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.