Global Gas Analytics

Gas market analysis driven by industry insight

Issue 12 ▪ September 2013

Interfax Information Services Group
www.interfaxenergy.com

IN THIS ISSUE

REGIONAL MARKETS

Asia Pacific: Total demand from the top markets will rise by around 6% in Q4

Europe & Russia: Restocks of storage in key markets have been too slow – the regional market will be tight this winter

Middle East & Africa: Growing domestic demand, backed by heavy subsidies, is creating gas shortages in GCC countries

Americas: Strength in the US dollar is making gas imports more expensive for major consumers such as Brazil and Argentina

Editorial
analytics@interfax.co.uk

Free trials and subscriptions
+44 (0)20 3004 6206
customer.service@interfax.co.uk

Interfax
Global Gas Analytics

Gas market analysis driven by industry insight

Issue 12
September 2013

EXECUTIVE SUMMARY

GLOBAL OUTLOOK

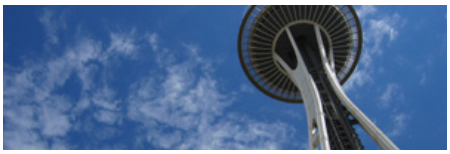
REGIONAL MARKETS

ASIA PACIFIC

EUROPE & RUSSIA

MIDDLE EAST & AFRICA

AMERICAS



FEATURES

END NOTES

NEXT ISSUE

The next issue of *Global Gas Analytics* will be published on 22 October 2013.

CHIEF ENERGY ANALYST
Peter Stewart
+44 (0)20 3004 6211
peter.stewart@interfax.co.uk

ENERGY & MODELLING ANALYST
Abhishek Kumar
+44 (0)20 3004 6212
abhishek.kumar@interfax.co.uk

SENIOR ENERGY ANALYST
Catriona Scott
+44 (0)20 3004 6214
catriona.scott@interfax.co.uk

CHIEF SUB-EDITOR
Rhys Timson

SUB-EDITORS
Doug Kitson, Bea Prokofiev, Rob Loveday

DESIGN & LAYOUT
Joseph Williams

interfax
Interfax Europe Ltd.
19-21 Great Tower Street,
London EC3R 5AQ,
United Kingdom
T +44 (0) 20 3004 6200
W interfaxenergy.com
E analytics@interfax.co.uk

EXECUTIVE SUMMARY

Pluto LNG plant, Australia. (Woodside)

Ahead of the winter period, further spot cargoes are expected to be required in Japan, while storage in France and Germany remains low for the time of year. In North America, demand is expected to fall on an annual basis this coming winter.

Market developments

- In Asia Pacific, spot prices have dipped over the past month, with average prices at around $15.25-15.5/MMBtu. Going into the winter period, spot prices are expected to rise, supported by Japan's requirements for further cargoes for delivery in Q4.
- Day-ahead prices at Europe's leading hubs have risen over the past month. As of mid-September, the NBP was around 66-67 p/th and the TTF was around €27/MWh. Going into winter, prices are expected to remain higher than last year.
- CME/NYMEX-traded Henry Hub futures were around $3.5/MMBtu, as of mid-September. Prices are likely to average $3.7/MMBtu and $4/MMBtu in Q4 2013 and Q1 2014, respectively, as heating-related demand gathers pace.
- The situation in Syria, together with declining oil production in Libya and Iraq has buoyed crude oil prices. However, prices have come off their peak levels as a result of US and Russia negotiations to avoid an escalation of their differences on how to respond to Syria's alleged use of chemical weapons.

Asia

- Over the first nine months of the year, total consumption from Asia Pacific's leading markets increased by 6% on an annual basis. Through Q4, total demand is expected to increase by around 6% year on year. Consumption declines in Japan could ease before the end of the year.
- Production in Australia and China is rising, while in India the rate of decline has softened. According to the latest statistics, Indian output has fallen by around 15% on an annual basis in recent months, an improvement from the declines seen earlier in the year.
- South Korean storage is strong ahead of winter, with stocks reported to be more than 90% full. The latest indicators for Japan show that storage levels are down compared with the same time in 2012.
- LNG imports to Asia Pacific have risen by around 3% on an annual basis over the first nine months of the year. Japan will need further spot cargoes for delivery in Q4. South Korea is well supplied through November, but will likely need spot cargoes for delivery in December if the weather is severe.

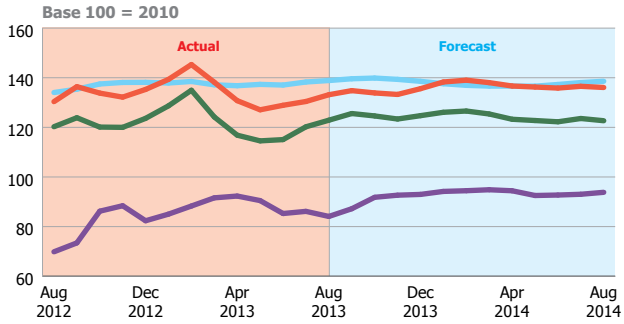
Europe

- The market in Europe will be tight this winter. Even though demand from the top six markets in Europe is expected to decline by around 3% on an annual basis in Q4, low stocks, falling indigenous production and limited LNG imports will support market tightness.
- Indigenous production is declining in Europe and will continue to do so through Q4 and into Q1 2014. European production fell by around 3% on an annual basis over the first nine months of the year.
- Storage in France and Germany remains a critical issue ahead of winter. While net injections have been seen in both markets over the past month, refilling stocks before the start of November will be a challenge. A similar situation can also be seen in smaller markets in Northern Europe.
- Europe will remain dependent on Russian supply through Q4.

Americas

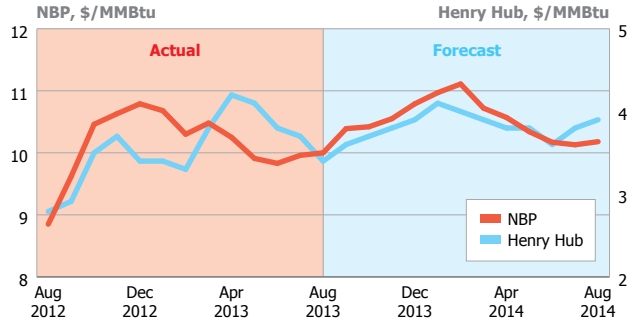
- Forecasts for a milder winter in North America could lead to a fall in gas demand in OECD Americas. Demand

FIGURE 1 Interfax gas indices



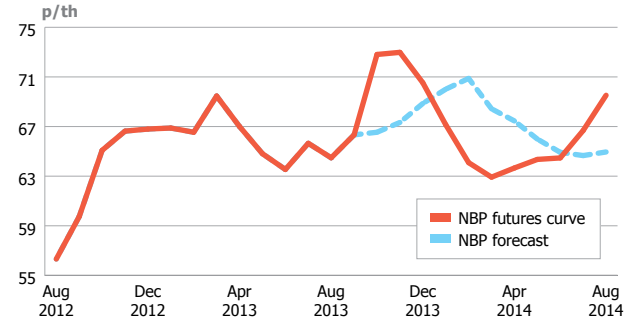
Source: ICE, NYMEX, *GA* estimates

FIGURE 2 NBP and Henry Hub



Source: ICE, NYMEX, *GA* estimates

FIGURE 3 NBP futures and forecast



Source: ICE, NYMEX, *GA* estimates

for gas will gather pace moving into the winter months; however, year-on-year demand is expected to fall by 1% in OECD Americas.

- Many regions of the United States, including Middle Atlantic and New England, will once again face supply tightness this winter, despite healthy gas storage levels in the country as a whole. This is a result of regional variations in storage levels, together with gas pipeline constraints.
- The strengthening US dollar is making LNG imports expensive for large consumers in Latin America such as Brazil, Argentina and Mexico. However, the countries have little choice but to increase reliance on imported gas as curbing demand will adversely affect their economies.
- Growing LNG demand in Latin America could potentially create supply constraints in the region as demand is also growing in Northeast Asia. A month-long shuttering of the Atlantic LNG Train 3 in Trinidad and Tobago from 3 September will exacerbate the tightness in the short term.

Middle East & Africa

- Higher oil prices and a declining Turkish lira are weighing on Turkish gas demand. With the government toning down the country's GDP growth estimates for this year and the next, the prospect for a resurgence in gas demand is unlikely.
- Many countries in the Gulf Cooperation Council are finding it increasingly difficult to fulfil growing domestic demand and meet gas export obligations at the same time. The situation is likely to deteriorate, making the group increasingly reliant on imported gas.
- LNG suppliers in the region will come under renewed pressure to meet demand from both Northeast Asia and Latin America during Q1 2014. The quarter coincides with peak heating-demand in Northeast Asia and air conditioning-related demand in South America.

METHODOLOGY

Disclaimer

Please note that forecasts and price information provided in *Global Gas Analytics* are for information only. The indices and forecasts represent the opinion of *Interfax* market analysts, and *Interfax* makes no representations or warranties, implied or otherwise, as to the accuracy of the information contained herein, or for the reliability and accuracy of the forecasts provided. Despite the best efforts of *Interfax*, it does not guarantee that any information contained is accurate and up-to-date. It is the sole responsibility of the user for any decision they may take based on the information provided herein. *Interfax* cannot accept any liability, direct or indirect, for any inaccuracies within or omissions to any content provided on or as a result of using the forecasts contained herein.

Indices

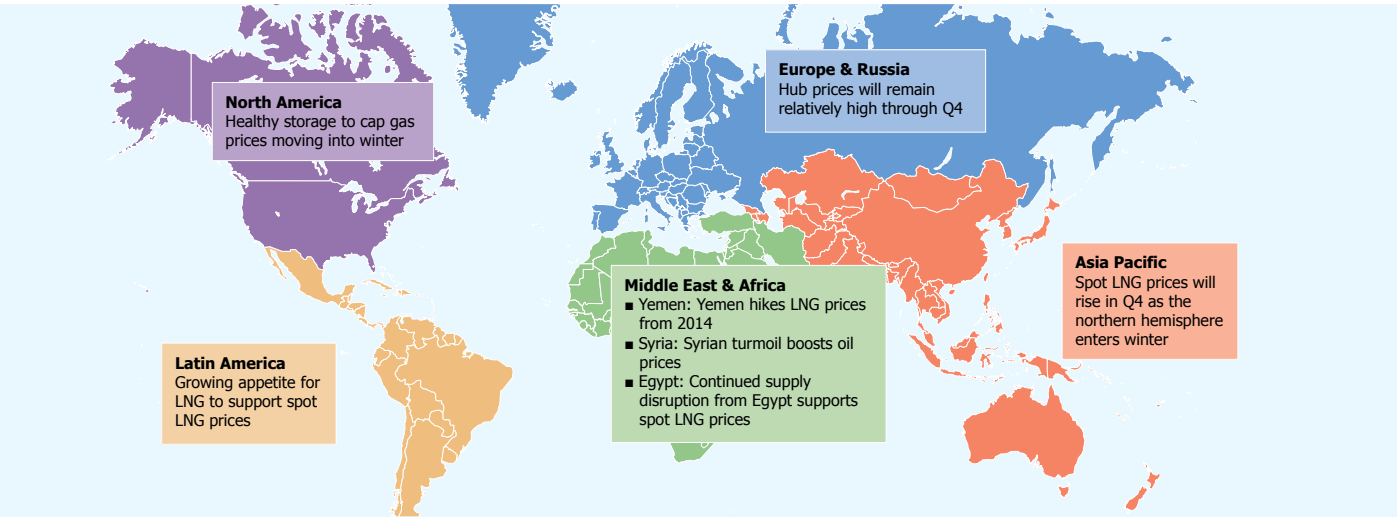
The *Interfax* gas indices express standardised values for gas traded relative to a 2010 base period. The aim is to allow meaningful comparison of gas values across regions, and to identify broad trends in the overall price.

Values are normalised to reflect the base year = 100, with current market values expressed as a multiple of this base value, with weightings in the basket based on known indexation patterns in each region.

Gas price forecasts

Global Gas Analytics bases its gas price forecasts on an analysis of market fundamentals. Although spreadsheets are used to analyse the suitability of various forecasting measures, and to assist analysts in coming to a view on the market, the forecasts are not the result of a forecasting model. The forecasts are based on analysis of supply and demand trends, supplemented by technical analysis and Commitment of Traders data published by the Commodities Futures Trading Commission. *Interfax* analysts are not registered investment advisers, and the forecasts contained herein reflect an opinion on market direction and are not provided as investment advice.

FORECAST HIGHLIGHTS



- Asian LNG spot prices will rise above $16.50/MMBtu going into the winter season as heating demand boosts gas consumption in the region. Asian LNG spot prices have come off the highs seen in late July, but the lull in prices is expected to be temporary.
- Demand for imports will support increased spot prices in Northeast Asia during Q4. While requirements for imports in Japan have fallen on an annual basis, reduced nuclear generation in the country will support the need for more spot cargoes before the end of the year.
- NBP day-ahead price will increase moving into the winter months. Average NBP prices are likely to be around 70 p/th in Q1 2014. Day-ahead prices at the TTF and NCG will also rise during the upcoming winter.
- The markets in Europe will have limited flexibility to react to short-term demand peaks as indigenous production declines and storage remains inadequate in some countries. This, combined with limited additional LNG imports could create supply tightness for major Northern European consumers. Dependence on Russian imports will continue.
- Spot LNG prices in Latin America will remain high during Q4 on the back of strong demand from large consumers such as Brazil, Argentina and Mexico. The situation is not expected to change in Q1 2014 either, as competition to secure additional cargoes intensifies in both Latin America and Northeast Asia.
- Henry Hub futures will receive support as heating-related demand picks up moving into the winter season. Healthy storage levels will limit price gains, but regional variations in prices are expected based on local factors.
- The growing gas glut in western Canada has caused the AECO-Henry Hub price differential to widen. The spread is unlikely to narrow before the onset of the winter when an increase in heating-related demand will reduce the glut.
- Oil prices will decline to around $108 per barrel by the end of the year, and will average around $110.9/bbl in 2014.

TABLE 1 Gas price forecasts ($/MMBtu)

Commodity	Jul 2013	Aug 2013	Sep 2013	Oct 2013	Nov 2013	Q4 2013	Q1 2014	Q2 2014	Q3 2014	2014
UK NBP	9.96	10.00	10.39	10.42	10.55	10.59	10.93	10.36	10.26	10.57
Dutch TTF	10.02	10.03	10.30	10.34	10.46	10.49	10.70	10.62	10.69	10.84
Zeebrugge	10.04	10.03	10.32	10.33	10.45	10.51	10.87	10.49	10.42	10.67
German import price	10.70	10.94	10.92	10.94	10.90	10.89	10.72	10.70	10.85	10.79
Japan Korea Spot	15.40	15.30	15.75	16.25	16.75	16.83	17.97	16.75	16.40	16.83
Japan import price	16.20	16.10	16.60	16.10	16.30	16.20	16.37	16.90	16.90	16.78
Henry Hub	3.70	3.40	3.60	3.70	3.80	3.80	4.00	3.73	3.87	3.90

Interfax indices and forecasts are for information purposes only, and should not be relied on for investment decisions. For details of methodology and legal disclaimer, see page 4 of *Global Gas Analytics*.

TABLE 2 Gas future market curves ($/MMBtu)

Commodity	Oct 2013	Nov 2013	Dec 2013	Jan 2014	Feb 2014	Q1 2014	Q2 2014	Q3 2014	Q4 2014	2015
NBP (ICE Futures)	10.38	10.80	11.13	11.33	11.35	11.22	10.06	9.97	10.74	10.28
Henry Hub (CME/NYMEX)	3.68	3.76	3.90	3.99	3.99	3.98	3.89	3.96	4.09	4.13

For regional detail and local currency forecasts, see regional commentaries. Values in this table reflect the daily settlements on 13 September.

PAGE INTENTIONALLY LEFT BLANK

GLOBAL OUTLOOK

FUNDAMENTAL SUPPLY/DEMAND DRIVERS

Requirements for imports will rise in Asia and Europe at the start of winter, while demand in North America is expected to fall.

Asia Pacific

- Demand from the leading markets in Asia Pacific is rising and growth of around 6% is estimated in Q4 on an annual basis.
- While demand has been rising in other major markets in the region, it has fallen so far in Japan. However, as winter without any nuclear generation is looking like a strong prospect, demand declines could ease in late 2013.
- Production in Australia and China is continuing to grow and continued increases will be seen through the remainder of 2013. In India, the rate of supply decline has softened; however, it is still high – at around 15% year on year.
- LNG imports into the region have risen overall. While Japan is likely to need more cargoes before the end of 2013, South Korea is well supplied through November, and its requirements in December will depend on the weather.

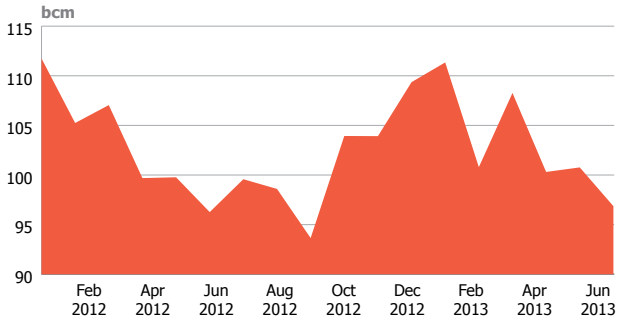
Europe

- Total demand from the top six markets in Europe will decline by around 3% on an annual basis in Q4. Germany will be an exception to this trend with growth expected through H2.
- Indigenous European production is continuing to fall. Rates of decline in the UK in H2 will be more moderate than last year, with a drop of around 8% estimated.
- Storage remains a critical issue for France and Germany in particular. While gains in restocks have been made, the pace of net injections has not been fast enough to ensure sufficient stores will be in place ahead of winter. Time to refill is running out. Smaller markets in Northern Europe are also facing risks of storage shortages this winter.
- Russian supplies into Europe have continued to increase on an annual basis. The region remains heavily dependent on imports from Russia, and this dependence will persist in 2014.

Americas

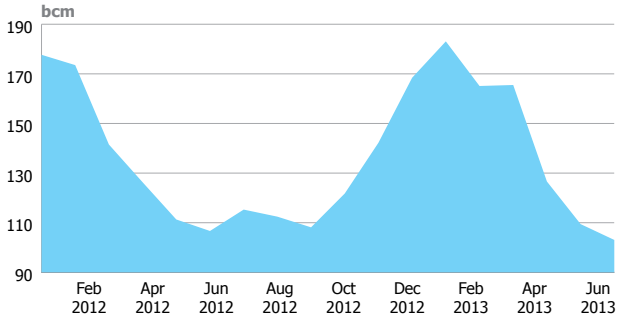
- The outlook for a mild winter could limit the upside in weather-related demand in the United States and Canada through Q4 2013 and into the start of 2014. Without heating requirements boosting demand, North American gas consumption will fall on an annual basis this winter.

FIGURE 1 OECD production, January 2012-June 2013



Source: IEA

FIGURE 2 OECD demand, January 2012-June 2013



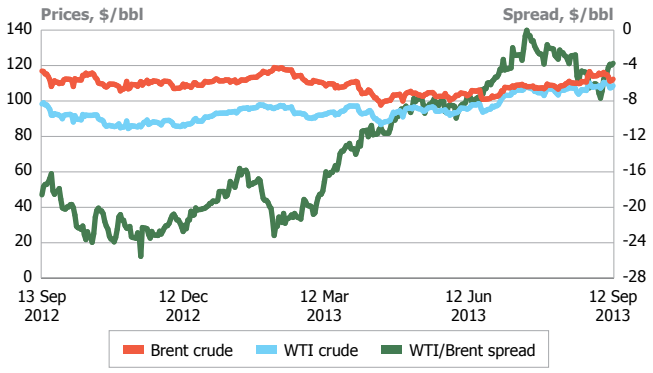
Source: IEA

- Gas storage volumes in North America have risen over recent weeks, and net injections will be seen through September.
- US production levels have been flat in 2013, a trend which is likely to persist through Q4. In South America, *GA* estimates the combined output from Brazil, Argentina and Mexico will fall in Q4.
- Planned maintenance at Atlantic LNG is expected to support supply tightness in the LNG market through the remainder of September and into October.

OIL MARKET OUTLOOK

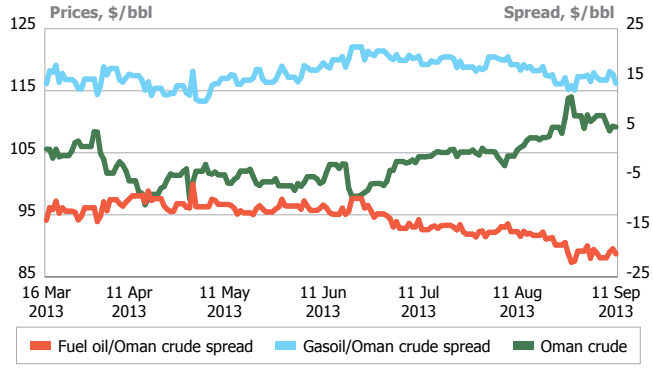
- World oil prices strengthened further in September as geopolitical tensions mounted over Syria.
- ICE Brent futures averaged $113.75/bbl in September to date, having hit intraday highs above $117/bbl on 6 September. ICE Brent averaged $110/bbl in August, up from $108/bbl in July. The front-month contract currently stands at $112.75/bbl.
- Crude oil's strength and recent volatility has been largely tied to the complex wrangling over how to respond to President Bashar al-Assad and his regime's alleged use of chemical weapons in the civil war in Syria.
- Oil futures dropped from their peak levels as United States President Barack Obama backed down from immediate military action against Damascus.
- Recent gains were pared further, when Russia proposed a plan, under which Syria would give up its stockpile of chemical weapons if the US said it would not attack.
- Although the prospect of immediate action has receded, it is still too early to completely rule out an attack on Syria, although this appears increasingly unlikely.
- Even though Brent prices have not yet broken out of their familiar band around $110/bbl, daily volatility has increased because of these tensions, and the backwardation in the market has steepened as oil supply risk boosts the premium held by oil for prompter delivery.
- US crude oil futures also strengthened, but less than Brent. The discount for US benchmark WTI to ICE Brent widened to $7.50/bbl in early September, having averaged $3.90/bbl in August. The spread narrowed to parity in July as new pipeline capacity relieved a glut in oil supply at Cushing, Oklahoma.
- The unstable situation in Syria reignited fears that the 15 million b/d of oil that passes through the Strait of Hormuz might be disrupted if the conflict grows. Syria has a land border with Israel, which is locked in a war of words with Iran, Syria's main ally in the region. Iran has threatened in the past to block the strait if it is attacked.
- Supply disruption from OPEC producers has already tightened the market and demand growth appears to be resuming.
- Libyan exports have dropped sharply as protests cut production to as little as 250,000 b/d in September, the lowest levels since the ousting of the country's former leader Muammar Gaddafi.
- A series of force majeures in Nigeria have heightened the anxieties about supply risk. Iraqi oil production has also dropped because of planned maintenance at the southern Basra oil terminal.
- Crude oil strength pushed up the outright price of petroleum products used in oil-indexed gas contracts. But crack spreads – reflecting the gap between oil products and the crude oil from which they are made – were mixed in September.
- Diesel crack spreads look set to strengthen in Q4 as winter restocking demand kicks in, while fuel oil cracks have been weak despite tight supplies of medium sour crude oil.

FIGURE 3 Spread between WTI and Brent crude futures



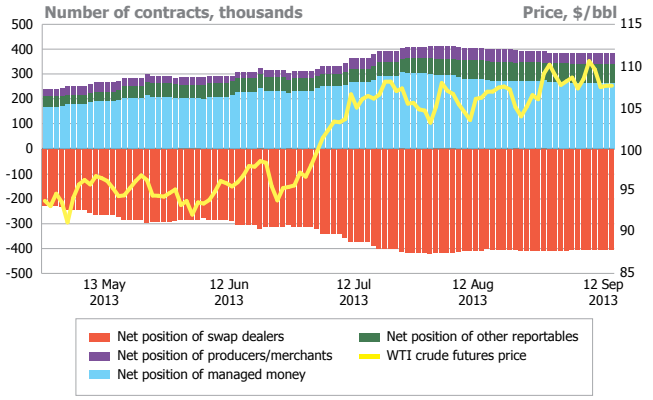
Source: NYMEX, ICE

FIGURE 4 Singapore fuel oil and gas oil crack spreads



Source: DME, Reuters

FIGURE 5 Disaggregated CFTC net positions in WTI crude futures



Source: NYMEX, CFTC

INTERFUEL COMPETITION

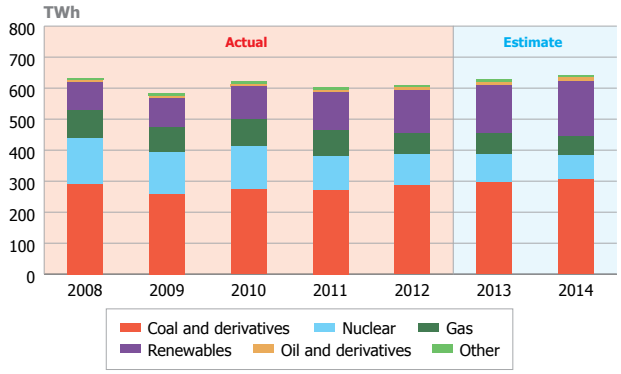
Gas vs. renewables, coal: Gas in power faces challenges from Germany's political circles

- With the German federal elections scheduled for 22 September, politicians are still grappling with presenting a credible energy plan. Meanwhile, utilities are bracing themselves for further financial pain given strong public opposition to fracking, growing subsidies for renewables, and the government's resistance towards nuclear.
- Gas in power has become a victim of political indecision as utilities such as E.On and RWE have recently started shuttering gas-fired generators in the country. Gas use in power generation is unlikely to revive.
- The share of gas in Germany's power generation portfolio has declined by 33% – to 99.5 TWh – in 2012 from 2008. *GA* expects the decline to continue and by 2014 the fuel will only be used to generate around 79 TWh of electricity.
- Germany has the fifth-largest gas market in the world. But the country is heavily reliant on gas imports from Russia, Norway and Netherlands. The fuel does not come cheap either, as a large portion of it is oil linked, which makes it difficult to compete with cheap coal or heavily subsidised renewables.
- Carbon prices in Europe have also hindered the growth of gas in the German power sector. The falling price of carbon emissions has been a double whammy for the sector.
- With an oversupply of carbon permits in the market, utilities have become inclined to burn more coal, the price of which is declining. Rotterdam coal prices – the European benchmark for coal – averaged $80.9/ton in the first eight months of 2013, which was a decline of 14% on an annual basis. Meanwhile, the EU Allowance futures on ICE fell sharply by 51% – to €3.44/ton – during the same period. *GA* estimates coal will be used to generate 296 TWh of electricity in 2013 – an increase of 3.5% compared with 2012.
- The German government has subsidised renewables in an effort to reduce the country's carbon footprint. The share of renewables in power generation has risen by 51% – to 137 TWh – in 2012 from 2008. *GA* estimates it will grow by 13% this year on an annual basis.
- However, a lack of focus on energy policy and emission-reduction targets in Germany has increased coal demand. This contradicts the government's efforts to promote renewables.

Gas vs. nuclear: The going gets tougher for nuclear in the United States

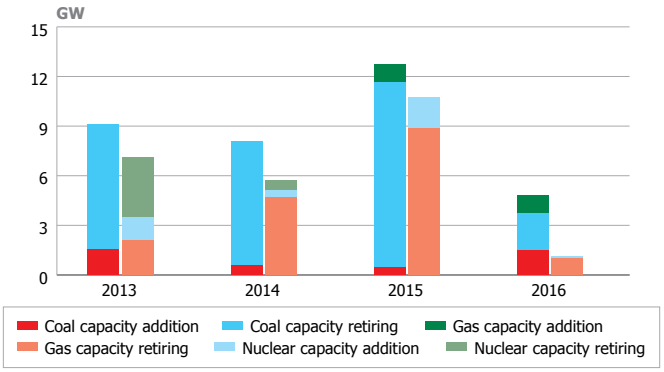
- The decision to close the Vermont Yankee nuclear power plant in Q4 2014 has refocused attention on the strain facing the nuclear industry in the United States. Nuclear has lost the largest share of generation capacity this year.
- Vermont Yankee was the fifth nuclear power unit in the US to be slated for closure. Other reactors facing a similar fate are Crystal River 3 in Florida, Kewaunee in Wisconsin, and San Onofre 2 and 3 in California, all of which are undergoing decommissioning. These are the first nuclear power units to be shut in the country since 1998. *GA* estimates it will take 7.8 bcm/y of gas to replace the total lost capacity, were it to be replaced by gas alone.
- More nuclear plants may close in the next few years. The Nuclear Regulatory Commission is considering licensing renewal applications for 14 nuclear units in the country, and another 15 applications are expected soon. The list includes Indian Point 2 and 3 in New York, and Diablo Canyon 1 and 2 in California, which may find it difficult to renew their licences.
- Low gas prices, high maintenance costs and stringent safety regulations were cited as reasons for shuttering the Vermont Yankee plant. Local opposition to the plant had grown since the disclosure of a leak of radioactive tritium in January 2010, with the state's governor leading the fight to close it.
- The nuclear plant accounted for almost 75% of Vermont's power generation capacity, with the rest coming from hydropower. However, hydro will not gain much from the closure, as it cannot be relied upon for peak-load demand. Therefore, Vermont will have to import power from Canada and neighbouring states in the short-to-medium term. Even in the short term, gas is likely to benefit from the closure, as it accounts for almost 50% of power generation in New England.
- In the longer run the state will need its own gas-fired generation capacity, to cope as power demand grows, as importing electricity entails transmission losses. Vermont's total energy consumption is the lowest in the country, and *GA* estimates 1.1 bcm/y of gas will be needed to replace the capacity lost because of the closure of the Vermont Yankee plant.

FIGURE 6 German power generation portfolio



Source: IEA, *GA* estimates

FIGURE 7 Net summer power generating capacity in the US



Source: US Nuclear Energy Institute, EIA

CONSENSUS OF ANALYST FORECASTS

Henry Hub

According to our latest poll, average Henry Hub prices will rise to around $4.6/MMBtu in 2015.

- "Although significant impact has not materialized, the height of the hurricane season does pose more risks to Gulf production in the near term. Overall, we believe prices should trade around the $3.50 level before the winter season. For Q4, we expect a slight seasonal recovery of prices to $3.80/MMBtu." Barclays Commodities Research, *Commodities Weekly*, September 2013
- "Combining all three metrics – cycle, value and technical – we think natural gas should trade sideways for the time being." Credit Suisse, Commodity Research, *Research Monthly*, August 2013

TABLE 1 US gas forecasts ($/MMBtu)

	Ave. 2013	Ave. 2014	Ave. 2015	Q3 2013	Q4 2013	Q1 2014	Q2 2014	Q3 2014
Average	3.90	4.25	4.57	3.86	4.16	4.31	4.20	4.27
High	4.79	4.75	5.25	4.20	4.78	4.99	4.60	4.75
Low	3.50	3.88	4.00	3.5	3.85	3.81	3.90	4.00

Source: *Global Gas Analytics* poll of analyst forecasts

- "Positive weather effects have helped to push gas prices higher, with the probability of gas being below $4/mmBtu now at 49%." Deutsche Bank, Markets Research, *Commodities Weekly*, September 2013

Brent

Our latest poll shows average prices for Brent falling to around $103/bbl in 2015.

- "We believe Brent crude price and curve structure are justified at current levels for the balance of 2013. Supply disruptions and supply risk are dominating price action. If supply risk subsides, Brent should pull back to the $105 - $110 per barrel range." Macquarie Commodities Research, *Jurassic Spark – A market dominated by supply risk*, September 2013
- "In the near term, the uncertainties about the Fed policy and developments in the Middle East could keep oil prices elevated. In fact, a serious test of the February high could be possible in the very near term." ABN AMRO Group Economics, *Energy Monitor September*, September 2013
- "Extensive oil supply disruptions in the North Sea, Middle East and Africa, most importantly Libya, present significant risk to our price forecasts. If Libyan output does not promptly bounce back above 1 mn b/d, Brent could temporarily spike back to $120/bbl, in our view." Bank of America Merrill Lynch, *Global Energy Weekly*, September 2013

TABLE 2 Brent crude oil forecasts ($/bbl)

	Ave. 2013	Ave. 2014	Ave. 2015	Q3 2013	Q4 2013	Q1 2014	Q2 2014	Q3 2014
Average	107.8	106.0	102.9	107.0	107.9	109.6	106.6	108.2
High	111.5	117.5	115.0	113.0	117.0	117.0	113.0	118.0
Low	105.0	95.0	90.0	102.3	101.7	101.0	102.0	101.0

Source: *Global Gas Analytics* poll of analyst forecasts

NBP

NBP prices will fall through 2015, according to our latest poll.

- "We have been surprised by the relatively wide spot-to-oil-indexed gas price differential seen in the market. This suggests oil-indexed gas prices for Russian gas may be lower than our current benchmark. This would pose a downside risk to our 4Q13 UK NBP gas price forecast of 81.3 p/th, which assumes near-parity with our oil-indexed gas price benchmark." Goldman Sachs Global Economics, Commodities and Strategy Research, *Commodity Watch*, September 2013
- "With European storage still 9.4 bcm below the level witnessed the same period last year, we will continue to need more Russian gas as neither LNG nor African pipe gas (Algeria or Libya) can relieve this situation. It therefore seems unlikely for prices to go much below the actual 64p/th level." Société Générale, Cross Asset Research, *European Gas & Power Drivers*, August 2013
- "We are increasing our Brent forecast by USD 3/bbl to USD 109/bbl for FY13. Our European gas price forecasts change to reflect the revised oil price profile." VTB Capital, Global Energy, *Energy Price Update*, September 2013

TABLE 3 UK gas forecasts (p/th)

	Ave. 2013	Ave. 2014	Ave. 2015	Q3 2013	Q4 2013	Q1 2014	Q2 2014	Q3 2014
Average	67.06	66.73	65.92	64.11	73.69	71.55	64.91	65.72
High	69.86	70.00	69.70	66.08	81.30	72.00	72.00	72.00
Low	63.60	63.10	61.90	62.00	68.00	70.70	60.63	61.17

Source: *Global Gas Analytics* poll of analyst forecasts

NOTE: The consensus forecasts in this section are provided as context, so that subscribers can compare the gas price forecasts in *Global Gas Analytics* with those from a range of well-known gas market analysts.

ASIA PACIFIC

Great Wall of China. (Sandra Kühr/stock.xchng)

FUNDAMENTALS

Economic overview

The leading economies in the region have had strong economic results recently, supporting expectations for growth during H2.

The latest economic indicators for China are positive. The official figures for August show manufacturing PMI reached 51, a rise from the 50.3 recorded in July. The Asia Development Bank's (ADB's) latest outlook for GDP is for 7.7% growth in 2013 and 7.5% in 2014. This represents a drop from the previous forecast and is relatively low for China when compared with recent years. However, if this growth is achieved, it will represent a stable economic climate and allow for expansion in the energy sector, including the gas market, in Q4.

In Japan, revised growth for Q2 supports improved economic projections for the year. The government released revised figures for Q2 in early September, which saw the annualised GDP growth rate for the quarter rise from 2.6% to 3.8%. This is a considerable increase. The recently released updated ADB GDP forecast for 2013 was also an improvement, with GDP now expected to grow by 1.8% – up from 1.2% in the previous forecast. The GDP forecast for 2014 remained unchanged at 1.4%. Japan is still dealing with ongoing nuclear problems in Fukushima. Reduced nuclear output, combined with expectations for economic expansion, will support demand for gas and LNG imports.

Economic growth in South Korea looks set to continue as demand for exports picks up. Exports grew by 7.7% on an annual basis in August to reach $46.4 billion. This will support growth in Q3 as exports account for more than half of GDP. The latest official figures for South Korea show the economy grew by 2.3% in Q2, in line with the Bank of Korea's forecast. Based on steady growth in Q2 and expectations for a continuation of this during H2, the economic climate will support gas sector growth for the remainder of the year.

Gas consumption

Gas demand in the region is rising and the outlook is for strong annual demand growth this winter.

Gas consumption is estimated to have grown by 6% over the first three quarters of the year, led by China, where consumption is estimated to have grown by 14%. Regional growth has also been supported by most other major markets in the region, including South Korea, where gas consumption over the first nine months of the year is up by around 6% on annual basis. According to *GA* estimates, demand from the top five markets will grow by around 6% in Q4. If the start to the winter is particularly cold, the rate of growth could be higher.

Although gas demand in Japan has been falling this year, there is potential for moderate uplift in consumption as the country's only two operating nuclear plants have been shut for maintenance. Demand fell by around 3% on an annual basis between January and September, according to *GA* estimates. Targets to reduce energy consumption in 2011 and 2012 have changed demand patterns, this has been key to the drop in demand this year. However, by mid-September, Kansai Electric's two operational reactors at the Ohi plant, reactors 3 and 4, had

ASIA PACIFIC HIGHLIGHTS

- Spot LNG prices may have cooled to around $15-15.5/MMBtu, but this will not last for long
- Demand in Asia Pacific is rising and consumption in Q4 will be around 6% higher than last year
- Australia and China continue to increase production while the decline in India has softened
- The cost of LNG in local currencies is rising for Asia Pacific importers

TABLE 1 GDP forecast, 2013 and 2014

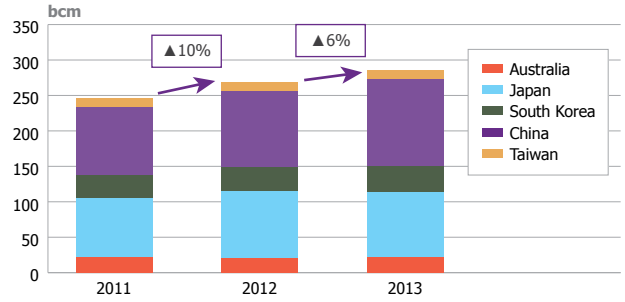
	ADO 2013	2013 Revised	ADO 2014	2014 Revised
Japan	1.2%	1.8%	1.4%	1.4%
China	8.2%	7.7%	8.0%	7.5%
India	6.0%	5.8%	6.5%	6.5%
ASEAN 5	5.4%	5.2%	5.7%	5.6%

ADO 2013 – Asia Development Outlook, April 2013. ASEAN 5 = Indonesia, Malaysia, Philippines, Thailand, Vietnam.
Source: Asia Development Bank – Outlook Supplement, July 2013

shut down. This has left Japan without nuclear capacity ahead of winter, and it could remain so through Q4. Even if some reactors do come back online before February 2014, nuclear generation this winter will be limited at best. While utilities are expected to switch to coal where possible,there are limits to the upside available from coal-fired generation.

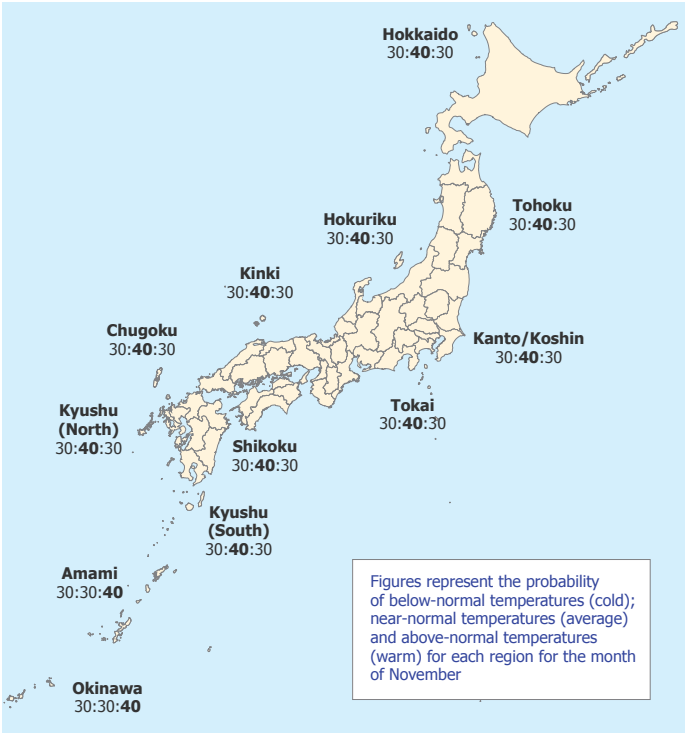
At present, Japan's weather outlook for November is for a strong chance of normal temperatures. While average or above-average temperature will not support a boost in gas demand, if temperatures are colder than average in November or December, it will support gas consumption. While total demand in 2013 is expected to be lower than that seen in 2012, the decline in consumption could ease before the end of the year.

FIGURE 1 Asia Pacific gas demand, January-September 2011-2013



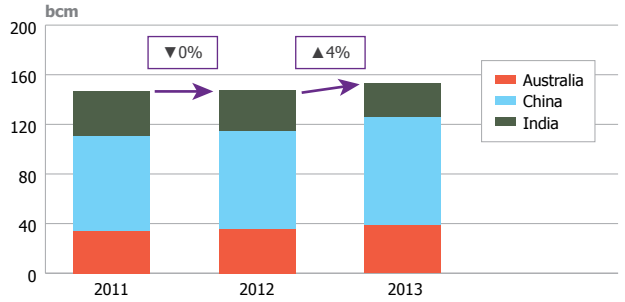
Source: IEA, national statistics, *GA* estimates

FIGURE 2 Japan's weather outlook, November 2013



Source: Japan Meteorological Agency

FIGURE 3 Asia Pacific gas production, January-September, 2011-2013



Source: IEA, national statistics, *GA* estimates

Storage

Storage levels in Japan were lower at the start of summer this year than in 2012, according to International Energy Agency (IEA) data.

Japan's storage volumes are down compared with the same time in 2012. Closing stocks fell on an annual basis in May and June. Closing storage inventories in June were flat month on month and down by 2% on an annual basis. Japan will require additional spot cargoes to meet demand this winter, even without severe cold weather.

In South Korea, storage capacity is more than 90% full, according to Kogas. This puts the country in a safe position ahead of winter. Solid re-injections were achieved through spring and summer as South Korea continued to build stocks. In June, closing inventories were up by 21% on an annual basis. Kogas has been active on the spot market over recent weeks and it is understood that spot supplies, instead of storage, were used to meet peak demand over the summer period. No further cargoes will be required before December, and the need for spot in December will be weather driven. South Korea should enter Q1 in a strong storage position.

Gas production

Production from China and Australia continues to outpace that seen in 2012. In India, the rate of decline has reduced.

Production in Australia rose by around 8% on an annual basis over the first three quarters of the year, according to IEA data and *GA* estimates. Looking ahead to Q4, production in Australia is expected to continue to rise. Rises in domestic conventional gas production have been supported by increased supplies from the Gippsland Basin. Gippsland accounted for around 32% of total conventional domestic gas production between H3 2012 and H2 2013. Production from the basin increased by around 12% on an annual basis during this period.

Other basins which also had significant increases in output during the year to June 2013 included Perth, Bonaparte and Bass. However, as these account for relatively small supply volumes, the impact on total national output was not great. Overall, total conventional domestic output was up by around 4% year on year between H3 2012 and H2 2013.

According to the latest statistics from the Indian Ministry of Petroleum, the rate of decline of gas production has started to fall. The figures for July show an annual decline of 15%. While this is still a significant drop in output, it is an improvement from the higher rates of 17-20% seen earlier this year. Production was still more than 200 million cubic metres below target in July. A number of reasons were cited as the cause of the continued decline. These included commissioning delays, technical

problems and poor levels of demand. *GA* estimates production in Q4 will continue to drop, with a potential decline of around 10-15% likely to be seen.

Gas production is rising in China and is expected to increase steadily through the rest of 2013. Production increased by around 11% over the first nine months of the year, and a similar average rate is estimated for Q4. This situation is the result of improved output from conventional production, which is expected to continue.

China National Petroleum Corp. (CNPC) recently formed its first joint venture with a local government-owned company for the exploration and production of shale. CNPC has a 55% stake in the JV while Sichuan Energy Industry Investment Group holds 30%. The remaining stakes are held by Yibin (10%) and Guolian Industry Investment Group (5%).

While this step into shale is significant for CNPC, progress in the sector remains slow. The government has a target of producing 6.5 billion cubic metres of gas from shale by 2015, but this is unlikely to be achieved. Out of the approximately 16 firms that won exploration licences in 2012, none have made any serious progress in developing their assets. Even plans for exploration from PetroChina and Sinopec, which hold the assets with the best prospects, fall below what will be required to boost production to levels in line with government targets. The prospect of shale gas supplies adding any significant support to total production looks to be increasingly distant.

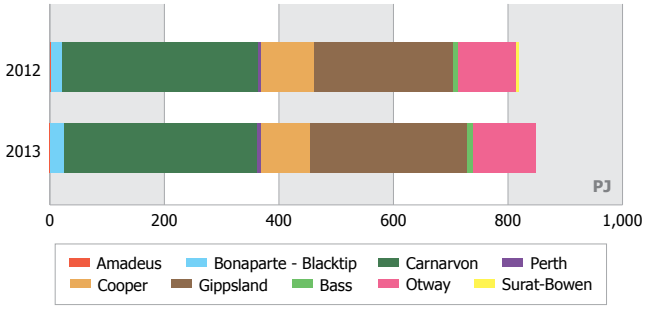
Trade

LNG imports into the region are growing, while in China piped supplies continue to dominate gas imports.

LNG imports into Japan, South Korea, China and Taiwan are estimated to have increased by around 3% over the first nine months of 2013. While imports into Japan are estimated to have fallen by around 2%, according to *GA* estimates, imports into the other leading markets in the region have risen. Looking ahead to Q4, total LNG imports into the top four LNG markets in East Asia are expected to rise. Requirements for additional LNG imports in South Korea will be boosted by growing gas demand in the country which is expected to continue through Q4. In Japan, further spot cargoes are also expected to be needed in the coming months.

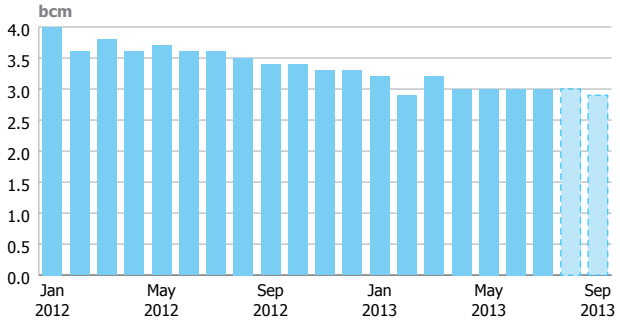
Monthly piped imports into China have been rising by at least 14% on an annual basis since the start of the year. July marked the sixth month in a row where piped import volumes were greater than LNG imports. With Central Asian gas expected to continue to dominate – even as supplies from Myanmar ramp up – estimates are for growth to continue during Q4. Looking out to the longer term, China has recently agreed additional piped supplies from Turkmenistan, expected to start in 2018. While recent announcements from Gazprom have stated that negotiations on piped supplies from Russia to China have progressed, and a gas sales purchase agreement is still targeted for the end of the year, the issue of price remains to be agreed. As price has been the major stumbling block in previously proposed Russia-China pipeline projects, the future of the pipeline remains uncertain despite progress on other points.

FIGURE 4 Domestic conventional gas production in Australia by basin



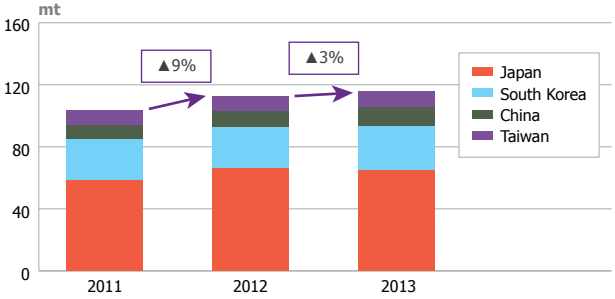
Source: EnergyQuest

FIGURE 5 Indian gas production, January 2012-July 2013



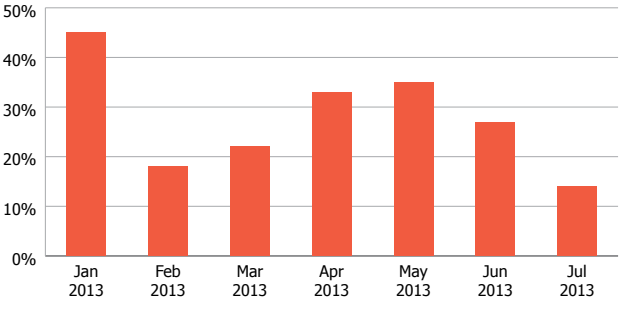
Source: national statistics, *GA* estimates

FIGURE 6 Selected Asian LNG imports, January-September 2011-2013



Source: IEA, national statistics, *GA* estimates

FIGURE 7 Annual percentage growth in China's piped imports, January-July 2013



Source: National statistics, *GA* estimates

PRICE TRENDS

Price overview

Although spot prices have softened in recent weeks, a rebound is expected with high prices still a threat this winter.

Spot prices have come down from summer highs. Average prices traded for deliveries in the coming months have fallen to around $15.25-$15.5/MMBtu. A temporary drop is not unusual ahead of winter. However, even with a dip, prices remain higher than they were at the same time in 2012. In 2012, spot prices for deliveries in November and December were below $14/MMBtu.

Average LNG import prices in July fell for most of the region's major LNG importers. Japan's average LNG import price was $16.2/MMBtu, down by 10% year on year. A similar fall was seen in China, where the average LNG price was $10.8/MMBtu compared with $12/MMBtu in July 2012. The fall in South Korean prices was smaller, at only 5%, with July prices around $15/MMBtu – the same as recorded for June. The latest data for Taiwan shows the average import price in June rose to nearly $15/MMBtu, up by 4% on an annual basis.

Spot, forward and futures markets

As winter demand picks up in the second half of Q4, support for spot prices will rise.

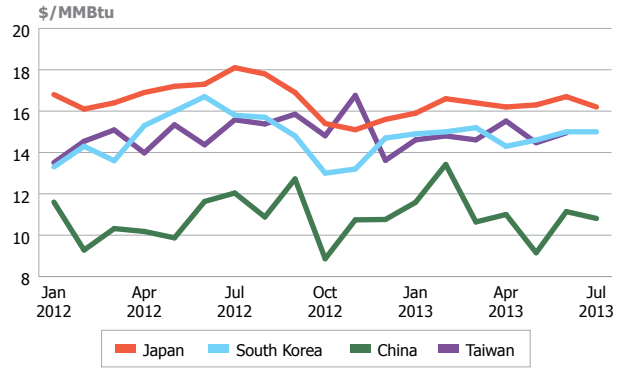
With demand expected to be strong this coming winter, support for spot prices will likely keep average prices higher than last year through Q4. Japan will likely need more cargoes for delivery in November and December. Storage volumes are lower than last year. Additionally, while there is some uncertainty around restarts, Japan could be nuclear free through Q4 as the only two operational Ohi reactors closed for maintenance in September.

South Korea is in a better storage position. Kogas is not expected to buy any further cargoes for delivery before December, and requirements for December will be largely weather dependent. With strong levels of gas in stock, Kogas will only need further spot cargoes for December if the weather is significantly below average. However, looking out to Q1, further spot is expected to be needed.

On the supply side, while there are fewer projects facing immediate disruptions to supply, there has also been little in the way of new supply. This, combined with higher regional demand, is expected to push up spot prices over the winter.

South Korea could be facing higher LNG prices from the start of 2014. Yemen is seeking to raise the price of the LNG it sells to Kogas. This would bring the cost of supplies from Yemen up and raise the typical average monthly price South Korea pays for

FIGURE 8 Asia Pacific LNG import prices, January 2012 - July 2013



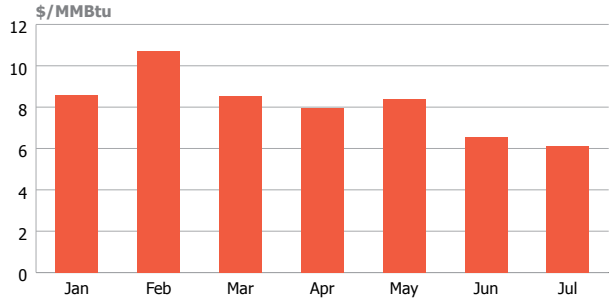
Source: National statistics

TABLE 2 South Korea's LNG imports, July 2013

Country	$ million	LNG, tons	$/ton	$/MMBtu
Australia	49.4	70,334	702	13.56
Brunei	58.0	64,429	900	17.38
Indonesia	227.8	344,799	661	12.75
Malaysia	75.2	170,170	442	8.54
Nigeria	50.9	60,763	838	16.17
Oman	343.1	363,287	944	18.23
Panama	92.3	93,245	990	19.12
Qatar	747.1	784,298	953	18.39
Russian Federation	50.6	63,846	793	15.31
Trinidad & Tobago	110.3	170,586	647	12.48
Yemen	76.1	239,942	317	6.12
Total	1,880.9	2,425,700	775	14.97

Source: Customs statistics

FIGURE 9 Average monthly price of South Korean imports from Yemen



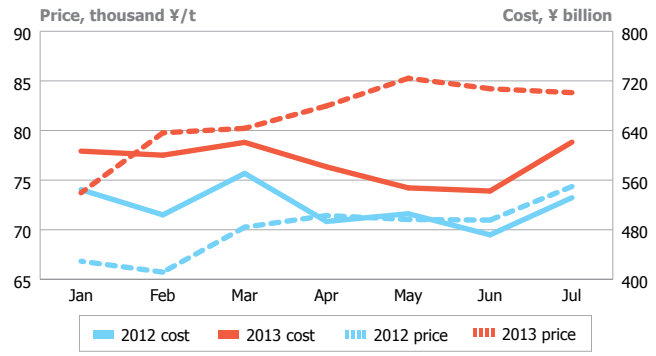
Source: Customs statistics

TABLE 3 Interfax Asian gas forecasts

Commodity	Units	Jul 2013	Aug 2013	Sep 2013	Oct 2013	Nov 2013	Q4 2013	Q1 2014	Q2 2014	Q3 2014	2014
LNG DES Japan Spot	$/MMBtu	15.40	15.30	15.75	16.25	16.75	16.83	17.97	16.75	16.40	16.83
LNG DES Japan Contract	$/MMBtu	16.20	16.10	16.60	16.10	16.30	16.20	16.37	16.90	16.90	16.78
LNG FOB Qatar Netback	$/MMBtu	13.27	13.14	13.64	14.11	14.61	14.70	15.82	14.61	14.27	14.70
Japan Crude Cocktail	$/bbl	103.66	107.66	106.67	105.09	104.50	105.64	111.03	111.12	111.91	110.90
Fuel Oil FOB Singapore	$/t	605.20	606.56	625.22	622.32	619.39	624.32	628.72	624.99	638.43	627.94

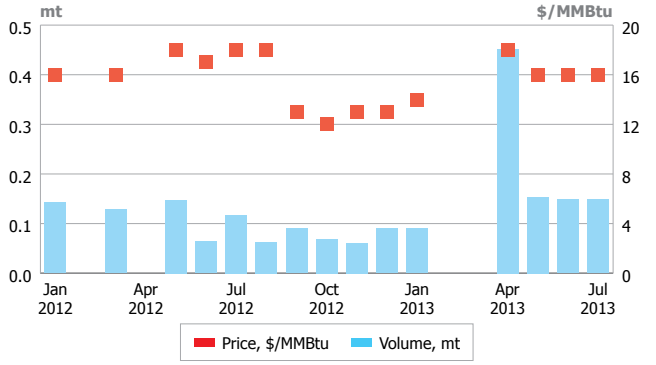
Interfax indices and forecasts are for information purposes only. For details of methodology and legal disclaimer, see page 4 of *Global Gas Analytics*

FIGURE 10 Japan's LNG imports, January-July 2013



Source: Japan customs statistics, *GA* estimates

FIGURE 11 Thailand's LNG imports, January 2012-July 2013



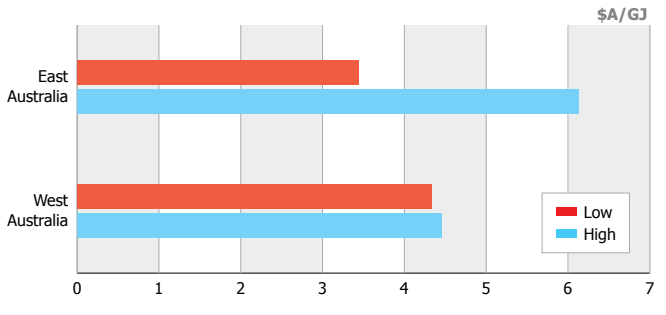
Source: Customs statistics

TABLE 4 Thailand imports, 2013

Month	Country	$ million	LNG, tons	$/ton	$/MMBtu
January	**Qatar**	65.0	90,115	722	13.9
April	**Qatar**	423.5	452,159	937	18.1
May	**Qatar**	71.3	89,987	792	15.3
May	**France**	59.6	63,291	942	18.2
June	**Nigeria**	50.7	58,973	860	16.6
June	**Qatar**	68.8	89,822	766	14.8
July	**Guinea**	50.9	58,798	865	16.7
July	**Qatar**	70.8	89,864	788	15.2

Source: Thailand customs statistics

FIGURE 12 Australian gas prices, Q2 2013



Source: EnergyQuest

LNG. Yemen agreed a new price with other importers, Total and GDF Suez, in late 2012.

According to statistics from the South Korea Customs Service, average monthly prices for LNG from Yemen into South Korea have ranged between $6 and $11/MMBtu so far this year. As volumes of LNG imports have risen on an annual basis in 2013, so too has the total cost. Cost increased by 19% over H1 year on year. The total volume increase over the same period was 17%. Even without a hike from Yemen, costs could rise in 2014.

Japan's total monthly LNG import bill hit a new high in July. According to statistics from the Customs Service, the total cost of imports was ¥621.3 billion ($6.4 billion). This is marginally higher than the previous 2013 high of ¥620.9 billion, seen in March. As the value of the yen has fallen, Japan's import bill has risen, even with a year-on-year drop in the total volume of imports. While the average price of imports has fallen in dollars, the yen value has increased. In July, the average contract price of $16.2/MMBtu represented a 10% drop from the July 2012 price of $18/MMBtu. However, the price in yen in July 2013 climbed by 13% from the same time in 2012. Looking ahead to Q4, the value and price of LNG will continue to climb unless the yen picks up in value. The bill will rise even with continued declines in the levels of imports, and a rise in import volumes could be seen over the coming months.

As Thailand's LNG imports have risen in volume over 2013, so too has their cost. Over the first seven months of 2013, total volumes reached nearly 1 mtpa, according to the latest government trade statistics. This is a 65% increase over the volumes imported over the same period in 2012. Estimates for the period between January and August are for imports to have reached 1.07 mtpa. The total cost increase of LNG imports in Thai baht between January and July 2013 compared with the same period in 2012 was around 55%. The increased cost and volume this year has partly been driven by the particularly high volume of imports in April.

As Thailand imports all of its LNG on a spot basis, monthly import prices vary considerably. So far this year, average monthly prices have ranged between $14 and $18/MMBtu. Thailand's first long-term contract with Qatar, for 2 mtpa, starts in 2015.

Wholesale and retail markets

Australia's domestic gas prices are rising, and are expected to continue to do so.

Gas prices in both eastern and western Australia are continuing to rise in 2013. According to data from EnergyQuest, prices in the east of Australia ranged between A$3.44 ($3.13) and A$6.13/GJ in Q2. At the high end, this marks a 61% increase from Q2 2012. In west Australia, prices ranged between A$4.33 and A$4.46/GJ in Q2. The average price achieved by Woodside in west Australia was at the lower end of regional prices, at $4.33/GJ; however, this still represented a 3.3% rise from prices in Q1. Apache's west Australia price of A$4.46/GJ was an increase of 8.3% over the first quarter. Further prices hikes in Australia are expected over the next few years as domestic prices move towards international prices. Forecasts for east Australia are for prices to reach around A$9/GJ.

EUROPE & RUSSIA

Red Square, Moscow. (Vladimir Fofanov/stock.xchng)

FUNDAMENTALS

Economic overview

The economic climate is improving in the UK and the eurozone, with growth in the UK and Germany expected to be among the strongest in the region.

The German economy will expand in H2 2013, with the construction sector and strong domestic demand supporting growth. Germany's GDP is forecast to grow by 0.7% in 2013, according to the latest outlook from the OECD. The latest updates for Q2 2013 from the European Commission show that, in Q2, GDP growth was 0.5% on an annual basis. Growth in the manufacturing and industrial sectors through the rest of the year will support increased gas demand over the coming months.

The UK's economic recovery is picking up pace. The latest figures for Q2 growth and forecasts for the rest of the year suggest improvements in the country's economic performance are likely to continue. Recently revised data from the commission shows that on an annual basis, the UK's GDP grew by 1.5% in Q2. Annual growth was forecast at 1.5% in the OECD's interim assessment, released at the start of September. Support for this growth was seen in July and August when the service PMI was 60.2 and 60.5 respectively. The August PMI was the highest since the end of 2006. While the economic climate improves, there could be some uplift for the energy market, but this is not expected to follow to an increase in gas demand.

In France, while latest PMI results for August showed contraction in the service and manufacturing sector, modest GDP growth is still being forecast for the year. The OECD's latest 2013 forecast is for GDP growth of 0.3% in 2013. This is the same rate of growth as achieved in Q2 2013 according to the latest figures from the commission. However, the composite PMI for August – which represents the private sectors, including the manufacturing and service sectors – was 48.8, just below the level needed for growth. Without a boost from weather-related demand, consumption will likely contract in H2 2013.

Gas consumption

Total demand from the top markets in Europe will decline in Q4, but consumption in Germany is expected to buck this trend.

Demand in the UK has been falling on an annual basis for several years, and is expected to fall in Q4 2013. *GA* estimates demand in Q4 will drop by around 5% on an annual basis. However, some quarters have bucked the annual demand decline. When they have, it has generally been weather related. In Q4 2012 and Q1 2013 demand increased on an annual basis by 5% and 12%, respectively. The particularly sharp jump in Q1 was driven by severe and late cold weather.

Looking out to the winter period, while it is still early for seasonal forecasts, the Met Office's three-month outlook, which runs from September through November, states that overall, temperatures in Northwest Europe are likely to be above average. However, the chance of colder-than-average temperatures, particularly in November, is also noted. This view

EUROPE & RUSSIA HIGHLIGHTS

- While demand from the top markets in Europe will fall by around 3% in Q4, growth is expected in Germany
- Indigenous production is continuing to decline faster than demand
- Net injections have been seen in September but stocks in Germany, the UK and France remain low for the time of year
- Average NBP prices will rise to around 70 p/th in Q1 2014

TABLE 1 Annual percentage change in GDP growth rates by quarter, Q3 2012-Q2 2013

	Q3 2012	Q4 2012	Q1 2013	Q2 2013
Germany	0.9	0.3	-0.3	0.5
Spain	-1.7	-2.1	-2.0	-1.6
France	0.0	-0.3	-0.5	0.3
Italy	-2.6	-2.8	-2.3	-2.0
Netherlands*	-1.5	-1.5	-1.4	-1.8
UK	0.1	0.0	0.3	1.5

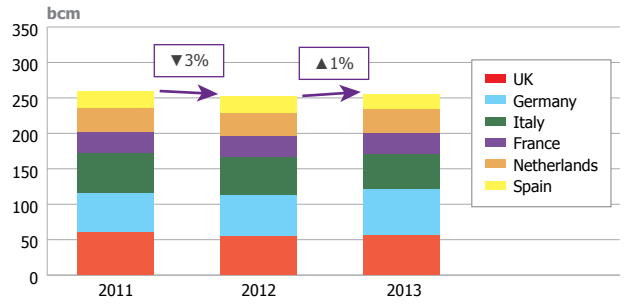
*Growth rates are calculated using the trend component.
Source: Eurostat - September update

is supported by other forecasts for the region. Even with normal temperatures, markets will be likely to need to draw down on stocks in November. There are real risks of a tight market in Q4.

Total demand from the top-six markets in Europe is expected to fall by around 3% on an annual basis in Q4. While declines are expected for total demand from the major markets, year-on-year increases in consumption in Germany are anticipated. An improved economic climate should work to boost demand from the industrial sector.

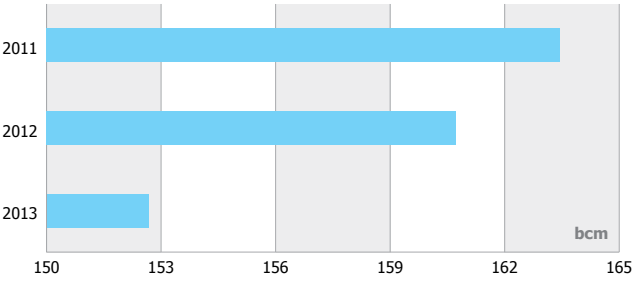
In the Netherlands, demand has grown over the first half of the year. However, according to the latest statistics, demand in June fell by 6% on an annual basis. An annual decline in Dutch consumption is expected to be seen in Q4.

FIGURE 1 Demand in key European markets, January-September 2011-2013



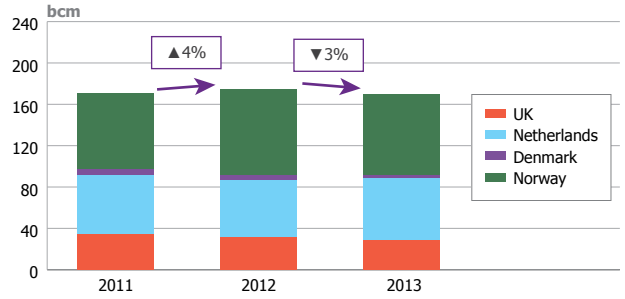
Source: IEA, national statistics, *GA* estimates

FIGURE 2 Estimated H2 demand in Europe's top six markets



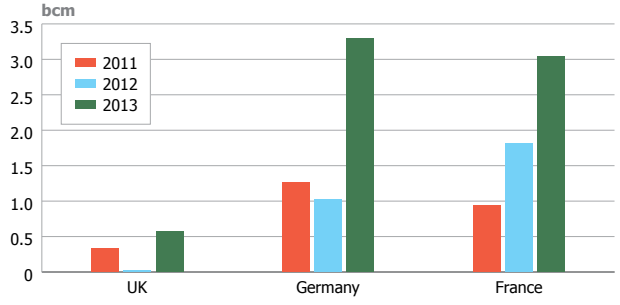
Source: IEA, national statistics, *GA* estimates

FIGURE 3 Production for key European suppliers, January-September 2011-2013



Source: IEA, national statistics, *GA* estimates

FIGURE 4 Storage gap in key European markets, September-November



Source: GIE Europe

Storage

Despite gains in stock levels over the past month, the increase in gas in store has been too slow to reduce the risk of leading markets having low stocks at the start of winter.

While the storage situation in key markets in Europe is improving, it is not improving fast enough. As of early September, stocks are still down on an annual basis in the leading markets of the UK, Germany and France. This is the case both in terms of levels of gas in store and the percentage share of capacity. At the start of September 2012, the UK's storage was 98% full; this year, it was 85%. In Germany stocks were 89% full in early September 2012 compared with just 75% at the start of this month, and in France the 2012 figure was 72% compared with 63% at the start of September this year. The risk of Germany and France in particular entering the winter with insufficient gas in store is high. Smaller Northern European markets, such as Austria, are in a similar storage position.

To reach similar levels of gas in store at the start of November as were achieved in 2011 and 2012, Germany and France both still need more than 3 billion cubic metres, while the UK needs around 600 million cubic metres. This represents a total of around 6-7 bcm of gas needed for restocks for the three markets in September and October. This is around 4 bcm more than required at the same time in 2012.

Net injections in the UK and Germany over August were higher than last year, but in France, stock building over the month was less than seen at the same time in 2012. Even for the UK and Germany, while more gas was injected, the total for the month was not enough to materially improve either country's storage position. The time to close the gap is disappearing.

Gas production

Increases in Dutch supply will not be sustained through H2. Total indigenous production from Europe's key supplies is continuing to decline.

UK gas production has been declining and will continue to do so through H2 2013. Gas production in H2 2013 will decrease by around 8% on an annual basis, according to *GA* estimates. This will be consistent with the annual decline expected for the full year. This fall will be in spite of new fields coming online. A recently released report from Oil & Gas UK said total oil and gas production in 2012 fell by 14.5% from 2011 and further declines are forecast for 2013. International Energy Agency data show gas production in 2012 fell by just under 14% from 2011, to around 41 bcm. Despite higher operating costs, new investments to boost production are being made. However, even if they are successful, it will take time for new finds or improved reserve estimates to result in higher production

volumes. Through 2014, at least, a reversal of the UK's declining production trend is unlikely.

In Norway, production is expected to continue to decline, despite an increase in output on an annual basis in July. Maintenance will reduce flows by 2-3 bcm in September, according to *GA* estimates based on data from Gassco. September typically sees increased scheduled maintenance and lower production than other months of the year. However, the reductions come when supplies from Norway have already been declining on an annual basis, making the interruptions more keenly felt in the market. Additionally, supplies from Troll will be reduced through September 2014 because of required maintenance. This will result in a reduction of output equivalent to around 10% of Norway's 2012 production levels.

Total European gas output is expected to fall by around 3% over the first three quarters of 2013. The Netherlands remains the exception to the declining trend, with output up by around 7% over the period. Looking out to Q4, total European indigenous output is expected to continue to decline, with a shift in production volumes from the Netherlands likely to contribute to a faster rate of total regional decline.

Trade

The trade balance in Europe will remain tight in Q4, even with declining demand in key leading markets.

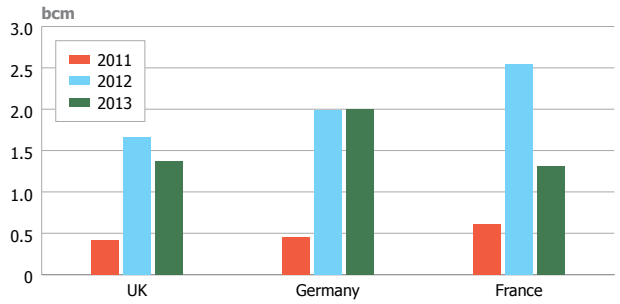
Total imports into Northern Europe will rise in Q4, driven in part by requirements for restocks in October and the decline in indigenous production. However, declining imports will continue in Italy and Spain through the remainder of 2013.

The UK's supply/demand gap is growing. The requirement for total imports is expected to increase by more than 10% in 2013 compared with 2012. Although demand has been falling in recent years, production has decreased at a faster rate. As a result of falling production, the boost in demand seen in H1 this year and ongoing requirements for additional imports to fill storage facilities ahead of winter, the gap will grow in 2013. Even with falling demand in H2, the requirements for storage and falling production will likely see imports rise.

Russian production rose by 7% on an annual basis in August while output from Gazprom increased by 3% year on year. Over the first eight months of the year, total Gazprom output declined on an annual basis. However, annual increases in production have been seen in the most recent months. Despite the decline in output, Gazprom's sales to Europe and profits are up. Profits in Q1 2013 are reported to have risen by 5%, with net sales to the region in rubles up by 11% on an annual basis for the period. Over Q1, sales were boosted by a 30% year-on-year increase in exports in March. A similar jump in export volumes was realised in August when exports to Europe increased by 34% on an annual basis.

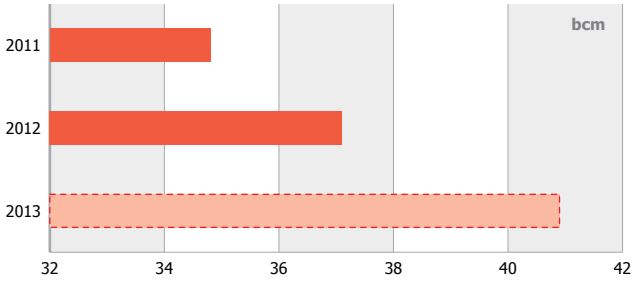
Estimates for September are for total Russian gas production to have increased by around 4% year on year, to reach nearly 52 bcm. Russian exports to Europe are expected to be around 13 bcm in September. Through the remainder of 2013, supplies from Russia will continue to be key to Europe's supply balance.

FIGURE 5 Net storage injections in key European markets, August 2011-2013



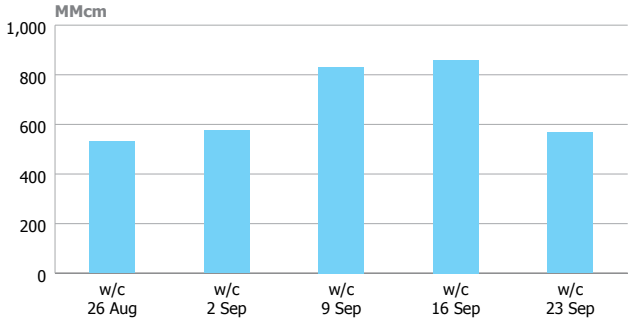
Source: GIE Europe

FIGURE 6 UK supply/demand gap, 2011-2013



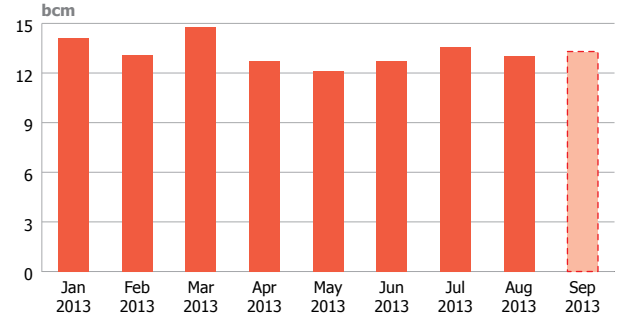
Source: IEA, DECC, *GA* estimates

FIGURE 7 Reduced flows from Norway to Europe, late August-September



Source: Gassco, *GA* estimates

FIGURE 8 Gazprom exports into Europe, January-September



Source: Fuel and Energy Dispatch Centre, *GA* estimates

PRICE TRENDS

Price overview

European hub prices are high for the time of year and this will persist ahead of the winter period.

NBP day-ahead prices increased sharply in mid-September to reach around 66-67 p/th by the middle of the month. From highs of nearly 67 p/th at the start of August, NBP day-ahead prices in early September fell to around 64-65 p/th. However, this dip was short lived. TTF and NCG prices were around €26/MWh over the first half of September.

GA estimates that average monthly NBP prices will rise to around 70 p/th in Q1 2014.

If the start to the winter is cold, the chance of price spikes will be high. Reduced indigenous production and a heavy reliance on Russian output will mean the supply side will not be well placed to respond quickly to short-term demand spikes. While storage can, and likely will be used, storage levels for key markets will be relatively low at the start of winter and countries may look to preserve gas in store as much as possible. Additionally, any spot LNG available over the winter period is likely to remain expensive for the region, so only limited relief – at best – can be expected from LNG imports.

At present, the Met Office's forecast for the period between September and November is for average to above-average temperatures. Although it is still early for seasonal outlooks, this encourages the view that support of price rises from demand over Q4 will be moderate. However, market tightness will persist and will be driven by low levels of regional supply and storage.

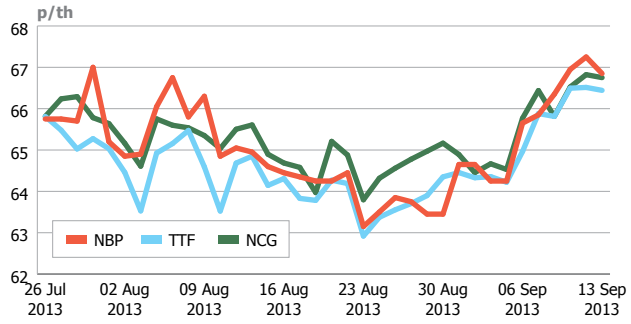
Spot, forward and futures markets

Market tightness has seen NBP day-ahead prices rise in mid-September, while the TTF and NCG have been more stable.

As of early September, the NBP, TTF and NCG day-ahead prices were all around 66-67 p/th. The drop in day-ahead prices at the TTF and NCG from August to early September was less marked that those of the NBP. The NCG declined by roughly 1 p/th from the start of August to early September. The TTF has seen greater fluctuation, and hit a low of just under 63 p/th at the end of August, but by early September it was back up to more than 64 p/th and more than 66 p/th by the middle of the month.

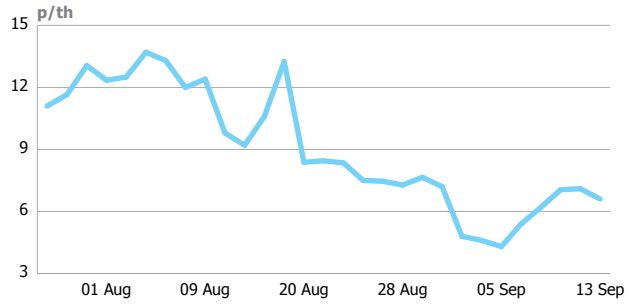
Maintenance in Norway will result in a reduction of flows over September, which should limit pressure on hub prices during the month. Prices are expected to be relatively stable over the coming weeks, with only moderate rises during the onset of the winter period. Price increases will not be more marked until the region enters the winter period in Q4. In addition to previously scheduled maintenance, Gassco – the Norwegian

FIGURE 9 NBP, TTF and NCG day-ahead, late July-mid September



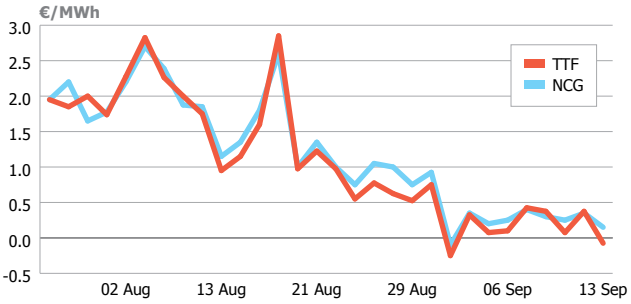
Source: Spectron

FIGURE 10 NBP day-ahead – price rise in 2013 over 2012



Source: Spectron

FIGURE 11 TTF and NCG day-ahead – price rise in 2013 over 2012



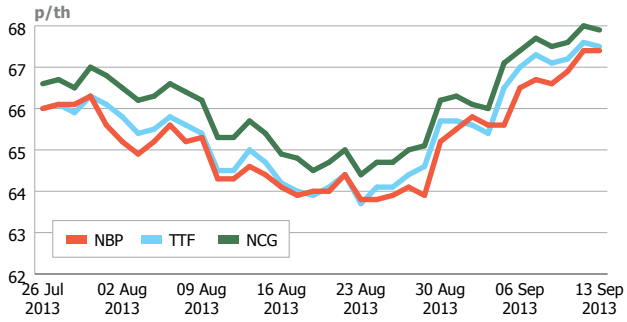
Source: Spectron

TABLE 2 Interfax European gas forecasts

Commodity	Units	Jul 2013	Aug 2013	Sep 2013	Oct 2013	Nov 2013	Q4 2013	Q1 2014	Q2 2014	Q3 2014	2014
NBP	p/th	65.65	64.48	66.33	66.54	67.33	67.57	69.77	66.12	65.46	67.47
TTF	€/MWh	26.16	25.70	26.60	26.71	27.01	27.09	27.64	27.41	27.60	27.99
Zeebrugge	p/th	66.18	64.66	65.87	65.94	66.73	67.11	69.37	66.95	66.49	68.09
Brent crude oil	$/bbl	107.94	111.26	112.60	110.50	108.00	108.75	109.42	109.50	110.25	109.29
Heating oil FOB ARA	$/t	915.86	938.13	951.90	943.69	925.05	933.12	922.14	916.38	927.72	923.60
Fuel oil FOB ARA	$/t	607.55	619.43	627.91	633.71	632.10	642.85	663.81	661.13	675.64	664.62

Interfax indices and forecasts are for information purposes only. For details of methodology and legal disclaimer, see page 4 of *Global Gas Analytics*

FIGURE 12 NBP, TTF and NCG month-ahead, late July-mid September



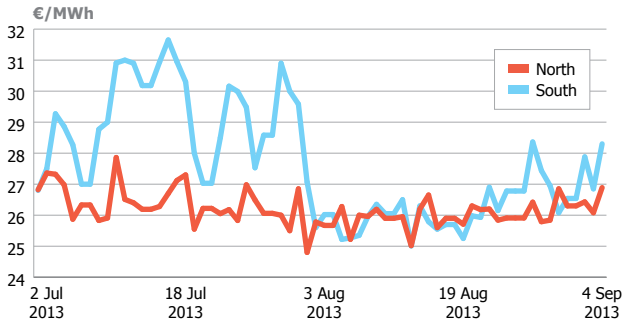
Source: Spectron

TABLE 3 European hub gas trading volumes, August 2013

	Daily average, TWh	Total, TWh	% total	% change year on year
UK NBP	34.7	728.7	42%	-20%
Netherlands TTF	29.6	621.6	36%	6%
Germany NCG	5.2	110.1	6%	32%
Germany GasPool	4.9	102.1	6%	56%
France PEG	1.4	30.2	2%	58%
Austria Baumgarten	0.8	16.3	1%	–
Italy PSV	0.6	13.3	1%	–
Other gas	4.8	101.7	6%	79%
Total gas	82.1	1724.1	–	–

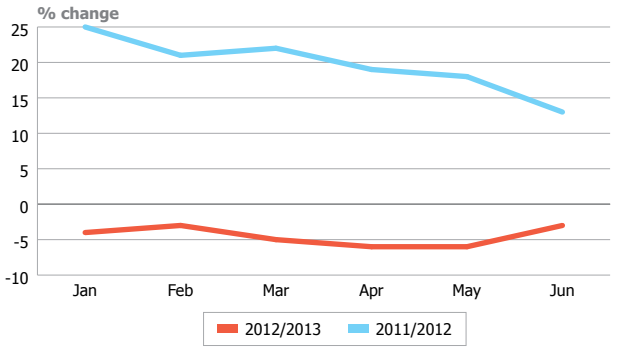
Source: LEBA, www.leba.org.uk

FIGURE 13 French provisional reference hub prices*



*Balancing price. Source: GRT

FIGURE 14 German average border prices, % change year on year



Source: BAFA

pipeline operator – announced in August that maintenance at Troll will be required through September 2014. This will result in a reduction of around 12 billion cubic metres of output over the year, equivalent to 10% of Norwegian production in 2012. This, combined with already reduced supplies, will limit the upside in supply from Norway over the coming winter.

NBP day-ahead prices are higher than those seen at the same time in 2012 and are expected to remain so. However, the gap decreased in early September. In early August, NBP day-ahead prices were nearly 14 p/th higher than in early August 2012. By early September, they were around 4-5 p/th higher. While NBP day-ahead prices fell over early September, at the same time in 2012, they rose. The combination of the upward price movement in 2012 and the decrease in 2013 is behind the closing gap.

Day-ahead prices at the TTF and NCG are also still higher than at the same time last year, but as with the NBP, the gap has narrowed in early September. In mid-August, prices at both hubs were around €3/MWh higher than at the same time in 2012. In early September, prices temporarily dropped below where they were a year ago, before rising to around €0.5/MWh above 2012 prices. The trends behind this are much the same as with the NBP – with prices a year ago having risen at the same time that they were falling this year.

As of mid-September, month-ahead prices at the NBP were around 66-67 p/th, with prices at the TTF and NCG slightly higher, at 67-68 p/th. Month-ahead prices have climbed since the end of August. The NBP, TTF and NCG have been trading closely, with the NBP generally maintaining a slight discount to the continental hubs over the past month.

NBP trading activity continues to decline and the gap between the NBP and TTF is closing. August LEBA data shows that over the first eight months of the year, total activity for the NBP has declined by 20%. The NBP accounted for 42% of total activity in August while activity at the TTF accounted for 36%.

Wholesale and retail markets

Hub prices in Southern France have fallen as LNG has entered the market.

Following a strong spike in prices in Southern France in July, a return to prices which are much more aligned with those of the northern hub have been seen in August and early September. Increased LNG volumes into the southern French market have helped to ease prices in the region. Although a divergence in the hubs was seen in late August when prices at PEG Sud went up to more than €28/MWh and prices started to climb in early September, the price rises were relatively small, as were the gaps between the two hubs. Risks of price spikes in PEG Sud remain, particularly if LNG flows into the southern market fall.

Average German border prices have continued to fall on an annual basis, according to the latest data available from BAFA. This trend is expected to continue in H2 2013 and is driven by the increased level of gas indexation in German supplies. Although the drop from 2012 prices has been steady, prices in 2013 are still above those seen at the same time in 2011. The year-on-year increase in 2012 averaged around 21% over the first half of the year and 2013 price drops have been just 5% on average over the same period.

MIDDLE EAST & AFRICA

Kuwait Towers, Kuwait City. (Asif Akbar/stock.xchng)

FUNDAMENTALS & PRICE TRENDS

Macroeconomic overview

Oil prices hit a peak of $117 per barrel and remained above $110/bbl during September, as the civil war in Syria kept the Middle East and North Africa region on edge.

United States President Barack Obama has scaled back and delayed plans for military action against Syria to give time to garner Congressional support, after key allies such as the UK failed to obtain a mandate to back an attack. Obama also paused plans for an attack after Russia suggested Syria put its chemical weapons under international control. However, Obama is sceptical Damascus will deliver, and air strikes cannot be ruled out.

The Syrian war is a powder keg for the oil and gas markets because Iran is Syria's closest ally in the region, and has a history of friction with Israel, which is allied with the US. In 2011, Iran threatened to close the Strait of Hormuz – a major conduit to the global oil and LNG trade which accounted for 35% of sea-borne oil trade that year. Most of the crude exported from Saudi Arabia, Iran, the United Arab Emirates, Kuwait and Iraq takes this route, together with most of the LNG from Qatar.

Meanwhile, political turmoil in the region is being compounded by the military takeover in Egypt, which faces renewed financial pressure as it struggles with spiralling debt.

Gas consumption

With growing domestic gas demand and declining production, Egypt has struggled to meet its LNG export obligations and a recent rift with Qatar has worsened the situation.

Qatar had been supplying LNG to Egypt, but relations have soured since the ousting of former President Mohamed Morsi. Qatar donated five LNG cargoes to Egypt to help the country meet its export requirements during the summer. Egypt had been negotiating with Qatar for another 13 LNG shipments priced at around $13/MMBtu, but the talk has now stalled.

This will increase the country's financial reliance on other members of the Gulf Cooperation Council (GCC) – namely Saudi Arabia, the United Arab Emirates and Kuwait from which Egypt is already receiving financial assistance. The UAE is understood to be considering an LNG tender for Egypt.

Meanwhile, Egypt is preparing a timetable for repaying arrears on the debts it owes to foreign oil companies. These were in excess of $6 billion, according to the country's Prime Minister, as Egypt had to divert gas intended for LNG export purposes to fulfil domestic demand.

Turkey is almost entirely dependent on imported gas to meet domestic demand, but the strength in crude oil prices – to which most of the country's imported gas is linked – and declines in the value of the Turkish lira have made imports more expensive.

MIDDLE EAST & AFRICA HIGHLIGHTS

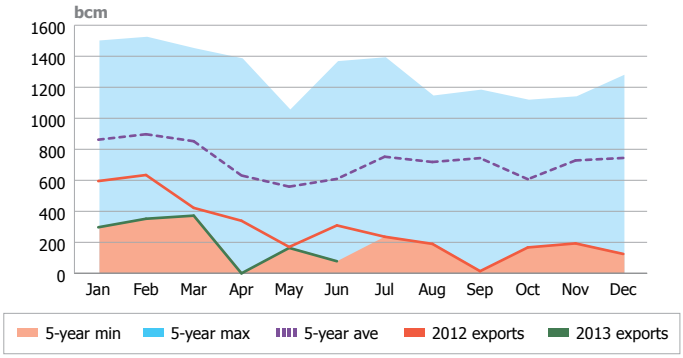
- Oil prices remain firm even though US military action against Syria has been delayed by political wrangling. The US wants to punish Damascus for allegedly using chemical weapons in the country's bloody civil war.
- Despite rising short-term LNG supplies from Algeria, Nigeria and Angola, the market looks set to remain tight during the northern hemisphere winter. Higher oil prices will translate into firmer contract prices over the winter.
- Gas shortages in Gulf Cooperation Council countries are expected to become more acute by 2015. GCC countries are faced with the challenge of meeting strong domestic demand growth which has been stimulated by heavily subsidised prices.
- High oil prices and a weakening Turkish lira have dampened gas consumption in Turkey.

TABLE 1 Quarterly and annual year-on-year GDP growth rates

	Q4 2012	Q1 2013	Q2 2013	2013	2014	2015
Qatar	6.6%	6.2%	*5.2%	*5.2%	*5.0%	*6.6%
Egypt	2.2%	2.2%	*2.0%	*2.0%	*3.3%	*5.5%
Saudi Arabia	4.4%	2.1%	2.7%	*4.4%	*4.2%	*4.4%
Nigeria	7.0%	6.6%	6.2%	*7.2%	*7.0%	*7.0%
South Africa	2.5%	1.9%	2.0%	*2.8%	*3.3%	*3.4%

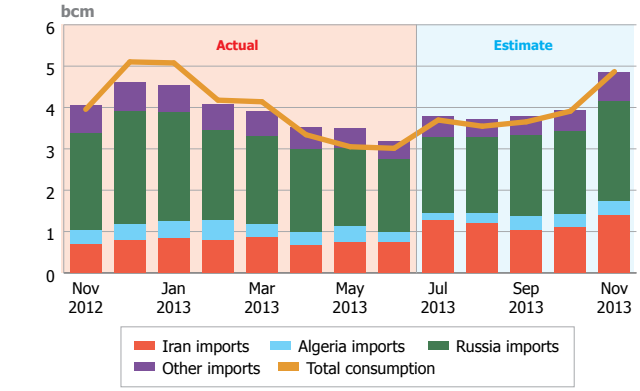
Source: Regional government sources, IMF WEO projections

FIGURE 1 Egyptian gas exports to OECD countries



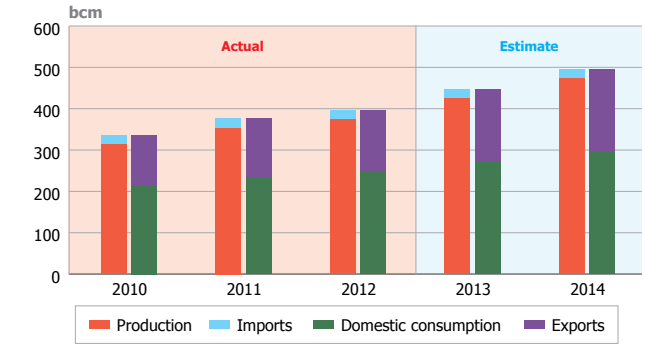
Source: IEA, *GA* estimates

FIGURE 2 Turkish gas consumption and imports



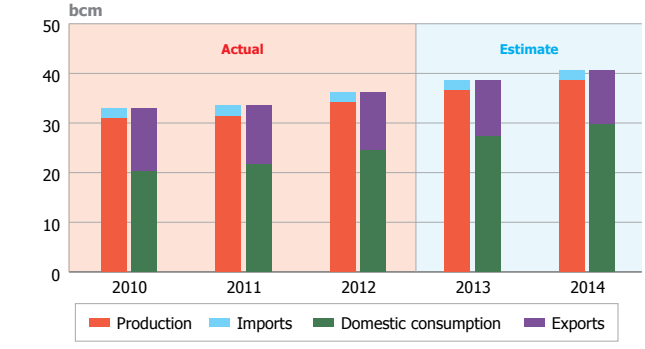
Source: IEA, Botas, *GA* estimates

FIGURE 3 Gas fundamentals in GCC countries



Source: IEA, *GA* estimates

FIGURE 4 Oman's gas fundamentals



Source: IEA, *GA* estimates

The two factors are the driving force behind Turkey's widening current account deficit – currently more than 7% of GDP. The government estimates these two factors could increase the country's energy expenditure by another $2 billion in H2 2013. Turkey's economy is being adversely impacted by the tensions in the Middle East, anticipation of the US Federal Reserve tapering its stimulus programme, and the risk of higher oil prices. This in turn will weigh on gas demand.

The government now expects the economy to grow by 3-4% in 2013 and 4% in 2014, from its previous projections of 4% and 5%, respectively. *GA* expects gas consumption in Turkey will decline by around 4% – to 43.4 billion cubic metres – in 2013. This will be followed by a fall of 2.5% year on year in 2014 which will result in demand being around 42.3 bcm.

Gas production

Associated gas production in Libya has dropped sharply since the end of June as protests by armed groups, security guards and oil workers have escalated.

Severe shortages in the domestic market are likely if the disruption continues. Associated gas constitutes a third of the total gas production in Libya. Oil production has been crippled after protests engulfed oil installations in both the east and the west of the country. According to official estimates, oil output for the first four weeks of August averaged 630,000 barrels per day – the lowest since November 2011 – and the decline is affecting gas output.

Production of non-associated gas has been less severely affected than associated gas. However, disruption is escalating in western Libya, where the Western Libya Gas Project (WLGP) accounts for most non-associated gas produced in the country. The gas comes from two fields: the offshore Bahr Essalam field, and the onshore Waha field near the border with Algeria. Production from WLGP has been little affected so far, but companies such as the Austrian firm OMV, which has operations in western Libya, halted production at the beginning of September.

Elsewhere, GCC countries continue to boost domestic production to avert supply shortages in the coming years, but more needs to be done.

Saudi Arabia's Midyan gas field project in the Red Sea is expected to start production at the rate of 75 million cubic feet per day (2.12 million cubic metres per day: MMcm/d) in H1 2014, according to government estimates. The gas will be pumped to the province of Duba to feed new power stations planned by Saudi Electric Co. and Aramco. Russia's Lukoil also plans to start production in the country from the Block A project in 2014.

However, in a major setback, Saudi Arabia and Kuwait have reportedly shelved the Dorra offshore gas project after disagreeing over how to share the gas. The field is estimated to contain at least 1.7 trillion cubic metres of reserves, shared between Kuwait, Saudi Arabia and Iran. Kuwait was expecting to receive 14.16 MMcm/d of gas from the field to meet surging domestic demand.

BP and Oman are expected to sign a commercial agreement by the end of the year to build a large gas plant to process gas from Block 61 in north-central Oman. The plant will have the

capacity to process 28.32 MMcm/d. However, first supplies are not expected any earlier than 2017, which is unlikely to help in the short term.

GA estimates gas production in the GCC countries will grow by 13% – to 424 bcm – in 2013 on an annual basis. However, domestic consumption is expected to grow by almost 9% – to 270 bcm, and export requirements will increase by 20% – to 177 bcm. This makes the group around 23 bcm short of gas in 2013, a situation that will persist in 2014.

Trade

Higher LNG output from Algeria, Nigeria and Angola has eased supply tightness in recent weeks, but this is a short-term fix.

Algeria's state-run company Sonatrach has reportedly launched several LNG sales tenders, including for single cargoes and a six-cargo strip from October. The company is also working on a 12-month supply commitment, details of which have yet to be released. In September so far, fourteen spot LNG cargoes arrived in Europe from Algeria, and one arrived in Japan. It is understood Algeria has additional contracted gas available after long-term pipeline buyers in Italy turned down supplies. This has allowed it to provide extra LNG volumes.

Meanwhile, supplies from Nigeria are back to normal, and Petronas and BG Group have each won a cargo from the Bonny Island facility, loaded in early September.

Angola LNG has also dispatched three cargoes – one each to Brazil, China and Japan, since June. It is expected a fourth cargo may be delivered before the plant shuts down for diagnostic tests.

The two Omani LNG companies – Oman LNG (OLNG) and Qalhat LNG – entered into an integration agreement on 1 September and will operate under the OLNG umbrella. Between them, the two companies exported 11.7 bcm of gas as LNG in 2012, and a total of 131 cargoes. The move is intended to streamline the industry and eliminate the perception that the two firms compete with each other.

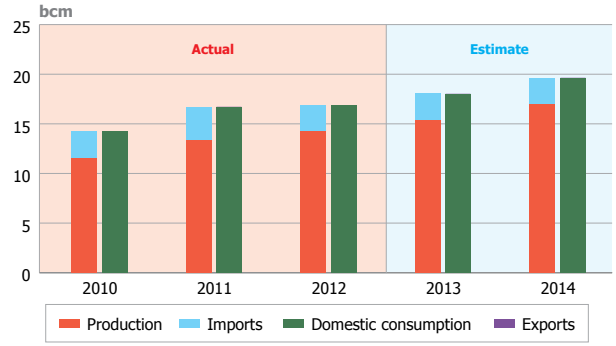
In the longer term, Oman is projected to become a net gas importer. Oman signed a memorandum of understanding with Iran to import gas from 2015. Gas will be imported under a 25-year deal worth around $60 billion. Volumes and prices for the deal have not been made public. Oman has been importing gas from Qatar, but it has been forced to look for new suppliers as rising demand has outpaced production growth. *GA* estimates gas import requirements in the country will increase by 9.5% – to 2.2 bcm – in 2014 from 2012.

Price trends

Yemen will sell LNG at global market prices from 2014 after negotiations with its buyers, according to the country's oil minister.

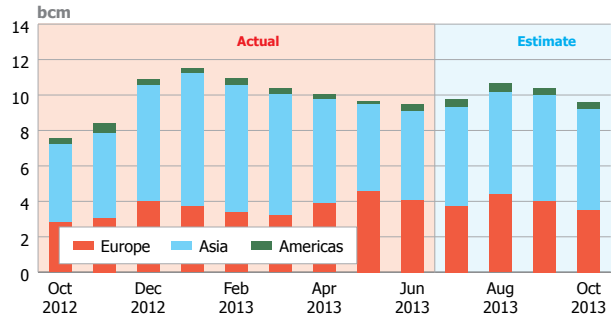
This will make the fuel even more expensive for key Asian and Latin American customers. The country reached agreements with Total and GDF Suez at the end of 2012 to more than double the price to $7.21/MMBtu, according to reported figures. More importantly, Yemen has been in talks with its biggest LNG buyer, Kogas, for a similar agreement. The discussions are still ongoing, but it is understood Kogas will also pay a higher price.

FIGURE 5 Kuwaiti gas fundamentals



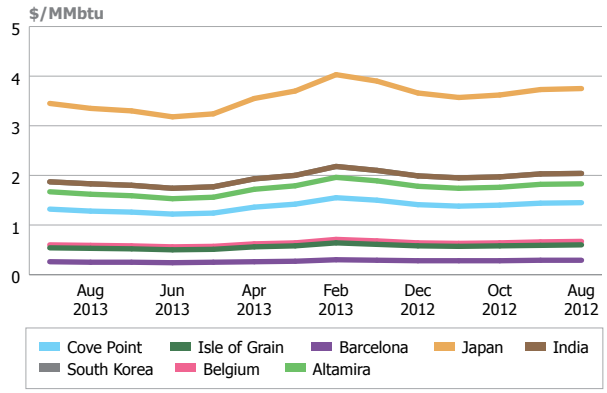
Source: IEA, *GA* estimates

FIGURE 6 LNG exports from the Middle East & Africa to OECD countries



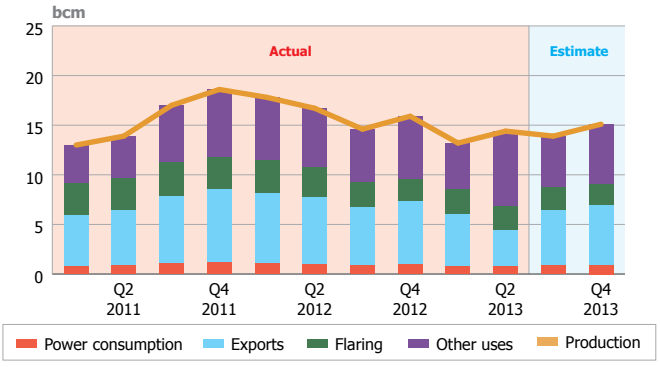
Source: IEA, *GA* estimates

FIGURE 7 Freight rates from Algeria



Source: Reuters/Waterborne

FIGURE 8 Nigerian gas fundamentals



Source: Nigerian National Petroleum Corp., *GA* estimates

AMERICAS

Seattle Space Needle, USA. (Christopher Disher/stock.xchng)

FUNDAMENTALS

Economic overview

The strength of the United States dollar – bolstered by the growing anticipation that the US Federal Reserve will start tapering its loose monetary policy – has become an issue for gas importers in the region by making the fuel more expensive.

The Fed is expected to start slowing down the pace of monetary stimulus in Q4 2013. A gradual removal of monetary accommodation will signal improving macroeconomic conditions in the US, but the country's economic growth is still timid. GDP grew by 1.6% in Q2 2013 on an annual basis, compared with a growth rate of 1.3% in the previous quarter.

An American economic resurgence will support US equities, and with the Fed starting to reduce its portfolio of government bonds, bond yields will rise. This has started to drain investment away from regional markets such as Brazil and into the US, in turn weakening currencies such as the Brazilian real.

Substantial declines were observed in the value of the Argentine peso and the Brazilian real in August, with the former falling by 13% and the latter 15% against the dollar year on year. Both countries rely heavily on LNG imports to meet domestic demand, and can ill-afford a weakening local currency.

Despite weakening currencies, the two countries have little choice but to continue buying expensive LNG, as supressing demand could harm the economy. The volume of gas imported by the two countries rose by 66% – to 5.5 billion cubic metres – in H1 2013 from H1 2012, which will go against their trade balance. *GA* estimates combined LNG demand by the two countries will rise by 70% – to 13.6 bcm – in 2013 year on year.

In contrast, Chile has reacted by reducing its reliance on imported LNG. This is largely because Chile has already been running a substantial current account deficit since Q3 2011, which is a factor against importing expensive LNG at a time when the dollar is gaining strength. As a consequence, LNG imports by the country declined by 3.7% – to 1.8 bcm – in H1 2013 on an annual basis.

Gas consumption

Gas demand in OECD Americas will gather pace in Q4 2013 and Q1 2014 as a result of heating-related demand from the US and Canada. However, consumption is likely to fall on an annual basis if predictions of a comparatively mild winter prove correct.

AMERICAS HIGHLIGHTS

- The New England and Middle Atlantic regions of the US will face supply tightness during the upcoming winter, despite healthy storage levels in the country as a whole
- Competition to secure LNG cargoes will intensify in Latin America in the months ahead as gas demand outstrips domestic production
- A month-long shutdown of Train 3 at Trinidad and Tobago's Atlantic LNG plant, starting from 3 September, will tighten LNG supplies further in the region
- The strengthening of the US dollar against most currencies in the region is making imported gas expensive to large importers

TABLE 1 Quarterly and annual year-on-year GDP growth rates

	Q4 2012	Q1 2013	Q2 2013	2013	2014	2015
US	2.0%	1.3%	1.6%	*1.9%	*2.9%	*3.6%
Canada	1.0%	1.4%	1.4%	*1.5%	*2.4%	*2.5%
Mexico	3.2%	0.8%	1.5%	*3.4%	*3.4%	*3.3%
Brazil	1.4%	1.9%	3.3%	*3.0%	*4.0%	*4.1%
Argentina	2.1%	3.0%	*2.8%	*2.8%	*3.5%	*3.0%

Source: Regional government sources. *IMF WEO projections

Despite the likelihood of a year-on-year fall in gas consumption, several parts of the US will suffer from supply constraints. Growing domestic demand in Canada, together with a lack of production growth, will limit Canadian gas exports to the US. This in turn will tighten the market in the East North Central and West North Central regions of the country that rely on gas from Canada. Supply tightness will also be observed in Middle Atlantic and New England regions, which often suffer from gas pipeline supply constraints during winter. This is also likely to result in additional volatility in regional gas prices.

Residential and commercial gas demand will peak during

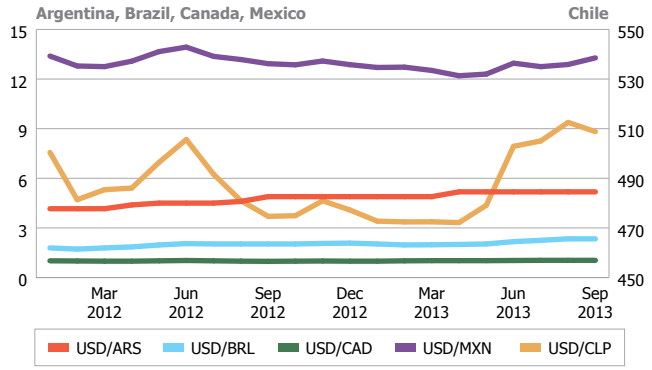
winter in the US, which will be supportive of overall gas consumption in the country. Total residential and commercial demand in the US has risen by 20% – to 137.2 bcm – in H1 2013 on an annual basis, which demonstrates the growing popularity of the fuel in these sectors. The trend will continue during winter, which could tighten the markets in Middle Atlantic and New England even further. Companies distributing gas to residential and commercial customers most often have firm supply contracts with gas pipeline operators. This gives them priority over electric utilities on interruptible service contracts. Gas supplies to utilities will be squeezed further because of high demand growth rates in the residential and commercial sectors.

Heating-related demand is likely to see year-on-year increases during Q4 2013 in the New England and Middle Atlantic regions, despite forecasts for a milder winter in the US as a whole. *GA* estimates combined gas demand in the two regions will increase by 3% – to 24.2 bcm – in Q4 2013 on an annual basis.

Brazilian gas demand is rising partly because of an ongoing drought in the northeast part of the country. The region is going through its dry season, which will last until the end of the year. This will increase the country's reliance on imported gas even further. The situation is likely to improve in January 2014, with an increased probability of rain. For January, the likelihood of above-normal, near-normal and below-normal rainfall is 0.4, 0.35 and 0.25, respectively.

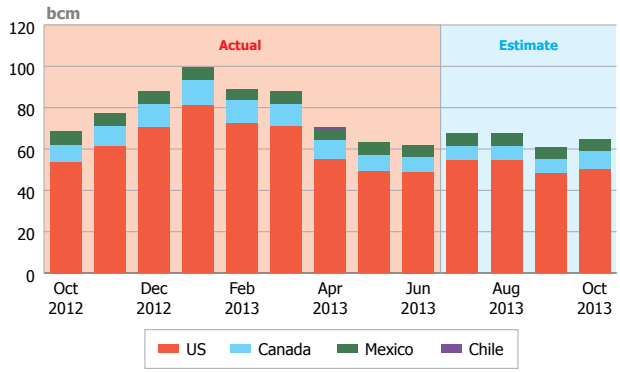
Gas consumption in Brazil is likely to remain high during Q1 2014, which is when the country will face peak summer demand. *GA* estimates gas demand in Brazil will increase by 25% – to 42.1 bcm – in 2013 from 2012.

FIGURE 1 Performance of regional currencies against the US dollar



Source: IMF

FIGURE 2 Gas consumption trends in the Americas



Source: IEA, *GA* estimates

TABLE 2 Regional heating/cooling-related gas demand forecast in the US

	September 2013		October 2013		November 2013	
	Degree days (F)	Gas demand (bcm)	Degree days (F)	Gas demand (bcm)	Degree days (F)	Gas demand (bcm)
New England	149	1.58	438	1.64	704	1.94
Middle Atlantic	148	3.84	378	4.49	642	5.89
East North Central	169	2.25	409	3.71	717	6.19
West North Central	214	6.76	419	1.06	786	1.97
South Atlantic	285	5.43	274	5.21	375	5.45
East South Central	239	1.45	244	1.37	432	1.71
West South Central	376	5.50	213	4.44	289	4.33
Mountain	317	2.43	392	2.54	616	3.18
Pacific	193	4.96	225	5.20	393	5.99

Source: EIA, *GA* estimates

Storage

North American gas storage levels continued to rise during August. While the storage builds provide a comfortable cushion to meet demand peaks during the winter months, they have also limited gains in gas prices in the continent.

The amount of gas in storage increased by 11% – to 111 bcm – in August 2013 on a monthly basis, and also went above the five-year average for the first time in 2013. However, storage levels in August were 6% below those seen in August 2012. Growth in gas production in North America was the primary reason for the storage builds in 2012. However, in 2013, falling gas demand in the US, with flat production growth, have contributed towards the build.

Storage levels in the US reached 92.1 bcm, or around 76.5% of full capacity, in the week ending 6 September. This compared with the situation at the same time last year when US gas storage was 81% full. *GA* estimates storage levels will reach 81% of full capacity by the end of September. Meanwhile, Canadian gas storage levels reached 18 bcm, or 87% of capacity, in the week ending 6 September. Storage levels were at 92% of capacity the same time last year. *GA* expects Canadian gas storage levels to be at 91% of capacity by the end of September.

Supply tightness relative to other regions will prevail during the upcoming winter in the New England and Middle Atlantic regions in the US, despite healthy gas storage levels. This is because gas storage is not equally full everywhere in the country. In the East Consuming Region, which includes New England and the Middle Atlantic, storage levels were still 6.5% below their five-year average in the week ending on 6 September. In contrast, total US storage levels were 1.5% above the five-year average during the same week. This distinction becomes starker during the winter months, which partly explains

the supply tightness expected in those regions.

Gas production

Recent weakness in US gas demand, together with healthy storage levels and low gas prices in North America, have weighed on gas production in OECD Americas.

According to data from the US Energy Information Administration, gross production of gas in the country declined by 0.1% – to 421 bcm – in H1 2013 from H1 2012. Meanwhile, marketed gas production grew marginally by 0.5% – to 356 bcm – during the same period. The prospect of flat production growth in the US this year and the next on an annual basis has limited losses in gas prices in North America.

In Latin America, the combined gas production in Brazil, Argentina and Mexico is expected to fall by 2.7% – to 27.9 bcm – in Q4 2013 from Q4 2012. This will make these countries even more dependent on imported gas, given their rising demand. *GA* expects the combined gas consumption in the group to increase by 3.7% – to 39.6 bcm – during the period.

The Bolivian state-owned company YPFB plans to increase domestic gas production by 37% – to 25.6 bcm – in 2014, from 2012. This will come as a respite to Brazil and Argentina, which rely heavily on gas pipeline imports from Bolivia. The government expects the increase in production to be sufficient to meet domestic demand and fulfil export obligations.

Trade

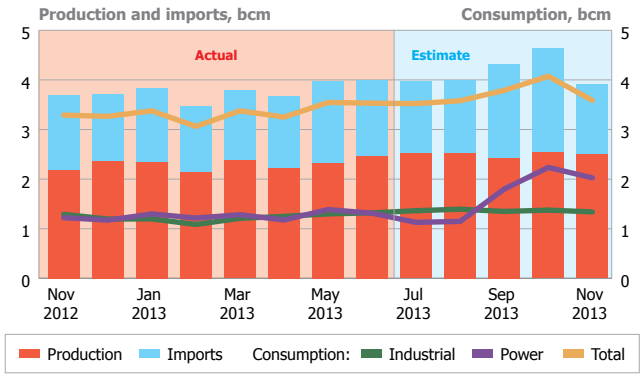
Major maintenance work in Trinidad and Tobago during September and October may create supply tightness in the LNG market in the near term.

The BP-operated Cassia B hub and BG's Dolphin platform in Trinidad and Tobago are undergoing maintenance work during September and October. Train 3 of the Atlantic LNG plant was also taken offline for about a month from 3 September. The government has taken steps to minimise disruptions to domestic supplies, however, LNG exports are likely to be affected. Train 3 has a capacity of 3.3 mtpa, which is equivalent to 22% of total for the Atlantic LNG plant.

Trinidad is a major supplier of LNG to Argentina, and it has also sent cargoes to other major Latin American consumers, including Brazil and Mexico. The race to secure additional LNG shipments in the spot market will intensify in the region during September and October.

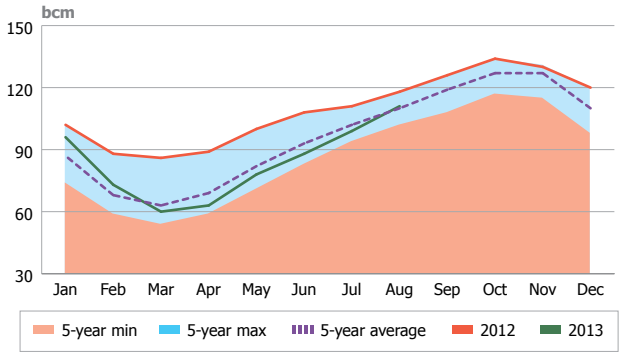
The US Department of Energy (DOE) gave conditional authorisation for LNG exports from another facility to non-free trade agreement (FTA) countries on 11 September. Dominion Resource's Cove Point plant in Maryland can now export up to 21.08 million cubic metres per day (MMcm/d) of gas to non-FTA countries, subject to approval by the Federal Energy Regulatory Commission (FERC). This is the fourth non-FTA export approval given by the DOE and the third this year, meaning the country can now export a combined volume of up to 186.91 MMcm/d of gas to FTA and non-FTA countries. More approvals are expected after the US Energy Secretary Ernest Moniz said earlier this year he will accelerate the pace of clearances. Sabine Pass LNG facility in Louisiana is the only plant approved by the FERC so far to export LNG. Freeport LNG in Texas, Lake Charles LNG in Louisiana and Cove Point LNG are still awaiting approval.

FIGURE 3 Brazilian gas fundamentals



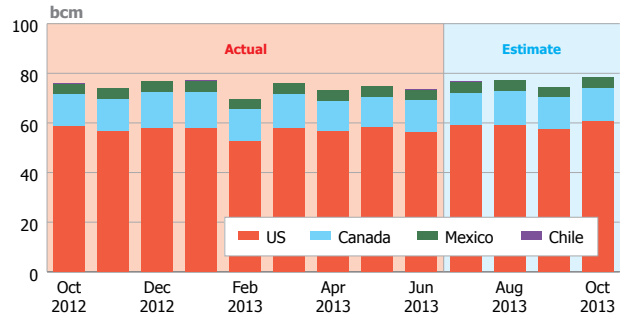
Source: Brazilian Ministry of Mines and Energy, *GA* estimates

FIGURE 4 North American gas storage



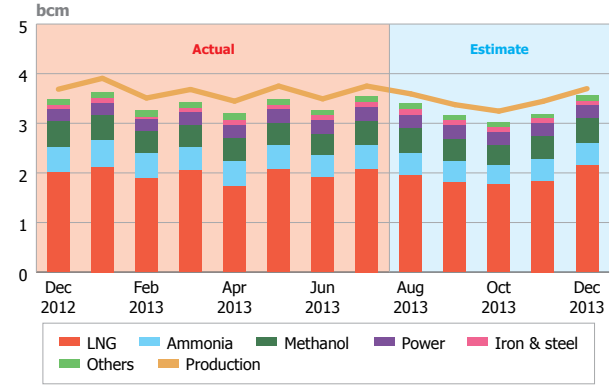
Source: EIA, Canadian Gas Association

FIGURE 5 Gas production trends in the Americas



Source: IEA, *GA* estimates

FIGURE 6 Gas consumption in Trinidad and Tobago by sector



Source: Trinidad and Tobago Energy Ministry, *GA* estimates

PRICE TRENDS

Price overview

Gas prices in North America will rise as a result of heating-related demand during the northern hemisphere winter.

CME/NYMEX-traded Henry Hub futures moved higher after touching a daily session closing low of $3.23/MMBtu on 9 August. The ascent was primarily driven by a forecast for warmer weather in parts of the United States. However, futures have been range-bound during September. Canadian NGX prompt prices traded at a discount to Henry Hub futures, and generally followed the same trend as Henry Hub.

Spot LNG prices in Latin America have fallen from their peaks reached during the southern hemisphere winter. However, they are still high year on year as demand from countries such as Brazil, Argentina and Mexico persists.

Forward and futures markets

Mixed fundamental signals prevented Henry Hub futures from making a decisive move up or down during August. However, prices will gain strength during the forthcoming winter as a result of heating-related demand.

Total degree days (TDD) in the US registered a value of 371 degree Fahrenheit in August, which was the highest level for the month since 2007. TDD in August 2013 was also around 9% higher than the level in August 2012. Both these factors were supportive of Henry Hub prices.

The activities of speculative traders also supported prices during August and September. Speculators had started to narrow their net short positions since the middle of August, which buoyed prices, and became marginally net long during the first week of September. Prices will receive additional support if the net long position is strengthened further during the month.

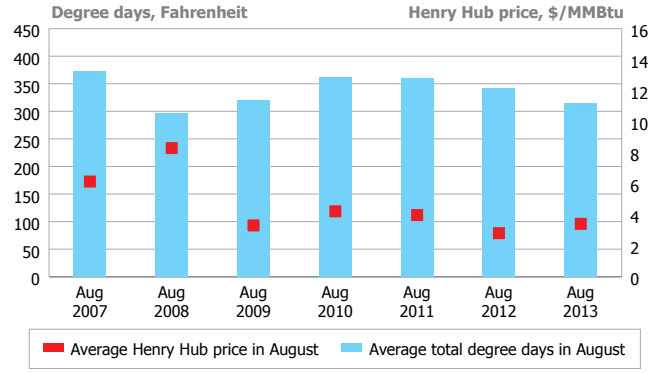
Despite the above-mentioned bullish factors, persistent builds in the US gas storage limited gains in Henry Hub futures. As the injection season in the US lasts until the end of October, this will keep on exerting pressure on prices. Total builds in US gas storage amounted to 9.7 bcm in August 2013, which was an increase of 85% from August 2012. This was also the highest stock build for the month since 2008.

The number of nuclear power plant outages in the country also kept prices in check. Substantial declines were observed in plant outages. A prolonged 2012/2013 winter resulted in delays in scheduled maintenance for nuclear plants, meaning more plants are online as the maintenance period ends. Nuclear outages fell by 63% – to 3 GW – in August 2013 from August 2012. This was also 28% down from the level observed in July 2013.

Despite flat production growth in the US, gas demand has also fallen, limiting gains in gas prices. US gas demand fell by 5% – to 153.2 bcm – in Q2 2013 on an annual basis. This has also been a bearish factor for Henry Hub prices.

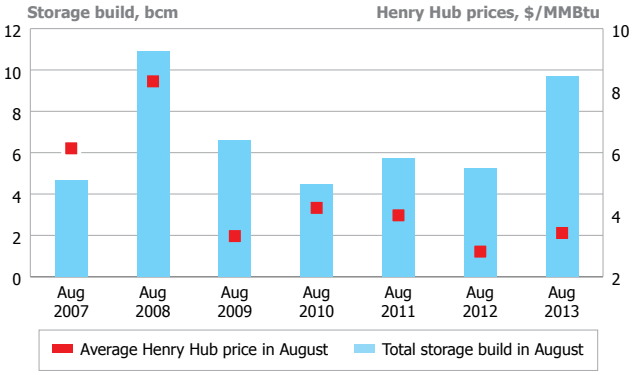
The liquidity in Henry Hub markets remained unusually thin during August. The average volume of traded Henry Hub futures

FIGURE 7 Total degree days and Henry Hub futures



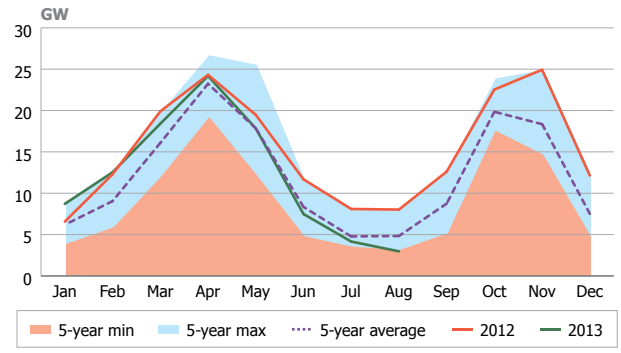
Source: EIA, NYMEX

FIGURE 8 Gas storage builds and Henry Hub futures



Source: EIA, NYMEX

FIGURE 9 US nuclear power plant outages



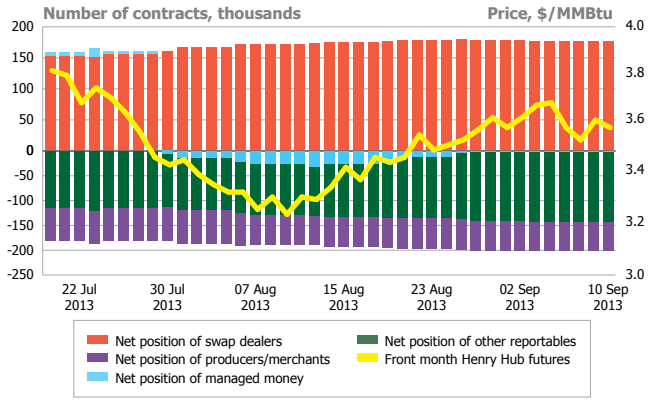
Source: US Nuclear Energy Institute

TABLE 3 Interfax Americas gas forecasts

Commodity	Units	Jul 2013	Aug 2013	Sep 2013	Oct 2013	Nov 2013	Q4 2013	Q1 2014	Q2 2014	Q3 2014	2014
Henry Hub	$/MMBtu	3.70	3.40	3.60	3.70	3.80	3.80	4.00	3.73	3.87	3.90
LNG Export Parity	$/MMBtu	7.66	7.66	7.76	7.94	8.03	8.00	7.94	7.99	8.06	8.09

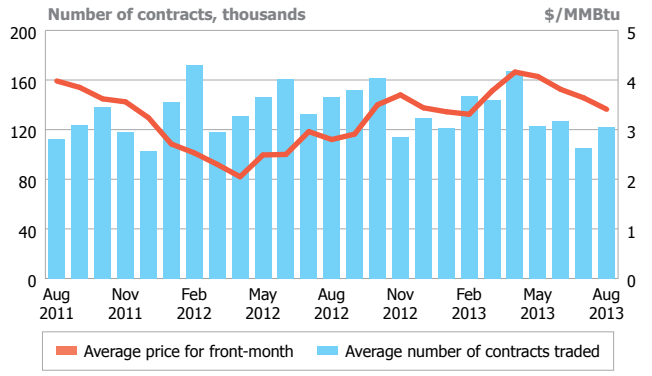
Interfax indices and forecasts are for information purposes only. For details of methodology and legal disclaimer, see page 4 of *Global Gas Analytics*

FIGURE 10 Disaggregated CFTC net positions in Henry Hub futures



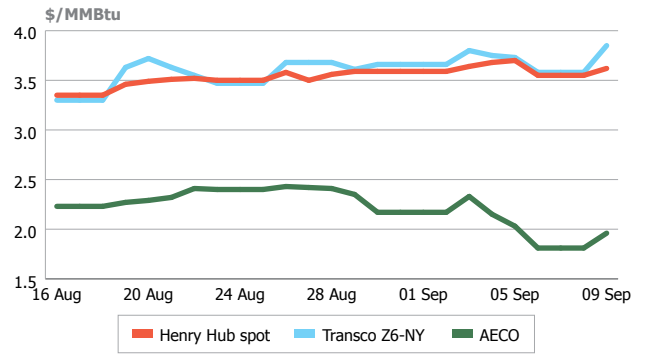
Source: CFTC, NYMEX

FIGURE 11 Monthly prices and volumes for Henry Hub futures



Source: NYMEX

FIGURE 12 Gas prices at selected pricing points in the US



Source: Regional pipeline operators

TABLE 4 LNG landed price in Americas ($/MMBtu)

Country	Terminal	Landed price for Sep 2013	Landed price for Aug 2013	Landed price for Sep 2012
USA	Cove Point	2.95	3.36	2.82
USA	Lake Charles	3.06	3.30	2.54
Canada	Canaport	3.05	3.59	3.00
Mexico	Altamira	16.51	16.75	3.02
Brazil	Rio de Janeiro	14.95	15.15	12.48
Argentina	Bahia Blanca	15.95	16.17	13.30

Source: Waterborne, Reuters

declined by 16% during the month compared with August 2012. This promoted volatility in the market. Trading volumes are likely to rise during September and October, which may make the market less volatile.

Spot, wholesale and retail markets

The price differential between Henry Hub spot and the AECO hub at the Canada-Montana border has widened in recent months, a trend that is likely to persist in the months ahead.

The spot price for gas produced in Western Canada and sold in Alberta, called the AECO-C price, does not include the cost of transportation. That is paid by utilities primarily based in Ontario and Quebec. However, the Henry Hub spot price is based on the delivery at the Henry Hub in Louisiana. This explains the persistent price differential between Henry Hub spot and AECO hub prices.

Recently, the utilities in Eastern Canada have grown dissatisfied with the extra charge and have been rejecting higher tolls. Instead, they have increased consumption of gas from storage in Eastern Canada. This has led to a gas glut in the west, which in turn has put pressure on the AECO hub price.

The price differential has widened by around 40% since the beginning of July. The trend will persist until at least the onset of winter in Canada, when increased heating-related demand may reduce the glut in the market, thereby narrowing the gap.

Price volatility at Transco Z6 continued during August, partly driven by air-conditioning related demand. Volatility at the pricing point will intensify during the upcoming winter once heating-related demand kicks in. Gas pipeline capacity constraints have been the root cause of volatility at the hub. On 27 August, Transco increased the available capacity to customers on its gas pipeline for one day to meet an expected increase in demand because of rising temperatures. This may happen again if there is a sudden increase in demand. However, this is only a temporary fix, and may prompt the company to improve pipeline infrastructure in the region.

LNG and import prices

Spot LNG prices in Latin America will remain high, supported by strong demand in the region. High prices will persist in Q1 2014, which coincides with the peak of southern hemisphere summer.

Landed prices in Brazil, Argentina and Mexico have fallen from the peaks observed during winter in the southern hemisphere. However, prices are still higher year on year because of persistent demand for LNG by the major consumers in the region. LNG landed prices for September 2013 delivery were around 20% higher in Brazil and Argentina on an annual basis.

A shortage of LNG vessels in the Atlantic Basin market, with only a handful of carriers open for charter, could further increase spot prices. Trinidad issued a sell tender for three LNG cargoes in September. However, the reception was lacklustre despite demand in the region as bidders were unable to secure additional vessels. The tender was initially supposed to happen in late August, but Trinidad pushed the date back to allow bidders enough time to charter tankers. The availability of free tankers may tighten even further in Q1 2013, when the peak of heating-related demand in Northeast Asia coincides with cooling demand peak in South America.

Israeli flag. (stock.xchng)

Israel's export cap: how will it affect Leviathan?

In an article first published in the August edition of *Oxford Energy Forum*[1], Leigh Elston from *Natural Gas Daily* and Peter Stewart, chief energy analyst of *Global Gas Analytics*, discuss the impact of Israel's gas export cap on the Leviathan development in the Eastern Mediterranean.

THE Israeli government's decision to cap gas exports at 40%, or 320 billion cubic metres – 13% lower than the export limit recommended by the interministerial Tzemach committee last year – was naturally met with disappointment by drillers in the Levant basin. However, on second glance, the government's slide to a more conservative gas policy will not necessarily restrict export options from the giant Leviathan field.

Not only will the Israeli government allow the Leviathan partners to swap gas export credits with smaller fields, but investors are hopeful that the gas reserve pie – now estimated at 920 bcm – from which the 40% export slice will be cut will only grow bigger as further exploration gets underway. Nevertheless, news of the 40% export cap raised questions over whether Woodside Energy will withdraw from its $1.3 billion deal to take a 30% stake in the Leviathan field.

The Australian LNG player agreed to farm into Leviathan on the understanding that at least 50% of the field's reserves could be exported as LNG. The new policy has led to speculation that the partners may no longer proceed with a two-train, 10 mtpa Israeli-based export project as originally envisaged. Woodside has remained tight-lipped on whether it will proceed with its investment, stating only that the company looks "forward to considering the detail of the gas export policy".

But it looks unlikely Woodside will pull out of the project. The 40% cap applies to the total gas reserves within Israel's Exclusive Economic Zone (EEZ), not to any one field in particular. As the Leviathan partners have the option to swap export credits with developers of smaller fields – which may only be looking to supply the domestic market anyway – it could still potentially be allowed to export up to 75% of Leviathan gas.

Ultimately it is the environmental and security risks of building a plant that are likely to hamper the development of an LNG plant on Israel territory, rather than export restrictions. Any major infrastructure facility will meet fierce opposition from environmentalists and residents along Israel's small but beautiful coastline, and these protests are likely to stall an already cumbersome licensing process. With Lebanon and Israel still technically in a state of war – and no agreement reached on the maritime border between the two countries – Hezbollah is viewed as a serious threat to the safe development of Israel's offshore gas industry.

With these complications in mind, the simplest option to export LNG from Leviathan could be to pipe Israeli gas to Cyprus and liquefy it through an LNG facility there. The Cypriot government, which sees gas exports as a lifeline for hauling it out of its economic crisis, has been quick to promote the island as a potential Eastern Mediterranean LNG export hub, and to that end has already cleared a site with the potential to accommodate an initial three 5 mtpa trains at the port of Vasilikos.

In the meantime, Nicosia is pushing to start exports from its own block 12 gas reserves as early as 2020. Noble Energy, the operator of the licence, is now carrying out appraisal drilling at the block and should announce, before the end of 2013, whether there are enough reserves to justify an LNG development.

The Texan explorer, along with block 12 partners Delek Drilling and Avner Oil, signed an memorandum of

[1]The purpose of Oxford Energy Forum (OEF) is to provide a quarterly forum that is dedicated to the debate of topical subjects of concern to the energy world and is published by the Oxford Institute for Energy Studies.

To download this and previous issues, visit www.oxfordenergy.org/category/publications/oxford-energy-forum/

FIGURE 1 Gas-fired power plant at Vasiliko. The Cypriot government has been quick to promote the island as a potential Eastern Mediterranean LNG export hub with Phase 1 of the new Vasiliko terminal project scheduled for completion in 2014.

understanding (MOU) with the Cypriot government in June agreeing to make a decision on whether to proceed with the 5 mtpa project by the end of 2013. Although Woodside was not party to the MOU, the Australian company is reported to be interested in joining its Leviathan partners in the project. None of the block 12 partners have any liquefaction experience and, as Noble draws up a shortlist of strategic partners to help build the project, Woodside is, unsurprisingly, one of the likely candidates.

The third way

There is a third possible option for exporting Leviathan gas: building a 10 bcm/y pipeline to Israel's one-time ally, Turkey. The project is still viewed as the cheapest and quickest way of monetising Leviathan gas. Cost estimates for the deepwater subsea pipeline vary between $6 and $8 billion depending on the final route – a factor Cyprus will be pivotal in determining, as the most direct channel from Israel to Turkey would pass through its EEZ.

However, Nicosia is unlikely to grant permission for the construction of the project; firstly, because Ankara's stance on drilling offshore Cyprus has only served to aggravate the long-running tensions between the two states; secondly, because pipeline exports would undermine its ambitions to become a regional LNG hub.

On a more positive note, the potential to import Israeli gas into Turkey's booming market may have been – at least in part – a catalyst for the recent thawing in relations between Ankara and Tel Aviv. Following Israel's apology for the 2010 Gaza flotilla raid, the prospects for building the pipeline were revived. Furthermore, as the Turkish gas market is expected to grow by 20-40 bcm/y within the next 15 years, Ankara is prepared to pay a premium to secure new gas supplies. Israel is reportedly negotiating shipping its supplies for at least $10/MMBtu.

Waiting for the appeal

The 550 bcm of gas earmarked for the Israeli domestic market is, even by conservative estimates, thought to be ample to cover the country's demand for at least the next 25 years. However, some opposition MPs are lobbying for the export quota to be cut further and four members of the Knesset and four environmental and social policy groups have appealed the government's export decision. The group petitioned the Supreme Court for a permanent injunction against gas exports and a nullification of the government's export sanction, demanding that the Knesset – not the cabinet – be the body to sanction exports.

The Supreme Court is expected to make a decision in late October. Until then, no further announcement on Israel's export projects is expected. So far, the only casualty of the government's policy seems to be the Tamar FLNG project. Gazprom Marketing & Trading signed a heads of agreement to market up to 3.5 mtpa of LNG from the project in February. Noble has already signed gas supply contracts with domestic offtakers for 92 bcm of gas from the field, but the Israeli government is not counting these volumes as part of the field's 60% local market quota.

It is considered that 40% of the remaining 190 bcm of reserves is too small to base a 3.5 mtpa LNG plant on, so it seems the project may be scrapped. Enthusiasm for Russian participation in Israel's gas sector has faded in light of President Putin's support for Syrian leader Bashar al-Assad. Relations between the traditional allies may cool further if Israeli gas exports head towards Europe and start to nibble into the Russian gas monopoly's core export market.

Leigh Elston is Middle East & Africa editor for sister publication, *Natural Gas Daily*
Peter Stewart is chief energy analyst and editor for *Global Gas Analytics*

Sakhalin 2 liquefaction plant. (PA)

Russian LNG – we have lift off?

The new players on Russia's LNG export scene could be the ones to open up the sector, while the prospect of other proposed projects are becoming increasingly distant.

Russia's LNG exports have the potential to expand significantly by 2020. Five new export projects – including three from Gazprom – are either planned or proposed. If they move forward as officially scheduled, they would raise Russia's LNG total export capacity to more than 65 mtpa by 2020. However, this will not happen. *GA* estimates that Russia will have four operational LNG export facilities by 2020, bringing the country's liquefaction capacity to around 25 mtpa.

Russia's only operating LNG terminal is Gazprom's Sakhalin 2 – a 9.6 mtpa terminal which was commissioned in February 2009. Of the five terminals being proposed, the two being developed by Novatek and Rosneft are likely to commission first. However, a number of factors stand as major hurdles to the various potential projects, and the timeframes for Shtokman and Baltic LNG are looking increasingly distant.

Let's go!

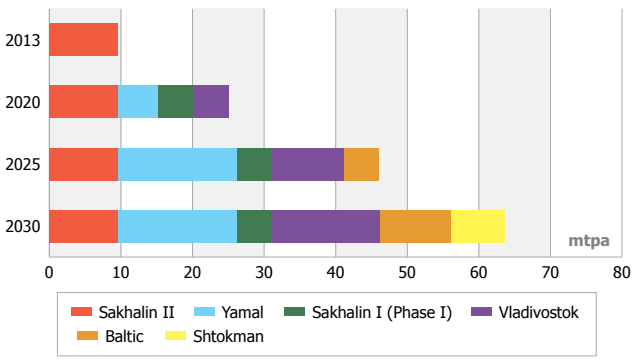
Novatek's proposed Yamal LNG terminal is officially planned to commission in 2016. While this is an optimistic timeframe, it is plausible for the terminal to commission before 2020. The initial capacity will be around 5-6 mtpa, but when fully operational it is planned to be extended to 16.5 mtpa. At present, Novatek holds an 80% stake in the project; Total owns 20%. In Q4, it is expected that an agreement with China National Petroleum Corp. (CNPC) will be finalised, which will see Novatek sell the state-owned Chinese company a 20% stake. A further 9% is also up for sale which would reduce Novatek's share in the project to 51%.

If finalised, the deal with CNPC could also see the project's first sales and purchase agreement (SPA). CNPC's framework agreement with Novatek for investment in the project includes an initial agreement for 3 mtpa of LNG from the facility. However, the project will need other contracts or an increase in offtake from CNPC. In early September, a memorandum of understanding for financing was reportedly secured via CNPC. A consortium of Chinese banks is behind the deal.

One of the technical and logistical challenges Yamal faces is that it cannot ship LNG to Northeast Asia year round. The northern route will generally be impassable between January and March, and *GA* understands that supplies will primarily be shipped between April and November. Consequently, not only does it mean Yamal cannot supply Northeast Asia during the peak demand months in the winter, it also means Yamal would likely need to secure sales into Europe over the winter months. While this is a viable option, it means the project will compete with Gazprom. Additionally, netbacks to Europe will likely be lower than those achieved from sales into Northeast Asia.

Rosneft-owned Sakhalin 1 (Phase I) will be 5 mtpa. The terminal is targeted to commission in 2018/2019 and it is possible this will be achieved. In June this year, Rosneft signed three Heads of Agreement (HoAs) for sales from the planned facility. Vitol, Sodeco and Marubeni have signed up for supplies of 2.75 mtpa, 1 mtpa and 1.25 mtpa respectively, all starting in 2019. If these contracts are progressed to SPAs, the initial phase of the terminal will be fully contracted.

FIGURE 1 *GA*-estimated liquefaction capacities



Source: *GA*

FIGURE 2 Russian LNG projects – existing and planned. (*GA*)

Of the planned and proposed terminals, Sakhalin 1 and Yamal are the most advanced in terms of sales contract negotiation. Getting project financing and achieving FID is contingent on finalising firm SPAs. However, while Novatek hopes to reach FID before the end of the year, no SPAs will be signed before LNG exports from Russia are liberalised, which is expected to be implemented on a project-by-project basis.

During the autumn session of the Duma, a better view on the potential timeframe for liberalisation should be revealed. It is expected that new, non-Gazprom, LNG facilities will be approved; only two terminals fall into this category – Yamal and Sakhalin 1. However, the sequencing and timing of the next steps for both Yamal and Sakhalin 1 will be crucial. Project approval to export LNG has to be obtained before sales contracts can be progressed and finalised. Following this, financing can be secured and FID taken. However, if the process takes too long, proposed commissioning schedules will slip.

Vladivostok LNG is targeted to commission in 2018. Of Gazprom's potential projects, it is the mostly likely to commission before 2020. The source of supply to the first two trains of the terminal is expected to be sourced from the Kirinsky field in Sakhalin 3. Reserves are understood to be sufficient to feed the first two trains at the proposed export facility. However, they are insufficient for a third train.

A third train will be dependent on supplies from East Siberia. The Chayandinskoye field in East Siberia could still be the source of supply for the third train. If supply does come from East Siberia, the third train will require pipeline exports from Russia to China to be agreed on to go forward. Without the pipeline, the economics of developing the required upstream infrastructure will be unviable. Gazprom's negotiations with CNPC for piped exports are ongoing and are planned to be completed before the end of the year. However, timing remains uncertain.

Potential piped exports from Russia to China have a long history of negotiations that have ended in disagreement. Insiders have said Gazprom needs to firm up agreements in 2014, otherwise the project risks being put on the back burner again. In the meantime, key issues for Vladivostok LNG remain unclear. In order for the project to progress within a timeframe that will allow for commissioning before 2020, supply issues need to be confirmed and sales purchase contracts agreed.

Gazprom's other potential export projects are the massive 15-30 mpta Shtokman and the 10 mtpa Baltic LNG. Both Shtokman and Baltic LNG had been targeted to supply the United States.

Shtokman will not commission by 2020; indeed, it may never be built. In early August, calls for bids for project document preparation were cancelled. The project is indefinitely delayed and – because of economics, technical problems and competition from other Gazprom supply into Europe – if it does move forward it will only be in the long term. While Baltic LNG is officially scheduled to start up around 2019, the terminal remains stuck at an early stage of development, and although it could commission by 2025, timing remains uncertain.

The expansion of Russia's LNG sector could make significant gains by the end of the year. Regulatory changes allowing companies other than Gazprom to export LNG would allow Novatek's Yamal and Rosneft's Sakhalin 1 LNG project to conclude negotiations and then move to secure project financing. On this basis, it is possible that FID on both projects will be taken in 2014. If this happens, both LNG liquefaction terminals could commission before 2020, marking an end to Gazprom's export monopoly.

Catriona Scott is senior energy analyst for *Global Gas Analytics*

TRINIDAD'S GAS PROSPECTS

Tanker docked at Atlantic LNG terminal. (BG Group)

Gas to remain lucrative for Trinidad and Tobago

Gas is crucial for Trinidad and Tobago's economy, providing the feedstock for large LNG and petrochemicals industries. But the expansion of the Panama Canal could be a game changer for the country's LNG exports

RATHER like Qatar, which has a tiny population but enormous LNG exports, Trinidad and Tobago punches well above its weight in terms of its gas industry. It is the sixth-largest LNG exporter and among the top 10 exporters of ammonia and methanol in the world. The three products account for 86% of the country's gas demand, with 56% of this coming from LNG alone. Trinidad exported 22.4 billion cubic metres of gas as LNG in 2012, according to data from its energy ministry.

The energy sector is the economic backbone of this island nation of 1.3 million people, constituting more than 40% of its GDP and more than 70% of foreign exchange earnings.

This dependence will continue in the medium-to-long term, despite concerns from some analysts that the country's shrinking gas reserves and maturing major fields may adversely affect its gas sector.

The dominance of gas exports

The expansion of the Panama Canal could be a game changer for LNG exports from Trinidad by substantially reducing transit times to Asian countries such as China, Japan and South Korea. According to the Panama Canal Authority, only 8.6% of the world's LNG fleet currently fits through the canal's locks. However, this is expected to increase to 88% by the time the expansion is completed in 2015. Trinidad's government has reacted positively to this by initiating LNG trade talks with China.

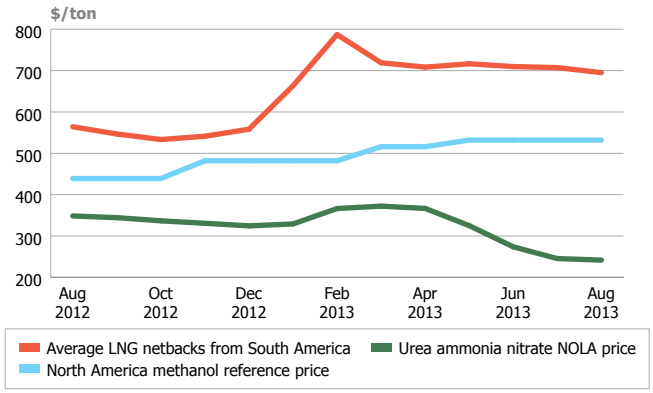
Trinidad is already the major supplier of LNG in the Americas. Within the region, the country has shipped LNG cargoes to the United States, Canada, Brazil, Argentina, Puerto Rico, Chile and the Dominican Republic. Other Latin American countries – such as Panama and Costa Rica – are preparing to build regasification terminals and are likely to take LNG from Trinidad as well. The country also sends LNG to Asian nations including South Korea, Japan, Taiwan and China, and European destinations including Spain and the UK.

Trinidad is seeking emerging-market destinations for its LNG, particularly in Asia. In July, Energy Minister Kevin Ramnarine held discussions with senior Chinese officials on establishing direct trading of LNG between Trinidad and China. The meeting followed up on issues raised during the visit of Chinese President Xi Jinping to Trinidad earlier in the year and also laid the groundwork for the upcoming state visit of Trinidad's Prime Minister to China later this year.

Trinidad exports LNG from the Atlantic LNG plant, which has four trains with a combined capacity of 14.8 mtpa. The plant has frequently operated at near full capacity because of the growing demand for LNG, and this has allowed the country to explore additional channels for gas exports.

Trinidad also has plans to boost LNG trade in the Caribbean region. The government signed a memorandum of understanding with Gasfin Development in 2012 for the construction of a mid-scale liquefaction plant at Brighton Port, La Brea in Trinidad. Gasfin has submitted a proposal for

FIGURE 1 Trinidad and Tobago's LNG, methanol and ammonia prices



Source: Reuters/Waterborne, Methanex

the construction of the plant, and is in discussions with the National Gas Company (NGC) of Trinidad regarding a gas supply agreement. The plant will be capable of producing 500,000 tpa of LNG to supply markets in the Caribbean. No decision has been taken on the target completion date for the project.

The country is also working on developing pipeline gas exports into the Caribbean. In November 2012, NGC commissioned a sub-sea gas pipeline from the BHP Billiton gas export platform in the Angostura Field off the northeast coast of Trinidad to the Cove industrial estate on Tobago. The pipeline has a capacity of 1.2 bcm/y. The pipeline is intended to provide a connection for the proposed Eastern Caribbean Pipeline Project, which will supply gas to Barbados and potentially to other islands in the eastern Caribbean. *GA* understands the first phase of the project to Barbados is expected to be operational in H2 2014.

The government's decision to promote pipeline exports is strategic, as they are generally cheaper than LNG exports. If pipeline gas from Trinidad establishes a market in the Caribbean, this will function as a backup should the country face tough competition in the LNG market from the US beyond 2017.

Petrochemicals exports follow suit

Trinidad is also a major exporter of petrochemicals such as methanol and ammonia, and the production of both of these uses gas as a feedstock. Gas consumption for the two products accounts for 28% of total gas demand in the country – half the demand for LNG production. This is because LNG offers better netbacks for Trinidad than exports of methanol and ammonia.

The government has also been working to encourage the use of methanol for the production of higher-value products such as dimethyl ether (DME). DME is a common substitute for propane in the LPG used as fuel in the residential and industrial sectors. In April, the government signed a project development agreement with seven entities, including Mitsubishi Corporation and Mitsubishi Gas Chemical Company, to construct the country's first DME plant. Construction is expected to start in 2014 and be completed in 2016.

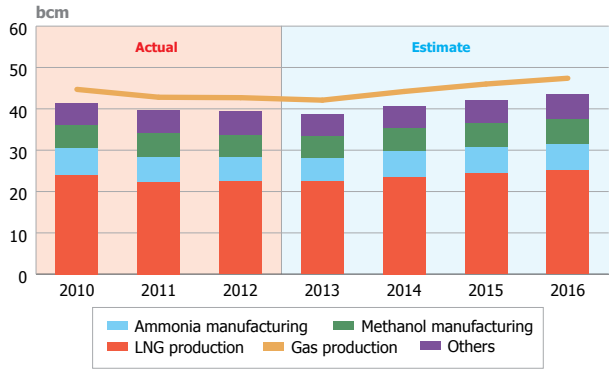
Trinidad's methanol capacity has grown substantially, highlighting the government's emphasis on the sector. Methanol capacity grew from 480,000 tpa in 1991 to 6.62 mtpa in 2006. The recent emphasis on DME production may result in further capacity expansion.

Petrochemicals provide a valuable source of income to the government. It has established a product-related pricing mechanism, pegging the price of gas sold to petrochemicals customers to the international market price of methanol and ammonia. This allows customers to benefit from lower prices in lean market conditions, while the NGC shares in the windfall when prices are high.

Ample supply of gas

Having enough gas available will be crucial for these plans. At the end of July, the government presented the 2012 audit of the country's non-associated gas reserves, conducted by the petroleum engineering consultancy Ryder Scott. The audit showed the government has generally been successful in slowing the decline in proven reserves. Ryder Scott quantified

FIGURE 2 Trinidad and Tobago's gas production and demand



Source: Trinidad and Tobago Ministry of Energy, *GA* estimates

proven reserves at 13.26 trillion cubic feet (375.52 bcm), which was a decrease of 1.1% from 2011. This compares with declines of 2%, 6.6%, 6.2%, and 9.5% in the previous four years respectively.

The Ryder Scott report categorises gas reserves as proven, probable and possible (3P) as well as exploration resources, which includes estimated potentially recoverable resources. The audit highlighted that Trinidad's exploration gas resources increased to 895.48 bcm in 2012 from 863.76 bcm in 2011. This was significant, as the audit excluded blocks awarded with effect from 2010. Among the excluded blocks were NCMA 2, NCMA 3, and 4(b), for which a total of five exploration wells are expected in fiscal year 2013/2014. These blocks are estimated to have total reserves of up to 574.33 bcm.

Gas production in the country is expected to increase in the next few years, with a number of fields and wells scheduled to come online. Production from the BP-operated Savonette platform will be ramped up by 36% – to 25.49 million cubic metres per day (MMcm/d) – by the end of the year. The Savonette 4 well is producing at the rate of 7.08 MMcm/d, and will be ramped up to 7.65 MMcm/d. Savonette 5 is producing at the rate of 4.39 MMcm/d, and will be ramped up to 4.67 MMcm/d. Meanwhile, the Savonette 6 well will be onstream by the year end with an estimated gas production of 5.66 MMcm/d.

Beyond this, BP is developing its Juniper field, production from which is expected to peak at 15.72 MMcm/d by the end of 2014.

Meanwhile, BG's Starfish field is expected to start operation in 2014, with a plateau rate of 7.36 MMcm/d. The company also has plans to develop its reserves in blocks 5C and 5D in 2015. BHP Billiton plans to bring its Angostura Phase 3 development online by 2016, adding 2.83 MMcm/d to overall production.

Trinidad's gas production scenario is, therefore, upbeat for the next few years – and the arrest in the fall in proven reserves could provide added assurance production can be further boosted if required. The medium-to-long term outlook for production is consequently conducive to the development of gas and petrochemicals exports.

Abhishek Kumar is energy and modelling analyst for *Global Gas Analytics*

Hazira LNG terminal in Gujarat, India. (Hazira LNG)

India's appetite for LNG wanes as rupee weakens

The relentless decline in the value of the Indian rupee is stifling LNG demand in the country, and will be supportive of coal consumption

INDIA is one of the largest importers of LNG in the world. The country has aspirations to become a gas-based economy and to achieve self-sufficiency in energy by 2030. However, persistent declines in domestic gas production, together with ballooning demand have made the country reliant on imports.

Recent falls in the value of the Indian rupee have made LNG imports more expensive, forcing lawmakers to align their ambitions for gas market development with economic reality.

The volume of LNG imported into India fell by 3% in H1 2013 from H1 2012 – to 8.1 billion cubic metres of gas equivalent. Meanwhile, the Indian rupee declined by 5.5% against the United States dollar during the same period. The rupee registered all-time lows against the dollar in August, hitting 69.22 per dollar on 28 August and averaging 62.9 against it over the month.

The rupee is unlikely to pare these losses before the next general election in India, which is expected to be held by the end of May 2014. Persistent weakness in the rupee look set to make dollar-denominated imports expensive, and will weigh on LNG imports.

GA expects, therefore, that Indian LNG imports will decline by 5% – to 16 bcm – in 2013 from 2012.

Government losing investors' confidence

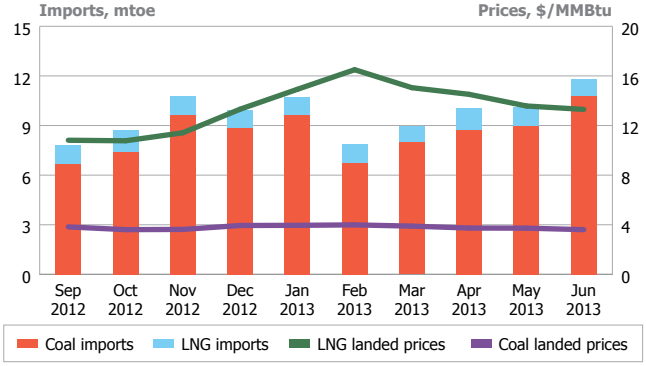
The decline in the value of the rupee against the dollar partly reflects the recent strength of the US currency, but also a loss of investor confidence in the Indian economy. Steps to prop up the rupee by the Reserve Bank of India have failed to yield results. The economy registered a GDP growth rate of 4.4% in Q2 2013 on an annual basis, which was the worst figure for the April-June quarter in more than a decade. Investors have not been encouraged by a political landscape beset by indecision and delays in implementing policies.

The gas sector itself has been directly affected by the political wrangling. In June, the Indian government decided to increase prices offered to gas producers in the country by tying them to international prices – effective from April 2014. The decision was taken to provide better incentives to companies seeking to boost domestic gas production. However, the policy has faced substantial opposition – both from within the government and outside. It has been challenged in the Supreme Court of India, which has the capacity to force the government to change its decision.

Demand for energy is growing in India, but declining conventional domestic gas production has made the country more reliant on imports. Meanwhile, it has failed to formulate a shale gas policy despite having significant resources. The government estimates the country could have 2-6 trillion cubic feet (56.64-169.92 bcm) of immediately recoverable shale gas resources. But lack of clarity in policy is stymieing the development of shale gas development as much as it has that of conventional gas.

The government estimates domestic gas production in India

FIGURE 1 India coal and LNG imports



Source: Indian Ministry of Petroleum and Natural Gas, Ministry of Coal, Reuters/ Waterborne, *GA* estimates

will rise by almost 78% – to 231 million cubic metres per day (MMcm/d) – in FY 2016-2017 from FY 2011-2012, according to projections by the Ministry of Petroleum and Natural Gas for the 12th five-year plan (FY 2012-2013 to FY 2016-2017). However, domestic demand is expected to grow by 140% – to 466 MMcm/d – during the same period. This will leave the country short of gas, increasing its dependence on imports. If the weakness in the rupee persists, this will prove an expensive and unaffordable strategy.

The government has taken steps to encourage gas consumption in India, but relentless declines in the rupee may make its efforts ineffective.

In July, the government decided to waive the import duty for any entity importing gas and LNG for electricity generation. Previously, this was only available to joint venture companies of Gail – Ratnagiri Gas and Power Private Limited and Petronet LNG. Other entities were required to pay an import duty of 5%. However, the 6.7% year-on-year decline in the value of the rupee against the dollar in the first eight months of 2013 has completely offset these incentives, limiting the effectiveness of the new measures.

The Indian central bank opened a special forex window at the end of August to shield public sector undertaking (PSU) oil companies against currency fluctuations. The window was opened for Indian Oil Corp. (IOC), Hindustan Petroleum (HPCL) and Bharat Petroleum (BPCL) – which require $8.5 billion per month to meet their foreign exchange requirements including fuel imports. The companies could have swapped the rupee with dollars provided by the central bank from its reserves, instead of going into the forex market. However, this is only a temporary measure as the central bank cannot sustain such a facility for a prolonged period.

The price of imported LNG is becoming a major concern for customers. The Petronet-operated Kochi LNG terminal at Puthuvype in the Indian state of Kerala received its first LNG cargo in August. However, *GA* understands Petronet's first two customers in the state – BPCL-Kochi Refinery and Fertilisers and Chemicals Travancore – are still negotiating on price, particularly in light of the recent declines in the value of the rupee. Pricing is also an issue with the other two immediate buyers – Hindustan Organic Chemicals and Nitta Gelatin India.

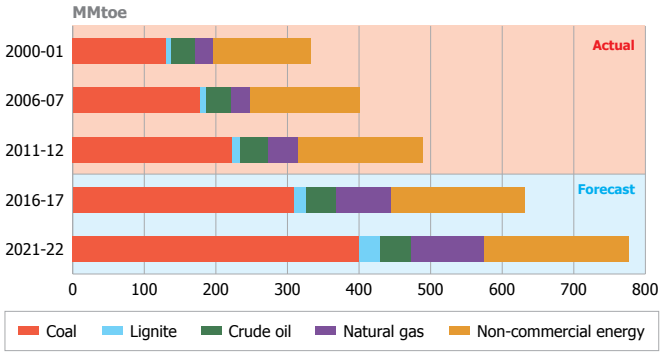
The average landed price in India in the first eight months of this year was $14.50/MMBtu. Industrial customers have to pay taxes such as VAT, transportation charges and customs duty on top of the landed price. *GA* estimates that, on average, industrial customers pay around $19/MMBtu including all taxes, making the fuel economically unattractive.

Rupee decline to boost coal demand

In contrast to its effect on LNG, the weakness in the rupee looks set to boost coal consumption in India. Coal import prices have declined in line with regional coal prices. The price of Newcastle coal from Australia – the Asian coal benchmark – declined by 14%, to $86.96/t, during the first eight months of 2013 on an annual basis. This has diluted the impact of the weakening rupee, allowing demand for imported coal to continue to rise.

Coal remains the dominant fuel in the country. It accounts for more than 50% of commercial energy supply and 67% of

FIGURE 2 Domestic production of fuels in India



Source: Indian Ministry of Petroleum and Natural Gas, Ministry of Coal, Ministry of New and Renewable Energy

electricity generation. India is a net importer of coal despite having abundant coal reserves, which are underutilised because of the difficulty in land acquisition and environmental concerns, among other factors.

Demand for coal in the country is rising. The government expects to import 165 mt of coal in FY 2013/2014, an increase of 20% from the previous financial year. However, *GA* projects Indian LNG imports will decline by 5.3% – to 15.5 bcm – during the same period.

Coal imports rose by 28.3% – to 75.7 mt – in H1 2013 from H1 2012. Coal India, which produces around 80% of the country's coal, is expected to issue its first import tender for FY 2013-2014 for 5 mt. State utility NTPC is seeking another 4 mt of thermal coal imports this financial year following its current tender for 5 mt of the fuel. The utility has been purchasing coal since the start of the financial year under previous tenders allowing it to import 7 mt.

Declines in the import price of coal are supportive of demand, despite the weakening rupee. This is in sharp contrast with LNG imports, the prices of which have risen. The average landed price for coal in India fell by 12.4% – to $3.8/MMBtu – in H1 2013 year on year. Meanwhile, the average landed price for LNG rose by 3.3% – to $14.7/MMBtu – during the same period.

The implication of this is twofold. Firstly, LNG imports are almost four times as expensive as coal imports, which favours coal consumption. Secondly, the rise in the dollar-denominated value of LNG, at a time when the rupee is weakening, is a double blow for importing countries such as India.

India is dependent upon energy imports partly because it is unable to fully harness its own resources. This has resulted in under-utilisation of its thermal power plants, whether coal- or gas-fired. This is the defining characteristic of the Indian energy crisis. Persistent weakness in the rupee will adversely impact imports in general. However, the effect will be more prominently observed for LNG than coal. This in turn will dampen demand for LNG in the country, and will discourage gas-infrastructure investment in India.

Abhishek Kumar is energy and modelling analyst for *Global Gas Analytics*

CONFERENCES & EVENTS

EVENTS CALENDAR

World Energy Congress

13-17 October Daegu, South Korea
www.daegu2013.kr/eng/index.do

The congress offers delegates, sponsors and exhibitors insights into the global energy sector and access to the leading global energy markets. Under the theme of 'Securing Tomorrow's Energy Today' the 22nd World Energy Congress will welcome 5,000 government and business leaders and other delegates from more than 100 countries.

European Shale Gas & Oil Summit

19-20 September London, UK
www.esgos.eu

Floating LNG 2013

23-25 September Houston, Texas
www.icbi-events.com/event/floating-lng-usa-conference

LNG Global Congress

24-26 September London, UK
www.lnggc.com/?domain=informaenergyevents.com

Gas China 2013

25-27 September Beijing, China
gaschina.shinemediaworld.com

Caribbean Oil, Gas, and Power Summit 2013

26-27 September The Bahamas
www.thecaribbeansummit.com

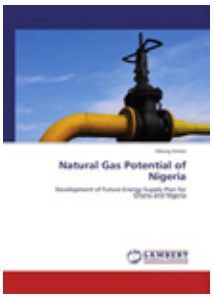
ECONOMIC INDICATORS

Date	Country	Release
18 Sep	UK	Minutes of Bank of England monetary policy meeting
18 Sep	US	DOE weekly oil inventory report
18 Sep	US	FOMC interest rate decision
18 Sep	Japan	Trade balance
19 Sep	US	EIA weekly natural gas storage change
20 Sep	Mexico	Unemployment rate
24 Sep	US	API weekly oil inventory report
25 Sep	US	DOE weekly oil inventory report
26 Sep	UK	GDP
26 Sep	Brazil	Unemployment rate
26 Sep	US	GDP
26 Sep	US	EIA weekly natural gas storage change
29 Sep	Japan	Industrial production
1 Oct	Australia	Reserve Bank of Australia interest rate decision
1 Oct	Eurozone	Unemployment rate
1 Oct	US	API weekly oil inventory report
2 Oct	Brazil	Industrial production
2 Oct	Eurozone	European Central Bank interest rate decision
2 Oct	US	DOE weekly oil inventory report
3 Oct	US	EIA weekly natural gas storage change
4 Oct	Australia	Trade balance
4 Oct	Japan	Bank of Japan interest rate decision
4 Oct	US	Unemployment rate
7 Oct	Eurozone	GDP
8 Oct	China	GDP
8 Oct	China	Industrial production
8 Oct	US	Trade balance
8 Oct	Canada	Trade balance
8 Oct	US	API weekly oil inventory report
8 Oct	Japan	Minutes of Bank of Japan monetary policy meeting
9 Oct	China	Trade balance
9 Oct	UK	Industrial production
9 Oct	US	DOE weekly oil inventory report
9 Oct	US	Minutes of the FOMC monetary policy meeting
9 Oct	Brazil	Interest rate decision
10 Oct	UK	Bank of England interest rate decision
10 Oct	World	OPEC monthly oil report
10 Oct	US	EIA weekly natural gas storage change
11 Oct	World	IEA monthly oil report
11 Oct	Mexico	Industrial production
14 Oct	Eurozone	Industrial production
16 Oct	UK	Unemployment rate
16 Oct	US	API weekly oil inventory report
17 Oct	US	Industrial production
17 Oct	US	DOE weekly oil inventory report
17 Oct	US	EIA weekly natural gas storage change
18 Oct	Mexico	Unemployment rate

BACK PAGE

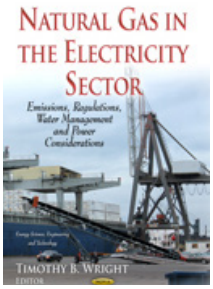
LITERATURE REVIEW

Natural Gas Potential of Nigeria: Development of Future Energy Supply Plan for Ghana and Nigeria (Ubong Simon, LAP LAMBERT Academic Publishing, 2013)



THERE are enormous energy resources of fossil fuels and renewable potentials in Nigeria. The need to encourage an energy supply mix that will emphasize the conservation of petroleum resources in such a way that will ensure their availability for economic development was analysed. Using three economic scenarios, the role of gas in Nigeria was studied to develop a future energy supply plan for Ghana and Nigeria. Results from the study show the growing demand for energy in Ghana and Nigeria can only be satisfied if a massive expansion of renewable energies is achieved, combined with energy system efficiency.

Natural Gas in the Electricity Sector (Timothy B Wright, ed., Nova Science Pub Inc., 2013)

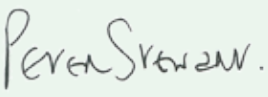


THIS book addresses several aspects of the changing context of gas in the United States's electric power sector. Increasingly plentiful and affordable gas has catalysed major changes in US power generation and has helped to boost US economic recovery. Increased substitution of gas for coal has also cut US greenhouse gas emissions. However, processes to produce gas, and shale gas in particular, have also elevated environmental and safety concerns in certain regions of the country. This book is intended to help inform energy policy and investment discussions, and outlines the dynamics of gas in the power sector.

LAST WORD

Saudi Arabia to refocus on gas

Saudi Arabia sits on the biggest oil reserves in the world, but despite having the fourth-biggest gas reserves in the world – at 8 trillion cubic metres – gas development has always taken a back seat in the kingdom. Now, according to a research note by Barclays analyst James West, Saudi Arabia is about to take action to change that. In recent years, bizarrely, the country's burgeoning power demand has forced it to burn crude oil to make electricity, despite its massive gas reserves. This represents a significant foregoing of revenues with oil prices above $100 per barrel. Paul Stevens highlighted the kingdom's dilemma in a 2011 paper for Chatham House – *Burning Oil to Keep Cool: The Hidden Energy Crisis in Saudi Arabia*. As domestic demand for oil products accelerates in the years ahead, the kingdom faces declining export earnings and its position as the largest oil exporter will be increasingly threatened. Because of this, Saudi Arabia is refocusing the strategy of national oil company Saudi Aramco, emphasising gas development, pursuing opportunities in unconventional resources and trying to become a technological leader, according to West. Barclays expects Saudi Aramco to boost E&P spending to $15 billion in 2013 from $11 billion in 2012, to develop gas and unconventional resource potential, including deepwater resources in the Red Sea. The ultimate scope of Saudi Arabia's gas ambitions is unclear. It appears unlikely to seek to develop gas exports to compete with neighbouring Qatar, but focusing on gas should allow it to stay in the top league of oil exporters in the long run.



Peter Stewart is editor of *Global Gas Analytics*

Interfax Global Gas Analytics

Interfax Europe Ltd.
19-21 Great Tower Street,
London EC3R 5AQ
United Kingdom
T +44 (0) 20 3004 6200
E analytics@interfax.co.uk
W interfaxenergy.com

Global Gas Analytics is published monthly by Interfax Europe Ltd, a subsidary of Interfax Information Services Group.

 ISSN 2052-0417