GAS
Medium-Term Market Report 2014

Market Analysis and Forecasts to 2019

International Energy Agency

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FOREWORD

Looking at its many positive attributes, natural gas should have a bright future. It emits less carbon dioxide than other fossil fuels and is supported by a large recoverable resource base. In addition, gas-fired plants have lower capital costs than many other power-producing technologies and are not as susceptible to not-in-my-backyard (NIMBY) issues; their flexibility makes gas-fired plants the ideal partner for intermittent renewable energies.

Yet, gaining further share in the global energy mix may prove challenging for natural gas. While our outlook on natural gas remains positive, it is slightly less so than in previous reports and highlights the factors which make gas struggle in a number of countries. On the one hand, gas has to compete against other fuels, notably coal and renewable energies in the power sector. In developed and developing countries alike, choices are often made based on an unfavourable pricing relationship versus cheaper coal, combined with the quasi absence of a carbon price that could trigger a shift back to natural gas. Consequently, natural gas hardly increases its share in the power generation mix in this report, which includes projections to 2019. On the other hand, limited access to natural gas supplies, such as insufficient production or imports, can constrain demand. An adequate pricing mechanism reflecting supply-and-demand fundamentals is therefore of paramount importance: subsidies exacerbate demand, discentivise production developments and quite often lead to shortages and import requirements some time later.

Natural gas has been subject to tremendous changes in market conditions over the past few years – from the North American shale gas revolution to the emergence of new future gas-producing regions such as East Africa and the East Mediterranean; from increased questioning of the prevailing methods for setting gas prices to the transformation of some exporting countries into importers and vice versa. In 2014, what comes next for natural gas markets?

The current situation of widely diverging gas prices seems unsustainable and Asian importers are taking steps to change these conditions. While the issue is primarily that of high price levels, it is the oil indexation mechanism, which has been a backbone of long-term contracts, which is under attack. Most existing long-term contracts as well as those supporting liquefied natural gas (LNG) projects – except in the United States – are linked to oil prices. The question is therefore whether US LNG exports alone can transform this system. The European example shows that such changes can take place over a few years, as more than half of European gas is now based on hub pricing.

While non-Organisation for Economic Co-operation and Development (OECD) countries have been the primary source of new gas supply, the upcoming five years will be different, as a large share of incremental gas supply, in particular most exports, will originate from North America and Australia. This shift will occur mostly at the expense of Former Soviet Union producers. Meanwhile, shale gas will not quite take off outside North America during this decade, but the ground is being prepared for this to potentially happen during the 2020s. How shale gas or other unconventional gas types will evolve and impact future natural gas trade represents one of the major uncertainties for the next 20 years, while at the same time, projects looking to bridge the expected import gap must take final investment decisions much sooner. And whether methane hydrates could create the same transformation as shale gas remains highly uncertain.

Against this backdrop, the natural gas industry does not stand still but keeps responding to the changing market. Where affording new supplies may be difficult, countries and companies are thinking about new ways of buying together as a consortium. Where LNG import terminals are under-utilised, LNG re-exports and other activities such as LNG bunkering or transforming idle LNG import terminals into LNG export plants are being considered. The natural gas industry also views with increased interest one sector where considerable opportunity lies: transport, as road, maritime and railroad travel and freight are all potential new markets. But the path to take that prize will be a long one.

This report is produced under my authority as Executive Director of the IEA.

Maria van der Hoeven
Executive Director
International Energy Agency

ACKNOWLEDGEMENTS

This *Medium-Term Gas Market Report* was prepared by the Gas, Coal and Power Division (GCP) of the International Energy Agency (IEA). The analysis was led and coordinated by Anne-Sophie Corbeau, senior gas expert, with significant contributions from the GCP gas team: Anne Braaksma, Ichiro Fukuda, Farid Hussin, Rodrigo Pinto Scholtbach and Takuro Yamamoto, as well as from members of other divisions Toril Bosoni, Anselm Eisentraut, and Marc-Antoine Eyl-Mazzega.

Valuable comments, data and feedback were received within the IEA, from Keisuke Sadamori, Laszlo Varro, Yasmina Adbelijah, Heymi Bahar, Suleyman Bulut, Chris Besson, Pierpaolo Cazzola, Ian Cronshaw, Charles Esser, Carlos Fernandez Alvarez, Capella Festa, Rebecca Gaghen, Jean-François Gagné, Steven Gallogly, Dagmar Graczyk, Tim Gould, Antoine Halff, Jon Hansen, Thea Khitarishvili, Matthew Parry, Kristine Petrosyan, Cédric Philibert, Valerio Pilio, Uwe Remme, Christopher Segar, Kees Van Noort, Dennis Volk, Michael Waldron, Yayoi Yagoto and Haoping Zhang.

Timely and comprehensive data from the Statistical Division were fundamental to the report.

A special thank you goes to Janet Pape, Therese Walsh and Jonas Weisel for editing the report.

The IEA Communication and Information Office (CIO), particularly Astrid Dumond, Muriel Custodio, Greg Frost, Angela Gosmann, and Bertrand Sadin, provided essential support towards the report's production and launch.

The review was made possible by assistance from GasTerra B.V., Tokyo Gas, Petronas and the Ministry of Economic Affairs of the Netherlands.

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EXECUTIVE SUMMARY

Gas grows more slowly than other fuels in 2013

In 2013, global natural gas demand gained only 1.2%, reaching around 3 500 billion cubic metres (bcm). Against the backdrop of a sluggish economic economy, competition from coal and renewable energies in the power generation sector and supply constraints, consumption increased less than forecast in the previous *Medium-Term Gas Market Report* (*MTGMR*) for that year (1.6%). There is nothing new in gas being outpaced by coal and renewable electricity generation; this has been the case over the past decade, but it is unusual that gas demand growth is behind oil too, which increased by 1.4% in 2013.

Another marked change comes from the non-OECD regions which exhibited subdued demand growth (1.2%) in 2013, significantly below the healthy pace of 4.1% per year seen over 2000-12. Non-OECD regions, which had been a backbone of demand growth, grew only slightly faster than OECD regions (1.1%). While diverging only slightly from the pace set since 2000 (1.5% per year), the OECD region's gas consumption growth can be considered as illusory, because it is largely driven by abnormal weather, notably a long winter in Europe in early 2013 and a cold end of the year in North America. If not for the weather factors, OECD gas demand should have dropped by around 1%; consequently, the world would have exhibited stable natural gas consumption in 2013.

Once again, the People's Republic of China remains the driver behind global gas demand with a 13.3% growth rate, by itself responsible for half of the world's additional gas consumption. In contrast, many other non-OECD regions show modest growth, while demand even declined in non-OECD Asia and in the Former Soviet Union (FSU)/non-OECD Europe. One exception is Latin America, where droughts forced power generators to resort to gas-fired plants and drove exceptional increases in both gas demand and liquefied natural gas (LNG) imports.

Besides intrinsic demand factors such as economic growth, relative fuel prices, and transport and import infrastructure, both supply and trade play a paramount role in determining natural gas demand. Global supply grew by 1.1% in 2013, reaching an estimated 3 480 bcm. Among the highlights for 2013 were that the recovery of the FSU's gas production was driven by higher exports, while OECD Americas' growth abruptly slowed down. Africa's production plummeted by 4%, as large producers – in particular, Egypt – underperformed. In contrast, China's output surged by 9%, even though this increase only covered half of the additional demand. Many countries still face shortages, either due to their inability to increase domestic gas production, owing to the maturity of producing fields, the country's declining reserves or the new fields' cost of development being higher than subsidised domestic gas prices. Geo-political events also played a role, with the attack on Algeria's In Amenas complex and the war in Syria, but they had less impact than the other reasons mentioned earlier.

Global interregional trade features almost stable LNG trade compared with surging interregional pipeline imports from Europe and China. Flat LNG supply growth in 2013 after a 2% drop in 2012 is a drastic change for an industry that had been growing relentlessly over the past two decades. Not only does it put pressure on demand, but the LNG supplies have shifted to Asia (including OECD Asia Oceania, non-OECD Asia and China), which now imports close to three-quarters of global LNG. The gap between Asian prices and US spot prices narrowed slightly in 2013, but remained large, with

Asian LNG importers paying on average USD 16/MBtu. This price is consequently higher than the average prices seen in Europe and explains why Asia is able to divert LNG away from Europe, where LNG imports collapsed and represented a mere 14% of global LNG trade.

Gas is on its way to cross the 4 000 bcm mark by 2020

The medium-term outlook remains optimistic for the future of natural gas, with demand reaching 3 980 bcm by 2019, despite a slight reduction from last year's outlook due to lower growth in Europe and FSU/non-OECD Europe (Table 1). Nothing is set in stone, however. European gas and power companies would not have predicted in 2010 that their gas-fired plants would have to close three years later. Still, the power generation sector represents the backbone (53%) of future natural gas demand growth across all regions, even Europe, followed by industry (32%).

Table 1 Demand and supply changes, *MTGMR 2014* versus *MTGMR 2013* (bcm)*

Total	Demand	Supply
OECD Europe	-26	-9
OECD Americas	-12	-19
OECD Asia Oceania	-6	-9
Africa	-3	-7
Non-OECD Asia	-16	-15
China	-5	9
FSU/non-OECD Europe	-31	-51
Latin America	6	3
Middle East	24	32

* Negative values indicate a downward revision compared to *MTGMR 2013*.

Source: unless otherwise indicated, all material in figures and tables is derived from IEA data.

Despite this strong demand hike, gas's share in total power generation will increase by only 0.5%, comprising only 22% of the total, due to competition with other fuels, as well as insufficient supplies in many developing countries. In particular, the Middle Eastern power generators do not have sufficient domestic gas supplies to displace oil with gas and LNG imports are expensive. On the contrary, oil demand there will continue its relentless growth, even if its share in total power generation drops slightly. In Saudi Arabia, oil-fired generation is forecast to gain 27% over 2013-19 on the back of insufficiently growing gas production and the very low efficiency of Saudi power plants.

Non-OECD regions continue to drive natural gas demand: they will provide 85% of the additional consumption. China alone represents 30% of this demand, followed by the Middle East with 22%. In contrast, consumption in FSU/non-OECD Europe remains stable. OECD countries are unlikely to provide similar additional volumes due to the maturity of most markets, slower economic growth, and competition with renewable energies and/or coal across the three regions. Still, the OECD Americas region will contribute to around 50 bcm, approximately 10% of the incremental consumption over 2013-19.

Despite all its well-known qualities, natural gas will find it difficult to gain market shares, notably in the power generation sector. Europe is certainly the best example, with declining gas-fired generation. But the recent recovery in coal-fired generation in the United States and difficulties for gas to compete against coal in Asian countries reinforces this assertion. Natural gas also suffers from the fact that it always has a substitute in all sectors. In residential, natural gas must compete against electricity and oil products; in industry, the main competitors are oil products; and in the power generation section, coal, renewable energies and nuclear are the alternative energies. Presently, the difficulty mostly arises from the competition with either renewable energies or coal in the power sector.

Meanwhile, natural gas is trying to make inroads in new sectors such as transport. While a promising new outlet, with demand projected to double in road transport to 93 bcm by 2019, this market could prove to be a long and challenging process, with the main risk being the respective relationship between oil and gas prices. Using gas for shipping is particularly promising for the post-2020 period. Due to stricter emissions standards being put in place, the sulphur content of fuels used in some specific coastal areas will be limited from 1% today to 0.1% from 2015 onwards. This tighter limit could be extended to other international waters with a 0.5% threshold as soon as 2020, instead of the current 3.5%. Three alternatives compete: use of marine diesel oil (MDO), scrubbers or LNG. This market requires creating not only new infrastructure for international and domestic navigation, but also building or retrofitting vessels. Here again, the price difference between LNG and MDO could be crucial. China could be among the first to develop LNG use for inland waterway transport due to the pressure to reduce emissions from diesel on rivers, such as the Yangtze and Pearl.

OECD regions feed 40% of supply growth, the FSU region falls behind

Two OECD regions (Americas and Asia Oceania) will provide around 40% of the additional gas volumes, while the Middle East contributes 19%. Nevertheless, the drivers behind the growth of the two OECD regions differ greatly: OECD Americas will primarily meet domestic demand and then export gas in the form of LNG from the United States from 2016 onwards. The role of natural gas liquids (NGLs) in supporting US gas production will be essential, as prices remain below USD 5 per million British thermal units (MBtu) over the forecast period. In contrast, the growth in OECD Asia Oceania is almost entirely dedicated to LNG exports from Australia. The exception in this region is that Israel's[1] new gas will go mostly to its domestic market, along with some limited regional pipeline exports.

Meanwhile, the FSU/non-OECD Europe region falls significantly behind, providing only 6% of additional volumes. Even Africa, non-OECD Asia and China bring individually more volumes. This quite drastic change from previous outlooks comes as the result of limited import needs from Europe, where FSU gas competes against LNG as well as lower intra-regional exports from Russia to other FSU/non-OECD European countries. Russia also suffers from the absence of a pipeline to China (which is not expected to be operational before 2020) and a delayed start of planned LNG export projects. Against this backdrop, Central Asian producers will benefit from the expansion of the Central Asia Gas Pipeline to increase their deliveries to the gas-hungry Chinese market and Azerbaijan from the start of the Trans Adriatic (TAP) and Trans Anatolian (TANAP) pipelines to deliver more gas to Europe. Consequently, Russia's gas production will remain relatively flat over the projection period, while US output will increase significantly on the back of higher domestic demand, LNG exports and the absence of recovery of Canada's production. This relatively bleak outlook for FSU gas does not mean that Europe will reduce significantly its dependency on Russian gas, as pipeline supplies remain a key component of the region's supplies: the region will also need them in the short term, as more LNG will be heading to Asia. In the absence of increased pipeline supplies from North Africa, additional pipeline gas can only come from Russia and from Azerbaijan from 2019 onwards.

[1] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

For all its reserves, the Middle East finds it difficult to develop its large resource base. The issue is essentially above ground and has its roots in the discrepancy between the cost of developing non-associated or tight gas fields and domestic gas prices, often below USD 2/MBtu. Consequently, new volumes from the Middle East meet only 88% of its additional demand, requiring the region to import more LNG. The deal regarding Oman's Khazzan field shows that the development of more complex and expensive fields is possible if the country were to raise its domestic prices, as Oman did for industrials. This *MTGMR* is more optimistic regarding Iran's production developments, considering the recent developments on the international scene. Iran is also working on a new type of contract, different from the previous buy-back contract, with the aim of making it more attractive for foreign investors. But for the country to become a significant exporter of natural gas, sanctions would have be totally lifted, while gas demand would need to be curbed down through energy efficiency measures and price increases. Numerous pipeline export projects are in the planning stages and could move forward quickly should Iran increase its gas production faster than demand, but a decade would be needed for the country to enter the LNG market.

Elsewhere, China will be the fastest-growing region, with its production surging by 65% to 193 bcm on the back of new conventional gas developments supported by recent discoveries, shale gas, and coal gasification, which is expected to provide some 40 bcm of additional gas supply by 2019. After its collapse in 2013, Africa's production should recover quite well, to 254 bcm by 2019. For once, the traditional large producers are not the only source of growth, but production does not start to pick up in Eastern Africa, where LNG projects are expected to begin only after 2020. Equally impressive is the 14% increase in non-OECD Asia to 357 bcm, with Papua New Guinea, Myanmar and Viet Nam providing new volumes, while India recovers. Despite a 19% growth, Latin America is considered as underperforming, as most of the growth originates from Brazil, while large reserve holders continue to struggle. Against this backdrop, Europe is the only region where gas production is likely to drop.

The Asian price stalemate: who blinks first?

The wide gap between Asian and US gas prices, which amounted to USD 12/MBtu in 2013, seems to have captured the gas industry's attention as it will affect not only future prices, but also investments and trade. While this gap concerns Asian buyers firsthand, it has also wide implications for the gas and energy world. Natural gas demand in Asia (including OECD Asia Oceania, China and the other non-OECD Asian countries) grows by around 250 bcm over the projection period, representing half of the world's incremental needs. Around 100 bcm will be fed by LNG imports, supported by additional LNG regasification being built. Still, this growth is fragile and depends also on prices. If gas cannot fill power generation needs, it will leave room for coal. Recent trends actually show coal coming back in many OECD Asia Oceania countries, while maintaining a large role in China and non-OECD Asia. Future gas pricing will also determine which of the new generation of LNG suppliers may take the baton from Qatar over the coming decade and whether other new trends in the LNG business will appear or expand over the coming years, such as the re-exports of LNG, which appeared as a consequence of the price spread. The future natural gas supply/demand balance in Asia will, therefore, have far-reaching consequences for global gas trade and whether the world will be short of gas, in the near to medium term.

For suppliers and buyers, the question is, therefore, who blinks first? On the one hand, Asian buyers are no longer ready to pay record oil-linked prices that harm their economies, with consequences such as Japan developing a trade deficit in 2011, a situation unseen for the past 31 years. There is also the question of the flexibility of gas supplies. As demand in Asia grows faster than in other regions, Asian countries think they should get better terms and are now considering developing co-operation among buyers. Additionally, companies are looking for different pricing mechanisms and more flexibility in the delivery terms. Signing up for cheaper hub-priced LNG from the United States seems very attractive at the current US price levels.

But, on the other hand, new greenfield projects are increasingly expensive, calling for securing revenues through long-term contracts preferably linked to oil prices. Around 150 bcm per year of LNG liquefaction capacity is under construction as of May 2014. Australia will provide about half of this capacity, but investment costs there are also at record highs – almost USD 4 000 per ton (including upstream and LNG costs). Global LNG trade is expected to rise from 322 bcm in 2013 to reach 450 bcm by 2019; this 40% gain is much higher than that of interregional pipeline trade. More LNG will be needed thereafter, and given the five-year construction period that any greenfield LNG projects usually require, decisions must be taken now for supply arriving to the markets by 2020. Although many LNG projects are at the planning stage, actually very few final investment decisions (FIDs) have been taken since mid-2012. The FID taken by Russia's project Yamal LNG following the adoption of a law breaking the stranglehold of Gazprom on LNG exports shows that the Russian government has perfectly understood that the window of opportunity to capture a slice in the LNG pie may be closing soon, as US LNG projects progress. However, the Department of Energy's (DOE) approval of LNG projects' aiming at exporting to non-free trade agreement countries should not be confused with a formal FID. Indeed, this may be the main stumbling block in the path of US LNG projects, but it is not the only one. Other authorisations are necessary, and the financial side of the projects also matters. Only one single US LNG plant is under construction as of May 2014, even though this report assumes that US LNG will represent 5% of global trade (pipeline and LNG) by 2019.

Four regions are competing to take the largest slice of the quite limited Asian LNG import pie: North America, Australia, Russia and East Africa. Solely based on resources, all of them could provide over 100 bcm of LNG liquefaction capacity. The United States has clearly departed from the traditional oil-linked long-term contracts with final destination clauses by proposing Henry Hub (HH)-based long-term contracts with no destination clauses. Of note is the fact that US LNG export plants still need long-term contracts and that those moving ahead have already sold a fair share of their output. No other supplier has formally made this change. But is price indexation the issue, or is it the price level? What buyers really want are lower gas prices, which also determine the profitability of future supply prospects. The industry faces the following options while trying to renegotiate existing long-term contracts and negotiate on new LNG contracts for projects still at the planning stage:

- continue with oil indexation but with lower slopes, lower reference price and S-curves triggered at lower oil prices,
- use an existing hub indexation such as HH,
- or include the possibility of using a still-to-be-determined Asian hub, once its liquidity is deemed sufficient (such an option could be included in contracts).

Decisions will need to be made and the options chosen will determine how the Asian market develops over the next decade.

DEMAND

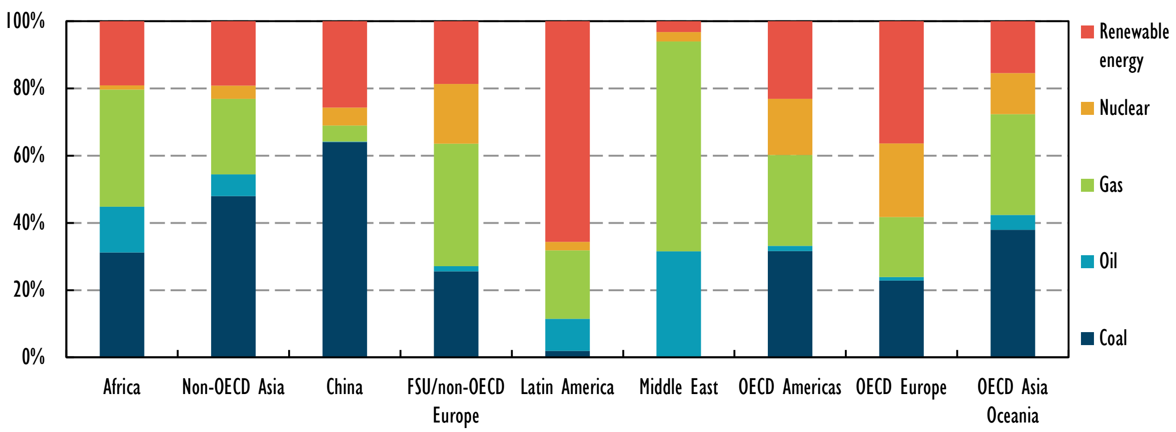
Summary

- Gas demand increased only 1.2% to around 3 500 billion cubic metres (bcm) in 2013 on the back of a slowing global economy, competition from coal and renewable energies, and supply constraints affecting non-OECD (Organisation for Economic Co-operation and Development) regions. This rate is below the growth of oil (1.4%), coal (3-4%) and renewable energies (>4%). Surprisingly, non-OECD regions, which had been a constant driver behind the gas consumption increase over the past decade, delivered only a 1.2% increase, barely higher than the OECD regions (1.1%).

- World gas demand is expected to amount to 3 980 bcm by 2019 (or 2.2% per year over 2013-19), on its way to crossing the 4 000 bcm threshold by 2020. This level represents, nevertheless, a 2% downward revision compared to last year's forecasts. The largest downward revisions affect Europe and the Former Soviet Union (FSU)/non-OECD Europe region.

- The power generation sector represents the largest source of demand, followed by the industry sector. Together they account for 84% of the new consumption. Still, gas's share in total power generation barely increases by 0.5% to 2019, comprising only 22% of the total due to the competition of renewable energies or coal in OECD regions, Latin America, non-OECD Asia and the People's Republic of China, as well as insufficient supplies in many developing countries (Figure 1). Despite many merits, such as large reserves, its clean burning qualities and flexibility, gas has to fight to maintain its position in all the regions, facing different challenges in each. An adequate pricing mechanism reflecting supply-and-demand fundamentals is of paramount importance: subsidies exacerbate demand and inevitably lead to shortages a decade later, while high prices shatter the competitiveness of gas, favouring other energies.

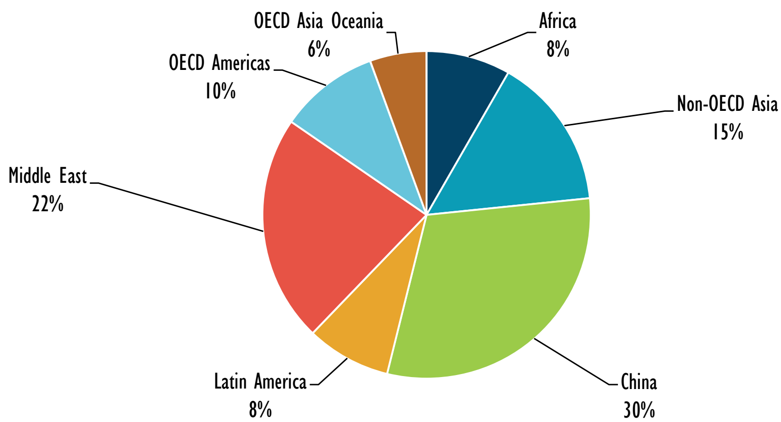
Figure 1 Power generation mix by region, 2019



Source: unless otherwise indicated, all material in figures and tables is derived from IEA data.

- The shift of gas demand towards non-OECD regions will continue as their share increases from parity with OECD regions in 2007 to 57% in 2019. Together non-OECD countries will account for 85% of new demand. Besides the need to support economic activity, access to modern energy is still lacking for hundreds of millions of people in Africa and non-OECD Asia. There is also a need to use cleaner fuels and switch away from coal, notably in the power generation sector, and oil. China alone represents 30% of the incremental 490 bcm that will be needed over 2013-19, due to the priority given to clean air affecting demand in most sectors (Figure 2). The Middle East and non-OECD Asia follow, representing 22% and 15% of total additional demand. While OECD Americas' consumption will gain only 50 bcm, the year 2013 was colder than average, so the temperature-adjusted gain may be closer to 70 bcm. European demand remains stable, with a small gain in demand (1 bcm), but this apparent stability hides an impressive short-term, 34 bcm collapse in 2014 due to mild weather, the slow economy and booming renewable energies. In OECD Asia Oceania, gas is facing intense competition from coal-fired plants. Meanwhile, the FSU/non-OECD region is characterised by stable demand.

Figure 2 Split of incremental demand by region, 2013-19



- The Middle East is not able to displace oil by gas and renewables in the power generation sector. On the contrary, oil demand will continue its relentless growth due to insufficient domestic gas production and expensive liquefied natural gas (LNG) imports, even if the share of oil in total power generation drops slightly. This trend is particularly striking in Saudi Arabia, where oil-fired generation rises by around one-third over 2013-19 due to insufficiently growing gas production. Besides the issue of gas supplies, many power plants have very low efficiency, often below 30%.

- The road transport sector will continue to support gas demand, adding 45 bcm over the forecast period, two-thirds of which will originate from China. Over the longer term, one sector to watch will be maritime transportation, where gas could play a major role if the right conditions are present. Due to stricter emissions standards, the sulphur content of fuels used in some specific coastal areas will be limited to 0.1% from 2015 onwards. This restriction could be extended to other international waters with a 0.5% threshold as soon as 2020. LNG could be a viable solution over the other two alternatives – scrubbers and use of marine diesel oil (MDO). This option involves building new LNG-fuelled vessels or potentially retrofitting existing vessels, and deploying the refilling infrastructure alongside the main inland shipping routes as well as in the key sea harbours. Future price and policy assumptions are crucial for the economics of such a switch because investments are usually made for a period of 15 to 20 years: the price difference between LNG and MDO should allow for the additional cost of an LNG-fuelled ship to be recovered. Beyond international navigation, China could be among the first to develop LNG use for inland waterway transport due to the pressure to reduce emissions from diesel on rivers such as the Yangtze.

Recent trends

World gas demand: An abnormal year?

Natural gas has many merits, such as large reserves, its role as a clean burning fuel compared to other fossil fuels, and flexibility. Yet, despite these qualities, it is not always available everywhere, cost-competitive against other energy sources and is not carbon neutral. Global gas demand increased by a modest 1.2% in 2013 to 3 490 bcm, making it the fuel with the lowest relative growth as oil rose 1.4%, coal between 3% and 4%, and renewable power generation above 4% (Table 2). Gas demand remained subdued in 2013, its growth rate much lower than what was observed over the past decade (2.8% per year). But was 2013 an abnormal year or a taste of things to come?

This lower growth is in line with the expectations of the *Medium-Term Gas Market Report (MTGMR) 2013* which forecast 1.6% growth for that year. Besides the expected slowdown of gas demand growth in mature OECD countries, non-OECD countries continue to face insufficient supplies, constraining their gas consumption. On the one hand, insufficient supplies are due to the inability to increase production adequately. Production is lagging owing to the maturity of existing fields, declining reserves, the high cost of the development of new fields in the context of low domestic gas prices, as well as geo-political events affecting the delivery of existing fields or the development of new prospects. On the other hand, insufficient supply is caused by the inability to import adequate quantities of natural gas. Imports are impeded due to high prices, lack of infrastructure, or limited quantities of additional supply physically available. In 2013, global LNG trade remained roughly the same as in 2012, failing to provide substantial additional supply to thirsty developing markets, while additional pipeline exports were also constrained by the absence of significant infrastructure development. Consequently, many countries in Latin America, non-OECD Asia, the Middle East and Africa continue to face gas shortages driven by one or several of the reasons mentioned above. The only country that did not fail to meet growth expectations was China, where consumption gained a healthy 13%, bringing demand to 166 bcm.

Table 2 World gas demand by region (bcm)

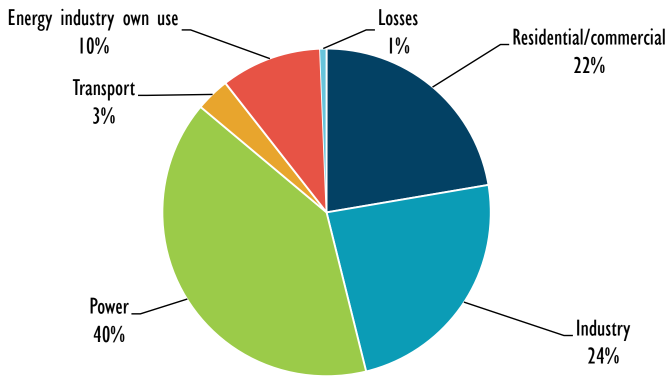
Total	2000	2010	2012	2013*	2013/12 (%)
OECD Europe	475	567	507	504	-0.7
OECD Americas	794	851	902	920	2.0
OECD Asia Oceania	131	198	225	229	1.8
Africa	55	105	118	119	0.6
Non-OECD Asia (exc. China)	155	288	287	283	-1.3
China	28	109	147	166	13.3
FSU/non-OECD Europe	597	681	693	680	-1.9
Latin America	93	151	155	164	5.7
Middle East	180	376	416	426	2.3
Total	**2 508**	**3 326**	**3 450**	**3 490**	**1.2**

*2013 data are estimated.

Note: OECD Americas includes four countries: Canada, Chile, Mexico and the United States. OECD Asia Oceania includes Australia, Israel, Japan, the Republic of Korea and New Zealand.

But slow gas demand growth is not only a matter of natural gas supply availability; interfuel competition also plays a large role. Besides the macro-economic factors, gas has to be competitive against other fuels to increase volumes delivered. Two fuels have emerged as the most prominent competitors to natural gas: coal and renewable energies. The largest share of demand is in the power generation sector, which represents 40% of global gas demand as of 2013 (Figure 3). Over the past three years, OECD Europe's gas demand lost almost 40 bcm in the power generation sector alone due to the combined pressure of renewable energies and coal. Likewise, US gas demand in the power market plummeted by 26 bcm in 2013 after gas prices increased there. In OECD Asia Oceania, coal is winning market shares back from natural gas in Japan. Meanwhile, coal continues to make inroads in Asia and in some Latin American countries, while oil-fired generation is the replacement solution in the absence of other fuels or insufficient gas supplies, for example in Africa and the Middle East.

Figure 3 World's gas demand by sector, 2013 (estimates)



OECD regions: The illusion of the déjà vu

Gas demand in the OECD regions grew 1.1% in 2013, much less than the previous year (1.6%). But this growth is actually artificially inflated because an estimated 30 bcm of gas demand gains came from abnormally weather in 2012; consequently OECD gas demand should have dropped by around 1%. The story appears to be quite the same for the two previous years, whereby the 19 bcm gain was supported once again by OECD Americas and OECD Asia Oceania (Table 3). These two regions continue to drive consumption growth even though they posted much lower gains due to diverging paths among their member countries. From a sectoral point of view, the sharp rise in residential/ commercial consumption, helped by a small hike from industrial users, was sufficient to hide the 30 bcm drop in power generation and the difficulties that gas-fired power plants encountered to remain competitive in the different regions.

The trend in OECD Americas seems to reflect that of the US gas consumption with a healthy 2% growth rate. Seasonally adjusted demand, however, should have been almost flat. Gas consumption in the OECD Americas region gained 18 bcm or 2% in 2013, reaching 920 bcm. The region is by far the largest consumer of natural gas, with a 240 bcm gap above the second-largest consuming region – the FSU/non-OECD Europe. Consumption was on an upward trend in the United States, Mexico and Canada, but declining in Chile. Gas demand in the United States increased again, after an exceptional year in 2012: even though a mild winter reduced residential/commercial demand by 11%, gas use by power generators surged and largely compensated for this slackening so that US demand recorded a 30 bcm gain. Assuming normal weather conditions, a drop in US gas demand was to be expected based on a return to higher gas prices putting pressure on the US power generation sector. The power generation sector showed an estimated 7% reduction after the 20% increase observed in 2012, but this reduction was counterbalanced by the surge in residential demand. Low gas prices, together with an improving economy, continue to benefit industrial gas users whose demand gained almost

3%. Similar to the United States, Canada benefited from the recovery in the residential/commercial sector. Mexico is still a developing economy, and natural gas is a key fuel supporting this economic development. Its demand could even be higher, if it were not for its dwindling gas production.

Table 3 OECD gas demand by country (bcm)

	2012	2013*	%		2012	2013*	%
Europe	507.3	503.6	-0.7	*Slovakia*	5.3	4.8	-10.1
Austria	9.0	8.6	-5.3	*Slovenia*	0.9	0.8	-5.7
Belgium	18.3	18.1	-1.3	*Spain*	32.4	29.8	-8.0
Czech Republic	8.4	8.6	2.4	*Sweden*	1.2	1.1	-4.0
Denmark	3.9	3.7	-4.3	*Switzerland*	3.6	3.8	5.4
Estonia	0.7	0.7	1.6	*Turkey*	45.3	45.7	0.9
Finland	3.7	3.5	-5.4	*United Kingdom*	78.0	77.3	-0.9
France	42.1	42.8	1.7	Asia Oceania	225.0	229.1	1.8
Germany	85.8	91.3	6.4	*Australia***	35.9	34.2	-5.0
Greece	4.3	3.8	-11.5	*Israel*	2.6	7.0	172.9
Hungary	10.1	9.2	-8.3	*Japan***	131.8	130.5	-1.0
Iceland	0.0	0.0	0.0	*Korea***	50.2	52.9	5.3
Ireland	4.7	4.6	-3.2	*New Zealand*	4.5	4.7	3.8
Italy	74.9	70.0	-6.5	Americas	902.0	920.2	2.0
Luxembourg	1.2	1.1	-8.6	*Canada*	105.8	108.4	2.5
Netherlands	46.0	46.9	1.8	*Chile*	4.9	4.5	-7.7
Norway	5.2	5.2	1.4	*Mexico***	68.3	69.8	2.1
Poland	18.0	18.1	0.5	*United States*	723.0	737.5	2.0
Portugal	4.5	4.2	-7.0	OECD	1 634.3	1 652.8	1.1

Note: in this report, the percentage points mentioned in tables may not correspond to changes calculated based on yearly numbers due to rounding.

* 2013 data are estimates as of May 2014.

** Data on Japan, Korea and Australia are based on fiscal years (from April to March for Japan and Korea, from July to June for Australia). Due to important statistical differences, Mexican gas demand is calculated based on production, imports and exports.

After two years of sharp decline, European gas demand lost another 4 bcm (0.7%), falling 504 bcm. Still, demand was supported by a cold and long winter, which lingered until the beginning of June 2013. Without these exceptional weather conditions, European gas demand would have dropped even more, based on high gas prices and low gross domestic product (GDP) growth weighing down industrial and power generation gas demand. In that respect, nothing has changed in Europe, and many gas companies openly wonder whether European gas demand will recover before 2020 – or ever. While the results are better than expected, European consumption levels have now returned to the same level as they were ten years ago in 2003. Without the weather effect, European gas demand would have crossed the 500 bcm threshold. At an individual country level, Germany is the largest-consuming country in Europe; the weather was largely responsible for the 6.4% gain observed in that country. In contrast, the United Kingdom had slightly declining gas consumption and was therefore largely outpaced by Germany as the gap between the two largest European gas consumers rose to 14 bcm. Germany overtook the United Kingdom in 2011, after 15 years during which UK demand was above Germany's. Many European countries are now back to levels unseen since 2000, or even in some cases 1996. This decline is notably the case for the Czech Republic, Denmark, Estonia, Finland, Hungary, the Netherlands, Slovakia and the United Kingdom. The two sectors responsible for this decline in demand are the same across all countries: industry and power generation. Within power generation itself, three factors are still at play: low power demand growth, increasing renewables and gas-to-coal switching. Two countries (Slovakia and Greece) had double-digit losses, although it is worth noting that neither of these countries is a major consumer.

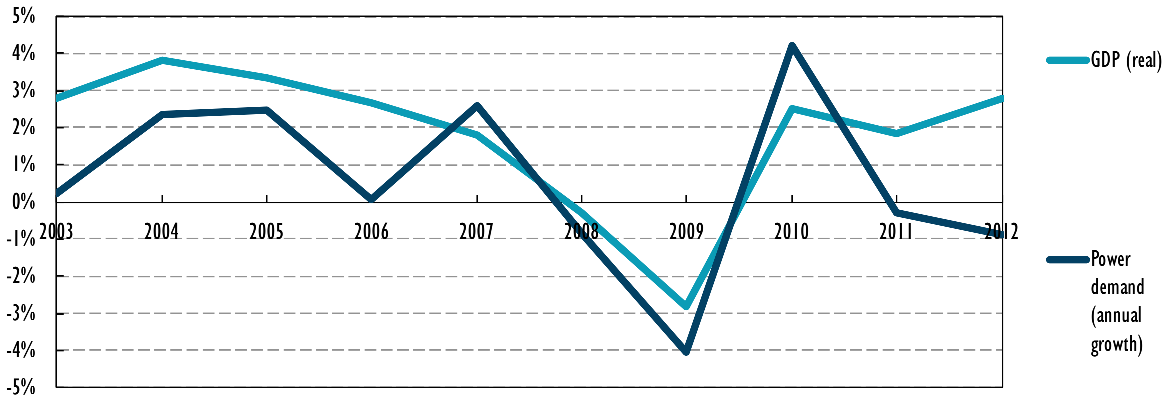
The most interesting, not-weather biased, developments certainly took place in OECD Asia Oceania. In contrast to the other two regions, OECD Asia Oceania saw genuine demand growth: Israel and Korea were the motors behind it, even though Japan's gas consumption dropped for the first time since the Fukushima accident in March 2011. Israel's demand multiplied by 2.8 due to the Tamar field coming online in April 2013. Despite the lack of Egyptian pipeline supplies, the country is now in a position to meet its present and future demand needs, notably in the power generation sector. Another surprising development took place in Japan, where gas demand almost stood still for the first time since the Fukushima accident. In the Japanese power generation mix, coal was the fuel with the highest absolute growth: as LNG's price reached above oil parity levels occasionally during winter, while coal prices made coal-fired generation more affordable. Since September 2013, no nuclear power plant has been operating in Japan after the closure of Ohi for planned maintenance. When, whether and how many nuclear power plants will come back online in Japan remains a key uncertainty over the medium term. In contrast, the increase in gas demand in Korea was mostly driven by closures of a few nuclear power plants due to falsified documentation related to control cabling, which was discovered in May 2013 at four reactors. The Nuclear Safety and Security Commission ordered the operator KHNP to stop operation of Shin Kori 2 and Shin Wolsong 1, and to keep Shin Kori 1 offline. The construction of several new nuclear power plants has been delayed. The nuclear power plants were cleared to restart in January 2014. Elsewhere in the region, Australia's gas demand declined due to a combination of lower power demand and increasing gas prices, which affected the use of gas in the power generation sector.

Power generation

In all three OECD regions, natural gas demand in the power generation sector was constrained by two other sources of energy: renewable energies and coal. Consequently, gas consumption for power generation is estimated to have decreased by 6% to 575 bcm from 615 bcm in 2012. The competition takes place once again in a context of low power demand growth. More than ever, coal benefited from a stronger position in terms of relative fuel and, when relevant, very low carbon prices. While this picture has remained the same as during the two previous years in Europe, it represents a major change in OECD Americas and OECD Asia Oceania, notably in Japan and the United States (where coal was at an historical low in 2012). In these countries, coal has made a noticeable comeback, as coal-fired generation increased by almost 5% in the United States and 10% in Japan.

The total electricity supplied in the OECD regions, which is our proxy for power demand, expanded by 0.5%. While in Europe, the 0.8% drop is the clear result of low economic growth and demand destruction, in other countries such as the United States, a delinkage also seems to exist between the GDP and power demand growth over the past few years. Power demand growth was relatively stable despite the US GDP growing at 2.1% per year on average over 2011-13 (Figure 4). In Europe, power demand dropped in major countries such as Germany, Italy, the United Kingdom and Spain. However, French power demand was boosted by the effect of a long winter due to its high share of residential electric heating.

Figure 4 Variations in US power demand and annual GDP growth, 2003-12



In total, renewable energy grew by over 4% (estimated) in 2013 (IEA, 2014b). Renewable energies now represent around 22% of total OECD power generation. This share is the largest in Europe because European Union countries share the target to increase the contribution of renewable energy to 20% of its gross final energy consumption by 2020. The increase in the contribution of renewable energies to the power sector is more than three times higher than the drop in electricity supplied.

Additionally, nuclear generation posted a slight increase, mostly driven by higher output in OECD Americas, while nuclear output dropped slightly in Europe and sharply in OECD Asia Oceania. These trends mean that the share of combustible fuels once again decreased, from 61% in 2012 to 60% in 2013. The outcome for natural gas was lower demand in OECD Americas and OECD Europe, even though the reasons varied.

In the OECD Americas region, the generation from combustible fuels receded by over 30 terawatt hours (TWh) despite the small increase in power demand. The surge in renewable energies, notably wind and solar, and in nuclear, was indeed much larger than the incremental power demand. After the remarkable 200 TWh additional US gas-fired generation in 2012, a drop in 2013 was to be expected based on normal weather conditions and given the increase in gas prices. In 2012, gas-fired power generation benefited from the exceptionally hot summer and low gas prices (USD 2.7 per million British thermal units (MBtu) on average). However, in 2013, coal-fired plants were again in a competitive position against gas-fired plants as gas prices rose to USD 3.8/MBtu. As renewable energies grew more than power demand, the combined output from combustible fuels dropped; consequently, the gain in coal-fired generation was lower than the drop in US gas-fired generation. In Mexico, combustible fuels' output remained stable, benefiting from a sharp reduction in hydro output while nuclear generation increased by half.

European power generators may wonder whether a floor exists to that region's gas consumption, as it dropped by an estimated 18 bcm in 2013, following an already significant 23 bcm drop in 2012.[2] Demand in this sector has not been so low since 2002, and the share of the power generation sector now amounts to 28%, while it peaked at around 35% over 2007-11. Again in 2013, gas-fired power plants suffered from the triple combination of lower power demand, higher contribution of renewable energies and the unfavourable pricing relationship of gas against coal in the absence of any significant CO_2 price. Taking into consideration the renewable increase, the drop in power demand, nuclear

[2] Although the IEA does collect data on power generation in individual countries by fuel, reporting this data set is not compulsory, and one-quarter of the OECD countries do not give any data.

generation and the import/export balance, generation from combustible fuels lost almost 100 TWh, which is equivalent to a gas demand of around 25 bcm. In many cases, gas-fired power plants are still not competitive against coal-fired plants, and their generation decreased further in 2013. IEA preliminary data show that the results differ depending on the European countries observed: in the United Kingdom and Ireland, the relative decline of gas and coal was the same. In Spain, coal-fired generation declined more than gas, while the opposite was the case for Hungary. Coal-fired generation increased while gas declined in Austria, Germany, the Netherlands, Portugal and Poland. In Belgium and the Czech Republic, coal-fired generation receded while gas-fired generation regained some strength.

Within the OECD Asia Oceania region, coal rebounded in Japan, where coal-fired generation increased by around 10%, while gas-fired generation remained broadly stable. Gas and oil in Japan had been the backbones of incremental power generation since the Fukushima accident and the progressive closure of nuclear power plants due to permanent damage or for scheduled maintenance. During 2013, only two nuclear units had been operating (Ohi 3 and 4), and both closed down in September 2013, leaving Japan without any nuclear generation. Before Fukushima, nuclear represented around one-fourth of the country's total generation. In 2010, nuclear power plants generated 288 TWh. This output dropped to 13 TWh in 2013 (Box 1).

Elsewhere in OECD Asia Oceania, in Australia, both coal- and gas-fired generation fell due to lower power demand and increased output of renewables. This trend signals the end of the relentless increase in gas-fired generation that had been taking place since 2006. Early 2014 may give a different path to gas-fired generation: due to the heat wave in Australia, notably in Victoria and South Australia, gas-fired generation contributed to respectively 50% and 90% of the incremental power needs in these areas. Korea and Israel were the only two countries featuring a sharp increase in gas-fired generation, albeit for widely different reasons. Israel benefited from new additional domestic supplies coming from the recently started Tamar field. Korea faced a drop in nuclear generation while demand increased slightly and renewables remained stable. In that context, both coal and gas-fired plants contributed additional power supplies, but gas took the lion's share.

Box 1 Three years after the Fukushima accident, how is Japan coping in the absence of nuclear?

An earthquake in Fukushima, Japan in March 2011 and the tsunami that followed inflicted enormous damage on the Japanese electricity sector. Around 40 gigawatts (GW) of capacity were lost, including damage to thermal and nuclear power plants owned by the Tokyo Electric Power Company (TEPCO) and the Tohoku Electric Power Company. Among these damaged plants, the Fukushima nuclear power complexes were severely damaged, particularly four units of Fukushima Daiichi. Ten units of four nuclear power complexes, with a combined total capacity of 10 GW, were shut down. All six reactors of Fukushima Daiichi (4.7 GW) were decommissioned, although others may be restored in the future.

Nuclear power plants unaffected by the earthquake were shut down month after month in association with regular inspections, and all nuclear power plants were shut down for the first time since 1970; the last operating plant, Tomari unit 3, closed in May 2012. However, two units of Ohi passed the "stress test" and restarted in time to meet summer peak demand in July 2012. The two units had been operating for over a year, but were shut down due to regular inspection again in September 2013. Since then, no electricity has been generated by nuclear power plants in Japan.

Box 1 Three years after the Fukushima accident, how is Japan coping in the absence of nuclear? (continued)

Moreover, damaged thermal power plants have restarted progressively after the earthquake and have helped to compensate for the missing power generation. In addition, over ten units of antiquated, mothballed, oil-fired power plants (3.3 GW) resumed operations, and some 20 units of diesel and gas-fired power plants (4.1 GW) were installed urgently to cover the loss of nuclear. Although rolling blackouts were executed for two weeks shortly after the earthquake for the first time since the World War II period, Japan managed to replace missing power generation by initiating a power conservation campaign for all consumers, as well as by using old and newly built thermal power plants. A broad range of electricity-saving measures was implemented during the campaign, including thinning out and extinction of lights, mitigating temperature settings of air conditioners, reducing train operations, and shifting operating days and hours of factories. As a result, power demand in fiscal year (FY) 2011 decreased by 5.8% compared with FY 2010, and by a further 1.7% in FY 2012.

In spite of the power conservation initiatives, the missing nuclear generation had to be replaced by fossil fuels, because renewable energies excluding hydro represented only a small share of total generation (4% or 46 TWh in FY 2010) and could not be expected to replace the 288 TWh of nuclear electricity generated in FY 2010. Therefore, increased gas- and oil-fired generation boosted the dependence on hydrocarbon fuels in the composition of power supply in Japan, while the share of nuclear sharply decreased over 2011-13. Consequently, the share of fossil fuels in total power generation leaped, from 62% in FY 2010 to 77% in FY 2011 and 86% in FY 2012 (Figure 5).

Figure 5 Source of power supply in Japan, April 2010 to December 2013

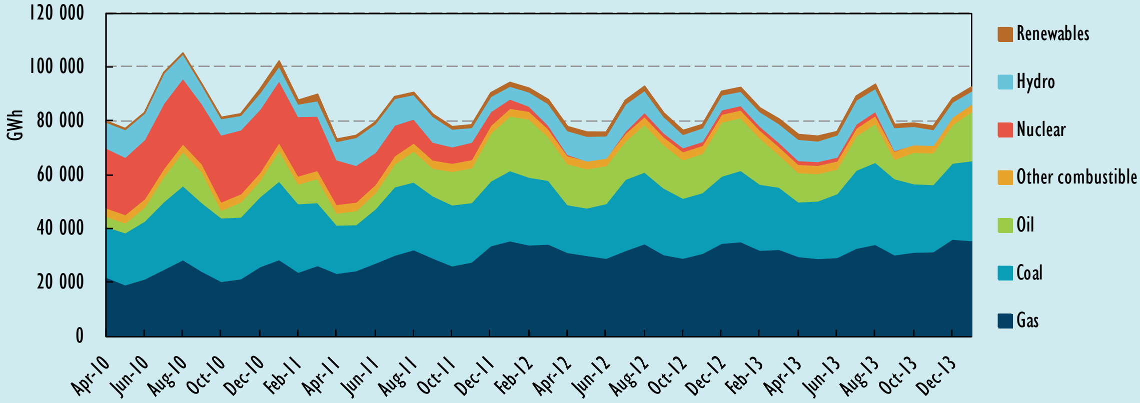
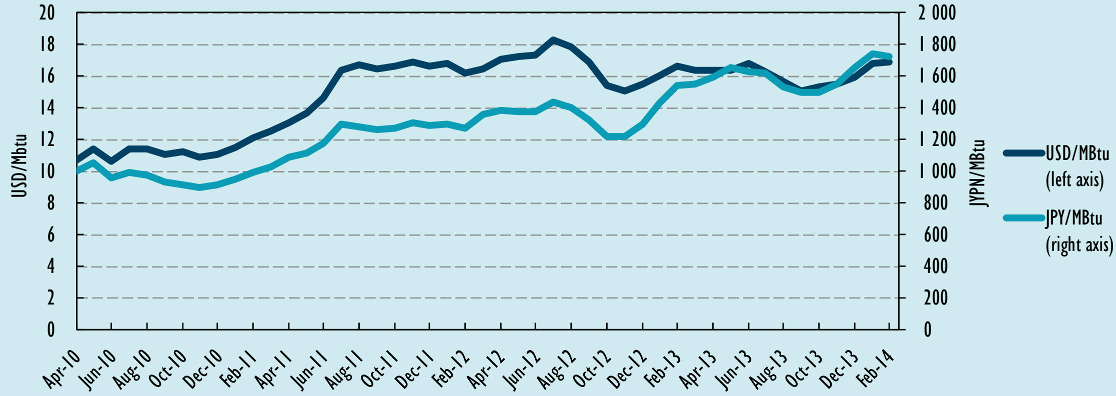


Figure 6 Monthly Japanese LNG import prices, USD and JPY, April 2010 to February 2014



Box 1 Three years after the Fukushima accident, how is Japan coping in the absence of nuclear? (continued)

LNG imports to Japan have grown every year after the earthquake. In FY 2012, LNG imports marked a record high of 86.9 million tonnes against 70.6 million tonnes in FY 2010. The new record was again set in FY 2013 with LNG imports marking 87.7 million tonnes under the influence of cold weather in early 2014. Nevertheless, LNG import growth has clearly slowed down over the past year.

The share of oil generation also increased, from 8% in FY 2010 to 17% in FY 2012. However, it turned downward to 16% during April to December 2013, from 19% during the same period the previous year, as high-cost oil generation was replaced by coal and gas-fired power generation. The share of coal remained almost unchanged for over two years after the earthquake, as coal-fired power plants had already been used to the maximum as a base-load source of electricity. Nevertheless, the share of coal-fired generation increased in FY 2013 to over 30% from 27% before, due to improved operations, as well as start-up of two coal-powered units in December 2013.

Increased dependency on fossil fuels, along with weaker yen and high oil prices, has intensified the strains on the Japanese economy and has put pressure on the profits of electricity companies. The total amount of LNG imports has been rocketing from USD 41.6 billion (JPY 3.5 trillion) in FY 2010 to USD 74.6 billion (JPY 6.2 trillion) in FY 2012 (Figure 6). Although the total amount of LNG from April 2013 to February 2014 came down by 3.4% in USD compared to the same period last year, the total amount in yen increased by 17.9% due to weaker yen. Increased imports of LNG and oil helped contribute to Japan experiencing trade deficits in 2011, for the first time in 31 years; the trade deficit in FY 2013 marked a record high of USD 134 billion (JPY 13.7 trillion).

Japan's increasing LNG import situation has heightened the momentum to reduce the LNG import price as well as improved the flexibility of LNG trading. To achieve these goals, the Japanese government has taken a series of actions, such as adopting leading role in discussions with India and Korea to mitigate increasing LNG import costs; hosting an LNG producer consumer conference; approaching gas-producing countries such as Qatar, Canada and Russia; considering the establishment of debt guarantees for Japanese LNG industries; and endeavouring to establish an LNG futures market by end-2014.

Meanwhile, the private sector is also actively engaged in reducing LNG prices by procuring LNG from new suppliers, especially from North America. Japanese companies have already signed as much as 28 bcm per year of Heads of Agreement (HoAs) with the United States (Table 4). Japan's biggest LNG buyer, TEPCO, announced its strategy to procure approximately half of its LNG (equivalent to 10 million tonnes per annum [mtpa]) from lean LNG from mainly shale gas and coalbed methane (CBM) in ten years and started the renovation work on its existing regasification terminals.

Table 4 HoAs between projects in the United States and Japan (as of May 2014)

Project	Importer	Volume (bcm/y)	Companies and volume to be resold (non-binding agreement)
Cameron	Mitsubishi	5.4	TEPCO (0.5 bcm/y)*, Tohoku Electric (0.4 bcm/y)
Cameron	Mitsui	5.4	Toho Gas (0.4 bcm/y), TEPCO (0.5 bcm/y), Kansai Electric (0.5bcm/y)
Cameron	GDF Suez	5.4	Tohoku Electric (0.4 bcm/y)
Cove Point	Sumitomo	3.1	Tokyo Gas (1.9 bcm/y), Kansai Electric (1.1 bcm/y)
Freeport	Osaka Gas	3.0	-
Freeport	Chubu Electric	3.0	-
Freeport	Toshiba	3.0	-
Total		**28.3**	

* Currently under negotiation.

Source: IEA and company websites.

Box 1 Three years after the Fukushima accident, how is Japan coping in the absence of nuclear? (continued)

All 48 of Japan's commercial nuclear reactors are idle as of May 2014. In preparation for resuming nuclear power plant operations, the Nuclear Regulation Authority (NRA) was set up in September 2012 and drew up strict nuclear safety standard in July 2013. Based on the new standard, 17 reactors in ten nuclear complexes owned by eight electricity companies have applied for the safety review. Although the review was initially estimated to take about six months with the first restart taking place around end-2013, the review has been substantially protracted. In addition, the NRA later decided to invite public opinion and conduct hearings at local governments where nuclear power plants are located after the review statement for each reactor is drafted. Therefore, the first restart is expected to be delayed to the beginning of summer 2014 at the earliest.

The Japanese cabinet approved the new Basic Energy Plan in mid-April 2014. Although the plan does not specify a target in terms of share in the future Japanese energy mix, nuclear power was presented as an important base-load power source. In case nuclear power plants do restart smoothly, power supply from LNG would be replaced by nuclear, and LNG demand would be expected to decline slightly over 2014-15. The first victim of a nuclear restart, however, would be the inefficient oil-fired generation because gas is on average less expensive than oil and gas-fired plants, especially the newly built ones, are much more efficient. Coal-fired generation would increase as well due to new capacity recently started or planned and coal-fired electricity being less expensive than gas. In contrast, LNG demand would hover at current high levels in the case of a low nuclear restart. In this matter, the future LNG demand in Japan highly depends on the pace of the restarting of nuclear power plants, and this is almost impossible to predict with certainty.

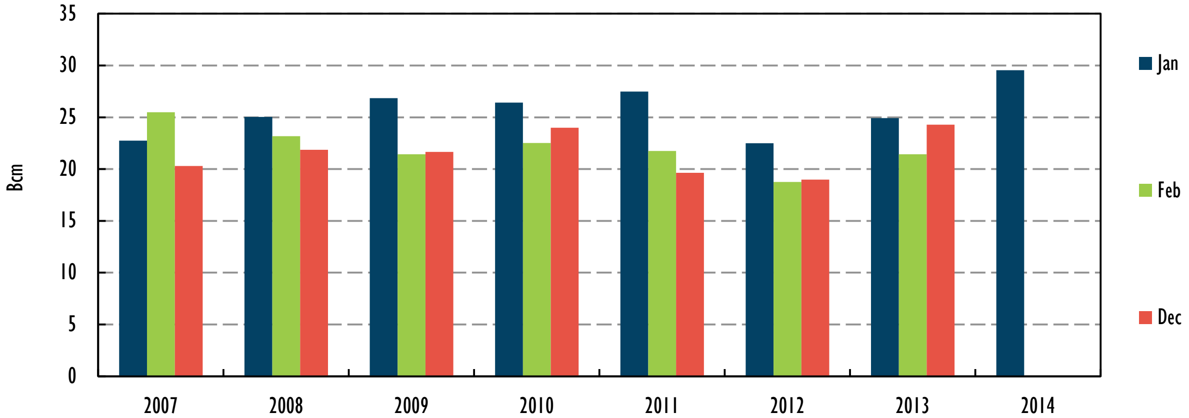
Residential/commercial sector

Residential/commercial gas demand across OECD regions broke an historical record as it reached 536 bcm in 2013, 52 bcm above the 2012 level (the equivalent of the annual French gas consumption). It benefited from colder weather conditions compared to 2012. In Europe, the winter extended well into May and early June 2013. Meanwhile in the United States, weather conditions were almost normal most of the year, compared to the exceptionally mild weather experienced in early 2012, but the month of December was exceptionally cold.

In 2013, European residential/commercial gas consumption is estimated to have increased by 15 bcm to 218 bcm, reflecting the longer winter. Heating degree days (HDD) were not particularly higher than in 2012; actually, even fewer occurred in some countries such as Germany. But the winter was long, and many west European customers did not stop heating until early June. A few other European countries such as Turkey faced milder weather conditions than in 2012 with a reduction in HDD by 7%. Seasonally adjusted French gas consumption would have receded by 3%, but actually gained 1.4%. In particular, customers connected to the distribution network increased their consumption by over 3%. Similarly, neighbouring distribution users in Belgium used 6.4% more. The weather effect seems to have been much larger in Germany as total demand gained 6.4%. In the Netherlands, gas delivered via the regional grid (predominantly to residential and small commercial users) gained 4%.

In the United States, a return to relatively normal weather conditions over January-November helped natural gas demand in the residential/commercial sector to rebound by 15% (Figure 7). But an exceptionally cold December resulted in a 17% increase of the annual natural gas demand, with US residential/commercial gas demand gaining 34 bcm, which is more than total Spanish gas demand. Most of the additional demand occurred during the first four months and in December, with a record difference for March (11 bcm). But US residential/commercial gas demand is likely to break another record in 2014 should the rest of the year be normal. Indeed, the first months were very cold and boosted demand to record levels: 46 bcm were consumed in January 2014 by residential and commercial users, compared with the average monthly demand during a normal year of around 20 bcm per month.

Figure 7 US residential gas demand in winter months, 2007-14



Industry

The trends in industrial gas demand across OECD regions differ greatly. While European industrials consumed broadly the same amount as in 2012, consumption increased in both the OECD Americas and OECD Asia Oceania regions. Even the picture of OECD European gas demand is not uniform, as some countries saw positive demand growth. One way to assess how the industry is doing in terms of gas consumption is to look at two elements: the production from the manufacturing industry, and gas prices. Production from the manufacturing industry indices show that industries in most OECD countries are still struggling and have not yet recovered, but most industries are now on an upward trend. The indices also show that the majority of European countries are still below their early 2008 levels. In fact, only a handful of countries have reached these pre-crisis levels: Belgium, Estonia, Ireland, Norway, Poland, Slovakia, Switzerland and Turkey. Unsurprisingly, Greece shows the largest decrease among OECD countries, with a 30% loss versus early 2008 as of end-2013.

In the other OECD regions, Korea, Israel and Mexico's indices for the manufacturing industry's production are now above early 2008 levels, while Japan's indices are still below 2008 levels. Interestingly, the United States is also still not back at its early 2008 levels. Meanwhile, these indices have been on a declining trend in Australia over the past two years, which is worrisome and certainly due to the increase of the Australian dollar's value against other currencies and high wages, notably in the energy and mining sectors, resulting in the loss of competitiveness of Australian products. The impact of impending LNG exports is already pushing up wholesale gas prices and affecting industrial gas demand. On the price side, the trends observed over the past two years have totally changed: US gas prices abruptly stopped declining and increased by one-third in 2013, and on the back of cold weather increased further in first quarter 2014, and have remained stubbornly high (USD 4.5/MBtu). Meanwhile the German border price, which reflects the current status of long-term contracts in Europe, and Japan's border price both lost a few percentage points. Only the National Balancing Point (NBP) in the United Kingdom continued on its relentless increase since 2009.

Box 2 European Union (EU) worries about industry competitiveness

In contrast to the positive developments in North America, the impact of high energy prices on the competitiveness of European industry has become a key speaking point in European political speeches, reflecting worries that this additional burden could cloud the economic recovery of European industry. The main reason is the emerging gap between cheap US gas and electricity prices and those in Europe. This trend triggered an in-depth study commissioned by the European Commission (EC), which was released on 22 January 2014, along with the other documents related to the 2030 energy and climate strategy (EC, 2014). The European Council in 2013 already highlighted that

> "Industry finds it hard to compete with foreign firms who pay half the price for electricity, like in the United States. So all leaders are keenly aware that sustainable and affordable energy is key to keep factories and jobs in Europe."

Among the potential solutions proposed were energy efficiency, turning the different markets into one single energy market, investing in infrastructure such as pipelines and diversifying energy supplies to exploit Europe's domestic resources, notably renewables and shale gas. Energy efficiency remains clearly one of the most important hidden fuels, but it is also the one for which no clear target was set in the last energy and climate strategy published by the EC in 2014. Regarding shale gas, it remains to be seen whether Europe will deliver any of the dreamed volumes as Poland has failed to concretise any of the hopes so far. It is also unclear whether domestic shale gas could result in lower gas bills and be cheaper than imports of US shale gas in the form of LNG.

The EC study looked in depth at energy costs among EU countries, notably at gas and electricity prices, arguing that both oil and coal markets are global and that consumers pay broadly the same price, which is true if one does not take subsidies into account. Energy costs consist of three parts: the wholesale element, the retail element (network costs), and taxes and levies. The picture is, therefore, neither uniform, nor black and white. First, significant differences exist between member states due to variations in these three elements. Second, industrial gas prices are not skyrocketing everywhere: they actually fell for industrial consumers in Belgium, the Czech Republic, Germany, Italy, the Netherlands, Romania and Slovakia, while double-digit annual growth rates were registered in Bulgaria and Croatia. Interestingly, the energy component of gas prices has stayed stable since 2008, while on average the network component has gained 14% and taxation 12% for industry.

The evolution was nevertheless drastically different from one country to another: while France's energy component lost 25% over 2008-12, Bulgaria and Luxembourg had to pay 50% and 75% more. Additionally, some member states – notably the Baltic countries – pay wholesale prices that are around 40% higher than in Spain, which has among the lowest wholesale prices. In contrast, the network costs dropped in many countries (up to 47% in Hungary), but were multiplied by 2.5 in France. Finally, the tax-related elements have a different impact depending on their share in total gas price: they account for less than 5% of the total price in Belgium, Luxembourg and the United Kingdom, whereas in Austria, Finland and Sweden they represented more than a third of the price. Taxes and levies, therefore, ranged from EUR 0.06/kWh in Luxembourg to EUR 3.83/kWh in Sweden; nevertheless, the majority of member states were situated within a range of EUR 0.5/kWh to EUR 1.5/kWh.

The increases in all the components are much larger for household consumers. Moreover, a nationwide or regional perspective can hide significant differences among industries: while EU average industrial gas prices rose by less than 1% in 2008-12, certain energy-intensive industries reported gas price rises of between 27% and 40% in the period 2010-12. The conclusion from this study is that, despite the focus on the wholesale part of the gas price, which of course is the largest component of the final price, the two other components are also worthy of attention. The EU study looked in depth at a few specific industries, such as glass manufacturers, wall and floor tile producers and fertiliser producers. The analysis was based on a sample of plants across different countries and focused on the period 2010-12, which does not allow a direct comparison with the rest of the study. But it highlights that in almost every case, the wholesale price increased along with its share in the total gas price.

Box 2 European Union (EU) worries about industry competitiveness (continued)

A comparison of international industrial gas prices offers some interesting insights (Figure 8). While on average, EU countries are clearly on the high end of the range, some countries with a strong industrial base such as Japan, Korea and Brazil[3] pay higher prices on average. Regarding the comparison with the United States, two points may be noted. First, the comparison shown in Figure 8 was made in 2012, when US gas prices were at a record low. Already in 2013, the energy component was 35% higher. According to Energy Information Administration (EIA) data, this change translated into a 20% increase in the industrial gas price in 2013 compared to 2012 levels. Additionally, regional wholesale prices can differ depending on the season and the circumstances.

Finally, after the recent cold snap in early 2014, US gas prices rose. Canada is likely to follow in the footsteps of the United States. Russia, however, can be expected to continue to benefit from reasonably low gas prices, as industry benefit from the competition between suppliers. The growth of wholesale regulated prices has been frozen at the level of inflation until 2016. Finally, it is doubtful that all industrial gas users can benefit from the low gas prices shown on Figure 8: such prices reflect the Administrative Price Mechanism (APM) level to which users such as fertiliser producers may have access. But many industrials have to buy gas based on imported LNG, which is much more expensive. Additionally, India had announced a substantial increase in natural gas prices for 2014, which would put prices at a higher level, but this reform has been postponed to a later date. Should the reform proceed, Indian industrials would pay higher prices than shown on Figure 8.

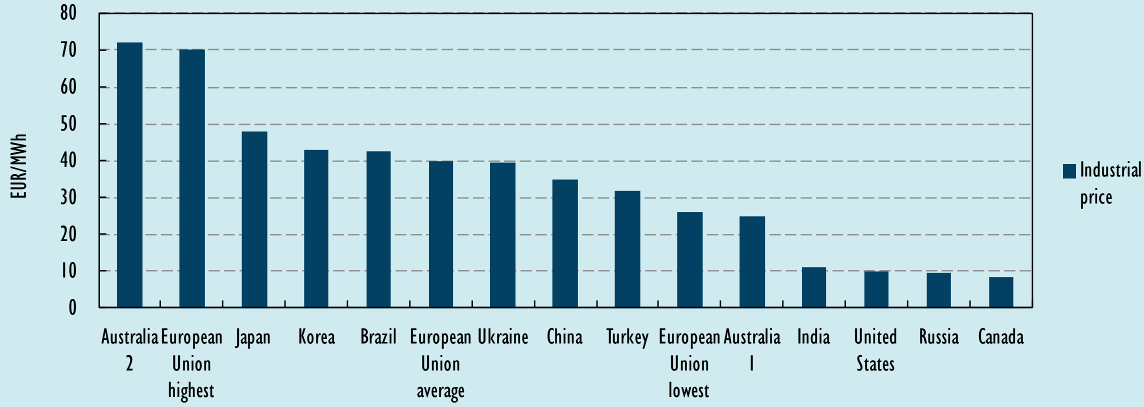
US shale gas did contribute to a reduction of European gas bills. As the United States no longer needed to import LNG, large amounts of LNG were freed up for global gas markets in 2009, at a time when gas demand was reduced by the economic crisis. European companies were caught between a rock and a hard place: on the one hand, oil-linked and expensive long-term contracts required delivering gas to wholesale markets at around USD 10 to USD 12/MBtu; on the other hand, LNG cargoes were available at half that price. NBP prices were effectively hovering at USD 5/MBtu in 2009. Consequently, industrial users and power generators were requesting the cheap gas that the big European companies were not always in a position to get. In addition, a volume issue arose as demand dropped so much that the European companies had difficulties meeting the minimum requirements in their long-term contracts. Since 2010, European gas companies have, therefore, been renegotiating their long-term contracts, including partial spot indexation or obtaining a discount versus the original price. They also negotiated greater flexibility regarding gas volumes. The price reduction varies depending on the supplier and the buyer, their respective bargaining power and their historical relationship. Nevertheless, the result of that bargain is clearly visible in the delinkage between European and Japanese gas prices. The latter have remained fully indexed to oil prices and increased to USD 16 to USD 17/MBtu, a trend European gas prices did not follow (see Trade chapter). But as of today, European gas prices are still high in relation to US gas prices, even though they are much lower than in Japan or Korea.

Finally, the report also analysed energy intensity versus gross value-added and energy consumption. Energy intensity has been reduced recently, probably due to energy efficiency improvements and restructuring towards higher value-added products. In many industrial sectors, reductions in gas consumption could be observed. Not all industries have the same exposure to energy costs, and this factor differs for gas and electricity. Also whether the end product can be easily transported is of importance while looking at global competition. Actually, not everyone shares the view on whether and how to tackle energy competitiveness. A study released by Brueghel (*Manufacturing Europe's future*) argues that energy prices are only one aspect of industry’s overall competitiveness (Brueghel, 2013). Based on an in-depth study of industrial behaviour in OECD countries, researchers found that countries with low energy prices are effectively better places for energy-intensive industries. But high energy prices force other countries to turn to more elaborated products, which in fact generate more jobs and higher value-added than the energy-intensive products exported by low energy price countries.

[3] Despite a large gas production, Brazil’s domestic gas prices are indexed to oil, which means that industrials pay gas at higher levels than most international competitors.

Box 2 European Union (EU) worries about industry competitiveness (continued)

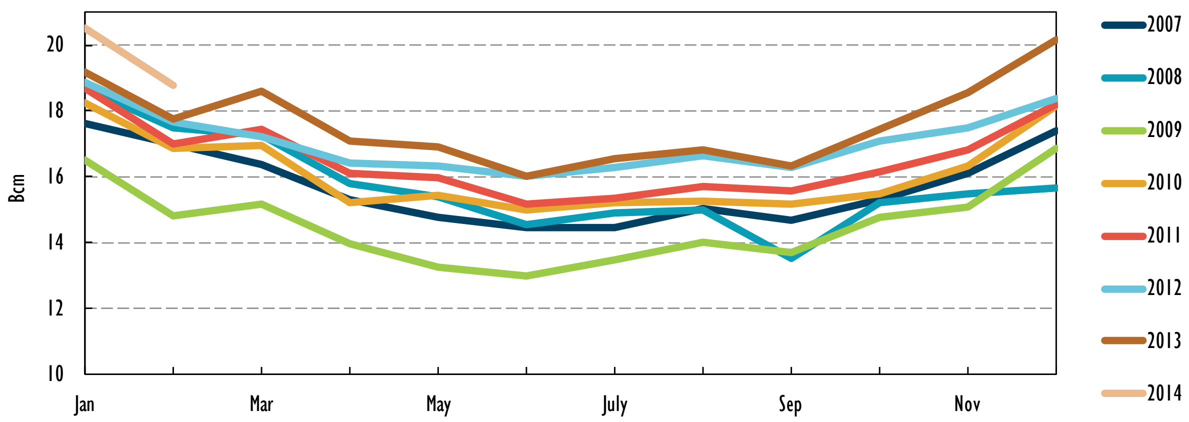
Figure 8 Comparison of international industrial gas prices (2012)



Notes: Australia 1 refers to prices paid under new contracts by large industrial consumers; Australia 2 means prices paid by small business consumers and by households, respectively, and is based on information on standing offers (default tariffs, exclusive of general sales tax). Prices for Korea and Japan refer to 2011. Prices for Japan, Ukraine, China, Turkey, New Zealand, Russia, Canada and the European Union exclude value-added tax (in the case of European Union and Turkey, also other recoverable taxes, if any). Prices for Korea (2011) and the United States include taxes. No data on taxation in India. The price for Brazil includes federal taxes as PIS and COFINS (social contribution taxes) and state taxes such as ICMS (tax on circulation of goods and services; no value-added or general sales tax in Brazil), which has different rates for each state.

Source: EC, 2014.

Figure 9 US industrial gas demand, 2007-14



The US industrial sector continued to consume increasing volumes of gas, as demonstrated by a 3% gain in consumption (Figure 9). Considering the relatively sharp increase in US gas prices in 2013 over the previous year, this gain is a sign of the healthy prospects in the US industrial sector. Based on announcements of new factories and industrial demand centres, such a trend is expected to continue. In early February 2014, the American Chemistry Council (ACC) announced that the US chemical industry could invest up to USD 100 billion as a result of the increase in US gas production and availability of cheap gas (and natural gas liquids – see special focus in the Supply chapter). This plan was mentioned by President Obama in his State of the Union speech in early 2014. As many as 148 projects have been announced and could potentially concretise by 2023, leading to an expected additional yearly output of USD 81 billion and 637 000 permanent new jobs. Interestingly, the United States is now seen by international companies as an investment hub since more than half of the investment planned is by firms based outside the country.

Non-OECD regions: China dwarfs all other developments

Non-OECD regions usually provide the backbone of additional gas consumption, due to the need to support economic growth with energy, and if possible, clean burning fuels. Consequently, gas demand in these regions was growing at a healthy pace of 4.1% per year over 2000-12. But 2013 was an abnormal year, as demand from non-OECD regions increased only 1.2%. Over the past decade, this is the second lowest annual growth recorded – the lowest being -1.9% in 2009 due to the economic crisis.

An overarching theme, nevertheless, exists for many non-OECD regions (excluding the FSU/non-OECD Europe region): the difficulty to access affordable gas supplies. Non-OECD countries face issues such as the lack of import infrastructure, i.e. LNG import terminals and pipelines, and a low level of domestic gas prices, which either affects domestic gas production or fails to attract the interest of suppliers of pipeline gas and LNG. When countries decide to import gas at market prices and sell it domestically at subsidised gas prices, they often do so at the expense of their state budget. Large oil and gas producers usually compensate for the losses in the gas sector through oil revenues: Saudi Arabia is an example of such a case. Another overarching theme is the competition of gas against other fuels in the power generation mix, whereby gas is not always the winner, despite its numerous advantages. Gas has to compete against coal in China, India, Southeast Asian countries, and some Latin American countries.

While China's natural gas demand increased by 13% or 20 bcm in 2013, putting the country in third place in terms of gas consumers behind the United States and Russia, gas consumption grew less in other non-OECD regions (it even dropped in two of them), albeit for very different reasons. Latin America came in second behind China in terms of relative gas demand growth, with its gas demand growing at 5.7%, adding 9 bcm. Even though the region consumes as much as China alone, it is still one of the lowest consuming regions, since only Africa consumes less. All countries experienced gas demand growth in 2013, and once again, the highest incremental volume originated from Brazil (+6 bcm). Both Argentina and Brazil suffered from lower hydro levels in 2013, prompting them to issue tenders for LNG cargoes. Demand has increased in Brazil in preparation for the football World Cup, and given the shortages in hydro power generation, demand from gas-fired plants has surged by two-thirds. Brazil signed a new import contract with Bolivia for 0.82 bcm per year to fuel a 480 MW power plant near the border. Domestic production also provided a large share of the additional supply. In Brazil, besides the power generation sector, none of the other sectors posted such a strong demand growth; for example, demand in the industrial and transport sectors actually dropped, which is likely to be due to the high, oil-linked, gas prices prevailing in Brazil. Argentina showed different growth patterns, with the residential and commercial sectors driving the growth, while demand from all the other sectors receded.

Gas consumption in the Middle East gained an estimated 2.3%, benefiting from gas production growth in some countries of the region. In contrast, African countries consumed only 0.6% more gas in 2013. Gas demand even declined in Egypt due to the sharp drop in domestic production, which was not compensated by an almost complete cessation of LNG and pipeline exports to redirect gas to the domestic market.

In contrast, natural gas consumption dropped in two regions (non-OECD Asia excluding China, and FSU/non-OECD Europe), albeit for widely different reasons. As mentioned earlier, FSU/non-OECD Europe is a relatively mature market, and demand should be expected to decline over time. In 2013, Russia was the main driver behind the region's demand trajectory. Meanwhile, potential demand in non-OECD Asia is much higher than the current consumption due to gas shortages. This trend is precisely what happened in 2013 in non-OECD Asia (excluding China), as the drop in demand came essentially from India and Indonesia, which both struggled with their domestic gas production. Meanwhile, demand increased in most other countries, except for Brunei, but this was insufficient to compensate for the drops in India and Indonesia.

Medium-term gas demand forecasts

Assumptions and methodology

The demand forecasts in the *MTGMR 2014* are supported by two major assumptions: economic growth and energy prices. In all regions, weather conditions are assumed to be at historical averages throughout the whole forecast period. Like the previous *MTGMR* and the other Medium-Term Reports, our economic forecasts are based on International Monetary Fund (IMF) GDP forecasts. Those forecasts used in this publication are based on October 2013's Outlook. IMF foresees some improvement regarding the future state of the global economy, as the annual growth of the world's GDP is projected to increase from 2.8% in 2013 to 4.2% in 2019. Near-term real growth (2014) is to recover to 3.5%. The gap between advanced and emerging economies remains over the forecast period as the economies of OECD countries will grow at 2.5% on average compared to 5.5% for non-OECD countries.

Regarding energy prices, the series of Medium-Term Reports use forward curves as an input to price forecasts. These prices do not in any manner represent IEA forecasts, but rather an external assumption. Oil price assumptions are consistent with those from the *Medium-Term Oil Market Report 2014* (IEA, 2014a). Nominal oil prices are broadly in line with the previous *MTGMR 2013*: they are set to slightly decline over the forecast period, from their top level of USD 109 per barrel (bbl) in 2013 to USD 91/bbl in 2019. Oil price assumptions will, therefore, be higher than the previous year's until 2015, with a premium of USD 2 to USD 3/bbl in the short term. Prices at the end of the forecast period are lower than the previous year's. Prices will cross the USD 100/bbl threshold in 2016 and remain below that threshold thereafter.

Real US coal prices (USD 2012) are expected to remain relatively stable in the three main US regions (Eastern, Central and Western), while real Continental European coal prices are assumed to drop from USD 97 per tonne (t) to USD 94/t. A similar trend will follow in the Mediterranean region. In contrast, real coal prices in Central Europe and in the United Kingdom will be on an upward trend. In China, real domestic coal prices are to drop from their current highs and remain stable for the rest of the forecast period. Prices in both India and Australia will see a substantial increase, by up to USD 35/t.

Assumptions on gas prices are based on 15-day averages of the forward curves as of late March to early April 2014. A progressive reduction of the gap between Asian and US gas prices is foreseen, not driven by any fundamental market change, but by the progressive decrease in oil prices pushing contract prices downwards. The creation of a fully liquid Asian market by 2019 looks relatively unlikely. Hence the gap will slim down from USD 12.5/MBtu in 2013 to USD 8.8/MBtu. Despite the surge experienced in early 2014 due to the very cold winter 2013/14, average Henry Hub (HH) gas prices are expected to progressively depart from USD 3.8/MBtu to cross the USD 4/MBtu in 2014 and to remain at USD 4.4/MBtu on average (Table 5). They will not, however, increase up to USD 5/MBtu. European gas prices remain relatively in line with what was prevailing over the past few years: Continental European gas prices will average USD 10.4/MBtu over the forecast period, while the NBP will be at USD 10.1/MBtu. During the forecast period, UK prices will be at a discount against Continental gas prices, except for the year 2019. Given the levels of US gas prices, US LNG is unlikely to arrive to Europe at prices much lower than USD 9.5/MBtu, thus providing a floor to European gas prices. Even though US LNG will be at a discount to Asian contract gas prices, volumes available over 2017-19 will not be sufficient to significantly affect the average Asian import prices.

Table 5 Assumed annual gas prices (USD/MBtu)

	2013	2015	2017	2019
Henry Hub	3.7	4.3	4.3	4.6
NBP	10.4	10.2	10.2	10.2
Continental Europe	10.7	10.9	10.4	9.9
Asia (Japan)	16.3	15.0	14.3	13.2

World gas demand is on its way to exceed 4 000 bcm by 2020

Global gas demand will slightly miss the 4 000 bcm mark in 2019, reaching 3 980 bcm but on its way to reach that target by 2020. Demand is set to increase by 490 bcm over 2013-19, implying a 2.2% per year growth rate. Slower economic growth, the ever-strong competition from both coal and renewable energies, together with high gas prices, are all slowing down the growth of natural gas across all sectors. The main conclusions from this outlook are that:

- Gas demand growth is essentially supported by non-OECD regions, which will provide 85% of the additional consumption. OECD countries are unlikely to provide similar additional volumes due to the maturity of most markets, slower economic growth, and competition from renewable energies or coal across the three regions. The only vector of market uncertainty is the United States, which could generate another unexpected development, such as a surge of gas use in road and maritime transport.
- China remains by far the fastest-growing market, a conclusion unchanged from the *MTGMR 2013*. Even if this trend includes a revision of China's GDP by around 1% over the whole forecast period, a stronger priority to environmental issues will result in a higher use of gas in the transport, power, and industry sectors, therefore compensating almost entirely for the GDP effect. The success of China in ramping up gas consumption relies also on pursuing all different options in terms of domestic gas production (such as shale gas, but also coal gasification) and developing supply sources – both pipeline and LNG. Pipeline supplies from Central Asia and Myanmar are de facto locked in to supply China, so that demand levels are largely determined by the ability of China to have access to global LNG supplies. These supplies will expand markedly over 2013-19 reaching 57 bcm by 2019 as China develops the corresponding LNG infrastructure and Chinese companies get involved in LNG projects around the world (see Trade chapter).
- All the other non-OECD regions but one present high annual growth rates, varying from 3.8% per year for Latin America to 5% in Africa. The road to higher consumption is, nevertheless, relatively bumpy and subject to both the timely development of domestic production for all non-OECD regions (FSU being an exception), and to being in a position to get access to imported gas, from an infrastructure, contract or price point of view. The exception among non-OECD regions is the FSU/non-OECD Europe region, where gas demand is stable. The main driver behind this stability is the strong decline in gas demand in non-OECD Europe and Ukraine; altogether, these countries lose

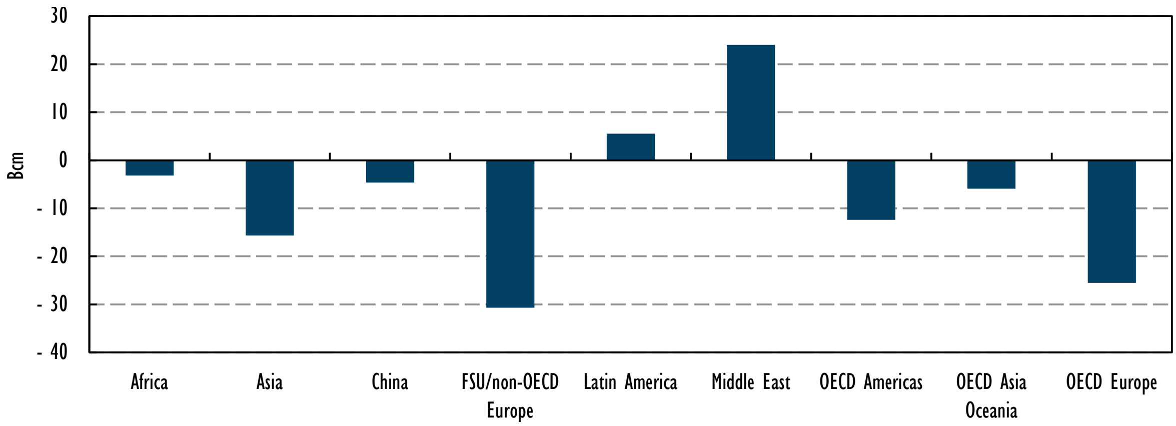
17 bcm, almost a quarter of their current consumption as they try to lessen their dependency on natural gas. Consequently, demand forecasts in this region represent the largest revision compared to last year (around 30 bcm).

- The power generation sector is by far the single most important source of incremental demand, representing 53% of the 490 bcm needed. The industrial sector stands well behind, with only 32%. But the interactions between fuels, uncertainties regarding the future power demand paths, policy decisions and capacities of new power plants coming online also make the power sector the single most complex sector to understand. As the European case has shown, lower power demand, the stronger than expected growth of one type of energy and high gas prices can easily send gas demand in the doldrums for an extended period of time. Actually, any one of these factors alone can already have a significant influence. But developments in the power sector can also work to the advantage of natural gas when countries want to replace more expensive or polluting fuels.
- Over the past few years, shale gas has significantly changed not only the gas market, but also the entire energy landscape. This unexpected development came from the supply side. A demand-side surprise is equally possible, although it may not have the magnitude of the shale gas revolution. Of all the sectors, gas has always had difficulty penetrating the transport sector. But China's five-fold increase in demand in the road sector in five years shows that the potential is there. Other promising sectors, even though longer term, are the use of gas for shipping and transport by rail. This report features a special focus on the use of LNG for shipping.

Table 6 Gas demand by region (bcm), 2013-19

	2013	2015	2017	2019	CAGR 2019/13 (%)
OECD Americas	920	923	955	968	0.8
OECD Asia Oceania	229	237	248	256	1.9
OECD Europe	504	486	498	504	0.0
Africa	119	132	145	159	5.0
Non-OECD Asia	283	310	335	357	3.9
China	166	213	263	315	11.3
FSU/non-OECD Europe	680	675	676	681	0.0
Latin America	164	171	186	204	3.8
Middle East	426	456	495	535	3.9
Total	**3 490**	**3 602**	**3 800**	**3 980**	**2.2**

Figure 10 Forecast changes from *MTGMR 2013* to *MTGMR 2014* (2018)



Compared to the *MTGMR 2013*, demand was revised down mostly in two regions: Europe and FSU/non-OECD Europe region (Table 6). Demand grows also less than expected last year in OECD Americas, notably due to revisions to the power demand forecasts. Even though the restarting of nuclear in Japan had been anticipated last year, most of the difference has been borne by oil-fired generation, not by gas. A revision also took place in Australia on the back of lower power demand forecasts and worsening competitiveness of gas-fired plants. Just as in Europe, combined-cycle gas turbines (CCGTs), which were built to be mid-merit, have progressively moved to peak production and are finally unprofitable. Among the positive revisions is that of the Middle East, owing to expectations of improvement in Iran and a stronger ramp-up of production in Oman (Figure 10).

OECD regions

OECD gas demand is projected to grow from 1 653 bcm in 2013 to 1 729 bcm by 2019, translating into a 0.7% per year increase over 2013-19. With this 76 bcm gain, OECD regions represent only 15% of incremental consumption. The three regions continue to have widely different futures, as different as their demand evolution during the year 2013. Demand grows in all three regions: OECD Americas represents around 63% of the 76 bcm growth, while OECD Asia Oceania represents 36%. In contrast, Europe accounts for the reminder (a very small 1 bcm gain).

While absolute growth in OECD Americas seems limited (the region's demand gained over 100 bcm over 2008-13), this is also partially due to a quite high consumption in the base year because 2013 was colder than usual. Therefore, temperature-adjusted demand increase is expected to be larger, at around 70 bcm. North America's demand will not return to a normal growth path before 2015, because the first months of 2014 were also exceptionally cold and resulted in record residential consumption. The industry and power generators of OECD Americas continue to enjoy relatively low gas prices compared to OECD Europe and OECD Asia Oceania, so that natural gas is projected to represent a growing share in these two sectors. The same logic could apply to Europe due to the long winter in 2013, which resulted in additional demand during late winter/early spring. Nevertheless, this growth can be hardly the basis for a recovery in Europe, as demand stays around 500 bcm on average during the forecast period; it will actually fall below that level more often than above. Meanwhile, a large part of demand growth in OECD Asia Oceania is supported by Israel as the country develops its own domestic resources.

From a sectoral point of view, two sectors follow a declining path: the residential/commercial sector and losses (Table 7). Two reasons support the decline in the first sector: the very high level in 2013 and a declining trend in many European countries and in the United States, where individual consumption is expected to decrease. This forecast also assumes a return to normal temperatures. Against this backdrop, the power generation sector is fuelling the increase in gas demand (+62 bcm). While a large part of these additions originate from OECD Americas (+42 bcm), eventually this demand also increases in Europe (+15 bcm). The current very low levels are starting to test the limits of the whole power system, and the decommissioning of coal-fired plants in the United Kingdom will help the return of gas use in the power sector. Meanwhile, the transport sector is the fastest growing on a relative basis, due to a strong growth in the United States. The industrial sector continues to expand faster than total gas demand growth: in North America, this sector is supported by low gas prices. On an individual basis, Israel uses part of the Tamar field's gas to enable switching from oil products to gas; many contracts with industrials have already been signed.

Table 7 OECD gas demand by sector (bcm), 2013-19

	2013	2015	2017	2019	CAGR 2019/13 (%)
Residential/commercial	536	498	494	490	-1.5
Industry	350	360	374	382	1.5
Power generation	575	593	625	637	1.7
Transport	31	33	37	42	5.2
Own energy use	158	159	168	174	1.7
Losses	3	3	3	3	-0.5
Total	**1 653**	**1 646**	**1 701**	**1 729**	**0.7**

OECD Europe: Buckle up for a tough ride in the next two years

Gas demand in OECD Europe has been on free fall since 2010, dropping 64 bcm (11%) over three years to 504 bcm in 2013, with no change in sight for 2014. With a long winter in 2013, seasonally adjusted demand should have been closer from 490 bcm. Moreover, the years to come promise to continue this *annus horribilis* for European gas companies, as demand is expected to remain below the 500 bcm mark until 2018. Two sectors decline over time: the residential sector as well as energy industry own use, while power generators and industrials are expected to use slightly more gas by 2019.

The year 2014 will have the lowest demand in the forecast period, as the mild weather of the period January 2014 to April 2014 has already been taken into account in the forecasts, resulting in European gas demand plummeting to 470 bcm, a level below that in 2000. The recovery will take time and come from the power generation sector and industry. In contrast, residential demand is expected to decline, but again, the base year had an unusual high residential demand. The rebound in 2015 to 486 bcm will be driven by a return to normal weather, while the situation in the power generation sector will only stabilise and industrial gas demand continue to fall. A real pickup of demand to 494 bcm only happens in 2016, but this level is still a far cry from levels reached in 2010 (567 bcm).

No additional demand growth is expected to come from the residential sector, due to the maturity of the markets, declining population in many countries, energy efficiency requirements in new households, use of alternative energies such as heat pumps, solar panels and the increasing cost of energy, which prompts customers to turn down the heater's temperature. Residential/commercial demand drops to 201 bcm by 2019. In most countries, very few new customers will be connected; in most cases, distribution companies hesitate to expand the gas network to new small cities, especially if the consumption per household continues to decline. Demand is more likely to grow incrementally in cities with an existing pipeline network, which just requires a specific building or household to be connected. The French gas distribution network operator GrDF mentioned that around 200 000 customers have stopped using gas over the past five years, mostly users consuming gas for cooking, while the numbers of users needing gas for heating continues to increase. For a country that used to add 150 000 new users per year in the years 2000s, the drop is impressive. Nevertheless, the company also notes an overarching declining trend in consumption among gas users, which can be found across European countries in the consumption per household per HDD.

While no real increase is expected from the residential/commercial sector, some improvement can be expected in the power generation sector, even though the current mood among power generators is driving them to close down or mothball gas-fired plants. Demand recovers to 154 bcm by 2019. At some point, the drop has to stabilise to preserve the stability of the entire power system.

At this stage, even much higher gas prices – all other things such as power demand, renewable and nuclear generation being equal – would not significantly affect gas-fired generation. However, gas will be far from being restored as the preferred fuel in the power sector, nor will it even greatly increase the demand in this sector. With an expected 673 TWh generated by gas-fired plants by 2019, that level stands 170 TWh below the peak in 2008. Indeed, generation from renewable sources continues to perform well despite a slowdown from the previous fast-track growth experienced over 2000-12 when power from renewable sources gained some 374 TWh, roughly 10% of the current generation (Box 3). Renewable sources will gain around 260 TWh according to preliminary estimates of the forthcoming IEA *Medium-Term Renewable Energy Market Report 2014*, to be issued in August 2014 (IEA, 2014b). In particular, generation from wind continues to increase strongly. Against this backdrop, renewable energies generate more additional power than the additional generation needed. If not for a declining nuclear output, combustible fuels (gas, coal and oil) would face an absolute decline, but the drop in nuclear actually compensates for the surplus of renewable sources.

European nuclear generation will hold up quite well until 2018, despite a dip in 2015, as new power plants have not yet come online. Nuclear drops slightly from 873 TWh in 2013 to 852 TWh in 2018, before plummeting to 825 TWh as more nuclear power plants are decommissioned. The second stage of the German phase-out will come into force from 2015 onwards, while in the United Kingdom, other nuclear power plants will be decommissioned. A few new nuclear power plants will come online but they will not compensate for the decommissioning of older plants.

This outlook leaves very little room for growth in gas demand, even though the share of gas in total generation gains one percentage point, from 16.7% to 17.8%. While gas-fired plants benefit from the ongoing decline of oil-fired plants by around one-third over 2013-19, the competition with coal is still ongoing, and gas only wins when coal-fired plants are decommissioned due to policy decisions, as is the case in the United Kingdom due to the large combustion plant directive (LCPD). Even though the price relationship slightly improves over time in the forecast as gas prices slowly decline, gas-fired plants quite often remain out of the money.

The industrial sector can be expected to rebound slightly to 123 bcm by 2019 from 119 bcm in 2013, also due to declining gas prices and slightly better economic environment as European economies are expected to grow at almost 2% per year towards the end of the forecast period, but this is not a recovery, by far. OECD Europe without Turkey does not even reach the levels of the pre-economic crisis (2008); meanwhile, Turkey alone accounts for most (87%) of the 4 bcm demand gain. The underlying declining trend, which started in 2000, was caused by heavy industry moving offshore, energy efficiency measures employed to compensate for higher energy costs and plant closures due to the economic crisis. This trend will slow down, except in the petrochemical sector, which continues to face competition from US-based industrials. European-based fertiliser producers will consume a roughly constant amount of gas, with Turkey and Poland compensating for the drops in other countries. Gas use by the energy industry itself drops by 9% over 2013-19, driven by lower oil and gas production in countries such as the United Kingdom and the Netherlands. Gas use in the transport sector increases very slightly, with around 4 bcm consumed in 2019, close to 1% of OECD Europe's gas consumption.

Box 3 European Union proposes new targets for 2030

On 22 January 2014, the EC proposed objectives to be met by 2030 on energy, the climate and competitiveness. The release of these objectives came with several documents, notably the following:

- a policy framework for climate and energy in the period from 2020 to 2030
- an impact assessment on energy and climate policy up to 2030
- communication and a full report on energy prices and costs
- a report on energy economic development in Europe
- legislative proposals for emission trading scheme (ETS) structural reform (stability reserve) for the period after 2021
- minimum principles on shale gas.

A broad compromise could be reached in 2014, enabling the EC to turn these proposals into legislation in 2015. This is taking place in a context of the European Parliamentary elections and the nomination of new Commissioners in 2014. A key piece of the framework is the target to reduce greenhouse gas (GHG) emissions by 40% below the 1990 level by 2030, in order to be on track to meet the 80% reduction target by 2050. This target is more ambitious than a simple continuation of the existing policies, but one has to take into account that the GHG emissions were already estimated 18% below 1990 in 2012. It is, therefore, likely that the 2020 target will be overachieved. This new target is based entirely on domestic reductions, and no use of international credits is allowed. The sectors covered by the ETS would have to reduce their emissions by 43% compared to 2005. Meanwhile, emissions from sectors outside the European Union ETS would need to be cut by 30% below the 2005 level, and this effort would be shared equitably between the member states.

Another important component of the package is the EU-wide binding renewable energy target of at least 27% in 2030 in the energy mix. However, this target will be translated not into binding national targets but into flexible individual national plans, raising the question of how to treat global EU non-compliance and how to make sure that countries will exert sufficient effort to reach a global EU target. This approach promotes a more market-oriented approach for emerging technologies, while phasing out mature energy technology support. Meanwhile, the role of energy efficiency in the 2030 framework will be further reviewed by the Energy Efficiency Directive later in 2014.

The EC is proposing to reform the EU ETS by creating a market stability reserve at the beginning of the next ETS trading period in 2021. The reserve would address the current surplus of emission allowances by automatically adjusting the supply, according to pre-defined rules that would leave no discretion to the commission or member states. This proposal implicitly recognises that the ETS is not robust in times of economic crises, resulting in low carbon prices, which can no longer foster investment in mitigation options, or even a coal-to-gas switching. European Union carbon prices have been hovering at EUR 5/tonne for the past three years. The proposal for a market stability reserve may not reduce uncertainties regarding the carbon price development. Worse, the proposed possibility of releasing allowances placed in the market stability reserve if the carbon price is “for more than six consecutive months more than three times the average carbon price during the two preceding years” could potentially prevent any increase of the CO_2 price at levels fostering mitigation options.

A rosy outlook for OECD Americas?

The 50 bcm gain in the OECD Americas certainly makes the region’s gas outlook brighter than that of European countries, with gas demand in the OECD Americas predicted to rise from 920 bcm in 2013 to 968 bcm in 2019. But one should not become overly enthusiastic regarding these forecasts. While gas demand is to grow in the industry, power generation and energy industry own use sectors, it will also recede in the residential/commercial sector, and this latter development is not entirely due to a temperature adjustment but to an underlying trend. At the country level, consumption will drop in Canada, and remain at low levels in Chile due to competition against coal in the power sector. Mexico could have increased its consumption much more than the additional 16 bcm if sufficient gas were available, but in the opposite case, Mexico will continue to use oil and a stable stream of coal, also benefiting from a strong push in wind and solar. The country with the largest increase is the United States (+27 bcm), mostly driven by the power generation sector, while two other sectors – industry and transport – are also showing healthy trends. Gas demand in the United States will rise from an estimated 737 bcm in 2013 to 765 bcm in 2019.

The power generation sector continues to represent the backbone of additional demand requirements, but the competition from coal remains tough over the whole forecast period. Besides, electricity demand forecasts have been revised downward due to the recent trends in US power demand. As gas prices slowly increase, gas-fired plants struggle to maintain their hedge against coal-fired plants. Many recall the 2012 picture of large coal-to-gas switching in response to record low gas prices, but forget that the 2013 picture was the other way around. With HH prices at USD 3.7/MBtu, coal came back and gas-fired generation dropped significantly. Actually, in these forecasts, coal-fired generation holds up quite well until 2015, then starts to decline slightly. Gas-fired plants benefit from the still increasing power demand minus the growing contribution from renewable energies and nuclear. Should the power demand continue to be delinked from the GDP and grow at a slower rate than expected, this trend would affect all energies and gas in particular. This factor represents one of the largest uncertainties in this outlook, and could result in a potential flattening of gas demand in the US power sector.

Demand in the residential/commercial sector stands out as one of the exceptions in OECD Americas region, because demand is forecast to decrease (by 33 bcm). The two countries representing almost the entire demand in this sector – the United States and Canada – are showing a decline in gas use per HDD per connected household, similar to that observed in mature European countries. Even though the case could be made for additional residential connections in these countries, it is again a question of population density and the economics of connecting a significant amount of new users. Roughly half of the drop can be explained by the temperature adjustment.

The industrial sector continues to benefit from relatively low gas prices over the projection period, averaging USD 4.4/MBtu. After the impressive drop of gas demand from 236 bcm in 2000 to 159 bcm in 2009 due to the economic crisis, industrial gas consumption recovered to 198 bcm in 2013 and is expected to reach 215 bcm in 2019. Of note, Mexico contributes 4 bcm out of the 18 bcm growth in the region, while the US market accounts for most of the remainder. This growth is driven partly by the increased competitiveness of the US petrochemical sector. Fertiliser producers are particularly keen to benefit from the still low gas prices in North America, and may either restart mothballed plants or build new facilities, notably in the United States.

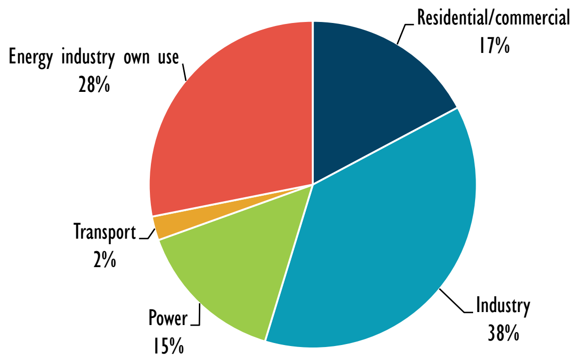
The energy industry's gas consumption is projected to grow by 9% or 11 bcm, owing to increasing oil and gas production in the United States, Canada and to a lesser extent in Mexico, while the use of gas for the upcoming liquefaction plants is expected to add a new consumption item in the United States. As mentioned later in the special focus on transport, after China, the United States is the market showing the second-largest growth in absolute terms, even though industrials involved in the different parts of the value chain still need to overcome some obstacles.

OECD Asia Oceania: beware of coal!

It may be counter-intuitive to consider coal as an alternative to gas in OECD Asia Oceania, but coal is actually a serious alternative – or even a competitor – to natural gas in Japan, Korea and Australia. According to the new energy strategy of Japan, coal will be an important base-load fuel in the power sector, benefiting from lower power generation costs relative to natural gas and oil, which would improve Japan's trade balance over time. The 2 GW Haramachi coal-fired power plant restarted in 2013 after having been hit by the 2011 earthquake and tsunami. New capacity recently came online such as TEPCO's 1 GW coal-fired unit at the Hitachinaka power plant in eastern Japan and the 600 MW Hirono coal-fired power plant; both started operations in December 2013. Nevertheless, no other power plant will start over the projection period besides the small 166 MW Osaki coal-fired power plant scheduled for 2017; others currently under consideration will start by 2020 at the earliest. Rapidly rising power demand in Korea has fostered investment in new coal-fired plants, and at least 10 GW are scheduled to come online during the projection period (IEA, 2013a). Australia represents one of the major downward revisions in this demand outlook due to the deteriorating conditions for gas-fired power plants. Power consumption has stalled due in particular to the closure of some energy-intensive industries because of rapid price rises in all categories of users, including industrials. Meanwhile, gas prices are expected to increase, notably in Eastern Australia (see Box 4), deteriorating further the competitiveness of gas-fired plants. This can also be seen as a consequence of the move to abandon the carbon price which was set at quite a high level and was expected to boost gas-fired power vis-à-vis coal. The new coalition government has indicated it will repeal the carbon tax, and legislation to achieve this, and now awaits approval by the Senate, expected in July this year. They are also reviewing the renewable energy target in 2014, so that the risk to renewable energy is to the downside.

Coal's comeback is, therefore, the major reason why gas demand will not increase much in this region over 2013-19. The additional demand of 27 bcm (an additional 12%) is still impressive as it makes the region the fastest growing among all OECD regions. But this gain is actually much lower than the growth trend observed over a similar six-year period before Fukushima. The 27 bcm breaks down as follows (Figure 11): 5 bcm will come from the residential/commercial sector, 10 bcm from industry (with 4 bcm coming from Israel alone), 8 bcm from the own industry energy use due to new liquefaction plants in Australia and a small 4 bcm in the power sector. At a country level, demand declines in both Australia and New Zealand, stabilises in Japan and Korea, and increases in Israel.

Figure 11 Incremental gas demand split by sector in OECD Asia Oceania, 2013-19



Box 4 Gas prices in Eastern Australia

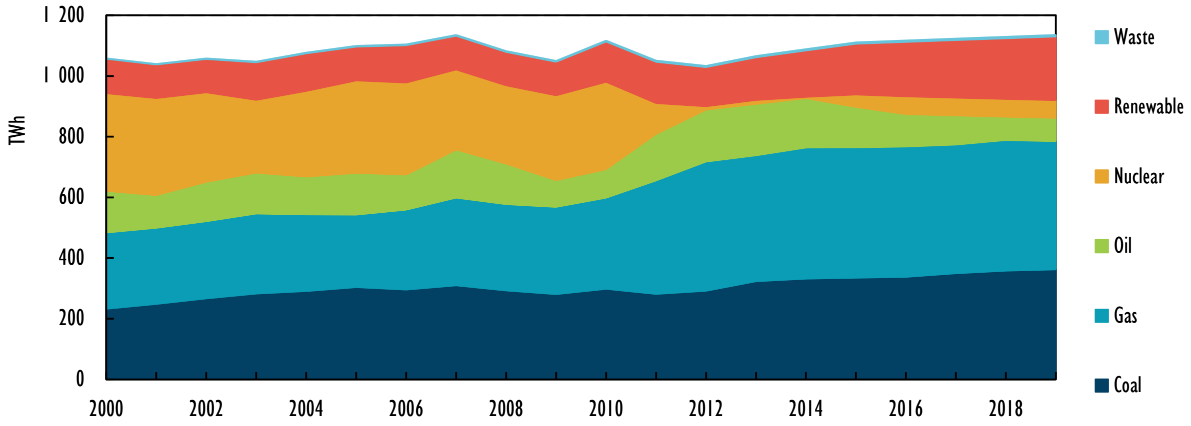
A currently heated debate in Australia concerns the evolution of gas prices over the coming decade, notably in the Eastern Australian market. Australia's domestic market is comprised of three different and quite independent regional markets – the Northern, Western and Eastern Australian markets. With a consumption of around 35 bcm, gas has been gaining ground over the past decade, notably in the power generation sector. The Northern and Western markets are the only markets exposed to global LNG markets, and will remain so until late-2014. This will change as the three new liquefaction plants come on line in Gladstone in Eastern Australia: the region will then be exposed to global LNG markets. This market represented 59% of total Australian gas demand in 2011-12, with manufacturing and power generation being the largest consumers of natural gas. On the domestic Australian markets, most of the gas was sold based on long-term bilateral contracts, even though some development of a spot market has occurred in the Eastern region.

As LNG starts in Eastern Australia, some concern has been raised about the impact on the domestic gas market. While many buyers of LNG complain about increasing gas prices, Eastern Australia is likely to face a sharp increase of domestic gas prices as well, reflecting the much higher cost base of new supplies. In Western Australia, prices started to increase in 2006-07, reflecting tighter supply due to higher demand for LNG exports and the development of new and more expensive gas resources. Even though the average price remains relatively low at AUD 4.3/GJ (USD 4.1/MBtu), new contracts are more expensive, with an average estimated at around AUD 8/GJ (USD 7.7/MBtu).

Until now, the Eastern Australian market enjoyed wholesale prices based on long-term contracts averaging from AUD 3 to AUD 4/GJ (USD 2.9 to USD 3.9/MBtu). But most existing long-term contracts will expire in the coming years, exactly when the new LNG export plants are coming online. By 2018, only 15% of the demand in New South Wales will be met by existing contracts. Prices are, therefore, expected to rise to around AUD 6-10/GJ (USD 5.8 to USD 9.6/MBtu), a notable increase. Hence, industrial users have been quite vocal about potential shortages of natural gas for the domestic market, asking for part of the gas to be reserved for Eastern Australia while the rest could be exported as LNG. From the producers' point of view, no such shortage exists: gas is and will be available, but no longer at the cheap prices enjoyed previously by the industrials. The need to invest in more expensive resources and build pipelines justifies an increase in domestic gas prices, with development costs reported at AUD 4 to AUD 6/GJ (USD 3.9 to USD 5.8/MBtu) notably for coal seam gas. Besides, producers maintain that without the LNG exports, the reserves feeding into the LNG plants would not have been developed at all, because the size of the Eastern Australian gas market would not have justified it.

It will be particularly interesting to observe the transition and stabilisation phases occurring over the next few years as production ramps up to fill in the LNG plants and then stabilises once these plants have reached plateau. Some experts argue that prices could be based on the netback value of LNG exports, because for the producer, selling the gas to the domestic or international gas markets would not matter. According to an analysis from the Bureau of Resources and Energy Economics (BREE), real contract prices in Eastern Australia will vary between AUD 7/MBtu and AUD 8.5/MBtu (USD 6.7 to USD 8.2/MBtu) over the longer term (BREE, 2013). Such prices could be seen as ceiling prices, while the floor prices would be determined by the cost of bringing additional volumes to the market. These costs are not fixed but depend on the total volumes produced because less expensive resources are exploited first. This is likely to have an impact on future gas demand as well, as buyers and sellers are trying to find a balance between the buyers' needs and the producers' requirements in terms of development costs. A well-functioning domestic gas market needs to be properly established. Recent demand forecasts of Australian gas demand are more subdued due to rising gas prices, but also lower-than-expected power demand growth.

Figure 12 Power generation by fuel in Japan, 2000-19



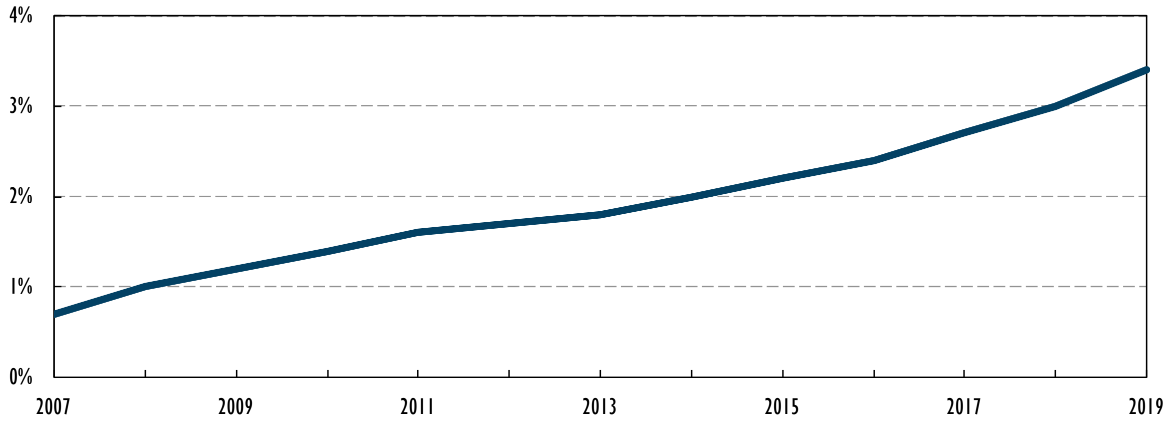
While a significant focus has been on nuclear energy in Japan, a return of some nuclear power plants would affect mostly oil and would affect natural gas in a more limited way (Figure 12). The impact would be greater should more nuclear power plants come back, but given the current uncertainties, this report has taken a conservative stance on future Japanese nuclear generation. While the Cabinet of the Prime Minister approved the new Energy Policy, which will promote the reactivation of nuclear reactors, no timeline and no quantification of the shares have been given because the issue of nuclear coming back is very sensitive politically. Consequently, nuclear output is assumed to reach a maximum of 59 TWh by 2016, and to stay at this level over the rest of the projection period. As this report goes to press, no certainty yet exists regarding new plants starting in summer 2014.

The residential/commercial sector represents a small share in the region's total gas consumption, mostly present in Japan and Korea. Its growth will, therefore, remain quite limited, with demand rising from 48 bcm to 53 bcm. In contrast, gas use in the industrial sector will increase significantly, by 4.6% per year over 2013-19. The largest increases come from Korea and Israel, both adding around 4 bcm. Finally, the largest relative increase will take place in own energy industry use, where gas consumption increases at 7.7% per year, reaching 21 bcm, driven by Australia, where not only use for oil and gas production surges but also use in LNG liquefaction plants (Box 4). Gas consumption in this sector will also increase in Korea, due to the higher needs of regasification plants.

Special focus: Use of gas for road transport and shipping

The transport sector is largely dominated by oil products, a domination that is increasingly challenged by alternatives such as natural gas vehicles (NGVs) and electric vehicles (EVs). Around 50 million barrels per day (mb/d) (54% of the current oil demand) are currently used in the transport sector. This demand will grow over the medium term, essentially in the non-OECD regions. In the *Medium-Term Gas Market Report 2013*, the IEA looked at the potential of the road transport sector to be a game changer and concluded that NGVs had good chances to contribute significantly to incremental consumption over the next five years, representing some 9% of incremental gas demand (IEA, 2013b). Two regions are of paramount importance in this switch from oil products to natural gas: China and North America. These forecasts are still valid, even though some numbers have been revised down in some countries facing more acute shortages than anticipated last year such as Egypt and Pakistan, where the priority is put on freeing gas for the power sector rather than for transport. In this report, NGV demand is expected to reach 93 bcm in 2019, double its demand in 2013, which represents 10% of incremental global demand. Two-thirds of this demand growth originates from China alone. Natural gas will win shares in the transport sector at the expense of oil over the next few years, as its share against oil will increase from an estimated 1.8% in 2013 to 3.4% in 2019 (Figure 13).

Figure 13 Percentage of gas versus oil in the transport sector, 2007-19

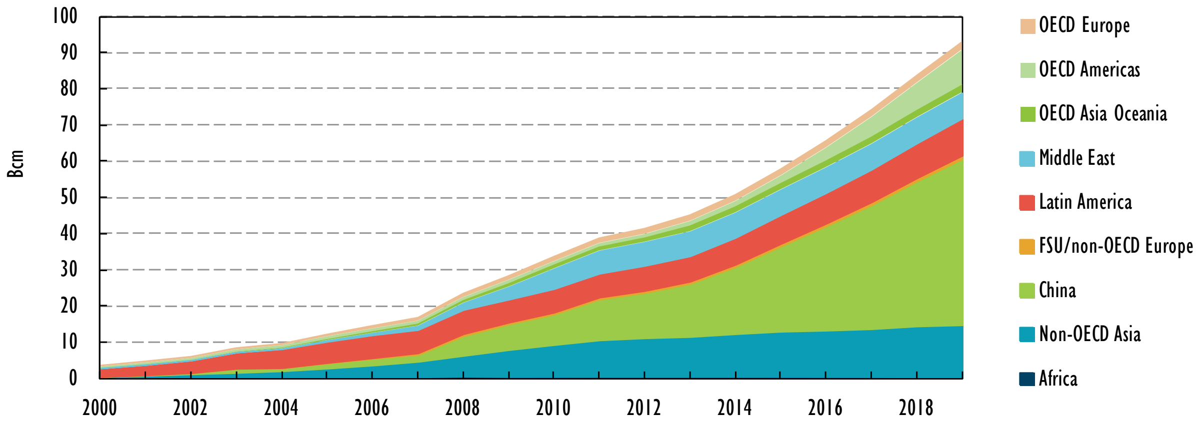


As environmental issues have moved to the top of the agenda, China is taking a leading position in terms of developing gas in the transport sector due to serious concerns regarding local air pollution (Figure 14). According to official statistics, China had just over 1.5 million NGVs on its roads and added between 473 000 and 600 000 in early 2013 (based on various estimates). The number of LNG vehicles doubled in 2012 to 80 000. Over half of the NGVs are located in Xinjiang, Shandong, and Sichuan, with over 300 000 in each province. Meanwhile, 3 014 compressed natural gas (CNG) stations were in operation across the country. The number of LNG stations similarly surged to 600 at the end of 2012, 200 more than in 2011. Nevertheless, the cost of the LNG value chain is much higher than normal diesel, from the absolute cost of the refilling station to the cost of buying an LNG vehicle. Such a transition is difficult without governmental support; hence around 80% of all LNG vehicles are buses, while the rest are taxis and other types of vehicles for commercial usage.

The second leading country is the United States, albeit significantly behind China in terms of gas use, where important incremental demand is expected with the development of the use of LNG for trucks. But a wider adoption of LNG by truck operators can take time, as first movers face higher than expected costs, lack of training in truck service and maintenance shops, and some technical glitches with the operation of the trucks. Westport Innovations, a leading natural gas engine designer behind many models currently running on the road, is working on improving its technology. As companies gain experience, maintenance costs can be expected to go down as well as the premium that LNG-powered trucks hold against diesel vehicles. As long as a significant gap remains between gas and diesel prices, switching is likely to occur.

Increasing gas use for transport is also taking place in non-OECD Asian countries and Latin America, but the increase is expected to remain subdued due to gas shortages in countries with a current high number of NGVs such as Bangladesh, Pakistan and Argentina. In some cases, demand for gas in transport actually goes down as the fuel is redirected to power plants. Natural gas demand can also suffer from price changes, such as the planned price increase in India. While public transport buses would still continue to use natural gas, private owners may act differently if the cost is too high. NGV consumption remains limited in Africa, where only Egypt had developed such an infrastructure: due to gas shortages, consumption is unlikely to expand further. Similarly in the Middle East, only Iran remains an important consumer. Meanwhile, developments of natural gas in Europe remain relatively modest, even though the gas industry is looking at expanding the offer, notably around LNG terminals offering LNG for trucks and ships.

Figure 14 Natural gas demand in road transport, 2000-19



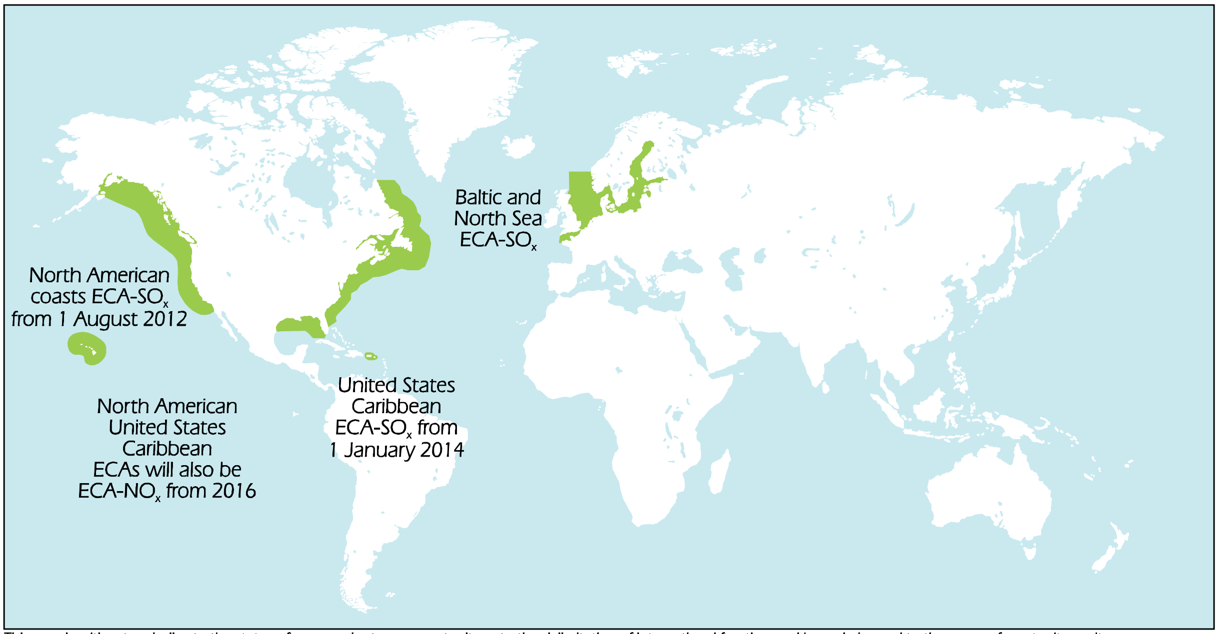
Shipping

Although it is slightly outside of the medium-term horizon, the maritime transport sector is worth looking at in depth. Much debate is taking place today about the potential adoption of LNG as a bunker fuel, which means using liquefied gas as a fuel in ships, either those sailing on rivers or on international waters. The main driver for such a transition is environmental compliance, notably in terms of tighter international requirements on sulphur emissions. This change would have an impact for all players in the oil, gas and shipping industry: oil refiners, gas companies, LNG suppliers, ship owners and ports. International marine bunker demand is currently estimated to be a 4 mb/d market based on IEA statistics on "world marine bunker", representing around 4% of global oil demand. In the IEA Annual Statistics, global marine bunkers are indeed listed as "fuels to ships of all flags that are engaged in international navigation for the world total. The international navigation may take place at sea, on inland lakes and waterways, and in coastal waters". This is the energy equivalent of an annual gas consumption of 230 bcm, two-thirds of the current global LNG market. Looking forward, the IEA expects energy demand from world marine bunkers to increase to over 4 mb/d by 2019 (IEA, 2014a). The definition here is of crucial importance because it does not include domestic shipping, which would add another 0.9 mb/d.

There are, however, some discrepancies between diverging assessments of such demand. Estimates from different organisations vary between 3.5 mb/d and 6.5 mb/d. Underestimating of total historical demand may occur through a misallocation of residual fuels (i.e. fuel that is reported as inland residual fuel is, in fact, used as marine bunker fuel). The potential for such misreporting is evident. For instance, statistical sources tend to show total bunker demand for the Middle East that is less than that for the port of Fujairah alone and unfeasibly modest bunker demand in the FSU. The objective of the report is not, however, to look at this issue, although it is dealt with in more detail in the *Medium-Term Oil Market Report 2014* (IEA, 2014a).

The shipping sector, whether domestic or international, currently uses oil products to power its vast engines. Over 85% of the fuel used in global marine bunkers in 2012 was residual fuel oil, mostly high sulphur fuel oil (HSFO). But it has recently lost some market share to cleaner fuels such as gasoil, also called MDO, due to tightening environmental standards. As of today, an estimated 60 000 cargo-carrying vessels and a total of 90 000 vessels (except fishing boats and military vessels) are on the seas. It is difficult to get an accurate picture of the number of ships using LNG, but the number is unlikely to exceed a few hundreds. An estimated 8 000 vessels would be affected by the new regulations explained below.

Map 1 Emission Control Areas (ECAs) in the world as of 2014



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

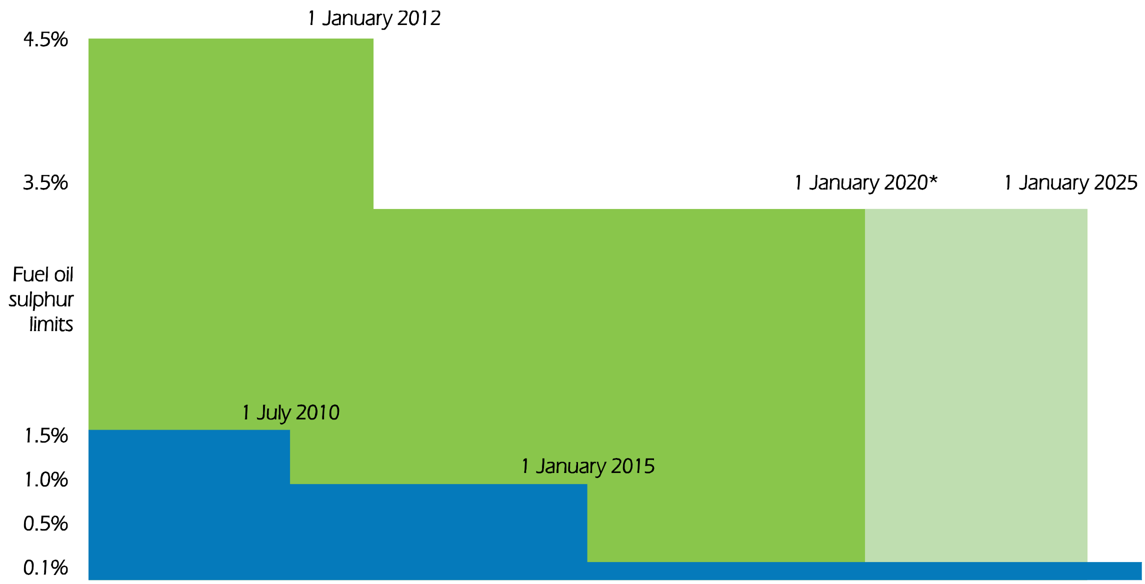
The price spreads between the different fuels on a regional basis could also play a role, notably in North America. Different studies have estimated the scale of the emissions coming from the shipping sector. For example, the Thematic Strategy on air pollution from 2005 concluded that sulphur oxide (SO_x) and nitrogen oxide (NO_x) emissions from shipping were forecast to exceed those from all land-based sources in Europe by 2020 (EC, 2005). By comparison, the combustion of LNG does not produce SO_x or particulate matter (PM), and 80% to 90% less NO_x and 10% to 20% less CO_2. Further CO_2 reduction is envisaged through technology improvement.

The transition from heavy fuel oil to other fuels, including potentially LNG, in the shipping business is essentially the result of stricter emissions being put in place and further tightening on a global scale. GHG emissions from international marine bunkers are not covered by the Kyoto Protocol, and are increasing rapidly. The need to control maritime emissions resulted in the International Maritime Organisation (IMO) setting up the International Convention for the Prevention of Pollution from Ships (MARPOL) Annex VI regulations, which cover a wide range of pollutants, including SO_x, NO_x and PM emissions, applying to all combustion equipment and devices on board. The IMO set up ECAs established to control the quantity of air pollutants, notably SO_x, in sensitive, high-volume shipping zones by limiting notably the maximum sulphur content of fuel oils used on board (Map 1). An ECA was first set up in 2005 in Europe (Baltic Sea), spreading later in 2006 to encompass the North Sea and the English Channel as well. In 2012, another ECA was put in place around North American coastline (200 nautical miles) and Hawaii. New ECAs are also under consideration in Australia, Japan, Korea, Pearl River China, the Mediterranean and Dubai. According to a study from the Environmental Protection

Agency (EPA), demand in the North American ECAs will represent an estimated oil consumption of around 20 million tonnes (0.35 mb/d) of fuel by 2020 (EPA, 2009). Stricter regulatory restrictions may justify the uptake of LNG for inland navigation in cases with much higher exposure of people (and therefore much higher health impacts) to SO_x emissions than in the case of ocean going ships.

The sulphur content of fuel burnt in ECAs must currently not exceed 1% (limit applicable since July 2010), and is legislated to fall to 0.1% by 2015 (Figure 15). The issue is that the availability of low-sulphur fuel oil (LSFO) at such a level is relatively limited, calling for other potential alternatives in the ECAs. Since January 2012, the limit outside the ECAs is 3.5% and could come down to 0.5% by 2020 if a decision is taken based on a IMO's study to be completed by 2018. The study will look at whether refiners can provide shippers with fuel respecting the 0.5% standard or whether the deadline should be pushed back to 2025. As of now, most experts seem to agree that the deadline is likely to slip to 2025. Besides, concerns have been raised as to how such global sulphur limits could be realistically implemented, let alone how the industry could afford to satisfy them (Box 5). Indeed, a key issue will consist of monitoring real emissions, because unless the emissions are tracked, ship owners could ignore tougher regulations. Various international bodies, such as the Marine Environment Protection Committee and the European Commission, are working on establishing reliable monitoring measures. It remains to be seen how this monitoring will work in practice at a local and then international level.

Figure 15 Sulphur limits according to MARPOL regulations



* Depending on the decision of the IMO.

These different sulphur limits between ECAs zones and the rest of the world create some technical hurdles. Most ships that operate both outside and inside these ECA are indeed likely to operate on different fuels, in order to minimise fuel costs (low-sulphur fuels are more costly as explained later) while complying with the respective limits. Ships would hence switch from one fuel to another in the middle of the sea. In 2011, the Eleventh United States Coast Guard District issued a Marine Safety Alert to increase awareness and reiterate general guidance on fuel systems and fuel switching safety because they had noticed an increasing number of reported loss-of-propulsion incidents on deep draft vessels, leading to many interventions to rescue these ships.

Box 5 Understanding the implications for the refining industry

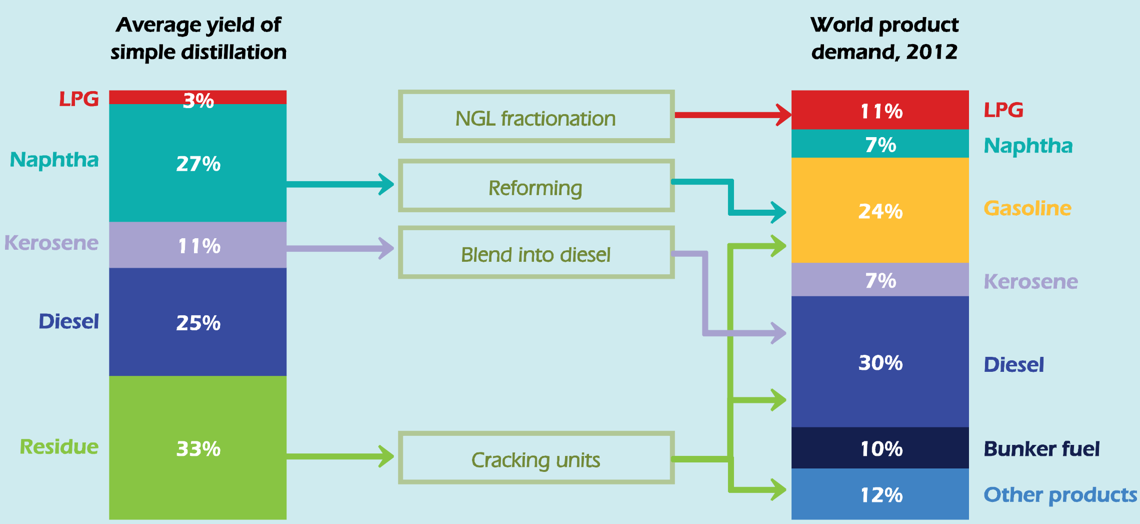
Changing regulations regarding bunker fuel emissions could have a significant impact on both fuel oil and distillate markets in the years to come, and thus on the refining industry at large. As the adoption of the 0.1% sulphur limit for sulphur emission control areas (SECAs) in January 2015 approaches, the share of fuel oil in bunker demand will decrease steadily. Once the global switch to 0.5% sulphur, either in 2020 or 2025, arrives, fuel oil demand will shrink further, though the extent to which it declines depends largely on the relative adoption of alternative fuels such as LNG or scrubbing technology.

The inevitable decrease in fuel oil demand in international marine shipping poses an enormous challenge for refiners. The industry has come a long way since beginning to reduce its share of fuel oil in total refinery production, from more than 30% in the early 1970s to only 13.2% in 2011, the last year for which complete global energy statistics are available. This change has come at a great investment cost and in response to declining global fuel oil demand, especially in the power sector, with plants switching to natural gas, renewable energy or nuclear wherever possible. As a result, international shipping today is in effect the last outlet for this bottom of the barrel, fuel oil.

The amount of fuel oil produced in a refinery depends largely on two things: the feedstock processed and the complexity of the refinery itself. While the average yield of fuel oil of simple distillation is around 33%, it also depends on the feedstock processed. In general terms, the heavier the crude oil, the higher the yield of middle distillates and residual fuel produced. Lighter crudes, such as light tight oil from the United States, for example, contain significantly higher amounts of light ends such as liquefied petroleum gas (LPG) and naphtha.

In addition to initial distillation of crude oil, refineries contain a variety of secondary processing units that use a range of catalysts and hydrogen to process intermediate feedstocks into finished products (Figure 16). Crude distillation units (CDU), or topping units, are the starting point for crude oil refining operations, where the crude is essentially boiled to separate it into different fractions. The lightest fractions, such as LPG, comes out at the top of the distillation tower, followed by light and heavy naphtha, kerosene and straight-run gasoil and finally residual fuel, which has the highest boiling point, above 350 degrees Celsius.

Figure 16 Output from simple distillation versus final product demand



Box 5 Understanding the implications for the refining industry (continued)

Residual fuels can be used with little or no further processing to make heavy products such as fuel oil used for power generation, bunker fuel, lubricants, asphalt or bitumen, or they can be partially converted into lighter products. A refinery's ability to do so depends on its complexity. In addition to their CDUs, simple refineries might have only reformers or hydrotreaters – converting naphtha into gasoline and removing sulphur. More complex refineries have a range of specialised units to convert the heavier residues into lighter, more valuable products. They include vacuum distillation units (VDUs), catalytic cracking units (FCCs), hydrocrackers and coking units. Hydrocrackers are ideal for converting residues into middle distillates, but are expensive to build and operate, and require a large hydrogen supply.

As the global refining industry is currently going through a challenging period, faced with overcapacity and poor margins, the case for increased investment in upgrading units such as hydrocrackers is not inevitable. Since the financial crisis of 2008, more than 5 mb/d of refinery capacity has had to shut permanently, most of it in mature OECD economies, and a large part in Europe and the Pacific. Margins, outside of the United States, where refiners enjoy better profitability on the back of discounted feedstock and natural gas used as refinery fuel, have remained in the doldrums for the last years. Simple refinery margins indeed are largely negative. As the global shipping industry adapts to the tighter environmental regulation and the fuel oil market shrinks further, simple refiners will see their business environment deteriorate further, and many more closures will come. Fuel oil cracks, or the difference between the price of fuel oil and that of crude oil, will also weaken, as opposed to a rising gasoil crack. In turn, the differential will make the case for scrubbing technology more attractive and improve on margins for more complex refineries with a high distillate yield. How the market plays out in the end remains to be seen, but what is certain is that the refining and shipping industry alike will have to adapt to face the challenges ahead.

Two issues, therefore, face the shipping industry. One immediate issue is for ship owners operating partly or totally in the ECAs, who will be affected by the lower sulphur limit of 0.1% as soon as 2015, assuming a tight adherence to this legislature. The second issue is for the other ship owners to prepare for the upcoming tightening of sulphur limits, be it in 2020 or 2025. Currently three main alternatives to the use of heavy fuel oil are available:

- Using marine gasoil (MDO)
- Continuing to use fuel oil with higher sulphur content while implementing scrubber technology
- Using LNG.

It is no longer a question of whether the shipping industry will reduce its sulphur footprint but rather the pace at which it will happen and the resultant fuel mix that will address the change. Still, while some among the shipping industry have taken a wait-and-see approach so far, new investments in scrubbers have also been reported. LNG carriers were among the first to use LNG, notably by opting for dual-fuel engines. Qatar has announced having retrofitted most of its new Q-flex and Q-max LNG tankers so that they can use boil-off LNG. Now, RasGas is considering converting its 12 Q-Flex and 1 Q-Max LNG carriers from diesel to LNG-powered engines, depending on the results of a prototype test. In China, attention is on inland shipping on the Yangtze River where no more diesel-powered vessels are going to be allowed on the Grand Canal. To date, 12 vessels have already been retrofitted, and two new LNG-powered ships have been built. Almost 100 additional vessels are waiting for implementation. Other existing LNG-fuelled ships are ferries and offshore service boats operating in Europe, but they are used for mostly domestic shipping. The 2015 deadline is coming quickly, and the short-term solution is likely to be an increase use of MDO, because this deadline is arriving too soon for LNG or scrubbers to be able to make significant inroads into the problem. Looking further ahead, the shipping industry is unlikely to adopt a one-size-fits-all approach because emissions regulations and fuel prices differ regionally. Given the time lags to retrofit or build new vessels, LNG demand in the shipping sector is unlikely to be significant by 2020, but it could be by 2025 should LNG be chosen by a majority of market participants. Besides, the potential for increased demand also depends on whether the companies would have ships cruising exclusively in ECAs, or not. Some pleasure cruise ferry companies are among the businesses eyeing conversion to LNG. For example, the excursion ferry operator HADAG, located in Hamburg, is considering converting its 23-ship fleet to LNG.

Discussions with various companies show that using MDO is often seen as a short-term, but costly, solution; scrubbers are perceived as a medium-term solution. LNG could appear as the long-term solution, but it is unlikely to be visible in terms of consumption before 2020. Depending on the characteristics of their vessels – notably their age, size and annual consumption, and whether they operate in existing ECAs – companies could choose different options, ranging from retrofitting to new builds, scrubber or LNG.

Diesel oil

The transition to MDO, which will be driven by the lack of realistic alternatives prior to 2015, may be easy from an investment point of view (none is necessary), but it could prove to be very expensive. Fuel costs represent an increasing share of vessel operating costs, with wide variations depending on the size of the vessels, their sailing speed, the bunker cost, and the degree of other costs such as container costs and administrative charges. The choice of the next bunker fuel is, therefore, crucial in terms of economics. When the MARCOL regulations were put in place, oil was at USD 20 per barrel and the Henry Hub and European gas prices at around USD 2 to USD 3/MBtu. Today oil prices are five times higher, European gas prices at USD 10 to USD 12/MBtu, and Asian prices at USD14 to USD 16/MBtu. Only North American prices are still low, at around USD 4/MBtu. Additionally, the gasoil-fuel oil price differential increased substantially over that period. Ships currently sailing in ECAs are required to use LSFO at 0.5% until 1 January 2015, which is currently approximately USD 200 per mt (USD 4.5/MBtu) more expensive than HSFO. But after 2015, they will be required to use the much costlier marine gasoil, currently standing at USD 350 per mt (USD 7.8/MBtu) over heavy fuel oil (HFO). While gasoil will certainly be the first choice in order to replace HSFO use in the ECA zones, it is also likely to result in a further surge in gasoil prices and therefore a rush to find alternatives. Land competition (if possible) may divert some of the bunker demand: trucks will circulate around Northern Europe rather than take ferries when the fares nearly double. That will be notably the case in countries such as the United Kingdom and France, for which only part of the coast is going to be subject to ECAs (see Map 1). Nevertheless, other options, involving upfront investments, will have lower operating costs. Consequently, scrubbers or LNG can be economic.

Scrubbers

The first option is the exhaust gas cleaning system, also called exhaust gas scrubbers (EGS) or more simply scrubbers. This technology has a proven track record for land-based applications, but so far has not been widely used in maritime applications. Despite the IMO's decision to allow their use, scrubbers are still seeking wider commercial acceptance, and the technology for maritime applications remains in its infancy. Issues such as corrosion and space in small ships will arise, even though some manufacturers have anticipated the latter challenge by developing a full range of EGS with heights ranging from 4 metres to 16.5 metres. Besides, installation costs are high, and a lack of shipyard capacity is likely to make retro-installation difficult. Capital investment in a scrubber is reported around

USD 3 million for a 10 MW engine and three 0.5 MW auxiliary engines, but depending on the ship, the cost can vary between USD 1 and USD 5 million; an additional cost (USD 0.5 million) may be necessary to install Selective Catalytic Reduction (SCR) to reduce NO_x emissions as well.

EGS treat exhaust gases, effectively removing SO_2 as well as PM out of the exhaust gases. Quite often, seawater is used, and its hydrogen carbonate (HCO_3) and sulphate (SO_4) react with the sulphur oxides, producing sulphates. No other chemical component is needed. The wastewater can then be re-circulated back into the sea, which already contains a high concentration in sulphates. No real study of the long-term impact of such wide recirculation has been made, should EGS be the dominant technology. A closed loop scrubber can also be used, whereby freshwater is used and constantly recycled. To bind sulphur dioxide (SO_2), sodium hydroxide is used. SO_2 emissions can be reduced by up to 97%, while PM can be reduced by 80% to 85%. NO_x is reduced only negligibly though, unless another reaction is performed with the SCR, whereby ammonia or urea reacts with the NO_x to produce nitrogen and oxygen.

Some consolidation within this industry has already occurred in anticipation of the tightening in 2015. Hamworthy Krystallon announced a first commercial order for a maritime scrubber in 2010, followed by Wärtsilä some time later. In 2012, Wärtsilä acquired Hamworthy Krystallon. Meanwhile, Alfa Laval acquired Aalborg Industries in 2011.

LNG

LNG bunkers are not new but tend to be a rare thing on oceans. Until now they have been mostly confined to the North Sea, most of them located in Norway. However, a full range of designs are available, ranging from barges to LNG tankers, while marine engine manufacturers offer dual-fuel or LNG-fuelled engines. While LNG-fuelled vessels are more expensive than the fuel oil alternative, they benefit from lower fuel costs. To achieve more widespread use, LNG will need to overcome several barriers, involving the physics, costs, availability, and infrastructure.

Despite being liquefied at -162°C, LNG still takes on average 1.6 times more room than oil fuels. This difference implies that tanks have to be larger to travel the same distance. Retrofitting a cargo to use LNG is doable, but this would be at the expense of the cargo volume, which affects revenues. Moreover, LNG tanks need further insulation to keep LNG cold, and this requires therefore more space.

Unlike the LNG cargoes currently sailing on domestic waters, LNG cargoes sailing on international seas need a global network. Currently, most of the ports offering bunkering services are in Europe, but interest is increasing to develop them as well in Asia (including OECD Asia Oceania, China and non-OECD Asia). Ship owners are unlikely to move to LNG if a widespread infrastructure is not available. Bunker stations will need to be built alongside the main inland shipping routes as well as in the key sea harbours. Several alternatives are available in terms of LNG bunkering service: an LNG liquefaction or regasification terminal, or using existing LNG carriers as floating storage and regasification units (FSRU). This latter option has lower capital costs, is scalable, and is easier to put in place when space is limited. However, the life expectancy is lower (15 years on average), it is subject to weather conditions and operational costs may be high since LNG vessels are scarce.

Future price assumptions are crucial for the economics of shipping because the investments are usually made for a period of 15 to 20 years. A crucial uncertainty is the development of the price of

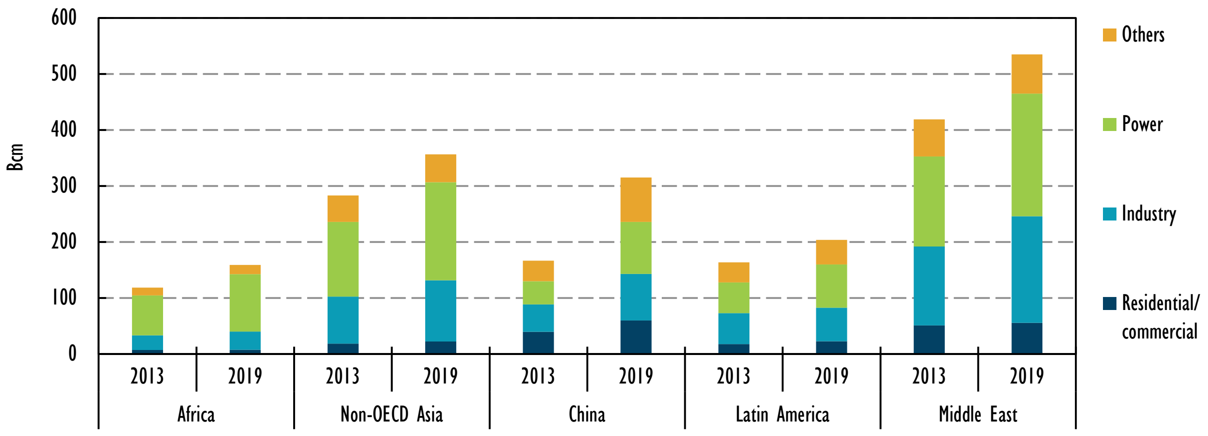
LNG, notably in Asia. Given an estimated 20% to 40% higher price for LNG-fuelled ships, LNG needs to be cheaper than the alternatives, notably MDO, for that investment to make sense.

Other factors can play a role as well, such as environmental priorities or price differentials, which could encourage use of LNG on domestic shipping routes. In China, according to the Ministry of Transport, around 10 000 vessels representing 10% of fuel consumption should be using LNG by 2020. In 2011, domestic navigation represented a total of 16.8 mtoe, roughly 20 bcm of gas. Already in early 2013, CNOOC, Sinotrans & CSC Group – a large ship owner – and China Sanjiang Space Group signed an agreement to develop the use of LNG on the Yangtze River. Sinotrans would convert 2 000 ships, while CNOOC plans to build 20 LNG refilling stations. This infrastructure would represent some 0.6 bcm of gas demand. While LNG is less cost-effective than fuel oil, it is still better than diesel; should the LNG price not change too much, LNG could be considered as a viable alternative for inland use. While many problems remain in terms of legislation, technology, developing LNG liquefaction plants along the rivers and convincing fleet owners, LNG demand for inland shipping could be visible by 2020, taking into account a replacement and test periods.

Non-OECD regions

The non-OECD region continues to support the largest part of incremental gas consumption (85%) over the upcoming five years (Figure 17). Non-OECD gas demand will reach 1 956 bcm in 2015, before increasing to 2 251 bcm in 2019. The short-term period (2014 and the early part of 2015) will continue to reflect the scarcity of supply available to developing markets and constraints in terms of infrastructure, notably pipeline.

Figure 17 Demand evolution in selected non-OECD regions, 2013, 2015 and 2019



Wide differences among the regions, nevertheless, exist when it comes to the additional volumes consumed and the ease of access to additional supplies. China grows the fastest, both in terms of additional volumes consumed as demand almost doubles from 2013 levels, and in percentage terms (+11.3% per year). The fundamental reasons for this growth are a demand push from the different sectors to respond to new environmental constraints, and the supply available from Central Asia, Myanmar and LNG (Table 8). China is in competition with other countries to get the LNG, but is the only outlet for Central Asian and Myanmar gas. The Middle East follows, consuming an additional 110 bcm, supported mostly by domestic production as well as by LNG imports from a few countries such as Kuwait. Latin America and Africa features much lower incremental volumes but still relatively high yearly growth rates.

Table 8 Non-OECD demand by sector (bcm)

	2010	2013	2015	2017	2019	2019/13 (%)
Residential/commercial	225	243	254	266	278	2.3
Industry	426	482	514	560	604	3.9
Power generation	777	820	879	944	1017	3.6
Transport	79	85	96	109	125	6.5
Energy industry own use	178	189	195	201	209	1.7
Losses	24	19	19	19	19	0.4
Total	**1 710**	**1 838**	**1 956**	**2 100**	**2 251**	**3.4**

Note: detailed demand data by country and by sector are available in Tables 35 and 36 in the chapter "The Essentials".

Note: the transport sector includes road, maritime transport as well as use for pipelines.

The power generation sector is responsible for the largest incremental gas consumption (around 196 bcm, 47% of additional demand) (Figure 18). While impressive, this rate implies that natural gas increases only modestly its share in non-OECD power generation mix from 19.3% to 20.0%, generating 3 237 TWh by 2019. Total power generation in the non-OECD region is expected to increase to around 16 200 TWh in 2019, from around 11 800 TWh in 2012, while power demand rises from 11 100 TWh to around 15 200 TWh. Africa will be the fastest-growing region in terms of power generation (+56% per year), owing to high GDP growth and a rapid population increase. This increased power generation still leaves hundreds of millions of Africans without access to power. Asian and Middle Eastern countries also feature a rapid increase in power generation (+5.3% per year), while the FSU/non-OECD region is the slowest growing region (1.9% per year), gaining nevertheless around 200 TWh, twice as much as the Dutch generation. This quantity is dwarfed as China's additional power generation during the same timeframe is 1 700 TWh, equivalent to more than the power generation of Japan and Korea. China and non-OECD Asian countries together will add around 2 600 TWh, more than half of US power generation.

Gas generation remains the backbone of total generation in both the Middle East and FSU/non-OECD Europe regions, where it keeps its dominant role well ahead all other fuels (Figure 19). Gas shortages in the Middle East, nevertheless, mean a continued reliance on oil because neither nuclear nor renewable energies are in a position to provide significant alternative power generation. In other regions, gas remains behind coal (China and other non-OECD Asian countries), oil (Latin America), and bioenergy (Africa). In Asia, gas is not able to be competitive against coal, notably domestic coal. Access to coal supplies is often easier than access to natural gas. One of the main issues leading to high gas consumption in this sector is the relatively low efficiency of gas-fired plants. This issue is exemplified by the situation in Saudi Arabia (see special focus), but is actually quite common among non-OECD countries.

Fossil fuels will contribute 53% of additional power generation over the projection period, or around 2 000 TWh (Figure 20). Consequently, non-OECD countries are not following the path of decarbonisation of the power sector. Renewable energies are assumed to bring around 1 300 TWh over 2013-19, half of which will come from hydro. Nuclear generation increases modestly by 500 TWh. As of end-2012, 67 nuclear power plants were under construction in the world, 44 of them located in Asia and 15 in FSU/non-OECD Europe. They represent an additional capacity of 64 GW, while 373 GW of nuclear capacity was installed across the world in 2012. China and Russia have the highest number of nuclear plants under construction (29 and 11). Nuclear generation in non-OECD countries will, therefore, almost double to reach around 1 000 TWh by 2019.

Figure 18 Power generation in non-OECD regions, 2000-19

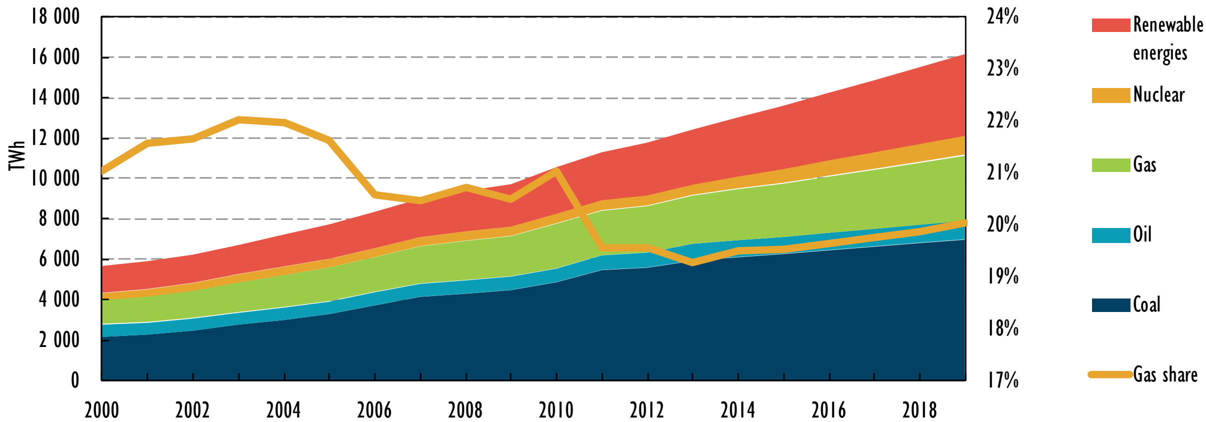


Figure 19 Gas generation against total generation by region in 2019

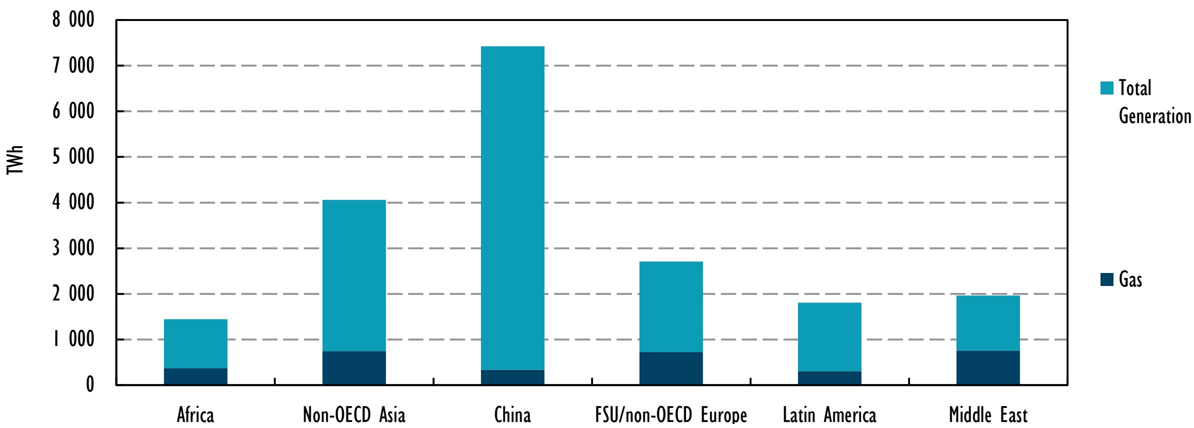
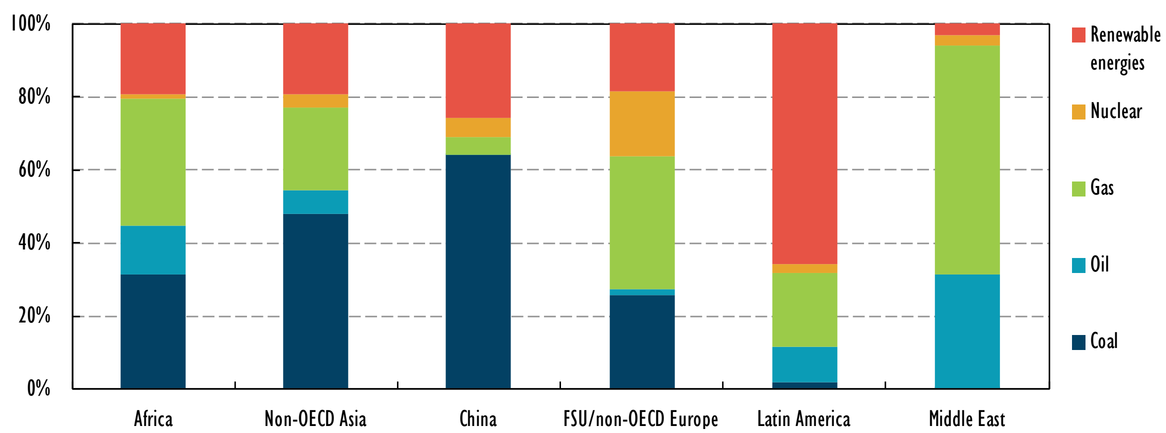


Figure 20 Non-OECD countries' power generation mix in 2019



Industrial gas use is the second-largest consuming sector and is projected to grow at 3.9% per year over the reference period, reaching 604 bcm by 2019. This projection reflects two factors: 1) the stronger economic growth of the non-OECD region, growing on average at 4.5% per year over the forecast period, and 2) the preference for natural gas, and the switch away from coal and oil products, when sufficient and cheap gas supplies are available. Meanwhile, the transport sector proves to be the fastest growing, due to a rapid increase of road transport in China as well as limited use of gas for inland shipping. Gas use in the residential/commercial sector gains around 35 bcm, a relatively limited increase coming mostly from China. Gas consumption for energy use will grow at slow rates in the absence of major gas-to-liquids (GTL) installation and the low number of new liquefaction plants starting in non-OECD countries during the reference period. Additionally, more efficient techniques implemented in oil and gas production limit the growth.

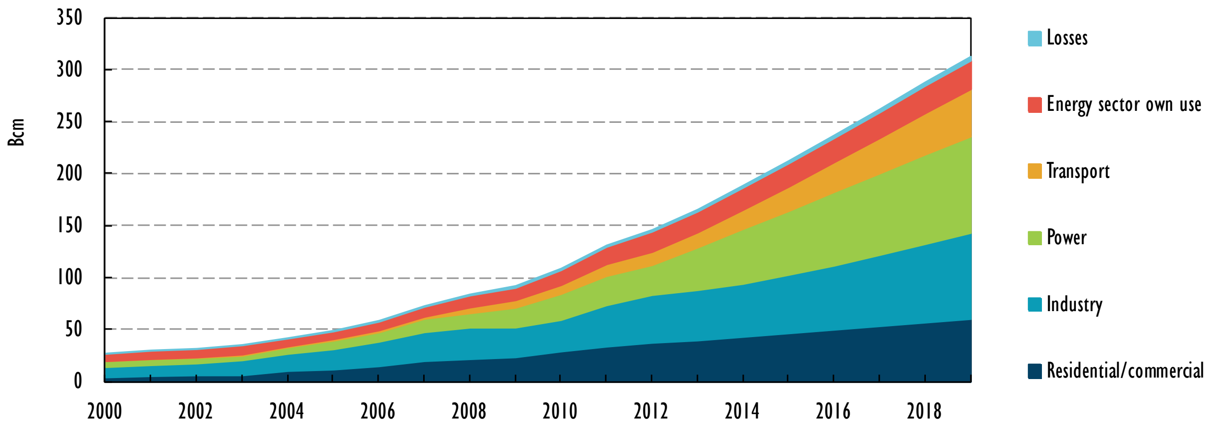
China

Tackling the air pollution issue in major cities has become China's priority and is likely to support many of its energy policy decisions. The already bad situation seems to have worsened over 2013. Over the past year, the pressure to remedy Beijing's (and other cities) smog problem has increased dramatically. This is resulting in efforts to reduce coal consumption in the regions of Beijing-Tianjin-Hebei, the Yangtze River Delta and the Pearl River Delta. As of 2013, China has become the third-largest gas user behind the United States and Russia, and ahead of Iran. The country has witnessed a robust growth in gas demand particularly in urban coastal areas, and such a trend is expected to continue. China's gas consumption (including Hong Kong) is projected to grow at 11.3% per year over 2013-19, which brings the region's gas consumption to 315 bcm by 2019. This level represents an additional demand of 149 bcm, half of which will be met by domestic gas production, and the rest by imports.

The push to reduce coal consumption in the power sector is resulting in gas shortages during the peak winter season. In October 2013, the National Development and Reform Commission (NDRC) warned that it would need to limit gas use as a result of shortages that had already appeared in cities such as Beijing and Urumqi. Residential and commercial users have been switching massively to the cleaner fuel and are expected to continue to do so, preferring gas over LPG. Beijing had also pledged to cap coal consumption in the city, but meeting this pledge will have to take into account the availability of natural gas supplies, both domestic and imported. Consequently, both annual and daily gas use has surged since 2012 (Figure 21). Beijing used 9.2 bcm in 2012 against 7.6 bcm in 2011. An estimated 6.8 bcm came from the residential/commercial sector alone, which contributed to half this annual growth. Daily peak consumption was 64.4 Mcm, 24% higher than in 2011. Such shortages have implications for industrial gas users, which would typically see their supplies diminish – if not being cancelled – when winter is coming. Some fertiliser producers had to stop production due to the disruption of their natural gas supplies as early as November. The NDRC also asked LNG plants in many provinces to reduce or stop operations. One of the issues is that China still lacks sufficient storage capacity as total working gas represents around 2% of total demand, well below what can be observed in developed countries with a similar high share of residential/commercial demand. For reference, Germany and France have a ratio over 20%. Even though the country benefits from a large domestic supply base, these fields are often located a thousand kilometres away from the coastal markets and cannot offer the same flexibility.

The availability of gas supplies will constraint natural gas demand growth over the coming years as China becomes increasingly reliant on imported gas. Despite many uncertainties regarding future domestic gas production, it is expected to grow quite strongly, reaching almost 200 bcm by 2019. Shale gas is expected to perform slightly better than expected, while coal gasification is now promoted as a way to add more domestic supply (see Supply chapter). Imported gas is not expected to suffer many constraints in terms of importing capacity as both the pipeline and the LNG regasification capacities are rapidly scaled up. But whether gas supplies will be affordable is another question. Moreover, shortages during the winter period are likely to remain an issue as long as storage capacity remains insufficient. The government has pledged in its 12th Five-Year Plan (2011-15) to increase storage capacity to 25.7 bcm by 2015. Storage capacity was assessed at around 3 bcm in 2012, while two new facilities (Hutubi and Shuangqiao) are said to be now operating. In that context, the government is reassessing its priorities, despite its resolve to address the air pollution issue. The priorities will continue to be residential gas use as well as the rapid development of NGVs. However, promoters of gas-based industrial and power generation projects must first secure gas supplies and set gas prices before starting building such projects; otherwise, the authorities will not approve the construction.

Figure 21 Gas demand in China, 2000-19



Gas demand by 2019 will be split between power generation (30%), followed by industry (26%) and residential/commercial (19%). As highlighted previously, gas demand in the transport sector will be the fastest growing over the period 2013-19, owing to both road and maritime transport. Although figures regarding the growth in NGVs added in 2012 differ slightly – from 473 000 to 600 000 – they nevertheless attest to the capacity of China to add massive numbers of NGVs every year and become the largest NGV market by 2015. This growth will be supported by the rapid expansion of both CNG and LNG filling stations.

The power generation sector is foreseen to become the largest-consuming sector as soon as 2014. The 12th Five-Year Plan (FYP) projects 56 GW by 2015, a target that may not be reached. Nevertheless, supply shortages are expected to ease after 2016, when the new LNG wave starts coming to the markets and new storage capacity is expected to have been built. By 2019, the power sector will consume 93 bcm. Besides the availability of gas, another uncertainty is the future load factor of this newly added capacity, as power generators struggle to pass through higher costs of gas in the face of electricity prices, which are regulated and capped. This situation implies that some reforms be implemented on the electricity pricing side to recognise the environmental benefits of natural gas in the power generation sector. The 12^{th} FYP for Energy actually advocates speeding up an electricity pricing reform and establishing a pricing mechanism that would allow the market to determine the price of power generated and sold, with the government regulating the price for transmission and distribution.

Non-OECD Asia (excluding China)

Non-OECD Asia's gas demand will continue to grow at a healthy pace, notably after 2016 when ample LNG supply arrives on global gas markets. Demand is expected to gain around 74 bcm, while the region's net exports will decrease from 30 bcm in 2013 to 1 bcm in 2019 (Box 6). With 357 bcm, Asia will still consume around 40 bcm more than China, but the gap between the two regions will progressively dwindle. No other country besides those with LNG import terminals existing or under construction will become an LNG importer before 2019, even though Bangladesh and Pakistan are planning to build LNG import terminals. Meanwhile, despite the plans to develop a regional pipeline network around the Natuna gas field, such expansion is not foreseen to be completed in the forecast period.

India remains by far the largest gas-consuming country among non-OECD Asian countries, representing around 22% of the region's gas demand (Figure 22). Over the timeframe, India will remain reliant on domestic gas and LNG supplies. The improvement on the situation regarding domestic gas supplies enables India's gas consumption to meet the largest part of its incremental gas demand, as global LNG supplies remain quite expensive, as demonstrated by the difficulties of GAIL to market its contracted US LNG supplies, which are based on HH indexation and, therefore, thought to be less expensive than oil-indexed gas supplies. Nevertheless, even at HH prices at USD 4/MBtu, US LNG is unlikely to arrive to India at prices much lower than USD 11/MBtu. To that, an LNG tax and the transport cost to the consumer must be added. In the power generation sector, gas use is still dwarfed by that of coal, even though coal's share declines over the projection period (Figure 23). At the same time, both renewable energies and nuclear are gaining ground.

Figure 22 Non-OECD Asian gas demand by country, 2000-19

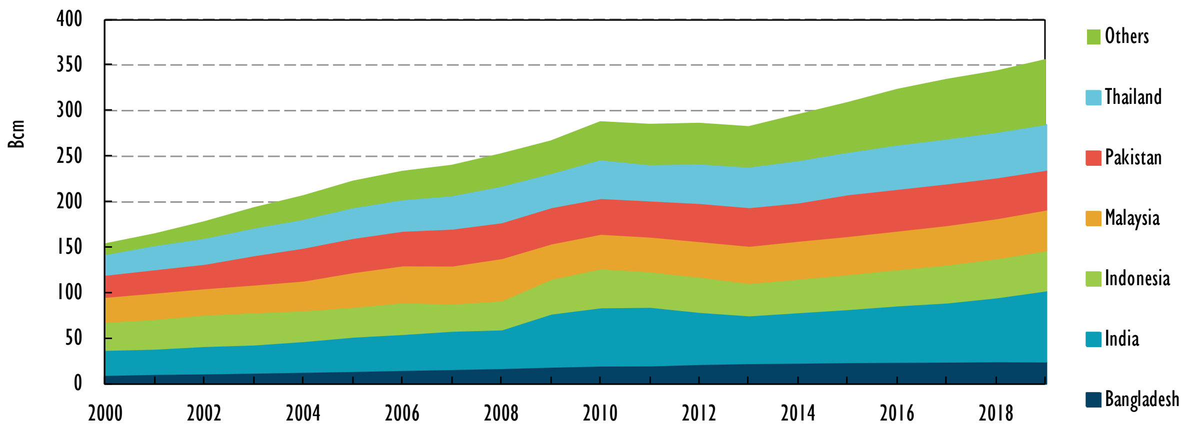
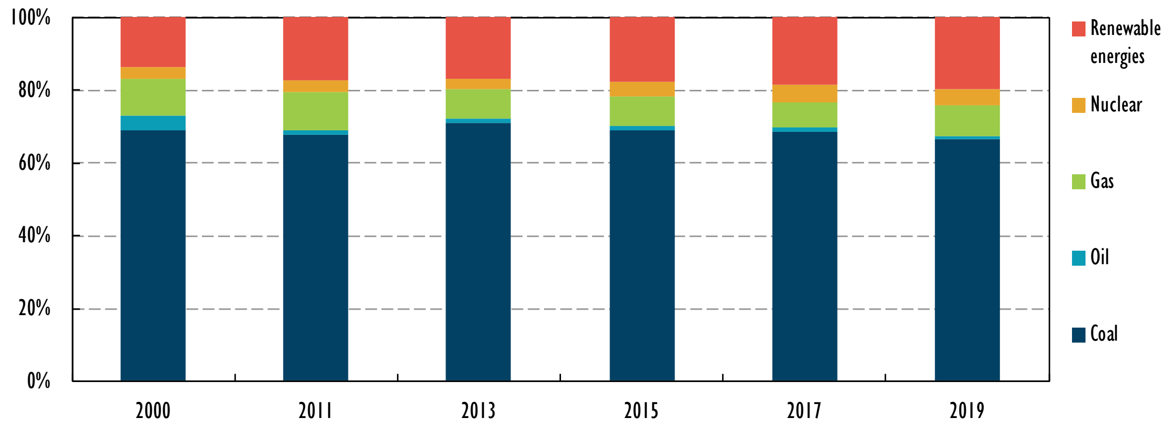


Figure 23 India's power generation mix, 2000-19



Indonesia and Malaysia have now become LNG importers, so that their future gas demand will be determined by how much LNG will be imported and exported, as well as the path of domestic gas production. Gas demand in both countries will add another 12 bcm over 2013-19. Indonesia is an archipelago; demand is mainly concentrated in Java, whereas the available supply comes mainly from Kalimantan and Sumatra – hence the need for LNG import terminals near the consuming centres. Unlike Malaysia, Indonesia is currently re-routing its LNG to its existing regasification terminal, the 3 mtpa Nusantara. In 2014, Arun, which is currently an LNG liquefaction plant, will be converted into a regasification terminal. The FSRU Lampung is also under construction and planned to come online in 2014. Future LNG supply will come from domestic LNG (Bontang), as well as from imports. Pertamina is currently trying to secure US LNG supplies.

Box 6 Pricing reforms in Asia: how to tackle low and subsidised gas prices

Most Asian countries suffer from the discrepancy between domestic gas prices and market prices, which are defined by prevailing regional LNG import prices. Low domestic gas prices do not encourage either energy efficiency on the demand side or exploration and production (E&P) activities on the supply side. Low prices also result in heavy burdens for the state budget when gas has to be imported before being resold at lower prices. The three main Asian gas users facing these issues – India, Indonesia and Malaysia – have developed different strategies.

In July 2013, the Indian government decided to change the pricing model driving the production sharing contracts. Such a reform would have started to affect Indian gas prices from April 1, 2014. However, the reform was postponed to an undetermined date due to the elections in spring 2014, even though the reform is seen as necessary to incentivise production. India has several different pricing mechanisms: the APM, non-APM gas and LNG import prices. The wish of the government was to use an arm's length gas price, similar to the spot prices in Europe and North America. However, such a price does not exist in the Indian gas market. Hence, a policy on natural gas pricing had been proposed, whereby an unbiased arm's length price would be based on an average of two prices, seen as the best alternative estimates of an arm's length price for an Indian gas producer. One price would be estimating the netback price of Indian LNG imports at the well head of exporting countries, subtracting costs of liquefaction and transport. The other would be the volume-weighted price of Henry Hub, NBP and the Japan Custom Cleared prices also for the past 12 months. This price, calculated as the average of the two price estimates, would apply equally to all sectors. While the press immediately concluded that Indian gas prices would double to USD 8.4/MBtu when the reform was announced in July 2013, that conclusion was apparently premature simply because the April 2014 prices would be based on prices for January-December 2013. It remains to be seen whether the new government will indeed implement this reform, or another, during the coming years.

Indonesia's fossil fuels are heavily subsidised, which contributes to the rapid growth in natural gas demand in the country and fails to incentivise domestic gas production. The unintended effects of fossil fuel subsidies, as highlighted in the IEA 2011 *World Energy Outlook* (WEO), include market distortions that affect the country's economy (IEA, 2011). This outcome has pushed the government to implement a subsidy reform programme, albeit at a slow pace due to public resistance. Previous cuts in fossil fuel subsidies have been followed by strong protests, notably in 1998 and 2003. The IEA 2008 *Indonesia Energy Policy Review* recommended the removal of subsidies through a phased schedule that is published in advance, accompanied by well-targeted social measures and a clear explanation of the negative impacts of subsidies on the government ability to fund services and infrastructure. Some of the measures have already been put into practice by the Indonesian government (IEA, 2008). The benefit is evident from the subsequent subsidies reduction in 2008 that saw lessening resistance, which is seen as resulting from the government's direct cash transfer programme to poor households. Perusahaan Gas Negara (PGN) average selling price is USD 6.85/MBtu, well below the prevailing prices in Asia. The government is committed to phasing out the fossil fuels subsidies by 2014, as outlined in its Medium-Term Development Plan, but many doubts remain regarding whether the removal plan will materialise as per the timeline, given the presidential election that will take place this year.

Box 6 Pricing reforms in Asia: how to tackle low and subsidised gas prices (continued)

The fast growing demand for natural gas in Malaysia is, to a certain extent, inflated due to the subsidised price enjoyed by consumers (RM 15.2/MBtu, or around USD 5/MBtu). In line with the government's plan to phase out subsidies to liberalise the market by 2015, as outlined in the tenth Malaysia Plan, the government's Performance Management and Delivery Unit (Pemandu) launched the Subsidy Rationalisation Programme in May 2010. The programme was designed to gradually remove subsidies every six months from 2010 to 2014. However, the changes to the gas subsidies occurred only once instead of the planned four times so far, and the government subsequently suspended the programme in 2011 to focus on the cost of living. The move is seen by many quarters as politically driven since it was a major election issue that saw the ruling coalition party, which had governed the country since independence in 1957, managing to retain its hold on power in 2013's election with a reduced majority. The government has repeatedly mentioned since then that the current subsidy is not sustainable and revised the gas price upward by 1.1% in January 2014. The original timeline of reaching market parity (Asian spot prices) by 2015 is thus virtually impossible unless drastic changes are made to remove the gas subsidy. The chances of this happening are very remote based on the previous stance taken by the government and strong reaction from the public. Nevertheless, it would be intriguing to see demand patterns after the complete removal of the gas subsidy. Although existing consumers are likely to reduce their demand to cope with the increase in cost due to the higher price, the void will be filled by new demand from industry players that were previously not able to have access to the gas due to the shortage. Gas Malaysia, a natural gas distribution company, announced in 2012 that the company will purchase additional volumes from Petronas at market prices from the Malacca's LNG terminal and mentioned that industrial customers are prepared to pay for gas at market prices because it is still cheaper than using alternative fuels such as refined products.

Other Asian countries such as Viet Nam, Thailand and Singapore will consume an additional 18 bcm. Singapore now has access to the global LNG markets, but the government has also decided on a moratorium on new pipeline supply from Malaysia and Indonesia. Demand in Pakistan, the Philippines and Bangladesh remains contingent on domestic production developments and is therefore limited.

The Middle East

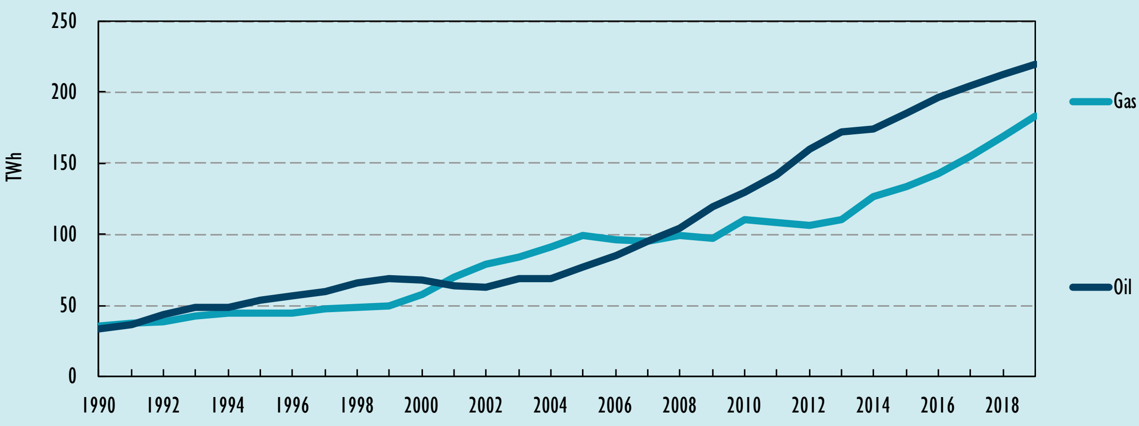
The Middle East is the second-largest source of incremental demand, with domestic production filling in only 88% of the additional needs, thus implying that the region's net exports are to decline over time. The region has always been a significant growth centre, but this trend will slow down over the projection period as incremental consumption is lower than it was over 2007-13. By 2019, Middle Eastern gas consumption is projected to reach 535 bcm; these forecasts are slightly higher than those from the *MTGMR 2013*. The fastest-growing countries are Saudi Arabia, Iran and Iraq (Box 7). Iran is very much a wild card due to the uncertainties regarding future political developments, both on the international scene and on the domestic market, but the domestic market is expected to benefit from the completion – albeit late – of phases of South Pars (see the Supply chapter). For Iraq, it will be mostly a question of using gas currently being flared in the power generation sector. Gas demand in Qatar is supported by the development in domestic production, but as no further plan beyond 2016 has been announced, demand growth in the last part of the projection period will be more limited. Oman's gas consumption will remain subdued until 2018, when the Khazzan-Makharem gas field comes online, which would restore LNG exports and bring new supplies to the domestic market. Meanwhile, the United Arab Emirates, Kuwait and Bahrain import more and more LNG. Demand growth will remain limited in Syria due to the uncertain development of the war, as well as in Jordan, which is, nevertheless, expected to receive contracted gas supplies from Israel. Lebanon, however, is not expected to be consuming any gas, neither from its potential domestic resources nor from imports.

Box 7 Will Saudi Arabia's power sector reduce its oil intake?

Like most of its neighbours, Saudi Arabia's power generation sector consumes essentially two types of fuels: oil products and natural gas (Figure 24). Both have had different roles over time. While generation from natural gas-fired plants managed to overtake that from oil-fired plants from 2000 onwards in the power mix, oil overtook natural gas again in 2008, so that natural gas contributed 108 TWh of electricity generation in 2011 compared to 142 TWh for oil. Originally, the plan involved a major increase of gas in the power mix; however, in 2006, the government issued a royal decree stating that future power plants would be fired on HFO, which explains the plateauing of natural gas consumption by power generators since then. This reversal highlights the increasing perceived "shortage" of natural gas due to a rapidly increasing power demand (at 6.5% per year on average). However, the new trend of ordered power capacity seems to show a switch back in favour of natural gas. Should the existing oil generation be fully replaced by gas, it would require 47 bcm, based on the current average efficiency of Saudi's gas-fired plants (but only 27 bcm based on 50% efficient plants). Meanwhile, this would free around 900 kb/d, which is the current consumption of oil in the power sector.

Looking at the next 20 years, the first major uncertainty is the growth rate of electricity demand. As of 2013, electricity generation amounted to over 280 TWh. As demand is determined by the simultaneous growth of population and of the economy, forecasting electricity demand is relatively tricky. The population is expected to increase to almost 35.6 million inhabitants by 2030, compared to over 28 million in 2012; meanwhile the economy will grow at over 4% per year on average. These projections assume that power demand growth continues to grow over 2013-19 at 6.3% per year, implying that electricity generation would reach over 400 TWh by 2019. While gas manages to increase its share in the total power mix, it fails to stop oil demand growth, as oil-fired generation grows by almost 50 TWh over 2013-19. This projection implies an additional demand of 280 kb/d. The forthcoming IEA *Medium-Term Renewables Market Report 2014* expects renewables generation to reach only a few TWh by 2019, which is very low compared to the Saudi government's declared long-term objectives in terms of solar (41 GW), wind (9 GW), and nuclear (17 GW) installed in 2032. Indeed, these objectives are for the longer term (2032). Nuclear generation could start in 2022 at the earliest. In the medium term, neither nuclear nor renewables will free Saudi Arabia from its dependency on oil and gas.

Figure 24 Generation by oil and gas-fired plants in Saudi Arabia, 2000-19



Should the entire additional generation have to be covered by natural gas, this would require an additional 42 bcm, based on the average plant efficiency of 27%. Burning additional gas is possible, but this requires finding and developing large quantities of natural gas production. The issue requires taking into account not only the production side of natural gas but also the competition from other uses of natural gas, notably in the petrochemical sector.

Box 7 Will Saudi Arabia's power sector reduce its oil intake? (continued)

Still, the type of gas turbines ordered and their efficiency are of paramount importance as shown by the large gap between the low and high consumption numbers mentioned earlier. The harsh conditions in Saudi Arabia may make it difficult to use these plants at maximum efficiency. Actual generation capacity shows that around 90% of the capacity involves steam or gas turbines, with very few efficient CCGTs. This explains the calculated low efficiency for natural gas. Different studies assume that efficiencies of gas-fired plants could be increased to 45% to 50%, even taking into account the Kingdom's harsh climatic conditions. Recent orders for Samsung or Siemens prove that CCGTs are now on order. High ambient temperatures result in increased power requirements for compression, which decrease the efficiency. Air cooling reduces these losses. Some specific ways are available to increase the efficiency through advanced components of gas turbines. Another way to reduce energy demand would be to use some of the heat generated by power generation for desalination projects; this combination can trigger energy efficiency improvement of 10% to 20%.

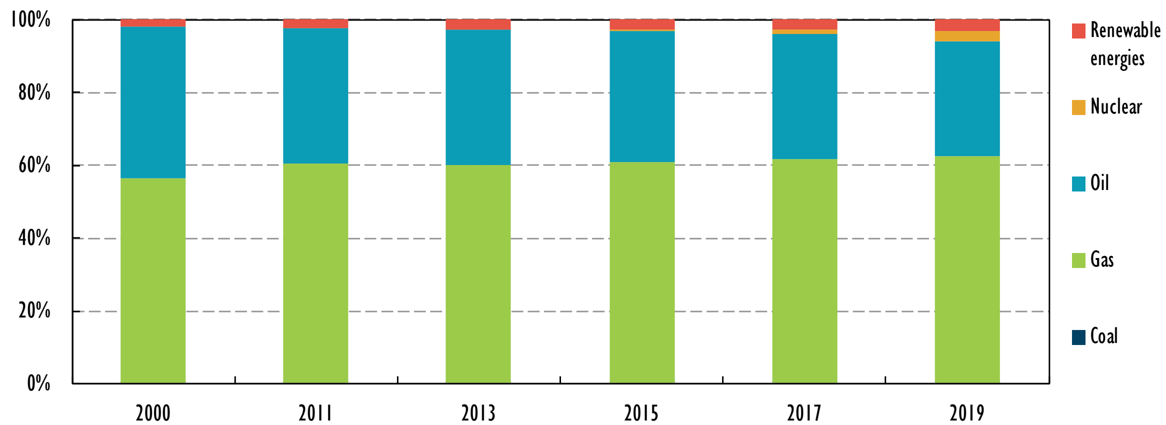
Another issue related to efficiency is technical, due to the large daily variations in daily power demand. During the summer, high energy demand results from air conditioning, which means that peak load can increase by one-third between off-peak and peak-time. Peak load power is usually provided by gas turbines due to their low start-up times and low capital costs. However, they are also less efficient than CCGTs (30% to 32% on average) and face a 20% efficiency loss at very hot temperatures. The fact that the reserve margin is relatively limited means that all the generating capacity has to be used at peak times, efficient or not. There is, nevertheless, a point in looking at converting some open-cycle gas turbines (OCGTs) into CCGTs, even though this conversion would require additional investment. The rationale should be to look at the implications in terms of oil savings at a certain international price and how fast these new investments could be recovered. This change can be done with relatively new OCGTs with enough water accessibility for air-cooling steam-condensing (plants located near the coast). Two other options are the regenerative cycle (when water is not available) and repowering for relatively old power plants.

The petrochemical sector is also a key gas-consuming sector in Saudi Arabia. The objective is to use cheap raw material to develop other industries than oil and gas production. In 2011, manufacturing GDP accounted for 9.8% of Saudi Arabia's GDP. The petrochemical sector contributed 11% of this 9.8%, in other terms, roughly 1% of the country's GDP. This amount is, of course, dwarfed by the 50% contribution from the oil and gas sector. SABIC is by far the largest company in the petrochemical and fertiliser sector, even though this sector has also seen private investment as well as the entry of Saudi Aramco with projects such as Petro-Rabigh. Cheap gas prices are considered as a crucial cost advantage for Saudi's industry, fostering its position on global markets.

Nevertheless, it is important to note the fact that even though the petrochemical industry benefits from low gas prices, it has a limited employment effect and a "small" share in the GDP. Considering the considerable gas and/or oil requirements in the power sector, it may be worthwhile for Saudi Arabia's petrochemical industry to consider as well the opportunity to continue investing in other countries, benefiting from ample resource base. This would free up gas volumes for the power sector, reduce the call on oil in the power sector and free up this oil for exports.

There is a tendency to believe that natural gas is displacing and will continue to displace oil in the power generation sector. This belief is not entirely true. Over the past decade, natural gas has indeed gained some market share against oil, as its share in total power generation grew from 56% to 64% in 2010, before dropping to 60% in 2011 (Figure 25). Oil has been coming back after its share dropped to 33% in 2005, averaging 37% over the period 2011-13. While oil is foreseen to slightly decrease again over the projection period to 32%, this decline is not entirely due to gas, but also to nuclear and renewable energies. Despite the region's continued addiction to oil and gas, renewable sources and nuclear will amount to 6% of total generation by 2019. The ambitious plans put forward by some countries in terms of renewable energies development (solar, wind) will come to fruition over the next decade, so that their impact will still be limited over the forecast period. Over time, they should be able to reverse the predilection for burning fossil fuels.

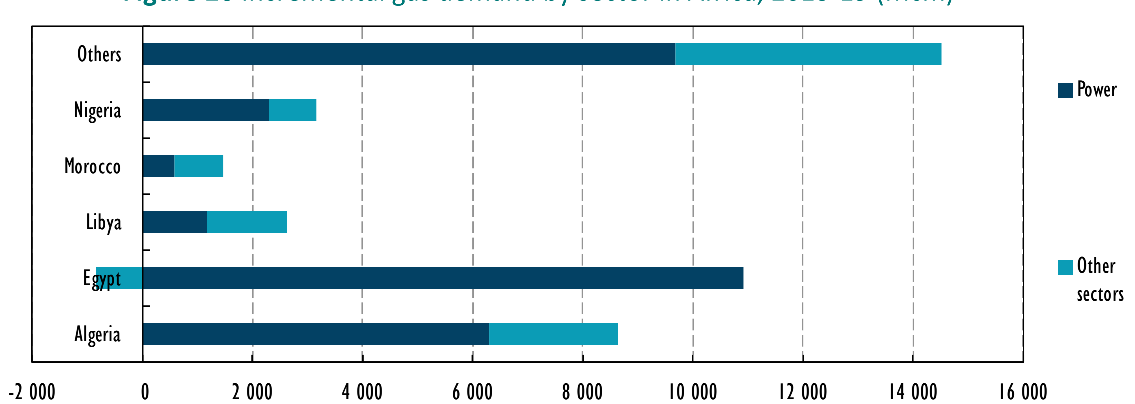
Figure 25 The Middle East's power generation mix, 2000-19



Africa

With a total primary energy demand of 700 mtoe as of 2011, Africa has one of the lowest consumption per capita (0.7 toe per capita); therefore giving people access to modern energy is of paramount importance. While renewable energies represent a high share of total energy demand as well as power generation, gas can provide some additional generation or alternatively displace more expensive oil-fired generation. The region's gas consumption is expected to reach 159 bcm in 2019, 41 bcm higher than the estimated 2013 level (Box 8). This rapid growth is actually also partly due to recovery in countries such as Libya, Nigeria or Egypt (Figure 26). These three countries and Algeria represent around 60% of the incremental growth over the projection period; this trend is unlikely to change until gas resources are developed in Eastern Africa in the post-2020 period. Nevertheless, these forecasts contain a certain part of optimism assuming: 1) that the situation in Libya will achieve a potential recovery or improvement – with domestic production returning to pre-war levels and exceeding them later in the forecast period; 2) that Egypt will solve its gas shortages and reverse the abrupt decline in gas production; and 3) that Nigeria manages to attract investors' confidence to develop further its natural gas resources.

Figure 26 Incremental gas demand by sector in Africa, 2013-19 (Mcm)



In Africa, the power generation sector supports three-quarters of the growth, while demand in the industrial sector will only increase by 6 bcm. This projection is due to the diversion of volumes previously used by the industrial sector in Egypt for the power generation sector. Industrials are assumed to see prices increasing sharply in order for the government to maintain gas prices in the power sector at low levels. Meanwhile, the residential/commercial sector gains another 1 bcm, and gas use by the energy industry for oil and gas production as well as liquefaction plant (Angola) gains 3 bcm. Consumption in the transport sector gains 0.1 bcm: here again, gas shortages in Egypt imply that this gas use is restricted.

Box 8 New African gas consumers

A few countries will start or restart consuming natural gas over the projection period, even if their consumption remains very limited and concentrated in the power generation sector: Benin, Mauritania, Namibia, and Togo. In the case of Benin and Togo, it is expected that the West Africa Gas Pipeline (WAGP) will finally start delivering natural gas, although the pipeline has been operational since 2008. Mauritania and Namibia will benefit from the development of domestic fields. In Mauritania, the Banda field developed by Tullow was declared commercial in 2012 and will serve to support local power generation project.

The WAGP links Nigeria's Escravos region area to three countries: Benin, Togo and Ghana. The pipeline started operating in 2008; but as of now, only Ghana and Togo are reported to be getting natural gas supplies. According to the government of Togo, deliveries stopped in September 2012 and restarted in July 2013, but at a much lower rate. Consequently, only two out of the six turbines of the Lomé pozer plant receive natural gas, while the others run on a more expensive HFO. Meanwhile, Benin is facing power shortages as the 80 MW Maria-Gléta does not get the gas it would need, first because of the issues with the WAGP but also because the distribution pipeline to connect the power plant is still missing. Benin needs around 250 MW to meet its power demand. Instead, the power plant has to use expensive jet fuel A1; given the resulting prohibitive cost of power generation, the power plant has been under-utilised at around four hours per day, even though it is fully operational.

The FSU and non-OECD Europe

While being the second-largest market behind OECD Americas, the FSU/non-OECD Europe region is the only one where demand is not expected to grow. Demand will, therefore, remain stable at 681 bcm, but it will actually go down over the projection period before recovering later (Figure 27). One of the main reasons for the initial decline is Ukraine reducing its gas demand due to its difficulties in paying for gas imports as well as low GDP growth. It is not the first time that the region sees important demand reductions: demand dropped by around 200 bcm over 1991-98, following the collapse of the FSU. Besides, the region holds a very important energy efficiency potential across all sectors (Figure 28). The distinction is made between two groups with different behaviours – the non-OECD Europe plus Ukraine and the others. In the first group, gas demand is to decrease, while most of the other countries' gas consumption continues to increase due to the important role of natural gas in their economies and the power generation sector in particular.

Four sectors will see a decline in gas consumption: the residential/commercial, power generation, transport (pipelines) and losses, while the use by the energy industry and industrials will be growing. Power generation incremental needs will amount to 210 TWh, of which gas will only contribute to 41 TWh, while coal will contribute to 89 TWh. Power generation, nevertheless, continues to represent the lion's share of the region's total demand, followed by the industry sector representing 19%. The relatively high percentage of the transport sector in total consumption does not relate to the use of gas by NGVs, but to an important utilisation by pipelines to transport and export gas.

Figure 27 Demand evolution in FSU/non-OECD Europe, 2000-19

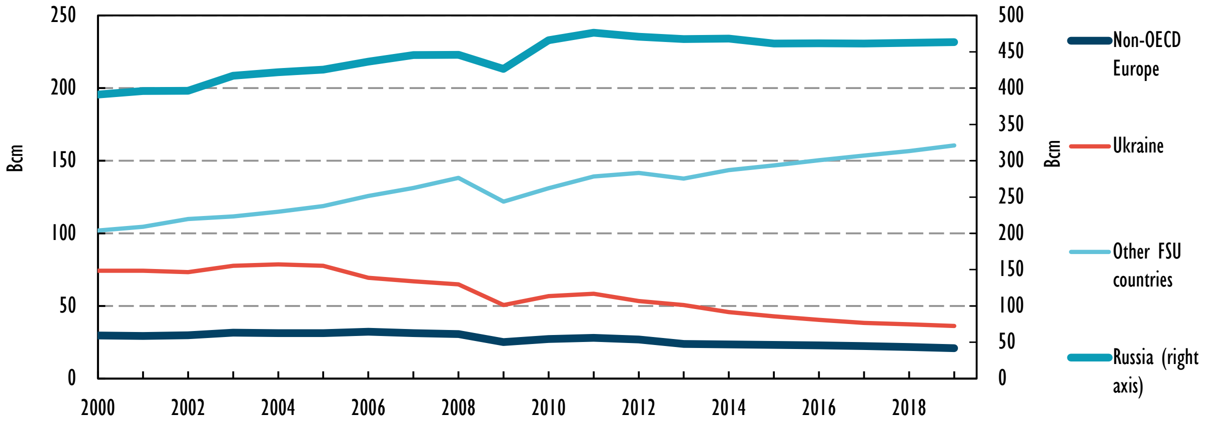
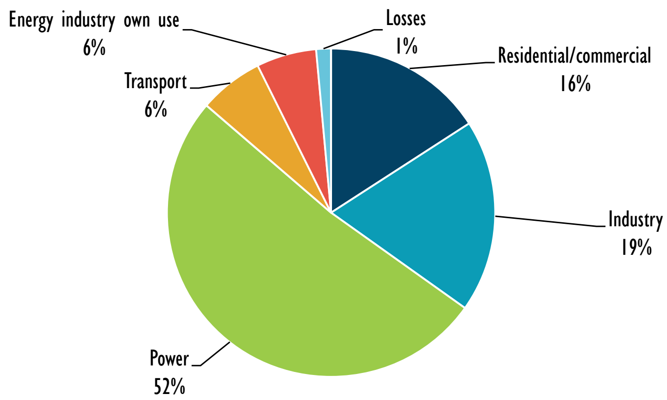


Figure 28 Demand by sector in FSU/non-OECD Europe, 2019



Latin America

Latin America's gas demand is projected to increase by 3.8% per year over 2013-19, from 164 bcm in 2013 to 204 bcm in 2019, a 41 bcm increase, while production will only grow by 33 bcm. While the region remains a net exporter of LNG, it becomes increasingly import dependent. During the forecast period, Uruguay and Colombia will start importing LNG, while Colombia will also start exporting LNG and continue exporting some pipeline gas to Venezuela. Meanwhile, Brazil's gas demand increases by 15 bcm: it is boosted by domestic gas production developments as well as LNG imports. As Argentina fails to increase gas output sufficiently, it has to import increasing amounts of LNG. Besides, new countries are looking at becoming natural gas consumers (Box 9).

In terms of sectoral gas demand, the fastest growth is the transport sector at 7% per year, faster than the power generation sector (5.7% per year). But while transport adds 4 bcm, power generators will consume 22 bcm more, or half of the additional demand. Many countries have opted to use natural gas in the transport sector in Latin America, while two countries have more than 1 million NGVs on the roads – Argentina and Brazil. While the power generation sector is the largest contributor to gas demand, gas is not the fuel of choice in Latin America. Most of the additional power generation (almost two-thirds of the 1 500 TWh needed) is coming from renewable energies, while gas contributes only 300 TWh. Of note is the fact that a few countries are building coal-fired plants, notably Colombia, an important coal producer. Meanwhile, industrials and residential users will contribute to 5 bcm and 6 bcm of additional gas consumption.

Box 9 Central American countries turn to LNG to switch away from oil

To be in a position to use natural gas, many Central American countries have no other choice but to import LNG. In Central America, no country is producing gas, so that the only alternative is LNG imports. This also applies to islands such as the Dominican Republic and Jamaica. Two islands of the region currently import LNG: the Dominican Republic and Puerto Rico. When they started importing LNG in the early 2000s, they were an exception compared to the overwhelming majority of other LNG importers – mostly OECD countries or large developing countries such as China and India. Only recently has it been usual to see countries developing LNG import terminals for smaller markets, as is the case in Indonesia and Malaysia.

The rationale for these countries to develop LNG imports is very simple: when they do not have sufficient renewable energy sources, they have to rely on expensive oil products to generate electricity. This is costly for the country and generates more emissions than natural gas. Hence, the attempt to switch to natural gas. The Dominican Republic started importing LNG in 2003 through the Punta Caucedo LNG terminal and is planning to increase its LNG import capacity through construction of a new terminal in San Pedro de Macoris by the Antillean Gas Company. The terminal construction, which was launched by the country's president in February 2014, will contribute 1.3 bcm per year to the total LNG capacity of the country.

Meanwhile, Panama, which will play a significant role in the global LNG trade through the expanded Panama Canal, is also planning to build a regasification terminal in the country. Gunvor, the LNG aggregator for the terminal through an agreement signed with LNG Group Panama in 2012, has signed a tolling contract/term sheet with Magnolia LNG for the purchase of 2.7 bcm per year of LNG from the project. The LNG terminal is part of the country's plan to reduce its dependency on hydropower and oil for its electricity generation. Panama's plan to import gas from Colombia seems to be delayed. However, it remains to be seen whether the Panama LNG terminal will be completed as planned, or in a more pessimistic view, whether it will even materialise. To date, the project's commencement date has already been deferred once from the original target of 2015 to 2017.

Elsewhere, Jamaica has been considering importing LNG since 2004, and awarded a tender to Samsung in 2012 to construct a floating regasification terminal, with the expected completion date in 2014. However, to date, construction of the terminal has yet to take place. El Salvador faces a similar situation as the plan by Cutuco Energy to develop a regasification terminal in the country has been delayed several times. The LNG industry is currently dominated by big players due to the required massive capital investment. It will be a big challenge for smaller market players such as Caribbean countries to have the required facilities and the ability to secure LNG supply. Nevertheless, the LNG plan in these Caribbean countries still shows a promising outlook due to their proximity to the US LNG projects, their free trade agreement (FTA) status with the United States, and the current state of electricity generation, which is largely dominated by oil.

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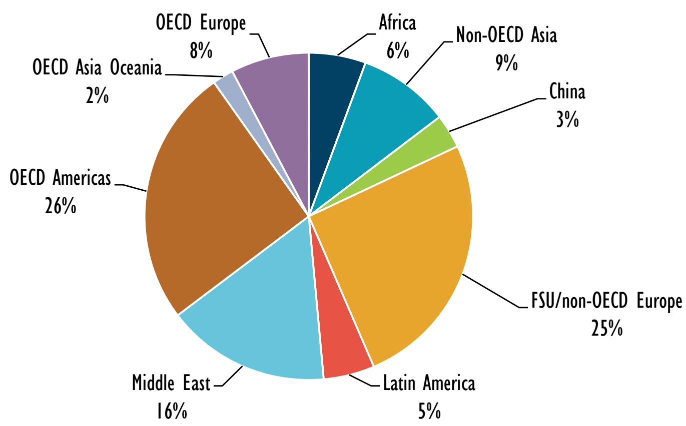
SUPPLY

Summary

- Global gas supply gained 1.1% in 2013, reaching 3 480 billion cubic metres (bcm) (Figure 29). The Former Soviet Union (FSU)/non-OECD (Organisation for Economic Co-operation and Development) Europe and the Middle East were the major contributors to this additional output. The People's Republic of China ranked third in terms of additional volumes produced. FSU/non-OECD Europe's recovery was supported by large exports from Russia to Europe as well as from Turkmenistan to China. Unlike the previous years, OECD Americas failed to deliver significant additional volumes as US gas production growth slowed down for the first time since 2005. Both OECD Americas and FSU/non-OECD Europe production levels are similar (889 bcm). However, major drops were recorded in Africa (-4%) as well as in Europe (-3%), while non-OECD Asia's production continued to drop (-1%). Finally, the year 2013 was somewhat lacklustre in terms of major gas discoveries; however, early 2014 seemed to prove otherwise.

Figure 29 Gas production by region in 2013

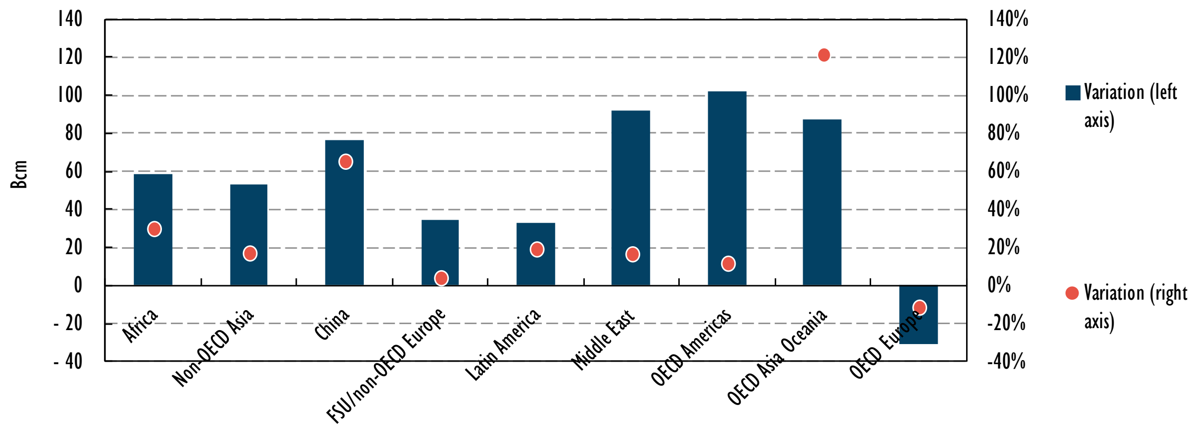


Source: unless otherwise indicated, all material in figures and tables is derived from IEA data.

- Looking forward to the period to 2019, two OECD regions (Americas and Asia Oceania) as well as the Middle East are the major contributors to increasing gas output, while the FSU/non-OECD Europe region falls significantly behind. This marked change from previous outlooks results from limited import needs from Europe, competition from liquefied natural gas (LNG) in this market, lower intra-regional exports from Russia to other FSU/non-OECD European countries, the absence of a pipeline from Russia to China and a delayed start of Russian LNG export projects. Against this backdrop, Central Asian gas producers will benefit from the expansion of the Central Asia Gas Pipeline to increase their deliveries to the gas-hungry Chinese market. Azerbaijan will benefit from the start of the Trans Adriatic Pipeline (TAP) and Trans Anatolian Gas Pipeline (TANAP) to deliver more gas to Europe. Consequently, Russia's gas production remains relatively flat over the projection period, while US output increases significantly on the back of higher domestic demand, LNG exports and the lack of recovery in Canada's production. The role of natural gas liquids (NGLs) in supporting US gas production will be essential as prices remain below USD 5 per million British thermal units (MBtu) over the forecast period.

- China will be one of the fastest-growing regions as its output surges by 65% through new conventional gas developments supported by recent discoveries, shale gas and coal gasification (Figure 30). Africa's recovery by 30% is also quite impressive, taking into account the recent drop; the region sees countries such as Angola emerging as sources of new gas supply besides the traditional large producers, which are still facing numerous challenges to attract investors. Equally impressive is the recovery of non-OECD Asia as production recovers in India, while Papua New Guinea, Myanmar and Viet Nam provide substantial new volumes. Despite a forecast 19% growth, Latin America is considered as underperforming as key producers such as Venezuela and Argentina struggle to reverse declining trends. Against this backdrop, Europe is the only region where gas production is likely to drop. While Norwegian gas production will provide some additional, albeit limited volumes, and UK production declines more slowly than in the past, declining Dutch production will drag the country into an importing mode by the next decade.

Figure 30 Production variations (bcm and %) by region over 2013-19



- The forecast period will also be decisive for future production developments in countries that are still considered wild cards, the most important being Iran. The recent changes on the international political scene give some hope that the country could come back on the global gas market should sanctions be totally removed. However, Iran still has a long way to go before it develops new pipeline exports and at least a decade before it could export LNG. East Africa also holds significant resources, but still needs to tackle many issues such as the remoteness of the resources, the inexperience of the local governments, and competition from other LNG-exporting regions; at the same time, some resources owners are still looking at selling their stakes. Some investors may, nevertheless, take a cautious stance regarding the appetite of these countries for natural gas, having in mind a potential "Egyptian syndrome," whereby the country would redirect LNG export volumes to its domestic market.

- Unconventional gas represented an estimated 18% of global gas production as of 2013 (627 bcm). While unconventional gas grows faster than global gas production, its growth has slowed down over the past two years. Shale gas is no longer an exclusively North American phenomenon, as China and Argentina are producing as well. China is now likely to reach its 2015 production target of 6.5 bcm. Over the medium term, developments will be concentrated in North America, China and Australia. In China, coal gasification is expected to take off, contributing 40 bcm of the country's production by 2019. Other countries with significant shale gas potential still face numerous challenges such as local opposition, environmental challenges, low prices, lack of infrastructure and under-developed service industry.

Recent trends

Global gas production posted a quite modest gain of 39 bcm (1.1%) in 2013, the second lowest growth since the beginning of the decade. The supply picture of the year 2013 diverged greatly from that of 2012 (Table 9). In some regions, it seems indeed to have been exactly the opposite. FSU production, usually constrained by the region's export markets, notably to Europe, benefited from a long and cold winter in Europe and ever-increasing Chinese import needs. After having lost 13 bcm in 2012, FSU/non-OECD Europe production bounced back by 20 bcm. In contrast, North American gas output growth slowed down abruptly from 27 bcm in 2012 to 4 bcm in 2013, a result of the modest performance of the United States and the still struggling Canadian and Mexican industry. In Europe, the respite lasted one year, and gas output resumed its decline, driven by a sharp drop in Norwegian gas. Africa's gas posted a record production drop of around 4% as its main producers – Algeria, Nigeria and Egypt – faced declining domestic gas production, albeit for different reasons. Angola's entry into the global LNG scene in mid-2013 failed to compensate for the others' lower outputs.

Table 9 World gas supply by region (bcm)

	2000	2011	2012	2012/11 (%)	2013	2013/12 (%)
OECD Europe	303	272	276	1.3	268	-2.9
OECD Americas	760	859	885	3.1	889	0.4
OECD Asia Oceania	42	64	67	4.8	72	8.2
Africa	119	200	204	2.0	196	-4.2
Non-OECD Asia (exc. China)	221	323	318	-1.5	313	-1.4
China	27	103	107	4.4	117	9.0
FSU/non-OECD Europe	725	882	869	-1.5	889	2.3
Latin America	102	166	171	2.8	175	2.4
Middle East	202	519	544	4.8	562	3.2
Total	**2 502**	**3 387**	**3 441**	**1.6**	**3 480**	**1.1**

Note: OECD Americas includes four countries: Canada, Chile, Mexico and the United States. OECD Asia Oceania includes Australia, Israel, Japan, the Republic of Korea and New Zealand.

Source: unless otherwise indicated, all material in figures and tables are derived from IEA data.

In contrast, China continued on the path that it had been walking over the past decade with a strongly increasing gas production; actually, the growth rate (+9%) was even higher than previous years. This rising trend is also shared by OECD Asia Oceania, Latin America, and the Middle East. OECD Asia Oceania's output grew 6 bcm, powered by the Pluto LNG coming to plateau and the start of Israel's Tamar field in April 2013. The increase in Australian gas production is still modest in comparison with the surge expected to take place between 2015 and 2020, when most of the new LNG liquefaction capacity is to come online and then plateau. Middle Eastern LNG exporters reported higher LNG exports, which, combined with their growing appetite for gas in their domestic markets, supports a higher production estimate. Non-OECD Asia's gas production lost around 4 bcm, an additional drop since the region's output started to fall in 2010 after peaking at 332 bcm. For a region where hundreds of millions lack access to energy and which is trying to increase the share of cleaner fuels in its energy mix, this decline means an ever-increasing reliance on imported gas, notably LNG. As the region is still a large LNG exporter, this drop in production also translated into a reduction in net LNG exports.

The year 2013 was somewhat lacklustre in terms of major gas discoveries. There were discoveries, but none of them was big enough to support, for example, a stand-alone 5 million tonnes per annum (mtpa) LNG train to export gas. Most discoveries were made in Africa, in regions lacking gas infrastructure.

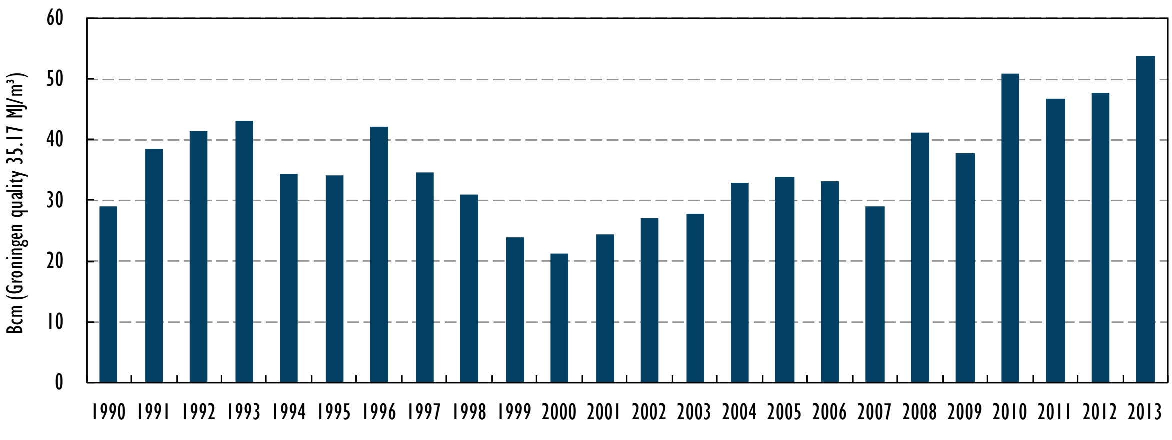
Similar to the previous years, East Africa yielded again a few important discoveries, notably Eni's Agulha (up to 7 trillion cubic feet [tcf] or 190 bcm) in Mozambique and Statoil's and ExxonMobil's discovery of up to 6 tcf (170 bcm) of gas in place around the Tangawizi-1 well in Tanzania. Another major African gas discovery was Cobalt's Lontra discovery in Angola (a low estimate of 700 million barrels oil equivalent (Mboe), with 35% to 45% of liquids, meaning around 1.6 tcf of gas [45 bcm]). Eni made another discovery, the Nene Marine in Congo (0.7 tcf or 20 bcm). The offshore discovery Salamat by BP in Egypt (first estimates of 1.2 tcf or 34 bcm) shows that the country is still rich in gas resources, but suffers from above-ground issues. Away from Africa, Newfield found gas offshore of Sarawak in Malaysia; estimates of gas initially in place range from 1.5 tcf to 3 tcf (85 bcm).

Will 2014 prove to be different? CNPC already announced in February 2014 a large discovery in Sichuan, which could hold up to 440 bcm of natural gas, 308 bcm of which would be technically recoverable. Such a field would certainly support a 5 mtpa LNG plant, but China needs the gas domestically as reaching a production level of 100 bcm of shale gas still seem years away.

OECD gas production

OECD gas production remained relatively stable, gaining only 1 bcm, but with wide regional differences. After having bounced back in 2012, European gas production became reconciled to previous declining trends in 2013, highlighted by a cumulative 8 bcm loss. Were it not for the Netherlands, which boosted its production to the third-highest level since 2000 (85 bcm), the drop would have been even more marked, reaching 13 bcm. The long winter called for more Groningen gas to be delivered to the market, and the field delivered an exceptional 53 bcm (Figure 31). This record is now likely to remain untouched, given that the Dutch government has limited future Groningen gas production (see section on Europe later in this chapter).

Figure 31 Groningen gas production, 1990-2013



Source: Dutch Oil and Gas Portal (2013).

Elsewhere in Europe, gas output recorded two-digit drops in many countries: Austria and France lost almost one-third of their production, Denmark around one-quarter, and Hungary and Turkey around one-sixth. The largest drop on a volumetric basis (6 bcm) took place in Norway; nevertheless, such an outcome was widely expected by the markets and announced by major Norwegian producers such as Statoil after the exceptional production level reached in 2012 (114 bcm). Output from both the Troll and the Åsgard fields was considerably lower than in 2012.

In recent years, analysts have speculated whether US gas production would finally start declining, as it keeps expanding despite the odds: a record low number of rigs, low gas prices, a switch of focus from gas to oil and NGLs on the production side and producers losing money with dry gas fields. The beginning of 2013 seemed to point in that direction, with year-on-year declines posted in both January and February. Following that, however, all the succeeding months but September posted production gains, up to 2.4% from the previous year's level. Looking back at 2013, US gas output grew 6 bcm (0.9%), the smallest gain since the relentless, shale gas-driven production increase started in 2005. The US market did benefit from higher gas prices, which moved into the more comfortable zone of USD 3.5 to USD 4.5/MBtu. Despite a price increase in early 2014, the forward price curve stubbornly shows prices hovering between USD 4/MBtu and USD 5/MBtu until the end of the decade. This projection does not reassure producers still struggling with dry gas plays (see section on US gas and NGLs production in this chapter). The Arctic chill descending across the United States in early 2014 exposed other issues regarding natural gas production, such as bottlenecks in the transport system, notably in the Northeast region, which saw very sharp price spikes. While US gas production has increased dramatically over the past few years, pipelines have failed to keep up with these new supplies in some areas. This was especially the case in New England and New York, where prices surged to 20 times the Henry Hub level (above USD 100/MBtu) during the cold spell in early 2014.

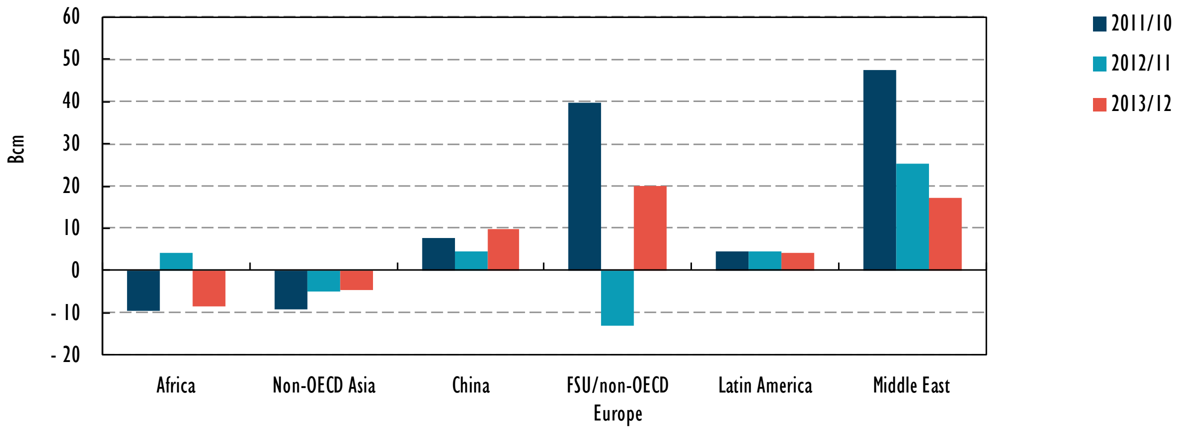
Annual production in the OECD Asia Oceania region is starting to attract attention as Australia moves towards becoming the world's largest LNG producer. Meanwhile, with the successful development of the Tamar gas field, Israel's gas production grew an amazing 159%. Despite production only starting in April, Tamar's production reached 5.5 bcm in 2013. Together with the Yam Thetis fields, this output implies a total production of 6.5 bcm, 2.6 times higher than the 2.5 bcm registered in 2012. In contrast, Australia featured only a modest production gain of 3.1% as Pluto LNG gradually came to plateau. Coal seam gas output stalled at 6.5 bcm; most of the increase is planned for end-2014 and 2015. In separate developments, production in Western Australia increased by 5% while east coast output declined slightly. This also reflects changes in regional demand, as demand fell on the east coast, notably due to lower call from power generators. As far as production feeding the LNG plants was concerned, North West Shelf (NWS) LNG output dropped slightly, but this was largely compensated for by higher output for Pluto LNG.

Non-OECD gas production

The year 2013 was a successful one for Russia as production gained a healthy 2.3%, equating to 15 bcm, putting the country's production back to where it was in 2011 (Figure 32). Russia's gains are different from Gazprom's gains, however, as the company's production has been flat. Gazprom now faces mounting competition on the domestic market, where its deliveries are declining, so that the export markets are increasingly important for the company. Meanwhile, Rosneft posted a healthy 133% increase in natural gas production in 2013, reaching 38 bcm. The company is the third-largest gas producer in Russia behind Gazprom and Novatek. This growth is largely due to the acquisition of assets from TNK-BP and the consolidation of Itera's assets, while only 22% came from organic growth. Meanwhile, Novatek's gas production increased by "only" 8.5% to 62 bcm.

This trend reflects the fundamental changes that the Russian gas industry has been undergoing for a few years: the transition from dry gas from super giants to wet gas from smaller fields, the rise of the independents and oil producers, and the stagnation (or even decline) of Gazprom. This evolution seems to have culminated with the authorisation given to some key other Russian producers to export LNG, an historical breakaway from Gazprom's export monopoly that seemed unthinkable a few years ago (see the Trade chapter). Kazakhstan's natural gas production increased slightly by 0.5%, while Turkmenistan benefited from higher exports to China (+4.5 bcm). Although Uzbekistan also exported more to China, its output nonetheless dropped from 63 bcm to 61 bcm. Meanwhile, Azerbaijan posted a healthy 11% growth on the back of higher gas exports to Turkey following contractual changes.

Figure 32 Production changes in non-OECD regions



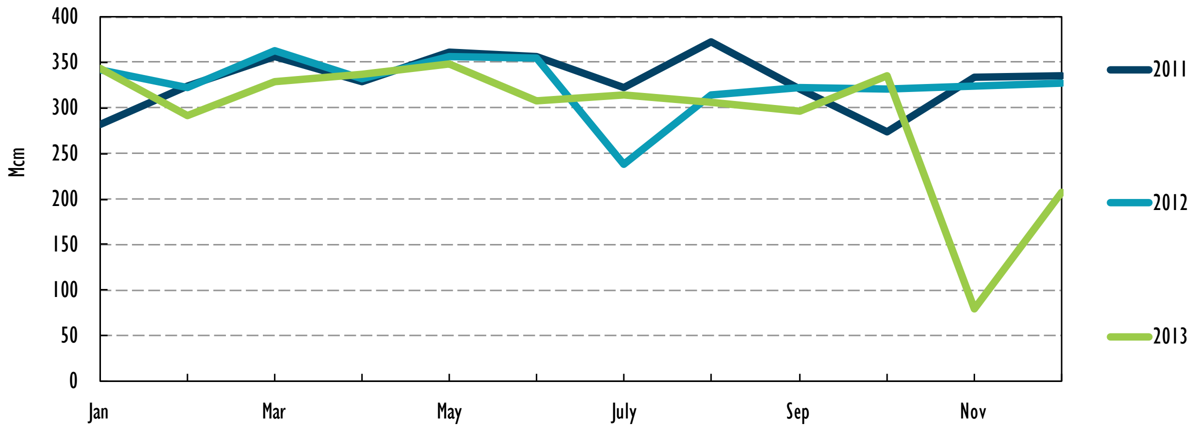
Reliable production data on African countries remains difficult to obtain. Nevertheless, Africa's gas production saw a major setback for the continent's three main producers. Egypt's gas production fell throughout 2013, from a monthly 4.8 bcm in early 2013 (57.9 bcm on an annual basis) to a monthly 4.4 bcm (52.5 bcm on an annual basis) in late 2013, a level unseen since 2007. Consequently, output dropped by 7%, LNG exports were almost halved compared to 2012 and power cuts continued. Algeria could have maintained a stable output if not for the In Amenas attack, which resulted in withdrawal of one train for most of the year. Consequently, exports declined, driven by a sharp fall in pipeline exports to Europe (-4 bcm) and lower LNG exports (-1 bcm). Nigeria faced several *forces majeures* triggered by pipeline sabotage and oil theft during the year, which affected both Nigeria's production and LNG exports. The start of Angola's LNG liquefaction plant in mid-2013 and its relatively slow ramp-up to plateau failed to compensate for the others' lower output.

The Middle East contributed 18 bcm to the world's additional supply. In Saudi Arabia, Saudi Aramco brought the Karan gas field on stream in 2011, and it reached its plateau production of around 18 bcm in early 2013, contributing significantly to the increase in production over the past two years. The field is the first offshore non-associated gas field in Saudi Arabia. The next significant development on the gas side is the Wasit Gas Programme, but it is expected to come online only later in 2014. Other Middle Eastern countries also had higher production levels, albeit more modest. War in Syria is assumed to have markedly reduced gas output (-13%), but this decline is smaller in proportion to the 33% year-on-year drop in oil production. Yemen had the largest relative change, where LNG exports bounced back by one-third (2.3 bcm) due to fewer terrorist attacks on the pipeline to its LNG liquefaction plant.

China's gas production unexpectedly jumped 9%, to 117 bcm in 2013. Despite contributing an additional 10 bcm to the world, China's additional output lags behind the country's incremental demand (20 bcm). While production remains concentrated in the hands of CNPC, which controls around three-quarters of China's gas production, gas production also comes from only a handful of fields. The main contributors are CNPC's Changqing and Tarim oil fields, which together represent around 55 bcm of production in 2013, followed by Sinopec's Puguang gas field with around 8 bcm.

The production situation varied for Asian countries in 2013.[4] Indonesia's production is estimated to have dropped by 7 bcm, affecting both LNG and pipeline exports. In that respect, it is useful to remember that Singapore began to import LNG in 2013, and thus most likely imported less natural gas from Indonesia. India reported the second-largest decline in the region as production of the field KG-D6 continued to decline, putting domestic output at around 36 bcm, a far cry from the 2010 level of 51 bcm. Total offshore production, which once peaked at 43 bcm including 17 bcm from Mumbai High, is assumed to have fallen to around 26 bcm in 2013. Brunei, another major LNG exporter, also reported a small diminution in production, which translated into lower LNG exports. Typhoon Haiyan devastated the Philippines in November 2013, knocking out natural gas production; it only partially recovered one month later (Figure 33). Given the country's self-sufficiency, presumably part of the demand was also wiped out.

Figure 33 Gas production in the Philippines, 2011-13



Production grew in other Asian countries, even those struggling to increase their gas output, such as Bangladesh and Pakistan. Myanmar benefited from the start of the Shwe field feeding the recently commissioned pipeline to the south of China, even though the field delivered only 0.2 bcm during 2013. Thailand produced 2% more gas, the largest increase coming from the Bongkot field, which now represents a quarter of the country's total production, against 17% in 2010. Viet Nam's production also increased strongly.

In Latin America, production expanded in all countries except Argentina. The country's gas production is now down to levels unseen since 1999, and there is no sign of improvement, despite the government's priority on increasing gas production and several companies, such as Shell and Petrobras, announcing they would step up investments. Notwithstanding high interest from producers, the Neuquén province registered the sharpest production fall, followed by the southern region. Meanwhile, both Bolivia and Brazil recorded double-digit growth. In Brazil, offshore and onshore production increased by roughly the same amount, but offshore production continues to represent the lion's share (almost three-quarters) of total gas output. Noteworthy is the strong increase in non-associated gas production. Out of 313 fields, around 100 represent three-quarters of the production. The Lula field is the most productive, with a daily output of up to 6.3 million cubic metres (Mcm) (2.3 bcm per year). Bolivia's rising gas output mostly responded to import needs from Brazil and Argentina. Trinidad and Tobago production gained a small 1%, while Peru grew only 3%, a far cry from the double-digit increases registered in 2010 and 2011, when the LNG plant came on stream.

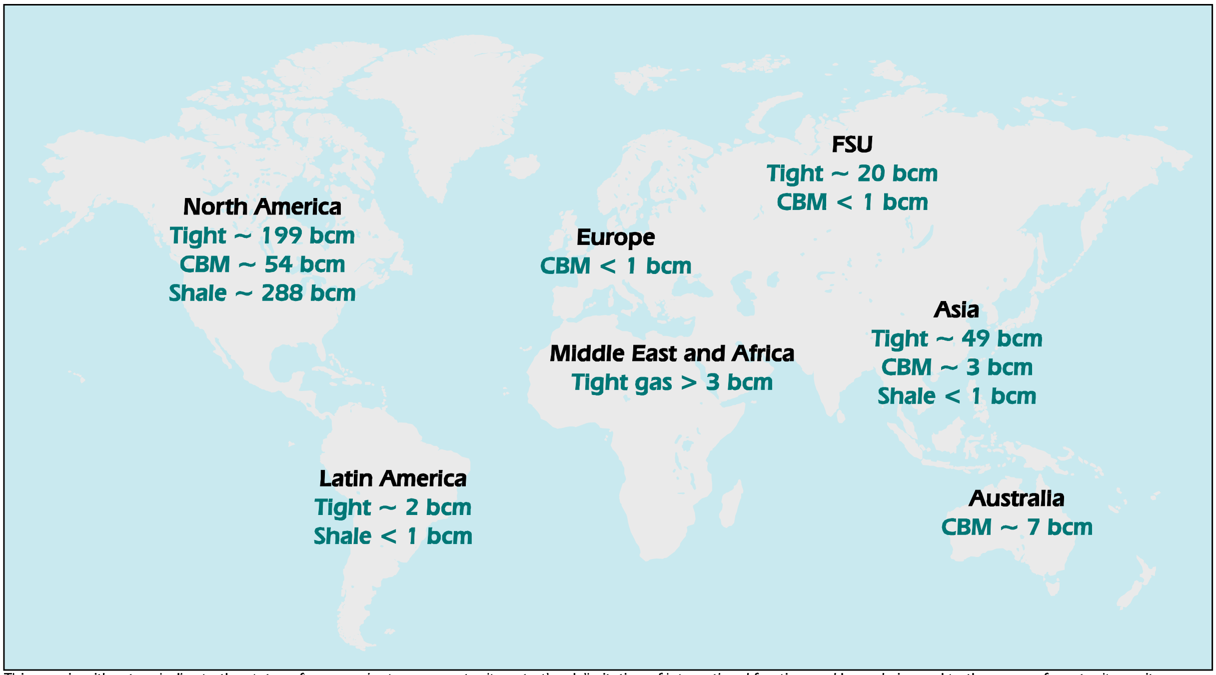
[4] NB: estimates derived from partial data available for most countries.

Global unconventional gas developments

The 2013 picture

Global unconventional gas production in 2013 is estimated at around 627 bcm, against an estimated production of 606 bcm in 2012 (Map 2). It includes tight gas, coalbed methane (CBM) and shale gas. Tight gas production amounts to 273 bcm and originates from many regions across the world (despite a strong concentration in North America), while shale gas production reached 288 bcm. Global shale and tight gas production, therefore, seem to be roughly at the same level. Nevertheless, companies rarely differentiate between conventional gas and tight gas, making tight gas production estimates less reliable. No major breakthrough in production took place in 2013. Despite high interest from investors and politicians, major developments for the upcoming years will include large amounts of CBM production in Australia starting later in 2014, and Chinese shale gas exceeding 30 bcm later in the decade. In 2013, the drivers behind the increase in unconventional gas production were North America, China and Australia.

Map 2 Unconventional gas developments (2013)



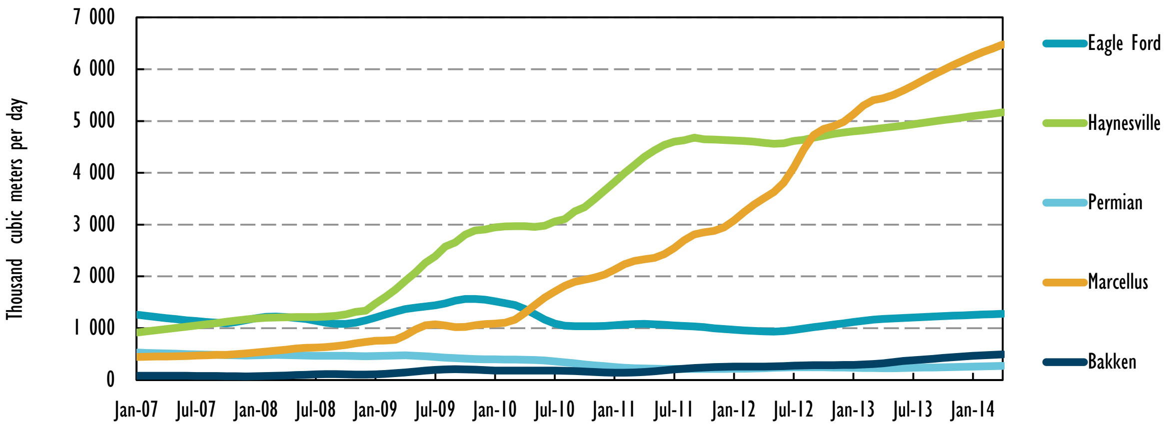
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

North America still accounts for around 86% of global unconventional gas output, but no longer the totality of shale gas production. As of 2013, shale gas is being produced in the United States, Canada Argentina and China. But Chinese and Argentinean shale gas production in 2013 still differs from North American by a factor of 1 000. With almost 50 bcm of unconventional gas output, China stands far behind North America in terms of total unconventional gas production output; according to first estimates, China produced around 3 bcm of CBM in 2013 (but there was about 10 bcm of coal mine methane), 0.2 bcm of shale gas and around 45 bcm of tight gas.

As prices remain relatively low in North America, the growth there has slowed down considerably compared to 2010 or 2011. Some uncertainty has arisen regarding the fate of shale gas in the United States: according to the Energy Information Administration's (EIA's) Annual Energy Outlook 2014, published in April 2014, shale gas production in 2013 declined from 275 bcm in 2012 to 265 bcm in

2013, despite the fact that Marcellus gas production grew tremendously during 2013 (EIA, 2013a). The EIA has also substantially revised historical data: shale gas production in 2012 has been revised upward from an estimated 230 bcm to 275 bcm. Tight gas production was revised downwards from around 166 bcm to 143 bcm for 2011, and from 163 bcm to 138 bcm for 2012. Hence, the 2012 unconventional gas production is higher (458 bcm against 440 bcm), so that the 2013 estimate is accordingly higher too. Tight gas is now estimated to stand at around 148 bcm, which implies a recovery of tight gas production during 2013, unlike the estimates for shale gas. CBM data show a small increase in production from 44 bcm in 2012 to 46 bcm in 2013, in line with US gas production growth.

Figure 34 Production per day in different shale gas and shale oil plays



Source: EIA (EIA, 2014).

Nevertheless, the shale gas estimate seems to contradict other data showing production of the different shale gas plays, including the prolific Marcellus, where total production has increased substantially (EIA, 2014). Marcellus production increased to almost 12.5 bcm per month in April 2014 against only 8.6 bcm per month in early 2013; average annual production in 2013 was at 123 bcm. Several shale gas plays show a production increase, notably Marcellus, Bakken, Eagle Ford and Permian, while production fell in Haynesville. One important factor is the increasing productivity of natural gas wells in many US regions due to the increasing precision and efficiency of horizontal drilling and hydraulic fracturing. The increasing yield is quite important for both Marcellus and Haynesville, but this growth did not compensate for the drop in the number of rigs at Haynesville (Figure 34).

Medium-term supply forecasts

Assumptions and methodology

Like the demand forecasts, the production forecasts are performed on a country-by-country basis. The IEA data provide the historical basis, which for this report extends to end-2012. Revised data for OECD countries were available in early April 2014 and have been taken into account. Due to an earlier publication date of this report compared to previous years, it was not possible to use revised data for non-OECD countries, because these would only be available later. The production forecasts also build upon the Rystad AS Ucube database for historical production on a field-by-field basis and identification of the next generation of fields expected to start over the coming decade. Most of the fields expected to start within the next five years have already been discovered, and companies are working on their plans for development and operations. Forecasts also make use of publicly available data, industry presentations as well as regular discussions with companies and governments. The approach relies on using a combination of expectations from both governmental bodies and companies regarding a country's gas output and informed by data and forecasts about single fields. A conservative approach to field start and production ramp-up has been taken, taking into consideration demand, supply, and infrastructure available to transport or export new gas sources.

World gas supply: Russia lags behind in terms of growth

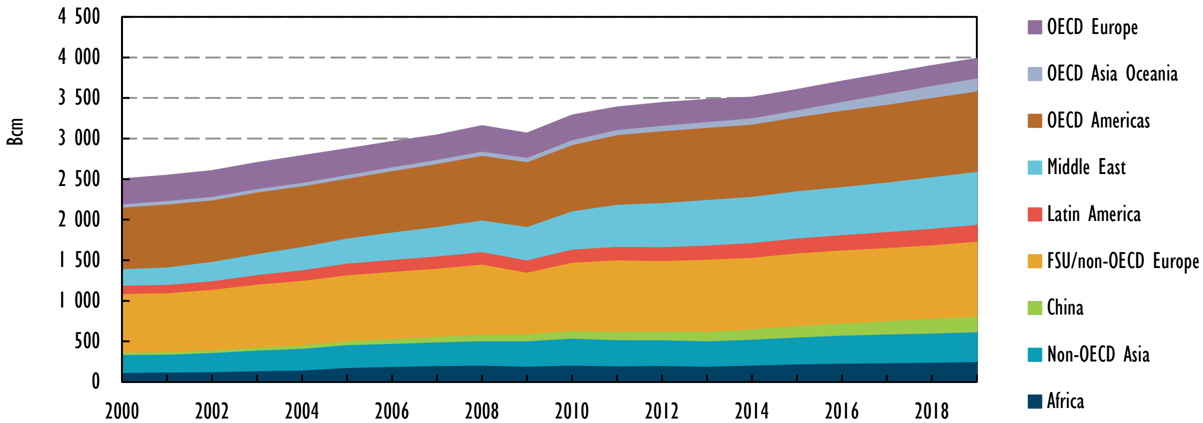
Global gas supply is expected to reach 3 980 bcm by 2019, a 500 bcm increase over 2013 (Table 10, Figure 35, Box 10). Continuous investments in the upstream sector remain a challenge among rising costs (notably to develop export infrastructure), subsidised gas prices, recent unrest, political instability and failure to put in place a sound investment framework. These factors represent a hindrance for future gas field developments. The main conclusions from this report are that:

- Similar to the previous years' forecasts, two OECD regions will provide significant additional volumes: OECD Americas and OECD Asia Oceania, together contributing 190 bcm. OECD Asia Oceania is the fastest-growing producing region, as output grows 121%. In contrast, OECD Europe is the only region where production declines. OECD Americas features a 102 bcm growth, the largest among all regions, primarily supported by US production growth to meet at the same time North America's domestic demand and future LNG exports. Meanwhile OECD Asia Oceania's production growth is primarily driven by Australia, and to a lesser extent, by Israel. It serves primarily one purpose: feeding Australia LNG plants for exports.
- Middle East production continues to grow, although not enough to meet additional demand. In contrast, Russia and other FSU countries are no longer expected to be among the largest providers of additional gas supply. Their production, notably Russia's, will be constrained by sluggish European gas demand, lower intra-regional exports to other FSU countries and by the absence of additional infrastructure to deliver pipeline gas to Asia or LNG to global gas markets. This trend represents a significant variation compared to previous *MTGMRs*.
- China is one the fastest-growing regions as its output surges by 65% on the back of new conventional gas developments, unconventional gas as well as coal gasification. Even if it makes sense from an economic point of view, the latter will generate additional emissions, albeit far away from cities. Although this growth is impressive, and shale gas is more likely to reach its short-term production targets, additional production will meet only half of the additional demand, leaving China even more import dependent.
- While Africa, Latin America as well as non-OECD Asia show relative strong growth, many key producers, such as Algeria, Argentina, Egypt, India, Nigeria, Pakistan and Venezuela struggle to increase their production. Many among these countries benefit from large resources and a number of recent discoveries, but they face numerous above-ground issues. These issues find their roots in the policies of these producers, including low domestic gas prices compared to fields' development costs, discouraging fiscal terms, unpaid bills, political uncertainty and priority given to the domestic market versus exports. Consequently, the additional growth in these regions is also supported by other, sometimes smaller, producers such as Angola, Brazil, Myanmar, Papua New Guinea and Viet Nam. Despite a 19% growth, Latin America can be considered as underperforming, as key producers such as Venezuela and Argentina struggle to reverse declines.
- Against this backdrop, Europe is the only region where gas production is likely to drop, and despite some hopes, shale gas in the United Kingdom or in Poland will not reverse the trend because it will account for only a couple of billion cubic metres. While Norwegian gas production will provide some additional, albeit limited volumes, and UK production declines more slowly than in the past, the decline in Dutch production means that the country is likely to become a net importer by the next decade. Europe's production drop means that the region becomes even more import dependent.

Table 10 World gas supply by region (bcm), 2013-19

	2013	2015	2017	2019	CAGR
OECD Europe	268	252	247	242	-1.7
OECD Americas	889	912	958	991	1.8
OECD Asia Oceania	72	85	133	160	14.1
Africa	196	224	239	254	4.4
Non-OECD Asia (exc. China)	313	329	347	357	2.2
China	117	141	164	193	8.7
FSU/non-OECD Europe	889	891	899	917	0.5
Latin America	175	184	196	208	2.9
Middle East	562	584	616	658	2.6
Total	**3 480**	**3 602**	**3 800**	**3 980**	**2.3**

Figure 35 Production by region, 2013-19



Box 10 Biomethane, a low-carbon alternative for natural gas

The production of biogas – a methane-containing gas produced through anaerobic digestion of organic material – has been growing strongly over the last decades, and reached 1.1 exajoule (EJ) globally in 2011. China was the world's largest producer of biogas in 2011 (0.3 EJ), thanks to more than 40 million household biogas digesters that have been deployed in rural areas since the 1980s. The United States ranked second (0.2 EJ), followed by Germany (0.2 EJ)[5].

Today, biogas is typically used on site for heat production, for instance in rural households in China, or for power generation in electricity and co-generation plants. Much of the recent growth, in particular in the European Union, has been driven by support policies for biogas electricity generation. In Germany, Europe's leader in biogas electricity production, the power capacity of biogas has increased almost twentyfold over the last ten years, with biogas electricity generation reaching around 20 TWh in 2013.

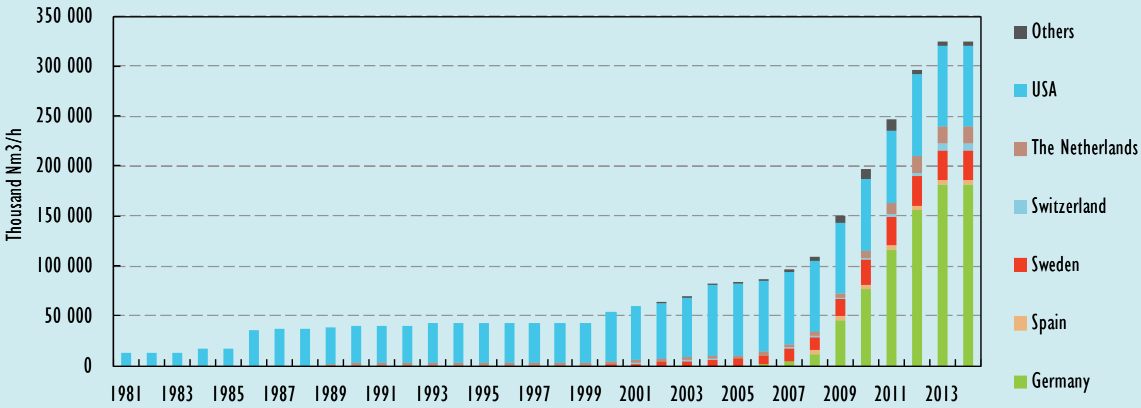
The rapid growth in biogas production also led to a new trend in a number of countries, in particular within the European Union. Instead of converting the raw biogas into electricity and heat on site, biogas is upgraded to biomethane, with a composition similar to natural gas, and then injected into the natural gas grid. In the United States, biomethane plants were first established in the 1980s, whereas biogas upgrading in the European Union started to pick up only in the middle of the last decade.

[5] 1 exajoule is equivalent to 25 bxm.

Box 10 Biomethane, a low-carbon alternative for natural gas (continued)

Since then, Germany has led the global growth in capacity additions, and is now the global leader in biomethane upgrading, and to a smaller extent, Sweden and other countries (Figure 36). With world capacity now at 340 thousand normal cubic metres per hour (Nm^3/h) (i.e. biomethane production of 2.2 bcm per year, assuming a capacity factor of 75%), biomethane is still tiny compared to world natural gas production of 3 480 bcm in 2013.

Figure 36 World biomethane upgrading capacity, 1981-2014



Source: IEA Bioenergy Task 37 database, www.iea-biogas.net.

The upgrading of biogas to biomethane has a number of advantages compared to the on-site conversion of biogas to electricity and heat. The injection of biomethane into the natural gas grid allows for use of the fuel in large-scale co-generation plants, with higher efficiency of electricity generation and better opportunities for the use of heat than in the small, on-site, co-generation gas engines. An additional advantage is that biomethane can be stored in the natural gas grid and then converted into electricity when needed. Furthermore, biomethane can be used as a vehicle fuel, as is the case in Sweden and, to a smaller extent, in Germany, or used for heat production in heating plants and private households.

Another technological pathway for conversion of biomass to biomethane is through thermochemical conversion of biomass into bio-synthetic natural gas (bio-SNG). The technology has been tested in a couple of demonstration plants, for instance in the city of Güssing in Austria, and the first larger-scale plants are now entering the market. In March 2014, the 20 MW GoBiGas plant opened in the city of Göteborg in Sweden, and will be followed by an 80 MW to 100 MW plant that is to be completed in 2016. E.ON is also currently investigating the construction of an up to 200 MW bio-SNG plant in Sweden in the next few years. Given the significant scale of the projects, bio-SNG production could significantly enhance the use of natural gas grid infrastructure for distribution of biomethane.

Based on its characteristics, biomethane can be seen as a fully-fledged substitute to natural gas, which is reflected, for instance, in the German government's target to replace 6% of the country's natural gas consumption with biomethane by 2020. However, the costs for biomethane are currently in the range of EUR 19 to 23/GJ, thus 2.75 times more expensive than German gas, for example, which limits the sector's growth potential in the absence of support policies. With new policies in place in France and elsewhere, growth in biogas and biomethane production in the European Union should continue over the next few years, although the German market is likely to grow only slowly in light of proposed policy changes. The longer-term perspectives for the sector will depend on a variety of factors, including the scope for cost reductions, the relative competitiveness with natural gas and the availability of feedstocks, among others.

Global unconventional gas developments

Looking forward, the conclusion of the previous *Medium-Term Gas Market Reports* remains: while much attention is dedicated to unconventional gas, and notably to shale gas, expectations are unlikely to be met before 2020. Unconventional gas production growth will originate mostly from North America. The rest of this decade will be the preparation for the potential spillover of the shale gas revolution onto other regions. Apart from a few exceptions, unconventional gas volumes will remain modest, with the exception of China and Australia. Others with potential include Argentina and Mexico.

North America

The United States will remain the uncontested leader in unconventional gas developments. While CBM production is expected to remain broadly at the same levels as today, tight gas and shale gas are likely to benefit from a slight recovery in US gas prices, and shale gas remains the main driver behind the evolution of US gas production. Among all the different plays, Marcellus is the one that will determine the growth path of US gas production over the forecast period. EIA's forecasts feature a sharp increase of shale gas production to 350 bcm by 2019 and of tight gas to 179 bcm. Total US unconventional gas production would, therefore, reach around 580 bcm.

Canada's production will depend mostly on access to alternative markets in the United States, notably through the development of shale gas production feeding future LNG liquefaction plants in British Columbia. In the absence of Final Investment Decision (FID) as of mid-2014, these plants are unlikely to be online by the end of the forecast period. Asian companies are investing in Canada's shale gas resources with the view to exporting it back to Asia. The Japanese government announced support of CAD 10 billion through direct investments in western Canada's LNG sector; it is also prepared to cover that amount through loan guarantees to accelerate the advent of LNG supplies serving Japan. Japan's Prime Minister Shinzo Abe and Canada's Prime Minister Stephen Harper agreed in September 2013 that Canada would export shale gas to Japan. These political announcements came after several Japanese companies had started investing in upstream shale gas assets in western Canada. Chinese companies have also been investing, either by taking acreage or through takeovers, notably that of Nexen by CNOOC for USD 15.1 billion, which was finalised in early 2013. Meanwhile, Petronas has been quite actively developing an integrated upstream and LNG project, even though it sold around 38% of the project to different Asian parties. Several projects have already received key export approvals.

The wild card in North America is Mexico. The country is estimated to have technically recoverable shale gas resources almost on par with those in the United States, at around 15 tcm, while the country currently produces 15 times less gas than the United States, or 46 bcm. Mexico's shale gas resources, such as the Burgos Basin, are a continuity of those lying just on the other side of the border, such as Eagle Ford, which in principle would remove doubts about their quality and the recovery rate. But so far, few shale gas wells have been drilled; only three were authorised in 2012. The issue is partly on the policy side. Recent energy reform is of crucial importance. After year-long efforts, President Pena Nieto managed to deliver a significant reform of Mexico's energy policy in December 2013. The new law enables the Secretary of Energy to grant licenses to private companies for downstream activities, including pipelines. While the law does not give ownership of oil or gas resources to (foreign) private companies, it will now be possible for them to produce the gas. More pressure will also be on PEMEX to deliver results. The company will be more profit-oriented because its revenues will depend on its production revenues and its profit contracts. Indeed, the contracts to develop oil and gas resources will be awarded by the National Hydrocarbon Commission (CNH). While PEMEX will have priority, this advantage will last for only 90 days. PEMEX will then have only three to five years to develop the resource. In case PEMEX chooses to develop the petroleum resources, it can also enter into a joint venture with private (potentially foreign) companies on the basis of a contract for profit. After that period, CNH can award four different types of contracts to private companies, either foreign or Mexican. These are service contracts, profit sharing contracts, production sharing contracts and licenses. This arrangement could benefit companies familiar with structures such as Eagle Ford including EOG Resources, Chesapeake, and ConocoPhillips. But Mexico still faces challenges to develop its shale gas, including water access issues, infrastructure limitations and security concerns due to the presence of drug trafficking organisations in the region. These organisations try to control trade routes and are also engaged in kidnapping. In particular, water will represent a major issue in this very arid region. Finally, it would also depend on the competitiveness of new Mexican shale gas against imports of US shale gas by pipelines, which may prove to be cheaper as US companies benefit from much longer experience. Provided that these challenges are tackled, the end of the forecast period could, nevertheless, experience an upward shift in of Mexican gas production.

Asia

Outside North America, China remains the principal unconventional gas producer and the main source of growth. As the country needs to feed its ever-increasing energy needs, but also wants to turn to greener fuels, it is engaged in a strong push to develop unconventional gas resources. Intense developments have been under way on the exploration and production sides. China's national oil companies CNPC and Sinopec have been concentrating on unconventional oil and gas developments. A large part of shale gas production comes from the Fuling area in the Southwest of China (0.13 bcm in 2013). This block has already entered commercial production stage with an output of 2.7 Mcm per day in April 2014, which is much earlier than planned.

Whereas tight gas already comprises an important share of total gas production (38%), and CBM is growing, even though the utilisation rates remain low, shale is still waiting to take off. But the short-term outlook may turn out better than expected. While companies such as CNPC and Sinopec previously planned to produce around 3 bcm of shale gas by 2015, half the target set by the government (6.5 bcm), Sinopec is now more confident that it could produce 5 bcm by end-2015 thanks to its Fuling block. Although the 2015 target could be reached, there is still a long way to go before reaching the target of 60 to 100 bcm by 2020. However, based on recent developments, half of that target could be reached. More than 150 shale gas wells have been drilled in China as of early 2014, and about one-third of them are horizontal wells. More than 70% of the horizontal wells have been connected to the network. More pipelines and other infrastructure are under construction in Sichuan and will be finished before 2015. China still faces significant challenges in developing its shale resources. Chinese shale is deeper and tends to have more clay than US shale. Water will also be an issue because hydraulic fracturing requires large amounts of water. Uncertainties regarding future liberalisation of prices and third-party access are also important factors, along with the absence of a single set of detailed rules to regulate shale gas activity.

Another tender for shale gas is likely to take place during spring 2014, after having been delayed from December 2013. The blocks offered will be located in Sichuan, Chongqing and Hubei. As the three incumbents hold rights to the most lucrative shale gas blocks, the Ministry of Land and Resources (MLR) is envisaging having the companies relinquish the blocks in order to reoffer them during the tender. This tender will be the third, after a first in 2011 and a second in 2012. A progressive opening to a wider range of companies has been observed as the government wishes to develop its shale gas resources quickly. While the first tender was restricted to six state-owned companies, the second was open to private companies and foreign joint ventures as well as state-owned enterprises. The new regulations issued in 2013 to further develop Chinese shale gas include subsidies and tax incentives. The government will offer subsidies of CNY 0.4/m^3 (USD 2/MBtu) for shale gas, and the subsidies categorise shale gas as a special type of mineral. The current wellhead cost of shale gas in Sichuan is estimated to be close to USD 10/MBtu. The regulations can be seen as a way to trigger a more rapid development of shale gas, but their duration is still a question mark.

In other Asian countries, developments are slow, and the outlook for a significant development in the region remains bleak. Indonesia's Energy and Mineral Resources Ministry reported the total estimated reserves for shale gas in that country at around 16.3 tcm (574 tcf) and CBM reserves at 12.8 tcm (453 tcf). Pertamina kick-started the country's shale gas industry in 2013 when it was awarded the contract for exploration activities in the Sumbagut block. In contrast, more activity has been involved with CBM, but prospects have failed to materialise so far. Indonesia is faced with colossal obstacles to replicate the success story in monetising the gas, despite the abundant reserves available. The key hindrances to the access of Indonesia's unconventional gas are the location's topography and lack of infrastructure. Most reserves are situated in Kalimantan and Sumatra; Kalimantan is known for its swamps and Sumatra its forests. Combined with mountainous areas in both places, these shortcomings contribute to the lack of existing infrastructure to support the development of unconventional gas on these two islands. Being an archipelago does not help either, as the demand is mainly concentrated in Java, whereas the available supply is mainly from these two islands. The government has passed new legislation to develop CBM resources, increasing notably the operators' profit sharing to 45%, while oil and gas operators usually receive 15% and 30%, but most believe that CBM production is unlikely to take off over the medium term.

India and Pakistan are also reported to have significant recoverable shale gas and CBM potential, but development so far has been limited. India has organised five CBM rounds since 2002 (the last one was launched in December 2013), and despite interest from some companies, results have been disappointing in terms of production per well: India's CBM production remains extremely low so far, amounting to a few million cubic metres. CBM production could benefit from the discussed change in the pricing system, which was expected to take place in April 2014 but has been postponed. CBM production is unlikely to reach even a few bcm over the forecast period. After a few years of discussion, India finally issued a policy on shale gas in late 2013, whereby it authorises its national oil companies (NOCs) – Oil and Natural Gas Corp (ONGC) and Oil India Ltd (OIL) – to explore shale resources from onshore blocks awarded to them before the New Exploration Licensing Policy (NELP) started in 1999. While ONGC will take up 175 blocks, Oil India will do it in 15 blocks in three assessment phases of up to three years each. Royalty and taxes will be payable on par with conventional oil/gas being produced from the respective areas. In a second stage, the government plans to offer shale gas (and oil) blocks to other (private) companies through another Cabinet approval, but the decision shows a preference towards NOCs. As in the case of conventional gas, international oil companies (IOCs) may remain relatively absent from India's unconventional scene. ONGC announced that 30 shale gas wells would be drilled over the next two years, while the company also signed an agreement with ConocoPhillips in 2013 to undertake shale gas exploration. The shale gas industry in India is, therefore, likely to remain in its infancy over the forecast period.

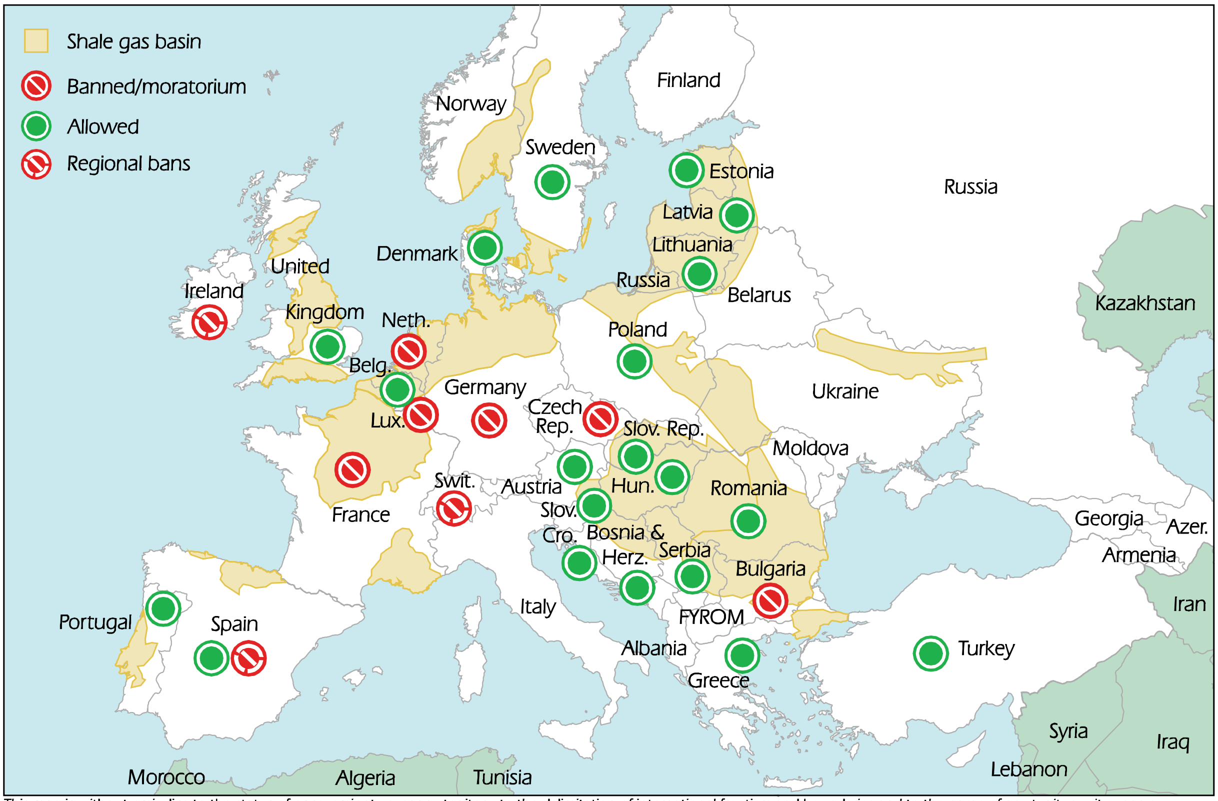
Pakistan reached a new milestone in 2013 when the country's first tight gas started production at about 0.2 bcm per year in June 2013. However, the country's biggest wildcard is shale gas. According to the EIA's *2013 World Shale Gas Report*, estimated recoverable reserves of shale gas in Pakistan stand at 105 tcf (2.9 tcm), which is about 70 times higher than the country's annual gas consumption (EIA, 2013b). Seen as the natural solution to the country's gas crisis due to its abundant reserves, the government is supportive of the shale gas development and is currently formulating a new shale gas policy. Pakistan needs to tackle issues such as complex reservoirs, an unattractive price regime and environmental concerns, including availability of water resources. Thus, shale gas could only serve as the long-term solution to the country's gas crisis because huge government efforts will be required to address these issues.

Europe

On the legislative side, after much thought on potential regulation of hydraulic fracturing, the European Commission (EC) decided in early 2014 not to regulate, but instead published a list of non-binding recommendations and left it up to its member states to implement their own different measures. Producing countries already have legislation concerning upstream measures in place. The EC requires them to undertake public consultations and carry out environmental assessments before companies can use hydraulic fracturing. The EC will, nevertheless, continue to monitor the developments through a scoreboard of actions undertaken by each member state. It plans to review the situation and may still decide to institute legislation.

Many European countries have allowed shale gas extraction and even issued permits. Countries against shale gas have voted against hydraulic fracturing in response to concerns over air and water pollution as well as induced seismic activity (Map 3). Should other potentially safer techniques be developed, such bans could potentially be revoked. These countries include France where hydraulic fracturing (fracking) has been banned since 2011 after a vote by the French parliament under the previous government of President Sarkozy. Despite calls from some members of the new socialist government such as Minister Montebourg, it seems unlikely that President Hollande would rescind the ban. Energy Minister Royal, nominated in April 2014, had positioned herself against shale gas, but is nevertheless in favour of pursuing research on alternative exploration and production (E&P) technologies. In Bulgaria, the parliament banned exploration for shale gas using fracking in 2012 and revoked the permit granted to Chevron. In 2013, the Dutch government announced that no decision would be taken on whether to begin fracking for shale gas until further research has been done, postponing a decision making until early 2015. Research would help determining which areas could be drilled, make an inventory of the most innovative technologies to reduce the risks as much as possible. Still, some municipal councils, such as Haaren and Boxtel, have opposed shale gas extraction. Meanwhile, the bank Rabobank announced in July 2013 that it would not lend money to companies involved in unconventional gas extraction or to farmers leasing their land to these companies. In Luxembourg, the parliament voted against a motion to enable shale gas E&P, but shale gas resources are unlikely to be significant. Meanwhile, the Czech government established a two-year ban on shale gas exploration until a new law is enacted regarding production techniques. Finally, following the elections in late 2013 in Germany, the new coalition agreed to put a moratorium on fracking in place until environmental concerns are resolved. This position contradicts the earlier moves of Chancellor Merkel's government in early 2013 to issue regulations to allow shale gas exploitation, with the exception of wetland areas.

Map 3 Positions of European countries regarding shale gas



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Furthermore, some regions in countries that have not banned shale gas have set up moratoria. The Swiss canton of Fribourg, Northern Ireland and the Spanish region of Cantabria have all banned drilling. However, Spain's central government plans to challenge this ban, as the country legalised hydraulic fracturing in late 2013 by amending a 1998 hydrocarbon exploration law. Some Irish county councils such as Roscommon, Clare, and Leitrim have also banned fracking.

Among the countries open to shale gas exploration and production, the United Kingdom is drawing the most attention after its U-turn in end-2012. United Kingdom Prime Minister David Cameron has decided to put the emphasis on shale gas, despite some local opposition. He announced specific measures such as community incentives, offering local communities the totality of the revenues from the business tax levied on shale gas (up from around 50%) to lessen local opposition. The UK oil and gas industry is also thinking of additional measures to win the support of local communities, but they remain hesitant to offer too much until the viability of shale gas resources has been proven. This promotional campaign seems to have succeeded, as companies such as Centrica, Total and GDF Suez have responded by announcing investments. They follow Cuadrilla, which had been one of the first companies to target shale gas in the United Kingdom. The company plans to move forward at two sites in Lancashire, while still carefully monitoring seismic activity, which has previously proved to be a hurdle to its development plans. Depending on obtaining the permit, drilling could start in early 2015. Cuadrilla said that it would offer GBP 100 000 per well drilled. The United Kingdom will launch its fourteenth onshore licensing round in mid-2014, with up to 150 licences expected to be issued. The round had been much delayed as it was originally slated for 2010. Shale gas licenses would be available in regions stretching from Central Scotland to the southern coast. A recent study by the

Department of Energy and Climate Change and the British Geological Survey put the best estimate for shale gas in place potential in the Bowland Basin at 1 329 tcf (37 tcm). This is significantly higher than Cuadrilla's estimates of 200 tcf (5.7 tcm), with a recovery rate of 10%, implying around 570 bcm of recoverable gas.

Poland's shale gas potential has yet to be fully realised. On the one hand, San Leon seems to be moving closer to commercial operations at its Lewino well. The company flowed 1.2 to 1.7 thousand cubic metres per day from the well (not even 1 Mcm per year), but the company expects flow rates ten times higher. On the other hand, Eni let two of its three shale gas concession permits expire without renewing them. Some other companies – ExxonMobil, Talisman, Marathon Oil, and more recently Total – exited Poland as well, allegedly due to disappointing results, but also due to legislation and regulations still pending. Meanwhile, the government tried to get five state-owned companies to cooperate on shale gas developments, but this attempt fell apart.

Other countries, such as Romania, are attracting investment, despite difficult relationships with shale gas. The moratorium issued in May 2012 was abolished in early 2013. In late 2013, Chevron, which has three concessions in Romania, restarted exploration in the northeastern part of the country six weeks after having suspended operations following protests. Chevron promised to use only conventional technologies. Meanwhile, the company pulled out of Lithuania a month after winning a tender to explore for shale gas, citing potential changes to the country's laws, such as requiring local government approval before doing an environmental impact assessment and plans to hike the tax rate to 40%. Lithuania is now considering changing its legislation to attract companies back. Turkey also wants to develop its shale gas, which exists in two shale basins: the Southeast Anatolia basin and the Thrace basin. TPAO has had some shale gas activity along with Shell since 2012; other companies such as Anatolia Energy are also involved in shale gas exploration, but without concrete results yet. Limited activity has taken place in other countries. Latvia and Estonia lie on the same basin as Lithuania, and Estonia is famous for its oil shale (which is very different from the US shale oil), but little activity has been reported there. Hungary, which has large estimated unconventional gas resources, is taking a relatively neutral stance. In Austria, OMV abandoned shale gas plans in 2012 as environmental costs would make the project unprofitable.

The Former Soviet Union (FSU)

Ukraine is in the spotlight as it tries to lessen its dependency on imported Russian gas by developing domestic gas supplies. Several companies have planned investments, but some are also facing local opposition. Chevron signed a deal in 2012 for the Olesska area in Western Ukraine, which is believed to hold between 0.8 tcm and 1.5 tcm of shale gas. But signing the Production Sharing Agreement (PSA) has dragged on for months due to local protests. The situation was markedly different in East Ukraine, where Shell signed a USD 10 billon PSA for the Yuzivska shale area in early 2013, as the region was also a stronghold of the then ruling Party of Regions. It remains to be seen how the situation will unfold following the recent troubles and the presidential election. It is obviously in the country's interest to foster shale gas developments to lessen import dependency.

Africa and the Middle East

Exploration activities in Africa are centred in Algeria and South Africa. In South Africa, opposition to hydraulic fracturing remains strong. South Africa's government has proposed that energy companies exploring for shale gas in the Karoo region must declare the chemicals they plan to use during hydraulic fracturing. Following the review in 2012, which found that the current hydrocarbon legislation was not adapted for unconventional gas E&P, the government proposed several changes, notably increased governmental participation, but also benchmarking operating standards and environmental measures on international standards. Algeria's focus this decade will be dedicated to tight gas production, while shale gas is seen as a valuable long-term potential (see section on Algeria later in this chapter). Surprisingly, water issues are brushed aside due to the presence of large aquifers and low population density in shale gas areas.

Saudi Arabia may hold large unconventional gas resources, notably tight gas and shale gas. An Unconventional Gas Initiative launched in 2011 became fully operational in 2012. Saudi Oil Minister Ali al-Naimi has given an estimate of over 600 tcf (17 tcm) of unconventional gas resources, which is double that of Saudi Arabia's current proven conventional gas reserves, estimated at 8.2 tcm as of end-2012. Exploration and appraisal drilling have already been carried out in three prospective areas in the northwest, in South Ghawar and in the Rub' al-Khali. Such unconventional gas resources will help Saudi Arabia to meet its increasing gas demand, notably in the power sector, but are also thought to be expensive to produce (USD 8 to USD 9/MBtu). In early 2014, Lukoil announced its interest in tapping unconventional gas resources located in the Empty Quarter.

Latin America

Latin America has been attracting producers' attention over the past few years, despite the uncertain regulatory environment in some countries. Argentina holds promising technically recoverable shale gas, estimated to be the second-largest in the world (EIA, 2013b). The production of shale gas, however, is still below 1 bcm. But the volatile regulatory environment and high governmental intervention in the energy sector make the country risky for potential investors. The Argentinean government had offered oil and mining companies tax breaks amounting to almost USD 500 million in 2011 but withdrew them in early 2012, ordering the companies to repatriate 2011 export revenues and convert them into Argentinean pesos. Moreover, cautiousness of foreign companies in general is still present after the sudden nationalisation of Yacimientos Petrolíferos Fiscales (YPF) in 2012. Developing tight and shale gas is, nevertheless, essential for Argentina to tackle its gas shortages, and the government can be expected to take a more investor-friendly stance. The government has tried to make investments more appealing through higher prices. Domestic production is now encouraged by the increase of the regulated wellhead price to USD 7.5/MBtu in 2013. As a result of this measure, companies such as Chevron, Wintershall, Total and CNOOC closed deals with YPF, the Argentine energy company, for development of Argentinean shale gas. Nevertheless, other factors could delay the development of shale gas. The country does not yet have the skilled labour needed to develop its shale resources, nor the infrastructure in place needed to ship the water and the sand necessary for hydraulic fracturing. Furthermore, the impediments for companies to import the necessary equipment for shale gas production limit the access to the required technology. All these factors contribute to uncertainty about future development of natural gas in Argentina.

Brazil has substantial shale gas potential, mostly concentrated in the southeast of the country. While studies are being conducted about the technology, costs and environmental impact to produce this gas, the country currently focuses more on pre-salt, making shale gas a more distant prospect. This potential, nevertheless, must be assessed more thoroughly. One issue could be the importance held by Petrobras on gas production, which leaves relatively little room for smaller private companies. This may require the government to develop a shale gas strategy through Petrobras or provide support to private companies to investigate this niche market, or a combination of both. Environmental considerations could also play an important role, considering the consequences of the oil spill experienced by Chevron in 2012.

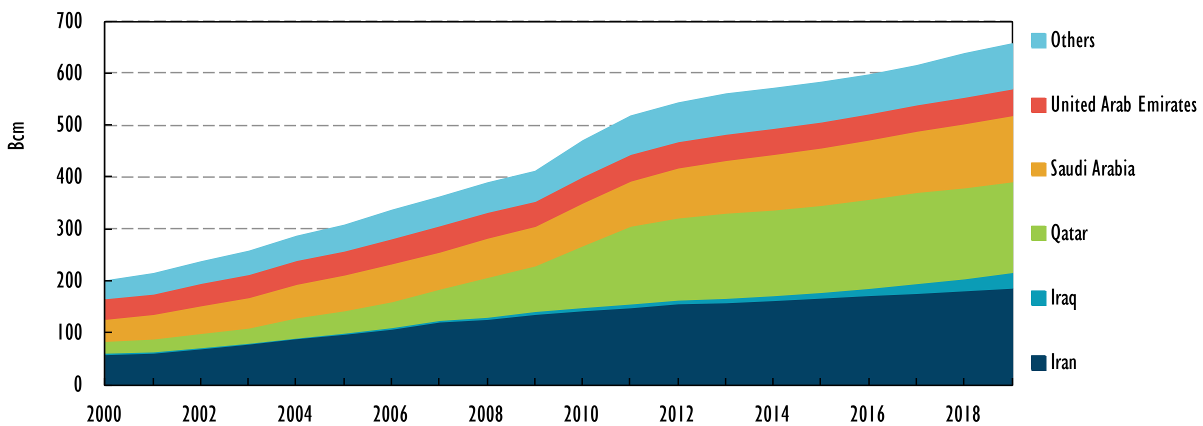
Unconventional gas was found in Chile in 2013 through two exploration wells. Once this resource enters in production, it would serve residential consumers in the southernmost part of Chile. Being part of a broader national exploration programme to find shale gas in southern Chile, this discovery opens new perspectives for the country. The country's estimated recoverable shale gas resources are an extension of Argentina's and were estimated at 1.4 tcm (48 tcf), a huge amount compared to current annual production of 0.2 bcm. Paraguay is also estimated to hold around 2.1 tcm (75 tcf), located in the Chaco and Parana basins (EIA, 2013b). Some companies, such as Dahava Oils Company, are planning to invest there.

Middle East

The last few months have witnessed a new development with Iran coming progressively back to the international scene. While recent negotiations have raised hopes of resolving nuclear issues, sanctions against the country remain in place. Besides, there is still a long road from the alleviation of international sanctions to Iran coming back – or actually entering – the global gas market as a significant exporter. For all of its proven gas reserves (the second-largest in the world after Russia), Iran is an importing country and exports only up to 9 bcm to Turkey, Armenia and Azerbaijan. The country is also the fourth largest gas producer. While Iran is and remains the wild card in the Middle East, attention should also be directed to Iraq, or rather the Kurdistan Region, which aims at becoming a significant exporter of pipeline gas to Turkey.

Besides these two countries, the outlook for the Middle East remains largely unchanged (Figure 37). The region remains a large gas producer and one of the fastest-growing ones, but this is insufficient to cover natural gas demand growth. Although natural gas production is foreseen to expand from 562 bcm in 2013 to 658 bcm in 2019, total gas exports will fall by 11 bcm.

Figure 37 Middle East gas production, 2000-19



Saudi Arabia's gas production is planned to increase significantly over the coming years. Current gas production was 95 bcm in 2012 and an estimated 100 bcm in 2013. The country's target is to increase output to 150 bcm by 2018, while this report foresees gas production to increase to 126 bcm by 2019. In 2012, 100 gas exploration and development wells were completed, while two gas fields were discovered – Sha'ur and Umm Ramil – which brings the total number of Saudi Aramco's oil and gas discoveries to 116. The next significant development on the gas side is the Wasit Gas Programme, which will be one of the largest gas plants Saudi Aramco has ever built. Based on the fields Arabiyah and Hasbah, it is expected to come online in 2014 and bring an additional 18 bcm of sales gas.

Oman has been facing gas shortages for some years, threatening the viability of its LNG exports and resulting in pipeline imports from Qatar. However, the country does have gas resources to be developed, one of the fields being the tight gas field Khazzan, which holds around 200 bcm. Its operator, BP, has been negotiating with the government for many years regarding the gas price, while the Oman government was simultaneously renegotiating gas prices for industrial customers. Finally, at end-2013, BP signed a gas sales agreement and an amended PSA, which will extend for 30 years. Development of the tight gas field will cost around USD 16 billion (including prior investment) and involve drilling around 300 wells over a 15-year period. The first gas is expected in late 2017, ramping up to plateau in 2018 and therefore bringing a much needed 10 bcm per year (equal to one-third of the country's current production). Block 61 contains a significant volume of unconventional gas, distributed across several reservoirs, with estimates of total gas in place of up to 100 tcf (2.8 tcm). This agreement may unlock other tight gas resources.

Could Iran enter the club of major exporters?

The answer is – not any time soon. As of today, 2025 may be the most realistic target for Iran to become an LNG exporter. Pipeline exports could start sooner, potentially before 2020. Nevertheless, it is crucial to emphasise that this perspective looks much more likely than it was one year ago. Iran's natural gas exports are a crucial parameter for assessing future perspectives on Iran's gas production. The issues are multi-fold: 20 years of international sanctions seem the obvious cause for Iran's absence on the international gas exports scene, but other factors must be taken into account such as the role of gas in Iran's domestic energy mix, its foreign policy, the relationship with foreign investors and the investment framework (OIES, 2014).

Iran benefits from large domestic gas resources, with proven resources amounting to 33.6 tcm (as of end-2012), almost ten times the global annual gas demand. It is ideally located between two major markets – Europe and Asia – as well as surrounded by Middle Eastern gas-importing countries such as Kuwait, the United Arab Emirates, Oman and Jordan. All these markets can be reached by both pipeline and LNG. Yet, the fact that the country is currently a gas importer (from Turkmenistan) certainly comes as a surprise, but can be explained by the historical development of the Iranian gas industry and the fact that a large share of domestic demand is in the north while fields are mostly in the south (Map 4).

Iran's gas resources

Unlike its neighbour Qatar, Iran has over 20 gas fields, some of which can be qualified as giant or super-giant. One field alone (the offshore South Pars, shared with Qatar) represents "only" 42% of the country's total proven gas reserves. Many fields had been discovered in the early stages of Iran's gas history. South Pars, also named the North Field in Qatar, was discovered in 1971. The field is the largest discovered so far in the world and has estimated proven reserves of 24 tcm, 14 tcm of which are in Iran. This gave confidence to the Khatami government (1997-2005) that it had largely sufficient gas resources to resume export projects. Other important fields include North Pars, Kish and Golshan. The 1.3 tcm North Pars gas field is linked to a four-phase development plan to support a 20 mtpa LNG plant. It has been assigned to CNOOC through a buy-back contract. Kish's recoverable gas reserves are estimated at 1.3 tcm of gas; the field is expected to be developed in three phases of 10 bcm each. The field is said to be under development with a first phase planned for 2014. Finally, a buy-back contract has been signed with Malaysia's SKS to develop Golshan.

Over the past 20 years, the accent has been put on developing the 24 phases of South Pars, which would ultimately bring almost 300 bcm per year of natural gas supplies (Table 11). Ten phases are estimated to have been developed so far. According to the ambitious schedule given by the Pars Oil and Gas Company, all other 14 phases would be developed by 2020. Phases 12, 15 and 16 were supposed to be up and running by 2013, but have yet to start. More realistically, five phases may be able to move forward by 2020, bringing a maximum production capacity of 67 bcm of additional gas. The most advanced phase is Phase 12, which would produce 31 bcm per year. The first 5 bcm train would start in 2014, and the five others would be completed in 2015. Phases 15 and 16 could start by 2016 at the earliest, bringing an additional 18 bcm to the market. Phases 17 and 18 are at an earlier stage of development and may not be fully ready by the end of the forecast period. While Phase 11 was initially planned for 2015-16, it suffered from the withdrawal of CNPC, and Petropars has now taken over development of this phase. Phase 13 suffered a huge setback when one of its offshore platforms sank in early 2013. While the first eight phases brought the experience of IOCs, this is no longer the case for the upcoming phases due to international sanctions. Some NOCs, such as PDVSA, are still participating in these developments. More than any other field, South Pars is key for export projects. Against this backdrop, Iran's gas production is expected to reach around 190 bcm by 2019.

Table 11 South Pars phases

	Production (bcm)	Start	Players
In operation			
Phase 1	10.2	2004	Petropars
Phase 2, 3	20.4	2002	Total, Gazprom, Petronas
Phase 4-6	20.4	2004	Eni, Petropars, NIOC
Phase 7, 8	38.0	2008-09	Petropars
Phase 9, 10	18.2	2012	LG International; OIEC;IOEC
Planned/under development			
Phase 11	20.4	2020+	Petropars
Phase 12	31.0	2014-15	Petropars, PDVSA, Sonangol
Phase 13	19.8	2020+	Petro Paydar, Mapna, SADRA
Phase 14	19.8	2020+	IDRO, NIDC, IOEC
Phase 15-16	18.2	2016+	KACH; IOEC; Saaf; ISOICO
Phase 17-18	18.2	2018+	IDRO, IOEC, OIEC
Phase 19	19.8	2020+	Petropars, IOEC
Phase 20-21	18.2	2020+	OIEC
Phase 22-24	18.2	2020+	Petro Sina Arian, SADRA

Sources: Pars Oil and Gas Company's website, press releases, IEA.

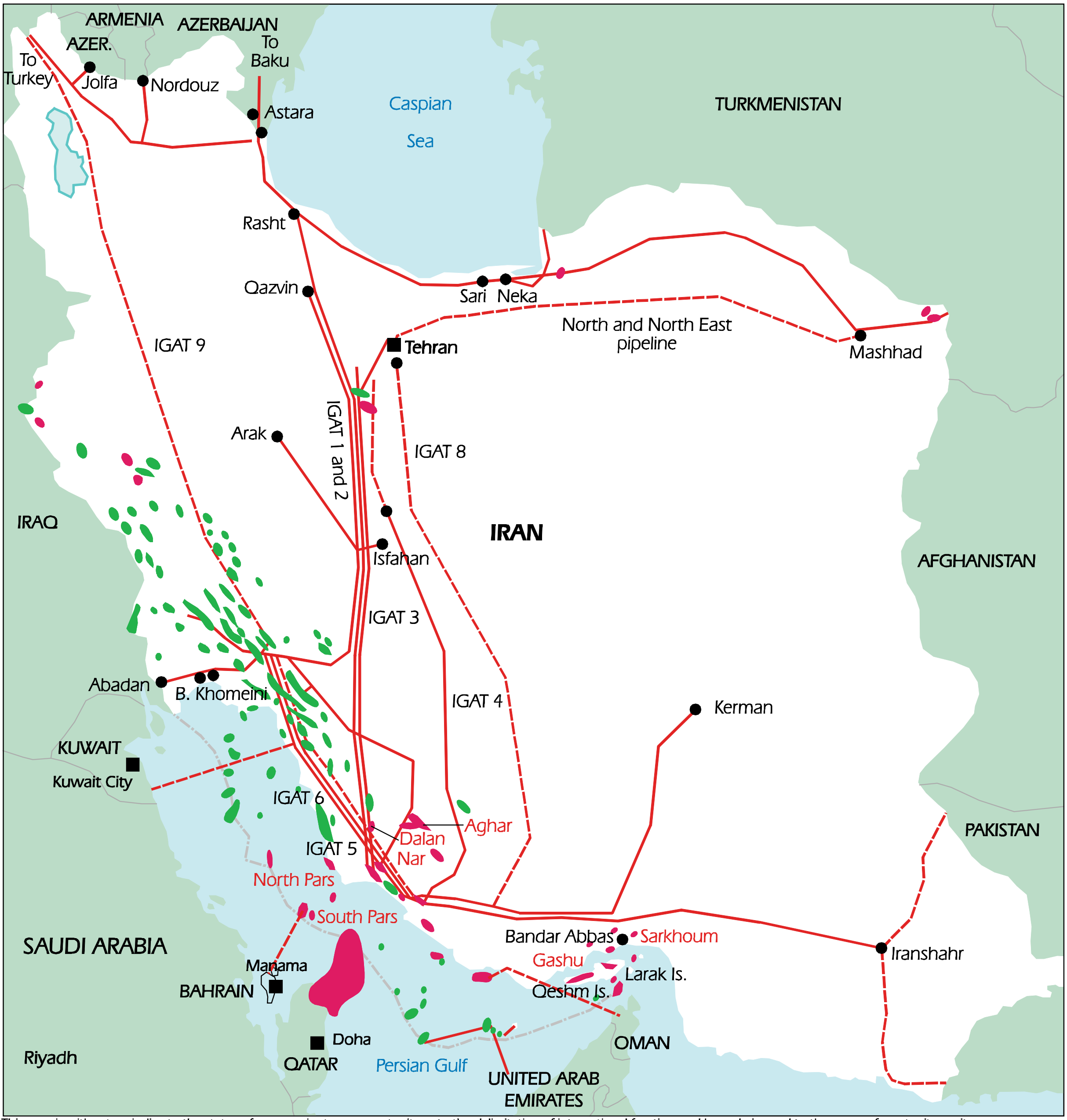
Oil industries engineering and construction (OIEC), Iranian offshore engineering company (IOEC), Industrial Development and Renovation Organisation (IDRO), National Iranian Drilling Company (NIDC), National Iranian Oil Company (NIOC), Khatam Al-Anbia Construction Headquarters (KACH), Iran Shipbuilding & Offshore Industries Complex (ISOICO).

Historical perspective on Iran's policies on natural gas

Iran has developed a major gas-based economy, as illustrated by the significant use of gas in transport. It has also allowed the country to sustain high availability of oil for export. Over the past 50 years, the different governments have taken various positions regarding the respective use of natural gas for exports or domestic use (OIES, 2014). During the period preceding the revolution, the government pursued an export-oriented policy that still allowed for the domestic market to develop, notably the petrochemical industry. Iranian gas exports to the FSU began in 1970 and culminated in 1977 at

9 bcm. During the 1970s, several negotiations were undertaken to export pipeline gas to countries in Europe (Federal Republic of Germany, France and Austria) and the FSU, as well as LNG to the United States, Western Europe and Japan.

Map 4 Iran's gas infrastructure



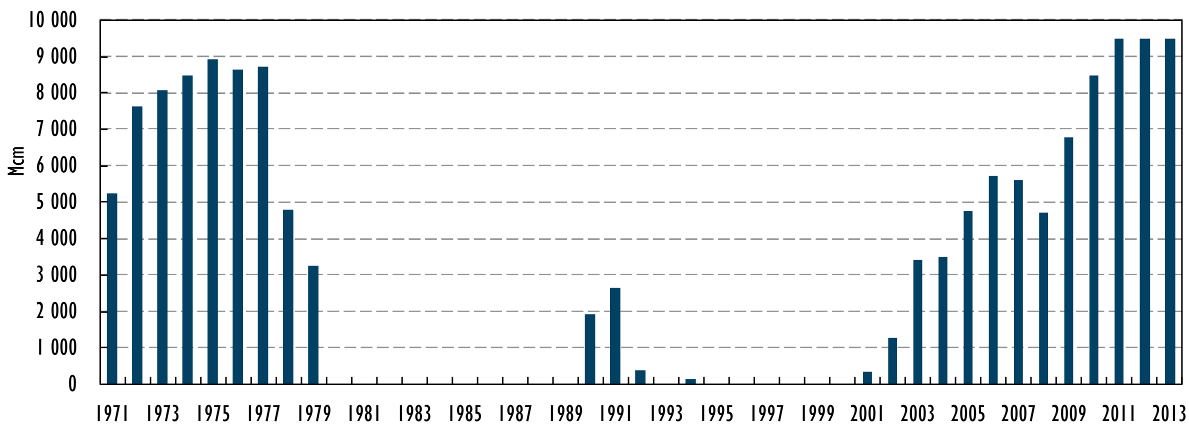
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

The revolution in 1979 brought a policy aggressively oriented towards the domestic market, even though the eight-year Iraq-Iran war shattered Iran's economy. Exports to the FSU also stopped at the same time and resumed over 1990-92, but at limited rates (Figure 38). After 1979, the domestic gas market became the priority; natural gas demand quadrupled over 1979-90 and tripled again over the following decade. Demand has more than doubled over 2000-12. This growth was due to nationwide subsidies and the technological advance of gas reinjection to enhance the rate of recovery in oil fields, both of which still continue today.[6] This expansion was performed on the back of the development of the domestic pipeline system called Gas Trunkline (IGAT). As of today, eight IGAT pipelines exist; most of them deliver South Pars' gas to the market. Two new pipelines are planned: IGAT-9 and IGAT-10. IGAT-9 is a 35 bcm per year pipeline designed to connect South Pars to the European markets through Turkey.

Another radical change brought about by the revolution was that the NIOC became a public company; its management team consisted of political figures directly elected by the government and was strictly supervised by the Iranian parliament. It also became regular practice to have the different energy stakeholders intervene on the energy scene, from the Ministry of Petroleum to the parliament or the president. As of today, three companies control most of Iran's gas industry: NIOC, National Iran Gas Company (NIGC) and National Iran Gas Exports Company (NIGEC). NIOC is responsible for upstream activities through different subsidiaries such as the National Iranian South Oil Company (NISOC), the Iranian Central Oil Fields Company (ICOFC), the Iranian Offshore Oil Company (IOOC) and Pars Oil and Gas Company (POGC). NIGC handles the downstream industry, including transmission, distribution and storage. Both NIOC and NIGC depend on the Ministry of Petroleum. NIGEC depends on NIOC and handles natural gas marketing and sales. However, these companies have sometimes overlapping responsibilities, and the different governments have changed their respective relationships over time (OIES, 2014).

The coming to power of President Khatami in 1997 saw the promotion of both domestic and export markets. These efforts were in line with the development of South Pars and with Khatami's attempts to reduce tensions with Western countries. They resulted in the start of exports to Turkey, Azerbaijan and Armenia, but the election of President Ahmadinejad in 2005 again changed Iran's natural gas policy. His tough stand against the international community, in addition to the tensions created by Iran's nuclear programme, led to the termination of almost all gas investment and development activities, postponing any hope for Iran to develop further natural gas exports. Iran seemed slow to react to sanctions in 2008; at that time, some South Pars phases could have been developed for pipeline exports, for example to Turkey. The election of President Rouhani may change this outlook again. But for significant change to happen, sanctions must be completely lifted.

Figure 38 Iran's gross gas exports since 1971



[6] The IEA does not include reinjection in demand.

International sanctions

The United States and international sanctions have had an impact on the Iranian petroleum industry, even though an exact quantification is difficult due to lack of data. During the period up to 2007, Iran faced mostly higher costs to develop upstream because of limited access to the international banking, shipping, and insurance systems, for example. The toughening of international sanctions starting in 2010 has had a much harsher impact due to the wider range of areas affected, ranging from trade to energy, including technologies to financial services. Furthermore, provision of insurance and reinsurance by insurers in EU member states to Iran and Iranian-owned companies was banned. Under the new EU sanction regime, European firms were no longer allowed to sell equipment to Iran for use in oil and gas exploration, refining and the production of LNG. Cash transfers above USD 10 000 met increased scrutiny, insurance contracts longer than two years had to end, and contracts under two years were discouraged. While the sanctions were led by the European Union and the United States, other countries, such as Japan and Korea, followed.

The sanctions restricted the access to international finance and made some key components and know-how unavailable. Many European companies such as Total, Eni and Repsol (all involved in the development of South Pars) were forced to withdraw, depriving the country of their expertise. Iran tried to enhance its co-operation with Chinese, Russian and other Asian companies, but even those investments were reported to be falling due to logistical constraints. CNPC pulled out of Phase 11 of South Pars in mid-2012 after years of delays. The US government has also exerted pressure on pipeline projects to India, Pakistan and Europe. Finally, international sanctions have profoundly affected Iran's LNG projects, as the newly enforced Comprehensive Iran Sanctions, Accountability, and Divestment Act (CISADA) specifically targeted LNG projects. Unlike pipelines, LNG projects are much more capital intensive and require specific experience, know-how and technology, patents for which are owned by United States, European and Asian firms, none of which can invest in Iran under the sanctions.

Should the sanctions be lifted tomorrow, how fast would Iran be able to develop its gas resources and become an LNG exporter? Since President Rohani came to power in 2013, a particularly interesting development has been the return of some of the key personnel who used to run Iran's hydrocarbons industry. For example, the new oil minister is Bijan Namdar Zanganeh – who held the post in the pre-Ahmadinejad era. The new managing director of the NIOC is none other than Rokneddin Javadi. He also holds the post of deputy oil minister. He had resigned his post as head of NIGEC a few months after the election of Ahmadinejad in 2005.

Foreign investments

But sanctions are actually only one part of the problem; the other is the relationship with foreign investment and the absence of an investment-friendly legal and contractual framework. While allowing investments from foreign countries since 1995, the Iranian government has been very careful to set limits, being mindful of the historical developments. Heavy restrictions regarding foreign investment in the petroleum industry were included in both the Constitution and the Petroleum Act of 1987. The alternative was, therefore, buy-back contracts, which are essentially risk-service contracts. Unlike concession contract arrangements, the host country retains ownership of the petroleum resources. Many other countries have a similar system. The new system was heavily influenced by the *shari'a* in terms of sovereignty, ownership, control and management of mineral and petroleum rights. The buy-back contract was perceived to be more favourable to Iran than to the IOCs, which would perform the investments and be remunerated based on a fixed fee as long as they completed a minimum work requirement. Oil and gas companies have the right to a share of the production revenues based on a production sharing contract (PSC); the Iranian buy-back contract also provides for in-kind compensation for the investments. Rates of return are fixed, independent of the risk faced by the contractor. No incentive exists to minimise costs since companies would be fully compensated, irrespective of the amounts spent. Also, the IOCs would be only involved in exploration and development, not production. Finally, the contract's life is short – five to eight years – so there is no incentive to use state-of-the-art technology, since this would be eventually transferred to NIOC. Besides, this arrangement is insufficient to incentivise the developments of complex fields. Nevertheless, criticisms also exist from NIOC's side, which argues that fixed rates of return put the oil price risk on its shoulders and that the IOC has no incentive to achieve the best production profile, transfer technology and train NIOC's personal to ensure an optimal hand-over. Nevertheless, despite shortcomings, Iran still managed to attract billions of dollars of investments before international sanctions pushed IOCs out of the country, even though, in the end, most of the IOCs which had invested in Iran were unhappy at the way the buy-back contract system worked out.

Many discussions have taken place regarding a move to an alternative, which would depart from the buy-back contract while not being a normal PSC. Over the past year the Ministry of Petroleum has been developing on a new type of contract, called the Iran Petroleum Contract (IPC). The government has been working on the terms to make them more attractive, and has held talks with many IOCs. Iranian authorities are planning a roadshow in London in 2014. In the new IPC, the reward would depend on the risk that companies would be taking. The contract's lifetime would be extended to 20 to 25 years, including production as well as exploration and development, and encouraging technology transfer to local companies. Reward payment would start along with production, but full payment would be made only when the plateau target has been reached. Incentives would encourage cost savings. The IPC would also include full cost recovery, which is a more balanced risk for the contractor. Such improvement of the existing contractual framework could attract foreign companies back to Iran, should international sanctions be lifted. But the IPC would not cross the red line on the ownership of the petroleum resources. However, first discussions suggest that IOCs could be allowed to book their reserves if they clearly state that Iran has not given them ownership.

Two drivers behind natural gas production: domestic demand and exports

While looking at Iran as a potential exporter, one tends to look first at its huge gas reserves. Nevertheless, it is of equal importance to look at the demand side. Iranian gas demand started to increase tremendously after the 1979 revolution. Hamid Katouzian, head of Iran's Ministry of Petroleum Research Center, said recently that unless something drastic is done to curb its domestic gas demand, Iran could be the largest gas importer in the world by 2025. He notably cited the very inefficient use of gas in the power generation sector, where power plants have a very low efficiency. Demand in the power generation sector amounts to around 40 bcm. Most of the power generation plants in Iran have reached the end of their design lives and need to be replaced. Seasonal gas shortages force power plants to run on fuel oil and diesel, as was the case in winter 2013/14. The residential/commercial sector, the largest-consuming sector, represents one-third of total consumption. The high share of this sector means that winter demand can be very high and result in high peak demand. The industrial sector consumes 45 bcm, split between 16 bcm for the petrochemical industry and the rest for other industries. Iran is also at the forefront in terms of development of gas in the transport sector; as of mid-2013, 3.3 million natural gas vehicles (NGVs) are in Iran. This means an estimated 8 bcm of gas consumption. This conversion from gasoline or diesel-driven cars to gas has been promoted by the government and has reduced the need for imports of refined petroleum products.

The first phase of the plan to slash subsidies was quite well executed by the Ahmedinejad government. But the second phase was voted down in the Majlis and may have been deemed too painful for the population, already affected by high inflation. The target was to have residential and commercial consumers paying 75% of the average export price by 2015. Now, gas prices are expected to increase slowly by 10% from March 2014. The petrochemical industry is expected to see higher price increases, to USD 3.5/MBtu from USD 0.8/MBtu today. This increase would certainly change the economics of many projects.

Despite the underperformance of gas production in relation to gas resources, Iran continues to pursue gas export strategies. Following the Islamic revolution of 1979, all export projects were shelved; but, almost 25 years later, in 2002, Iran resumed exporting, notably to Turkey. These exports have, nevertheless, been marked by many failures to fulfil commitments due to disputes over the price and the gas quality or due to disruption following sharp demand increases in the Iranian gas market during the winter. As of today, Iran continues to pursue plans for several export pipelines, described below. The most recently discussed, and most likely, are the ones with Oman and Iraq.

- To Oman: the deal to export 10 bcm by 2015-16 was resurrected in March 2014 after the two heads of state signed an agreement for USD 60 billion. Part of the gas will be used to feed the existing Omani LNG plant, which is under-utilised. Gas will be shipped through a 260 km pipeline that will be built through Iran's Hormuzgan Province to Oman's Sohar port.
- To Iraq: a contract to deliver 9 bcm by 2015 has been signed, and volumes could be increased to 16 bcm. Both countries are building pipelines on their territory. The 270 km pipeline would deliver gas to power plants near Baghdad, but its completion has been delayed by security problems.
- To the United Arab Emirates: the contract for 5.2 bcm per year between NIOC and Crescent Petroleum was signed in 2001. Due to price disputes (the agreed price was below USD 1/MBtu), exports never started.
- To Syria: despite a Memorandum of Understanding (MoU) signed in 2007, no final agreement was signed. The current situation in Syria makes any progress unlikely.
- To Kuwait: despite talks in 2009 for exports of 3 to 4 bcm, nothing concrete has happened since then.
- To India and Pakistan: the Iranian pipeline section has been built, but Pakistan still needs to build its section and suffers from lack of capital. Additionally, the pipeline is under pressure from the United States government, and Pakistan is also trying to secure LNG supplies (see section on pipeline).
- To Europe: Iran was once quoted as a potential source for either Nabucco or TAP. The Swiss company EGL even signed a contract to import Iranian gas. The international sanctions ended start-up of those proposals.

LNG export plans have fallen victim to international sanctions due to the withdrawals of international partners and potential technology providers. Given the time needed to take FID on an LNG plant, plant development would realistically not come to fruition before 2020, assuming that a window of opportunity would still exist for Iranian LNG at that time. An LNG plant would first need to have sanctions on LNG liquefaction lifted, access to international finance restored, agreement between investment partners on upstream terms, and finally, signature of the long-term contracts for LNG. A project such as Iran LNG, based on two trains of 5.4 mtpa, would have a chance to proceed. Other potentially projects include Pars LNG and Quesh LNG.

In Iraq, the Kurdistan Regional Government is looking at gas exports

Since 2003 significant reserves of both oil and gas have been discovered and proven in the area of northern Iraq administered by the Kurdistan Regional Government (KRG). The KRG has ambitious plans to export gas to Turkey. A deal signed in November 2013 foresees annual exports of 4 bcm by

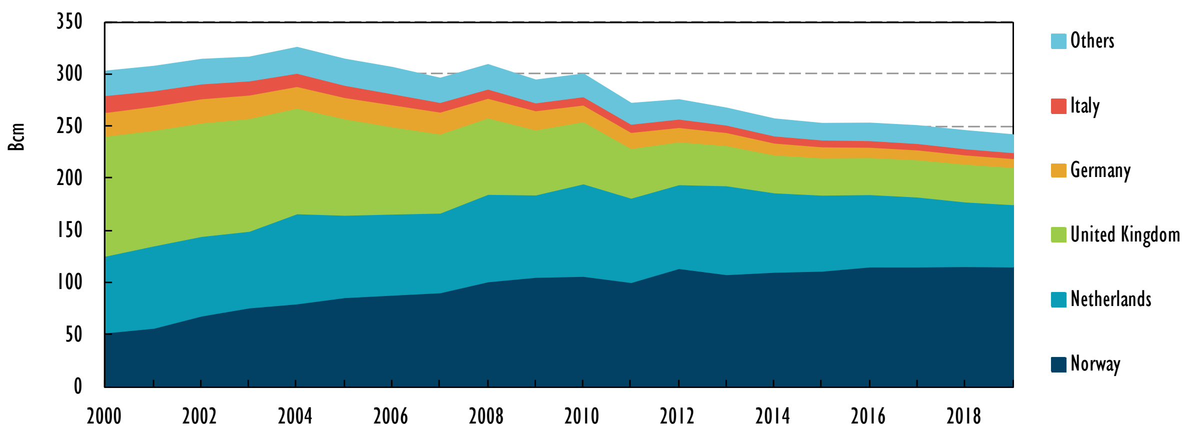
2017 rising to 10 bcm by 2020. Direct oil exports between both countries already exist, though only by truck on a regular basis while arrangements for pipeline exports remain under discussion with Baghdad. Gas exports would be based on Genel Energy's Miran field and the Bina Bawi field, which is owned by OMV (56%) and Genel (44%). The two fields' recoverable resources are estimated at between 220 bcm and 400 bcm. The agreement is highly political and comes during negotiations for a partnership between Turkey and Iraqi Kurdistan, which is upsetting the central government of Iraq. Tensions between the central government and the KRG are not new and relate to revenue allocation from KRG's hydrocarbons exports and disagreements on Iraq's State Oil Marketing Organisation (SOMO)'s future export plans. The central government also insists on approving KRG's export deals and SOMO being the only entity allowed to sell oil and choose the customers, while several companies eager to sign contracts to develop oil and gas fields in KRG have faced threats by Iraq to cancel similar deals. Discussions between KRG and Baghdad will be crucial for this deal. Meanwhile, limited progress has been reported regarding the Chemchemal and Khor Mor fields.

Iraq's other big gas projects have seemed to move slower than planned. The southern gas project led by Shell officially kicked off in May 2013, with aims to reduce flaring and to increase production from 4 bcm to 20 bcm. By early 2014, the company was treating around 5 bcm, twice as much as a year ago, but this level is still far from the 13 bcm target set for 2015 and still leaves around 10 bcm of gas being flared in Iraq. The company has to coordinate gas deliveries from three different fields: North Rumaila (BP), Zubair (Eni) and West Qurna (ExxonMobil). A pipeline from North Rumaila is operating, while the one to Zubair is being built. The ramp-up of these different fields and what their plateau production will be is uncertain. Meanwhile, Kogas announced in early 2014 its intention to reduce its share in the non-associated gas field Akkas because of the deteriorating security situation in western Iraq.

European output will lose 25 bcm over 2013-19

European gas production is forecast to decline even more than previously foreseen due to changes in Dutch gas policy. No upside factor seems able to counterbalance the expected decline of European gas production, which will amount to around 25 bcm over 2013-19. Of particular interest is the more rapid drop in Dutch production as the Netherlands is the largest European gas producer behind Norway.

Figure 39 European gas production, 2000-19



The Netherlands: seeking a balance between security of supply and safety

In August 2012, an earthquake with a magnitude of 3.6 on the Richter scale shook the area of the Groningen field in the Netherlands. This is the largest natural gas field in Western Europe, with about

300 wells, spread over 29 production clusters. The magnitude approached the previously expected maximum for an earthquake related to gas production of 3.9 on the Richter scale and caused damage to buildings and houses surrounding the epicentre in Loppersum, resulting in around 12 000 damage reports.

After the earthquake and based on a new study, the State Supervision of Mines of the Dutch Government declared that it was impossible to exclude potential new earthquakes occurring with a magnitude higher than 3.9 and that the number of earthquakes was not expected to decrease in the short term. The State Supervision of Mines also determined that a reduction in gas production would lead to a proportional reduction in the number of earthquakes.

In reaction to these new results and the increasing unrest among the citizens in areas surrounding the Groningen field, the government called for 14 studies to investigate preventive and corrective measures, like limiting production and upgrading the structure of houses, but also to review or adjust the production plans of the Groningen field's producer NAM, owned 50-50 by ExxonMobil and Shell.

The Groningen field plays a key role supplying volumes and providing seasonal flexibility to the northwest European lower calorific value gas market. Groningen natural gas has its own typical gas quality. It is of lower calorific value than most of the rest of the Dutch natural gas, because of a higher share of nitrogen. A dual pipeline system handles both qualities of gas separately. The lower calorific value gas network in which Groningen gas is injected spreads across north-western Europe, supplying the domestic market via the title transfer facility (TTF), and exporting it to Belgium, France and Germany by long-term contracts that will exist throughout the period after 2020. In the Dutch market, the gas is used for heating and cooking by more than 90% of its residential consumers. In the total northwest European market for lower calorific gas, the Groningen field plays the largest role, but this market is to a lesser extent also supplied by German production of lower calorific value, by blending some higher-calorific gas and potentially by a mixture of high calorific gas blending and nitrogen.

The field has produced 2 075 bcm (at Groningen quality) since it came on stream in 1963. Since 2006, production levels are linked to a provision in the Dutch Gas Law which sets a maximum allowance for Groningen total output to ensure that the Groningen field can provide long-term security of supply. This limit has been set at a ten-year cumulative volume of 425 bcm (at Groningen quality) and was set again after five years at the same volume for another ten-year period. The multi-year cap structure allowed commercial production flexibility between the years. Despite annual production variations due to weather fluctuations, production has been increasing throughout the first cap period, moving towards the annual average of the production limit. Production from Groningen totalled 49 bcm in 2012 when average temperatures were rather normal. The first half of 2013 turned out to be colder than normal, resulting in an annual production increase of 4 bcm to 53 bcm. This means that Groningen's share in total Dutch production was boosted from around 40% in the first half of the 2000s to 67% in 2013.

Based on the 14 issued studies, the Minister of Economic Affairs of the Netherlands presented a package of measures in January 2014. The main measures are:

- a targeted reduction of gas extraction for reasons of safety through the Mining Law;
- large-scale preventive reinforcement of houses, other buildings and infrastructure and adequate settlement of damage claims and;
- improving regional economic perspectives by encouraging economic activity.

What would be the consequences for the Dutch and the export markets? The decision is to scale down Groningen production, notably the Loppersum clusters, to 42.5 bcm over the years 2014 and 2015, and 40 bcm in 2016, without affecting deliveries of flexibility during winter months. This new limit means a reduction of 20% of the total production of the Groningen field for 2014 and 2015 compared to 2013. Production from the Loppersum cluster, where the damage has been the most severe, will be reduced by 80%. European gas production is likely to plummet in 2014, probably by at least 10 bcm – the difference between Groningen's 2013 production and the limit set – given that other European producers and the Dutch small fields are unlikely to be able to compensate for this reduction. Due to the maturity of the Dutch market, volumes delivered to the residential/commercial market are unlikely to increase, but may be on a slightly downward trend because of increasing energy efficiency. Volumes for exports are generally bound by long-term export contracts. When these contracts come to an end, the specific parts of lower calorific market are gradually replaced by higher-calorific value gas. Via the Penta Gas Forum, the Netherlands is working together with the low-calorific value gas-consuming countries to manage this transition, the pace of which is also set by the limits and the needs of switching to new appliances that can handle the other gas qualities. Conversion is expected to start in Germany as of 2020, followed by Belgium and France around 2025 and finally the Dutch domestic market after 2030, according to IEA latest In-Depth Policy Review of the Netherlands (IEA, 2014a).

Besides gas, the Groningen field has also been generating substantial revenues for the government for decades. During the last years, the government's total gas revenues were around EUR 13 billion, with more than EUR 10 billion generated by the Groningen field alone. The government expects that the reduced volumes from the Groningen field will have result in a loss of state revenues of EUR 0.7 billion in 2014 and EUR 0.6 billion in 2015. For 2016, revenues are expected to be some EUR 1.0 billion lower.

The package of measures for Groningen will amount to EUR 1.18 billion for the entire period 2014-18 and will be largely funded by the producer Nederlandse Aardolie Maatschappij BV (NAM) and the State, which will pay for the claim settlements and prevention measures as well as the liveability programme, through reduced natural gas revenues, estimated at EUR 144 million per year.

A follow-up study is to be performed as basis for the preparation of the decision on future gas extraction after 2016 which will be discussed with the region. In addition NAM will work in the meantime on a new production plan to be presented before 1 July 2016. The Dutch government hopes that this step will create the needed room to define the new gas production policy during the next three years.

The FSU region

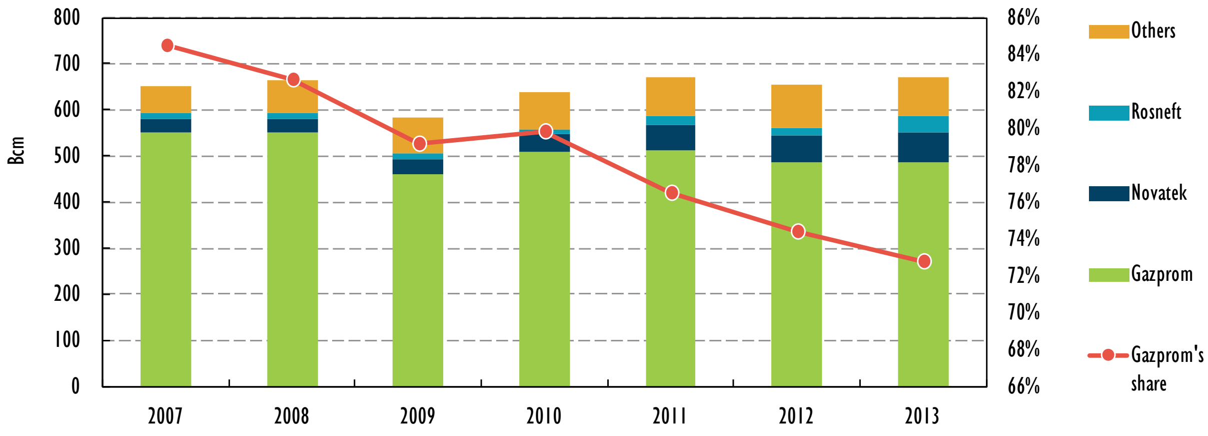
Along with OECD Americas, the FSU region is the largest gas-producing region; but unlike OECD Americas, its production patterns depend largely on exports and less on domestic demand, for which growth is limited. Hence the region's production growth remains subdued, reaching 917 bcm, despite a much higher production potential. The region is ideally located between two large markets, Europe and Asia, and also plans to increase its contribution as an LNG supplier. But while European gas import needs are limited due to low demand growth and competition among suppliers, gas exports to Asia are constrained by the lack of infrastructure, both pipelines and LNG liquefaction plants. FSU countries are actually competing among themselves for the European and Asian markets. Meanwhile, LNG would also give Russia, the only country planning LNG exports, access to global gas markets.

Russia

In 2013, a number of fundamental trends in the Russian gas market seen over the past few years have been confirmed. Against the backdrop of slow economic growth in Russia (3.5% in 2012 and 1.3% in 2013) and a slight decline in power generation, figures from the Ministry of Energy show gas consumption in Russia has been almost flat. It is thus timely that the Russian government has ordered the preparation of a new Energy Strategy to 2035, to be approved in autumn 2014, which should aim at reflecting the implications of changes in international markets, as well as in the Russian economy and energy markets.

Meanwhile, Russia's gas production has increased by 2.3%, reaching 669 bcm in 2013, very close to the production record seen in 2011. Yet, Gazprom's production has been flat at 487 bcm, while its technical production capacity is reportedly over 600 bcm. This situation further confirms two parallel trends that are unfolding: production from "independent" companies has been further growing, from 166 bcm in 2012 to 182 bcm in 2013, while Gazprom's own production is limited by absent growth on the domestic market, and competition from "independents" on that same market who are benefiting from lower production taxation and the possibility to sell gas to the wholesale market below the regulated tariffs at which Gazprom has to sell its gas (Figure 40). Competition has actually started within the Russian domestic market. Gazprom's flat production is also explained by very slow progress regarding gas exports at a time when Gazprom maintained gas imports from the Central Asia and Azerbaijan at a plateau. Since 2011, Gazprom managed to increase its exports to Europe by over 10 bcm, but, at the same time, reduced exports to Commonwealth of Independent States (CIS) markets by almost 25 bcm. As a consequence, the share of Gazprom in total Russian domestic production is thus likely to continue to decline: it was 84.5% in 2007 and about 73% in 2013.

Figure 40 Russian gas production by company, 2007-13



Source: companies' websites.

Gazprom's future production

Gazprom's production over the next five years will increasingly come from Bovanenkovo, where production started in 2012. Gazprom is indeed continuing to invest in this field and reportedly allocated USD 2.9 billion in 2012 and USD 2 billion in 2013. Production from Bovanenkovo is expected to ramp up quickly, while production from Gazprom's traditional super giant fields continues to decline. In 2012, gas production in Bovanenkovo was 4.9 bcm, reaching 22.8 bcm in 2013, lower than initially planned. In 2014, gas production is expected to reach 40.8 bcm. After 2017, it will reach the full capacity at

115 bcm, with 775 wells planned to be operational and, finally, possibly 140 bcm at a later stage. These targets may be revised somewhat to match the development of demand in Russia and abroad.

Gazprom has also been advancing E&P activities in Sakhalin. Gazprom holds licenses for three offshore blocks within the Sakhalin-3 project: Kirinsky, Ayashsky and Vostochno-Odoptinsky. Total gas reserves of these blocks are estimated by Gazprom at about 1.5 tcm. The Kirinskoye field (90 metres depth) in the Kirinsky block, currently believed to hold 162.5 bcm, is Gazprom's priority, and could produce 5.5 bcm per year. It started producing in October 2013. This field is Gazprom's first completely self-developed offshore project. Gazprom also discovered the large Yuzhno-Kirinskoye field within the Kirinsky block in 2010. Peak annual production from Sakhalin-3 is currently projected to be over 20 bcm, yet this may well come over a somewhat long term. Production at Yuzhno-Kirinskoye is set to start no earlier than 2019 and should reach a peak of 16 bcm by 2023-24. But some delays may be incurred, related to the discovery of oil in this field. Produced gas from these fields is planned to be delivered to the onshore processing facility via undersea connecting pipelines and shipped onwards via the Sakhalin-Khabarovsk-Vladivostok gas transmission system. More production is thus expected to come from the Sakhalin province.

In the Far East, the new greenfield projects aimed at supplying gas to China and Asian markets have been postponed. Gazprom announced that it will develop Chayanda first, estimating its cost at USD 13.7 billion and plateau production at 25 bcm in 2021 (plus 1.5 Mt of oil production in 2027 at plateau). In October 2012, the Gazprom Management Committee adopted the FID on the Investment Rationale for the Chayanda field pre-development, transmission and processing of gas, with the field to be commissioned in 2017. Yet, this date has been pushed back further to no earlier than 2019, and it is likely to incur some further delays (Gazprom, 2013b).

Independents: Novatek continues rising and leading, Rosneft catching up quickly

Novatek in 2013 continued on its path to reach the 100 bcm production level targeted by 2020, with a spectacular increase in production from 20.9 bcm in 2004 to 62 bcm in 2013 and a 9% increase year-on-year, which is set to continue in 2014. Novatek's production thus more than doubled over this period thanks to the fields being fully developed (such as Yurkharovskoye phase 2), expansion of its processing capacities, but also acquisition of assets: in 2010, a controlling stake in Sibneftegaz (swapped later on); in 2012, a 49% stake in Nortgas; and in 2013 the consolidation of stakes in SeverEnergia and Nortgas. As a consequence, the production growth is not entirely related to Novatek's initial fields and resources. Nortgas, a 50-50 joint venture with Gazprom, holds the licence for the Severo-Urengoyskoye gas condensate field located in the Yamal-Nenets Autonomous Area (YNAA), which produced about 3.5 bcm in 2013 and is likely to produce about 10 bcm in 2014, as a total of 18 wells will be operating, alongside the Purovsky gas-processing plant. Novatek also more than doubled its proven reserves from 2008 to 2012, to 1.75 tcm.

SeverEnergia, initially a joint venture between GazpromNeft, Novatek, Enel and Eni, changed ownership: in autumn 2013, Enel sold its stake to Rosneft and Eni to Novatek and GazpromNeft, and subsequently Rosneft and Novatek made an asset swap (Novatek's stakes in Sibneftegaz in exchange for Rosneft's stakes in SeverEnergia), so that Novatek ended up controlling a 59.8% share in SeverErgia, with the remainder held by GazpromNeft. In April 2014, Novatek then announced it has sold further stakes to GazpromNeft, bringing its ownership to 50%. SeverEnergia started producing 1.8 bcm in 2012 at the Sumburgskoye field. Production reached 5 bcm in 2013 as a second gas treatment train was put in operation in December 2012. Two additional gas treatment trains are to be commissioned in 2014 in the Urengoyskoye area, bringing total production of SeverEnergia to 12 bcm. Yet a fire that broke out at the field in May 2014 could delay this target. SeverEnergia holds a number of additional licences in the Urengoyskoye area (Yaro-Yakhinskiy, Severo-Chaselskiy and Yevo-Yakhinskiy). Total annual production could be as much as about 35 bcm by 2017 (on top of 145 000 barrels per day of liquids).

In the medium term, Novatek is thus expected to continue increasing production, in particular also from the South Tambeyskoye field, which should be commissioned in 2017 (plateau production expected to be 27 bcm a few years later) and which will supply gas for the Yamal LNG first train expected to be commissioned by 2018, even though this date seems optimistic for a greenfield LNG project. The company is, therefore, very likely to move close to 90 bcm to 100 bcm production by 2019-20.

An appraisal of the Yuzhno-Russkoe field in the YNAA, developed by a joint venture among Gazprom, E.ON and Wintershall, predicts that reserves may well produce 5 bcm to 8 bcm more than the current 25 bcm, following the success of a pilot project to tap complex Turonian gas deposits. An additional well will be built in 2014; however, realising this additional potential may well happen after 2020.

Rosneft has seen spectacular production growth driven by asset acquisitions which followed the acquisition of TNK-BP, as well as the full acquisition of Itera, Alrosa and Sibneftegaz: from 16.39 bcm in 2012 to 38.17 bcm in 2013, and an expected 55 bcm in 2014. Moreover, Rosneft's production potential from associated gas, some new greenfields, and continued acquisition of assets drives its strong ambitions to increase its share in domestic gas production and supply (80 bcm per year is reportedly contracted on the Russian domestic market) and to enter the export segment with LNG at Sakhalin. The company is poised to become a significant gas producer over the current decade, with a target of 100 bcm by 2020 – which would require some further acquisitions or large investments.

Following its acquisition of TNK-BP, Rosneft is also building on TNK-BP's own plans set out in 2011 to produce 35 bcm of gas by 2020, up from 13.2 bcm of mostly associated gas in 2012. Indeed, TNK-BP was working to maximise associated gas utilisation and its subsidiary, Rospan International, holds licences to develop two gas and condensate fields, Vostochno-Urengoiskoe and Novo-Urengoiskoe located in YNAA. Rospan, which produced 3.5 bcm in 2012, is currently developing the deep gas reserves of the Valangin and Achimov formations in these fields. According to TNK-BP, work was under way for phase 1 ramp-up to 8.5 bcm by late 2016 and 16 bcm by 2020, and the company also considered sales to the power sector. Rosneft will be developing gas production from the Kynsko-Chaselskiy group of fields and especially from the Kharampur gas field in West Siberia (YNAA), set to start in 2017 with some 8 bcm, and an expected yearly plateau production of 20 bcm to 24 bcm for the longer term. In addition, as Rosneft's oil production grows and as the company is compelled to comply (alongside other oil companies) with strict gas-flaring reduction obligations, its marketable associated gas production will also increase (Box 11). Rosneft is actively pursuing projects aimed at processing associated gas, such as at its Vankor oil field, which could produce up to 6 bcm per year.

As a consequence, Rosneft and Novatek are each likely to come close to the 100 bcm production benchmark by 2019-20, adding a combined new additional production that be estimated at about 50 bcm to 60 bcm, the remainder coming from asset takeovers. Yet, at the same time, Gazprom itself is projecting to increase its own production by the end of the decade, while it plans for only small or flat production growth in the short term, to 483 bcm in 2015. This downward revision of production numbers cannot be seen in isolation from the recent drop in demand in Russia's main export markets, the European and FSU countries, and from the stagnation of demand on the Russian market. However, Gazprom plans to produce about 530 bcm by 2020 (Gazprom, 2013b), while key independents also have production growth ambitions in a market where demand is unlikely to pick up sharply.

Box 11 Russia's efforts to reduce flaring of associated gas

Gas flaring in Russia has been an ongoing issue and has only recently been addressed more resolutely by the government, which has set strong targets, imposed high fines and incentivised investment to reduce the flaring. These efforts are likely to pay off, so that more associated gas utilisation is also to be expected in the medium term. The current objective is to reduce gas flaring to just 5% of associated gas by 2016. Gazprom, for example, had a 70% average utilisation level in 2012, including 65.7% for GazpromNeft (Gazprom, 2013a). Most oil companies including Rosneft with the exceptions of Tatneft and Surgutneftegaz are reportedly still a long way from complying, with a level of utilisation below 70%. A key obstacle for greater utilisation is the lack of metering and efficient third-party access (TPA) alongside insufficient infrastructure to collect and treat the gas or power generation facilities to monetise the gas.

The fee for flaring associated gas rose sharply beginning on 1 January 2013. On 8 November 2012, the Russian government passed a decree approving a new formula for calculating pollution fees related to associated gas flaring. The coefficient used in the formula for calculating payments in 2013 would jump from 4.5 in 2012 to 12 in 2013, and from 12 to 25 in 2014 for gas flared in excess of the 5% limit, with fees thus increasing by around three times in 2013 and six times in 2014 compared with the 2012 level. At the same time, associated gas has priority access to the grid and unmetered associated gas flaring leads to massive standardised fines. Fines for associated gas flaring are in a range of USD 500 to USD 600 million per year, according to the Ministry of Natural Resources and Environment, or equivalent to about USD 13 to USD 16 million per bcm.

The newly introduced regulation also addresses gaps in the previous 2009 regulation. The federal environmental watchdog regularly imposes fines for under-utilisation of associated gas at the level stipulated in licence agreements or the law. The regulation envisages a grace period for new fields, or "green fields", where the requirements to utilise 95% of the associated gas produced will not apply during the initial stage.

To foster the utilisation of associated gas and reduce flaring, and as part of some import-substitution policy effort, the government is also encouraging the development of Russia's petrochemical industry near oil fields with associated gas production so as to benefit from this feedstock. An example is Sibur's USD 2 billion Tobolsk-Polymer plant commissioned in 2013 and producing polypropylene. The plant should use about 5 bcm of associated gas per year. Rosneft is also developing similar projects in Russia's Far East. Another example is the construction of the Yuzhno-Priobsky gas-processing plant by GazpromNeft and Sibur, which is to be operational in 2015. Currently, the share of associated gas is 8.4% of the total and in constant increase, from 42.6 bcm in 2005 to 54.7 bcm in 2012.

This assessment raises the question: can the Russian domestic market and export markets absorb such higher production levels, which would amount to around 100 bcm based only on the targets of Gazprom, Rosneft and Novatek? The Russian Ministry of Energy is confident and has a bullish forecast, envisaging a production of 826 bcm by 2020, which would imply an increase of about 150 bcm, or +23.5% from 2013 levels, consistent with the three companies' forecasts. If this projection is realised, Gazprom, Novatek and Rosneft would be able to confidently raise production and find customers for their additional gas output net of acquisitions, because this forecast would imply that the Ministry also sees demand for this gas in Russia and abroad.

Yet, if combined total Russian gas production would instead be lower (as Russia's domestic gas demand only increases very slowly), if Gazprom's import levels of Central Asian and Azeri gas were to remain unchanged, and if its export volumes were to remain unchanged, then obviously not all three companies – Gazprom, Rosneft and Novatek – would be able to meet their production targets and potential. In fact, considering the gas consumption trends in 2012 and 2013 and the economic growth outlook, gas demand growth over 3% per year looks quite unrealistic. It is, therefore, very likely that Gazprom's production will only slightly increase (if not remain flat) by 2020. While Novatek's production increase until 2020 is planned to serve in part export markets and depends on the timely completion of Yamal LNG, Rosneft's production increase, which is meant for the Russian market, may thus be slightly lower than what is currently envisaged or would need to come from further acquisitions.

Other FSU countries

Gas production in Ukraine was slightly higher than 2012 (+4%) and reached 21 bcm in 2013. In the medium term, exploration activities in shale gas plays for which Shell and Chevron signed PSAs are likely to happen; yet significant production from these plays is still unlikely in the medium term. Ukraine's annual production can thus be projected to remain flat.

Kazakhstan's gas production, which is 90% associated gas, has continued its slow and progressive increase in 2013. About 55% of total gas output is used for commercial consumption. Total production of natural gas in 2013 was 42.3 bcm, up 5.5%. About 22.8 bcm was used for commercial production and made available for exports and domestic consumption after processing. Domestic consumption was 10.9 bcm. About 8.2 bcm were exported by KazRosGaz to Russia for processing at the Orenburg plant, and part of this gas was then re-imported into Kazakhstan. The government expected production to increase to 45 bcm by 2015, particularly once the Kashagan commences production. After the start of oil production in September 2013, the field was shut down shortly due to a gas leak, caused by multiple cracks in the pipeline, believed to be caused by the highly corrosive sulphur-containing gas produced as a by-product of Kashagan's oil. According to the Kashagan operating company, both oil and gas lines might have to be fully replaced, which indicates further significant delays. Once Kashagan oil production ramps up, associated gas will be re-injected or used for power generation, but some volumes may be processed and used for the industrial and residential sectors. Kazakhstan is planning to build a USD 3.7 billion gas-processing plant at Karachaganak, to be commissioned by 2017, with a capacity of up to 5 bcm per year by 2019-21, to increase gas processing and provide gas supplies to cities such as Astana via a pipeline that would also need to be built. But it is unclear whether this plan will go ahead, what its final capacity will be and whether injecting gas to foster oil production will ultimately take precedence. In 2013, about 17 bcm of gas were extracted from Karachaganak, of which 49% was re-injected.

Turkmenistan's gas production rose in 2013 to a level close to 70 bcm (+3 bcm to 5 bcm). The year was marked by the launch of the world's second-largest gas field, Galkynysh. The first phase is to plateau at a level of 30 bcm of production by 2018-20. The second phase of the field is due to be commissioned by 2017 or 2018 and progressively reach plateau production in the following years. Moreover, CNPC's PSA over Bagtyyarlyk will start producing, with production estimated at 12 bcm to 15 bcm in the coming years. Altogether, these developments would put Turkmen production at about 95 bcm to 100 bcm by 2019-2020, and even possibly 100 bcm to 105 bcm if Dragon Oil can make commercial use of its potential gas production from the Cheleken area offshore in the Caspian Sea, where it currently produces significant oil volumes. The company is currently tendering for a gas treatment plant in Hazar, which could make gas available for exports (for example, to Russia, Iran or China). Finally, in a sign that Turkmenistan is prioritising an increase in exports, a decision was made to cap free gas supplies to the residential sector and to charge for consumption over a certain threshold.

Gas production in Uzbekistan continued its temporary downward trend to around 61 bcm in 2013, falling slightly from 63 bcm in 2012. Indeed, production is likely to ramp up in the medium term mainly due to Lukoil's production increase at its major fields following large investments over past years. The production slowdown and cold temperatures in winter have led to temporary reduction or halts in exports to Russia and neighbouring countries. Lukoil's production is likely to increase from about 6 bcm in 2013 to up to 16 bcm to 18 bcm by 2019, and total Uzbek production is likely to increase to about 68 bcm by 2019-20.

Azerbaijan's raw gas production increased by 11% in 2013 to 29.5 bcm, from 26.8 bcm in 2012. Production from Shah Deniz increased to 9.8 bcm in 2013, compared to 7 bcm in 2012, and is set to increase further to about 10.4 bcm in 2014. The Shah Deniz 2 field will be commissioned by 2019 and will plateau at a level of 16 bcm by 2022. In the medium term, SOCAR is also likely to ramp up production from the Umid-Babek block, where more wells are being drilled, and which has been producing since September 2012. Other resources such as Shafag Asiman (SOCAR-BP), Absheron or deep gas below Shah Deniz – Shah Deniz 3 – are likely to produce in the longer term extending into the 2020s. More associated gas is being extracted from Azeri-Chirag-Guneshli (ACG) Deep Layers, but this gas is then re-injected.

North America: NGLs are a major pillar of gas production growth

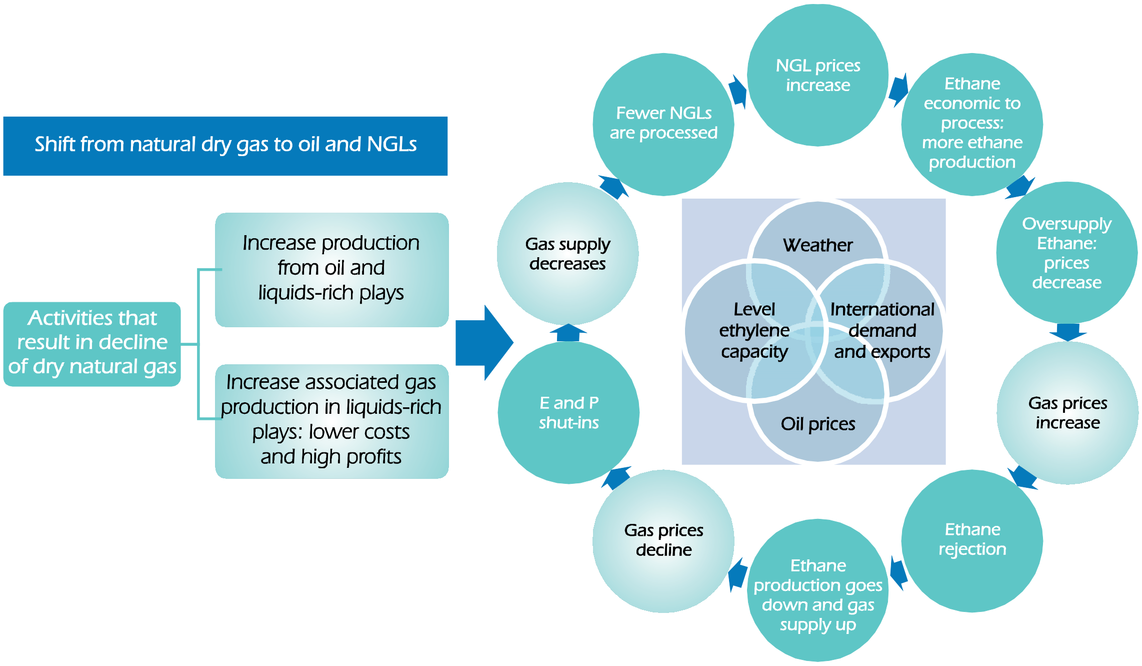
In 2013, US natural gas production continued increasing, mainly driven by the expansive growth in the Northeast and the production from NGL-rich areas, such as Eagle Ford Shale in Texas. Once again a new production record was broken, attaining 688 bcm, or 0.9% over 2012 levels. Production of natural gas is expected to keep rising strongly over the forecast period, reaching 797 bcm in 2019, compared to a total demand of 765 bcm. The growth will be largely generated by onshore production, notably shale gas. During the forecast period, the Gulf of Mexico production from existing fields will continue showing a declining trend, with fewer companies willing to bear the cost of offshore production activities in light of the relatively low gas prices and the more favourable economics of onshore drilling. Gas flaring and venting accounted for around 6 bcm in 2012, almost stable compared to 2011 levels, but 2.3 times higher than in 2000. The largest contributors to this increase include North Dakota, Wyoming and Texas.

In 2013, the Northeast was the largest productive US region. The most remarkable growth took place in West Virginia and nearby counties in south-western Pennsylvania. Supplying the Northeast markets, the Marcellus formation is becoming the most productive gas area of the United States. In 2010, the Marcellus region produced around 20 bcm. Three years later, its production crossed the 100 bcm mark. Increasing volumes from the Marcellus formation are also leading to the displacement of gas from the Gulf Coast and other long-haul supplies, changing the flows' landscape in the eastern part of the United States.

The increased production in the Northeast was made possible by the substantial expansion of pipelines to transport natural gas from production areas to the market. Huge pipeline extensions and several new major pipelines coming online, such as the Tennessee Northeast Upgrade Project, the extension of the Texas Eastern Pipeline and the Northeast Supply Link have made their way to metropolitan areas in the Northeast. Through these projects, gas flows from Marcellus and other sources reaching the metropolitan areas have increased by one-third, making an important impact on prices in this part of the United States. Indeed, this regional gas oversupply sent prices in some trading locations like Tennessee Gas Pipeline Zone 5 to an average of USD 1.85/MBtu during June 2013 to August 2013, dropping even to below USD 0.50/MBtu several times.

A key question over the forecast period is the development of gas supply relative to gas prices and vice versa. In this report, as well as in all the Medium-Term Reports, the IEA takes forward curves as an assumption. The price curve showing gas prices staying around USD 4.5/MBtu up until 2019, along with booming associated gas production supports an increase in natural gas production. Uncertainties, nevertheless, exist on whether growing domestic demand for natural gas and LNG exports would boost prices more than expected towards the end of the forecast period. Prices could also get a boost as lower cost resources deplete and production gradually shifts to less productive and more expensive resources. Nevertheless, one should not underestimate further potential efficiency and technological improvements.

Figure 41 Interaction between the production of ethane and natural gas in liquids-rich plays



This 2014 report looks in detail at one of the consequences of natural gas production – the boom of NGLs. As production becomes wetter, it drives significant NGL production build-up. In this recent period of low gas prices, NGLs have become an essential component of gas producers' revenues, helping them to maintain a healthy flow. Hence, gas production still continues to grow despite the unfavourable pricing environment. The interaction between NGLs and gas prices and production is subtle (Figure 41). Besides NGL prices, finding demand outlets for these additional products is considered to cause a bottleneck, which affects the output of both gas and NGLs.

NGLs as production drivers of natural gas

NGL is the general term for all liquid products separated from natural gas at a gas-processing plant. It includes ethane, propane, butane, and pentanes. When NGLs are present with methane, which is the primary component of natural gas, the natural gas is characterised as “hot” or “wet” gas. After the gathering phase, the extracted wet gas is brought to a processing plant where impurities are removed and where the hydrocarbon components are separated into pure natural gas (methane) and mixed natural gas liquids. Once the NGLs are separated from the methane, the natural gas is referred to as “dry” gas, which is what most consumers use. The liquids are then transported to a fractionation plant to be further separated into several different components. When referring to production of NGLs, the term gallons per thousand cubic feet of gas (GPM) is used to measure the hydrocarbon richness (Table 12). Dry gas contains 1 GPM while wet gas fields can have much higher levels. A very rich gas may contain 5 gallons to 6 gallons of recoverable liquids per mcf.

Traditionally, NGLs were considered by-products of gas production. But due to low natural gas prices in the United States, gas has gone from being the main product to the position of co-product. Currently, NGL processing from natural gas accounts for approximately 70 % of the total US NGL production; the rest comes from the crude oil refining process. The expectation is that the United States will see a structural NGLs oversupply during the coming years (Figure 42).

In contrast with gas, the main value of most NGLs is not in their calorific content to create heat, but as base materials to produce industrial goods. Liquids such as ethane, propane, butane, and condensates are composed of longer chains of carbon molecules than methane. Global markets use liquids to produce several petrochemical products and to blend them with crude oil to make more valuable products. Some liquids can also be combusted directly, such as liquefied petroleum gas (LPG) which is a mixture of hydrocarbon gases mainly used as fuel for domestic cooking, vehicles and industry. Because of the worldwide use of liquids, NGL prices are influenced by global prices until bottlenecks arise.

Table 12 NGLs production of some shale plays in 2013

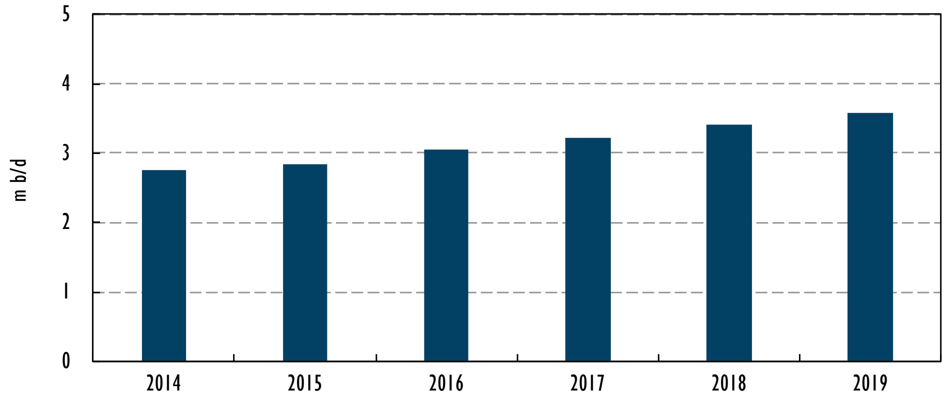
Rich Gas Shale Plays	Gallons of NGL per Mcf (GPM)	Production*
Bakken (oil shale play and associated gas)	6 to 12	80 000 b/d
Barnett (gas shale play)	2.5 to 3.5	230 000 b/d
Woodford (gas shale play)	4 to 9	100 000 b/d
Eagle Ford (oil and gas shale play)	4 to 9	350 000 b/d
Niobrara (oil and gas shale play)	4 to 9	130 000 b/d
Marcellus-Utica (oil and gas shale play)	4 to 9	100 000 b/d

* Approximate.

US total liquids output (excluding biofuels and refinery processing gain) exceeded 10 mb/d for the first time in decades in mid-2013. In 2014, the United States is poised to become the largest non-OPEC liquids producer, ahead of Russia, even if biofuels and refinery gain are not taken into account (but including additives and oxygenates) (IEA, 2013).

Observing recent operating trends in natural gas-producing shale plays, it is obvious that liquids-rich plays will largely contribute to determine the natural gas production levels of the forecast period. Most US dry natural gas companies turned towards oil and NGL production, while selling gas and offshore assets. The current forward curve shows gas prices remaining around USD 4 to USD 4.5/MBtu for the rest of the decade, a level that companies often mention as the low end for healthy returns. Hence, most companies are unlikely to switch back to dry gas any time soon. The cost of gas production in liquids-rich plays is much lower (sometimes even negative), and the profits are higher than drilling wells solely for dry gas. In the course of 2013, several major companies lowered the book value of their natural gas properties by billions of US dollars.

Figure 42 US NGLs forecast production, 2014-19



Note: Ethane, propane, butane, isobutene and pentanes plus.

Source: (IEA, 2014b), preliminary data.

Price formation of NGL products

Historically, the individual NGL products have been priced against oil, except for ethane. US oil prices have remained higher since 2005 relative to natural gas, driving growth of wet gas production. As NGL prices tend to follow oil prices, liquids are more valuable if they are sold separately than combined with methane natural gas volumes. The spread between the NGL product sales price and the purchase price of natural gas with an equivalent Btu content is called the ‘‘fractionation spread’’. The frac spread increases when NGL prices increase relative to natural gas prices.

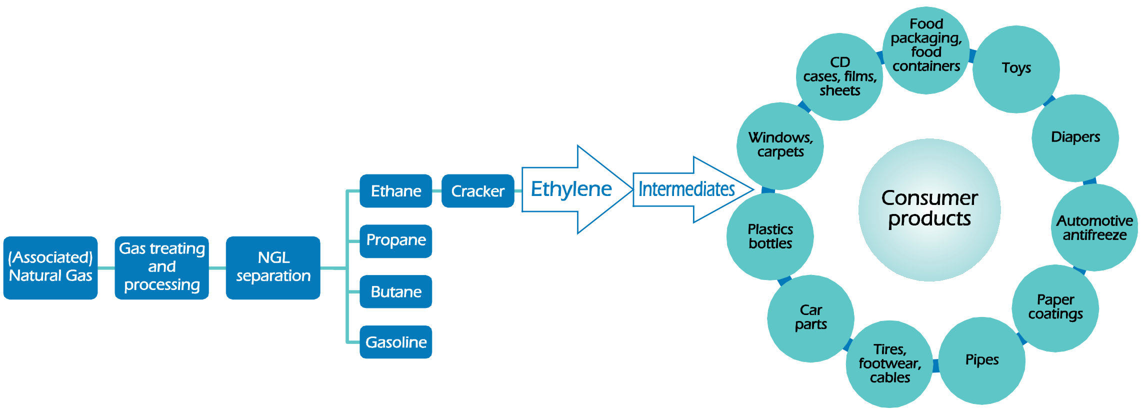
In recent years, the frac spreads, and consequently the net operating margins for companies with natural gas-processing operations have in general been positive. But during the first part of 2013, NGLs prices – ethane, propane, normal butane, isobutane, and natural gasoline – were continuously declining because of a combination of higher gas prices than in 2012, abundant supply, flat or moderate demand, and export and domestic infrastructure constraints affecting NGL products. Frac spreads reached their lowest levels in June 2013 (around USD 20 per barrel) but recovered strongly during the second part of the year, mainly as a result of the increase of oil prices, the stagnation of natural gas prices and an expansion of propane export capacity.

At the moment, nearly all the capacity of chemical companies to process ethane and propane is being used. Once extra capacity for processing ethane and propane comes online or more export capacity is available, an additional long-term demand for liquids can be generated, which will result in higher frac spreads. This economic effect is already visible with the recent increases in propane exports to Asia. At the same time, some analysts now question whether enough propane will be available to utilise all of the planned augmentation in export capacity.

Each liquid has its own market

Besides the general developments concerning the frac spreads, a more detailed analysis of the NGL market shows that each liquid has its own market dynamics and its own value (Figure 43). A typical NGL barrel is approximately composed of 40% to 45% ethane, 25% to 30% propane, 5% to 10% normal butane, 10% isobutane and 10% to 15% natural gasoline (pentanes plus).

Figure 43 From natural gas to consumer products



- Ethane is mainly consumed by the petrochemical industry and primarily used as a feedstock for ethylene, a product that can also be produced from naphtha (Table 13). Due to the lower cost of natural gas in relation to the crude oil prices in North America, ethane has been gaining a larger share as a petrochemical feedstock, reducing the use of naphtha. Ethylene is the most important raw material in the downstream plastics industry and accounts for almost 50% of global chemical volumes. A unit of cracked ethane produces higher units of ethylene than the cracking process of naphtha. However, naphtha has more potential uses than ethane.

Table 13 Type of feedstock and composition of products

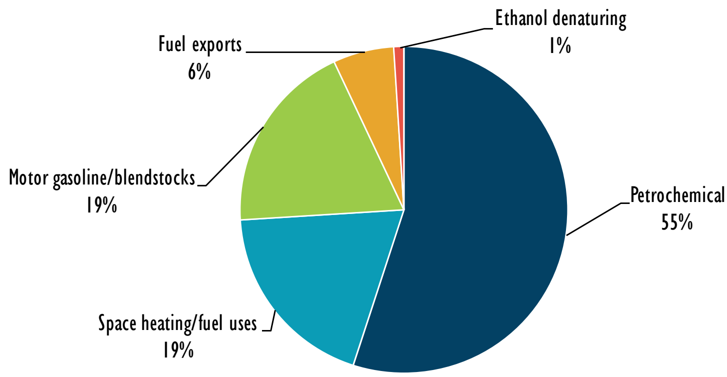
	Ethylene	Propylene	Butadiene	C5 higher aromatics	Methane and hydrogen	Losses
Naphtha	29% to34%	13-16%	4-5%	19% to 30%	14% to 16%	1% to 2%
Ethane	80% to 84%	1-2%	2-4%	2-4%	6% to 10%	1% to 2%

Source: CE Delft (2013).

  - Since December 2008, ethylene prices have been increasing substantially, and US natural gas prices have been decreasing continuously, reaching a historically low level in the middle of 2012. This combination of price developments has made ethane cracking profitable. At the same time, higher oil and naphtha prices have weakened the competitive position of naphtha-based crackers.
  - During 2013, the market for ethane continued to deal with a structural oversupply. Ethane does not have a price premium over natural gas. In comparison with gas prices, ethane prices have been extremely low, forcing gas producers to keep large volumes of ethane in the natural gas stream while separating the other wet gas products. Producers then ship the natural gas – with ethane included – into pipelines, a process known as "ethane rejection". There are estimates that ethane rejection in the United States exceeded 200 000 b/d in 2013. During the coming years (2014-16), the ethane market will remain oversupplied, resulting in ethane rejection at many US gas plants.

- Propane is used as petrochemical feedstock like ethane, but it is also consumed as a heating fuel. Since 2012, propane produced in the United States from domestic NGLs and crude oil resources exceeded the total consumer demand.
  - US consumer propane demand is expected to remain stable. The increased production has led to increased exports, primarily to Latin America. The effects on prices have been mitigated by the increasing exports. From July 2012 until the winter of 2013, with extremely cold temperatures, propane prices were relatively stable. Traditionally propane has been a crude oil derivative, with the same supply security issues as other petroleum products. The cold winter of 2013-14 increased demand in the United States and caused temporary propane shortages, leading to sky-high prices.
  - As propane prices have fallen, the petrochemical industry demand for propane has increased. The petrochemical industry is planning to significantly expand propane use in the future.
- Normal butane is mainly used for gasoline blending, as a fuel gas, either alone or in a mixture with propane. This liquid is also used as a feedstock for the manufacture of ethylene and butadiene, a key ingredient of synthetic rubber. Isobutane is primarily used by refineries to blend motor gasoline. In 2013, lower-than-usual gasoline demand, in combination with increased supply, reduced demand for these products and exerted downward pressure on prices. The increasing export capacity will enable the export of propane and butanes, potentially shifting both propane and butane markets to a better balance by late 2014 or 2015.

Figure 44 Sectoral consumption of NGLs in the United States (2012)



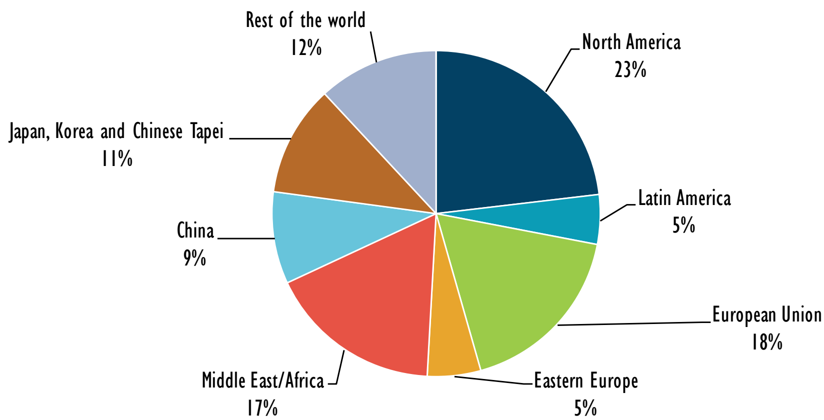
The increase in NGL production is already having an impact on many sectors, most notably petrochemicals, industry and transport (Figure 44). The US petrochemical plant capacity is increasing rapidly, mainly as a result of the price of gas. So far, the projects announced that would come online through 2017 would lead to a rise in US ethylene capacity of more than 35%. But the IEA expects only a fraction of the proposed projects to be completed within this timeframe (see the forthcoming *Medium-Term Oil Market Report 2014*). The vast majority of these ethylene plants are expected to be built in the Gulf Coast region. Of 20 projects announced, six would be located in Louisiana. The expectation is that as a result of demand increases and steady supply growth, prices will remain relatively stable during the next years.

NGLs: an increasingly competitive market

The growth in production of NGLs is gradually becoming a critical component in the revival of the US petrochemical sector. Low feedstock prices, together with lower factory power costs than those in the European Union and Japan, are giving the United States an unprecedented advantage. The low prices are causing a structural feedstock shift, which leads to increases in production of ethylene from ethane and LPG, mostly at the expense of naphtha. This is a fundamental shift in the US manufacturing sector, affecting the competitiveness of the oil and naphtha-based industries in other parts of the world.

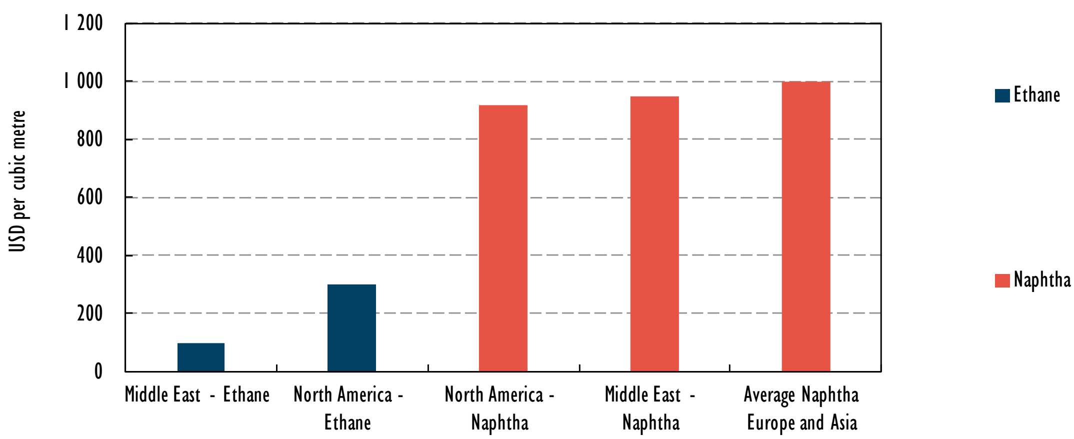
The use of ethane as an alternative to naphtha will probably also result in lower greenhouse gas emissions of the US chemical industry in comparison with the naphtha-based European petrochemical industry, for example. The increasing share of ethylene feedstock will be driven not only by ethane-based capacity in the United States, but also by the Middle East, due to low natural gas prices in some producing countries.

Figure 45 Worldwide ethylene capacity in percentages



Source: IEA estimation based on various sources.

Figure 46 Global cost to produce ethylene in 2013



Globally, operating petrochemical companies are looking for ethane as a cheaper alternative to oil-derived naphtha. Production facilities in Europe are mainly based on naphtha feedstock, with only around 3% of the existing capacity currently running on ethane feedstock. At the moment, there are a couple of European companies with solid plans to import ethane from the United States, but to expect that a large part of the European manufacturing sector can shift to ethane is not realistic. For importing regions such as Europe, naphtha will remain economically the most attractive feedstock. Despite the low US gas prices, importing US ethane for gas cracking ethylene production installations in Europe will be relatively expensive: ethane is a gas under atmospheric pressure, and liquefaction is the only option to transport it. This requirement will bring the selling costs of ethane to the cost level of naphtha imports (Figure 46).

As analysed in the *WEO 2013*, Japan and the European Union may lose one-third of their combined export market share of energy-intensive goods over 2011-35, partly because of their high natural gas, coal and electricity costs (IEA, 2013). The disparities in regional energy prices and feedstock prices are already influencing investments decisions and company strategies, making the United States a more attractive place to invest than Europe and Asia.

New strategic alliances

During recent years, the booming NGL development has led to new strategic alliances between producers, pipeline companies and processors to extract the liquids from formations such as Marcellus and Utica and to deliver the high-value hydrocarbons to US and foreign markets.

The NGL developments are also attracting new foreign companies and investors. International investors have been increasingly participating in the shale gas upstream activities and in LNG facilities. A second wave of international joint ventures and investments in the NGL-midstream sector is now taking place.

The new pipelines are reshaping the United States NGL landscape, connecting the liquids-rich shale plays with fractionation plants and storage capacity, which is mainly concentrated in major NGLs hubs of North America such as Mont Belvieu (Texas), Conway (Kansas), Edmonton (Alberta) and Sarnia (Ontario). The pipeline projects follow different commercial strategies and aim at different domestic and international markets (Table 14).

In 2013, Oneok Partners LP finalised its 60 kb/d Bakken NGL pipeline. This connection runs 600 miles (966 km) from Oneok and other gas-processing plants in the Bakken region to a northern Colorado interconnection with the Overland Pass pipeline, for further shipment to Conway and the Gulf Coast. In July 2013, the company completed its right-of-way acquisition process and entered the construction phase of the Sterling III Pipeline, which will transport NGLs from Medford, Oklahoma to Mont Belvieu, Texas for refining.

Table 14 NGLs corridors

NGLs Corridors	Capacity (b/d)
From the Bakken shale to the Midcontinent	60 000 - 135 000
From the Midcontinent to the US Gulf Coast	543 000 - 660 000
From the Rockies to West Texas and Conway, Kansas	289 000 - 415 000
From West Texas to the US Gulf Coast	580 000 - 640 000
From the Marcellus and Utica shales to the US Gulf Coast	200 000 - 400 000

With the Appalachia-to-Texas Express Pipeline (ATEX) pipeline, Enterprise Products Partners will be able to transport NGLs from the Marcellus-Utica Shale region of Pennsylvania, West Virginia and Ohio to the Texas Gulf Coast near Houston. With this connection, the company will have access to the nation's premiere NGL storage facility in Mount Belvieu, Texas. The 425 kb/d pipeline is expected to begin initial deliveries in the second quarter of 2014. The company is also developing an 82 kb/d Rocky Mountain expansion of its Mid-America pipeline system in New Mexico. In July 2013, the United

States Bureau of Land Management approved this expansion. Through this connection, new liquids production can be brought from Uinta, Piceance and the Great Green River basin to Mont Belvieu.

In May 2014, the joint venture of Williams Cos. and Boardwalk Pipeline Partners LP decided to postpone the Bluegrass pipeline to transport mixed NGLs from the Marcellus and Utica shales to the US Gulf Coast petrochemical markets, primarily due to insufficient firm customer commitments. Phase one of the pipeline had been designed to provide customers with 200 000 b/d of mixed NGLs take-away capacity in Ohio, West Virginia and Pennsylvania. With phase two, the two companies aimed to increase capacity to 400 000 b/d. The pipeline would deliver mixed NGLs from the producing areas to proposed new fractionation and storage facilities that would in turn, connect with petrochemical facilities and product pipelines along the coasts of Louisiana and Texas. In addition to these domestic markets, the fractionation and storage facilities were expected to connect with a proposed new LPG export terminal that, based on current market conditions, would offer producers an attractive option for exporting propane and butane. Williams and Boardwalk were targeting the project to begin operation in late 2015. After the postponement, the companies continue to talk with potential customers regarding the firm contractual commitments needed to support any future investment.

Sunoco Logistics Partners LP and MarkWest Energy Partners LP's Mariner West pipeline will move 65 000 b/d of ethane from the Pennsylvania section of the Marcellus shale to Sarnia, Ontario, Canada. The pipeline came online in early 2013. Mariner East will follow in the first half of 2015, moving 40 000 b/d of ethane for export from Sunoco's Marcus Hook, Pennsylvania, terminal. The pipeline will have a total initial capacity of 70 000 b/d, but it could be expanded if demand grows.

In July 2013, the United States State Department approved construction of the North Dakota portion of a gas pipeline from Tioga into the Canadian province of Alberta, which was completed in 1Q 2014, with the first shipment reaching Alberta in early May 2014. The Vantage pipeline will move 40 kb/d to 60 kb/d of purity ethane to Edmonton-Fort Saskatchewan from the Williston basin (which includes the Bakken shale) by the end of 2014. The completed pipeline extends 400 miles (644 km), bringing ethane to facilities in Empress, Alberta, Canada, where it connects into the Alberta Ethane Gathering System.

The US Gulf Coast as the centre of the NGLs boom

The US Gulf Coast will continue to be the country's primary hub for fractionation and petrochemicals production, as well as for exporting propane. The US Gulf Coast also remains at the centre of the NGLs boom from shale gas. The region's concentration of pipelines, fractionation and cracking infrastructure, coupled with its seaborne access to overseas markets, makes it the natural epicentre of the US NGLs industry. The industry in Louisiana and Texas will have direct access to shale gas from the growing supply basins. One of the main initiatives is the South Louisiana Expansion (SOLA) pipeline project, which is designed to transport natural gas from various supply basins, including Eagle Ford, South Texas, the Gulf Coast, and offshore US Gulf of Mexico.

An important component of the NGL production and marketing process is storage. Since NGLs are not always consumed when and where they are produced, appropriate storage locations are important. In the United States, NGLs are usually stored in salt dome formations, most of which are found in East Texas, near Mont Belvieu. Not surprisingly, most of the petrochemical production capacity and refiners, (both major NGL consumers), are also located in this region. Because of this central role, many new projects are designed to move liquids from the price-disadvantaged trading hub at Conway, Kansas to the preferred destination at Mont Belvieu.

As the largest NGL-consuming area in North America, the Mont Belvieu market is the "price setter", or NGL price reference point for the NGL markets in North America, including the price for Canadian liquids. The primary factor affecting the Mont Belvieu price is the demand for petrochemical feedstocks, leading to a higher price than in the rest of the country. These price differentials act as a major incentive for shippers to move NGLs to Mont Belvieu. Around 75% of the new production of NGLs will be transported to fractionators in Mont Belvieu, and some of these volumes will be exported. However, more distant producers must figure in higher transport costs, which can reduce their netbacks to Mont Belvieu.

The United States as a major NGL exporter

In the foreseeable future, the United States could become an important NGL exporter. Under current US federal regulations, exporting crude oil (including wellhead condensate) is prohibited, and LNG exports are only permitted under certain conditions or with certain special approvals. In contrast to this restrictive legislation, NGLs (including pentanes plus aka natural gasoline) can be freely exported without special export requirements. Canadian oil producers are reliant on US exports of pentanes plus for use as diluents, as Canadian indigenous production is insufficient.

Several companies are working to expand the capacity of US export terminals to increase the exports of NGLs (particularly propane) by ship to Europe and of natural gasoline to Canada by pipeline. The energy boom is reshaping the country's industrial landscape and also the ranking of the largest US exporting regions. In 2013, the greater Houston area, located along the Gulf Coast region in Texas, replaced New York City as the largest US goods-exporting region on the back of booming petroleum products exports. The second-largest category of Houston's exports is chemicals, worth USD 31 billion last year, which benefited from cheap natural gas used as a raw material for many commonly used products.

Based on the supply-demand balance of the United States, the expectation is that most of the new propane production will go to markets outside the United States. The United States already exports about 15% of total propane supply (ICF International, 2013) and it began exporting ethane from the Marcellus shale play to Canada in July 2013 and from the Williston Basin to Canada in May 2014. Ship-home exports of ethane to Ineos' European cracking facilities are expected to commence in 2015.

Expansion of Panama Canal will allow increased NGLs trade with Asia

With the opening of the new Enterprise Houston export terminal in March 2014, several US cargoes of LPG have made their way to Japan every month. Major Japanese importers and traders such as Astomos Energy, Eneos Globe, TonenGeneral, Idemitsu Kosan and Iwatani Corp. have concluded multi-year term supply deals with Enterprise Product Partners. By doing so, they are not only benefiting from these imports to diversify their supply sources but these importers are also increasing their "bargaining power" in front of the traditional LPG exporters from the Middle East. The increasing LPG demand in Asia is coming from the petrochemical sector and other industrial segments, and from demand for city gas supplies. City gas companies are using LPG to increase the calorific value of gas.

Over the medium term, an increase of NGLs exports to Asia is expected, especially after completion of the Panama Canal expansion after 2015, which will allow larger shipments. The expansion of the canal makes the transportation of goods through the route around South America unnecessary, reducing the distance to about 9 000 miles (14 500 km) from 16 000 (26 000 km) and the duration of the journey by six days between Asia and the United States Gulf coast. A shorter route is likely to reduce the transportation costs, but this depends on the Panama Canal's transit fee which at this stage is still unknown. The cargoes will not only go to Asia; some of them will also be directed to Europe.

China cements its position as one of the largest natural gas producers

In 2013, China became the sixth-largest producer of natural gas in the world as production reached 117 bcm, moving up from seventh position in 2012. Gas production is foreseen to rise to 193 bcm by 2019, implying a 76 bcm additional production from 2013 levels. This additional output will only cover 51% of additional demand occurring during the same timeframe. While conventional gas production is expected to increase moderately, unconventional gas resources will represent the backbone of additional output. Besides tight gas, CBM and shale gas, one should not dismiss gas produced from coal gasification, which has become a new feature in the past two years (Box 12). Despite the current low levels of shale gas production, China's target of 6.5 bcm per year by 2015, which previously seemed beyond reach, now looks more achievable (see section on global unconventional gas developments). Also in 2013, China's natural gas portfolio grew when China's MLR announced the discovery of methane hydrates in the Pearl River Mouth basin with estimated resources of 100 to 150 bcm of natural gas.

The Ordos and Sichuan basins continue to be the backbone of the country's natural gas industry, with half of the production in 2013 coming from these two areas. At the same time, more discoveries throughout 2013 and 2014 are expected to sustain the healthy growth, although these additional reserves will be lower than those in 2012. The recently discovered Anyue gas field is expected to produce up to 4 bcm of gas during the first phase, with a potential production rate of 10 bcm per year upon completion of the second phase of the project. At the same time, the recent price reform in the country as announced by the government is expected to further boost China's natural gas production. In July 2013, the government announced a gas price revision for non-residential use that increases the price for existing gas supply by around 15%. A new pricing mechanism for residential use will be introduced by the end of 2015. Although the reform is primarily due to the increase in LNG import prices that resulted in operating losses for Chinese companies, it will also benefit development of the unconventional gas industry, notably shale gas, which currently contributes a very small percentage to the overall domestic production, despite huge estimated resources.

A wildcard for China's natural gas industry is the extent of the abundant gas reserves located at areas between China and its neighbouring countries – namely the East China Sea shared with Japan, and the South China Sea shared with ASEAN countries. China signed an agreement with Japan in 2008 to jointly develop the areas in the East China Sea; however, to date, no reports have been made of development in the area. Compared to the East China Sea, the South China Sea plausibly carries more weight due to its bigger potential reserves and the number of countries involved. While the East China Sea has estimated recoverable resources of around 28 bcm to 56 bcm of gas, the South China Sea's estimated resources stand at 5.3 tcm, although the majority of those are located in undisputed areas. Because it may take considerable time before China and other countries can reach a consensus, the most practical option to monetise gas in the areas and thus ensure a win-win situation would be through joint co-operation as practised between Thailand and Viet Nam and between Brunei and Malaysia.

Box 12 Coal-based SNG

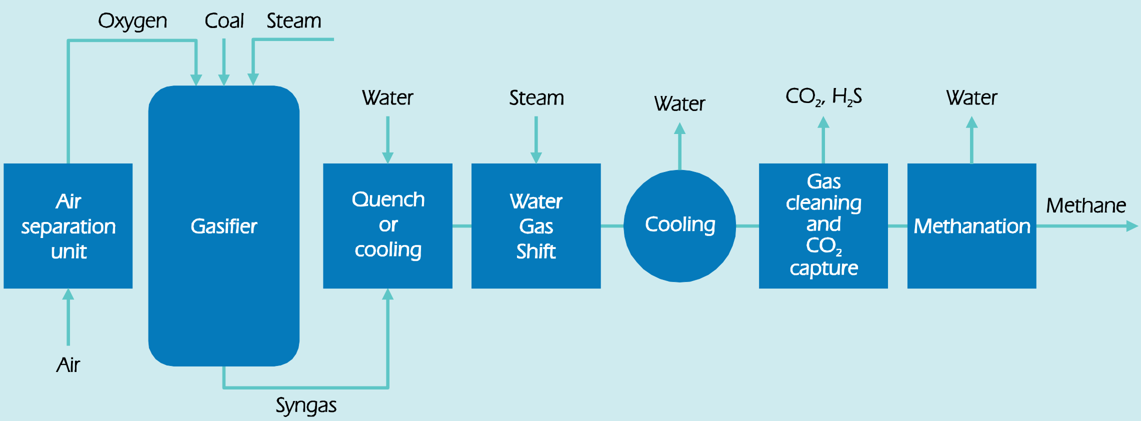
Coal gasification is a well-known technology that has been applied for many years. Fischer-Tropsch synthesis, developed in Germany during the early decades of the 20th century, has been improved and commercially used by Sasol in South Africa to produce synthetic liquid fuels since the 1980s. A few Integrated Gasification Combined Cycles (IGCC) units are working around the world. In an IGCC, the synthesis gas produced by coal gasification generates power in a combined-cycle plant. This requires higher investment costs than a standard pulverised coal plant, but, on the other hand, the process is more efficient, with lower fuel costs and emissions. Coal gasification has been massively applied in China during the last decade to produce chemicals and fertilisers.

Despite all these examples of coal gasification, the idea to produce synthetic natural gas (methane) from coal is, in principle, counter-intuitive. Several sound explanations, however, are available. One of the main objectives of Chinese energy policy is to reduce local pollution. Reducing smog in the big cities is an issue that has the public opinion behind it and that the government needs to tackle. Natural gas can play a key role because it is much cleaner than coal, especially in relation to local pollutants. It is also cleaner than oil for use in transportation. Large amounts of *stranded* coal can be found in China, i.e. low-cost coal far from consuming centres. That coal is ideal for gasification, because inland transportation of coal may add significant costs, especially if the coal has a low calorific value. It is not surprising, therefore, that most of the SNG projects are located in Xinjiang and Inner Mongolia, where large reserves of stranded coal are located. Finally, one rationale for coal gasification involves the economy. Domestically produced SNG will mostly displace more expensive imported gas, with clear advantages in terms of jobs and wealth creation energy security. Moreover, current coal and gas prices make coal-based SNG fully competitive.

The process

The coal gasification process produces methane from coal (Figure 47).

Figure 47 Coal gasification process



First, in the gasifier, steam and oxygen are introduced together with the pulverised coal.

$$2\ C + H_2O + ½\ O_2 \rightarrow 2\ CO + H_2$$

The mixture $CO + H_2$ is called synthesis gas or syngas. Its calorific value is approximately between one-fifth and one-third of methane. It can be used directly to produce electricity in a turbine, as feedstock to produce chemicals or liquid fuels, or to produce methane. In this last case, after cooling, water gas shifting (WGS) is required to get the adequate proportion of hydrogen in the mixture, which involves the following reaction:

$$CO + H_2O \rightarrow H_2 + CO_2$$

Box 12 Coal-based SNG (continued)

After the shifting, gas is cooled and cleaned before the methanation:

$$3\ H_2 + CO \rightarrow CH_4 + H_2O$$

Following dehydration, methane can be injected into the pipeline. Most of those reactions require catalyst and are exothermic. Hence, cooling is a very important part of the process.

Although WGS in combination with former methanation is the most common process to produce SNG, direct methanation without the WGS reaction can also be used. In this case, the syngas and hydrogen react to form methane and carbon dioxide (CO_2).

$$2\ H_2 + 2\ CO \rightarrow CH_4 + CO_2$$

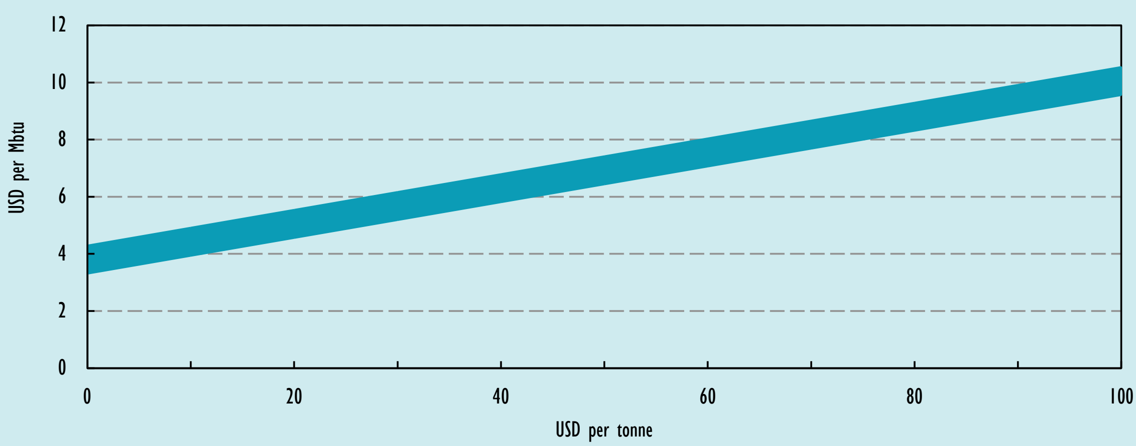
Water is pivotal for SNG production as both an input of different processes and for cooling. Recycling and air-cooling systems may reduce consumption dramatically; yet, needs for the process are still significant (over 3 m^3 of water, and probably from 5 m^3 to 8 m^3 depending on design and efficiency of the process, per each thousand cubic metres (mcm) of SNG). The need for water might result in the biggest impediment for SNG deployment, because some of the areas with large potential are also arid regions, i.e. Xinjiang and Inner Mongolia.

The economics

The main component of cost in coal-based SNG is coal, and the break-even price at which the process is profitable is defined by the gap between coal cost and gas price (Figure 48). One cubic metre of gas typically requires about 2.5 kg to 3 kg of coal (obviously, 1 mcm requires 2.5 to 3 tonnes of coal), depending on the calorific value of coal and the efficiency of the process. Therefore, current Asian gas prices at over USD 500/mcm, combined with competitive coal, at USD 30/tonne mine mouth in places such as Inner Mongolia or Xinjiang, provide a huge margin for the profitability of the projects. Initial capital costs are also significant and can be typically estimated at USD 1/cubic metre.

The main operation and maintenance costs are personal wages, catalysts and filters, as well as power consumption, because pumps and other auxiliary systems, especially the air separation unit, are power-intensive. Water and CO_2, if priced, could also contribute significantly to the cost of SNG.

Figure 48 Estimated gas price break-even cost depending on the coal price



Box 12 Coal-based SNG (continued)

Despite the absence of data on costs for a coal-based SNG plant, data from different gasification plants have been put together to estimate SNG costs depending on costs of coal used in the gasification process. Indeed, this calculation can only be a gross estimate, because many components are plant-specific and others are volatile, i.e. coal quality, the efficiency of the process, capital discount rates, dollar-to-local currency ratio, etc. Likewise, first-of-a-kind costs are expected to be higher than those of plants once the technology has been deployed. Moreover, given the versatility of syngas, the design of the plant may allow using part of the syngas for other purposes. Furthermore, by-products can be a burden for the plant if they must be disposed of in an environmentally friendly way, or they can be another source of revenues if they can be marketed. A good example is CO_2. In places with a carbon price, it is, in principle, a cost. However, if CO_2 can be sold (for example, for enhanced oil recovery), the economics work the other way round.

The projects

Currently, the largest commercial plant of coal-based methane production in the world is the Great Plains Synfuels Plant in North Dakota, United States, owned by the Dakota Gasification Company, where 16 000 daily tonnes of coal are introduced in 14 gasifiers to obtain a multi-product output, including ammonium sulphate, phenol, CO_2 for enhanced oil recovery and of course, methane. Profitability calculations for this plant cannot be transferred to other places, i.e. China, for several reasons. First, a significant share of revenues is made from CO_2 sales, but this arrangement will not be the case for most of SNG projects in China, where CO_2 will be a burden rather than a source of additional revenues in the medium term. Capital expenditures in Great Plains Plant are reduced, because the Dakota Gasification Company bought the plant after an administration process. Last, but not least, the US gas market is not a good benchmark, with gas price levels well below levels elsewhere.

Table 15 Selected projects under development in China

Company	Location	Capacity (bcm)
Datang	Inner Mongolia (Chifeng)	4
Ximeng	Inner Mongolia (Ordos)	4
CNOOC	Inner Mongolia (Ordos)	4
BEGCL	Inner Mongolia (Ordos)	4
Huineng	Inner Mongolia (Ordos)	2
Hebei CIG	Inner Mongolia (Ordos)	4
Guodian	Inner Mongolia (Xinganmeng)	4
Datang	Liaoning (Fuxing)	4
CNOOC	Shanxi (Datong)	4
CPI	Xinjiang (Yili, Huocheng)	6
Kingho	Xinjiang (Yili)	6
Xinwen Mining	Xinjiang (Yili)	2
Sinopec	Xinjiang (Zhundog, Changji)	8
Huanen	Xinjiang (Zhundog, Changji)	4
Longyu	Xinjiang (Zhundog)	4
Suxing	Xinjiang (Zhundog, Changji)	4
Guanghui	Xinjiang (Zhundog, Changji)	4
China Coal	Xinjiang (Zhundog, Changji)	4

Box 12 Coal-based SNG (continued)

In China, Datang's plant in Chifeng, Inner Mongolia and Kingho's plant in Yili, Xinjiang are currently in operation, with a combined production close to 3 bcm of synthetic natural gas in 2013. While it is difficult to know which projects will be built and how long development will take, projects listed in Table 15 are considered likely to start during the outlook period. Note that "capacity" in this case refers to final capacity once the whole project has been completed and hence it is not the capacity reached in 2019. Besides, the projects require gas pipelines to transport the gas. Finally, despite completion of these plants being considered likely, some delays and failures should be expected. This is why SNG production is expected to be only around 40 bcm by 2019, well below the 76 bcm of combined capacity of the projects listed in Table 15.

Conclusions

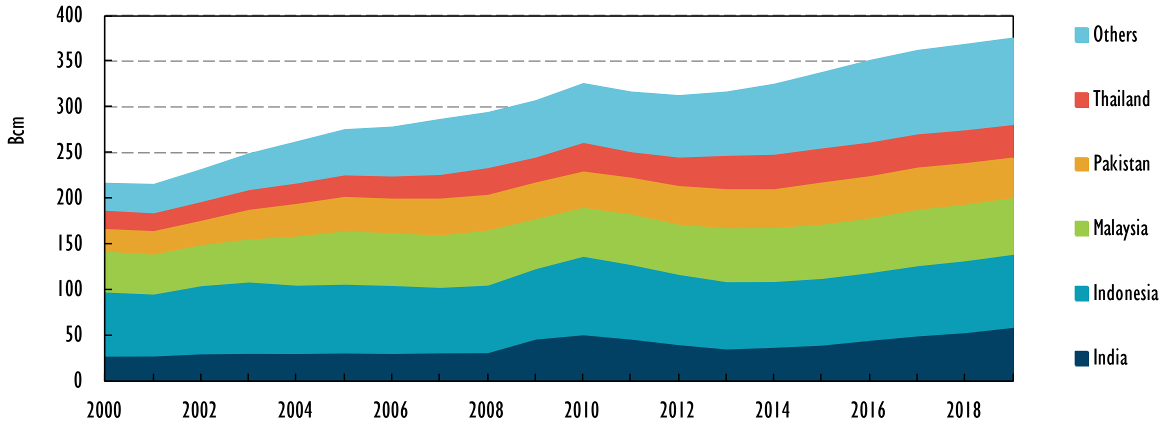
Given the economics of the process, synthetic natural gas from coal gasification can be deployed where stranded coal occurs. Whereas natural gas is considered a clean fuel, especially to tackle the issue of smog in big cities, coal gasification is a more CO_2-intensive technology (CO_2 emissions from natural gas use are approximately one-third to one-half that from coal gasification product use). Producing one cubic metre of SNG releases approximately 3 kg of CO_2. This is not only an environmental issue, but also an economic one if a CO_2 pricing system is in force. However, given that the stream after shifting is CO_2-intensive, CO_2 capture is simple. Therefore, if CCS is deployed, coal gasification will have a significant advantage. Consequently CO_2 and capital requirements are not likely to stop coal-based SNG in the coming years. However, the process is water-intensive, and this is the real issue in some of the most promising regions in China.

Non-OECD Asia (excluding China)

Non-OECD Asia's gas production is set to grow from an estimated 313 bcm to 357 bcm by 2019, which is quite impressive (Figure 49). Almost half of this increase comes from India's production recovering, while other increases come from Papua New Guinea and its new LNG liquefaction plant, from Myanmar increasing to export to China, and from Viet Nam. Elsewhere, most other countries are experiencing declines in their domestic gas production. Besides dwindling indigenous gas reserves, the unfavourable investment climate contributes to the decrease in exploration activities to replenish and sustain production, because an unattractive price regime and ambiguous regulations deter participation of foreign investors in the affected countries. The main uncertainty in this outlook is how India's gas production will behave after its abrupt fall since 2010. A recovery is likely, but its pace and curve are still highly uncertain. This report's outlook is relatively optimistic, anticipating a recovery of around 13 bcm over the forecast period, or one-third of the region's incremental output. New production would benefit from a pricing reform. Meanwhile, Indonesia and Malaysia, the two main Asian gas producers, will see their output slightly increase over the coming years. Bangladesh and Pakistan both feature modest production growth, while the two countries still struggle with gas shortages. In contrast, Thailand's gas production growth will abruptly slow over the coming years.

Despite this region's estimated large resources of unconventional gas, their development is a long-term endeavour, and it is still premature to rely on shale gas for the industry's future, given the geological and geographical constraints that the countries face to monetise the gas, over and above the existing challenges to the natural gas industry (see section on global unconventional gas developments).

Figure 49 Non-OECD Asia gas production, 2000-19



India's total conventional production is expected to start increasing again as soon as 2014. Even if it has been postponed, the announcement of a new price appears to be influencing development of India's unconventional gas as well. ONGC has announced that the company plans to start commercial production of shale gas from its Gujarat field this year. Despite clearing the first hurdle on price, the plan seems rather ambitious, because the country faces other major obstacles, namely lack of infrastructure, technology, regulatory framework, and availability of land and water.

Pakistan, like other Asian countries, is also struggling to meet its domestic demand. In spite of the steady growth in its indigenous gas production, which saw an increase in production of more than 60% from early 2000, the country's gas reserves are depleting rapidly. The country is having to turn to LNG imports and international gas pipelines to overcome its shortages. In 2013, Pakistan produced an estimated 42 bcm of natural gas, which was 1% more than in 2012. However, this increase was insufficient to support domestic demand, as the country experienced a gas shortage of up to 29 bcm in 2013.

Despite the current state of affairs pertaining to the depletion of gas reserves in the country, several discoveries were reported in 2013, particularly in the Sindh Province, which holds about 70% of natural gas reserves in Pakistan. In May 2013, Eni, the country's largest foreign gas producer, announced a new gas discovery in the Sukhpur Block, located in Sindh Province, with a flow rate equivalent to 0.3 bcm per year during production testing. Pakistan Petroleum Limited, which is 70% owned by the government, made two new discoveries in the Gambat South Block, also in the Sindh Province, in June and July 2013. Other notable discoveries in the Sindh Province were also announced in 2013, such as OMV's gas discovery and Pakistan Oilfields Limited's discovery.

Elsewhere, Myanmar's natural gas production is expected to increase by almost 100% with the commencement of three new gas fields, namely Mya, Shwe and Zawtika. Following the company's first production in Myanmar through Mya field in July 2013, Daewoo International announced production from its Shwe field in January 2014, which brings the total production from these two fields to 5 bcm per year. At the same time, PTTEP is developing the Zawtika field, which will add another 3 bcm per year to the country's total production when it comes online by mid-2014. The industry is also expected to benefit from increasing involvement by foreign investors since the establishment of a new government in 2011 after the dissolution of the military junta that ruled the country for almost half a century. Myanmar's 2013 highlight was the announcement of the results of its first licensing round since the lifting of the US sanction, when the government awarded contracts for 16 onshore blocks in October 2013. Meanwhile in Thailand, the natural gas output increased slightly in 2013, although its reserves decreased. The country's reserves are expected to last less than ten years in the absence of new discoveries.

2014 could be a pivotal point for Indonesia's ailing natural gas industry

Indonesia is a seasoned player in the natural gas industry and has been present in the global LNG market since 1977. Production is expected to remain relatively stable, varying around 70 bcm over the forecast period. The country is currently the largest gas producer in the region, and benefits from ample gas reserves, estimated at 2.9 tcm as of end-2012. Indonesia was the world's largest LNG supplier for three decades before Qatar surpassed it in 2006. Indonesia is now the fourth largest LNG supplier. But Indonesia's natural gas industry may be following the same fate as its oil industry as it moves from net exporter to net importer. Over the past few years, natural gas production has been hovering between 75 bcm and 85 bcm, without any clear pattern. Consequently, the country has been facing a shortage issue, since the domestic appetite for natural gas necessitates re-routing the gas supply intended for LNG plant to its domestic market. This gas production trend has resulted in reduced output in Indonesia's LNG exports, so that the country missed several contractual commitments to its long-term buyers, notably in 2005, when Indonesia's Pertamina decided to delay 51 LNG cargoes. Indonesia's LNG production has been decreasing since then, and the trend is expected to persist.

Indonesia's struggling natural gas production continued in 2013, as the country managed to produce 70 bcm, 9% less than production in 2012. Exploration activities have not been successful, since only a few discoveries were reported in 2013, notably in Sumatra, where new gas was discovered in the Block A PSC and the Jabung Block. The downward trend is expected to continue; Pertamina announced that it will produce 17% less LNG in 2014 than in 2013.

Despite already having one LNG regasification terminal in Java Bay operational since 2012 and two other LNG regasification terminals under construction, Indonesia is still actively looking at developing additional LNG liquefaction projects. Several new export projects currently on the way will nevertheless bring more gas to the domestic market through the implementation of Domestic Market Obligations (DMO), which requires producers to provide 25% of production for the domestic market: the East Natuna project, Sengkang LNG, Donggi-Senoro LNG, and the proposed Abadi LNG and Tangguh third train. Previously known as Natuna D-Alpha, the East Natuna gas field holds recoverable gas reserves of about 1.3 tcm (46 tcf), making it the largest gas field in non-OECD Asia. The project has been in planning for decades; however, the nature of its gas (it contains 70% carbon dioxide), coupled with several other issues, has resulted in a delay in developing the field. The gas from the field is expected to support Indonesia's domestic market, besides being the backbone for the Trans ASEAN Gas Pipeline (TAGP) project. In the face of previous delays to the signing of PSCs, the government is expected to grant the PSC in 2014 with a few incentives to support the development of the project, such as a longer PSC period, tax breaks and an improved production sharing split to the producers.

In spite of the decline in its indigenous gas production, Indonesia is also blessed with abundant unconventional gas resources from shale gas and CBM, but significant development seems unlikely in the medium term (see section on global unconventional developments). The current regulatory framework, which is perceived as being complicated and unclear, seems to discourage industry players from investing in this new venture, notably in CBM, where the laws overlap with those of natural gas and coal. The dissolution of the country's upstream regulator BPMigas in November 2012 by the Constitutional Court reflects the current uncertainty (since then replaced by new regulator SKK Migas). The existing gas law, which includes an obligatory portion for domestic use through DMOs seems to be aggravating the issue, hindering foreign investment into the country. The regulated price regime, which results in the price of domestic gas being cheaper than the production cost, is discouraging investments, particularly in this new venture, where the cost of extracting unconventional gas is higher than for the conventional one. With growing domestic demand and the implementation of DMO, the price reform is of the utmost importance in the government's to-do list to guarantee the future of country's unconventional gas.

Indonesia is faced with daunting tasks to develop its unconventional gas industry, from providing adequate infrastructure to implementing reforms to the regulatory framework and domestic price regime. Until all these measures are in place, it will be very difficult, but not impossible, for unconventional gas to become the second lease on life for Indonesia's ailing gas industry, despite the huge potential in its unconventional gas resources.

Furthermore, the government had also considered imposing a moratorium on the signing of new contracts for natural gas exports as part of the initiatives to support the increasing domestic demand anticipated by the Energy and Mines Ministry in July 2012. However, the Ministry ruled out the move later in the same month. A similar moratorium first occurred in 2005 and resurfaced several times in subsequent years, notably in 2009, initially prohibiting Donggi-Senoro LNG from exporting the gas. The project eventually obtained the government's approval in 2010 when it agreed to set aside 30% of volumes for domestic consumption. Despite numerous attempts to ban the country's gas exports, such a ban seems unlikely to happen in the foreseeable future, given the considerable revenue that the government receives from the export sector and the big gap between the international and current domestic market prices.

A merger between Pertamina and Perusahaan Gas Negara (PGN), the country's largest natural gas transportation and distribution company, has also been discussed. But little support seems to be available for this to happen.

Is the revival of Malaysia's natural gas industry attainable?

Malaysia is considered to be a veteran in the LNG industry, having entered into the global LNG market back in 1983 when its first liquefaction plant in Bintulu delivered its first LNG cargo to a Japanese buyer. Since then, Malaysia has been expanding its market presence and is currently the world's third-largest LNG supplier behind Qatar and Australia based on 2013 data. Like Indonesia, Malaysia is experiencing the decline of its domestic natural gas production. The increase in domestic demand aggravated the issue and resulted in gas shortages in 2011 that caused the electricity utility companies to purchase alternative fuels to compensate for the shortage.

In contrast to Indonesia's performance, Malaysia enjoyed a better year in 2013 as its domestic production bounced back to 65 bcm, an increase of 4 bcm compared to the previous year's production of 61 bcm. This positive growth is anticipated to be sustained to reach around 70 bcm, thanks to continued gas discoveries in 2013 following a similar success story in 2012. Several notable discoveries were made in 2013; this success is attributed to the amendment of the revised gas terms in Malaysia. Unlike its neighbour Indonesia, which sits on large deposits of unconventional gas, Malaysia's natural gas industry has been rejuvenated by the enhanced exploration activities in deepwater and stranded fields, the two areas that were previously overlooked due to technological and economic constraints.

Besides supply from domestic gas production, Malaysia has been importing gas from Indonesia and the Joint Development Area with Thailand to cater to its domestic demand. To address both the decline in domestic gas production and rising demand, Petronas, the national oil and gas company, started importing LNG in 2013. However, it announced that Malaysia is expected to be LNG import-free by 2016, when its new floating LNG and Bintulu's Train 9 come on stream. The development of LNG regasification terminals in Malacca and Johor is essential because the demand is centralised in peninsular Malaysia, where most of the ageing gas fields are located, whereas east Malaysia's gas fields are mainly dedicated for export through Bintulu's LNG liquefaction plant, owing to the relatively small demand by the local market.

Meanwhile, Malaysia is taking proactive measures to address the decline in indigenous production. In 2011, through the Petroleum Income Tax Act Amendment Bill, the government introduced tax incentives for exploration activities in deepwater, marginal and stranded fields, which include a reduction of the petroleum income tax from 38% to 25% and an increase in the reimbursement for a company's original investment from 70% to 100%. These incentives have contributed to the boost of exploration activities in fields that were not previously commercially viable. The development of nine stranded gas fields for the North Malay Basin project gives a new lifeline to the domestic gas market through supply of 1 bcm per year during the first phase, to reach a maximum production rate of 3 bcm per year in the second phase. The new gas terms support the monetisation of stranded gas fields through floating LNG technology. With the country's first floating LNG project currently under construction, the second floating LNG project is under way in the Rotan field, a deepwater and stranded gas field offshore Sabah. Petronas and Murphy, the field's partners, reached FID on the project in February 2014, and the project is expected to be online by 2018.

Besides incentives in the deepwater, stranded and marginal fields, Malaysia is also focusing on the enhanced oil recovery (EOR) technology to rejuvenate the existing fields as part of the initiatives under the Economic Transformation Programme (ETP)'s National Key Economic Area (NKEA) for oil, gas and energy. However, the technology is mainly for oil and benefits gas when associated gas in involved.

The ongoing initiatives to enhance the industry have resulted in immediate success. Malaysia was ranked fourth in terms of oil and gas reserves added in 2012. The national oil and gas company is also moving away from the traditional practice of using feedgas with low CO_2 content for the LNG liquefaction projects. The company is currently constructing an additional train to its existing LNG plant in Bintulu, the Train 9 project, which will be able to receive gas with CO_2 content of 20% to 30% compared to the current 2% to 6% of CO_2 that the plant is receiving from upstream at the moment. The facility's upgrade is expected to spur more exploration activities for gas fields that contain similar high CO_2 content, which were overlooked previously due to that technical constraint. The natural gas industry, which was languishing a few years ago due to the decline in domestic production, is expected to be revitalised thanks to the ongoing initiatives taken by both the government and industry players in overcoming the supply issues.

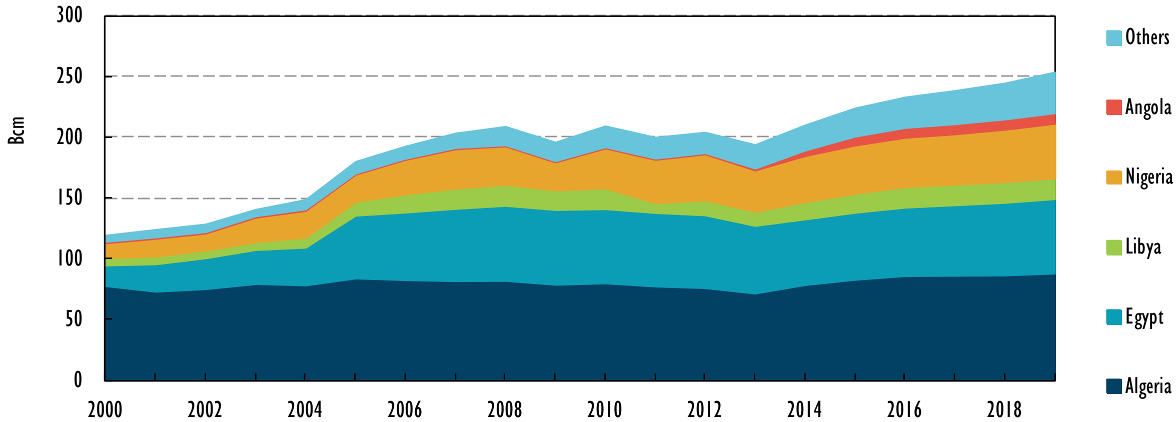
Africa

Africa's gas production dropped by 4% in 2013, which, considering the region's reserves, is quite disappointing (Figure 50). Africa's output is anticipated to rebound by around 60 bcm over the forecast period, reaching close to 255 bcm. Certainly the continuing fallout from the "Arab Spring" played a role in driving the decline in 2013, but the seeds for this lack of upside in production patterns had been planted long ago. Their roots are in the policies of the three main producers – Algeria, Nigeria and Egypt. Depending on the country, discouraging fiscal terms, low domestic gas prices, unpaid bills, political uncertainty, and priority given to the domestic market versus exports are among the main issues. Despite many discoveries in Algeria and Egypt and the abundance of resources in Nigeria, none of these countries seems to be able to provide a substantial addition to existing gas production. Other above-ground issues, such as war, remoteness or small size of the resources, political instability and failure to put in place a sound investment framework are the factors responsible for lack of output growth in other African countries.

Moreover, a serious risk has now arisen to deter further investments in developing countries, particularly in Africa, if potential investors fear an "Egyptian syndrome". Upstream investments have often been based on the tacit agreement that part of the gas resources would be earmarked to the low-priced domestic gas market, while the rest would be exported to higher-priced markets, providing the cash flow necessary to ensure sufficient rates of return for the investors. But since late 2012 in Egypt, the Damietta liquefaction plant run by Spain's Union Fenosa has been idle while BG's Idku has been running at around one-third of its capacity. The *force majeure* announced by BG in late January 2014 raises the question of whether and how much Egyptian LNG will continue to be exported in 2014 and later, as gas is increasingly being diverted to the domestic gas market. The situation is aggravated by payment delays from the national Egyptian gas companies to foreign producers. But the liquefaction plants are not even ten years old, a time insufficient to enable projects to recover their investments (estimated at USD 2.4 billion at that time). While investment costs around the world are increasing, investors may think twice before investing in some developing countries with uncertain demand development. Libya could have faced the same booming demand, as the small domestic market was to be boosted by new industries and power plants along the coast. The war put an end to the growth of domestic demand, which has still not recovered, nor have exports of pipeline gas to Italy. Mixed signals are coming from investors: some companies, such as PGNiG, are exiting, while others are confirming increased investments. The Libyan NOC is reported to be planning to allow foreign investors to take 40% in joint ventures dedicated to shale gas projects; that share would be twice that prevailing under the Qaddafi regime.

The tide, therefore, has turned in North Africa, with governments still trying to attract upstream investors in the face of political instability, terrorism issues and the fear of upsetting the population by raising gas prices. The governments have few choices to overcome these circumstances. One option is to increase gas prices for industrial users, for which the alternative is oil products – to the extent that those are not subsidised either. An increase of residential, transport or power prices could potentially be politically sensitive. Another option is to guarantee producers' revenues through export revenues, which means that exports should not be disrupted. This is easier said than done when a population suffers from power blackouts. But here is also the untapped potential for energy efficiency, both in the industrial and power generation sectors, which could allow both a reduction of domestic demand and an increase of prices, with potentially limited impact on the end user. Stronger investments in renewable energies could also reduce the future call for combustible fuels. Meanwhile, some countries could turn to imports while continuing to export LNG: Egypt is about to engage on that path, following the example of countries such as Indonesia, Malaysia, Oman and the United Arab Emirates.

Figure 50 Africa's gas production, 2000-19



When it comes to exports, LNG seems the only appealing option. North Africa's exports by pipeline no longer seem attractive. The main market, Europe, is facing substantial difficulties with uncertain demand developments. Even though import needs are foreseen to increase by around 25 bcm over 2013-19, the battle is fierce between Russian, Norwegian, now Caspian gas producers and LNG exporters. Obviously, pipeline exports are a 20-year investment, and project sponsors should look at a longer timeframe: European imports are deemed to increase by 140 bcm in the *WEO 2013* New Policies Scenario. But other factors enter into play because North Africa is tied by pipelines to Iberia and Italy. Spain has been one of the most devastated gas markets, with demand diving by 25% since its 2008 peak. Little hope exists for a recovery soon in that country, and gas supplies are notably stranded in the Iberia peninsula due to the limited interconnection to France. From 2019 onwards, the TAP pipeline is planned to provide fresh Caspian gas supplies to Italy, while the country's third LNG terminal just started. Caspian supplies are understood to be partially linked to the TTF index, which could make them more appealing in a few years' time. Importing countries can hedge by using both pipeline and LNG, but so can exporters: Algeria is re-opening LNG exports at Skikda even as pipeline exports to Spain are low.

The future of Africa's production is likely to rely increasingly on the southern part of the continent, in both Western and Eastern Africa, even if there is still a long way to go. Angola is visible proof that even in a country with a long oil history and the presence of majors with a long track record of project development, gas developments do not always proceed smoothly. Initiated in the late 1990s, the LNG project in that country came online only in mid-2013, with a one-year delay on the planned start of the liquefaction plant. The LNG plant is located near the historical oil-producing basin (Soyo). In contrast, Mozambique's new gas resources are located 1 600 km away from the capital city, away from any major road and transport infrastructure. The nearest port in Nacala is around 700 km by road from the largest northern city, Palma. And even if the flurry of new discoveries has managed to attract many major upstream players, so far, none has even entered the stage of production.

Production developments in other areas, albeit on a smaller scale, are equally probable and move faster. The Congo is a good example of unexploited gas. Eni, along with New Age and the Société Nationale des Pétroles du Congo, is planning for a rapid development of Congo's petroleum resources, notably oil, by 2016. Even though gas volumes remain small, they recently doubled and now feed newly installed gas-fired plants, which is a welcome development in a continent where hundreds of millions still lack access to electricity.

Algeria is unlikely to meet its ambitious plans

Algeria is sticking to its very ambitious production plans and seeks to double its natural gas production over the next decade from around 78 bcm in 2013, partly by boosting unconventional gas (tight gas) production. In this report, Algeria's gas production reaches 88 bcm in 2019. In early 2014, the country invited companies to bid for oil and gas exploration rights in its fourth competitive exploration tender. This effort will be a test following the new legislation, notably, the new tax incentives, and the In Amenas plant attack in early 2013. Alnaft has announced that contracts will be signed in September 2014. Nevertheless, the objective appears ambitious because Algerian gas production has been declining rather than increasing over the past seven years. Algerian authorities are aware of these challenges, and the number of blocks offered in the new round (31) is much higher than during the previous ones. The blocks are also located in different parts of the country, giving more choice to potential investors.

Unconventional gas is very much on the agenda of Algeria's government. Over the medium term, the focus is clearly on tight gas, but in the longer term, after 2020, shale gas could provide welcome additional volumes to the country. The fact that the new licensing round launched in 2014 includes several blocks with such an unconventional hydrocarbon profile is another proof of this interest. But there is still a long way to go, notably regarding shale gas. Despite an important alleged potential, a difference exists between technically and economically recoverable resources, especially if the unconventional gas resources are destined for the domestic market. But over the medium term, the production increase will be limited, while demand continues to grow fast. A risk also exists that consumption could grow even faster, as the government is comforted by important future unconventional gas resources, and decides to tap more into conventional gas resources in the medium term.

Over the forecast period, new fields will have to compensate for the decline of mature gas fields such as Hassi R'Mel, while Sonatrach needs to take steps to develop the many discoveries made over the past years. As of early 2014, Algeria has not yet recovered from the In Amenas attack. The full restart of the plant was constantly pushed back over 2013, and as of early 2014, the third train of the plant has not yet restarted. Train 1 resumed operations quickly by restarting as soon as February 2013, followed shortly after by Train 2. However, Train 3 was damaged during the attack and repairs have not yet been completed. The plant, therefore, produces at two-thirds of its capacity of 11 bcm per year. The In Amenas attack has already had impact on investments plans as expansions of In Amenas and In Salah have been delayed. Besides, companies are likely to ask for better security measures for staff working in these remote areas, but it is unclear whether the Algerian government will authorise companies to have their own security personnel rather than relying on Algerian authorities.

Looking forward, some new projects are moving ahead, others appear to have been delayed, and there is still uncertainty regarding those arriving after 2017 (Table 16). All the projects together would bring an annual output of around 20 bcm. BP's expansion of In Salah has been pushed back beyond 2014, but no date has been given so far. Other projects would arrive in 2016 at the earliest. GDF Suez's Touat project is still earmarked for late 2016 after the company (along with Sonatrach) signed an engineering, procurement, construction and commissioning (EPCC) contract in August 2013 to develop the field. The project will bring annual production of 4.5 bcm. Similarly, Reggane North, which will produce 3 bcm per year at peak during 12 years for a total lifespan of 25 years, is still expected to come on stream in 2016, unchanged from last year's expectations. The field is being developed by Sonatrach, Repsol, RWE and Edison. Meanwhile, the Timimoun project is now slated for 2017, after Samsung won a USD 800 million contract for EPCC in February 2014. The field, developed by Sonatrach, Total and Cepsa, was initially planned to start in 2010, but its development was constantly shelved and postponed. Total's initial development plan for Ahnet foresaw a 2015 start, but 2017 now seems more feasible. Sonatrach was hoping to sign a contract for the front-end engineering design (FEED) of Ain Tsila, developed together with Petroceltic, in early 2014 to be able to bring the field on stream in late 2017. The development of Hassi Ba Hamou seems uncertain after the exit of Gulf Keystone in 2012, but BG has not made any announcement regarding its development since then. Other fields such as Hassi Mouina, M'sari Akabli, Reggane Djebel Hirane, and Zarafa could be developed later, after 2018.

The development of these fields hinges on the development of pipeline infrastructure, which is often a bottleneck. Two pipelines are under development: the GR4 and GR5 pipelines. The GR4 has a capacity of 11.2 bcm per year, while GR5 will transport 9 bcm per year. GR4 takes the output from Hamra Quartzites, Eni's Menzel Ledjmet East, which started in 2013, and the Gassi Touil integrated project. The gas will be transported to Arzew LNG plant. Meanwhile, GR5 is essential for the next developments because it would carry gas from Reggane North, Ahnet, Touat, Timimoun, Hassi Ba Hamou, Hassi Mouina, M'sari Akabli, Reggane Djebel Hirane, and Zarafa. The pipeline will bring these supplies to Hassi R'Mel. It is expected to come online late 2016, in line with the expectations regarding the starting dates of the fields.

Table 16 Algeria's new fields

	Annual planned output (bcm)	Expected start date
In Salah	na	2015
Touat	4.5	Late 2016
Reggane North	3.0	Late 2016
Timimoun	1.6	2017
Ahnet	4.0	2017
Ain Tsila	3.7	Late 2017
Hassi Ba Hamoun, Hassi Mouina, M'sari Akabli, Reggane Djebel Hirane, and Zarafa	n.a.	2018+

Egypt's "bust and bust" cycle

After the record drop in 2013 to 56 bcm from 61 bcm in 2012, the medium-term outlook for Egypt does not look particularly bright with production reaching 63 bcm by 2019. Political turmoil has made the country's financial condition precarious, resulting in a weakening Egyptian pound. Hence, real GDP growth has slowed down from 7% over 2005-08 to an estimated 2.1% for fiscal year (FY) 2012/13. The country's debt ballooned from USD 34 billion in June 2012 to USD 43 billion in June 2013. In 2013, the country could still count on the help of some Gulf countries in terms of fuel supplies, but this assistance has proved insufficient. Since July 2013, Egypt has also been receiving USD 12 billion of direct financial support from United Arab Emirates, Kuwait and Saudi Arabia as a Bank Aid solution. Inflation has, nevertheless, been over 10% since mid-2013, and the public debt is at around 90% of GDP. Increasing energy subsidies have led to substantial external arrears by Egyptian General Petroleum (EGPC) with foreign energy companies. EGPC charges a fixed price to end users, but pays a higher price to foreign producers and waits to be reimbursed by the state. However, the debt to foreign producers continued to increase, reaching USD 6.3 billion in late 2013. Hence, the oil minister and the finance minister signed an MoU providing for EGPC to pay USD 3 billion. EGPC is to make monthly payments from December 2013 to December 2017. In coordination with the Central Bank, the government will make an immediate payment of USD 1.5 billion.

Low gas prices are the key issue in Egypt due to the double effect on demand and production. On the demand side, low gas prices have driven an energy-inefficient consumption of natural gas, notably in the power and industrial sectors. Consumption in the power sector more than tripled between 2000 and 2013. Domestic industrial users pay wholesale prices of USD 3/MBtu and residential users of USD 1.25/MBtu. At the beginning of the century, Egypt designed a basic policy allowing one-third of its gas to be exported, one-third for the domestic market and one-third for future generations. In 2000, Egypt's gas demand was only 17 bcm. But soon, what could have appeared to be a sound policy hit difficulty because of a double issue: the rapid increase in demand, which tripled over 2000-13, and a slowdown in discoveries. While the government solved the issue by using the gas intended for future generations, it simultaneously allowed demand to expand even further by promoting the role of gas in the economy, for example, in transport (by compressed natural gas [CNG]). Gas shortages mean that more and more oil has to be used for power generation, further aggravating the deficit. Finally, in May 2014, the supply shortfall became so dire that Egypt's government began the process of looking to import LNG rather than export it, contingent on a new floating LNG regasification terminal to be built. However, Egypt's LNG export facilities may still be used in the future, as the companies that have developed Israel's Tamar offshore gas field have signed a preliminary deal with Union Fenosa to supply gas for export via the Damietta Segas liquefaction plant.

On the production side, low gas prices are failing to incentivise companies to take FID on the development of fields, if the gas is to be sold on the domestic market. Seventeen discoveries were reported in 2012/13, according to EGAS, representing only around 34 bcm, half the current annual production. BP made an important discovery in the Nile Delta in September 2013. Yet, the country needs to create the right conditions to attract producers back and translate exploration and discoveries into production. Future production costs are likely to be higher, however. While the deepwater offshore area south of Israel's discoveries could seem promising, it is also likely to be more expensive. The new bid round for oil and gas exploration launched in December 2013 could serve as a test for renewed interest in the country, but there is still a long way to go before effectively moving to production.

The *force majeure* declared by BG in January 2014 appears to be a bad omen, even though it is not the first time that LNG supplies have been diverted to the domestic market. By the summer of 2013, EGAS was already incapable of supplying gas to BG for its LNG terminal. Domestic diversions in late 2013 were at around capacity (10 bcm per year). While the previous disruption took place in the middle of summer to ease power shortages exacerbated by the heat, this was not the case in winter when residential demand was relatively limited. That time, Qatar stepped in and provided five LNG cargoes to replace the missing ones. Both governments were discussing further such donations, but the overthrow of the recently elected President Morsi resulted in a collapse of these talks.

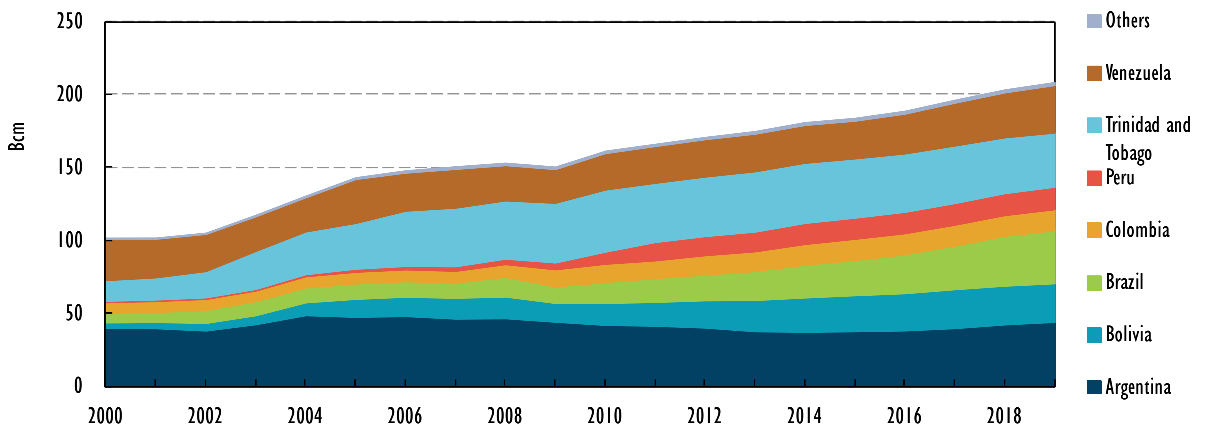
In 2012, Egypt's main foreign producers were BG (around 7 bcm), Eni (8.3 bcm), BP (4.9 bcm) and Apache (3.7 bcm). BG is particularly active in the West Delta Deep Marine (WDDM) offshore area, but its production has been declining over the past few years. A significant part of the gas is, in principle, dedicated to the LNG plant. Eni has been present since the 1950s, and its output has been relatively stable since 2010. BP has been active since the 1960s, and its production has increased slightly. A recent discovery made in 2013 seems also to brighten the future for the company. However, most of BP's sales are domestic, even though some of its gas was sold to Damietta. Other companies include Apache, Petroceltic, Dana Gas and Sinopec.

Despite the political turmoil, no company has withdrawn from Egypt, even though Apache sold 33% of its interest to Sinopec in 2013. But recent events show that companies are reluctant to commit to and actually held back new investments. The last licensing round launched in 2012 was relatively successful, attracting seven companies and awarding eight out of 15 blocks. EGAS and EGPC will again be in charge of the new licensing round and awards of oil and gas concessions. EGPC is offering 15 blocks in the Gulf of Suez and Western Desert, and EGAS is offering seven blocks in the Mediterranean and Nile Delta Basin, where most of the gas activities are already located. The awarding process has been simplified recently in that it does not have to go through the parliament, but can be signed by the president. Several agreements for blocks awarded in 2012 were signed only in the end of 2013. New discoveries and moves to production are dearly needed, as few new production projects have been announced over the past year. In March 2013, BG announced the development of phase 9 of WDDM, expected to start in late 2014. This development would mostly compensate for the decline in the project's existing wells. In early 2014, three PSAs were finalised between EGAS and foreign companies: two with a consortium of Eni and Petroceltic for the north Thekah offshore block and the South Idku block, and another with Dana Gas for the north El Arish offshore block. This news seems to indicate that the government wants to reduce the contract backlog (the blocks were awarded in 2012), but the government is also likely to have offered better pricing as these offshore blocks are more complex to develop and companies are unlikely to have accepted the usual USD 2.65/MBtu.

Latin America: Developing gas resources is still a hurdle

Latin American gas production is forecast to reach 208 bcm by 2019. This outlook remains relatively conservative, even if the situation could improve more than expected in a few countries, notably in Argentina, over the forecast period. Venezuela's production outlook has been revised downwards, reflecting the political instability. In the absence of tangible decisions regarding the development of the country's major gas fields, Mariscal Sucre and Cardon IV, their expected production start has been further deferred.

Figure 51 Latin America gas production, 2000-19



Despite the deceleration of some economies in Latin America, particularly pronounced in Brazil, the region's largest economy, the continent is still showing robust economic growth which will continue for the coming years. Several countries have been able to shape the needed conditions to increase business confidence, investments and capital inflows, also in the energy sector. Others, like Argentina, have import and exchange controls in place creating business uncertainties and hence limiting foreign investment. These conditions, added to the countries' gas needs and resources, will have a wide impact on future production developments. Production shortfalls will result in increasing LNG imports. In several countries, LNG is indeed used as a bridging fuel at moments of limited hydropower production. Domestic production is not quite able to provide the same amount of flexibility and the region still lacks underground gas storage.

The outlook will be widely different from what has taken place over the past few years. The only common trait is that the region's production growth is and will remain centred around Brazil, but this trend will become even more marked, as two-thirds of the region's production growth comes from Brazil alone. However, production growth in Peru and Bolivia, which together brought more supply on stream than Brazil alone over 2007-13, will remain subdued. Argentina's production decline is forecast to slow down, while gas output is expected to recover over the medium term, even if production by 2019 remains lower than its peak in 2006. While production is also expected to recover in Venezuela, this is surrounded by much uncertainty given the recent developments. Lower production would result in lower demand, as it is unlikely that the country will be able to import significantly more gas from Colombia.

Brazil

While Brazil has traditionally focused on oil production, gas production in Brazil is also increasing. Until a couple of years ago, associated gas was considered to be a by-product generally used for EOR. But with domestic gas demand growth, the focus has shifted towards gas as a fuel. Over the last few years, gas production at the Mexilhão, Lula and Tambaú fields has boomed and the start of operations in the Baleia Azul field further contributed to increasing production. With proven reserves of 459 bcm (around 23 times the current production), the Brazilian government has been intensifying exploration activities, looking notably for gas onshore in the vast inland basins of the country as it aims to increase gas demand (OIES, 2013). According to the EIA, shale gas resources in Brazil amount to 6.9 tcm, but these resources have so far attracted very little interest.

In its Strategic Plan 2030, Petrobras plans to develop onshore conventional and unconventional gas, aiming to invest USD 10 billion in natural gas production till 2017 (Petrobras, 2014). Gross domestic production of natural gas was approximately 24 bcm in 2012 with a projected increase to 35 bcm by 2015 and 65 bcm 2020. Petrobras's projections nevertheless differ from the IEA data as they include reinjection, which typically accounts for 15% of gross production, but may be higher in the future as oil production grows. In 2013, the government organised several E&P auctions for a large number of onshore and offshore blocks. One of the auctions was concentrated on natural gas in traditional basins and deposits as well as unconventional resources. While 26 companies qualified for the auction, only 12 participated; of the 240 blocks on offer, only 72 were sold. State-owned Petrobras dominated the round, taking stakes in 49 of the 72 blocks sold. This event demonstrated that Petrobras is still the dominant player, even though newcomers are getting more room in the E&P of Brazil.

Unlike many neighbouring countries, domestic gas prices are not an issue in Brazil. On the contrary, gas prices for domestic gas are linked to oil prices and are therefore relatively high. Domestic gas prices at the well head and city gate are not unbundled and float around USD 8 to USD 12/MBtu. Residential consumers pay prices above USD 50/MBtu. Large industrial consumers pay in excess of USD 16/MMBtu, affecting the industrial competitiveness of Brazil (OIES, 2013).

Argentina

Argentina once had the largest gas production in Latin America, but it lost this position to Trinidad and Tobago in 2010. Over the last years, production has been declining on a yearly average of 6% as a result of maturing fields, low domestic gas prices which are not incentivising new production developments, and state's intervention in E&P business which has resulted in the partial nationalisation of privately-held companies. Its alleged vast shale gas reserves remain mostly untapped. Restoring investor confidence is nevertheless crucial given that between 50% to 60% of the energy mix of Argentina consists of natural gas. A further decline of domestic production would only accentuate the dependency on energy imports, which has been gradually increasing during the last decade.

The current situation in Argentina is the result of measures dating back to the financial crisis in the early 2000s. These measures included the regulation of domestic gas prices at a fixed low level. It caused gas to become the cheapest source of energy, leading to increased domestic consumption. In the meantime, production has been declining in response to maturing fields and a lowly regulated wellhead price, limiting exploration of its vast (shale) gas reserves. Then, on top of this, in 2004 the weather turned dry and cold. The drought, which affected hydropower facilities, was compensated by gas-fired power generation, while the cold made residential gas consumption increase. Domestic production could not meet this demand. The combination of all these factors resulted in an energy crisis in 2004. In reaction to this crisis, the Argentinean government developed a policy to allow gas exports only after domestic demand was met, leading to severe cuts in natural gas exports to Chile and, consequently, an energy supply crisis in this neighbouring country. This measure, however, was still insufficient to prevent interruptions of deliveries to Argentinean industrial users (OIES, 2004).

Domestic production continued to decline, leading to more interruptions of natural gas supplies to industrial users during several winters in order to meet its residential demand. Seasonal shortages of natural gas now also appear during some summer months, as electricity demand soars with high temperatures. Argentina has transformed from a net-exporting country to a net-importing country. Natural gas imports to Argentina arrive via pipeline from Bolivia and by spot cargoes of LNG, mostly from Trinidad and Tobago.

With domestic energy prices regulated, in some cases around USD 2/MBtu, imports at market prices became an increasing expenditure for the government. Argentina ended 2013 paying a total amount of around USD 6 billion for gas supplies. This was a substantial share of the total amount of about USD 13 billion paid by the country for energy imports during last year. With these expenditures, Argentina spent around 40% of the gross dollar reserves of the country. In January 2014, the Argentinean government devaluated the peso. This was the largest devaluation after the deep economic and financial crisis of 2001. This monetary measure could have a positive effect on the inflation rate; however, in the meantime, it could have a negative effect on the investment climate to develop Argentinean shale gas.

Bolivia

Since the nationalisation of the petroleum sector in 2006, gas production has nearly doubled and revenues have increased substantially. Consumption comprises only one-fifth of the total production. With increasing production of associated gas, the government of the sixth-largest gas producer of Latin America is also trying to develop its own liquids industry in order to reduce its energy imports bill and to become less dependent on imports for these products. The large production increase translated into substantial exports to neighbours, notably Brazil and Argentina, and brings much needed revenue to the country.

In early 2014, the state-owned oil and gas company Yacimientos Petroliferos Fiscales Bolivianos (YPFB) announced an increase of gas production to an average of 23.6 bcm in 2014, against 20.5 bcm in 2013. Bolivia will therefore increase exports to Argentina by 20%, made possible by the capacity increase of the 1 454 km North Pipeline (El Gasoducto Norte), which runs from the San Jerónimo compressor plant in the Province of Santa Fe (Bolivia) to Campo Durán in the Province of Salta (Argentina). This planned production increase is attributed to expansions of the Itaú and Margarita fields, run by Petrobras and Repsol, respectively. In October 2013, the newly expanded Margarita natural gas-processing plant came online, with a capacity increased by nearly 70%. The expansion is an important part of a project that consists of the construction of gas pipelines and the drilling of four additional wells to increase output of the Margarita field, in which BG and Pan American Energy also have a stake.

In 2013, Bolivian President Evo Morales inaugurated the country's first NGLs separation plant in Rio Grande, Santa Cruz. With this plant, Bolivia will be able to separate liquids like propane, butane and ethane from rich gas before exporting gas to neighbouring countries. With this industrialisation policy, the government aims to reduce imports of NGLs to meet domestic demand. Until now the country has been paying international market prices for these products and subsidising the costs to industry and residential consumers.

The Rio Grande separation plant has capacity to process only 20% of the gas that Bolivian exports to Brazil. This means that exports to this country will still retain 80% of the liquid hydrocarbon components of the natural gas. To make optimal use of these liquids, two large petrochemical plants will be built near the Brazilian border. In the meantime, Bolivia has been trying to get compensation from Brazil for the liquid hydrocarbons (whose value is estimated to be around USD 80 to USD 100 million per year) delivered in its natural gas exports since 2007. Exporting rich gas (mixed with liquid hydrocarbons) to Argentina will be also reduced at the end of 2014 when a second separation plant comes online in the Gran Chaco region of Tarija.

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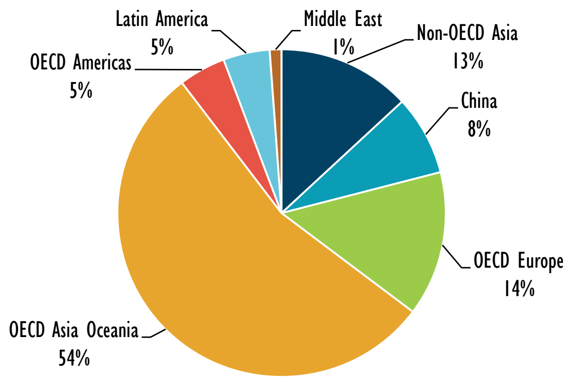
TRADE

Summary

- Global interregional trade in 2013 was boosted by the resurgence of pipeline imports into Europe and the People's Republic of China, while global liquefied natural gas (LNG) trade stalled for the second year in a row (Figure 52). Interregional trade now represents 17% of total global demand. Asia's (including OECD Asia Oceania, non-OECD Asia and China) share in global imports has now reached 48%, up from 45% in 2012, as the region was able to divert LNG away from Europe due to higher prices. In particular, China had the largest incremental increase. Droughts in Latin America led to a 40% surge in gas imports, with countries paying record prices, as high as USD 20 per million British thermal units (MBtu).

Figure 52 LNG imports by region, 2013



Source: unless otherwise indicated, all material in figures and tables is derived from IEA data.

- The price divergence between Asia and the United States persists, even though it dropped slightly in 2013. The extremely cold winter in the United States sent prices to levels unseen for years (briefly over USD 100/MBtu in some regions, showing that nothing is set in stone in terms of price development). Asian players continue to develop strategies to lower their gas import prices, looking for new sources of gas supply from North America, the prices for which will be indexed to gas instead of oil.

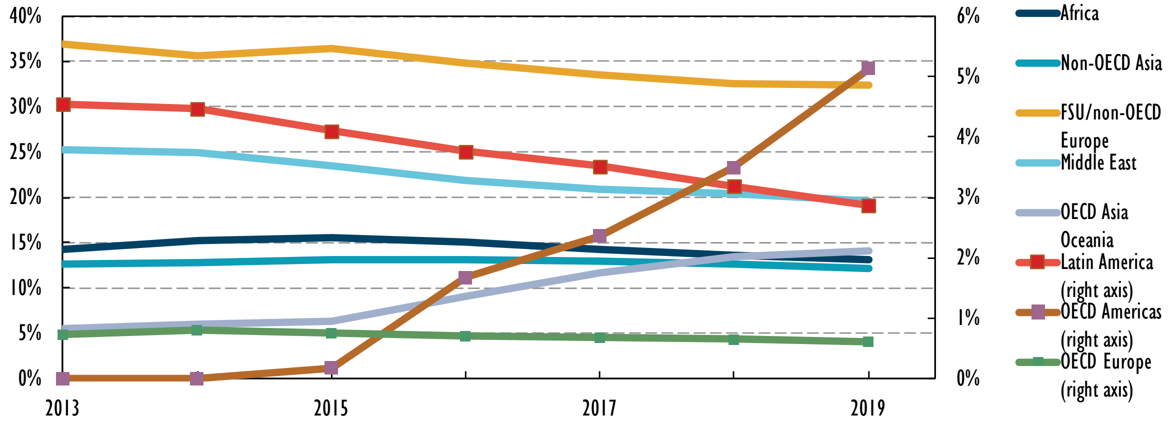
- As of mid-2014, 150 billion cubic metres (bcm) per year of LNG export capacity is under construction and planned for completion by 2019, 70% of which is located in Asia. Only one US LNG project is under construction as of May 2014, even though six projects received the Department of Energy's (DOE) approval to export to non-free trade agreement (FTA) countries. Four regions – North America, Russia, East Africa and Australia – all claim the largest new potential sources of LNG supply, but the US projects challenge the others in terms of price indexation and flexibility. Against this backdrop, only one pipeline project is actually moving forward – the Southern Corridor comprising the TAP and TANAP pipelines – linking Azerbaijan and OECD Europe. Its completion is expected in 2019. Meanwhile, China continues expanding its pipeline interconnections with Central Asia. The key event in 2014 is the agreement between China and Russia on a much-awaited pipeline linking Eastern Siberia to Eastern China, which was finally signed on 21 May 2014.

- Countries continue to expand their LNG import capacity, notably in Asia, which represents two-thirds of the regasification capacity under construction, with Europe and Latin America accounting for the rest. Regasification capacity now represents almost three times the total LNG trade, resulting in low utilisation rates in some regions, notably Europe. LNG terminal operators are, therefore, resorting to new business models such as LNG re-exports, but are also considering using their terminals for LNG bunkering, supplying both ships and trucks.

- Global interregional trade will expand by one-third, whereby OECD Asia Oceania will provide the largest additional exports, followed by OECD Americas and Former Soviet Union (FSU)/non-OECD Europe. Global LNG will expand faster (+40%) than interregional trade supported by the large LNG export capacity additions, while pipeline exports will be limited due to the slow growth of and competition to fill in incremental European imports.

- FSU will see its share in global exports declining from 37% in 2013 to 32% in 2019 (Figure 53). This trend is also shared by Latin America due to declining exports and the Middle East, where LNG exports remain at the same level in 2019 as in 2013. Despite growing exports, Africa, in the absence of new liquefaction plants coming on stream after 2014, and non-OECD Asia both see their shares in total trade declining over time. The Middle East, non-OECD Asia and Latin America will also face a decline in net exports. In 2019, non-OECD Asia's net exports will amount to only 1 bcm due to the rapid rise in LNG imports.

Figure 53 Evolution of regional shares in total exports



- OECD Europe remains by far the largest importer, while OECD Asia Oceania will rank second until 2018, when China's imports will exceed OECD Asia Oceania's net imports. China will absorb the largest incremental quantity of imports, ahead of non-OECD Asia and Europe. Over the short term, Europe will become increasingly dependent on pipeline imports, as LNG is redirected to Asia. LNG imports from Europe are expected to recover after 2016. In the absence of significant pipeline supply alternatives, significant gas supplies will still be coming from Russia, while Azeri supplies will increase from 2019 onwards. Should Asia's appetite for LNG be lower than expected, or global LNG supplies be higher, Europe will then be able to further lessen its dependency on pipeline imports from the FSU/non-OECD Europe region.

Recent trends in global trade

Global LNG trade stalls, boosting pipeline imports

Global interregional trade increased 4% in 2013 after a 2% drop in 2012, which was largely due to the decrease in global LNG trade and fewer European imports (Table 17). The trends in LNG trade and trade via pipeline diverged in 2013. Global interregional pipeline trade reached 255 bcm, 24 bcm higher than the previous year. Interregional pipeline trade was boosted by the resurgence of European pipeline imports, a consequence of declines in both domestic production and LNG imports. The other region for which pipeline imports matter (and are, indeed, in constant competition with LNG imports), is China. Both LNG and pipeline gas contributed to fill China's additional import needs during 2013, but pipeline imports expanded much faster because of additional pipeline capacity coming on line from Uzbekistan, following an ambitious export strategy and limited incremental LNG supply available. China's pipeline imports gained 44% compared to 2012.

In stark contrast with pipeline trade, the development of global LNG trade stalled for the second year in a row, growing a modest 0.3% over 2013. While the potential global demand for LNG was certainly increasing, notably in Asia, it remained unmet, as supply failed to expand among difficulties from LNG liquefaction plants in operation and disappointing results from the ones that started operations in 2013. Consequently, LNG plants delivered 322 bcm, which implies an 81% utilisation rate of global LNG liquefaction capacity. As of 2013, LNG still represents the majority of gas traded among regions, with a 57% share of total trade, slightly decreased from the 58% share in 2012.

Table 17 Imports by region, 2013 compared to 2012 (bcm)

	2012			2013			2013/12
	LNG	Pipe	Total	LNG	Pipe	Total	(%)
Africa	0	0	0	0	0	0	0
Non-OECD Asia (excl. China)	35	0	35	42	0	42	22
China	20	19	39	25	28	53	36
OECD Asia Oceania	169	5	174	175	6	181	4
OECD Americas	17	0	17	14	0	14	-11
OECD Europe	66	184	250	46	200	246	-2
Non-OECD Europe	0	16	16	0	12	12	-8
Former Soviet Union (FSU)	0	0	0	0	0	0	0
Latin America	11	0	11	15	0	15	40
Middle East	4	7	11	4	7	11	-3
Total	**321**	**231**	**552**	**322**	**255**	**577**	**4**

Note: data for 2013 are estimated.

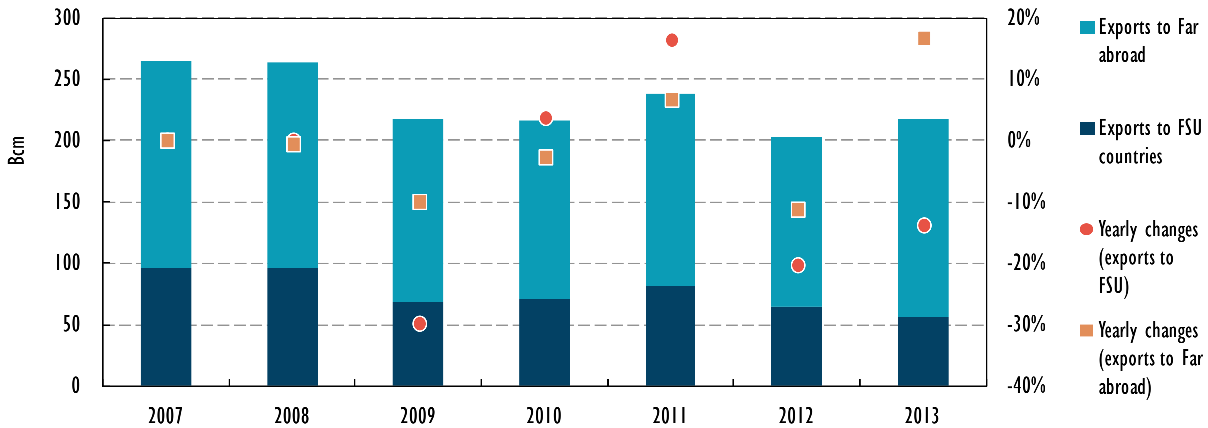
On a regional basis, Asia – including non-OECD Asia, China and OECD Asia Oceania – continues to attract increasing amounts of gas, notably in the form of LNG. Imports from within Asia increased by 28 bcm. Asia's share in global imports has now reached 48%, up from 45% in 2012. Nevertheless, OECD Europe remains by far the largest importer of natural gas on the back of large pipeline imports from the FSU, North Africa and the Middle East (Iran) and reduced amounts of LNG. European gas imports dropped by 4 bcm. The region's pipeline imports increased to 200 bcm, up 9% from 184 bcm in 2012, while in contrast, its LNG imports receded by one-third (20 bcm), and are now back to 46 bcm, a level unseen since 2006. Lower LNG imports, as well as lower pipeline imports from North Africa, largely benefited pipeline imports from Russia, which surged to the highest level ever recorded. Turkey's imports from Iran slightly increased from 8.2 bcm to 8.7 bcm, getting closer to the contractual annual quantity of 10 bcm.

With 181 bcm imported in 2013, OECD Asia Oceania is the second-largest importer of natural gas, albeit almost exclusively of LNG, as the region imports only a limited amount of pipeline gas from Timor Leste, corresponding to the gas feeding the Darwin LNG plant and coming from a joint production zone astride Australian-Timor maritime boundary. If not for the closure of nuclear power plants in the Republic of Korea and small LNG imports starting in Israel, LNG imports would have stalled or even declined.

China is maintaining its position as the third-largest natural gas-importing region, even though a big gap still exists between imports to China, OECD Asia Oceania and OECD Europe. Currently, OECD Europe alone continues to import more than China and OECD Asia Oceania together. The increase in China's net imports (14 bcm) in 2013 is, nevertheless, below the region's demand increase, estimated at 20 bcm. While Chinese LNG imports continue to reflect a diversified supply mix, this trend is now affecting pipeline supplies too. Until recently, Turkmenistan provided the overwhelming majority of pipeline gas supplies, but Uzbek gas and Myanmar gas represent now non-negligible portions. The Uzbek share of China's imports rose to 12% of total imports in December 2013. Gas imports from Myanmar started in August 2013 and have steadily increased over the past few months as the Shwe field progressively ramps up gas production. Quite interestingly, gas from Myanmar was the most expensive, at USD 11.8/MBtu, against Turkmen gas at USD 9.6/MBtu, and Uzbek gas at almost USD 9/MBtu at the border. Although Myanmar gas may appear expensive, it does not have to cross thousands of kilometres before reaching the final end user, unlike gas coming from Central Asia.

Elsewhere, the unexpected surge in Latin American LNG imports was due to dwindling production in Argentina and droughts that prompted power generation using gas. Latin America thus posts the highest relative increase in imports among all regions, with 40% more LNG imported year-on-year. In contrast, the Middle East imported less LNG, which is surprising given the region's growing appetite for natural gas and difficulties of some countries to increase their production. Little information is available regarding Turkmen pipeline exports to Iran or on Turkmenistan's supply-and-demand balance, so these have been estimated to be roughly the same as in 2012.

Figure 54 Russia's gas exports to FSU and "far-abroad" countries



Note: "Far-abroad" countries (a term translated from the Russian) include OECD Europe countries (except Estonia), Bosnia Herzegovina, Bulgaria, Croatia, Macedonia, Romania and Serbia.

OECD Americas is slowly moving towards self-sufficiency; at least this is true for the United States and Canada, which together imported a record low of 5 bcm of LNG. Meanwhile, two regions remain net exporters of natural gas and do not import: the Former Soviet Union and Africa. However, North African pipeline exports plummeted 14% to 34 bcm. They have slumped on the back of lower deliveries of Algerian and Libyan pipeline gas and the almost complete disruption of Egyptian pipeline exports to Jordan; other countries that previously received Egyptian gas are assumed to no longer get any more gas. Despite attempts, Egypt's plans to build an LNG import terminal and secure LNG cargoes have failed so far. Consequently, Africa still does not import any gas. These efforts to enter the LNG game are not an isolated case: Morocco is seriously considering building an LNG terminal in the region of Jorf Lasfar near Al Jadida. This addition would allow Morocco to diversify supply routes away from Algeria and develop its gas transmission pipeline network and supply cities in the coastal area. However, Morocco does not envisage the LNG plant to be finished before 2019-20. Meanwhile, the FSU's gas exports increased on the strength of increasing pipeline exports from Russia to Europe and from Central Asia to China (Figure 54).

LNG developments: Asia dominates, Latin America fights back

Asia's LNG imports reached 243 bcm in 2013, accounting for 76% of global LNG trade. This level means an exceptional concentration of LNG imports in one single region, even though the countries had extremely divergent trade patterns. This also implies longer shipping distances as the LNG supply located in the Pacific basin and the Middle East is no longer sufficient, so that gas also has to be imported from countries such as Nigeria or Egypt. Atlantic-based suppliers provided around 10% of Asia's LNG imports. Meanwhile, some Middle Eastern suppliers such as Qatar do not send all their LNG supply to Asia to maintain some demand diversity in their portfolios. Roughly one-quarter of Qatar's LNG still reaches European shores. For the first time since Fukushima, Japan's LNG imports slowed down in 2013 and were only 0.2% higher than in 2012. Nevertheless, the country remains by far the largest LNG importer, importing more than twice that of the second-largest LNG importer, Korea. The slow growth in LNG imports was also a pattern observed in Chinese Taipei, another key historical LNG importer in the region. By contrast, Korean LNG imports surged by 12% due to the closure of several nuclear power plants during 2013.

China is now the third-largest LNG importer on a country basis, but due to the competition from pipeline supplies and high costs of LNG supplies, its increase in LNG imports was subdued. China benefited from the addition of LNG regasification capacity in three new terminals. India also increased its LNG import capacity with the Dabhol and Kochi LNG import terminals coming on line; however, none of them can be fully utilised. Despite potential demand estimated around 117 bcm for the fiscal year 2013/14 according to the 2012-17 Five-Year Plan (FYP), India's LNG imports failed to increase as customers are reluctant to pay market prices. Malaysia and Singapore made their debuts as LNG importers, representing a total of 5 bcm together. Unlike Indonesia, which plans to use mostly domestic LNG shipped from the part of the country where production is located to its demand centres, Malaysia and Singapore will source their gas from global LNG markets.

OECD Americas' LNG imports now stand at 14 bcm, a far cry from the 24 bcm recorded in 2007. The picture is even more impressive when one looks at the United States alone, where LNG imports slumped from 22 bcm in 2007 to 2 bcm in 2013. Due to long-term contracts signed years ago, two terminals are still operating: Elba Island, Georgia and Everett, Massachusetts. Likewise, LNG imports from northeastern Canada also declined due to the competition of increasing supplies from the neighbouring Marcellus play. Two countries still continue to import LNG in this region: Mexico and Chile. Despite increased pipeline imports from the United States, Mexico still uses large amounts of

LNG and imported 7.7 bcm in 2013. The US lower 48 states or Canada have not started exporting LNG, and LNG re-exports have virtually disappeared, as only one cargo was reported in 2013.

As LNG is diverted to Asia, European LNG imports declined one-third on an aggregated basis, reaching 46 bcm. Utilisation rates of Europe's LNG import capacity stand at 24%, much lower than the world's average of 34%. This level shows that a lot of unused European LNG capacity could be used during a supply disruption, assuming that LNG could be sourced quickly at reasonable prices; however, it is also creating issues, as storage levels in the LNG tanks are sometimes too low, forcing the operator to shut down the facility (Box 13). None of the importing countries imported more than 10 bcm, with the exception of Spain (12.4 bcm). Apart from the Netherlands, all countries posted double-digit losses against the previous year; the sharpest fall was in Greece, which became the smallest LNG importer in Europe.

Box 13 The implications of low LNG imports on regasification terminals' operations

Many LNG terminals in Europe are facing very low LNG levels. This situation has practical consequences for their operations. The low number of LNG cargoes means that LNG terminals must have low send-out rates in the pipeline system to avoid depleting the LNG storage levels too rapidly. However, a very low flow requires the operator to flare the boil-off because it is no longer capable of recuperating this small remainder. Indeed, due to the very low temperature at which LNG is stored (-160°C), some LNG evaporates in the tanks, a phenomenon called "boil-off". This usually amounts to 0.05% per day. Under normal circumstances, the boil-off will be compressed and then re-injected into a flow of LNG taken from the send-out rates in the network. But if the send-out rates are too low, using part of them to incorporate the boil-off becomes technically difficult. Meanwhile, the boil-off has to be removed to avoid pressure building up in the LNG tank, so that gas is flared.

Besides, very low levels could potentially require an LNG terminal to be shut down when the cost of maintaining the tank's low temperature is greater than the cost of restarting the operations through cooling-down procedure – i.e. bringing back the tank's temperature from ambient temperature to the level of -160°C. In the United States, a regasification capacity of almost 200 bcm of LNG had been built, notably in the early 2000s, before shale gas production took off. As of today, only a handful of LNG terminals are still operating in the country.

The most interesting development in 2013 took place in Latin America, where LNG imports surged and contributed to create a price spike (USD 19 to USD 20/MBtu) in late 2013, as both Argentina and Brazil went hunting for cargoes. In several countries, LNG is actually used as a bridging fuel at moments of limited hydropower production. The seasonal nature of the energy mix makes LNG an emergency source for power generation. Most of the LNG cargoes finding their way to Latin America are spot cargoes. Almost half of the LNG is sourced from Trinidad and Tobago, which makes sense considering the shipping distance and the fact that Trinidad and Tobago needs to find alternative markets now that the LNG opportunities in the US market have almost entirely disappeared. But the region is also receiving around 3 bcm of re-exported cargoes, the rest of its LNG supply coming from Atlantic-based LNG exporters and Qatar.

Neither Argentina nor Brazil has long-term LNG supply contracts with suppliers. Because of the tightness of the LNG market, countries such as Brazil and Argentina have been paying some of the highest LNG prices in the world, competing with Asian buyers. Nevertheless, Petrobras has not discounted the possibility of signing long-term contracts with LNG suppliers to reach better gas prices and reduce the dependency on the spot market. As of early April 2014, advanced talks have been reported with Angola, which had initially developed its LNG supplies for the United States. As Angolan LNG is now being shipped to other regions as LNG spot cargoes, Petrobras obtained LNG cargoes on a free-on-board (FOB) basis, rather than on delivery ex-ship (DES) terms, by using its own fleet of tankers, increasing the flexibility for the company.

Another key aspect of the LNG story is on the supply side as the relatively stable LNG output is disappointing, considering the ever-increasing appetite for LNG from Asia and Latin America. While LNG export capacity increased modestly by 13 bcm in Angola and Algeria, this increase failed to translate into higher LNG exports. The first reason is that new suppliers brought very little or no additional LNG supply at all. Angola delivered only five cargoes, equivalent to 0.4 bcm. The plant in that country started more than a year later than planned and was shut down for maintenance in November 2013. Despite the Skikda LNG plant coming on line in mid-2013, Algerian LNG exports dropped again in 2013, raising questions about the country's ability to increase either pipeline or LNG exports. Indeed, this took place against the backdrop of lower pipeline exports to Europe, notably to Italy.

The second reason for the decline in LNG trade in 2012 and stable output in 2013 is that historical LNG suppliers face declining output, due either to the natural decline of the producing fields or to the competition of the domestic market. Sometimes, both factors contribute to an even larger drop in LNG exports. The most visible example of this is Egypt: Egyptian LNG exports were almost halved in 2013 and now stand at 3.6 bcm, against a capacity of 16 bcm. This is a far cry from when Egypt was still exporting 13 bcm of LNG in 2008. Now the Damietta LNG plant has been standing idle since December 2012 and BG declared *force majeure* on Idku in early 2014. Gas supply from the West Delta Deep Marine is likely to continue to be diverted to the domestic gas market. Nigeria also delivered fewer LNG exports (-16%), while Libyan LNG exports are still non-existent since the 2011 civil war.

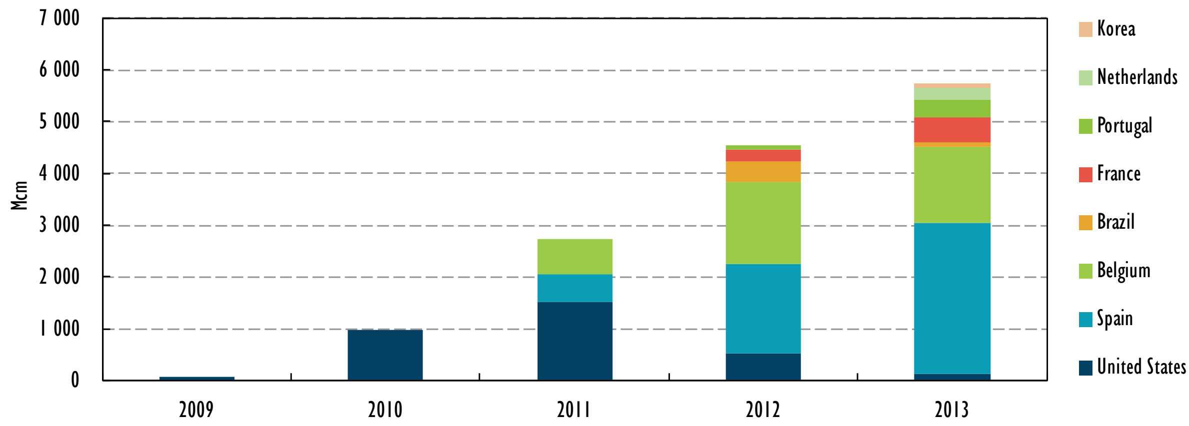
Several other traditional LNG exporters also experienced dwindling LNG supplies. Indonesia's exports dropped 3%, but note that the country redirected many cargoes from Bontang and Tangguh to its own domestic LNG terminals. The United Arab Emirates' LNG exports receded slightly as domestic demand continues to expand. Meanwhile, Norway's Snøvhit continues to face technical difficulties and delivered only 4 bcm.

In contrast, Malaysia and Oman, which had been facing tight supply-and-demand balances, increased their LNG exports in 2013, despite the fact that both are also importing gas. Trinidad and Tobago and Brunei also delivered more LNG to global gas markets. One of the largest surges in LNG exports came from Yemen, which suffered from pipeline bombings in 2012 and recovered in 2013. Russia continues to outperform, with Sakhalin 2's twin plants delivering almost 15 bcm to the markets.

Re-exports are becoming a European speciality

Re-exports of LNG cargoes to higher-paying markets increased again in 2013 compared to previous years (Figure 55). A large share (95%) of these cargoes originate from European countries (Spain, France, Belgium, Portugal and the Netherlands). In other regions, the United States, Brazil and Korea are re-exporting small volumes. In 2013, 5.7 bcm were re-exported globally, amounting to about 2% of total LNG volume trade. The main destinations were Asian and Latin American countries, which paid a significant premium to get these cargoes. While re-exports have become a new interesting feature of global LNG trade, one can wonder how long it will continue. This trend started in the United States, when the terminals experienced a sharp decline in their utilisation as a result of the shale gas boom. Some terminals received the authorisation and had the technical possibility to re-export LNG; this was notably the case for Sabine Pass, Cameron and Freeport. In 2013, only Freeport re-exported one LNG cargo.

Figure 55 LNG re-exports, 2009-13



Although European countries joined the practice later, they have now become experts. Low levels of European LNG imports require LNG importers to develop new business models and also to use the LNG terminals differently. For example, LNG terminals re-export increasing quantities of LNG towards premium markets, and many LNG terminal operators are now considering using their terminals for LNG bunkering, supplying both ships and trucks. Spain and Belgium, which started to re-export LNG in 2011, have now been joined by three other European countries. Only the United Kingdom, Italy, Greece and Turkey have yet to join the club. The United Kingdom receives large amounts of flexible LNG, which can be diverted to higher-paying markets without having to reach UK ports. Nevertheless, the National Grid is considering offering LNG reloading to its Isle of Grain LNG facility. Greece imports small volumes of LNG, which contribute to its supply diversity. As a country traditionally short of gas, Turkey has little interest in re-exporting LNG.

The driver behind re-exports is that, contractually, the LNG has to reach the country to respect the destination restriction, and also that the country – or in some cases, the buyer – must be oversupplied or have a cheaper alternative. In cases of oversupply, the buyer could incur losses by selling this LNG into the market, as it could potentially be more expensive than the prevailing market price. In the case of Spain, the continuous destruction of demand means that the country has contracted too much gas, which cannot be re-exported to the wider continental market either by pipeline or under the form of electricity. Indeed, gas demand has declined by 25% since 2008 and is unlikely to recover any time soon. In some cases buyer and seller could agree to divert LNG to other markets, but that would involve sharing the rent. Once the LNG cargo arrives in the country, the owner of the gas contracted can re-export the LNG and keep all the benefits. Another reason for such a development is the relative price transparency in Europe and North America due to the development of spot markets as well as third-party access (TPA) and transparent tariffs, which are set by the regulators (however, this is not the case for some US LNG terminals that do not always offer TPA). Some operators offer online tools to calculate the costs of reloading an LNG cargo.

The contract holders are not the only ones to benefit from these operations. LNG terminal operators can increase their revenues, especially in Europe, where LNG receiving terminals are under-utilised. Enagas, which holds significant LNG capacity in Spain, reports a 40% increase in ship loading, reaching 32 TWh in 2013.

Nevertheless, for this to make sense, the price in the re-export market must be not only higher than the delivered price, but the premium should also cover the transport costs and regasification costs to ensure a margin to the re-exporter of the LNG. Indeed, the owner of the gas would incur costs while the LNG is unloaded and stored in the facility, then reloaded and cooled down so that it can be brought back to the ship. From the operator's point of view, reloading cargoes should not affect the terminal's normal operations – e.g. the reloading rate of Zeebrugge (5 400 m^3 per hour) is much lower than for unloading (14 000 m^3 per hour).

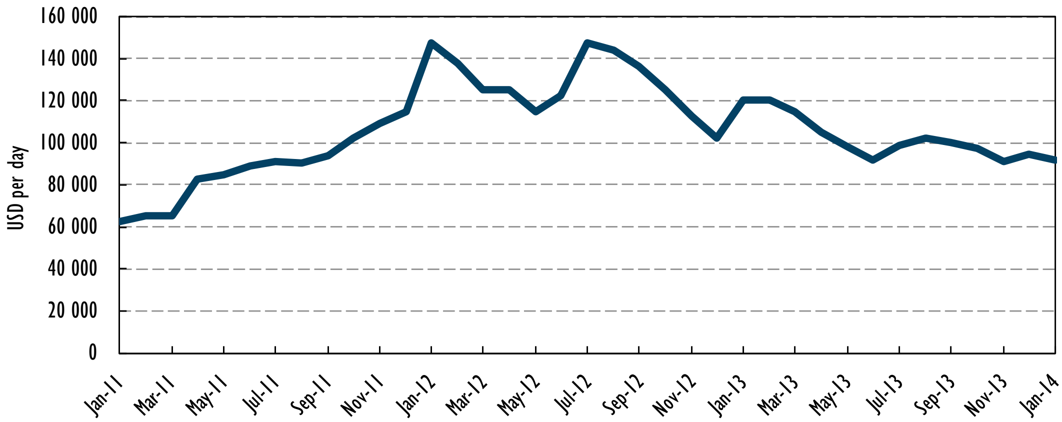
Will reloading die if the price differential declines or if contract terms change? Reloading will certainly be affected if the premium diminishes to the extent that it no longer covers shipping and terminal costs. Also, LNG contracts are becoming more flexible in terms of destination clauses, but at the same time, the buyers may want to keep all the profit. Interestingly, some LNG terminals operators in Asia also seem to be considering reloading options at their facilities. This trend can actually be a sign that other types of reloading could be performed – to fuel smaller ships and develop the maritime transport activity, as well as taking advantage of price seasonality.

Shipping and shipping rates

According to data from GIIGNL, the international organisation of LNG importers, 393 LNG tankers are now on the seas and 20 came on line in 2013 (GIIGNL, 2014). Altogether they performed 3 998 loaded voyages in 2013. The number of vessels newly delivered in 2013 is much higher than the year before, when only two ships were delivered in 2012 (which was the least since 2001). This number is still much less than half of the number of vessels delivered in 2008 (52 vessels were delivered in 2008, which is the highest year for new LNG tanker deliveries in history). Deliveries of LNG tankers have started to pick up as vessels, which were ordered after the Fukushima nuclear accident occurred in 2011, begin to be delivered. At the end of 2013, 113 vessels were on order. Roughly 32 vessels under construction at that time are expected to come on line in 2014, and more will also continue to come on line over the next few years, since 45 new orders were newly placed in 2013. Export projects in the United States could also be a positive factor for accelerating orders for new vessels in the near future.

Shipping rates for LNG spot trading started to rise after mid-2010 as the shipping market for conventional-sized LNG tankers began to tighten; the rate was USD 150 000 per day in mid-2012, which was the highest over the past ten years (Figure 56). This development followed the substantial growth in global LNG trade, which expanded from 247 bcm in 2009 to 328 bcm in 2011, as well as the Fukushima accident, which required additional cargoes to sail from the Atlantic basin to Japan to cover incremental needs. Besides, demand in other Asian countries has expanded over the past four years. The rate peaked since then, and is currently following a downward trend, mainly caused by the narrowing of the West/East arbitrage window, along with deliveries of new LNG vessels. The average shipping rates for LNG spot trading eased to USD 100 000 per day in 2013 compared with USD 120 000 in 2012. Since early 2013, the rates remain on a declining trend, with shipping rates falling to around USD 70 000 in the first quarter of 2014. The ongoing project to expand the Panama Canal would definitely have a beneficial impact on the shipping rates once the expansion project is completed in 2015 and conventional-sized LNG vessels could pass more easily between the Atlantic and Pacific Oceans (depending of course on the transit fees charged).

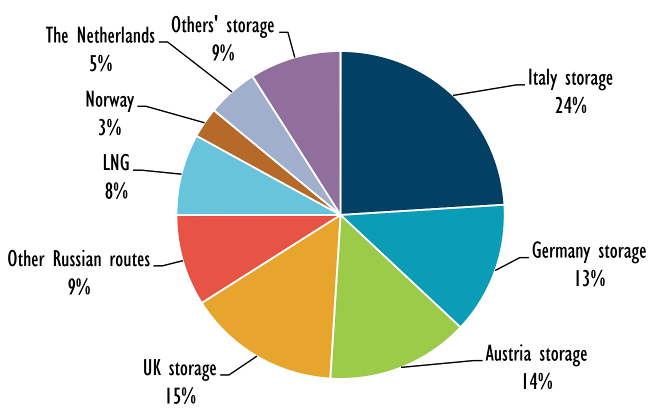
Figure 56 Evolution of shipping rates



Ukraine, five years after January 2009

In January 2009, due to a dispute between Russia and Ukraine, supplies to Europe through Ukraine were cut for two weeks during a period of very high demand. Altogether, 5 bcm were lacking; most countries were able to substitute the gas supplies lost with increased storage withdrawals (75%), supplies from other supply routes from Russia, and other suppliers, including via LNG (Figure 57). In terms of volumes, Germany and Italy reported the largest missing volumes.

Figure 57 How Europe replaced 5 bcm in January 2009



The cut-off Russian supplies affected mostly Eastern European countries that could not find alternative supplies to replace missing gas. These countries had no access to LNG, did not have sufficient storage or lacked efficient interconnections with neighbouring countries. The crisis, the worst the European gas sector had ever faced, highlighted the need for a better coordination and interconnections. It also showed that the best answer to a supply disruption is an efficient and working gas market that can answer in a matter of hours to such supply events.

The situation in 2014

Five years passed; the economic crisis and worsening situation in the power sector (see the Demand chapter) took a toll on European gas demand, which is now lower than it was in 2009, even though heating degree days were higher in 2013 so that the temperature-adjusted demand in 2013 should be lower. In 2013, OECD Europe consumed 504 bcm against 522 bcm in 2009. Within Europe, investments made have improved the interconnections between countries, enabling gas to flow more easily from one region to another, including flows that reverse the normal direction of trade. Better coordination also exists at the EU level through groups such as the Gas Coordination Group, which meets on a regular basis. The IEA has been expanding its work on security of gas issues and has notably included gas in the member countries' Emergency Response Reviews, which are performed approximately every five years. A new pipeline from Russia to Europe bypassing Ukraine has been built – the 55 bcm per year Nord Stream – and a few LNG terminals have been added over 2010-13 in France, Italy, the Netherlands and the United Kingdom, representing an additional import capacity of 41 bcm per year. Storage capacity has expanded too. But, at the same time, global gas markets have evolved. While North America no longer needs to import LNG, most LNG is now going to Asia, and the past two years have featured slightly declining global LNG trade (-2% over 2011-13). For Europe, this trend actually resulted in an increased reliance on Russian gas in 2013, while its LNG imports collapsed.

Russian gas is delivered to Europe through several routes:

- flows via Ukraine, supplying Slovakia, the Czech Republic, Hungary, and feeding into Western Europe, as well as to southeastern Europe and Turkey,
- directly to Germany via Nord Stream, and directly to Estonia and Latvia,
- to the Baltic States, Poland and Germany via Belarus,
- directly to Finland,
- and directly into Turkey via the Blue Stream pipeline.

Russian gas supplies recovered in 2013 on the back of lower deliveries from other suppliers (Table 18). The data shown in the table come from IEA Gas Trade Flow Map, which gives the flows at most entry and border points in Europe on a monthly basis. This tool was created following the 2009 crisis to enhance transparency. As can be seen, North African gas supplies have dropped sharply over the past few years, highlighting the competition from African gas demand and supply difficulties from Libya. The most striking change is the sharp drop of LNG imports, which have halved since 2010, as LNG is diverted to Asia where prices are higher. Physical Russian gas flows to Europe through Ukraine totalled about 82 bcm in 2013, still representing about half of Russia's total deliveries to Europe. This implies monthly deliveries of around 6.8 bcm.

Table 18 Imports of pipeline gas and LNG to Europe (OECD and non-OECD)

	2010	2011	2012	2013
Imports from Russia	144.6	156.3	148.2	167.3
Transit through Ukraine	93.9	99.1	78.9	82.3
Imports from North Africa	44.1	33.8	39.3	33.7
Imports from Azerbaijan and Iran	12.3	12.0	11.6	13.0
LNG imports	86.7	86.2	63.7	45.8

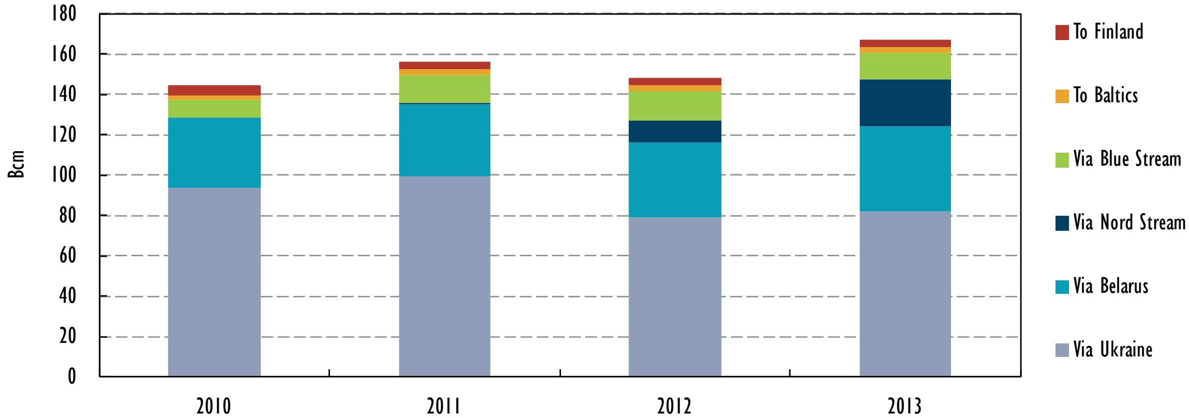
The situation has also changed in Ukraine. Demand collapsed following the 2009 financial crisis and due to higher gas prices. While domestic production remained stable at around 20 bcm, and imports from Russia stood at around 57 bcm to 59 bcm before 2009, they were cut in half by 2013, to 26 bcm. Imports are likely to drop even further in 2014 because the gas import price is expected to increase substantially from the price of USD 286/mcm enjoyed by Ukraine since December 2013. Indeed, Gazprom cancelled two discounts. Meanwhile, Ukraine started importing gas from Europe through reverse flow from Hungary and Poland in late 2012, amounting to 2.1 bcm in 2013, and the European Commission is advocating expanding the reverse flows from Slovakia to Ukraine.

Alternative sources of supply for Europe

Experience from previous disruptions of Ukrainian transit shows that alternative supplies can be provided by:

- alternative supply routes from the same supplier (in this case, the routes through Belarus, the Nord Stream and the Blue Stream pipelines);
- alternative suppliers (in this case, North Africa, Azerbaijan, Iran, LNG);
- domestic production;
- storage, both seasonal and fast cycling, noting that the latter tends to be more useful in a short-term crisis. Storage needs to be refilled at a later point, and is therefore an additional demand item; and
- demand reduction or fuel switching, notably in the power sector.

Figure 58 Russian gas flows to Europe through different routes, 2010-13



Alternative routes from Russia can provide some additional supply, but it would be limited at times, notably during winter, as both Blue Stream and the route through Belarus are used at capacity (Figure 58). These routes offer spare capacity during the rest of the year. The only route providing significant re-routing opportunities is Nord Stream. The full capacity of the pipeline (55 bcm per year) has been available since November 2013. By that time, the two connected pipelines in Germany (NEL and OPAL pipelines) became fully operational. Between 2.6 bcm and 2.8 bcm per month have been flowing through the pipeline since then, assuming that between 1.8 bcm and 2 bcm per month of additional gas could be shipped, and provided that the dispute between the European Commission and Gazprom over the regulatory regime applying to these pipelines is solved.

Suppliers to Europe from North Africa are not expected in the short run to be able to provide incremental supply because of high domestic demand and unrest. Algerian pipeline supplies have been falling over the past years, and all pipelines but one (Transmed) are targeting Spain, which has limited interconnections with Europe. Despite some spare capacity available, a non-negligible risk still exists that the Green Stream pipeline from Libya could face a disruption too. Iran's exports to Turkey are lower in winter due to higher Iranian domestic demand, and Iran itself faces rapidly increasing gas demand (see Supply chapter). Besides, Iranian exports are close to the pipeline's capacity, and disputes with Turkey over the pricing of the gas are ongoing. Azerbaijan could potentially provide some limited volumes, as the South Caucasus pipeline is not full. Due to the contractual increase of Azeri deliveries to Turkey, this spare capacity has been declining over 2013 and is now assessed at 0.2 bcm per month.

Domestic production would also provide small incremental supply. Norway could potentially provide 0.5 bcm to 1 bcm on a monthly basis, with a full utilisation of pipelines. Meanwhile, the restrictions imposed on Groningen production imply that the Netherlands would not be in a position to provide additional gas supply. No other European country can be expected to deliver more gas on a sustained basis.

Diverting LNG is another option, albeit quite expensive. In 2009, Egyptian gas was able to be quickly diverted to Greece and Turkey. However, in current market circumstances, reproducing that might be more difficult. Currently, it is questionable whether much LNG could arrive in Europe, even though European LNG terminals (comprising 196 bcm of import capacity) are currently under-utilised at around 25%. Constraints include: tightness of the LNG market, very high prices, uncertain availability of so-called spot cargoes and a time lag before the LNG arrives. LNG spot price levels had been around USD 19 to USD 20/MBtu in Asia during winter in contrast to USD 10.5/MBtu in Europe. Besides, the spot market itself is not very large. According to GIIGNL, the spot and short-term market represents around 27% of global LNG trade in 2013 (87 bcm). However, this estimate includes deals for up to four years, which is not exactly spot market trade; consequently, the spot market would be smaller. Besides, competition exists between Asia, Europe and Latin America for spot cargoes. Furthermore, the first ship would take three weeks to arrive due to the time needed to contract new supply and re-routing time. For example, it takes on average 13 days for a cargo to sail from Qatar to Spain (Cartagena) and 15 days for it to reach the United Kingdom. While diversions of cargoes can and do happen, their availability will continue to be hostage to market rigidities, such as destination clauses.

Storage is an option as long as facilities are relatively full. The winter of 2013/14 was mild, leaving storages well filled in Europe in April in comparison to previous years, despite some disparities between countries. However, note that storage withdrawals in early spring would be much lower than at the beginning of the winter as pressure drops (as well as withdrawal rates) when the storage facility is emptied. Besides, the injection period usually starts around April, at which point the value of storage changes from being a source of supply to a source of demand. Depleted fields and aquifers usually feature low injection rates, so filling them implies that the injection period is not reduced to a couple of months. However, salt caverns are fast-cycling storage and offer more flexibility regarding the duration and the time of refilling, and are generally more useful in times of crisis.

The implications for Europe

Two distinctive scenarios are possible: a “short” disruption similar to that in 2009 and a longer one of several months. In both cases, the timing is of paramount importance. A winter disruption means higher demand, but also that storage can be used. A summer disruption would see lower demand, but also the need to refill storage. In both cases, the assumption is that only a disruption of transit through Ukraine would occur, not a total disruption of Russian flows to European countries.

During wintertime, storage will continue to play a preponderant role, especially in the early winter period. Meanwhile, re-routing Russian gas via Nord Stream, Belarus and Blue Stream could bring on average 2.5 bcm per month, while additional volumes could come from Norway (0.5 bcm), Azerbaijan and potentially LNG, assuming the availability of spot cargoes near Europe. Re-exporting cargoes could speed up their availability. Demand-side measures could also be used, notably switch from gas to coal. But gas use in the power generation sector is at an historical low, reducing the impact of this measure. For Western Europe, demand could only be reduced by 1 bcm per month during wintertime. Nevertheless, southeastern Europe will likely face a disruption because limited alternative supply routes and little storage are available. The most affected country in terms of volumes is likely to be Italy, but it would be able to use efficient markets and storage to obtain missing gas supplies. On the demand side, the increasing importance of renewable energies should be noted. Notwithstanding, they are also an intermittent source of power generation. A windy and sunny season would reduce the demand for fossil fuels, but on the contrary, windless and cloudy weather could also increase demand for gas, worsening a disruption.

A longer disruption during wintertime would reduce the flow from storage facilities as these are progressively depleted. Flows from Russia, Azerbaijan or Norway would remain the same as during a short-term disruption, so that the alternative would be either additional LNG supplies or additional demand-side measures affecting both the industrial and power sectors. Total storage capacity in Europe amounts to 92 bcm and is usually filled at 90% as of end-October. During a normal winter, stocks would usually go down to 30% at the end of March, assuming that an average of 11 bcm per month is taken out of storage. Drawing additional volumes from a tight LNG market would undoubtedly have a price effect that could have a marked global impact. More LNG would, nevertheless, be available if Japan would restart its nuclear power plants and China imported more gas from Turkmenistan when the Line C is completed during 2014.

During summer, storage would not be available. Russia could redirect additional supplies because pipelines are usually less used during summer. While demand for heating would be much lower – demand would be limited to the need for cooking and water heating in most cases – gas would need to be re-injected in storage. A short disruption would be manageable, but a longer one resulting in the inability to refill storage facilities to acceptable levels would simply transfer the shortage to the following winter period. During summer, more switching from gas to coal is possible as the load factors of power plants are usually lower during summer due to lower demand (southern Europe being an exception due to air conditioning needs). Additionally, summer may allow for more LNG to be sourced from global gas markets, provided that countries such as Japan or China do not experience a hot summer, which would result in higher power demand needs.

Global trade to surge by one-third over 2013-19

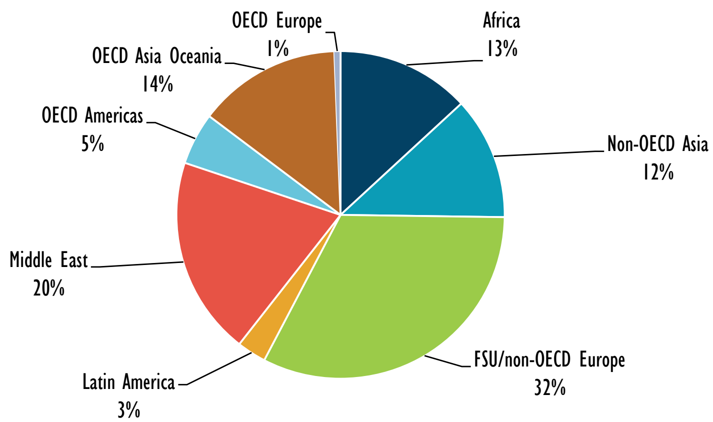
Global gas trade[7] is foreseen to expand by one-third from 2013 levels over the projection period, reaching around 730 bcm. Global LNG trade will bring 130 bcm of new supplies, grow to around 450 bcm by 2019, and thus will increase its share in global trade from 57% in 2013 to 62% in 2019. This growth is supported by the rapid expansion of both LNG liquefaction and regasification capacity (see section on investments in LNG export and import infrastructure). The most notable developments over 2013-19 are the following:

- Global LNG trade expands faster than global pipeline trade over the projection period, as LNG trade grows by 40%, twice faster than pipeline trade. Significant Central Asian deliveries to China enable the country to keep a balance between LNG and pipeline supplies, so that Asian customers do not absorb the entirety of new LNG supplies. Consequently, Europe's LNG imports recover over the forecast period and are in a position to cover most additional import needs. Additional LNG import infrastructure enables LNG to enter into new developing markets in Asia, Latin America and the Middle East.

[7] In this section, non-OECD Europe is included into the FSU region; global interregional trade is, therefore, lower than what is discussed in the recent trends.

- Although the FSU/non-OECD Europe remains by far the largest exporting region, ahead of the Middle East, non-OECD Asia and Africa, its share in global trade, nevertheless, drops from 37% in 2013 to 32% in 2019. The region will significantly penetrate the Chinese market on the back of Central Asian gas, but fail to progress much in Europe. The recovery of Europe's LNG imports after 2016 implies that the increase in FSU's exports to Europe is limited, which represents a significant change compared to our previous forecasts. This drop against total exports will be even more marked in the Middle East, as the region's exports dwindle unlike the FSU/non-OECD Europe. The OECD Americas region will represent 5% of global exports by 2019 from 0% in 2013 (Figure 59), while OECD Asian Oceania grows from 5% in 2013 to 14% in 2019.
- The FSU/non-OECD Europe, OECD Americas and Africa will be net-exporting regions by 2019, with exports increasing over time in each region. While OECD Asia Oceania will still be a net importing region, its exports increase more than any other region. With an additional 70 bcm brought onto the markets, OECD Asia Oceania's exports stand twice as high as those from OECD Americas. In 2016, the United States will start exporting LNG from the Gulf of Mexico, and will ramp up export capacity to become the third-largest LNG exporter by 2019.
- China will become the second-largest importer ahead of OECD Asia Oceania in 2018. Nevertheless, China's gas imports are lower than forecast in the previous *MTGMR 2013* (108 bcm in 2018 against 122 bcm) due to better than expected developments of domestic production. Unlike any other region, China does not export any gas.
- Several non-OECD regions see their net exports declining: non-OECD Asia and Latin America. This decline is driven partly by a combination of lower LNG exports from historical suppliers and increasing LNG imports. The most drastic evolution takes place in non-OECD Asia, where net exports plummet from 30 bcm in 2013 to 1 bcm by 2019 (Figure 63). In contrast, Middle East LNG exports remain relatively stable over 2013-19, despite a dip over the short term, but as the region needs to import more LNG, its net exports decline over time.
- The global LNG market will remain relatively tight over 2014-15. Demand grows in Asia, attracting more LNG away from Europe, where LNG imports will decline to historical low levels. On the supply side, limited additional LNG is expected to come on stream, notably in 2014, despite the timely arrival of the new liquefaction plant in Papua New Guinea. This forecast implies that over the short term, pipeline trade grows faster on the back of expanded deliveries to China and to Europe. Despite the region's attempts to diminish imports from Russia, these imports will still represent a significant portion of Europe's supply.

Figure 59 Total exports by region in 2019



Markets will remain tight over 2014-15 as LNG underperforms

One more year. As the gas industry enters the year 2014, all eyes are on the next one, 2015, when most of the new LNG wave is expected to concretise. Nevertheless, 2014 will not be a boring year. After two years of lower-than-expected LNG trade, LNG trade is widely expected to reconcile itself with its historical upward growth pattern, even though nobody would expect it to be an extraordinary vintage like 2010, which saw global LNG trade gain 59 bcm. Actually, this *MTGMR* forecasts relatively stable LNG trade in 2014. Even though two new LNG plants are expected to come on line (Arzew in Algeria and Queensland Curtis LNG in Australia), they are expected to achieve only limited additional LNG supply at they arrive in the second half of the year and will have to progressively ramp up to plateau by 2015. New LNG plants are, nevertheless, expected to perform better than the Angola LNG plant, which is not expected to reach plateau before end-2014, assuming that Angola's LNG supply in 2014 will be below the plant's capacity of 7 bcm per year.

These new LNG supplies will not compensate for declines in other regions in 2014. The new capacity additions are attracting attention, but the existing LNG supply, which has been dwindling for many years, is also worth watching. With exports standing at 25 bcm, Indonesia is now just a shadow of its previous self, having exported around 30 bcm around 2005. Pertamina already announced that 2014 production will be down by 36 cargoes (around 2.7 bcm) against 2013 levels. Indonesia's output is, therefore, likely to decline in 2014 before it could stabilise in 2015, when Donggi-Senoro starts producing. In the Middle East, both Oman and the United Arab Emirates will continue to face the difficult balancing act of meeting rapidly growing demand, exporting LNG and importing increasing quantities either through LNG or pipeline gas from Qatar. Although the latter is currently quite cheap, any additional pipeline imports or LNG imports would have to be paid at market prices and would be, consequently, considerably more expensive than the domestic gas prices of the countries. LNG exports of both Oman and the United Arab Emirates are, therefore, expected to slightly decline. Egypt is unlikely to be in a position to restore LNG exports to their previous levels, but the spectre of a complete halt of LNG exports looks increasingly likely. This report has taken the assumption of a complete halt of Egyptian LNG exports.

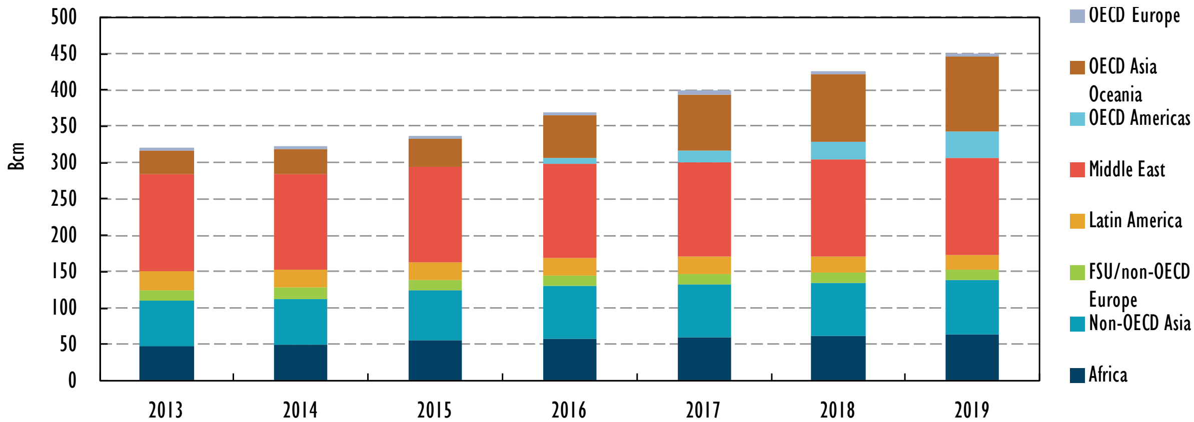
One element will limit the tightness of global gas markets in 2014: the collapse in European gas demand, which is expected to even surpass the drop in production by almost 20 bcm. As Asia continues to offer higher prices than Europe, more LNG will be diverted towards Asian markets. Consequently, the drop in imports from Europe (-20 bcm) is higher than the drop in its LNG imports.

Global LNG trade will, nevertheless, be supported by vessels entering service. Since shipping capacity increases faster than production, this capacity can be expected to bring some relief to charter rates, which had been very high (up to USD 150 000 per day) since Fukushima but have started to come down over the past year to levels around USD 70 000 per day. Such a trend is expected to continue, even though more LNG will find its way to Asia in 2014, implying a higher average shipping distance.

Global LNG trade will reach 450 bcm by 2019

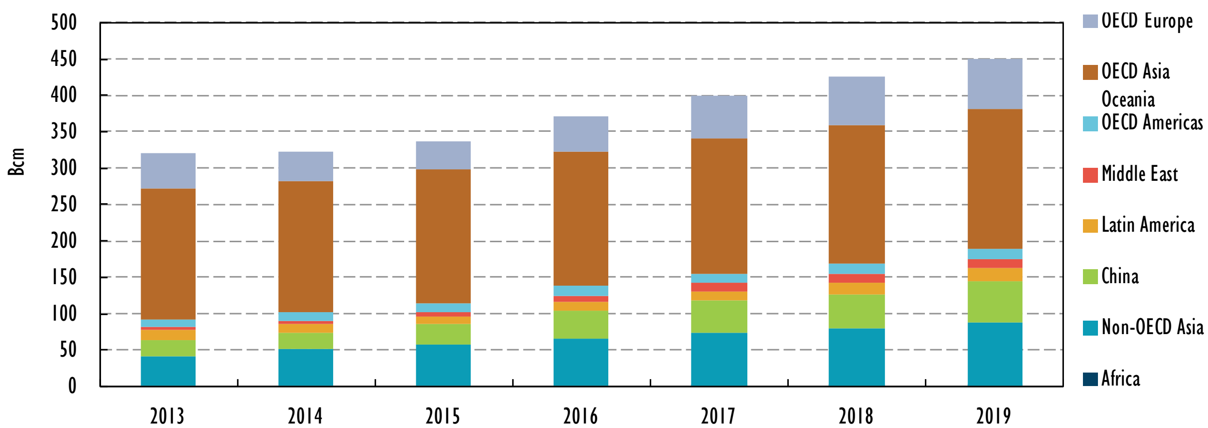
Global LNG trade will rise from 322 bcm to 450 bcm by 2019, whereby LNG will represent 11% of total gas demand (Figure 60). Meanwhile, interregional pipeline trade expands from around 240 bcm to 280 bcm, so that the share of LNG against pipeline gas continues to increase over time. Two reasons explain why global LNG trade expands faster than pipeline over the projection period. The first reason is the expansion in LNG export capacity and improved access to new developing countries through additional LNG regasification capacity. The second reason is that once LNG liquefaction plants are operational and run smoothly, they are expected to run at over 90% of their capacity, even though a question mark still remains over the performance of Australia's CBM-to-LNG plants. Against this backdrop, Asian countries will not swallow all the additional LNG coming on line, and some quantities, albeit limited, will find their way to Europe. Most of Europe's additional import needs over 2013-19 will be covered by LNG.

Figure 60 LNG exports by region, 2013-19



Global LNG trade will start to surge in 2016 as a large part of the Australian LNG projects under construction start operating, and the first US LNG export plant starts as well. By then Papua New Guinea's LNG export plant and Angola LNG are assumed to be fully operational. Export capacity of US LNG is expected to continue to build up over the following years, first based on the Sabine Pass LNG project currently under construction and then based on other projects that received the DOE's approval over 2013-14. Sabine Pass started construction in mid-2012 and is expected to start up late 2015/early 2016, assuming a construction period of 3.5 years, which would serve as a benchmark for other projects based on existing LNG import terminals.

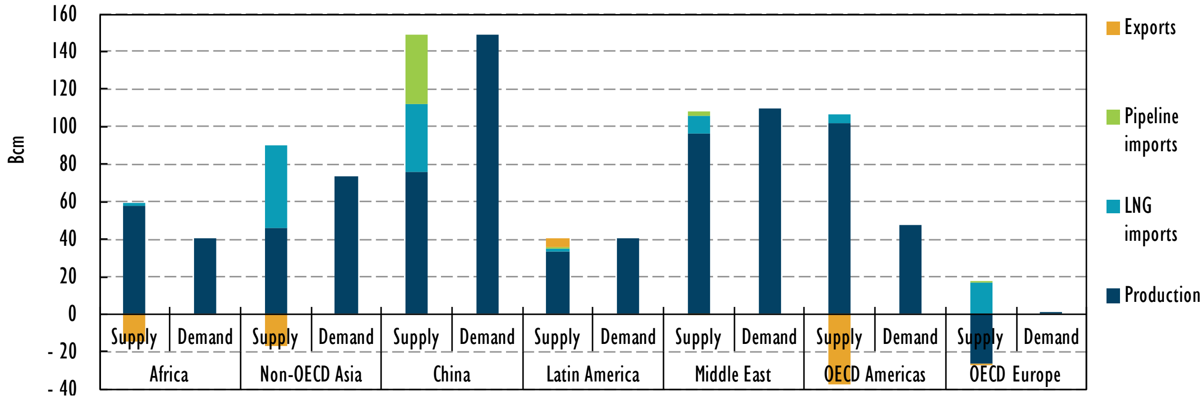
Figure 61 LNG imports by region, 2013-19



Regional trade developments

Europe will remain the largest importing region over the medium term, with imports accounting for around 270 bcm by 2019 (Figure 61). While demand stays almost flat, domestic production will plummet by around 25 bcm, leaving some room for exporters to increase their deliveries. Over the whole period, Europe remains a residual market for LNG, getting what Asian countries do not need, or, in the case of non-OECD Asian countries, cannot afford. Europe also benefits to a certain extent from diversification strategies from large LNG exporters. Due to the tightness in global LNG markets over 2014-15, LNG imports will plummet to a record low of 39 bcm in 2015, before increasing back to around 68 bcm by 2019. LNG imports, therefore, account for most of additional import needs. This forecast allows FSU pipeline exports to remain an important part of Europe's gas supplies, whereby a limited part will come from new Azeri supply to Turkey and the rest from Russia. While imports increase over the projection period, a dip will occur in 2014 as demand declines faster than production due to mild weather in the early part of the year.

Figure 62 How selected regions meet growing demand, 2013-19



Note: numbers may not add up in OECD Europe and OECD Americas due to storage.

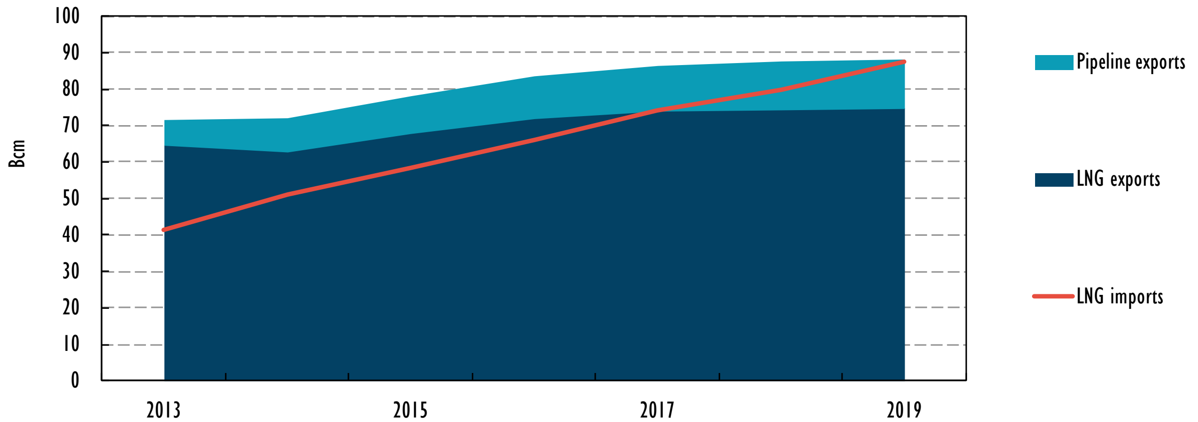
Note: negative values for exports mean that the regions' exports increase; a positive value means a decline. LNG and pipeline exports have been grouped together.

Additonal gas trade will be mostly directed to Asian countries, with China and non-OECD Asia accounting for 74% of the additonal trade (Figure 62). The whole Asian region, including OECD Asia Oceania, will, therefore, represent 56% of global gas trade by 2019. While China turns to both pipeline and LNG imports to meet the widening gap between demand and production, non-OECD Asia and OECD Asia Oceania resort only to LNG, as no pipeline is expected to come on stream by the end of the forecast period, despite many projects under consideration targeting non-OECD Asia. China climbs to the rank of second-largest net importer by 2019: half of its additional imports requirements are met by LNG supplies. Pipeline supplies from Central Asia and, to a lesser extent from Myanmar, account for the rest. Russian gas is not expected to be available by 2019, despite the agreement signed in May 2014. Such deliveries are supported by the expansion of pipeline infrastructure from Central Asia, with the line C of the Central Asia Gas Pipeline being completed by end-2014, while Central Asian producers eagerly ramp up production to supply the Chinese market.

LNG demand in non-OECD Asia will double, reaching almost 90 bcm by 2019 (Figure 63). India will resort to LNG imports: even though its domestic production recovers somewhat, it remains insufficient. Southeast Asian LNG importers will account for around 30 bcm, while they only started importing LNG in 2011. This forecast assumes that, from 2014 onwards, non-OECD Asia will import more LNG than Europe on every single year. At the same time, LNG exports from Brunei and Indonesia combined will decline, even though this decline is compensated for by the start of Papua New Guinea (PNG)

LNG in 2014 and additional liquefaction capacity starting in Malaysia in end-2014 and end-2015. Non-OECD Asian LNG exports consequently expand by 10 bcm, but this is far from compensating for the surge in LNG imports. Of note, the region will also ramp up pipeline exports as Myanmar expands its deliveries to southern China.

Figure 63 How non-OECD Asia moves towards net imports, 2013-19



The OECD Asia Oceania region will become the third-largest net importing region behind Europe and China. While the region's net imports continue to grow to around 200 bcm by 2019, this level stands way below the increase observed over the past decade. The increase in LNG imports is dwarfed by the surge of LNG exports coming from Australia. The country becomes the second-largest LNG supplier as soon as 2014, moving slightly ahead of Malaysia, but it will fail to exceed Qatar's LNG supplies by 2019. Israel's ambitions to become an LNG exporter will not be fulfilled by 2019, even though the country starts exporting pipeline gas to neighbouring countries.

Latin America is also moving towards becoming a net importer. Unlike non-OECD Asia, LNG exports will decline, driven by lower output from Trinidad and Tobago, where production declines. Meanwhile, LNG imports will increase to around 17 bcm by 2019, only 3 bcm higher than in 2013. Indeed, the year 2013 can be considered as exceptional in terms of regional LNG imports and is not expected to be replicated in 2014 and following years, assuming normal hydro levels. This implies lower LNG supplies to the Latin American market over the short term, even though new countries, such as Uruguay, will start importing LNG.

Three regions continue to be significant net exporters – FSU/non-OECD Europe, the Middle East and Africa – while OECD Americas enters this club as soon as 2016. The FSU/non-OECD Europe region is and remains the largest exporting region. Exports could be significantly larger than the quantities exported over the projection period, if one takes the ambitions of Russian producers into account. Russia's production remains actually constrained over 2013-19 due to a limited call for FSU gas in Europe as well as much lower intra-regional exports to other FSU countries. Most of the FSU incremental exports are therefore destined for China. Exports to Europe will be subject to significant variations over the forecast period, depending on the evolution of import needs, which will recover in 2015 on the back of normal weather, and on lower LNG supplies, before dropping afterwards as LNG supplies come back to Europe. The biggest constraint for Russia is the absence of a pipeline from Russia to China, for which a deal was signed in May 2014, but which is not expected to be operational by 2019.

The Middle East region remains the second-largest net exporter, well behind FSU/non-OECD Europe, for which exports are around 70% higher. Middle East's net exports drop over 2013-19 as no new export infrastructure comes on stream while, at the same time, LNG imports triple on the back of new or recently commissioned LNG infrastructure. Pipeline imports from Turkmenistan remain stable, while those from Egypt have stopped altogether. Noteworthy is the start of Jordan's pipeline imports from Israel following a recently signed deal. These supplies are not expected to reach other Middle Eastern countries such as Syria and Lebanon. Africa keeps its position as third-largest net exporter, on the back of new LNG infrastructure from Angola and Algeria, even though the increase in Algerian LNG exports is limited and actually comes from a transfer from pipeline to LNG exports. Consequently, pipeline exports drop over time. Egypt starts importing LNG towards the end of the projection period, so that Africa imports gas for the first time ever.

Investments in LNG export infrastructure

Very few additions have been made to LNG export capacity since the massive capacity increase in 2009-11, which mainly involved Qatar. Only two projects – Algeria's Skikda (6.1 bcm per year) and Angola LNG (7.1 bcm per year) – came on line in 2013. Although Algeria's Gassi Touil (6.4 bcm per year) was expected to be completed in 2013, there is still no certainty regarding a potential starting date, even though officials maintain that the plant will come on line before the end of 2014. As of early 2014, global LNG liquefaction capacity amounts to 390 bcm per year.

Table 19 LNG projects under construction (as of May 2014)

Country	Project	Capacity (bcm/y)	Major stakeholders	Target online
Algeria	Gassi Touil LNG	6.4	Sonatrach	2014
Indonesia	Donggi-Senoro LNG	2.7	Mitsubishi, Pertamina, Kogas, Medco	2014
Indonesia	Sengkang	2.7	Energy World Corporation	2014
Australia	Queensland Curtis LNG*	11.6	BG, CNOOC	2014-15
Malaysia	MLNG mid-scale LNG plant	0.9	Petronas	End-2014
Colombia	Pacific Rubiales FLNG	0.7	Pacific Rubiales, Exmar	2015
Malaysia	MLNG Train 9	4.9	Petronas	End-2015
Australia	Gorgon LNG	20.4	Chevron, Shell, Exxon Mobil	2015-16
Australia	Gladstone LNG*	10.6	Santos, Petronas, Total, Kogas	2015-16
Australia	Australia Pacific LNG (APLNG)*	12.2	ConocoPhillips, Origin, Sinopec	2015-16
Malaysia	Kanowit FLNG**	1.6	Petronas, MISC	2016
United States	Sabine Pass LNG	24.5	Cheniere Energy	2016-17
Australia	Wheatstone	12.1	Chevron, Apache, KUFPEC	2016-17
Australia	Prelude LNG**	4.9	Shell, Inpex, Kogas	2017
Australia	Ichthys	11.4	Inpex, Total	2017-18
Russia	Yamal LNG	22.4	Novatek, Total	2018-20
Total		**150.0**		

*CMB-to-LNG projects.

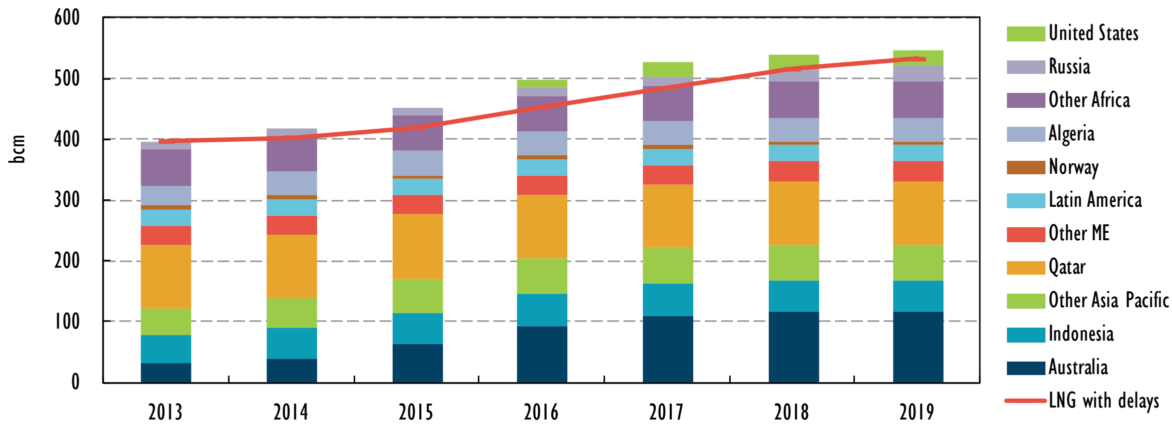
** A floating LNG project.

Source: IEA and companies' websites.

Nevertheless, the construction activity is tremendous (Table 19). Four new projects and one expansion started between early 2013 and early 2014. Malaysia's Petronas started importing LNG in 2013, but also building two new export projects in 2013. Construction of MLNG's train 9 (4.9 bcm per year) began in May 2013 and Kanowit floating LNG (FLNG) (1.6 bcm per year) in June 2013. In addition, Petronas took Final Investment Decision (FID) for the second FLNG project in January 2014, even though construction work had not started as of May 2014. The second FLNG, with LNG production planned to start in early-2018, will bring an additional capacity of 2.0 bcm per year capacity and will be moored at the Rotan gas field offshore Sabah.

Cheniere in the United States has been building the Sabine Pass first and second trains (6.1 bcm per year each) since June 2012 and took FID for the additional two trains (6.1 bcm per year each) in May 2013. In addition, Total and Novatek's Yamal LNG, the second LNG export project in Russia, took FID and announced the start of the construction of the three liquefaction trains of 7.5 bcm per year each in December 2013. Hence, a total liquefaction capacity of 43.3 bcm per year has taken FID since the beginning of 2013, which is quite remarkable on a historical basis. However, no projects in Australia have reached FID since the second train of APLNG in July 2012. In Latin America, a small FLNG project in Colombia is under construction. Gazprom's marketing affiliate has already signed a Heads of Agreement (HoA) to buy 0.7 bcm per year, representing the project's full capacity. The operator, Pacific Rubiales, aims to launch it in 2015, thus making it the first floating LNG in the world.

Figure 64 LNG export capacity, 2013-19



Note: this is based on existing projects as well as projects under construction as of May 2014.

As of May 2014, 16 projects amounting to 150 bcm per year of export capacity are under construction, two-thirds of which is in the Asia-Pacific region (and half of the total in Australia alone). LNG export capacity will start to expand rapidly in early 2015 with the completion of several projects currently under construction (Figure 64). Most projects under construction are to be completed by 2018, according to the companies' statements, apart from the second and third trains of Yamal LNG, which are planned to start in 2019 and 2020, respectively. However, the planned starting dates for the Yamal LNG project seem extremely optimistic. Judging from recent global standards, it takes at least five years to build greenfield LNG facilities. Almost all the recently launched projects such as Australia's Pluto, Angola LNG and Algeria's Skikda were completed about a year behind schedule. Australia's Gorgon and QCLNG have already announced delays from their initial targets. PNG is the only project that came on schedule recently. Many projects currently under construction, such as floating LNG, CBM-to-LNG and construction on permafrost, present technical challenges. Delays for some projects have been announced just before the scheduled completion date, making it difficult to predict outcomes until the projects actually start producing LNG. Based on the considerations above and taking into account the decommissioning of Indonesia's Arun and Algeria's old Skikda plants, global LNG export capacity is expected to reach at least 525 bcm per year by 2020. In addition, other projects looking at taking FID during 2014 could be operational by 2020, notably brownfield LNG regasification plants in the United States.

Who will take the baton from Qatar for 2020 and beyond?

The race to supply new LNG to the world took a new turn in 2013, as a number of US LNG projects were given authorisation to export to non-FTA countries by the United States DOE. Globally, four regions have emerged as being able to individually bring 50 to 100 bcm of LNG to the market: North America, Australia, East Africa and Russia. Against this backdrop, the LNG demand in Asia is limited, prompting non-US LNG suppliers to accelerate their FIDs. The decision by the Russian government to accelerate the LNG liberalisation law and allow non-Gazprom producers to join the LNG race shows that Russia perfectly understands the changing market conditions. Consequently, one Russian LNG project, Yamal, took a surprise FID in late 2013, and other projects are nearing FID. Projects in East Africa and Canada are, therefore, under increasing pressure to take FID, but both face the challenge of developing potentially expensive greenfield projects in remote locations. Meanwhile, Australia has many planned projects beyond those under construction with record-high construction costs. It is, therefore, uncertain whether the Australian LNG industry will further contribute to global LNG supply growth, or whether the current construction boom has already peaked, as appears to be the case. Beyond these four regions, many individual countries with one or several planned LNG projects could also take a slice of the pie by moving faster than others. For example, Malaysia has four small projects.

Australia: repeated cost overruns and delays cloud the next FID

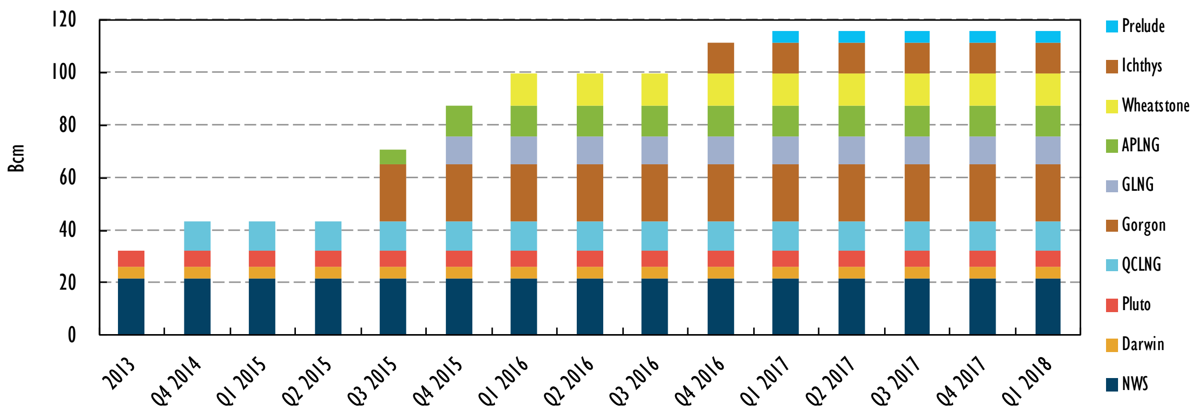
Three LNG liquefaction plants are currently in operation in Australia, representing a total of 32.9 bcm per year of LNG export capacity (Figure 65). All these projects are located in the north of Australia. The first LNG export project is North West Shelf LNG project (NWS), which started with three trains in 1989, adding the fourth and fifth trains in 2004 and 2008, respectively. The second project is Darwin LNG project, with a single train, which started in 2006. The third project, Pluto LNG, has one train, which came on line in mid-2012 after a 14-month delay and 25% cost overrun.

Australia has advantages for LNG projects such as abundant gas resources, a relatively small domestic market and a politically stable investment environment. In addition, healthy LNG demand prospects in neighbouring Asia have spawned an unprecedented FID boom in Australia. The boom started in September 2009 when Gorgon LNG took FID. The other six projects reached FID in a brief 15-month period from October 2010 to January 2012. In June 2012, the second train of APLNG reached FID. In addition to conventional LNG projects, Australia has challenging projects with three CBM-to-LNG projects in Queensland and a floating LNG project. Some 90% of the LNG supply from these projects under construction is already contracted on a long-term basis at oil-indexed prices, and more than 98% of contracted LNG is destined for the Asian market, mainly Japan, China and Korea.

In all, 83 bcm per year are under construction. Although no train will have been completed from mid-2012 to mid-2014, the big expansion of Australian LNG production capacity is anticipated to start in late 2014 with completion of the first train from QCLNG. The second train from QCLNG and the first trains from Gladstone LNG, Gorgon LNG and from APLNG are expected to start operation in 2015. The completion of the second train from APLNG, the first train from Wheatstone LNG and possibly two more trains from Gorgon LNG will follow in 2016. Shell put the starting date of Gorgon in 2016 in a presentation in early 2014, casting some doubts about when the plant would really start. With the second train from Wheatstone, Prelude LNG and two trains from Ichthys LNG also coming on line by 2017, Australia's LNG production capacity would reach 116 bcm per year (over 85 million tonnes per annum [mtpa]) based on projects under construction. Even though some further delays in project completion could occur, Australia is on the way to become the world's largest LNG exporter, ahead of Qatar, by 2020. Nevertheless, one major uncertainty surrounds the CBM projects: when will they reach plateau production, and can the upstream sector sustain gas supply? There are continuing doubts on whether a sufficient number of wells will be drilled in a timely fashion, and if insufficient wells are drilled, or they do not perform as expected, whether the domestic market can make up gas supply.

Australian LNG projects currently under construction are suffering from severe cost overruns and delays. Four out of the seven projects under construction – Gorgon LNG, QCLNG, Gladstone LNG and APLNG – have already announced cost overruns. The delays and cost overruns in Australia's LNG projects are due to several factors. The simultaneous construction rush of these seven LNG projects amid an investment boom in other mining sectors has resulted in a labour shortage and escalation of labour costs, including not only salaries but also housing allowances and fly-in fly-out (FIFO) benefits. Although the tight labour market has shown signs of improvement, the present trends of high labour costs are expected to continue for the foreseeable future. In addition, a lack of infrastructure capacity caused by concentrated location of construction sites has reduced the effectiveness of construction work. Increasing fuel and material costs and the massive and unexpected appreciation of the Australian dollar aggravated the situation. Against this backdrop, no Australian project has reached FID since July 2012, despite many projects now at the planning stage.

Figure 65 Australian LNG projects under construction (as of May 2014), 2013-19



Arrow LNG, a 50/50 joint venture between Shell and PetroChina, is another CBM-to-LNG project, located in Queensland. The proposed production capacity of the project is 10.8 bcm per year (based on two trains in the first phase), which could be expanded up to 24 bcm per year by adding two more trains in the future. PetroChina agreed to off take 5.4 bcm per year, equivalent to the full capacity of the first train, on a long-term basis. Shell also agreed to off take another 5.4 bcm per year from the second train as part of Shell's global LNG portfolio. However, reports indicate that the project has cut at least a fifth of its 1 200 staff, and Shell has ruled out making any commitment in 2014 regarding further development of the project. Although the project has not been formally shelved, investors are reviewing alternative development options such as abandoning construction of the liquefaction plant and selling gas either to the domestic market or to the three LNG projects under construction in Queensland.

Table 20 Potential LNG projects in Australia (as of May 2014)

Project	Capacity (bcm/y)	Major stakeholders	Earliest FID	Earliest online
Arrow LNG*	10.8+	Shell, PetroChina	2015	2020
Pluto LNG train 2**	5.9	Woodside	2014	2019
Gorgon LNG train 4**	6.8	Chevron, Shell, Exxon Mobil	2014	2018
Sunrise FLNG***	6.8	Woodside, Shell, ConocoPhillips	2014	2018
Bonaparte FLNG***	2.7-4.1	GDF Suez, Santos	2015	2019
Browse FLNG***	14.7	Woodside, Chevron, BP	2015	2020
Total	**47.7+**			

*CMB-to-LNG project.
** Expansion of the projects under construction or in operation.
*** A floating LNG project.

Source: IEA and companies' websites.

Woodside, the operator of the Pluto LNG project, has been engaged in two potential LNG projects, Sunrise LNG and Browse LNG, as well as Pluto LNG's expansion. The reservoir of Sunrise LNG straddles Australian water and the Joint Petroleum Development Area (JPDA), which is jointly governed by Australia and Timor Leste. Woodside proposed building a floating production storage and offloading vessel in the Timor Sea, because this option appeared more economic than alternative options. However, the Timor Leste government prefers its plan to build an onshore liquefaction plant in Timor Leste and a 250 km pipeline from the reservoir to the plant because the construction of an onshore plant would create thousands of jobs in the country. The discussion between the project partners and the Timor Leste government is ongoing, but shows no sign of a settlement; therefore, the project's timing remains uncertain.

Another potential Woodside project is Browse LNG. Woodside had initially planned to build a 16.3 bcm per year onshore plant with four trains, which could be potentially expanded to 34 bcm per year. Although it had targeted FID for 2012 and first gas production for 2017, in April 2013, Woodside abandoned the plan to build an onshore plant because the plan was not commercially feasible, and Woodside agreed with Shell to jointly study the possibility to adopt FLNG for the project. Browse had secured two foundation buyers, Osaka Gas and MIMI (a joint venture of Mitsui and Mitsubishi), which would each buy 1.5 mtpa (2 bcm per year). However, MIMI terminated the Sale and Purchase Agreement (SPA) since the project had not reached FID by the end of 2013, but it will maintain its 14.7% equity stake in the project. The current plan is to build three FLNG units of 3.6 mtpa (4.9 bcm per year) each, with front-end engineering and design (FEED) to commence by mid-2014 and to take FID in late 2015. However, Colin Barnett, the Premier of Western Australia, expressed extreme discomfort regarding the decision to abandon the plan to build an onshore liquefaction plant, putting a cloud over the project's future.

In addition to these two projects, Woodside was planning to expand Pluto LNG and had been looking for additional gas supply to feed the new train. However, the company announced in April 2013 that the expansion plan had been suspended because no additional gas resources could be secured.

Chevron, Gorgon LNG's operator, plans to expand the project's capacity by building a fourth train (6.8 bcm per year). Although Gorgon has sufficient gas reserves for the expansion, Chevron is taking a careful approach towards expansion, probably due to repeated cost overruns, intense construction work in the area and technical challenges such as CO_2 sequestration.

GDF Suez and Santos are the sponsors of the Bonaparte FLNG off the coast of Western Australia. The project's proposed capacity would be 2.7 to 4.1 bcm per year. GDF Suez has been very active in marketing its global LNG portfolio in Asia; Bonaparte LNG, once materialised, could become a reliable source of LNG supply to enhance the company's portfolio in Asia-Pacific. Design work was awarded to KBR in November 2012, and FID may be taken in mid-2015.

As just described, many potential LNG projects are planned in Australia. However, most potential projects face challenges such as insufficient gas resources, escalating construction costs, technical problems and, in a few cases, lack of government approval. Consequently, project stakeholders are likely to adopt a wait-and-see attitude. Meanwhile, Australia's LNG is exposed to increasingly severe international competition in the global market initially from the United States, and in the medium to longer term, Canada, Russia and East Africa.

Russia: the LNG liberalisation law opens the door for future LNG exports

As Sakhalin-2 is the only project in operation, the share of Russian LNG exports in global LNG trade is for only around 4%. Russia is very eager to enlarge its share in the global LNG market, especially its share in the Asian market. Nonetheless, the share of Russia gas exports to the Asia-Pacific region in total Russian gas exports remains at a low level – around 6% – and is currently lagging behind the country's ambitious goal. In March 2013, Russia released a plan to raise the share of Russian LNG exports in its total gas exports to 10.2% by 2020. The key target is the Asia-Pacific region, where Russia plans to increase its LNG and pipeline exports. The Russian energy ministry released a first concept note on its new energy strategy to 2035 in January 2014, which aims to increase the share of Russian gas in the region from 6% to 31% by 2035. The three-fold driving forces behind this policy are:

- to decrease Russia's dependence on the European market, where the room for future export increase is limited,
- to target Asian markets, where healthy demand growth is expected in both mature and developing countries and
- to monetise abundant and undeveloped gas resources in the East Siberia and Far East regions.

As the size of future incremental LNG imports is deemed to be limited (+130 bcm over 2013-19 against 150 bcm of capacity under construction), the Russian government moved to accelerate LNG development by liberalising LNG exports on 1 December 2013. The act marked the end of Gazprom's monopoly on LNG exports and allowed companies such as Novatek and Rosneft to export LNG. Accordingly, several LNG projects have made progress (Table 21). Yamal LNG took FID in end-2013 and is currently under construction, while Sakhalin-1, Vladivostok LNG and the Sakhalin-2 expansion are thought to be relatively advanced and near to reaching FID.

Table 21 Potential LNG projects in Russia (as of May 2014)

Project	Capacity (bcm/y)	Major stakeholders	Earliest FID	Earliest online
Sakhalin-1	6.8+	ExxonMobil, Rosneft	2015	2018+
Vladivostok LNG	20.4	Gazprom	2015	2018+
Sakhalin-2 expansion	6.8	Gazprom, Shell, Mitsui, Mitsubishi	2015	2018+
Baltic LNG	13.6	Gazprom	na	2018+
Total	**47.6+**			

Source: IEA and companies' websites.

Yamal LNG is the only project to have taken FID after the enforcement of LNG liberalisation law in December 2013 and it started construction immediately. Novatek has a 60% stake and is playing a leading role in the project. China's CNPC and Total have a 20% stake each, but Novatek plans to sell another 9% stake in the project. Japan's Mitsui and Mitsubishi and three Indian companies, Petronet LNG, ONGC and Indian Oil Corporation, reportedly have interest in the project. CNPC and Gas Natural Fenosa have already signed HoAs for the purchase of 3 mtpa (4.1 bcm per year) and 2.5 mtpa (3.4 bcm per year) of LNG from the project, respectively. The construction cost is estimated at USD 27 billion for all of the three trains of 5.5 mtpa (7.5 bcm per year). Novatek also plans to expand the projects by adding another three trains of 5.5 mtpa (7.5 bcm per year) each after 2022. Shipping to the market in winter season would require ice-breakers or ice-resistant LNG tankers, which have been already ordered by the partners. According to Novatek, Yamal LNG plans to start commercial launch of the first train in 2017. However, the project's construction is very challenging. The climate is very harsh, there is no infrastructure and Yamal LNG will be the world's first LNG project to be built on permafrost. The recent trend shows that the construction period of conventional greenfield LNG projects is five years or more. Therefore, completion of the first train in late 2018 (five years after FID) seems quite optimistic, and some delay could well be expected.

Another non-Gazprom project under consideration is Sakhalin-1, led by Rosneft and ExxonMobil on the basis of Sakhalin-1 gas resources. The project has abundant under-utilised gas and oil resources. An advantage of the project is its closeness to the Asian market and secured gas resources. The construction cost for the single train with a capacity of 5 mtpa (6.8 bcm per year) is expected to be USD 15 billion. Rosneft is considering expanding the project by utilising its other gas fields (Sakhalin-3 and 5) as a source of feedgas. All the LNG produced from the project is already pre-sold to Japanese SODECO and Marubeni and multi-national Vitol through HoA. ExxonMobil and Rosneft started pre-FEED of the project in October 2013, and the work is to be completed by end-2014. The partners expect FID in 2015 and the launch of the project in 2018. However, like Yamal LNG, completing a greenfield project within three to four years seems optimistic.

Gazprom is developing the Vladivostok LNG project. Japan Far East Gas, a consortium of five Japanese companies, signed a memorandum of understanding (MoU) in June 2013 to set the main principles of a further joint study of the project with Gazprom. The project is based on two trains of 5 mtpa (6.8 bcm per year) each with the possibility of further expansion. The construction cost is estimated at USD 13.5 billion for the liquefaction facilities alone. FEED is expected to be completed in the third quarter of 2014. Gazprom has very ambitious plans to start the first train in 2018, followed by the second train in late 2020, which seems very optimistic. The project is likely to be highly challenging, and the project cost will be huge because the project includes development of the gas field (Sakhalin-3, Chayanda, and Kovikta), building the 4 000 km "Power of Siberia" pipeline (which will have an annual capacity of 61 bcm), as well as building the liquefaction plant. However, gas sources could be the same as the Russia-China gas project signed in May 2014. Therefore, the feasibility and competitiveness of LNG produced by this project is still unclear. Given this uncertainty, no provisional gas sales agreements have been signed, even though Gazprom signed four MoUs with Indian companies in 2011 with no designated source of LNG supply.

Sakhalin-2, with two trains of 5 mtpa (6.8 bcm per year) each, is the only Russian LNG project in operation. The consortium of Sakhalin-2, Gazprom, Shell, Mitsui and Mitsubishi is planning to build an additional train to increase capacity by 5 mtpa (6.8 bcm per year). The construction cost is estimated at USD 5 to 7 billion, which is the most cost-effective of the four planned projects in Russia, since this is the only brownfield project. It is unclear which field can feed this project, because reserves of

Sakhalin-2 are not sufficient to supply the third train. One of the options is reserves of Sakhalin-3. Pre-FEED started in mid-2012, and the consortium is reported to be preparing for FEED. Although Gazprom intends to launch the project in 2018, along with the other proposed projects in Russia, the plan seems overly optimistic, even accounting for the advantage brownfield projects have in terms of construction time. This is especially true because the development of Sakhalin-3 might incur some delay.

Baltic LNG is another LNG project driven by Gazprom, with its production targeting in late 2018. Gazprom signed a MoU and Co-operation regarding LNG plant project with the Leningrad Region in June 2013, also with some progress seen by signing an Agreement of Co-operation with Gazprombank to jointly implement Baltic LNG and Vladivostok LNG projects in March 2014.

If all the projects under construction or consideration are completed on schedule, Russia's LNG export capacity would increase by 51.5 mtpa (70 bcm per year) by end-2020, reaching an LNG export capacity of 83.6 bcm per year. However, these assumptions appear to be too optimistic, given the five years or more needed to build greenfield LNG facilities and the challenges faced by the projects, such as the harsh climate, lack of infrastructure, high construction costs, and uncertainty of gas sources. In contrast, the United States will start exporting LNG in late 2015 or early 2016 at probably competitive prices with flexible delivery conditions, with additional projects likely to follow in fairly quick succession. Many competitors will emerge in the late 2010s or early 2020s, such as Canada and East Africa, while Australia will substantially increase its LNG exports from new projects currently under construction. Russia's success in the LNG business is highly dependent on whether Russian LNG can be launched in a timely manner at competitive prices.

North America

The United States

The defining moment for the US LNG industry came in 2013 with the DOE approval of three projects for delivery of LNG to the non-FTA countries, in addition to the DOE's previous authorisation of Sabine Pass in 2011. Freeport LNG was the first to receive the DOE's approval in May 2013, exactly two years after that of Sabine Pass. However, the approval pace increased exponentially when Lake Charles and Cove Point received approval in August and September, respectively. Cameron LNG and the Jordan Cove Energy Project are the latest projects to join the bandwagon, having received approvals from the DOE for non-FTA application in, respectively, February and March 2014 (Map 5). Cameron LNG is set to become the second project to receive Federal Energy Regulatory Commission (FERC)'s approval; on 30 April 2014, the project received a positive response from FERC in its final Environmental Impact Assessment (EIS) that recommended multiple mitigation measures for the project, while concluding that the environmental impact would not be significant i.e. same conclusion as the draft EIS issued on 10 January earlier this year (Table 22).

With DOE approval for deliveries to non-FTA countries, the United States has overcome one of the biggest obstacles to becoming one of the world's largest LNG suppliers, because the majority of LNG buyers are from non-FTA countries. However, the caveat exists that the DOE can revoke the export licence any time if it deems that the project is no longer in the public interest. Nevertheless, the likelihood of this option being exercised is considered very remote, based on two reasons. First, it will be hard to prove the basis of "not in the public interest", and the DOE has also mentioned that it would not revoke an export permit except in the event of extraordinary circumstances. Second, most of the major LNG importers are in the midst of discussing FTAs with the United States and will no longer be subject to this condition, should they sign an FTA agreement. However, another component is still missing: the FERC approval, which can take some time given that it involves looking at all environmental aspects. Finally, building the project may prove harder than many think if the same trend of spiralling costs as observed in Australia also takes place in the United States, although it should be recalled that most projects are based at existing import terminals, with much gas transport infrastructure already in place.

Freeport LNG's export application was an interesting case study in 2013. DOE approved one of the project's applications for exports to non-FTA countries in May for 1.4 billion cubic feet (bcf) per day (14.5 bcm per year) and an additional tranche later in November for another 0.4 bcf per day (4.1 bcm per year). Freeport LNG had requested 1.4 bcf per day of capacity in both applications. While DOE explained that the approved quantity was based on the plant capacity that the project submitted to FERC for approval, Freeport LNG questioned the decision, because the department has previously approved the total capacity of 2.8 bcf per day (29 bcm per year) for its FTA application. Regardless, the issue may be irrelevant, since one of its customers, SK E&S, is from Korea, which has signed an FTA agreement with the United States.

Table 22 US LNG projects with DOE's approval for non-FTA countries (as of May 2014)

Project	Non-FTA capacity (bcm/yr)	Major stakeholders	Expected FID	DOE's approval	FERC's approval
Sabine Pass	22.5	Cheniere Energy	2012	May 2011	April 2012
Freeport LNG	18.4	Freeport, Macquarie	2014	May, Nov 2013	Pending
Lake Charles	20.4	Energy Transfer, BG	2015	Aug 2013	Pending
Cove Point	7.9	Freeport, Macquarie	2014	Sep 2013	Pending
Cameron LNG	17.4	Sempra Energy	2014	Feb 2014	Pending
Jordan Cove Energy	8.2	Veresen	2015	Mar 2014	Pending
Total	**94.8**				

Source: IEA; companies' websites.

Nonetheless, DOE is expected to approve more projects; the Oregon LNG project is next in the queue. As of May 2014, the total approved quantity for exports to non-FTA countries from the five projects was 9.27 bcf per day, which is equivalent to 70 mtpa (95 bcm per year). By comparison, Qatar, which is currently the largest LNG exporter in the world, has a total production capacity of 77 mtpa (105 bcm per year). As of May 2014, the DOE is currently reviewing 23 non-FTA applications (excluding Trunkline's Freeport). Even if none of the remaining applications is approved by the DOE, the United States will still be the third-largest LNG exporter in the world by the end of the decade, or soon after, assuming all six projects obtain all necessary approvals by the relevant authorities, including FERC, and take FID in a timely fashion. Until now, only Sabine Pass has taken FID.

The United States has three competitive advantages that may put the country in the lead over other regions in capturing LNG demand from LNG buyers. An extensive gas infrastructure is already in place to support the LNG industry, and gas output is burgeoning on the back of remarkable growth in shale gas production. Liquid and transparent gas markets based on spot markets allow the projects to offer LNG contracts with Henry Hub-indexed pricing and no Take-or-Pay obligation, two items that are exceptionally desirable for Asian buyers. The capital cost for developing US LNG plants also contributes to the success of the country's LNG export industry, as it is relatively cheaper than other regions due to the brownfield nature of at least some of its LNG export projects. While Sabine Pass and several other proposed projects are brownfield, the rest are greenfield and as such will be one of the deciding factors for the total LNG export quantity from the United States in view of competition from other regions.

Map 5 US LNG liquefaction plants under construction and planned (as of May 2014)

No.	Project	Non-FTA capacity (Bcf/d)
United States Projects approved by DOE for both FTA and non-FTA applications		
1	Sabine Pass	2.2*
2	Freeport LNG	1.8
3	Lake Charles	2
4	Cove Point LNG	0.77
5	Cameron LNG	1.7
6	Jordan Cove Energy	0.8
United States Projects approved for FTA, pending approval from DOE for non-FTA application		
1	Carib Energy	0.01
2	Gulf Coast LNG	2.8
3	Gulf LNG	1.5
4	Oregon LNG	1.25
5	Southern LNG	0.5
6	Lavaca Bay LNG	1.38
7	Golden Pass	2.6
8	Corpus Christi LNG	2.1
9	CE FLNG	1.07
10	Waller LNG Services	0.19
11	Pangea LNG	1.09
12	Magnolia LNG	1.08**
13	Gasfin Development	0.2
14	Main Pass - Freeport-McMoRan	3.22
15	Venture Global	0.67
16	Eos LNG & Barca LNG	3.2
United States Projects pending approval from DOE for both FTA and non-FTA applications		
1	Delfin LNG	1.8
2	Texas LNG	0.27
United States Projects pending approval from DOE for FTA application		
1	Annova LNG	0.94
2	Louisiana LNG Energy	0.27

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

* Sabine Pass obtains non-FTA's approval for 2.2 Bcf/d and is awaiting approval from the DOE for another 1.38 Bcf/d as of February 2014.

** Magnolia LNG obtained FTA's approval for 0.54 Bcf/d and is awaiting approval from the DOE for another 0.54 Bcf/d and non-FTA's capacity of 1.08 Bcf/d.

Canada

If the US LNG projects became the centre of attention in 2012 for the LNG industry, the focus has expanded to include Canadian LNG projects as well (Table 23). Canada has outpaced its neighbour, based on the number of approved export applications. As of May 2014, 11 LNG projects including US projects Jordan Cove Energy and Oregon LNG have been approved by Canada's National Energy Board (NEB); five projects alone were approved by the Board in 2013. The nine Canadian projects represent an LNG export capacity of around 157 bcm per year. Most projects are quite large projects, while three projects have a capacity of around 3 bcm per year. The NEB is currently reviewing three other export applications. However, the projects still require approval from the federal government and other provincial authorities, including the First Nations, before they can proceed with construction. BC LNG and Kitimat LNG are in the race to become the first LNG project in Canada, with Kitimat LNG ahead, as it is in a more advanced stage than the former. In January 2014, Kitimat LNG awarded an engineering, procurement and construction (EPC) contract to the consortium of Fluor and JGC. The project obtained the NEB's approval in 2011 and is expected to announce FID this year after having had delays for several years.

The east coast of Canada stole the limelight from the west coast in June 2013, when Goldboro LNG, a 10 mtpa (13.6 bcm per year) capacity project, announced a deal with E.ON for LNG volumes of 5 mtpa (6.8 bcm per year) for 20 years. Pieridae Energy, the project developer, plans to take FID in 2015 and to commence commercial operations in 2020. The project is one of the export applications currently being reviewed by the NEB. Established only in 2011, Pieridae Energy is a newcomer to the industry, but its CEO was the founder of Galveston LNG, a former parent company of Kitimat LNG.

Although the United States is blessed with extensive gas infrastructure and the attractiveness of its contract terms, which offer full gas-indexed pricing, combined with no obligations to take (although the off-takers will still need to pay the liquefaction fee), this is not the case for Canada. The *MTGMR 2013* listed four key challenges for the country: namely, higher costs, the apparent insistence on oil price indexation, timing and the environmental impact of the projects. All LNG projects in the west coast are greenfield and require huge capital investments, especially to build the LNG plants and hundreds of kilometres of pipeline to bring the gas from the production fields in Alberta and eastern British Columbia, through the Rocky Mountains to the LNG plants.

The apparent high capital costs and timing emerge as potential drawbacks to developing the Canadian LNG industry. In February 2014, Suncor announced that it had pulled out from the LNG race and attributed the decision to the timing. Previously, Suncor announced in 2013 that the company planned to join the country's LNG export foray. Kitimat LNG's project developers are offering oil-indexed pricing to potential Asian buyers in a move seen to reflect the project's capital costs. However, it is not in line with the buyers' preference for gas-indexed pricing. Chevron, the co-developer of the project, admitted in April 2013 to issues with regard to the prices, but insisted that deviation from oil price indexation is a non-starter. In February 2014, the government of British Columbia announced an LNG tax proposal, consisting of a two-tiered tax plan. Under the tax plan, the LNG plants will be subject to 1.5% tax on the net income during the first tier, of which the rate could be increased up to 7% during the second tier once the plants recover the capital costs. The project developers have already responded to the tax plan, expressing concern about the high rate for the second tier and seeking further clarification from the government before making FID.

Table 23 Canada LNG projects with NEB's approval (as of May 2014)

Project	Capacity (bcm/yr)	Major stakeholders	Expected FID	NEB's approval	Target timeline
Kitimat LNG	13.6	Chevron, Apache	2014+	Oct 2011	2018+
BC LNG	2.4	LNG partners, Haisla First Nations	2014+	Feb 2012	2018+
LNG Canada	32.6	Shell, PetroChina, Kogas, Mitsubishi	2014+	Feb 2013	2019+
Pacific NorthWest LNG	16.3+	Petronas, Japan Petroleum Exploration (JAPEX), Petroleum Brunei, IOCL, Sinopec	2014	Dec 2013	2018+
Prince Rupert LNG	28.6	BG	2015	Dec 2013	2021+
WCC LNG	40.8	Imperial Oil, ExxonMobil	n/a	Dec 2013	2021+
Woodfibre LNG Export	2.9	Woodfibre	2015+	Dec 2013	2017+
Triton LNG (FLNG)	3.1	AltaGas, Idemitsu	2014+	Apr 2014	2017+
Aurora LNG	16.3+	CNOOC, Inpex, JGC	2015+	May 2014	2021+
Total	**156.6+**				

Source: IEA; companies' websites.

Box 14 Hybrid pricing: The way to go?

That some potential LNG exporters may favour oil-indexed pricing over gas-indexed pricing may be met with strong reservations from potential buyers, as can be seen in the case of Kitimat LNG. While the Henry Hub (HH) appears to be the ideal option for buyers, Canada has its own gas index comparable to Henry Hub, called the AECO Hub, owned by Niska Gas Storage. Between the two indices, AECO could be the ideal index for LNG projects located in Canada, based on a number of factors. Despite close correlation with Henry Hub at the moment, AECO Hub may behave differently in the future based on developments in the natural gas export industry in both the United States and Canada. Thus, the use of Henry Hub may result in a price risk to LNG players in Canada, as the country has no control over Henry Hub, but this may be a risk that players are willing to take. Even though HH tends to be volatile and susceptible to the extreme weather conditions (HH ranged from a low of USD 1.82/MBtu in April 2012 to a high of USD 7.90/MBtu in February 2014 due to cold weather), investors are interested in the long-term evolution, not in short-term variations. However, should LNG projects decide to employ AECO over Henry Hub, they may face an uphill task to convince their potential buyers, because it is relatively unknown to Asian buyers.

There are possible compromises to address this potential impasse on the pricing structure, which can significantly affect the future of LNG exports in Canada if not handled diligently. The first option is to follow the US pricing structure, albeit at a much higher constant (liquefaction fee) to reflect the capital cost and exclusion of oil indexation. In spite of shipping savings made from the shorter distance between Canada and Asian markets, the higher cost of building LNG plants and constructing pipelines from the gas fields to the plants is expected to outweigh the freight savings, hence the higher constant. At the same time, a slight premium may be added to the price formula to compensate for the removal of oil indexation, which has been part of the LNG price formula for decades. At the same time, the US example shows that LNG export plants and pipelines can be financed without oil indexation, but with contracts with capacity reservations. The second option is to adopt a hybrid pricing structure that comprises both oil and HH-indexed price formulas. Under this option, the LNG projects and potential buyers will need to agree on the percentage of oil and Henry Hub or AECO Hub-indexed price formulas on top of agreeing on the slopes and constants for both formulas. The latter option could be more attractive to both parties, as they still get to maintain their preferred index and can hedge any indices to mitigate any uncertainties and volatilities in the global LNG market. The market would seem ripe for more innovative approaches to pricing.

Notwithstanding that, the *MTGMR 2013* also highlighted two main advantages for Canada: the shorter distance to the Asian market and strong support from the government. Canada needs to find a new outlet for its natural gas because export volumes to the United States, until now Canada's sole customer for its natural gas, have been decreasing considerably due to the boom in the US shale gas industry. Thus, the Canadian government remains supportive of new exports. The shorter distance also has proved to be decisive, as a number of Asian companies are involved in the Canadian LNG projects. LNG suppliers Petronas and Petroleum Brunei are participating in the proposed projects. Besides serving existing customers in the Asian market, the volumes could also be transported to their respective countries to meet domestic demand.

In addition, one interesting arrangement that Canadian projects seem to employ is the participation of all partners throughout the business chain. Previously, LNG projects involved seller and buyer, and sometimes buyers were offered some equity, though a small portion, to entice them to purchase LNG from the project. PetroChina, Kogas, and Mitsubishi are expected to have off take volumes equivalent to their shares in the LNG Canada project. Japex, Brunei, IOCL and Sinopec are the current off-takers besides Petronas in the Pacific NorthWest LNG project. Canada's innovative arrangements, as applied by Petronas for its Pacific NorthWest LNG and potentially by Shell for its LNG Canada, are expected to attract potential buyers. While US LNG projects enjoy low investment costs of around USD 500/tonne per year by virtue of their brownfield nature, LNG project developers in Canada face investment costs of at least USD 1 000/tonne per year (not including pipeline and upstream costs). With the higher investment costs compared to the US counterparts, this arrangement may be the deciding factor for the success of the LNG industry in Canada, as the partners will try to reduce the cost as much as possible while at the same time ensuring reasonable returns on the projects.

East Africa

Exploration for oil and gas in East Africa started as early as 1904 in Mozambique. However, the recent huge offshore discoveries of natural gas in Mozambique and Tanzania from 2011 to 2013 have put East Africa on the global natural gas map (Table 24). The total discoveries of recoverable gas reserves of up to 140 tcf (3.9 tcm) in Mozambique and up to 35 tcf (1 tcm) in Tanzania make the case for East Africa competing with North America and Australia in terms of new LNG projects.

The two leading players in Mozambique, Eni and Anadarko, reached a milestone in December 2012 when they signed an HoA to jointly develop an LNG liquefaction plant in the Cabo Delgado province of northern Mozambique. The liquefaction plant will have an initial four trains each with capacity of 5 mtpa (6.8 bcm per year) and will have an eventual total capacity of up to 50 mtpa (68 bcm per year). At the same time, Eni and its partners are also considering building a floating LNG liquefaction terminal in their Area 4, although such a move is not favoured by the local government. Meanwhile in Tanzania, Statoil and BG also plan to jointly develop an LNG project and are currently working with the Tanzanian government and other partners to find a suitable location for the project.

Besides the four key companies, the other major players are also showing an interest in being part of the LNG revolution in the region. ExxonMobil is Statoil's partner in Tanzania, and its vast experience in upstream, development and operations of LNG plants is expected to boost the project's rating and feasibility. Shell was also joining the pursuit to have a stake in Mozambique before it eventually withdrew its bid, paving the way for PTTEP to successfully win the tender to become Anadarko's partner. Petronas and Total are also present in Mozambique, although their involvement is currently limited to exploration activities in Areas 3 and 6. In addition, Gazprom is also eyeing participation in the region, with ongoing discussions with Eni and the local governments in Mozambique and Tanzania.

Table 24 Summary of LNG projects in Mozambique and Tanzania (as of February 2014)

Project	Capacity (bcm/yr)	Major stakeholders	Gas field	Expected FID	Target online
Mozambique LNG	27.2+	Anadarko (op.), Mitsui, ENH, Bharat, ONGC, PTTEP	Area 1	2014	2018+
		Eni (op.), CNPC, ENH, Kogas, Galp	Area 4		
Mozambique FLNG	n/a	Eni (op.), CNPC, ENH, Kogas, Galp	Area 4		
Tanzania LNG	n/a	Statoil (op.), ExxonMobil	Block 2	2016+	2021+
		BG (op.), Ophir, Pavilion	Block 1, 3 and 4		
Total	**27.2+**				

Note: "ENH" is Empresa Nacional de Hidrocarbonetos.

Source: IEA; companies' websites.

East Africa could become one of the world's largest LNG exporters in the post 2020 period, based on its competitive advantages. Its geographical location, which is perfectly situated to serve Latin American, European and Asian markets, proves to be its key strength in attracting both potential investors and off-takers. As the closest Asian market, India is perceived as a natural market for East African gas. Unlike existing LNG projects in Asia-Pacific, where shipping distances to Far East and South East Asian regions are shorter than to India, East Africa can afford to have lower prices for Indian buyers through the freight savings made of about USD 0.5/MBtu. That several Indian companies are participating in Mozambique, together with ongoing discussions between GAIL and Ophir for a stake in Tanzania, exemplify this benefit. The East African LNG players can also utilise their geographical location to their advantage via arbitrage opportunities based on the current price divergence situation, particularly during the winter in the northern hemisphere. Having conventional gas fields can also add to the attractiveness of East African LNG projects, but the costs of developing offshore fields are still unknown. The massive size of gas fields found in Mozambique will contribute to a further reduction in unit cost, hence giving the upper hand to these developers.

The past few years attracted many new players eager to secure a foothold in East Africa's new gas resources. Many of these new investors are Asian buyers. Asian companies made a number of huge investments in East Africa in 2013, notwithstanding that some Asian companies such as Mitsui, Kogas, Bharat Petroleum and Petronas, have been present for a long time, even before the discoveries were made. China's CNPC bought 28.57% interest in Eni's East Africa for USD 4.2 billion, which is equivalent to 20% interest in Mozambique's Area 4. India's ONGC also participated in the race through purchase of Anadarko's 10% interest in Mozambique's Area 1 for USD 2.64 billion. Inpex too joined its fellow Japanese company Mitsui in Mozambique by acquiring Statoil's 25% share in Areas 2 and 5.

Companies from smaller LNG-importing countries are also investing, such as Thailand's PTTEP, which acquired an 8.5% share in Area 1 in 2012, after Shell pulled out. Meanwhile in Tanzania, Pavilion, the LNG trading arm for Singapore's Temasek, agreed to pay Ophir USD 1.3 billion for a 20% interest in Blocks 1, 3 and 4. Together, these blocks hold an estimated 15 tcf (0.4 tcm) of gas resources. The incorporation of the company is in line with Singapore's ambition to become Asia's LNG hub. The involvement by key LNG importers is anticipated to have a positive impact on the LNG agenda in East Africa, because the companies will want to ensure a positive return for their investments, alongside their top priority to have the lowest possible cost for delivery of LNG to their respective countries.

The involvement of Mitsui and Inpex in Mozambique gives a strong signal that part of the LNG volumes will definitely find a home in Japan, at a time when Japanese buyers are looking to find a more diversified supply portfolio and more competitive gas pricing to Japan. Mitsui stated that it plans to sell at least 5 mtpa (6.8 bcm per year) to Japan, and the big Japanese buyers – Tokyo Electric, Tokyo Gas and Osaka Gas – have also identified Mozambique for potential LNG supply. The Japanese government gave the same signal when Shinzo Abe, Japanese Prime Minister, pledged to invest JPY 70 billion (USD 0.7 billion) in energy-related projects in Mozambique during his trip to the African continent in early 2014. Meanwhile, Kogas, has expressed interest in increasing its current 10% interest in Area 4 in Mozambique in view of the promising outlook for the block while divesting part of its interest in Australian and Canadian projects due to potential low profitability.

Indian buyers have been very active in East Africa, given its proximity to India. Bharat Petroleum and Videocon own 10% of Anadarko's Area 1. In 2013, ONGC, together with Oil India, successfully acquired a 10% interest in the project after taking over Videocon's 10% shares. ONGC then increased its shares by another 10% by acquiring Anadarko's equity portion, bringing the total percentage held by Indian companies in Area 1 to 30%. In Tanzania, GAIL is still negotiating with Ophyr for the remaining shares in Tanzania's gas field, after having lost a bid for the 20% interest in Blocks 1, 3 and 4.

Mozambique is still leading the race

The *MTGMR 2013* highlighted that Mozambique seems to be leading the race in becoming the first East African country to export LNG. The developments throughout 2013 in both Mozambique and Tanzania (outlined below) suggest that this forecast still stands.

- **Sufficient gas reserves to support an LNG liquefaction plant.** To date, Anadarko and Eni have discovered 65 tcf (1.8 tcm) and 80 tcf (2.2 tcm), respectively. This is much more than enough to each build their own large LNG plants, although the companies are opting to jointly develop the LNG plant in northern Mozambique. As for Tanzania, the government has recommended that both Statoil and BG jointly develop the two-train LNG plant because of cost optimisation and because neither company has sufficient gas reserves to build a two-train LNG project separately. However, the recent discoveries announced by Statoil and BG in December 2013, which saw an increase of about 3 and 5 tcf, respectively, to their gas reserves portfolio may present a different story.
- **Domestic gas policy.** Mozambique has no objection to exporting its LNG due to its relatively small domestic market compared to the country's total gas reserves. In addition, the country has already been exporting the majority of its natural gas to South Africa via pipeline. The situation is different for Tanzania, however. The local government has made its intention clear to prioritise the domestic over the export market. The "Natural Gas Policy of Tanzania 2013", which was approved by Tanzania's cabinet in October 2013, states that the domestic market will be given first priority over the export market in gas supply. Although this is a commonly held practice in non-OECD exporting countries, it could be the main stumbling block to the country's natural gas development due to two issues: probable subsidised domestic prices and insufficient gas resources that could not be developed economically at a low regulated price. The anticipated low investment return on the subsidised domestic market, combined with a potential supply disruption of gas exports in favour of the domestic market, would make foreign investors think twice before investing in the country. The negative impact of this policy is evident from the gas shortage situation in Egypt, during which one of its LNG plants was shut down due to insufficient feedgas and the other one declared *force majeure* as the local government diverted the export supplies to the domestic market (see section on Egypt in the Supply chapter).

- **Policy implementation.** The Mozambique government has started working towards implementation of a Master Plan developed by consulting firm ICF International. The report emphasises the key elements of successful petroleum legal frameworks, as laid out in the World Bank Study, which attests that Mozambique is well positioned for a well-formed regulatory framework. In April 2013, Mozambique's national oil company ENH approved a study on a USD 4 billion gas pipeline to Maputo. The contents of Tanzania's natural gas policy are broad in general, thus the detailed implementation of the policy is paramount to determining the future of natural gas.

However, both Mozambique and Tanzania face huge obstacles to realise their dreams of joining the LNG foray as LNG suppliers. Besides the challenges highlighted in the *MTGMR 2013* – namely, the change in ownership of resources, the inexperience of local government and potential issues related to land access – the region is also faced with unfortunate timing, financing requirements, and lack of infrastructure and political stability, which could all be detrimental to their goal of exporting LNG by as early as 2018. East Africa's natural gas discoveries come at the critical time when LNG buyers are looking for lower LNG prices, based on spot indexation. Furthermore, only a limited LNG demand pie is available for all the planned projects and therefore a limited window of opportunity to take FID. In contrast, Australia's new LNG projects currently under construction were fortunate because they managed to secure contracts before the US shale gas boom. However, it is not the case at the moment for East Africa and other recently proposed LNG projects in Australia and Canada. Thus, the success of the East African LNG projects may hinge on the players' decisions to either expedite the projects and join the crowd now to capture whatever demand remains from the LNG market, or wait and hope that not all proposed LNG projects will be on line as reported, and subsequently capture the uncontracted demand at more favourable terms to them. Anadarko seems to prefer the former strategy by announcing its plan to sign a HoA with potential LNG buyers in 2013 and 2014 for FID late in 2014, to reach its target of shipping the first cargo in 2018.

Development of LNG projects requires a long lead time, large capital investments, and – most of the time – the developers will seek external financing in addition to contributions by all project partners. Normally, lenders will review the terms and conditions of the long-term sales agreements to ensure feasibility of the projects to have a stable stream of revenue before giving approval for financing. Take-or-Pay is a "must-have" clause in this approval process, unless the project sponsor takes the gas for its own portfolio. In contrast, the current trend is moving towards more flexible terms, whereby all rigid terms such as oil-indexed pricing and fixed destination are becoming obsolete, which can be seen in all LNG contracts signed by the US projects. Therefore, it will be interesting to see how East African players achieve the right balance between satisfying financing requirements by lenders and attracting potential buyers with the terms acceptable to them. At the same time, both Mozambique and Tanzania are essentially virgin areas, with no or very limited infrastructure to support big natural gas development. Eni and BG have already voiced their concerns on this challenge, and Eni, in particular, has mentioned that it will be very challenging to meet the target of 2018 based on the current state of infrastructure.

Political issues could also result in a reversal of positions between Mozambique and Tanzania in the race to export LNG. Tanzania has been enjoying stability since its independence in 1961 and is considered to be a role model for other African countries when it comes to peace and political stability. In contrast, Mozambique was caught up in a two-decade civil war from 1975 to 1992, which ended through the General Peace Agreement signed in October 1992. Since then, Mozambique has been enjoying peace and even appeared on the list of the 50 most peaceful countries in the world, surpassing Tanzania in a 2012 report published by Global Peace Index. However, this current state may be threatened by the recent conflict between the government and the country's largest opposition party, Renamo, during which the Renamo ended the 1992 peace pact in October 2012 after government forces attacked the base of its leader. The undeclared war that started in central Mozambique in 2013 has now spread into the northern and southern regions of the country.

Non-OECD Asia

Indonesia and Malaysia are traditional Asian LNG exporters that share the same fate of declining existing gas production and rising domestic demand. They are currently constructing new liquefaction plants and plan to build a few more in a move to fulfil domestic demand and maintain their positions as key LNG suppliers (Table 25). Indonesia's neighbour, Papua New Guinea, will also be joining the elite club of LNG exporters when its first LNG liquefaction plant starts producing cargo in mid-2014.

Table 25 Potential LNG projects in non-OECD Asia (as of May 2014)

Project	Capacity (bcm/y)	Major stakeholders	Earliest FID	Earliest online
Tangguh 3rd train	5.2	BP	2015	2019
Abadi LNG	3.4	Inpex	n/a	n/a
Gulf LNG	15.0	InterOil, Total	2016	2020
Stanley LNG	4.1	Horizon Oil, Osaka Gas, Mitsubishi, Talisman	n/a	n/a
Total	**27.7**			

Source: IEA and companies' websites.

Indonesia

The liquefaction projects under construction in Indonesia are Donggi-Senoro LNG and Sengkang LNG, owned by Mitsubishi and the Energy World Corporation, respectively. Both projects, which will be located in Sulawesi, are relatively small in size, with a planned production capacity of 2 mtpa (2.7 bcm per year) each. Donggi-Senoro has contracted its entire plant capacity to Asian buyers, but Sengkang LNG's volumes are yet to be sold. Previously, Sengkang LNG had signed HoAs with Indonesia's PGN in 2009 and Tokyo Gas in 2010. However, no progress has been reported on the contracts since then. Nevertheless, Energy World Corporation (EWC) continues to pursue construction of Sengkang LNG, and the project is expected to commence at the end of 2014, as per the company's target in its 2013 annual report.

Several other projects are also being planned, namely, Tangguh's third train and Abadi LNG. BP, the operator of Tangguh LNG, is planning to expand the plant capacity through addition of a 3.8 mtpa train. Tangguh currently has a production capacity of 7.6 mtpa (10.3 bcm per year) from the existing two trains. The Indonesian government approved the expansion plan in 2012, which will see 40% of the additional volumes being directed to the domestic market. Meanwhile, Inpex is also planning to build Indonesia's first floating LNG project in Masela, Abadi LNG, with a production capacity of 2.5 mtpa (3.4 bcm per year). The project obtained approval from the government in 2010 and is currently undergoing a FEED study.

Malaysia

Petronas is overseeing four ongoing LNG projects that will increase Malaysia's LNG production capacity by 7 mtpa (9.5 bcm per year) when completed by 2018. Malaysia LNG (MLNG), a subsidiary of Petronas, awarded a contract to Linde in November 2012 to build a mid-scale LNG plant through re-liquefaction of boil-off gases from LNG storage tanks and ships during loading. The mid-scale plant is expected to be completed by the end of 2014 and will give an additional volume of 0.67 mtpa (0.9 bcm per year) to the Bintulu plant. Petronas is also expanding the Bintulu plant's capacity through construction of a new train, dubbed Train 9 project, which is expected to be completed by the end of 2015. Construction started in mid-2013, which means that the plant would be completed in less than three years. Once operational, the new train will add 3.6 mtpa (4.9 bcm per year) to the existing total LNG production in Bintulu of 25.7 mtpa (35 bcm per year). Concurrently, the construction of Malaysia's first floating LNG project is under way and is expected to be completed at around the same time as the Train 9 project. Petronas's second floating LNG project (FLNG2) is also on track to be on line by 2018, as announced in February 2014 by the company, together with the US energy company Murphy Oil Corporation. The FLNG2 will have 1.5 mtpa (2 bcm per year) capacity through gas monetisation of the Rotan field, which is located offshore of Sabah.

PNG

PNG reached a big milestone in September 2013 with commissioning activities for the country's first LNG liquefaction plant. In April 2014, PNG LNG project's operator, ExxonMobil announced that the project had started production, ahead of schedule with the first LNG cargo expected to be shipped by June 2014. PNG LNG has already signed SPAs with Sinopec, Tokyo Electric, Osaka Gas and CPC for the total volume of 6.6 mtpa (9 bcm per year). The project is built in slightly less than five years, a remarkable feat given that no infrastructure existed in the country.

In addition to PNG LNG, two more LNG projects could be developed in Papua New Guinea. InterOil and Total are currently considering an LNG plant in Gulf Province using gas from the Elk and Antelope gas fields, which are considered the largest gas discoveries in Asia in recent years (recoverable reserves are between 193 bcm and 307 bcm). Total became InterOil's partner in December 2013 when it beat out ExxonMobil and Shell to acquire a 61.3% interest in the gas fields. The project, which obtained government approval in 2012, will have a capacity of 11 mtpa (15 bcm per year) when operational. InterOil and Total are expected to announce FID for the project by 2016, with first production of LNG in 2020, which may be optimistic in terms of construction time. Meanwhile, Horizon Oil is also planning to build a 3 mtpa (4.1 bcm per year) LNG plant, using its Stanley gas field, where it has a 30% interest. In spite of Horizon Oil's lack of experience in the LNG business, the project seems feasible, based on the experience and competency of other partners, namely Osaka Gas, Mitsubishi and Talisman.

In other regions: Many planned projects but no significant progress

LNG projects are also under consideration in other regions, such as the Middle East, Africa and OECD Asia Oceania, but none of them has made significant progress. Some, such as the LNG project in Israel, even suffered a significant setback.

In North Africa, two projects came on line in 2013, Algeria's Skikda (6.1 bcm per year) and Angola LNG (7.1 bcm per year). Algeria's Gassi Touil (6.4 bcm per year) is the only project still under construction in the region. Although planned for 2013, there is no certainty that the project will be launched in 2014. Nigeria has over 80 bcm of planned LNG capacity and has the greatest potential as the source of LNG supply in the region. Among the planned projects in the country, Brass LNG and NLNG train 7 are the most advanced projects. The largest shareholder in the projects, the Nigerian National Petroleum Company (NNCP), expected to take FID for both projects in 2013. However, this did not materialise and more than a decade has passed since NNCP's initial plan to take FID. Regarding Brass LNG, one of the major shareholders, ConocoPhillips, expressed the intention to sell its share of Brass LNG to pursue other business interests. In November 2013, the company postponed the deadline for withdrawal from the project until the end of June 2014. The project will not go forward until ConocoPhillips exits, and the project may suffer from further delays. Most LNG produced from NLNG train 7 is already committed to European buyers. However, the project has not completed long-term gas supply agreements with neighbouring gas suppliers and has not secured feedgas supply. This is thought to be one of the major factors delaying the project's FID. In addition, the Petroleum Industry Bill (PIB), which will impose heavy taxes on upstream natural gas, has been discussed in the Diet since 2008. The uncertainty of the direction of the PIB has been discouraging foreign investment in the country.

Box 15 Israel will put regional export options first

The Tamar gas field, which started producing in 2013 has already yielded 5.6 bcm. As of late 2013, the field had been even producing at plateau (10 bcm per year) at times of peak demand. The consortium responsible for the field's development – Noble Energy, Derek Drilling and Avner Oil Corporation – has signed many long-term contracts with Israeli customers. Most of these contracts are for a baseline period of 15 years, with some flexibility in terms of volumes and contract duration. Quite interestingly, most contracts are for very small quantities of a few billion cubic metres over the contract's life. Until early 2014, all the contracts signed by the consortium were with domestic industries and power generators.

The surprise came in early 2014, when the consortium managing Leviathan's development announced the signature of a first sales contract with the Palestine Power Generation Company for 4.75 bcm over 20 years. The quantity is small compared to Leviathan's gas reserves − the field is estimated to hold 540 bcm – but this is an important sign that Israel is putting pipeline exports forward and is ready to sign such export agreements. This contract, like all potential others, is subject not only to conditions such as the granting of regulatory approvals and finalisation of funding plans, but also to conditions involving the power plant being built in Palestinian Authority's territory. Before starting the field's development, the consortium must also obtain approval from the Ministry of National Infrastructure, Energy and Water regarding the location of the onshore reception terminal. The FID for Leviathan's development based on pipelines could be taken in 2014. Later in February 2014, Noble Energy signed two SPAs with Arab Potash and Jordan Bromine. This time, the gas will come from Tamar, with supplies starting in 2016 after completion of the construction of pipelines. The 15-year contract is for a total volume of 1.9 bcm. Tamar's production is now set to rise ultimately to 15 bcm per year. Meanwhile, potential additional resources may exist near the field.

The High Court of Justice has approved Israel's decision to export 40% of its gas reserves. The one-year debate has put off development of the Leviathan field by at least one year (according to Noble). Given the recent regional developments, notably Egyptian pipeline exports to neighbouring countries almost disappearing, Israel is now considering both pipeline and LNG export options. The pipeline options have become increasingly appealing due to their lower costs and the regional needs; besides, they could enable a faster start by exporting to surrounding countries, such as Jordan, Turkey and Egypt. Some of the pipeline infrastructure already exists, such as the former Arab Gas Pipeline running from Egypt to Syria. In any case, Noble Energy's management is said to see a diversity of export options as a safer long-term proposition. Despite initial reluctance, Egypt is starting to change its mind regarding imports of Israeli gas, currently considering imports of up to 8 bcm per year by pipeline; and this could be used either for domestic consumption or to supply Egypt's under-utilised LNG facilities.

This situation does not exclude a separate LNG option, but as for all LNG exporters, the window of opportunity may be limited depending on other potential LNG exporters' decisions. In December 2012, the Leviathan consortium (Noble Energy, Delek, and Ratio Oil Exploration) signed an agreement with Woodside Petroleum whereby the company would acquire 30% in Leviathan. Discussions had been put on hold due to the debate on reserves allocations and taxation. But Woodside failed to reach an agreement with other parties in May 2014, which makes the LNG option relatively uncertain. Project partners may still want to pursue the FLNG option. The antitrust authority also needs to decide whether the consortium holding Tamar and Leviathan represents a cartel or not.

The Middle East is an area where domestic gas demand is expected to rise significantly. Consequently, domestic demand needs compete with the export potential, and many countries are actually turning to LNG imports. Although a dozen projects are planned in the region, none is likely to achieve tangible progress in the near future. Iran's planned LNG capacity exceeds 100 bcm. However, all the projects are in an early phase of planning; due to sanctions, the projects are not expected to materialise before the mid-2020s at the earliest (see section on Iran in the Supply chapter).

New import infrastructure will be dominated by LNG

Recent investments in import infrastructure

2013 and early 2014 proved to be a busy period for the LNG regasification industry, particularly in Asia, where 13 terminals were successfully completed. These recently completed terminals added about 60 bcm per year of LNG capacity, bringing total regasification capacity to 950 bcm per year. Non-OECD Asia is leading the pack with 54% of the completed terminals located in this region.

In contrast, limited additional pipeline capacity came on line during 2013 and targeted exclusively China: the Myanmar-China gas pipeline (12 bcm per year) started in mid-2013. Despite continuous work, expansion of the Central Asia Gas Pipeline is still ongoing and did not result in new infrastructure being added in 2013.

In total, 47.4 bcm per year of LNG import infrastructure was added over 2013, and an additional 12.7 bcm came in early 2014. From a regional perspective, a clear shift has taken place away from the traditional (but still larger) importing region – Europe – where only one single LNG terminal came on line in 2013, towards Asia. In particular, a total of 24.6 bcm of import capacity was added in China. In retrospect, more LNG regasification additions were made during the years 2008, 2009 and 2011, where 80 bcm to 100 bcm were added annually (Figure 66, Table 26). Additions in Europe were also high over 2008-11 as decisions to invest in import infrastructure had been taken before the economic crisis in anticipation of much higher demand (and import) prospects. Asia's additional LNG import capacity, however, has never been so high as in 2013. Another important aspect is that smaller LNG importers such as the Middle East and Latin America have started to attract interest over the past few years.

Figure 66 Historical additions of LNG terminals, 2000-14

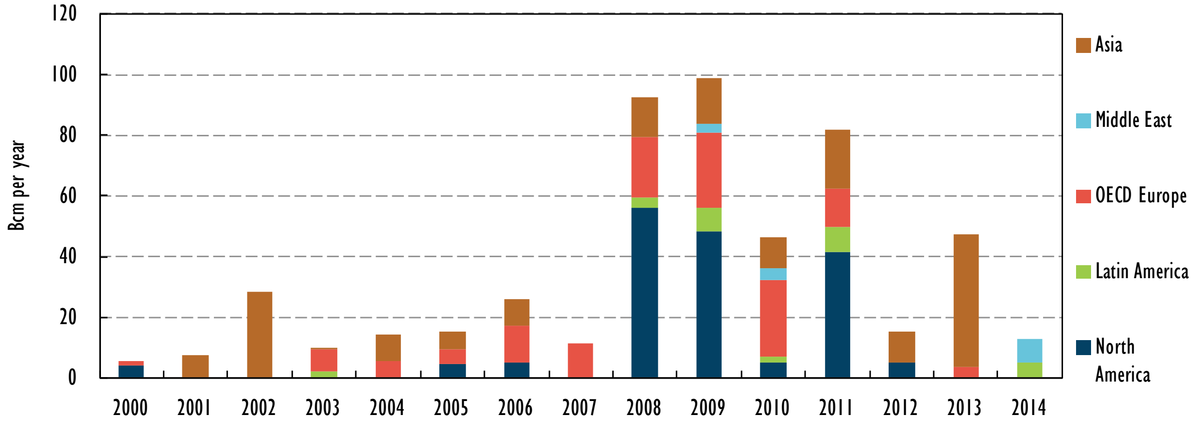


Table 26 LNG regasification terminals recently completed in 2013 and 2014 (as of May 2014)

Country	Project	Capacity (bcm/yr)	Major stakeholders	Online date
Israel	Hadera LNG (FSRU)	2.0	Israel Natural Gas Lines, Israel Electric	Jan 2013
India	Dabhol LNG	6.8	GAIL	Jan 2013
Singapore	Jurong Island	8.2	Energy Market Authority	May 2013
Malaysia	Malacca (FSRU)	5.2	Petronas	Jun 2013
India	Kochi LNG	6.8	Petronet	Aug 2013
China	Zhuhai LNG	4.8	CNOOC, Guangdong Power	Oct 2013
China	Tianjin LNG (FSRU)	3.0	CNOOC	Dec 2013
China	Tangshan LNG (Hebei)	4.8	PetroChina	Dec 2013
Italy	Livorno	3.8	E.ON	Dec 2013
Japan	Naoetsu LNG	2.0	Inpex	Dec 2013
Chile	Mejillones LNG (Phase 2)	2.0*	GDF Suez, Codelco	Jan 2014
Brazil	Bahia LNG (FSRU)	5.2	Petrobras	Jan 2014
Kuwait	Mina Al-Ahmadi (FSRU)	7.5	Kuwait National Petroleum Company	Apr 2014
Total		**60.1**		

* The Mejillones LNG's Phase 2 project is replacing the Phase 1's FSRU with an onshore LNG tank and does not produce additional capacity, hence the volumes are not added to the total capacity.

Source: IEA; companies' websites.

In 2013, the utilisation rate of LNG terminals in the North America dropped to around 6%, in step with the stalled global LNG trade, while the utilisation rate of the pipeline infrastructure slightly increased. The North American shale gas boom has completely undermined the rationale for LNG imports, resulting in the under-utilisation of LNG regasification terminals in the North American region. European terminals are also experiencing the same problem, although their utilisation rate of 24% in 2013 stands much higher compared to their North American counterparts. However, the higher utilisation rate for Asian regasification terminals (50%) has softened the overall impact that resulted in the global utilisation rate of 34% in 2013. While the existing terminals in North America are being converted into liquefaction terminals, European terminals are upgrading their facilities to enable re-export and LNG bunkering in a move to address both the low utilisation rate of the terminals and the higher unit cost, as a result of the low utilisation. As the low utilisation rate is anticipated to persist until the end of the decade, more new technologies and flexibilities, including small-scale LNG and transhipment of LNG, can be expected to be employed by terminals operators to address the issue.

Looking forward: Slow-moving pipelines may open the way to LNG

Most regions will become increasingly dependent on LNG imports, either due to geographical specificities – building a pipeline from another region does not make sense – or because LNG infrastructure is often considerably easier to build, less capital intensive and particularly appropriate for some regions such as Southeast Asia due to its insularity. Some concepts have become very popular: six of the recently completed 18 terminals, and two terminals currently under construction, are using the floating storage and regasification (FSRU) concept. Besides increasing gas demand and declining domestic production, investments in regasification terminals worldwide are also pushed by diversification of supply portfolio strategies, notably in Lithuania, Poland and Singapore, where the countries wish to diversify away from pipeline gas. The status of gas as clean energy compared to the other competing fuels also drives the growth in regasification terminals, particularly in China, as the country tries to move away from coal to overcome its air pollution issue. In contrast, very few pipelines are under construction; besides the further expansion of the Central Asia Gas Pipeline to 65 bcm per year, the most widely watched will be the Southern Corridor in Europe, which is finally moving ahead after a decade of discussion.

Looking forward, very few pipeline projects are under consideration. The key development in 2014 is the agreement between China and Russia to build the Russia-China pipeline, which has been under discussion for more than a decade. Despite much progress, notably on the choice of the pipeline route, some disagreement had persisted on the prices. Both countries reached an agreement in May 2014. The other carefully watched pipeline project is the South Stream project directly linking Russia to southern Europe, bypassing Ukraine. In the current context, such a pipeline has become even more political than before. For Russia, the matter is to ensure greater independence from Ukraine, while Europe is still seeking further supply diversification. The construction of South Stream would also imply a significant reduction of transit through Ukraine, affecting its transit revenues.

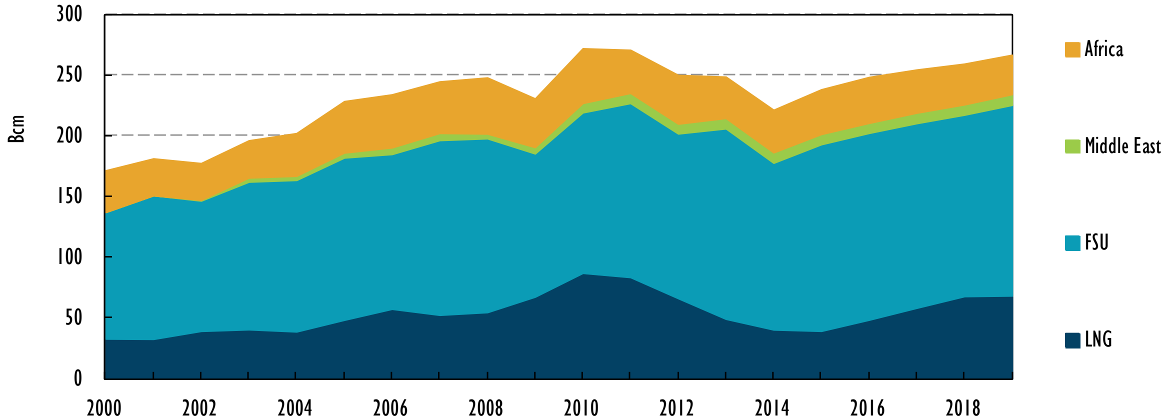
Globally, more than 720 bcm of planned LNG import capacity exists around the world. The 240 bcm still planned by OECD Americas are unlikely to move forward at a time when LNG exports are gaining momentum. Over the medium term, Europe has sufficient LNG import capacity to cover its import needs, but other countries in Central Europe could be interested in turning to LNG to improve energy security. An increasing number of Middle Eastern countries are seriously considering LNG imports due to the shortages faced by their economies, notably in the power generation sector. This is a reminder that most Middle Eastern countries – from Lebanon, Jordan and Syria to the United Arab Emirates, Oman and Iran – are natural gas importers, and this trend is only going to increase. Besides Qatar, which has a moratorium currently in place, and Iran in the distant future, no country is in a position to supply neighbours through intra-regional pipelines. The same issue arises in Latin America, where new LNG terminals are being considered or are even under construction in importing countries. LNG imports in Africa remain a distant prospect outside the forecast period, unless Egypt manages to get access to an FSRU if the more economical solution of Israeli pipeline imports fails to concretise.

In this context, Asia is likely to remain the centre of LNG import terminal investments, with 49 bcm under construction and 188 bcm at the planning stage. The region made a significant contribution to the global regasification capacity in 2013, with completion of nine terminals; five additional terminals are expected to be on line by end-2014, adding LNG capacity of 59 bcm per year over the 2013-14 period. Looking forward, the region will continue building LNG terminals in response to rising gas demand as well as import needs. Although players in Southeast Asia face little competition in terms of building new LNG terminals, which remain mostly in the hands of state-owned companies, China and India will continue to drive the interest of investors/sponsors in LNG import terminals.

New supply to Europe will come from the Caspian region

Despite gloomy perspectives on the demand side, European imports are still set to increase over 2013-19 as production declines by around 25 bcm (Figure 67). Over the very short term (2015-16) and in the absence of any major crisis between Russia, Ukraine and Europe leading to supply disruptions, Russia is set to be the only alternative to cover incremental gas import needs. Over the medium term, after 2016-17, when the LNG market loosens, LNG can be expected to come back to Europe, reducing the call on FSU supplies. Meanwhile, Caspian gas from Azerbaijan will jump noticeably, but only towards the end of the forecast period. No additional supply from North Africa is expected to reach European markets. Algeria will have limited additional exports, actually declining over the forecast period. It is also still difficult to forecast a positive evolution of the situation in Libya leading to a better export position than the post-2011 one.

Figure 67 European gas imports, 2000-19



TANAP and TAP have won the battle for transporting Caspian gas to Europe

One of the liveliest debates over the past 12 years has concerned the race to develop a new supply route to Europe – the so-called Southern Corridor, which would deliver Caspian and Middle Eastern gas resources to core European gas markets through southeastern Europe.[8] When forecasts on European gas demand were bullish, these new supply sources appeared as an essential component of future security of supply, bringing both additional volumes and a diversification of supply source and route. The security of supply issue was exacerbated by two supply disruptions of Russian gas to Europe in January 2006 and January 2009. The recent tensions between Russia and Europe around the events in Ukraine have rekindled the debate on the value of this new supply route.

The process of opening the Southern Gas Corridor has been marked by a decade-long and fierce competition among different pipeline projects and routes, alongside major uncertainties over supply from many possible supply sources (such as Azerbaijan, Egypt, Israel, Iraq, Iran, and Turkmenistan). Over the years, no fewer than 11 projects including variants (Map 6) have been proposed, backed by different consortia of producers, transporters and end users: Arab Gas Pipeline, Black Sea LNG, ITGI, Nabucco, Nabucco West, SEEP, TAP, TANAP, TransCaspian, Turkish grid upgrade, and White Stream. Different marketing schemes – and sometimes for one project, different combinations of regional suppliers – have been proposed over time as the project evolved. On the long road towards FID, the economics, pricing and volumes allocated to different markets may have seemed to take a back stage in public compared to high-profile policy discussions, but these issues were actually decisive factors in the end. While the European Commission was backing the flagship Nabucco project, alongside others, Gazprom developed the South Stream project, aimed at strengthening its commercial position on the same markets and at providing an alternative to the Ukrainian route. Ultimately, politics mattered less than the projects' economics, the financial and economic strengths of projects' backers, the interests of producers, the credibility of upstream projects and costs, and finally, market realities.

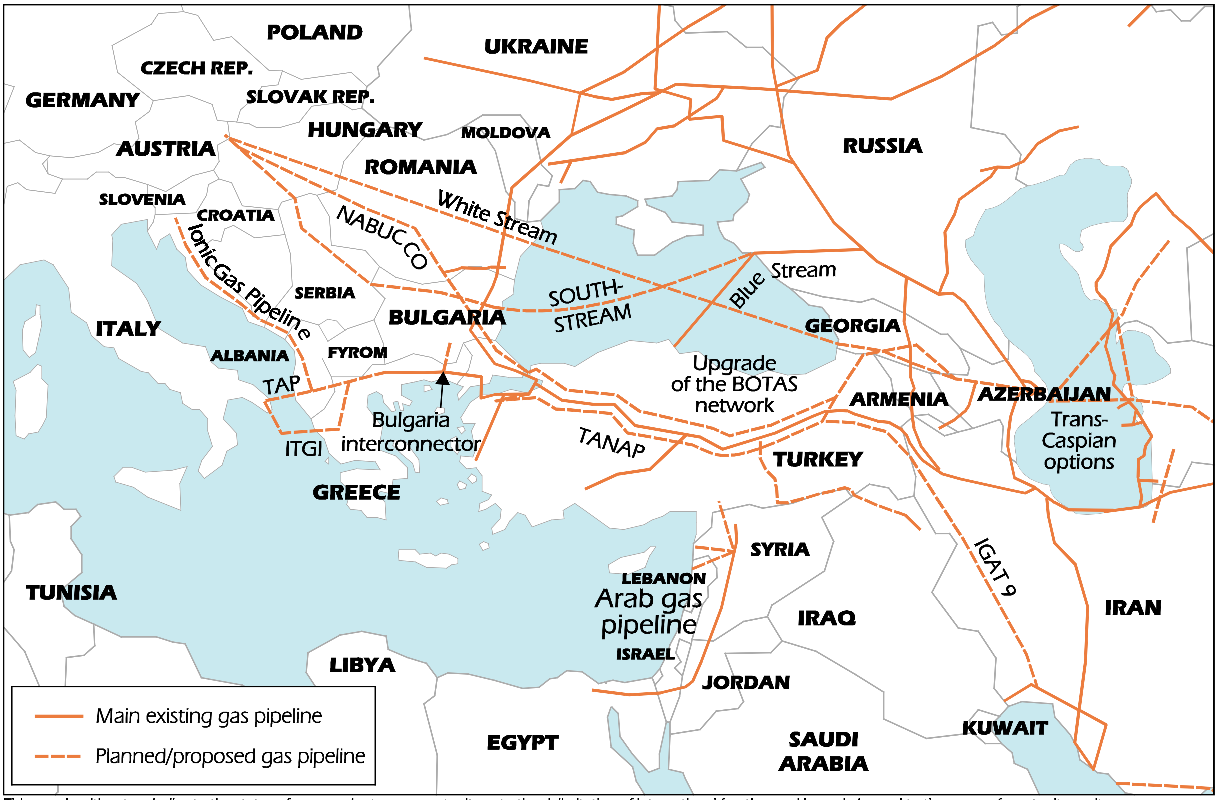
The end of 2013 witnessed the victory of two combined projects to ship Shah Deniz 2 gas to European markets – the Trans Anatolian Gas Pipeline (TANAP) and the Trans Adriatic Pipeline (TAP). Both appear to be backed by producers, as SOCAR and other Shah Deniz 2 shareholders will play a key role as shareholders (Table 27). With this success, instead of supplying Baumgarten and southeast and

[8] Actually Iranian gas had already been supplying Turkey since 2002 and Azerbaijan started exporting Shah Deniz gas in 2007, but these volumes were limited.

Central Europe, Azeri gas will end up supplying southern Italy, Greece, some Balkan countries, Bulgaria, and all countries onwards from Italy, such as Switzerland. In December 2013, the Shah Deniz (SD) consortium took FID to develop the second stage of the SD gas field in Azerbaijan. With a current annual production of 9 bcm, the SD field, located around 70 km offshore in the Azeri sector of the Caspian Sea, is the main gas-producing source of the country. With this FID, a new direct gas transportation link between the Caspian and the core European gas markets will be built. It will consist of three main parts: the expansion of the South Caucasus Pipeline (SCP) via Azerbaijan and Georgia, the construction of TANAP across Turkey, and the construction of TAP across Greece, Albania and into Italy. Moreover, some smaller parts may be added to the TAP pipeline: an interconnector from Greece to Bulgaria and the Ionic pipeline through the Balkans. Total costs of this first leg of the Southern Gas Corridor are estimated to be USD 45 billion.

The total cost of the SD Stage 2 and the expansion of the SCP via Azerbaijan and Georgia will be around USD 28 billion. The estimated construction costs of TANAP have skyrocketed from USD 7.5 billion to about USD 12 billion, increasing the financial risks for potential partners. That is undoubtedly one of the main reasons why – one day before the announcement of the FID – both Total and Statoil dropped their interest in TANAP. Consequently, their shares were redistributed among the project's other shareholders.

Map 6 Southern Corridor pipeline projects



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

In contrast with the previous projects, the TAP pipeline is supported by a mix of upstream players (Statoil, Total, SOCAR and BP), European utilities (EON and Axpo) as well as the Belgian transmission system operator (TSO) Fluxys. TAP's costs are currently estimated at USD 2.2 billion.

With the second stage of the SD project, this consortium wants to add 16 bcm to the current production. Of the new capacity, 6 bcm will be consumed by the booming Turkish domestic market. Nine European utilities and gas trading companies plan to transport and market 10 bcm in Eastern and Western Europe, based on already signed long-term contracts. The first gas volumes are planned to be delivered to Georgia and Turkey in 2018. First deliveries to Europe will follow approximately a year later. Note that, while 10 bcm represents around 2% of European total gas demand, 6 bcm represents a non-negligible 13% of Turkey's current demand.

Table 27 SOCAR's long-term contracts with European utilities for TAP gas

	Quantity per year (bcm)	Period	Start
E.ON	1.6	25-year contract	2019
GDF SUEZ	2.6	25-year contract	2019
Gas Natural Fenosa	1.0	25-year contract	2019
Italian Hera Trading	0.3	25-year contract	2019
Shell	Unknown	Unknown	2019
Bulgargas	Unknown	Unknown	2019
Enel	Unknown	Unknown	2019
Axpo	Unknown	Unknown	2019
DEPA	Unknown	Unknown	2019

Table 28 The consortia behind the South gas corridor

Project	Part of the Corridor	Companies	Estimated costs	Online
SD 2 and SCP	Upstream and Midstream	BP (28.8%), SOCAR (16.7%), Statoil (15.5%), National Iranian Oil Company (10%), Total (10%), Lukoil (10%), TPAO (9%).	USD 28 billion	Q3 2018
TANAP	Midstream	SOCAR (80%) BOTAŞ (15%) TPAO (5%)	USD 12 billion	Q1 2018
TAP	Midstream and Downstream	BP (20%) SOCAR (20%) Statoil (20%) Fluxys (16%), Total (10%) E.On (9%) Axpo (5%)	USD 2.2 billion	Early 2019

TANAP is likely to be realised entirely by a Turkish consortium, even though it will still be dominated by Azerbaijan's SOCAR (80%), the initiator and founding member of the consortium (Table 28). Two state-owned Turkish companies own 15% (BOTAS) and 5% (TPAO). The Turkish participation can be considered as instrumental in supporting Azerbaijan's attempt to acquire a much greater role throughout the whole Southern Gas Corridor value chain. But at the same time, the participation of two Turkish companies illustrates the importance of this project for Turkey. Confronted with rapid growth in demand, this country aims to diversify gas supplies and to reduce its dependence on Russian gas imports. This means that most of the 10 bcm earmarked for Europe is likely to stay in Turkey, especially with European gas demand so depressed (see Demand chapter). The SCP expansion and TANAP will also reinforce the interdependence between Turkey, Azerbaijan and Georgia and the need for them to closely cooperate.

SOCAR has a crucial position in the three parts of the Southern Gas Corridor. The increasing position of this company can also be illustrated by market developments in Greece, as one of the crucial transit countries for the Azeri gas. In December 2013, SOCAR acquired 66% share of the Greek TSO, DESFA. With this acquisition, the Azeri company acquired also a dominant position in the natural gas midstream sector of an EU member state. The signed agreement will come into force after approval by European Commission Directorate General for Energy and Antitrust Policy, which is expected in the second quarter of 2014.

Nabucco's end

The Nabucco project had a sadder end than the opera's character after which it was named. The issue for this pipeline is that it never had any firm supply source and any firm demand on the European side. Already on 28 June 2013, the SD consortium selected TAP to transport Caspian gas from the Turkish border to the European Union. This decision meant the definitive burial of the Nabucco project, which had enjoyed the full support of the EC for years. Preparations for the Nabucco project began in 2002, with first talks between Austrian OMV and Turkish BOTAŞ. Nabucco would transport gas through Turkey, Bulgaria, Romania and Hungary, ending at the gas hub of Baumgarten in Austria. Since then, the project became more and more a political symbol to counterbalance the dominant position of Russia (and Gazprom) as the main supplier of Europe, and therefore it was branded as the main rival to South Stream to transport more Russian gas to Europe. While Nabucco looked at many alternative sources, Azeri gas was always seen as the key pillar.

Before the SD consortium selected TAP, the Nabucco initiative disintegrated little by little for a combination of reasons, including uncertainty of sources for the natural gas to be provided, lack of political support from some European countries and the Azeri government, withdrawal of companies (Hungarian MOL, German RWE) from the Nabucco consortium and subsequent lack of a heavy-weight player, either a European utility or an upstream player, as most of the remaining players were small- to medium-sized companies. This was likely why the consortium was not able to organise the needed support to be considered an integral link between the upstream and downstream business to implement the project. A crucial moment in the process came in mid-2012 when Azerbaijan and Turkey signed an MoU for the construction of TANAP through Turkish territory to Europe. This decision made Nabucco's eastern wing on Turkey's territory an obsolete part of the initiative, reducing the proposal to a pipeline from the Turkish border to Baumgarten in Austria. This Nabucco west project crossed similar countries as the onshore part of South Stream, which continued to gather support from these countries through intergovernmental agreements.

With Nabucco's demise, countries such as Bulgaria lost an opportunity to become less dependent on Russian gas imports. With 87% of its gas coming from Russia, Bulgaria aims to reduce natural gas imports from Russia to 50% of its annual consumption within five years. In reaction to the SD consortium's selection of TAP, the Bulgarian government immediately sought ways to get involved in this pipeline project and to get, for example, gas from TANAP. Through the construction of additional gas transmission infrastructure, this country will become part of the Southern Gas Corridor.

Different factors contributed to this action:

- TAP is much shorter than the full Nabucco pipeline.
- TAP involved a key upstream player and shareholder in SD (SOCAR), while the selection of the pipeline was essentially an upstream decision.
- Nabucco had not signed any long-term contract.

- Expectations existed that gas prices in Italy and Greece will be higher than future prices in eastern European markets that were targeted initially by the Nabucco pipeline. TAP will be connected to Italy, providing firm capacity at the Italian virtual trading point (Punto di Scambio Virtuale [PSV]) from which all Italian gas exit points can be reached, offering a potential access to the wider European market should some pipelines be reversed, virtually or not.

South Stream

TAP thus becomes the main competitor of South Stream, a project supported by an international consortium consisting of four major companies that are shareholders in its offshore section: Gazprom (50%), Eni (20%), EDF (15%) and Wintershall (15%), and also backed by some European Union or Energy Community Member countries. South Stream is important from the Russian point of view to increase export capacity and options. South Stream's offshore section will start at the Russian Black Sea shore in the area of Anapa, Krasnodarskiy Krai, and will cross 900 kilometres of the Black Sea underwater through the Turkish Exclusive Economic Zone of the Black Sea. The offshore section will comprise four pipeline legs with a total capacity of 63 bcm. The onshore section is scheduled to transport part of this gas to Bulgaria, Serbia, Hungary and Austria (Baumgarten) as the routes to southern Italy via Greece, and the route to northern Italy via Slovenia, have been abandoned.

Initially, Gazprom estimated the costs of the South Stream pipeline system at USD 23.3 billion. At the end of 2013, the Russian company announced that it would spend an additional USD 23 billion until 2017 to upgrade its domestic gas system for South Stream, bringing the total costs to around USD 46 billion. Gazprom expected to be ready with a first phase to transport 15.75 bcm by the end of 2015, reaching full capacity in 2018. At the moment, it is highly questionable whether this schedule is achievable.

Table 29 Business model and structure of South Stream and the Trans Adriatic Pipeline

Project	Unbundled activities	Third-party access	Long-term agreements/contracts	Oil indexation
South Stream	Gazprom as producer and a supplier and owner of gas production and its transmission network	Exclusive right of Gazprom to supply gas via the pipeline	Intergovernmental agreements between Russia and the governments of Bulgaria (2008), Serbia (2008), Hungary (2008), Greece (2008) Slovenia (2009), Croatia (2010) and Austria (2010)	Yes, but currently under discussion
TAP	Some shareholders of TAP cover several parts of value chain from gas production to gas supply	Exemptions for a period of 25 years for the initial capacity of 10 bcm	Memorandum of Understanding between the governments of Italy, Greece and Albania and the TAP to confirm political support for the projects (2012) Agreement between TAP and the Interconnector Greece-Bulgaria (ICGB) to link the two projects and transport gas to Bulgaria (2014)	Some contracts are oil-linked, others based on European gas trading hubs

To arrange interstate transport within the European Union, Gazprom signed intergovernmental agreements with transit and supply countries. At the end of 2013, the EC declared these agreements illegal. According to the Commission, individual intergovernmental agreements between Russia and Bulgaria, Hungary, Greece, Slovenia, Croatia and Austria have to be renegotiated because they do not reflect essential principles of the European energy policy and laws. The business structure and model seem to be unacceptable for three main reasons: 1) Gazprom owns both the transport network and the gas exported, violating the rules of ownership unbundling; 2) as the only shipper, the company is infringing on the rules on third-party non-discriminatory access to the pipeline; and 3) the introduced transmission tariff structure is not in accordance with EU requirements, whereby the regulator sets the tariffs (Table 29).

Such a legal dispute could take a couple of years to be solved, causing, for example, difficulties in project financing and delay of gas deliveries to Europe. Already in January 2014, the EC and Russia agreed on further co-operation on the pipeline that will supply Europe with 12% of its natural gas needs by 2018 and the establishment of a commission to address technical and legal details. This agreement now depends crucially on the evolution of the relationships between Russia, Europe, and Ukraine. As this report goes into press, the future of these relationships remains very difficult to forecast.

Turkey: A key player in a great gas game

The decisive developments around the Southern Gas Corridor during the last year have strengthened Turkey's position in the regional gas market, where it plays an increasingly crucial role as a regional transit country. This development has been supported and stimulated by an official gas hub strategy from the side of the Turkish state. Turkey's energy dependency is expected to double in the next decade due to a massive rise of energy consumption. Electricity demand growth is expected to increase even faster. Meeting the growth in gas demand will require significant investments in natural gas infrastructure.

In recent years, Turkey has been paying around USD 60 billion per year for energy, driven mainly by large imports of oil and gas. Turkey is by far the fastest-growing natural gas market in Europe; it imports 57% of its gas from Russia, 18% from Iran, 9% from Azerbaijan and the remaining 14% through Turkey's two long-term LNG contracts with Algeria (4 bcm per year) and Nigeria (1.2 bcm per year). High price levels of some gas supplies have been one of the main concerns of the Turkish government during the last years, leading to disputes and renegotiations with suppliers such as Iran and Azerbaijan. Also, the depreciation of the Turkish lira, combined with high oil prices, has been negatively affecting the position of Turkey as a gas-importing country. In addition to these market developments, contractual "take-or-pay" conditions that require the country to import predetermined amounts of natural gas in long-term contracts are elements that need to be changed as the Turkish government wants to develop a gas trading hub. Despite price disputes between Turkey and Iran, the Turkish government announced in April 2013 that gas imports from its neighbour will increase through a major pipeline coming from Iran's south-western city of Ahvaz, which has already been partially established and will be completed with the participation of Turkish private companies. The issue is whether Iranian gas will be available to support the project (see Supply chapter). Furthermore, in April 2014, Turkey and Russia have agreed to raise the capacity of the Blue Stream pipeline, which brings in Russian gas via the Black Sea, from 16 to 19 bcm annually.

One of the targets in Turkey's diversification policy is to import natural gas from Iraqi Kurdistan. In November 2013, the Kurdistan Regional Government (KRG) agreed to a package of deals with Turkey to build multi-billion dollar oil and gas pipelines to transport the autonomous region's rich hydrocarbon reserves to Turkish markets. These agreements led to increasing tensions with the central government of Baghdad and also created opposition in Washington. The deals, which could have important geo-political consequences for the Middle East, could result in Kurdistan exporting at least 10 bcm per year of gas to Turkey after 2020. Deliveries are planned to start in late 2016 or early 2017, which sounds quite ambitious given the political challenges.

Empty European LNG terminals look for other business opportunities

The short-term outlook for European regasification terminals remains bleak. The current utilisation rate of the existing terminals in Europe, based on 2013 utilisation, stands at around 24%, which is considerably low compared to Asia's average of 50%. This level represents a worrying downward trend for European terminals that had utilisation rates of 37% in 2012. Terminals under construction have only been built due to supply diversification or to enable the access of a new entrant to the LNG market (France). In the present circumstances of low (even declining) demand in Europe, combined with excess import capacity, few FIDs are likely to be taken before the end of the decade, unless they satisfy one of the two targets above. Several terminal operators in Europe are developing new businesses to address the loss of traditional revenues.

Besides re-exporting cargoes, the European LNG terminal operators are also riding on the current trend in the region to employ LNG as a fuel for ship bunkering, to comply with the new law for low sulphur emissions, which will come into effect next year (see section on transport in the Demand chapter). As of May 2014, five existing terminals already have LNG bunkering facilities in place. Eight other existing terminals are considering including such facilities, and three terminals currently under construction plan to include this facility at their terminals. LNG bunkering is becoming a "must have" facility in the new regasification terminals across Europe. The new trend also receives strong support from the European Union through its Trans-European Transport Network (TENT-T), which is sponsoring studies on LNG bunkering across the region. Moreover, European terminals are also turning to small-scale LNG and transhipment to increase their flexibility and sustainability, in view of the current low utilisation. Like LNG bunkering, the small-scale LNG initiative that allows transportation of LNG in smaller ships to other terminals for bunkering and industrial use also receives strong support from the European body. In October 2013, the European Commission granted EUR 34 million for the development of the small-scale LNG Rotterdam-Gothenburg project, which will enable supply of LNG from the Gate LNG terminal to Gothenburg LNG terminal and other terminals in the Baltic Sea. Transhipment is also gaining momentum in Europe, albeit at a much slower pace compared to other new endeavours: France's Montoir LNG terminal performed the first transhipment in August 2013; Zeebrugge LNG terminal is expected to include it in 2015.

Italy's Livorno LNG regasification terminal commenced its commercial operation in December 2013 (Table 30). The terminal, which employs the FSRU concept by converting the existing Golar Frost ship, has an operating capacity of 3.8 bcm per year that will serve over 5% of the country's requirements. Other new terminals are currently being planned in the country, but the likelihood of them being built is remote. Lithuania's first LNG regasification terminal, which received approval from the European Commission in 2013, is expected to come on line by end-2014 as scheduled. The construction of the FSRU has already been completed in Korea, and it is expected to reach Lithuania by mid-2014 to meet the target commencement date in December 2014. Klaipedos Nafta, the project developer, signed the agreement with Hoegh LNG in 2012 to lease the FSRU for ten years. Once completed, the project will diversify Lithuania's source of gas as the country is now fully reliant on Russia. The timing of the terminal also coincides with the expiry of Gazprom's existing contract in 2015, which could be used as leverage for the country's contract renewal negotiations with Gazprom, as mentioned by Lithuania's president during the FSRU's inauguration ceremony.

Poland's Świnoujście LNG terminal reached 75% completion in February 2014. The country's first regasification is on a tight timeline to meet the scheduled online date by the end of this year. The target completion date was already deferred once from mid to end-2014 due to the bankruptcy of one of the project's contractors, which significantly slowed down the construction work in 2012, and the project still risks further delays that could see the terminal operational only in 2015. Meanwhile, France's Dunkerque LNG terminal, which is expected to become operational in 2015 at a capacity of 13 bcm per year, will increase the country's regasification capacity by 50% and will serve markets in both France and Belgium.

Table 30 LNG regasification terminals under construction in Europe (as of May 2014)

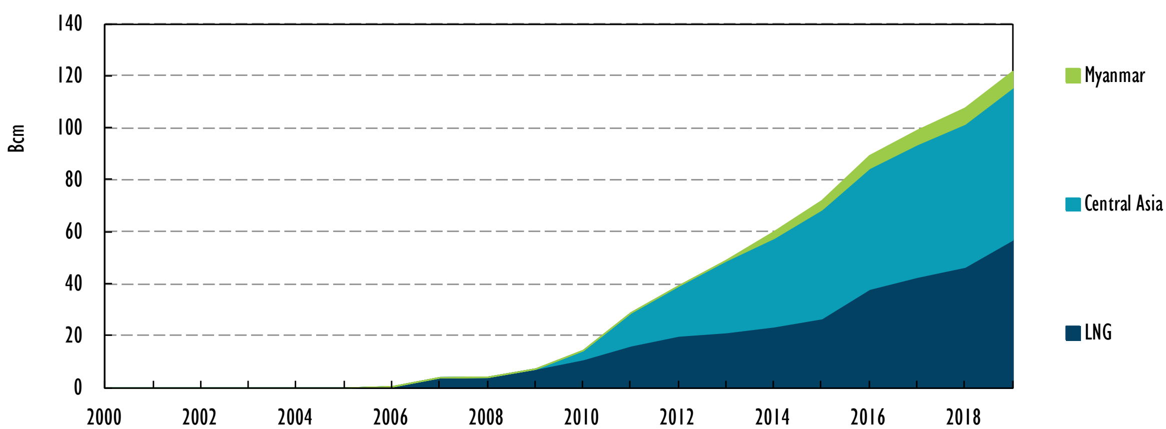
Country	Project	Capacity (bcm/yr)	Major stakeholders	Target online	Reloading facility	LNG bunkering
Lithuania	Klaipedos (FSRU)	3.0	Klaipedos	End-2014	Yes	Under study
Poland	Swinoujscie (Polskie LNG)	4.9	GAZ-SYSTEM	End-2014	Under study	Under study
France	Dunkerque LNG	13.0	EDF, Fluxys, Total	End-2015	Yes	Under study
Total		**20.9**				

Source: IEA; companies' websites.

Both pipeline gas and LNG are necessary to feed China's appetite for gas

China will become the second-largest net importing region of natural gas behind Europe as soon as 2016 (Figure 68). An important driver behind this trend is the Chinese government's policy priority on air quality since air pollution levels in big cities hover over the maximum health limit. To address the smog issue, which is worsening year after year, the government has made the increase of the share of renewable energies a number one priority, as well as more nuclear and natural gas. Chinese gas production is unlikely to grow as fast as demand, even though forecasts for domestic gas production have been revised upwards. This lack of new domestic supply requires large quantities of gas to be imported as demand outpaces the growth in production. In China, imports depend on the infrastructure being built and supplies being available to support this infrastructure.

Figure 68 Chinese gas imports, 2000-19



Russia and China sign the pipeline agreement

In early 2014, the question was whether the agreement between Russia and China on building a pipeline will finally be signed or delayed forever. The agreement was signed in May 2014. Russia's Asia policy is not new and dates from 1997. Plans advanced with the 2004 Discussion Package for the Interagency Working Group to develop a Programme for creating a Unified Gas Production, Transportation and Supply System in Eastern Siberia and the Far East that would enable exports to China and other Asian countries. But the first memorandum between Gazprom and CNPC was not signed until 2006. At that time, two pipelines were being considered. But discussions stumbled on prices, and China finally signed an agreement with Turkmenistan. Turkmen supplies started in 2010 and have been joined since then by Uzbek deliveries. The key difference for China is that they can invest all along the gas value chain in these Central Asian countries (upstream and pipelines), while Russia has so far ruled out giving CNPC equity participation.

Since then, Russia and China have often been a summer away from signing the pipeline deal. Besides the pricing issue and the fact that Gazprom wanted China to pay the same netback price as European customers, the issue was also about the pipeline route. From Russia's point of view, the Western route enabled tapping into brownfields in Western Siberia, but for China it meant a significant burden in terms of transmission costs in the country. The Western route indeed required the gas to transit through the whole country to reach coastal areas. In 2012, the Eastern route seemed to make progress, as President Putin asked Gazprom to accelerate the development of the Power of Siberia pipeline associated with the development of Chayandiskoye. But the decisive point was the summit between Presidents Xi Jinping and Vladimir Putin in March 2013, where they announced that they had decided to move ahead with a 38-bcm-per-year pipeline taking the Eastern route. While a binding agreement was signed in September 2013, the pricing details have not been finalised, and CNPC's investment in Yamal LNG, as well as the liberalisation of LNG exports, were two heavy blows for Gazprom's ambitions. The pricing issue is not easy to solve. Turkmen gas imports have hurt CNPC's results as the company incurred CNY 42 billion losses in 2012 in the import business and an estimated CNY 60 billion in 2013. It is, therefore, difficult for CNPC to sign another loss-making agreement, which is also probably why the NDRC did not allow it to proceed.

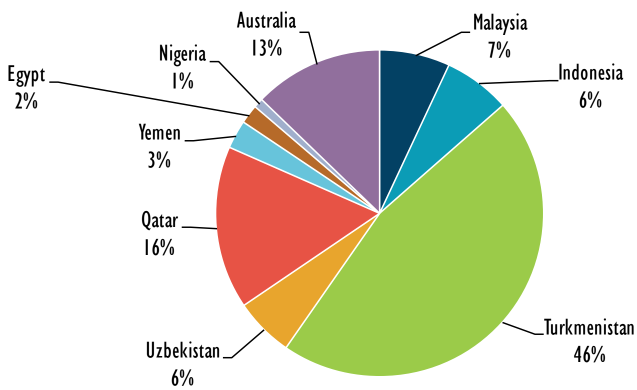
The preceding history made 2014 a key year for this agreement, which was finally signed late May 2014 in Shanghai between President Vladimir Putin and President Xi Jinping. The contract is for 38 bcm per year over 30 years, for a contract value of over USD 400 billion. Global competition to supply Asia, and China in particular, has been increasing, and China has made significant steps to invest upstream in North America, Australia, and East Africa, with the strategy of bringing LNG back home. The clock was therefore ticking as FIDs for these LNG projects are scheduled between 2014 and 2016. The current issues with Europe only reinforce the importance of Asia as a market. Finally, Gazprom is seeing its share declining on the domestic market, making the export market increasingly vital. This project is one of the keys to unlocking the Chinese market and therefore of paramount importance for the company. Besides, impatience has been growing on the Chinese side. The fact that CNOOC was permitted to build LNG regasification terminals north of Shanghai – a region where it has not been very present until now – could mean that the table is turning also for CNPC. With the FSRUs, CNOOC can potentially increase its foothold in northern China very rapidly and provide competition to Russian gas. Finally, shale gas presents a key uncertainty for Gazprom's ambitions, as well as for any exporter of gas to China. Should shale gas be a major success in China on the same order of magnitude as in the United States, it would provide a strong bargaining power to China in terms of future pricing negotiations – provided of course that this new source of gas supplies arrives at a price competitive with Russian imports at the city gate.

The Central Asia China gas pipeline

With the realisation of the Southern Gas Corridor, the European Union has been counting on supplies not only from Azerbaijan, but also from other countries such as Turkmenistan. However, there is little likelihood that Turkmen gas will each Europe’s borders, at least in the medium term. Turkmenistan has prioritised supplies to China, and the European gas market has changed to such an extent that political, commercial and economic obstacles to tapping Turkmen gas have been increasingly seen as surpassing the benefits of additional gas in a depressed market. Kazakhstan and Uzbekistan have started to supply China, using the same infrastructure as Turkmen supplies on top of the expansion of their own domestic networks. China thus took the lead in diversifying these countries’ gas exports away from Russia. Hence, the relations between China and Turkmenistan, Kazakhstan and Uzbekistan entered a new phase with the visit of President Xi Jinping to these three countries in September 2013 (Figure 69).

During this Chinese political and economic mission, the presidents of Turkmenistan and China announced the completion of the first construction phase of the Galkynysh gas field (previously known as South Yolotan), the world’s second-largest field, containing between 4 tcm and 14 tcm of gas. At the same time, both presidents signed new agreements and contracts to develop the second phase of the field, aiming to increase the supply of Turkmen gas to China to 65 bcm per year by 2020. To make this project possible, Turkmenistan's state company Turkmengaz and the China Development Bank signed an agreement to cooperate on financing the second phase, through an undisclosed loan to the Turkmen government. This deal is part of a broader co-operation between both countries. In a Joint Declaration on Establishing a Strategic Partnership, Turkmenistan and China stressed that they will also expand co-operation to include construction of infrastructure, telecommunications, chemical industry, textile industry, agriculture, healthcare, high technologies and implementation of large joint projects.

Figure 69 China’s gas imports in 2013



Turkmenistan began deliveries of gas to China in 2010, as a strategy to reduce its dependence on the Russian market, up to that point its only market outlet. In a few years, the country became the largest foreign supplier of natural gas to China, delivering around 52% of all Chinese gas imports in 2013. With the development of phase one of the Galkynysh deposit, 30 bcm will be produced through three gas-processing plants. The project has been developed by Petrofac International LLC from the United Arab Emirates, China’s CNPC and a Korean consortium of LG International and Hyundai Engineering Co. Ltd. The expectation is that this volume level will be reached at the end of 2014, but Turkmen forecasts tend to be slightly optimistic. The cost of phase one, USD 9.7 billion, was provided by Beijing. China will become by far the number one gas market for Turkmenistan, soon surpassing volumes delivered to Russia over the past decade, which peaked at 48 bcm.

The new natural gas pipeline Line D, in addition to the existing Lines A and B and Line C, which is under construction, will bring gas from Turkmenistan. Unlike the three others, Line C will be built through the territories of Uzbekistan (205 km), Tajikistan (415 km) and Kyrgyzstan (225 km). The pipeline is expected to come on line before 2020. Transit fees and direct investments related to the pipeline are to generate substantial incomes in Uzbekistan and Tajikistan.

Uzbekistan and Kazakhstan have also been eager to start supplying China. In April 2011, CNPC signed an agreement with Uzbekistan to deliver natural gas through a transmission line that would connect with the Central Asia China gas pipeline (CAGP). Uzbekistan was expected to send at least 4 bcm in 2013 and 10 bcm in 2014 with some of the gas produced by Lukoil. Kazakhstan and China also signed a joint venture agreement in 2010 to jointly construct a pipeline starting in western Kazakhstan and link to the CAGP. The pipeline will add another 10 bcm per year from Kazakhstan to the CAGP and commissioning could begin in 2015. During his visit in September 2013, the Chinese president, along with the president of Kazakhstan, commissioned the first phase of the Beineu-Bozoi-Shymkent gas pipeline and signed 22 contracts worth USD 30 billion. In Uzbekistan, the Chinese president discussed increasing bilateral trade to USD 5 billion by 2017 and the construction of another natural gas pipeline to supply China.

LNG capacity could double by 2020

China is leading in adding LNG import capacity, with three terminals completed in 2013 that add a total regasification capacity of 12.6 bcm per year, bringing total capacity to 46 bcm (Map 7, Table 30). CNOOC, the country's leading LNG terminal operator, now has six operating regasification terminals with the commencement of Zhuhai LNG in October 2013 and Tianjin LNG in December 2013. Tianjin LNG marks a significant milestone for the company as it is the country's first FSRU. Moreover, this development marks CNOOC's entry into the Northern region, previously held by CNPC and Sinopec. The fact that the construction of the LNG terminal was given the green light by NDRC was an indication to CNPC that, should the company not reach an agreement with Russia on the pipeline, CNOOC could be given the keys to unlock this region. The recently-signed Russia-China deal changes the situation. With FSRUs, this can be done in a short amount of time. Meanwhile, PetroChina also contributed to the 2013 list with the opening of its third terminal, Tangshan LNG in December 2013.

Table 31 LNG regasification terminals under construction in China (as of May 2014)

Country	Project	Capacity (bcm/yr)	Major stakeholders	Target online
China	Hainan LNG	2.7	CNOOC	2014
China	Shandong LNG	4.1	Sinopec	2014
China	Yuedong LNG	2.7	CNOOC	2015
China	Shenzhen LNG	5.4	CNOOC	2015
China	Beihai Guangxi	4.1	Sinopec	2015
China	Tianjin	4.0	Sinopec	2015
Total		**23.0**		

Source: IEA; companies' websites.

At the same time, six terminals currently under construction will add 23 bcm per year to China's regasification capacity. Sinopec's first regasification terminal, Shandong LNG terminal, is expected to begin operations in 2014. The timing coincides nicely with the commencement of Papua New Guinea LNG project (PNG LNG). Sinopec signed a long-term agreement with PNG LNG in 2009 for the supply of 2 mtpa (2.7 bcm per year) of LNG to Shandong LNG terminal. Besides the addition of new regasification terminals across China, the country's regasification capacity will undergo rapid growth through the expansion activities of existing terminals. Despite being in operation for less than a year, both Tianjin and Tangshan LNG will undergo expansion programmes that will increase the terminals' capacities by 8.2 bcm per year for Tianjin LNG and 8.8 bcm per year for Tangshan LNG. Fujian LNG, Guangdong LNG and Ningbo LNG are also in the midst of expansion activities, while other existing terminals are also mulling over expansion plans. In terms of ownership, CNOOC continues to have the lion's share, with majority ownership in 42.8 bcm of LNG terminals, against 22.5 bcm for PetroChina and 20.4 bcm for Sinopec. All these developments will see China reaching at least 90 bcm per year capacity by 2020.

Map 7 Chinese LNG terminals

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Non-OECD Asia

Further LNG capacity is built in non-OECD Asia

Following the commencement of Indonesia's first LNG regasification terminal called Nusantara Regas in 2012, another two regasification terminals are currently being constructed, one in Lampung and another one in Aceh, with expected completion in 2014 for both terminals (Table 32). Like Nusantara Regas terminal, Lampung LNG is an FSRU terminal, and is owned by Hoegh LNG. Indonesia's third regasification terminal is currently being constructed in Aceh through the conversion of the existing Arun LNG liquefaction terminal. This terminal brings the country's total LNG import capacity to 11 bcm. Singapore and Malaysia joined their neighbours, Thailand and Indonesia, in mid-2013 when their LNG regasification terminals began operations. Singapore LNG regasification terminal, which is Asia's first regasification terminal to have an LNG reloading facility, started its commercial operations in May 2013 and currently has 8.2 bcm per year capacity with the recent completion of its third tank. The project's sponsors are planning to expand the capacity by 4 bcm per year and to take FID in 2014. In addition to the first terminal in Jurong Island, Singapore is also considering building a second terminal that may enable the country's ambition to become the first natural gas hub in Asia, although it may only be on line post 2020 if it materialises. Meanwhile, Malaysia's Malacca LNG regasification terminal, which is also unique in that it is the world's first jetty regasification unit, started its commercial operations in June 2013, almost one year later than planned. Another two regasification terminals are planned to be built in Malaysia, i.e. Pengerang and Lahad Datu LNG terminals. The FID for Pengerang LNG is anticipated to be announced some time this year to meet the target online date of 2016. Once completed, Pengerang LNG will have operating capacity of 6.8 bcm per year; its primary objective is LNG trading, besides serving domestic demand. In contrast, it is not as rosy for Lahad Datu LNG as the terminal's development plan is currently on hold due to 2013's intrusion incident in the area and may possibly be scrapped.

Table 32 LNG regasification terminals currently under construction in non-OECD Asia (excluding China and India) (as of May 2014)

Country	Project	Capacity (bcm/yr)	Major stakeholders	Target online
Indonesia	Lampung (FSRU)	2.7	PGN	2014
Indonesia	Arun (converted)	4.1	Pertamina	2014
Philippines	Pagbilao LNG	4.1	EWC	2015
Total		**10.9**		

Source: IEA; companies' websites.

Other Southeast Asian countries, the Philippines and Viet Nam, are following suit, albeit at a much slower pace. EWC is currently constructing a new LNG regasification terminal with a 4.1 bcm per year capacity in Pagbilao, the Philippines; it will be the country's first LNG terminal when it becomes operational in 2015. Besides serving the local market, the company plans to use the terminal as an LNG hub to serve Asian LNG buyers. The majority of the volumes for Pagbilao LNG terminal will be supplied by EWC's Sengkang LNG project in Indonesia, currently under construction. The company is also considering purchasing LNG from other suppliers, although no agreement has taken place to date. Shell also plans to build an FSRU LNG terminal near its oil refinery in Batangas, the Philippines, and may announce FID in 2014. In Viet Nam, PetroVietnam Gas (PV Gas) is planning to build two regasification terminals; the first terminal is expected to be on line in late 2014, according to the company's website. However, the possibility of the country having the first LNG regasification terminal by end-2014 seems unlikely, as construction for the terminal has yet to take place.

In India, Petronet commissioned its Kochi LNG terminal in August 2013, which is the company's second terminal after the commencement of Dahej LNG terminal in 2004. The terminal is currently under-utilised, operating at only 8% of its capacity due to the constraints in the pipeline network. The terminal also experienced a setback in its gas sales when one of its major customers withdrew from purchasing LNG from the terminal in January 2014, citing the high LNG price as the reason. The LNG price by Petronet was reportedly quoted at USD 23.74/MBtu, which may be attributed to the current high spot price resulting from usual high winter demand from Far East buyers, combined with the low utilisation rate of the terminal. This price is much higher than most Asian prices, and higher than the oil equivalent. However, the issue may be temporary and is expected to be resolved once the terminal reaches its plateau and receives LNG from Petronet's long-term agreements. In Pakistan, after several unsuccessful attempts to issue the tender, the government, through its Inter-State Gas Systems (ISGS), finally awarded the contract to Engro's Elengy Terminal Pakistan to build a fast-track LNG import terminal in Karachi. According to the company's website, the 4-bcm-per-year terminal, which will be located at Port Qasim, will employ the FSRU concept and has already signed a term sheet with Excelerate for the FSRU. The company has an existing chemical handling terminal at the port, which is an added advantage to the development of the LNG terminal there. However, the controversies surrounding the project, particularly on the tender, may dampen the country's ambitions to have the terminal completed by end-2014 since the country's National Accountability Bureau (NAB) has started a probe into the award. The likelihood of the project not materialising is, therefore, probable; previous tenders issued by the government were not completed, despite successful awards to the companies involved.

Box 16 The Trans ASEAN Gas Pipeline: A dead-end or light at the end of the tunnel?

The Trans ASEAN Gas Pipeline (TAGP) project, which kick-started in 1999 during the 17th ASEAN Minister of Energy meeting, and subsequently was formalised through a memorandum of understanding signed during its 20th meeting in 2002, is meant to ensure greater security of supply in the region through pipelines interconnecting ASEAN countries. Having the East Natuna gas field as primary supply, the TAGP project is scheduled to start in 2024 with a total of 7 500 km of pipelines connecting the countries, with the exception of Philippines as the pipeline from East Natuna to the country is currently put on hold due to its commercial unfeasibility. However, as of 2014, only 3 000 km of pipelines have been completed while the remaining 4 500 km of pipelines connecting the East Natuna field with Indonesia, Malaysia, Thailand and Viet Nam are yet to be built.

The project experienced a significant hit in 2012 when Indonesia, which is struggling with declining domestic gas production, announced that it will prioritise the country's domestic gas pipeline project over the TAGP project. The success of the project also hinges of the future of East Natuna, which remains a big question mark as a result of several postponements to the project's FID. The consortium responsible for the field's development includes Total, Pertamina, ExxonMobil and PTTEP. Petronas left the project in 2012. The field is estimated to hold 1.3 tcm of gas reserves, but its development is exceptionally difficult due to the high content of CO_2. To compensate, the consortium asked for special conditions such as the contract's duration to be extended from 30 to 50 years, a five-year tax holiday and a 150% investment credit. However, the field could produce as much as 40 bcm per year at plateau during 20 years. At the same time, the countries that are expected to benefit most from the project by virtue of being net gas importers seem to have shifted their focus from the TAGP to LNG imports. Thailand began importing LNG via its Map Ta Phut terminal in 2011, while Singapore followed the move in 2013 with its Jurong terminal. Indonesia and Malaysia themselves, which are still net gas exporters, also built LNG regasification terminals to address gas shortages.

The growing numbers of LNG terminals in South East Asia thus could act like a double-edged sword to the success of the TAGP project. It could mean an end to the project's future since the countries that were in need of gas from the East Natuna field would be able to replace the required gas supplies with LNG imports. However, the TAGP project could also be revitalised through slight modification to the original concept: instead of providing energy security to gas-importing countries through the East Natuna field, the new concept would aim at improving supply diversity for the ASEAN countries through both LNG imports and East Natuna's gas. The role of LNG is also being considered by the task force in the TAGP project, although the details of the LNG plan are yet to be available. This is also in line with the ongoing efforts by Singapore to become the first natural gas hub in Asia because the improvised concept would ensure greater liquidity to the South East Asian market. However, despite the large potential of the LNG terminals to revive the TAGP project, it remains to be seen whether the project could still be a reality because price and technical and regulatory issues remain the largest hindrances to the full implementation of the project.

The TAPI and IPI pipelines fight against the odds

As Asia moves increasingly into importing, countries other than China are starting to attract the interest of producers. This is notably the case for India and Pakistan. Pakistan has been until now self-sufficient in terms of gas, but a large gas deficit affecting the power sector makes the country eager to attract gas supplies. Hence, it is looking at both LNG and pipeline options.

From the producers' side, two countries have been looking at supplying this region: Turkmenistan and Iran. The idea for a Turkmenistan-Afghanistan-Pakistan-India Pipeline (TAPI) started in the late 1990s and has made only small progress since then. The rationale for Turkmenistan is to diversify importers: originally, the country was very dependent on Russia, but is now increasingly depending on China. This project, with a total length of 1 735 km, would cross through the territory of Afghanistan, 200 kilometres through Turkmenistan and 800 kilometres through Pakistan before it reaches the border town of Fazilka in India. The USD 7.6 billion TAPI project would have a design capacity of 33 bcm per year. TAPI could provide 12.5 bcm each to Pakistan and India, satisfying almost a third of Pakistan's current 43 bcm consumption and a fifth of India's 65 bcm consumption.

In 2013, the four countries set up a consortium. The Asian Development Bank (ADB) was appointed as legal-technical consultant responsible for searching for a technically capable and financially sound company as consortium leader to design, finance, construct, own and operate the gas pipeline. In the view of the bank, TAPI offers an opportunity for regional co-operation at an unprecedented scale, linking the economies of the four countries together and delivering energy security through a balanced development of regional infrastructures and institutions. These preparations are based on SPAs between Turkmengaz, Pakistan's Inter-State Gas System Limited and GAIL signed in March 2012 and with the Afghanistan's Gas Corporation signed in July 2013. The signing of the agreement with Afghanistan can be considered an essential step in the preparative process. Nevertheless, the instability in Afghanistan still remains one of the main impediments to the construction and the security management of the pipeline, since the pipeline will pass through Herat, Helmand and Kandahar, all important areas of resistance against foreign forces. These impediments will, of course, arise most probably in the period after the withdrawal of the NATO-led forces in Afghanistan and after the responsibility for security is given to Afghan forces at the end of 2014. This makes an FID over the next two years relatively unlikely, since many investors would prefer to see how the situation evolves after this transition.

TAPI also enjoys the support of the United States administration, which prefers the project to the undesired Iran-Pakistan gas pipeline because of the Iran Sanctions Act. Despite the pressure from the United States, the construction of Pakistan's segment was officially launched by the presidents of both Pakistan and Iran in March 2013. The Pakistani part of the pipeline will be built by the Iranian company Tadbir; the plan is to complete the pipeline in 15 months. The Iranian part has already been constructed. Pakistan has been facing funding problems, even asking Iran to also fund the Pakistani part of the pipeline. It has recently argued that the project should be shelved until the United States sanctions against Iran are lifted. Pakistan is supposed to pay penalties (USD 3 million per day) associated with the planned 31 December 2014 deadline for completion of the project. Given that the construction of the Pakistani section has been stalled since the last elections, it will be interesting to see whether they will escape the penalties. Iran agreed a purchasing agreement with Pakistan for a 20-year period and the option of a five-year extension. The pipeline will be supplied from the South Pars field and would carry 8.7 bcm per year, as contracted to Pakistan, but will have a 40 bcm maximum capacity. With the new gas imports, Pakistan will be able to rapidly accommodate increasing demand and to notably replace the costly oil, which is used as fuel in power generation in the country.

OECD Asia Oceania remains wedded to LNG

This region remains heavily influenced by LNG infrastructure developments. Pipeline projects from Russia have been mentioned in the past, but they seem to have lost momentum. One major change in this region is the fact that Israel turned from a net pipeline importer to an LNG importer, and will soon become a pipeline exporter. Meanwhile, the majority of the LNG projects built remain in Japan and Korea, the two largest LNG importers (Table 33).

Table 33 LNG regasification terminals under construction in OECD Asia Oceania (as of May 2014)

Country	Project	Capacity (bcm/yr)	Major stakeholders	Target online
Japan	Hibiki LNG	1.4	Saibu Gas, Kyushu Electric	2014
Japan	Hitachi LNG	1.4	Tokyo Gas	2015
Japan	Hachinohe LNG	1.0	JX Nippon Oil	2015
Korea	Samcheok LNG	9.2	Kogas	2015+
Korea	Boryeong LNG	2.0	GS Energy, SK E&S	2015+
Total		**15.0**		

Source: IEA; companies' websites.

In theory, Japan has largely sufficient capacity to meet its LNG imports (260 bcm versus 120 bcm imported in 2013). However, the Japanese gas market is not integrated, and new entrants have difficulties gaining access to incumbents' LNG terminals. In addition the Fukushima nuclear incident and uncertainties on future nuclear policy have reignited the growth in Japan's LNG regasification capacity. This capacity has increased by one new terminal that reached completion in 2013; four new terminals are currently under construction. Naoetsu LNG terminal, Inpex's first regasification terminal, came into operation in December 2013. Hibiki LNG terminal, which started construction in 2010, is expected to be operational by November of this year, while the remaining three terminals currently under construction are expected to come on line by 2015. Two regasification terminals operated by JK Nippon Oil, Hachinohe LNG and Kushiro LNG Satellite terminals are scheduled to commence operations in April 2015. The company signed a long-term agreement with Shell in 2012 for the supply of 0.2 mtpa of LNG per year to Hachinohe LNG terminal, which in turn will be used to supply LNG to Kushiro LNG Satellite terminal as well. Tokyo Gas, the country's biggest gas company, is currently constructing its fourth regasification terminal, Hitachi LNG, with the expected completion in 2015. Meanwhile, JAPEX announced FID for its Soma LNG terminal in November 2013; it will start construction in 2014 to be on line by 2018.

Kogas, the world's largest LNG importer, is currently constructing Korea's fifth regasification terminal, Samcheok LNG terminal. In spite of the target completion date in 2014, the terminal's construction may only be completed in 2017, according to the company's 2013 annual report. Kogas is also planning to build a small LNG terminal on Jeju Island, with expected completion by 2017; however, its construction has not yet begun. The country's sixth regasification terminal is also under way, with the construction taking place in Boryeong. The completion of these two terminals will bring the country's regasification capacity to 114 bcm per year.

Israel reached a significant milestone in 2013 when the country joined the list of LNG importers through the commencement of the country's first regasification terminal, Hadera LNG terminal, in January 2013. The terminal, which uses Excelerate's FSRU, serves as a temporary solution to the country's gas shortage brought about as a result of the interruption of gas imports from Egypt. It will be operational until Tamar, which started producing in 2013, reaches plateau.

The Middle East turns to LNG

With rapid demand growth expected and shortages of gas becoming increasingly acute, many Middle Eastern countries are turning to LNG imports. Indeed, besides Qatar, which put a moratorium on future exports, no country seems in a position to supply its neighbours in the medium term. Several projects linking Iran to surrounding countries have been proposed in the past, but the country's supply/demand situation makes them unlikely to take off until the end of the decade. Moreover, the low volumes of Egyptian gas now flowing through the Arab Gas Pipeline require the countries once supplied to turn to other alternatives. Only Israel will be in a position to deliver pipeline gas to its neighbours, after Tamar further ramps up production and when Leviathan starts producing. Nevertheless, Israel as a supplier remains a highly political choice in a very unstable region, and also relies on the importing countries building not only the infrastructure but also the gas-fired plants that will consume that gas.

Following the United Arab Emirates (Dubai) and Kuwait, more countries are turning to LNG imports to address the rapidly increasing gap between domestic gas demand and production. FSRU proves to be the preferred choice for the terminal developers in the Middle East and Africa, as all projects that have been recently completed and are under construction employ this technology for their terminals. Kuwait, which began importing LNG in 2009 through its first regasification terminal in Mina Al-Ahmadi GasPort, is expanding the country's import capacity through commencement of a new FSRU in April 2014. Kuwait is replacing the existing vessel with Golar LNG's Golar Igloo, which was recently delivered to the company in February 2014. Kuwait is also planning to build another terminal and has awarded the contract to Foster Wheeler to construct a new onshore regasification terminal. With operating capacity of 15 bcm per year, the newly planned terminal will bring the country's import capacity to 23 bcm per year when completed in 2020. Meanwhile, in Jordan, in a move to address diminishing imports from Egypt, the country will begin importing LNG when its regasification terminal commences operations in 2015. Like Kuwait, Jordan will be chartering new FSRU from Golar LNG with the same capacity of 7.5 bcm per year for its Aqaba LNG terminal. Shell has been awarded a contract to supply LNG to the new terminal once it is operational.

In addition to the first regasification terminal in Dubai, the UAE through Mubadala Petroleum is planning to build Emirates LNG terminal in Fujairah. With a capacity of 12 bcm per year, the terminal is originally planned for two-phase development that involves FSRU for phase one and an onshore terminal for phase two. In January 2014, the project developer cancelled the FSRU plan and is expected to retender the project based on an onshore terminal some time in 2014. Egypt, which launched a tender in 2012, is still negotiating with potential contractors for the country's first LNG regasification terminal. Given the country's financial difficulties, it is relatively unlikely to see the new terminal to be on line by the middle of this year, as scheduled. Other countries in the regions – namely Bahrain and Lebanon – are also considering importing LNG through FSRU, although these are still in the planning stage.

New Latin American countries turn to LNG

If not for some political choices that led to a rapid drop in production in key producing countries, such as Argentina and Venezuela, and difficult relationships between a few countries, making intra-regional pipeline trade difficult, the region could be self-sufficient. But like the Middle East, Latin America has to turn to LNG imports to feed rapidly increasing demand. The years 2013 and 2014 saw healthy growth in LNG import capacity in Latin America, which was spurred by some gas shortages in specific countries, notably Argentina. The pertinence of this choice was highlighted by the region's active participation in the LNG spot market, particularly from the November to March period, where their high summer demand for gas coincides with the high winter demand by Asian buyers. While the spot demand for LNG in Asia is mainly driven by winter heating, Latin America, particularly Argentina and Brazil, are using LNG for thermal electric generation to substitute for hydroelectric power during the dry summer season. Brazil's third regasification terminal, Bahia LNG commenced operations in January 2014 and is employing Golar Winter as FSRU. Golar Winter was previously chartered by Brazil's Guanabara Bay LNG terminal, before it was replaced by Excelerate's FSRU as part of the terminal's expansion plan to increase the capacity to 7.3 bcm per year. Guanabara Bay LNG is currently employing Excelerate's Exquisite as the FSRU, while waiting for the completion of Excelerate's VT3, which is expected to be on line by mid-2014. Argentina, which is also very active in the current LNG spot market, currently has two operating regasification terminals with a total capacity of 10 bcm per year. Plans are being made to increase LNG import capacity to support the growing LNG demand in the country, and the government is seeking support from external parties, including Qatar, to build a new regasification terminal.

Meanwhile in Chile, the second phase of the Mejillones LNG regasification terminal was recently commissioned in February 2014. It now utilises onshore storage tanks to replace the FSRU's GDF Suez Brussels used during the first phase. The terminal is considering expanding the capacity to 3 bcm per year to cater to the potential increase in demand as a result of the terminal's open access system, which was introduced last year. The terminal is also considering a mid-scale LNG facility to enable domestic shuttling, using smaller ships in view of the country's geography. Chile's second existing terminal, Quintero LNG, is also undergoing expansion, with completion expected by end-2014 that will increase the terminal capacity by 50% from 3.4 to 5.1 bcm per year. At the same time, two other new terminals are currently on the way – i.e. Colbun LNG and GasAtacama LNG. Originally scheduled for completion in 2015, both projects, which adopt the FSRU concept, are now facing delays that could see the terminals become operational only by 2018, i.e. three years later than the original schedule of 2015. Uruguay is developing its first regasification terminal, GNL del Plata terminal, which will enable LNG imports of up to 5 bcm per year when the terminal becomes operational in 2015. GDF Suez, which won the contract to build the terminal, will be chartering Mitsui's FSRU for this purpose. However, GDF Suez will employ its existing FSRU during the commencement of the terminal in 2015 while waiting for the completion of Mitsui's FSRU, which is due for delivery in late 2016.

Elsewhere, Colombia could also become Latin America's next LNG importer since the country is considering developing its first regasification terminal. At the moment, Colombia is producing sufficient natural gas for domestic use and exports to Venezuela. Colombia is currently developing the country's first liquefaction terminal, with a capacity of 0.7 bcm per year. However, the high demand for gas during dry seasons, which results in gas shortages, has forced the country to turn to LNG imports. The planned import terminal is expected to come on stream as early as December 2015 and will be able to import about 3 bcm per year of LNG.

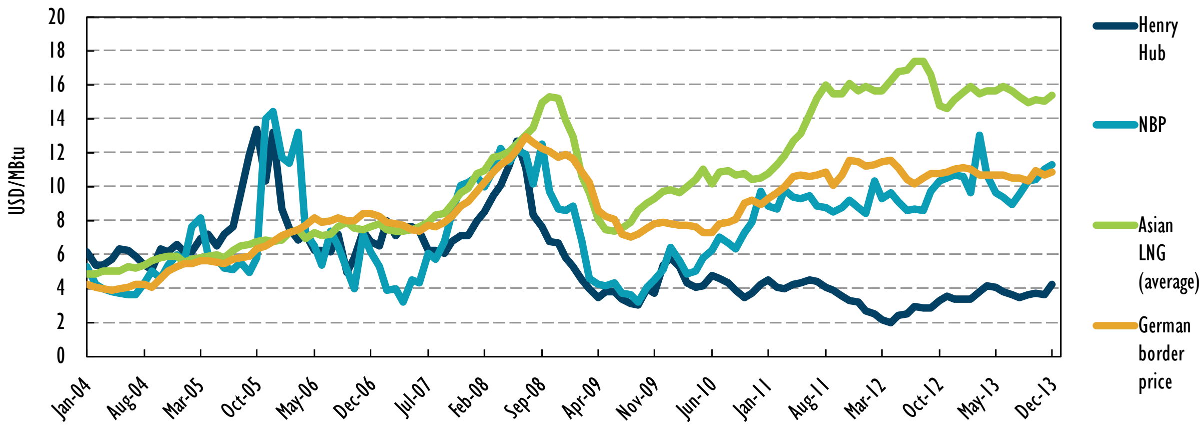
A small possibility exists that the region will develop interregional pipeline trade with Mexico. A project to build a pipeline to Guatemala has been mentioned by Guatemalan authorities, but this still needs to be confirmed by Mexico. Until the country develops its large shale gas resources, the prospects for such a pipeline seem bleak, as Mexico itself is short of gas.

Will Asian gas prices come down from their heights?

The spread between the Japanese and the US natural gas wholesale prices decreased in 2013 after reaching the largest difference of the last ten years in 2012 (USD 13.95/MBtu). Even though the highest prices, Japanese LNG prices, dropped by 4% to USD 16.05/MBtu and average Asian LNG prices by 4%, they still remain at very high levels on a historical basis (Figure 70). This price drop is a consequence of declining oil prices. But during the winter period, prices of LNG spot cargoes occasionally exceeded USD 20/MBtu, because the season included both, on the demand side, the heating season in Europe and Asia and exceptional droughts in Latin America, and on the supply side, limited additional LNG supply. Meanwhile, the United States continues to enjoy relatively low gas prices (USD 3.73/MBtu average Henry Hub in 2013), although these prices increased by 35% in 2013 compared to 2012 because of higher demand and a slowdown in US gas production. Gas prices on European spot markets increased in 2013, but remained in the middle of these extremes, varying between USD 10 and USD 12/MBtu.

Although the spread between natural gas prices worldwide declined in 2013, the difference is still large, at a factor of more than four. This difference is much higher than the difference in transportation costs between the gas markets, showing that natural gas prices are still determined by regional fundamentals and the lack of fungibility of natural gas. Regional fundamentals in 2013 include the strong reliance and increasing demand for gas in Asia, and weather influences such as droughts in Latin America and cold spells in the United Kingdom and the United States. Furthermore, the case of the United States shows that even when supply and demand are balanced at a national level, some shortages can occur due to capacity constraints when the increase in gas production outpaces infrastructure development.

Figure 70 Gas price developments in the three main regional markets, Jan 2004 to Jan 2014



US gas prices can diverge from forever low levels

For the past five years and until early 2014, the world has marvelled at low US gas prices, which have remained stubbornly below USD 4.5/MBtu. These low levels have been the driver behind the rush towards gas in transportation, the switch from coal to gas in the power sector, low electricity prices, LNG exporters turning away from North America, Canada's gas output in free fall since 2009 and the substantial number of planned US LNG export projects (Map 5). In simplest terms, they have changed gas markets. But the events in early 2014 show that nothing is set in stone, especially not prices, and that high-impact, low-probability events such as the North American cold wave, which took place in the first quarter of 2014, can change perspectives. Surely, this event has not affected the long-term price perspectives and the market confidence that gas can be produced and delivered at HH prices below USD 5/MBtu for the rest of the decade, but prices have remained in the USD 4.7 range well into the spring of 2014.

Traditionally, the price at the HH in the state of Louisiana has been a price marker throughout the United States, with the difference on the basis of the transport costs from Louisiana. The largest share of natural gas production in the United States is still located in the Gulf region. From there, interstate pipelines spread across the country. Located at the major pipeline crossing in Louisiana, HH serves as the key benchmark for natural gas pricing throughout the United States. In 2013, the average HH price increased by 35% to an average of USD 3.7/MBtu from USD 2.8/MBtu the year before.

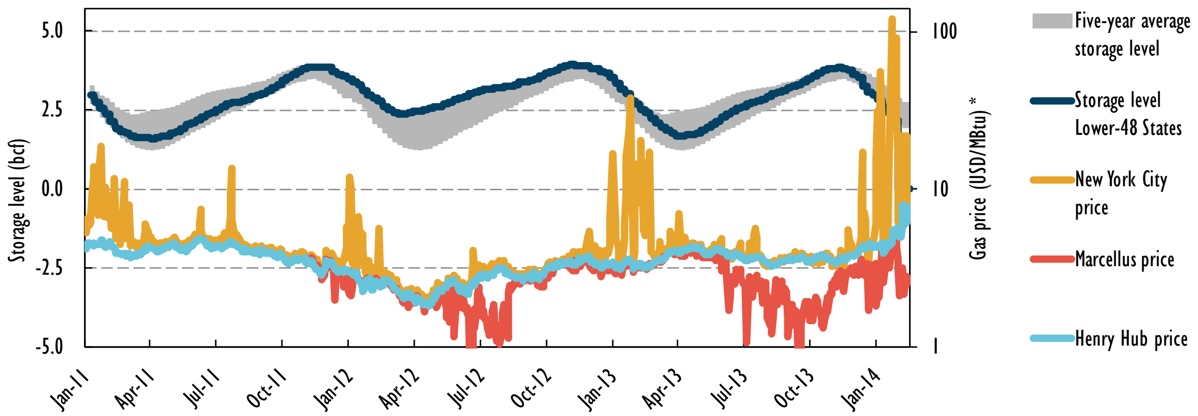
Natural gas pricing in the United States is entirely based on gas-to-gas competition (IGU, 2013). This means that the price is set as a result of natural gas supply-and-demand fundamentals. In principle, the US price can, therefore, be determined by the long-term marginal costs (LTMC) of production (IGU, 2012). With the lowest-cost production volumes first, the price is set at the point when these volumes meet demand. Hence, the development of prices is both the result of production volumes and costs and the development of gas demand. The storage component, as well as (now) limited Canadian imports, must also be taken into account. The increasing production of dry and associated shale gas by applying horizontal drilling and fracking has been a fundamental driver for the price development in the United States since 2009, notably due to the impressive cost reductions achieved by producers due to process improvements.

But supply-and-demand developments never go smoothly. This rapid production growth initially outpaced the growth in demand, resulting in lower prices. Furthermore, the increase in gas demand in 2012 was limited because of relatively warm temperatures in early 2012, which lowered demand for heating and for storage, and drove storage levels to their highest filling level of the last five years. This oversupply pressed prices downwards, even below levels considered viable for production. In principle, this trend should have driven gas production down. However, associated gas production continued to increase, as the value of liquids was high, maintaining daily gas prices below the long-term marginal production costs of some wells. The average HH gas price in 2012 was marked by the lowest level seen over a decade, with an average monthly value of less than USD 2/MBtu in April 2012. In early 2013, total demand – notably in the residential/commercial sector – rose faster than total supply, which contributed to upward pressure on prices. This was accelerated by large storage withdrawals, putting storage levels below five-year average levels (Figure 71).

Demand rose faster than total production in 2013 (14 bcm against 6 bcm), enabling HH prices to recover to almost USD 4/MBtu on average. The US market started the winter 2013/14 with relatively normal storage levels and with price expectations around USD 4.5/MBtu. However, the very cold weather affected HH price levels, which rose to reach the highest daily average since February 2010 of USD 5.7/MBtu on January 28th in reaction to higher demand. When winter weather returned, the volatility of HH stayed as well, as prices rose to USD 7.9/MBtu on 6 February 2014, a level unseen since early 2008. Although this level may appear very high compared to prices prevailing over the past six years, it was quite low if one takes into account the exceptional withdrawals from storage. For the first time in over 20 years, more than three weeks of weekly storage withdrawals higher than 6 bcm were recorded. Such record levels were observed during six non-consecutive weeks, and storage levels as of early March 2014 were half the five-year average levels.

While the HH price variations following the cold spell were not extreme in absolute terms, some gas prices witnessed much more important variations. The United States does not have one single price but rather different regional gas prices, reflecting different supply-and-demand dynamics. The Northeast is a traditional high-demand centre, but with low storage capacity. The proximity of the Marcellus play is progressively changing the region's supply-and-demand dynamics. In 2011, natural gas production grew especially in the Northeast from the Marcellus shale gas play. Production of this play made the local trading point (TGP-Z4 Marcellus) to diverge in 2012 from HH (Figure 71). The increase in production was constrained by the pipeline capacity to the consuming areas, causing local prices to drop (EIA, 2012). New pipeline expansions brought the price levels on par with HH prices in the second half of 2012. Since a quarter of the regional demand is used in the residential sector for heating, winter temperatures caused an increase in demand in winter 2012/13. Therefore, HH and Marcellus prices synchronised until the first months of 2013.

Figure 71 Gas price and storage level developments in the United States, Jan 2011 to Feb 2014



* Logarithmic scale.

Demand dropped with the arrival of spring, following the usual seasonal pattern. In the meantime, US gas production continued to increase, by around 0.9% in 2013. During 2013, pipeline capacity for the Marcellus region expanded by a hefty one-third. The Tennessee Northeast Upgrade Project, the extension of the TETCO-pipeline and the Northeast Supply Link contributed to improve the connection between supply and demand. This activity represented a very significant increase in capacity, but production volumes, nevertheless, managed to outpace it by doubling. As a consequence of the Marcellus area remaining oversupplied, prices during 2013 stayed at a discount to HH, averaging only a little over USD 3/MBtu. The low prices from Marcellus started to drag the prices of the New York area down to the HH level. Canadian imports now have a much weaker influence on the price setting in the Northeast because Canadian gas production at these low prices is not profitable anymore, resulting in a substantial drop in Canadian exports to the United States.

The start of the 2013/14 winter season led the price of Marcellus to climb towards that of HH. At the end of 2013 and the start of 2014, a record-setting cold spell swept through the United States and Canada. This event led to a strong increase in demand for heat and for power. The gas pipelines became constrained because they could not handle all the additional volumes requested. This caused prices in New York to spike at a daily average level of USD 55/MBtu on 6 January 2014 for delivery on the next day.

The sharp rise in Northeast natural gas and power demand also spurred record-high natural gas storage withdrawals. With storages at their lowest of the last five years, and another cold spell two weeks later, prices in New York went up to a weekly average of about USD 80/MBtu and a record high of

USD 121/MBtu on average for 22 January, up 700% compared to the same date in the warm winter of 2012. Although the winter of 2012/2013 had seen a price spike as well (to USD 37.98/MBtu), its much warmer winter weather and higher storage levels prevented prices from peaking like in early 2014. The cold had also spread across other parts of the country, increasing the demand for gas. In conclusion, apart from weather circumstances, the price spikes and regional price differences highlight the importance of enough capacity to deliver non-traditionally located supplies to demand areas.

What drives European gas prices?

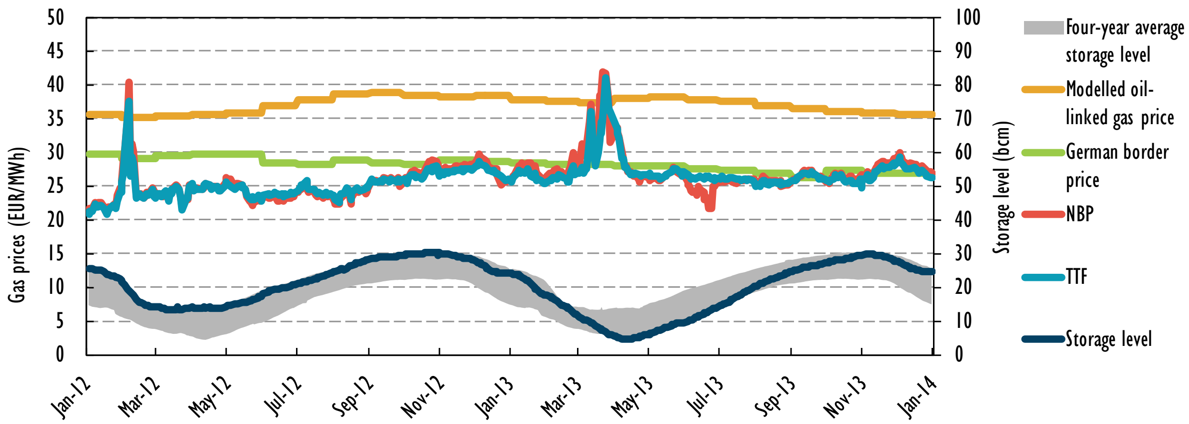
The level of European gas prices is puzzling. On the one hand, they are not high enough to attract LNG supplies to Europe based on the transport differential with Asia. Looking at the respective Asian and European gas prices, one can indeed wonder why European gas prices are not higher. On the other hand, gas prices are too high to make gas competitive in the power sector: the prevailing coal and CO_2 prices during the first quarter of 2014 imply that gas prices should be between USD 5/Mbtu and USD 6/Mbtu to enable a switch from coal to gas. Hence the question: what is determining European gas prices?

Europe has two gas pricing systems. One relies on long-term contracts, once linked predominantly to oil prices, but is now based on a mixture of indices ranging from oil, spot prices and possibly coal. The other system is on the basis of supply-and-demand fundamentals through gas-to-gas competition on spot markets. Such a price system now enters in the price setting of long-term contracts, making both systems strongly interrelated. Analysis from the bank Société Générale and The Economist (The Economist, 2014) states that the share of gas linked to the spot market increased from 15% in 2008 to more than half in 2013, while Northwest Europe would have about 70% of spot-linked gas. The economic downturn in 2009 resulted in lower gas demand and put pressure on the spot prices; meanwhile, oil-linked gas prices remained relatively high. Hence, long-term contracts were renegotiated. This was the result of the pressure felt by large European buyers on the reselling value of the long-term contracts priced with a link to oil, while gas could be bought at a lower price on the spot market by their competitors or their industrial and power generation customers. The increasing importance of spot markets over the past decade and price difference made it possible to renegotiate the contracts and include partial spot indexation, as buyers could argue that the economic circumstances had changed and that spot prices were increasingly the benchmark to be used.

In 2013, the levels of the traditional marker for long-term contracts – the German border price (GBP) – reached the average level of the spot markets, while the latter were still marked by seasonality. Compared to 2012, the average annual GBP dropped by 5%, while the National Balancing Point (NBP) price increased by 9% and those of the Title Transfer Facility (TTF) increased by 8% (Figure 72). After the winter of 2013/2014 the European spot prices have dropped to levels at around EUR 20/MWh (or USD 8/MBtu). As that winter was mild in Europe, gas withdrawal from storages was lower than normal, driving prices downwards. This trend started after December 2013, when usually the peak of the winter has passed, comforting the market with adequate supplies for higher demand in the remainder of the winter. When April began, the use of seasonal gas storages changed from withdrawal to injection. With still more gas in storage than normal, the prices continued to drop. While the prices for the next winter remained stable, the low prices in the beginning of the summer increased the spread between both prices and hence stimulating to refill the storages.

Due to contract renegotiations, the GBP has been lower than a gas price featuring the historical oil linkage prevailing before 2009. During 2012, the difference widened, mainly as a result of new renegotiations of long-term contracts or settlements after arbitration procedures, increasingly including a share of spot-linked pricing. During 2013, the difference remained rather stable, meaning that the decrease of the GBP in 2013 was driven by the 3% lower average Brent oil price during 2013 relative to 2012. Had no renegotiations in long-term contracts taken place over the last years, the GBP prices would have been around EUR 35/MWh (about USD 14/Mbtu). Russian gas imports increased in 2013 because of price reductions at the expense of Norwegian gas imports. Other factors that played a role in this shift are a reduction of LNG imports by half and production problems at Norway's Troll field. At the end of 2013, it seemed that the GBP import price lost its premium over spot prices.

Figure 72 Gas price and storage level developments in Europe, Jan 2012 to Feb 2014



* Storage levels on the basis of United Kingdom, Germany, PEG Nord region and the Netherlands, excluding Langelo and Grijpskerk.

Source: GSE.

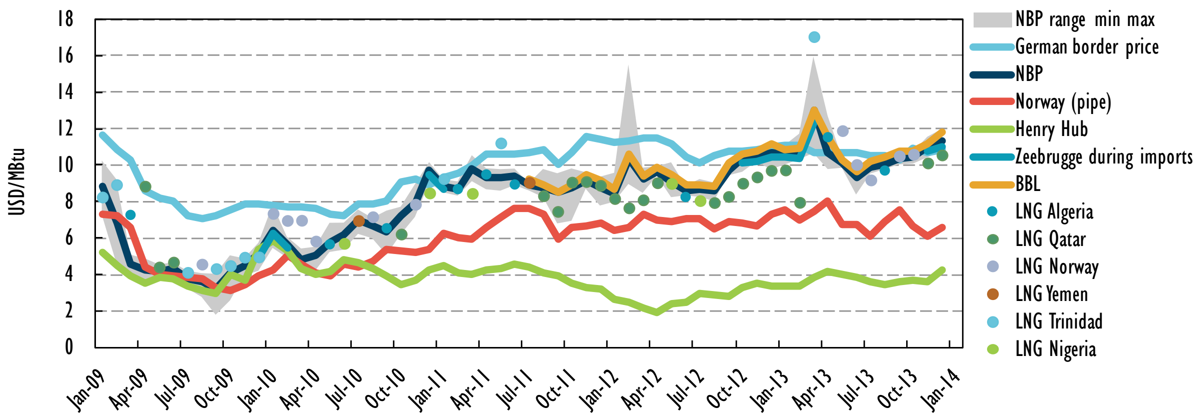
Besides the difference between spot and long-term contract prices, substantial differences still exist between European countries. Throughout 2013, prices on European gas hubs converged, suggesting a well-connected market. Occasional disruptions of interconnectivity between the hubs resulted in price divergence. For example, during June 2013, the NBP was oversupplied as the Interconnector to Belgium was in maintenance, hence resulting in lower UK prices. In contrast, prices in Eastern Europe are generally oil-linked, although the price levels differ between countries. For example, Turkey's gas imports via pipeline from Iran, Azerbaijan and Russia are presumably priced linked to oil. The price for Iranian gas was much higher than the price of other pipeline imports. In the beginning of 2012, Iranian gas exports to Turkey equalled the volumes of Russian gas exports to Bulgaria.

With all these different price levels in Europe, the best place to understand the price level is at the most open gas market with the most liquid spot market. Although this currently is the Dutch TTF, the longest history of an open market is found in the United Kingdom. In theory, pricing in an open market is driven by developments in supply and demand. But the United Kingdom is not an island in terms of gas supplies, because it is connected by pipelines to Norway, the Netherlands and Belgium. Gas flows through these pipelines contribute to the supply-and-demand balance and hence also to the price formation. Furthermore, that the country has been importing LNG for a long time adds a different supply driver for understanding the price levels at NBP.

Back in 2009, NBP prices converged with HH prices. The main reason for the decline of prices was the sudden oversupply in the market as the economic crisis engendered lower demand for gas. The sudden global oversupply of LNG, masking the growing demand in Asia, led to lower LNG prices and explains the overlap between the United States and the United Kingdom. European buyers preferred to maximise their off take of lower-priced LNG cargoes, as high oil-linked gas prices in Continental Europe remained twice as expensive, while swing producers such as Qatar took the opportunity to divert flexible cargoes away from the oversupplied US market. North America, therefore, acted as the residual market, remaining at a small discount against NBP spot prices. Norwegian gas deliveries, most of which were thought to be priced at NBP, followed this trend during that period.

But in 2010, when more imports were needed to compensate for lower gas production and meet recovering European demand (for example, demand increased by 9% in the United Kingdom in 2010 over 2009), other volumes took over in setting the price. Additionally, global LNG markets were no longer as loose as in 2010 when global gas demand jumped by 8%. Comparing coal- and gas-fired plant electricity generation costs during 2010, one can observe a very strong correlation between those costs, which disappears in 2011 as coal prices dived due to coal oversupply. The *Medium-Term Coal Market Report 2013* noted the strikingly strong 252-day correlation between TTF gas and API2 coal prices until mid-2011, when natural gas lost its edge over coal as a fuel for power generation (IEA, 2013b). Gas-fired plants moved from mid-merit to out of the money, so that interactions in the power sector were no longer a driver behind European gas prices.

Figure 73 UK supply sources' prices versus NBP, Jan 2009 to Jan 2014



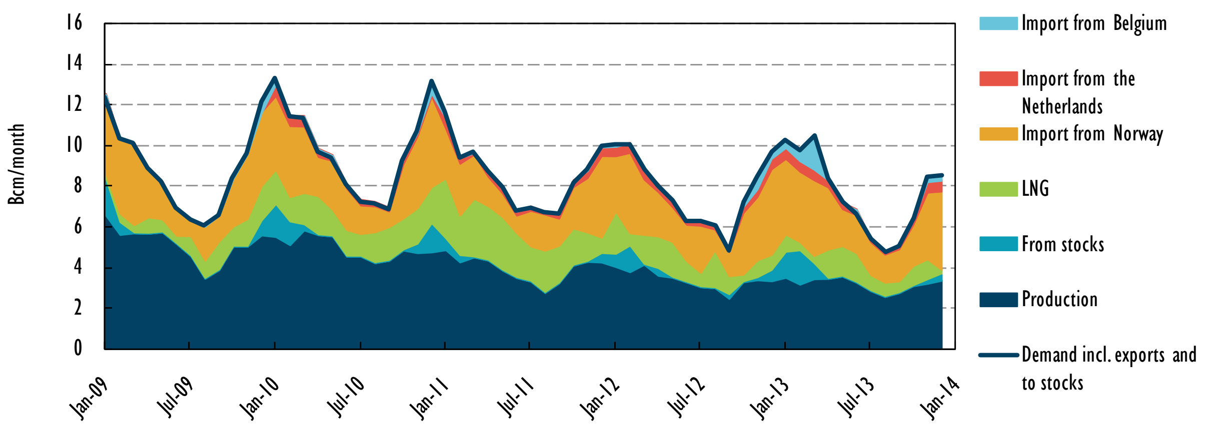
Source: IEA; UK customs.

After early 2011, the demand side was no longer setting the price, so that other supply factors were influencing the price. However, none of them seems to have been the defining factor setting the price. LNG had become a significant and constant part of supply, but NBP prices were much lower than what an LNG flow optimisation from the LNG swing suppliers would suggest, because the transport cost differential was much wider than the difference between Asian and NBP gas prices. The supply policy of the government of Qatar could explain part of this differential between Europe and Asia, because the country's potential to send more LNG to Asia would have had a downward effect on Asian gas prices and reduced the price gap between the two regions. The price impact on European gas prices, in normal times, would be limited due to the substantial spare capacity held by Russia. Besides, LNG shipments to the United Kingdom could be based on the NBP price, as is shown by the extension of the contract between Centrica and Qatargas signed in 2013. In such a case, these volumes are a result of the price, rather than setting the price. This principle is also shown by the LNG shipment of March 2013, when the NBP price was at a peak. Norway is also one of United Kingdom's largest suppliers. But Norwegian pipeline supplies are priced significantly below the NBP price (Figure 73), because a small share of these deliveries are based on some very low-priced historical North Sea contracts featuring S-curves or low slopes. The other and largest part of Norwegian deliveries to the UK market is Ormen Lange gas, which was assumed to be priced at NBP.

The commercial relationship between Continental Europe and the United Kingdom is, nevertheless, strengthening, raising the question of which price is driving the other. Prices of gas imported via the Balgzand Bacton Line (BBL) pipeline connecting the United Kingdom with the Netherlands and further to Russia show an equal path as those transacted on the NBP. This relationship could imply that this flow finally sets the price in the United Kingdom, because it is among the highest, and therefore the last, in a merit order-like system. But it seems more probable that these prices are the result of volumes that are indexed at NBP and are, therefore, a result of that price, rather than setting the price. This conclusion is shown by the price spikes during spates of cold weather in February 2012 and March 2013. In these periods, supply could not meet the sudden increasing demand. But still the prices of the NBP and the BBL flow perfectly match.

For many years, TTF and NBP prices strongly converged, with strong divergences usually linked to specific weather events or pipeline issues. Of note is that NBP prices, which had been at a discount to TTF prices on an annual basis from 2009 to 2011, are now at a premium on an annual basis. Although admittedly NBP was driving TTF in the early days of the increased connection through BBL in 2006, the question is now whether TTF is not driving NBP itself. The issue is complicated by the question of what is driving the TTF itself, which depends on the different contracted supplies arriving to the wider north-western Continental market, including Russian and Norwegian gas. Several factors play a role, such as the fact that Russian contracts have been reviewed individually with different concessions in terms of spot indexations and/or rebates.

Figure 74 UK gas supply and demand, Jan 2009 to Jan 2014



Since early 2013, the NBP seems to be back to a relationship that had disappeared some time ago, around 2007 (Figure 74). Then, NBP gas prices used to be at a discount to Continental contract gas prices (GBP) during the summer and at a premium during the winter, reflecting the fact that the country was short of gas supplies during the winter. This pattern has appeared again since the winter of 2012/13. Besides the BBL pipeline, the Interconnector pipeline between the United Kingdom and Belgium provides another source of supply, especially during winter times, and perfectly follows the price differentials between the hubs in both countries. A shortage and higher prices on one side of the Channel attracts flows from the other side.

A late winter cold period in March 2013 resulted in north-western European prices increasing by 35% to 40% from the month before. At the end of the winter, storage facilities were already quite empty compared to the four-year average. On top of this, the Norwegian Ormen Lange field had unplanned outages while LNG imports were also lower than normal, pushing storage levels even further down. When the Interconnector pipeline between the United Kingdom and Belgium was also interrupted, prices in the United Kingdom spiked above EUR 40/MWh (USD 15/MBtu) on a day-ahead basis. Within-Day prices spiked even higher, up to more than EUR 50/MWh or USD 18/MBtu. As temperatures dropped, LNG arrived and Norwegian production recovered, prices in north-western Europe restored. The storage facilities had to be filled in the following six months, preventing prices from significantly dropping during summer. This is a contrast to 2012, which had mild weather (apart from one short cold spike), and storages remained at high levels on average.

All things considered, explaining the level of the gas price in Europe remains difficult because of the mixture of hub-indexed flows of LNG and pipeline gas. Nevertheless, the flows through the Interconnector to Belgium show the arbitrage options between countries, making these the price-setting volumes during winter when the United Kingdom shows higher prices. The increasing dependency on imports increases the potential for volatility in case of extreme demand and/or unplanned outages of import infrastructure.

Table 34 Nominated (net traded) and physical volumes on European hubs (bcm)

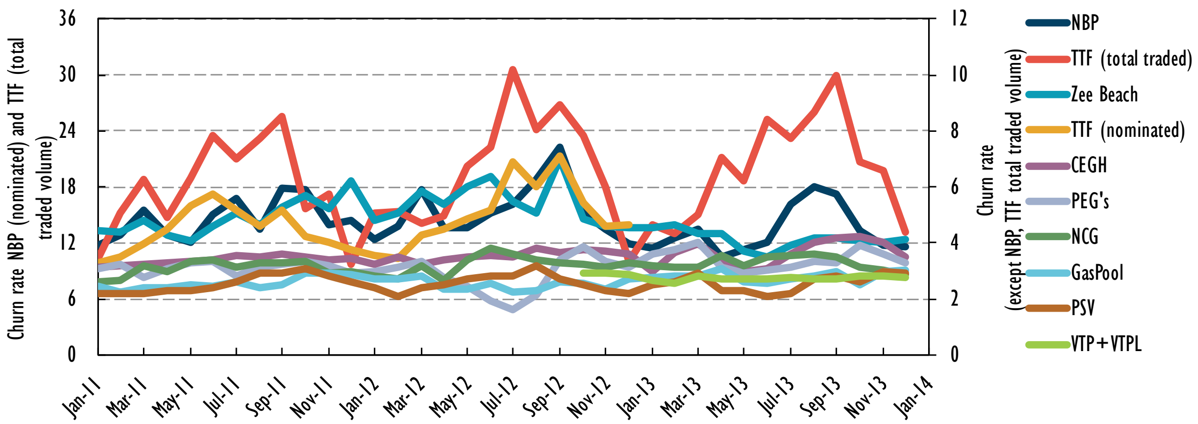
				Physical delivered volumes				
	NBP	**Zeebrugge**	**TTF**	**PSV**	**PEG's**	**GASPOOL**	**CEGH**	**NCG**
2007	66.8	7.9	7.4	6.8	5.1	2.2	6.9	4.1
2008	66.6	9.1	18.7	7.7	6.6	4.4	5.2	14.4
2009	74.6	12.9	25.0	11.0	8.1	12.9	7.6	25.0
2010	95.8	16.7	31.3	21.5	8.7	29.6	10.9	31.3
2011	79.6	14.3	35.6	23.0	12.8	29.6	11.6	35.5
2012	85.6	12.6	39.6	25.9	17.0	35.0	13.4	42.3
2013	85.4	16.8	42.5	25.3	16.3	40.0	9.7	47.4
				Net traded/nominated volumes				
	NBP	**Zeebrugge**	**TTF**	**PSV**	**PEG's**	**GASPOOL**	**CEGH**	**NCG**
2007	902.6	40.2	27.6	11.5	11.1	4.8	17.7	6.6
2008	960.8	45.4	60.5	15.6	16.5	9.7	14.9	25.3
2009	1016.1	64.9	73.6	23.5	23.1	28.6	22.8	56.0
2010	1095.5	65.2	106.5	43.1	27.8	65.0	34.1	84.1
2011	1137.2	69.3	151.7	57.7	39.8	75.8	39.2	108.5
2012	1271.0	66.6	187.9	64.7	46.3	88.3	47.3	133.1
2013	1094.0	69.4	786.9*	65.8	55.5	112.6	35.4	152.7

Note*: As of January 2013, the Dutch TSO GTS began to report only total traded volumes, including OTC trades. As other TSOs still report the nominated volumes, an equal comparison between TTF and the other European hub could not be made with the data currently available.

Sources: TSOs and regulators.

With possibly as much as half of the gas in Europe being traded at spot markets, the liquidity of European spot markets increased in general, although measuring liquidity levels is not unequivocal. Liquidity of trading is regularly expressed as the ratio between the traded volume and the physical volume, called the churn ratio (Figure 75). Additionally, data on traded volumes are often represented by the volumes that are nominated to the TSO. However, not all traded volumes are necessarily registered by the TSO. The TSOs only register volumes that are nominated. Volumes could be traded several times before being finally nominated. Trades at hubs can be executed via an energy exchange, over-the-counter (OTC) via brokers and bilaterally (Table 34). Differences exist between hubs in the way volumes are traded. For example, some hubs such as TTF have more OTC trades, while others such as NBP have more volume traded via the energy exchange. All trades – via the exchange, OTC and bilaterally – contribute to the total liquidity of the hub.

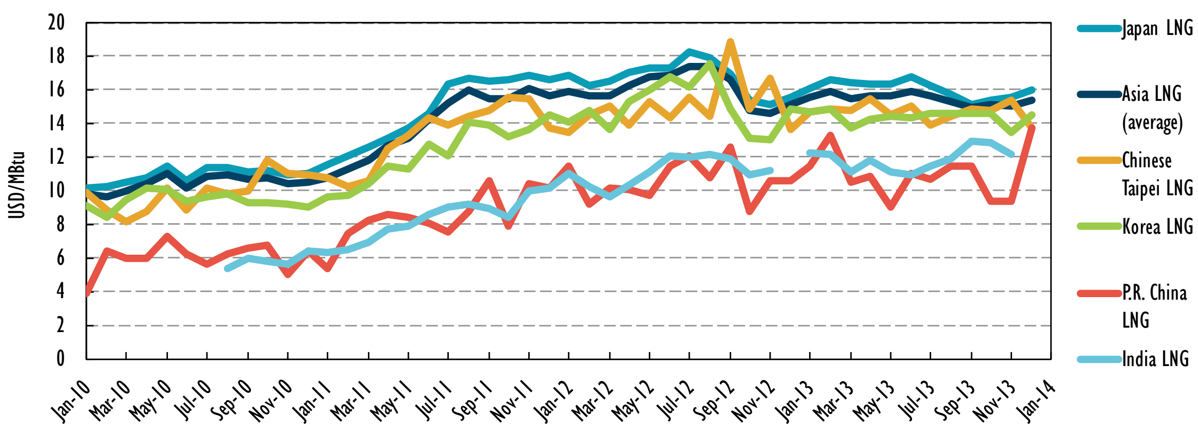
Figure 75 Development of churn rates at European hubs, Jan 2011 to Jan 2014



Asian gas prices

Gas prices in Asia continue to be based on oil indexation in the LNG import contracts (Figure 76). During 2013, the annual average Brent oil price was 3% lower compared to 2012. Consequently, the annual average LNG price was lower in 2013 as well. Asian LNG contract prices are usually based on oil, using an S-curve to dampen the impact of high oil prices for the buyer and low oil prices for the seller, which led to some attractively priced LNG for contracts concluded before 2008. Also, a drive to gain a share in the emerging Chinese gas market could have played a role to agree on lower prices. This result is notably the case for the Chinese LNG contract from Australia or Malaysia. However, these contracts could be prone to price increases resulting from renegotiations.

Figure 76 Asian gas price developments, Jan 2010 to Jan 2014



China

In 2013, China continued to pay the lowest price for its LNG among the large LNG-importing Asian countries. The main reason is that China still benefits from low-priced Australian, Indonesian and Malaysian LNG. The levels that determine the S-curve in the contracts between these three countries and China are probably low, as they originate from years with much lower oil prices. Other imports are more expensive: LNG is imported from Qatar at an average price level of USD 17.61/MBtu, down from USD 18.57/MBtu for 2012. Meanwhile, domestic production continues to support a large, albeit declining, share of Chinese gas demand: 68% in 2013, down from 72% in 2012, and was priced at the regulated tariff of around USD 7.7/MBtu.

The contracted imported volumes via pipelines were somewhat more expensive and represented the largest share of imports to China. The largest part of pipeline imports originate in Turkmenistan and this volume increased 22% in 2013 compared to a year earlier. In 2013, new pipeline imports started from Myanmar, with first recorded volumes in September. As for LNG, contracted pipeline imports are linked to the price of oil. During 2013, the price level for gas from Turkmenistan at the border was at around USD 9.6/MBtu, slightly lower compared with 2012, while Myanmar gas had an average price level of USD 11.8/MBtu at the Chinese border. Although Myanmar gas seems more expensive, one has to take into account a lower transportation distance within China compared to Turkmen gas.

During 2013, China raised its regulated gas price for non-residential users from about USD 7.7/MBtu (about CNY 1.70/m^3) to some USD 8.9/MBtu (about CNY 1.95/m^3) to deal with the increasing volumes and price for its natural gas imports. This increase helps to reduce losses for China's oil and gas companies because of their inability to pass on higher costs to consumers, although the increase of the regulated price does not cover the complete difference with the price paid for its LNG imports. This increase of Chinese domestic gas price also moves towards higher prices asked by the Russians for natural gas pipeline imports. Furthermore, higher prices in China could boost new production as one element to meet the growing demand.

Japan

The average price of Japanese LNG imports in 2013 was about 50% higher compared to those for China. This difference was somewhat lower than in 2012 as the Japanese average import price declined in 2013 by 4% to USD 16.05/MBtu because of a lower oil price. However, two factors caused the total costs for imports to increase: higher Japanese LNG imports in 2013 compared to 2012 (by 0.2%), and the devaluation of the yen. Aimed at boosting exports, the devaluation caused energy import costs to rise (expressed in yen terms) and increased the Japanese yearly trade deficit.

Japanese LNG import prices reached the lowest level of 2013 in September, at USD 15.10/MBtu. Prices rebounded in the following months, driven by supply uncertainty regarding the tight Japanese power market. Forced to meet winter peak demand in 2013 with no nuclear power, Japanese buyers frontloaded contracted LNG supplies during the last month of the year. In so doing, the buyers sought to secure enough supply before winter demand set in, so as to limit the exposure to high-priced LNG spot cargoes. The prices reached USD 15.97/MBtu, just over oil parity.

Korea

Korea's LNG imports increased by 11% in 2013, compared to one year earlier. LNG supplies in 2013 to Korea were derived from its contracts totalling almost 28 mtpa, supplemented in 2013 with 11 mtpa from the spot market. The contracted LNG from countries such as Malaysia and Russia was still attractively priced compared to spot cargoes. The higher costs for LNG imports into Korea were partly passed through to its domestic consumers, as it raised its regulated domestic gas price by 4.4% in 2013 and again by 5.8% in early 2014. In 2014 and 2015, additional LNG volumes for 3.2 mtpa and 1 mtpa are already contracted, reducing the dependency on spot markets. As these volumes are coming from new Australian projects, they are expected to feature oil indexation and are, therefore, unlikely to be cheap.

The Asian gas price stalemate

Asia is the fastest-growing LNG import market in a context of low European demand prospects and the withdrawal of North America from the LNG-importing picture. Only Latin American gas importers are occasionally competing with their Asian counterparts by high demand in the power sector. Asia is also an appealing market given the much higher average gas prices paid by the different countries in comparison with Europe, for example. Two trends seem to create a discrepancy on LNG prices between its Asian buyers and its suppliers. The LNG buyers are struggling with the long-term contracts with high LNG prices that are set by a high oil price. Therefore, signing up for cheaper hub-priced LNG from the United States is very attractive at the current price levels. On the supplier side, new greenfield projects are increasingly expensive, calling for securing revenues by long-term contracts preferably still linked to the high oil prices. This trend is also fed by different views on whether the global LNG market over the coming years will be short or long. Although many projects are at the planning stage, very few FIDs have been taken, and one should not confound the DOE's approval with a formal FID. Indeed, DOE approval is the main stumbling block in the path of US LNG projects, but it is not the only one. Other authorisations are necessary, and the financial side of the project also does matter.

Demand in Asian countries is still expected to significantly exceed domestic production growth, thus calling for imports. Due to the geographical specificities of the region, LNG is deemed to continue to play an increasing role. Only pipeline gas from the FSU could compete with LNG to gain a share of this growing pie, and the country the most likely to be targeted is China.

Asian countries are increasingly focusing on the need to lower gas import prices. Natural gas is an important fuel in a region where energy demand is still expected to grow by 60% until 2035. It remains to be seen what share of that demand will be natural gas, depending on different pricing paths. In the New Policies scenario of the *World Energy Outlook 2013*, non-OECD Asia's (including China) gas demand would increase by 2.5% per year. Nevertheless, infinite gas demand growth in the region cannot be taken for granted. It will be subject to available supplies, competitiveness (or lack thereof) of natural gas against coal and other sources of energy in the power sector, and the price at which natural gas reaches the different markets. Asian gas markets differ widely. Mature markets, such as Japan and Korea, have a higher (but not infinite) resilience to high prices, because very limited alternatives are available to fulfil the total demand for energy. In ASEAN countries, the pricing issue is all the more acute in that many members have a long history of price subsidies. The current prices are hence a burden for those governments. China and India have a huge and increasing demand for natural gas but cannot cope with high import costs, India less than China.

Hence, Asian gas customers want cheap gas. Until recently, most LNG was priced at oil-indexed prices. The only few exceptions were when the LNG was heading to a liquid market such as the United States or the United Kingdom, where spot prices with sufficient transparency and liquidity prevail. None of that exists in Asia. Still, US LNG exporters, following the example of Cheniere, are proposing HH-based prices, with LNG changing ownership at the liquefaction plant, breaking in one move both oil indexation and final destination clauses. A common thought nowadays is, therefore, that HH-priced gas is equal to cheap gas.

But is price indexation the issue, or the price level? What buyers really want are lower gas prices, a crucial issue because it will determine not only the pace of demand growth in Asian gas markets and future supply prospects, but also the willingness of LNG producers to invest in the next generation of LNG export plants as well as pipeline projects. The industry faces the following options while trying to renegotiate existing long-term contracts and negotiate new LNG contracts for projects still at the planning stage:

- continue with oil indexation but with lower slopes, lower reference price and S-curves triggered at lower oil prices,
- use an existing hub indexation such as HH, or
- include the possibility of using a still-to-be-determined Asian hub, once its liquidity is deemed sufficient (such an option could be included in contracts).

Each option has its pros and cons. Less and less competition exists between oil and gas at the end-user level, notably in the power generation sector. If anything, coal is the competitor to natural gas; but an indexation to coal would just move from one fuel to another. Additionally, finding a reliable and transparent Asian coal price could also prove to be tricky. Meanwhile, many producers are more comfortable with oil-indexed prices.

Using Henry Hub indexation rather than oil is the only credible alternative to change the pricing indexation over the medium term. Based on current Henry Hub prices of around USD 4/MBtu and on the Cheniere export price formula,[9] LNG can be delivered to Asian markets at around USD 11/MBtu, significantly below the current gas prices. But this option assumes that HH prices would stay low for 20 years, the duration of the long-term contracts. However, the dynamics of Henry Hub are, nevertheless, quite different from the Asian market, let alone the volatility of HH prices. Besides, many producers are reluctant to take this as an alternative, even though it is reported that some Canadian and East African sellers could settle for a hybrid indexation.

No spot price exists in Asia, unlike in Europe and North America. In the report *Developing a Natural Gas Trading Hub in Asia*, the IEA focused on the obstacles and opportunities for the Asia-Pacific economies to establish natural gas trading hubs that allow gas prices to reflect local/regional demand and supply (IEA, 2013a). Such a change would be based on the processes of gas market liberalisation that are already taking place in several countries, having a substantial influence on institutional changes, and structural conditions, including the existence of sufficient network capacity, transparent access to it, a number of participants sufficient to engender competition, and the involvement of financial institutions. The IEA analysis shows the change will take at least a decade to develop, so while this option could be used as a future indexation in long-term contracts, it will not have any meaningful impact on prices in the medium term. The progressive development could also reinforce the bargaining power of Asian buyers because it would provide another price signal that could come to life over the next 20 years (the duration of future long-term contract).

[9] The formula is based on an FOB prices of 115% Henry Hub gas prices, plus a tolling agreement of up to USD 3/MBtu. The buyer needs to add the transport cost, which depends on the shipping arrangements taken by the buyers.

But in the current tight market, LNG sellers are reluctant to accept some of the new terms and conditions, potentially leading to a shortage of new LNG projects, with only a few LNG projects in the United States taking FID over 2014-15. Since LNG demand is likely to continue to increase in Asia, not only are new LNG liquefaction projects needed to meet the incremental needs, but also some existing facilities where reserves are depleting need to be replaced. Additionally, some countries face increasing domestic demand, resulting in LNG production being reallocated to their domestic market. Egypt is the most visible example of these trends and sets an unwanted precedent for planned liquefaction projects based on at least a 20-year lifetime.

Box 17 Renegotiating LNG contracts: When the LNG seller gets low prices

In the current high price environment, it may seem counter-intuitive that an LNG seller would want to renegotiate an LNG contract price because it is too low. Nevertheless, Yemen's government has pushed towards a renegotiation of the long-term contracts with the three buyers of LNG due to low sales prices. The gas is indeed sold to three buyers: Korea's Kogas, GDF Suez and Total. The price previously paid by Kogas was USD 3.15/MBtu, one of the lowest in the world. The contract contains a Brent-based price formula with a floor and ceiling and a five-year renegotiation clause. Yemen LNG argues that when the deal was signed in 2005, it was comparable and in some cases, better than other SPAs to Korea. In late 2013, the contract was renegotiated, and Kogas will now pay around USD 14/MBtu at current oil prices.

Meanwhile, talks with Total and GDF Suez, which had their contracts pegged to HH prices, are still ongoing. Yemen LNG sales to these two buyers were originally earmarked to go to the United States and Europe. But following the sharp decline in HH prices, Yemen LNG renegotiated the agreements with Total GDF Suez to divert LNG cargoes to the higher-paying Asian market.

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THE ESSENTIALS

Table 35 World gas demand by region and key country

	2000	2010	2013	2015	2017	2019
OECD Europe	475	567	504	486	498	504
G4	*300*	*325*	*281*	*268*	*272*	*272*
Western Europe	*400*	*461*	*398*	*380*	*386*	*387*
Central and Southest Europe	*60*	*88*	*92*	*93*	*100*	*106*
OECD Americas	794	851	920	923	955	968
United States	*661*	*683*	*737*	*739*	*762*	*765*
OECD Asia Oceania	131	198	229	237	248	256
Japan	*83*	*109*	*130*	*137*	*137*	*138*
Africa	55	105	119	132	145	159
Algeria	*18*	*26*	*30*	*33*	*36*	*38*
Egypt	*18*	*47*	*53*	*56*	*59*	*63*
Non-OECD Asia	155	288	283	310	335	357
India	*28*	*64*	*53*	*58*	*65*	*78*
ASEAN	*87*	*151*	*148*	*160*	*174*	*182*
People's Republic of China	28	109	166	213	263	315
FSU/non-OECD Europe	597	681	680	675	676	681
Russia	*391*	*466*	*468*	*461*	*461*	*463*
Caspian region	*82*	*106*	*115*	*122*	*127*	*132*
Non-OECD Europe	*30*	*27*	*24*	*23*	*22*	*21*
Latin America	93	151	164	171	186	204
Brazil	*9*	*27*	*36*	*37*	*43*	*51*
Middle East	180	376	426	456	495	535
Iran	*62*	*145*	*156*	*167*	*175*	*184*
Qatar	*11*	*26*	*41*	*44*	*52*	*53*
Saudi Arabia	*42*	*81*	*100*	*109*	*117*	*126*
	2 508	3 326	3 490	3 602	3 800	3 980

Notes: Numbers may not add up due to rounding.
G4: France, Germany, Italy, and the United Kingdom.
Western Europe: Austria, Belgium, France, Germany, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain, Switzerland, and the United Kingdom.
Central and Southeast Europe: Czech Republic, Estonia, Greece, Hungary, Poland, Slovakia, Slovenia, and Turkey.
ASEAN: Brunei Darussalam, Cambodia, Indonesia, Laos, Malaysia, Myanmar, Philippines, Singapore, Thailand, and Viet Nam.
People's Republic of China includes Hong Kong.
Caspian region: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyz Republic, Tajikistan, Turkmenistan, Uzbekistan.
Non-OECD Europe: Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Gibraltar, Latvia, Lithuania, Former Yugoslav Republic of Macedonia, Malta, Montenegro, Romania, Serbia.

Table 36 World sectoral gas demand by region

	2000	2010	2013	2015	2017	2019
OECD Europe	475	567	504	486	498	504
Residential-commercial	*189*	*221*	*218*	*203*	*203*	*201*
Industry	*137*	*121*	*119*	*119*	*122*	*123*
Power generation	*125*	*196*	*139*	*138*	*147*	*154*
OECD Americas	794	851	920	923	955	968
Residential-commercial	*263*	*255*	*270*	*244*	*240*	*236*
Industry	*236*	*182*	*198*	*20*	*212*	*215*
Power generation	*190*	*275*	*304*	*323*	*344*	*347*
OECD Asia Oceania	131	198	229	237	248	256
Residential-commercial	*35*	*50*	*48*	*51*	*52*	*53*
Industry	*22*	*29*	*33*	*36*	*41*	*43*
Power generation	*70*	*103*	*132*	*132*	*134*	*136*
Africa	55	105	119	132	145	159
Residential-commercial	*3*	*6*	*7*	*8*	*8*	*8*
Industry	*12*	*25*	*26*	*28*	*30*	*32*
Power generation	*27*	*57*	*71*	*80*	*91*	*102*
Asia	155	288	283	310	335	357
Residential-commercial	*8*	*16*	*19*	*20*	*21*	*23*
Industry	*44*	*78*	*84*	*92*	*102*	*109*
Power generation	*69*	*146*	*134*	*150*	*163*	*175*
China*	28	109	166	213	263	315
Residential-commercial	*4*	*29*	*40*	*46*	*53*	*60*
Industry	*11*	*31*	*49*	*57*	*69*	*83*
Power generation	*6*	*25*	*41*	*62*	*79*	*93*
FSU/non-OECD Europe	597	681	680	675	676	681
Residential-commercial	*113*	*112*	*108*	*109*	*108*	*108*
Industry	*91*	*119*	*121*	*123*	*127*	*129*
Power generation	*319*	*352*	*358*	*350*	*348*	*350*
Latin America	93	151	164	171	186	204
Residential-commercial	*11*	*14*	*18*	*18*	*21*	*23*
Industry	*32*	*56*	*55*	*56*	*58*	*60*
Power generation	*24*	*44*	*55*	*59*	*67*	*77*
Middle East	180	376	426	456	495	535
Residential-commercial	*23*	*48*	*51*	*53*	*55*	*56*
Industry	*53*	*117*	*147*	*158*	*175*	*190*
Power generation	*76*	*153*	*161*	*178*	*197*	*219*
Total	2 508	3 326	3 490	3 602	3 800	3 980

Notes: Numbers may not add up due to rounding.

This table does not show other sectors such as energy industry own use, transport and losses. The industry sector includes gas use by fertiliser producers.

Table 37 World gas production by region and key country

	2000	2010	2013	2015	2017	2019
OECD Europe	303	300	268	252	247	242
Norway	*53*	*107*	*109*	*115*	*116*	*117*
OECD Americas	760	816	889	912	958	991
United States	*544*	*604*	*688*	*720*	*770*	*797*
OECD Asia Oceania	42	60	72	85	133	160
Australia	*33*	*48*	*58*	*66*	*110*	*135*
Africa	119	210	196	224	239	254
Algeria	*77*	*80*	*73*	*83*	*86*	*88*
Egypt	*18*	*62*	*56*	*56*	*58*	*62*
Non-OECD Asia	221	332	313	329	347	357
India	*28*	*51*	*36*	*36*	*40*	*49*
ASEAN	*159*	*216*	*206*	*211*	*220*	*223*
China	27	95	117	141	164	193
FSU/non-OECD Europe	725	842	889	891	899	917
Russia	*573*	*657*	*671*	*657*	*650*	*656*
Caspian region	*118*	*151*	*184*	*201*	*216*	*229*
Non-OECD Europe	*16*	*14*	*13*	*13*	*12*	*12*
Latin America	102	161	175	184	196	208
Brazil	*7*	*15*	*20*	*24*	*30*	*37*
Middle East	202	472	562	584	616	658
Iran	*59*	*145*	*160*	*169*	*178*	*189*
Qatar	*24*	*121*	*165*	*169*	*177*	*176*
Saudi Arabia	*42*	*81*	*100*	*109*	*117*	*126*
Total	2 502	3 288	3 480	3 602	3 800	3 980

Notes: Numbers may not add up due to rounding.
G4: France, Germany, Italy, and the United Kingdom.
Western Europe: Austria, Belgium, France, Germany, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain, Spain, Switzerland and the United Kingdom.
Central and Southeast Europe: Czech Republic, Estonia, Greece, Hungary, Poland, Slovakia, Slovenia, and Turkey.
ASEAN: Brunei Darussalam, Cambodia, Indonesia, Laos, Malaysia, Myanmar, Philippines, Singapore, Thailand, and Viet Nam.
China includes Hong Kong.
Caspian region: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyz Republic, Tajikistan, Turkmenistan, Uzbekistan.
Non-OECD Europe: Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Gibraltar, Latvia, Lithuania, Former Yugoslav Republic of Macedonia, Malta, Montenegro, Romania, Serbia.

Table 38 Fuel prices (USD/MBtu)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Natural gas										
Henry Hub	5.90	8.84	6.75	6.98	8.86	3.95	4.39	4.00	2.75	3.73
NBP	4.47	7.34	7.64	6.03	10.74	4.77	6.56	9.02	9.48	10.64
German border price	4.30	5.83	7.88	8.00	11.61	8.53	8.03	10.62	11.09	10.73
Japan LNG	5.19	6.02	7.12	7.74	12.66	9.04	10.90	14.78	16.70	16.05
Oil										
WTI	7.14	9.73	11.38	12.46	17.18	10.63	13.69	16.36	16.23	16.88
Brent	6.59	9.38	11.23	12.50	16.72	10.60	13.70	19.18	19.25	18.73
JCC	6.27	8.79	11.05	11.90	17.65	10.45	13.65	18.81	19.79	19.03
Coal										
US Appalachian	2.38	2.38	2.09	1.81	4.27	2.07	2.67	3.07	2.43	2.46
NW European steamcoal	3.03	2.55	2.69	3.72	6.18	2.96	3.82	5.10	3.89	3.43
Asian Coal marker	3.04	2.60	2.37	3.55	6.22	3.31	4.43	5.28	4.43	3.82

Table 39 Relative fuel prices (HH 2003/WTI 2003/US APP 2003 = 1)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Natural gas										
Henry Hub	1.00	1.50	1.14	1.18	1.50	0.67	0.74	0.68	0.47	0.63
NBP	0.76	1.24	1.30	1.02	1.82	0.81	1.11	1.53	1.61	1.80
German border price	0.73	0.99	1.33	1.36	1.97	1.45	1.36	1.78	1.85	1.82
Japan LNG	0.88	1.02	1.21	1.31	2.15	1.53	1.85	2.50	2.83	2.72
Oil										
WTI	1.00	1.36	1.59	1.74	2.40	1.49	1.92	2.29	2.27	2.36
Brent	0.92	1.31	1.57	1.75	2.34	1.48	1.92	2.69	2.70	2.62
JCC	0.88	1.23	1.55	1.67	2.47	1.46	1.91	2.63	2.77	2.66
Coal										
US Appalachian	1.00	1.00	0.88	0.76	1.80	0.87	1.12	1.29	1.05	1.03
NW European steamcoal	1.27	1.07	1.13	1.57	2.60	1.24	1.63	2.15	1.63	1.44
Asian Coal marker	1.28	1.09	1.00	1.49	2.62	1.39	1.86	2.22	1.86	1.61

Sources: IEA, ICE, German Customs, Japanese Customs, EIA, Bloomberg, McCloskey, Federal Reserve and European Central Bank.
Notes: All prices are yearly averages, of their respective average monthly prices. To convert oil prices in USD/bbl, the prices in USD/MBtu have to be multiplied by 5.8. To covert coal prices in USD/ton (6 000 kcal), the prices in USD/MBtu have to be multiplied by 23.8.

Table 40 LNG liquefaction (bcm per year, existing, under construction, planned projects)

Region	Operation	Construction	Planned
Asia	131	96	146
Australia	*33*	*83*	*104*
Brunei	*10*	-	-
Indonesia	*46*	*5*	*11*
Malaysia	*33*	*7*	*2*
Papua New Guinea	*9*	-	*28*
Middle East	137	-	109
Abu Dhabi	*8*	-	-
Iran	-	-	*84*
Iraq	-	-	*6*
Israel	-	-	*3*
Oman	*15*	-	-
Qatar	*105*	-	*16*
Yemen	*9*	-	-
Europe	6	-	
*Cyprus**	-	-	
Norway	*6*	-	
Eurasia	13	22	99
Russia	*13*	*22*	*99*
Africa	92	6	159
Algeria	*33*	*6*	-
Angola	*7*	-	*7*
Cameroon	-	-	*5*
Egypt	*16*	-	*5*
Equatorial Guinea	*5*	-	*10*
Libya	-	-	*8*
Mozambique	-	-	*27*
Nigeria	*30*	-	*83*
Tanzania	-	-	*14*

North America	-	24	298
Canada	-	-	*178*
United States	-	*24*	*133*
Latin America	27	1	25
Brazil	-	-	*5*
Colombia	-	*1*	-
Peru	*6*	-	-
Trinidad and Tobago	*21*	-	*1*
Venezuela	-	-	*19*
Total	**406**	**150**	**842**

* 1. Footnote by Turkey
The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of United Nations, Turkey shall preserve its position concerning the "Cyprus issue".
2. Footnote by all the European Union Member States of the OECD and the European Union
The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

Table 41 LNG regasification (bcm per year, existing, under construction, planned projects)

Region	Operation	Construction	Planned
OECD Asia Oceania	365	15	4
Israel	*2*	-	-
Japan	*260*	*4*	*3*
Korea	*103*	*11*	*0.1*
New Zealand	-	-	*2*
Non-OECD Asia (excl. China)	73	11	126
Bangladesh	-	-	*7*
Chinese Taipei	*14*	-	*3*
India	*34*	-	*68*
Indonesia	*4*	*7*	*10*
Malaysia	*5*	-	*8*
Pakistan	-	-	*5*
Philippines	-	*4*	*5*
Singapore	*8*	-	*4*
Thailand	*7*	-	*7*
Viet Nam	-	-	*10*
China	46	23	58
Europe	196	21	214
Albania	-	-	*8*
Belgium	*9*	-	*9*
Croatia	-	-	*5*
France	*25*	*13*	*15*
Germany	-	-	*4*
Greece	*5*	-	*9*
Ireland	-	-	*4*
Italy	*15*	-	*74*
Lithuania	-	*3*	-
Netherlands	*12*	-	*10*
Poland	-	*5*	-
Portugal	*6*	-	*3*
Romania	-	-	*5*
Spain	*60*	-	*26*
Sweden	*0.3*	-	-
Turkey	*13*	-	-
United Kingdom	*51*	-	*43*
FSU	-	-	5
Ukraine	-	-	*5*
Middle East & Africa	12	-	57
Bahrain	-	-	*4*
Côte d'Ivoire	-	-	*3*

Region	Operation	Construction	Planned
Jordan	*-*	*-*	*15*
Kuwait	*8*	*-*	*15*
South Africa	*-*	*-*	*2*
United Arab Emirates	*4*	*-*	*18*
North America	227	-	235
Canada	*10*	*-*	*16*
Mexico	*21*	*-*	*21*
Puerto Rico	*4*	*-*	*3*
United States	*192*	*-*	*197*
Latin America	31	3	54
Argentina	*10*	*-*	*11*
Brazil	*13*	*-*	*18*
Chile	*5*	*2*	*7*
Colombia	*-*	*-*	*4*
Cuba	*-*	*-*	*3*
Dominican Republic	*2*	*1*	*-*
El Salvador	*-*	*-*	*1*
Jamaica	*-*	*-*	*2*
Panama	*-*	*-*	*3*
Uruguay	*-*	*-*	*6*
Total	**949**	**73**	**753**

IEA Publications, 9, rue de la Fédération, 75739 Paris cedex 15

Printed in France by ISIPrint, June 2014
(612014131E1) ISBN 9789264211537; ISSN 2307-0269

GAS Medium-Term Market Report 2014

Global natural gas demand grew just 1.2% in 2013, underperforming other fuels, because of a slow economy, supply constraints, sluggish LNG trade, and competition from coal and renewables in the power sector. Growth in non-OECD countries, which had buoyed global demand over the past decade, retreated to nearly the same pace as in OECD countries. Without the effect of colder weather in OECD countries, demand there would have actually fallen and global demand would have been unchanged.

The IEA *Medium-Term Gas Market Report 2014* gives a detailed analysis of demand, supply and trade developments as well as infrastructure investments to meet the 2.2% annual growth in gas demand expected through 2019. It investigates the important changes that will transform the industry: rising regional disparities between gas-hungry regions such as China and the Middle East against weakening growth in the Former Soviet Union (FSU) and Europe; competition between FSU supplies and LNG from the United States and Australia, notably in Europe and Asia; the shift towards net imports in non-OECD Asia and Latin America; and uncertainty over whether Europe can ease its dependency on Russian gas. Besides enhanced coverage of gas in the power sector, this year's report features special focuses on the potential of gas in maritime transport; the competition between oil and gas to meet fast-growing power consumption in the Middle East; the implications of Iran's possible return to the international gas scene; and the interplay of natural gas liquids and natural gas in the United States.

Market Analysis and Forecasts to 2019

€100 (61 2014 13 1E1)
ISSN 2307-0269
ISBN: 978 92 64 21153 7