current indications are that the Japanese government supports the re-start-up of many of its nuclear power plants, within the rules set by the Japan Nuclear Regulatory Authority (NRA), but opposition to nuclear also remains high. In its LNG demand estimates, South-Court assumes that some nuclear power will start up and, as a result, oil demand for power will initially fall followed by some reduction in LNG demand. Chinese gas and LNG demand is expected to rise as the Chinese government seeks to increase gas from 5.8% of its energy mix to 9% by 2015 and over 10% by 2020[2] as China seeks to improve its air quality through reducing coal in primary energy consumption from 72% in 2011 to 65% by 2017[3]. LNG imports are expected to grow as new regasification capacity is constructed[4], but the level of this increase will depend on the extent to which China develops its shale gas reserve, as the country will always favour gas supply from domestic sources, for security of supply reasons. The extent and length of recession in Europe is also an uncertainty as well as the politics of European gas supply following the Ukraine Crisis and the ceding of Crimea to Russia in March 2014. All these remain major LNG demand uncertainties.

LNG supply growth, over the period to 2030, can be clearly divided into three phases, as set out in the diagram below.

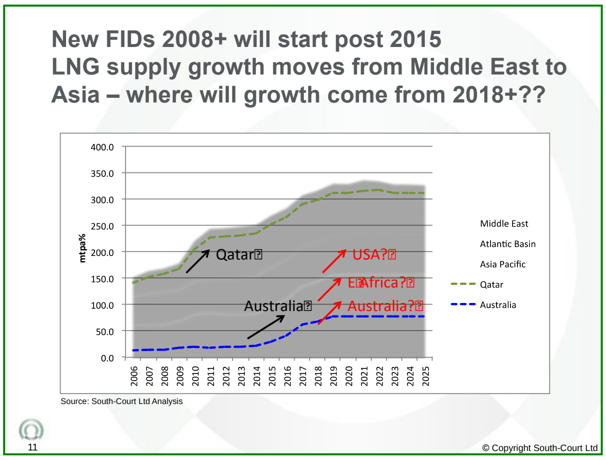
[1] BP Energy Outlook 2030, January 2013
[2] In 2013 it is estimated that over 30% Chinese gas consumption was imported
[3] China's Air pollution Prevention Action Plan
[4] Chinese LNG regasification capacity is 46 Bcm as at March 2014 with a further 27 Bcm under construction and 16 approved. In addition over 50 Bcm additional regasification capacity is planned, though not yet approved.

Phase 1 – immediate term (up to end 2014) – A period of continued supply tightness as Asian LNG buyers seek to secure LNG from Middle East and Atlantic Basin LNG suppliers to meet growing LNG demand, exacerbated by the post Fukishima nuclear shutdowns in Japan, Korea and Taiwan, and delays in new Australian supply projects. The first new supply is expected to come into operation at the end of 2014 (PNG LNG and BG's Curtis Island LNG projects). The market is finely balanced and short-term supply disruptions in Nigeria and Yemen and longer-term shutdowns in Egypt have caused rising prices in the Asian spot market[5]. This period of tightness could extend into 2015.

Phase 2 – Medium Term (2014-2018) – There is a general expectation that the LNG market will move from a period of relative shortness today to a more balanced position post 2017/8, as projects that are currently under construction start-up. Two-thirds of this capacity is in Asia, and as these projects start exporting LNG it should reduce the volume of Atlantic Basin LNG that is being moved out of the region to Asia. Middle Eastern LNG that has been moving to Asia should start to flow back into the Atlantic Basin. The key uncertainty in this period is the speed of start-ups of new capacity and how quickly the new facilities increase their production towards full capacity.



Phase 3 – Longer Term (after 2018) – This period includes the greatest uncertainty. South-Court Ltd, in line with other commentators, estimates that, 150 mtpa of new LNG supply will be required by the market by 2025. With five years to construct an LNG chain, this means that there must be 150mtpa project FIDs[6] over the next 5-6 years to ensure that there is sufficient LNG supply to meet future LNG demand estimates. There are estimates that there are over 700mtpa of potential projects, but project developers will have to secure offtakers in a challenging market. There is, however, considerable competition to meet this expected LNG demand growth, with potential new supply from the US Gulf, East Africa, West Canada and Australia – all of which land into Asia at similar cost levels. Which projects move forward will depend on a variety of factors, volume of upstream reserves, project economics and development status, ability to sell a large percentage of LNG on a long-term basis, government & geopolitical factors, sponsors with LNG experience and ability to deliver, ability to finance the project.



---

[5] In 2012 and 2013 plant utilization (LNG output divided by LNG capacity) was only 83%. This was due to short-term LNG supply disruptions (Yemen, Nigeria and Indonesia Tangguh) as well as structural changes in existing LNG supply due to shortages of feedgas and domestic demand increases in LNG producing countries (Egypt and Oman). Plant utilization averaged 86% between 2002-2012, but will never reach 100% due to plant maintenance shutdowns and operational flexibility requirements.

[6] Final Investment Decision - The date on which a project sponsors decide to make a binding financial decision to proceed with the project. Usually the key agreements related to the project are signed on this date (e.g. plant construction, gas purchase, LNG sales and financing agreements). Also known as FID date.

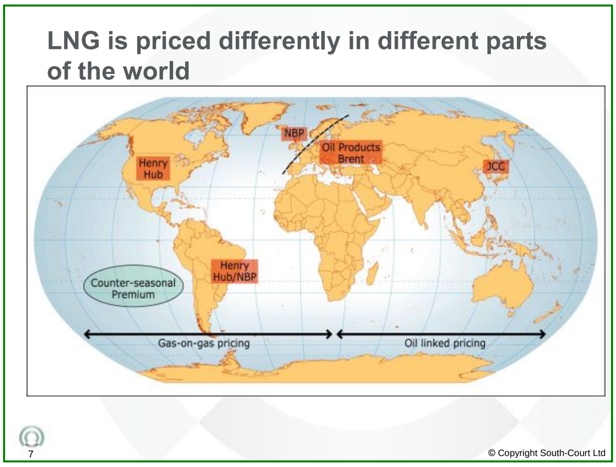
Global LNG demand is expected to rise to ~ 450 million tonnes by 2025 according to South-Court estimates (these are confirmed by other organisations such as BG and Qatargas). The graph sets out South-Court's estimated global LNG supply/demand balance, from existing projects and those under construction (i.e. those that have taken FID) to 2030.

LNG Pricing

Historically, LNG has been priced using different pricing structures depending on region, structured around whether the region has an operating liquid hub market pricing mechanism, or whether LNG prices are based on a formula linked to oil, (crude oil based in Asia, primarily JCC[7]) or crude oil/oil products in Europe. The diagram below sets out this regional pricing structure.

This regional pricing structure has been changing over the past two years, driven by three factors:

1. The growth of spot and short-term LNG sales into Asia has resulted in Asian buyers having to pay prices high enough to "pull" cargoes away from North-West Europe, often on a fixed price with levels determined by the price that sellers can get in alternative markets, namely North-West Europe, so based on NBP or TTF hub related prices[8].
2. The development of LNG export projects in North America, sourcing feedgas on a Henry Hub related price, which means that LNG can be sold into global markets on a hub basis. Low Henry Hub prices, following the growth in shale gas production, means that LNG can be sold economically into Asian markets at $12-13/MMBtu and Europe at $9-10/MMBtu. Henry Hub prices can at times be volatile, which may set some purchasers of LNG from the US challenges in managing their price exposure. If market prices are higher in these regions, spot LNG will, of course, be sold at the higher price.



3. Post March 2011, Japan's energy import costs have increased substantially as 22 Twh nuclear power capacity has been cut to zero. This resulted in Japan experiencing its first trade deficit for over thirty years in 2012 and led to the Japanese government putting pressure on LNG importers to reduce their LNG import costs. This will be difficult for many buyers as they are locked into long-term twenty year LNG purchase agreements, some with no price review. The Japanese government is putting further pressure on LNG buying utilities by proposing that they will not be able to automatically pass through the cost of LNG to the regulated market through power tariffs. This will push LNG buying companies to secure lower contract prices and therefore lower energy costs in Japan.

[7] Japanese custom cleared crude price or Japan Crude Cocktail, the average price of crude oil imported into Japan in a given month
[8] NBP= National Balancing Point (UK virtual gas trading hub) and TTF = Title Transfer Facility (the Netherlands virtual gas trading hub)

Recent LNG deals have also established the principles of: lower prices, flexible volumes, price reviews and, in some cases, the inclusion of some element of hub pricing. Buyers, therefore, have given some clear messages to LNG sellers:

1. Buyers are willing to take time to secure the right price, they see new LNG coming from new projects in US and East Africa (and Australia) and these suppliers may be willing to offer competitive pricing to get their project established (as the LNG market saw in the mid 2000s).
2. Buyers are willing to commit to smaller volumes to secure better prices. Buyers may also be willing to commit less on a term basis (especially once the direction of nuclear policy in Japan is clearer).
3. Buyers want to have a hybrid pricing formula, and expect prices to fall. In the case of Japanese buyers, they are under immense pressure from Ministry of Economy, Trade and Industry (METI) to get lower prices. If they do not, then it could impact on their financial results (Anadarko/Mitsui Mozambique LNG project is reportedly indicating a hybrid price with the hub element linked to UK NBP).
4. Buyers will seek price review clauses to make sure their contracts remain competitive with global LNG.
5. Buyers will seek volume flexibility in case gas/LNG demand in their local market reduces.

For the UK, this means that, as Asian prices fall and contracts become more flexible, the UK and Northern Europe will be able to attract LNG on Hub related pricing. Those companies that have taken long-term capacity in US LNG export projects will have a cost of LNG linked to the Henry Hub price. The cost to these companies of LNG supplied to Europe from the US projects will be calculated as follows:

Henry Hub price PLUS liquefaction fee PLUS freight

The liquefaction fee has varied depending on the time at which the liquefaction contract was concluded. The earliest deals secured a fee that was as low as Henry Hub plus $3.00-3.75/MMBtu, but more recent deals are being indicated at a higher premium of $3.50-4.25/MMBtu[9]. Assuming a freight of $1.30/MMBtu[10] from US Gulf facilities to the UK, this equates to an ex-ship LNG cost of Henry Hub plus $5.10-5.55/MMBtu. In a case of short-supply sellers will seek a premium to their cost level, but where LNG supply is in surplus, which could be expected 2019-2023/4, then sellers may discount below cost in order to minimise their potential losses on their US liquefaction capacity position.

Comments on the DECC Gas Price Projections 2014

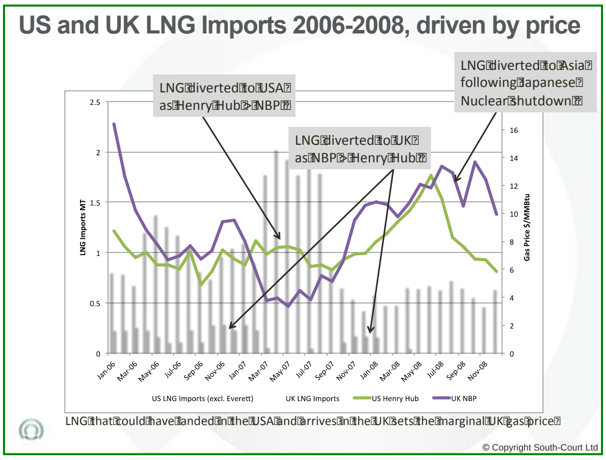
South-Court Ltd has reviewed the DECC Price Projections 2014 and has made the following observations.

The basis and factors behind the calculation of DECC's 2014 Gas Price Projections are sound. The logic that the marginal LNG supply source for gas to the UK, post 2019/20, will be through LNG, from the USA, is a reasonable assumption. This means that marginal gas could be priced on a Henry Hub

[9] The Sabine Pass trains 1 & 2 sales agreements are based on a formula (in US$/MMBtu) Henry Hub x 1.15 plus 2.25-3.00. Assuming Henry Hub price level of 5.00 this equates to an FOB cost level of 8.00-8.75 FOB. Later deals are understood by South-Court to be equivalent to having a premium of 3.50, equivalent to 8.50-9.25 FOB.

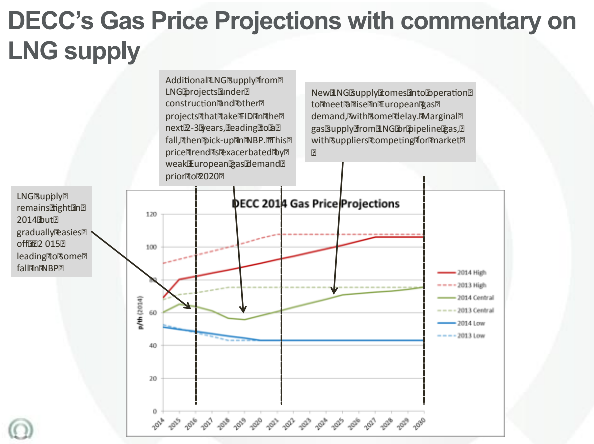
[10] This round trip freight cost of $1.30/MMBtu from the US Gulf (basis Sabine Pass) to the UK (basis Isle of Grain) assumes a 170,000m3 vessel, charter cost of $85,000/day, 4975 nm, Bunker cost of $600/MT and boiloff gas cost of $9/MMBtu. The freight cost from Eastern USA (basis Elba Island) is $0.30/MMBtu lower at $1.00/MMBtu due to the shorter distance, 3840 nm.

related basis. In the period 2006-2008, US Henry Hub and UK NBP prices were vying with each other as to which was the premium market and which market would pay the higher price for marginal LNG cargoes. The market that could pay more attracted the cargoes and, in the case of the UK market, the price of the LNG set the marginal cost of additional gas.



Gas price formulation in Europe is expected to continue the move from a relationship with oil to solely a hub price basis, where the price of gas is determined by supply-demand of natural gas. The issue is the pace of this change. In 2012, The International Gas Union study noted that regions of Europe had very different price formation mechanisms. In the North-West (50% of European gas demand), nearly 75% of gas was priced on a hub basis, while in the Mediterranean and South-East Europe; oil-linked and regulated pricing remained dominant[11]. In June 2013 Société Générale estimated that by 2014, hub based indexation pricing should represent more than half of European gas supply[12]. It is viewed, therefore, that the trend towards increased volumes of European gas, especially in Northern Europe, will increase until all gas is priced on that basis, probably by the end of the decade or in the early to mid 2020s.

In commenting on DECC's Gas Price Projections, it is necessary to examine the potential volume of LNG that could be available for Northern Europe. LNG supply will naturally be drawn to the highest priced market; these tend to be the firm markets of Asia that have limited or no other gas supply source. The markets of South America can also be treated as firm markets, especially during periods of low rainfall when hydroelectric power generation is reduced, until LNG demand in that market is fully satisfied. Once these markets are satisfied, then the LNG will move to the next highest priced market which can be Southern Europe, before supplying Northern European markets, which can be termed flexible markets as they have access to alternative pipeline gas supply. Which North-West European market the LNG moves to will depend on price and access to regasification capacity. As noted in South-Court's commentary above, it is expected that increasing volumes of LNG will be available 2017/18+ as new LNG projects in Australia and PNG reach plateau production and US LNG exports start to materialize. At this time, the UK should see an increase in LNG supply. The graph shows DECC's gas price projections with commentary on LNG supply availability during the different phases of the price forecasts. The conclusion is that gas price weakness from 2016 to 2020/1 can be expected and during this transition from tight LNG market to a period of relative weakness, the marginal LNG supply to the UK will switch to LNG from the US, which is sourced on the basis of Henry Hub prices. The $5.10/MMBtu premium to Henry Hub that DECC uses in its gas price forecasts, seems reasonable assuming that some LNG is sourced from US East Coast LNG supply sources. A



[11] International Gas Union, Wholesale Gas Price Formation, PCGB Study Group 2. A Report from the June 2012 World Gas Conference, Kuala Lumpur

[12] http://www.bloomberg.com/news/2012-06-11/europe-may-buy-most-gas-at-spot-prices-by-2014-socgen-says.html

linkage of NBP to Henry Hub during the 2020s seems reasonable, with marginal LNG supply from the USA, and some impact of pipeline gas, resulting in Northern European gas prices being less dependent on Henry Hub levels and more European Hub based.

South-Court concurs that the International Energy Agency's (IEA) New Policies Scenario estimates that US LNG exports will reach 50 Bcm by 2035 will be a minimum and it is more likely that LNG exports from the US could reach this level between 2020 and 2025. South-Court also agrees that new LNG supply from East Africa could be delayed into the early 2020s.

The global energy market is, however, increasingly uncertain and economic, political or natural events can change the outlook, these could include:

1. Continued weak economic growth in Europe and lower energy demand could reduce the volume of US LNG that is imported into the region and therefore the impact of Henry Hub gas prices on the UK gas market. This trend could be exacerbated if CO2 prices do not rise to a level where gas and coal fired power stations are on a similar economic basis, then the demand for coal for power could increase at the expense of gas.
2. Political will, with economic support, to diversify Europe's source of gas supply could increase demand for LNG into Europe.
3. Asian gas, demand rises faster than expected which could continue to pull LNG from Europe. This could be the case in China, especially if exploration and development of unconventional gas does not go as planned by the Chinese authorities. In Japan, if nuclear was not to return to at least 50-60% pre-Fukishima levels, then this would give added support for LNG demand into that country and potentially reduce LNG supply to Europe.
4. US LNG supply projects may not take FID as expected, or the scale of LNG export permits reduces, this would tighten LNG supply and Henry Hub sourced LNG.
5. LNG projects under construction could experience severe start-up delays, which could continue the period of market tightness beyond 2015/16.
6. Shale gas developments, outside North America, could increase thus creating another gas supply source available to the global market. If this happens in Europe, this could displace some LNG imports.
7. The transition from oil to hub based pricing for gas and LNG in Asia and Southern Europe could challenge the economics of new LNG supply projects. This, together with other project development factors, could defer FIDs on new LNG supply projects therefore reducing future LNG supply.
8. Short-term disruptions in the market due to political and market restructuring events could impact on global gas and LNG supply/demand.

The energy market has proven historically to be robust to changing global events, and it is expected that it will remain so in the future. It is expected, therefore, that the impact of these events on UK gas prices would be contained within the high and low gas price scenarios set out in the price forecasts.

David Ledesma
20th March 2014