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PANEL DISCUSSION

Current Developments in the Oil and Natural Gas Markets and their Implications for the Energy Sector in the Arab World

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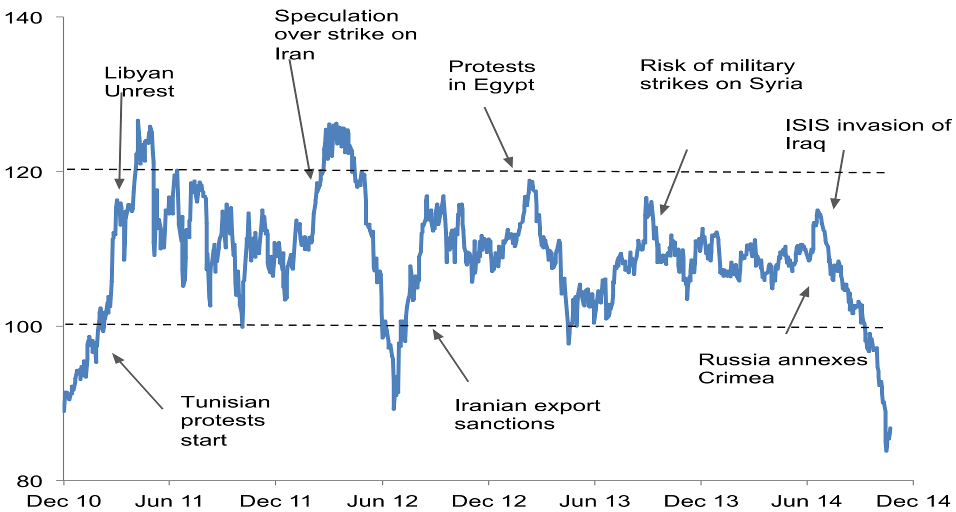
I. Recent Developments in the Oil Market

Between 2011 and mid 2013, the Brent price oscillated within a very narrow range, with quarterly average Brent prices exceeding the $100/barrel mark for 14 consecutive quarters. This relative stability has been remarkable given the various shocks that have hit the oil market ranging from macroeconomic shocks, to geopolitical shocks, to unplanned outages and to North America's positive supply shock. This price stability however was disrupted and since June 2014, the oil price has fallen sharply with Brent trading at below $80 per barrel at the time of writing. This fall in the oil price has occurred despite the general deterioration in the geopolitical backdrop in many parts of the world.

Figure 1: Brent prices, $/barrel



Source: Bloomberg Price Data

Oil Demand

Multiple factors can account for the recent sharp decline in the oil price. The most important factor is the downward revision of global oil demand expectations. While the global economy has rebounded from the 2008 financial crisis, the prospects facing the global economy remain highly uncertain. In their meeting in September 2013, the G20 noted that the 'global growth prospects have been marked down repeatedly over the last year, global rebalancing is incomplete, regional growth disparities remain wide, and unemployment, particularly among youth, remains unacceptably high… the recovery is too weak, and risks remain tilted to the downside'. In their latest meeting in November 2014, the G20 sent a similar message declaring that 'the global recovery is slow, uneven and not delivering the jobs needed. The global economy is being held back by a shortfall in demand, while addressing supply constraints is key to lifting potential growth. Risks persist, including in financial markets and from geopolitical tensions'.

The deterioration in global economic prospects has been reflected in oil forecasts and oil demand growth figures, which have changed drastically over a short period of time. In June the IEA's 2014 global oil demand growth forecasts hit a peak of 1.4 mb/d. At the time of writing, the global demand forecast has fallen almost by half. In the OECD, demand declines have stepped up, led by weak demand in Europe reflecting its poor economic performance and in Japan as cheaper coal and LNG substituted fuel and crude burn in the power sector.

Figure 2. OECD oil demand, y/y change%

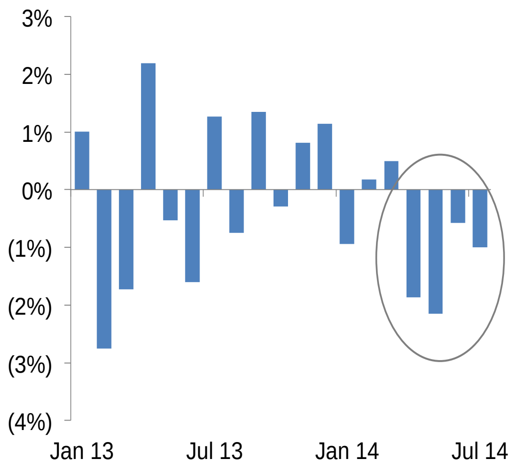
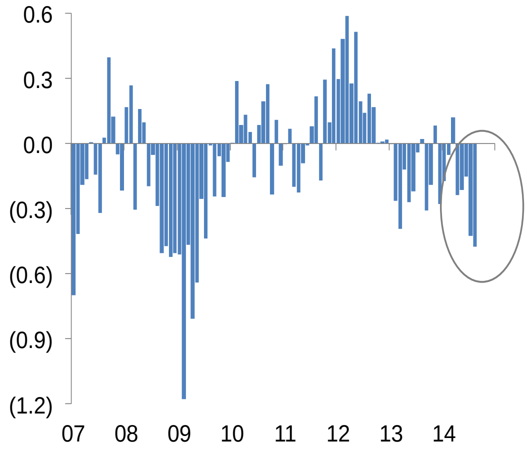


Figure 3: Japanese oil demand, y/y change mb/d



Meanwhile, in the non-OECD, Chinese oil demand growth has also slowed down as the Chinese economy continues to rebalance from high savings and fixed investment towards private consumption. The rebalancing has had some unintended consequences in terms of urban labour shortages and rising costs. Furthermore, one of biggest threats to rebalancing is the legacy of the fiscal stimulus, which resulted in the accumulation of large local government debt. While risks exist, the Chinese government still has ample scope to maintain growth. In 2013, non-OECD Asia outside of China and India made a large contribution to oil demand growth; while small in isolation, the combination of Indonesia, Thailand, Vietnam and Philippines held up Asian demand. Latest data however show that growth in Non-OECD Asia (ex India and China) has also started to slow down.

Figure 4. China's oil demand, y/y mb/d

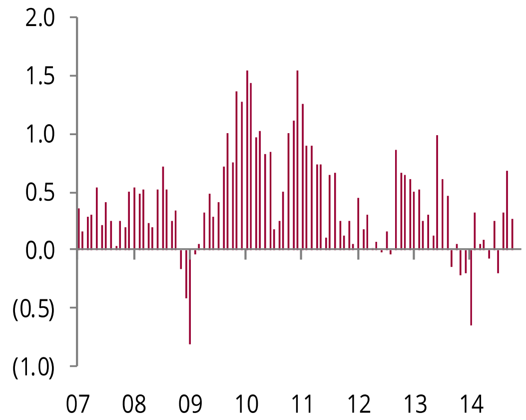
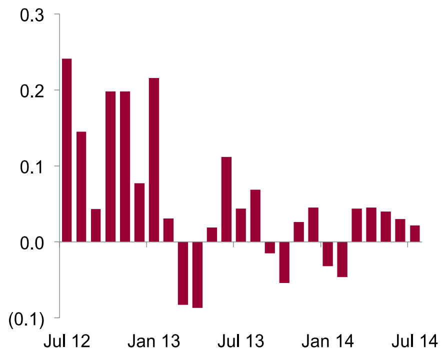


Figure 5. Non-OECD Asia ex India and China, y/y change mb/d



Box 1. Shifts in Product Demand Dynamics: The Case of China[1]

It is important to note that within non-OECD, there have been some changes in demand pattern across various fuels. Fuelled by trade and investment, China's growth has strongly supported diesel demand over the last decade. The dominant position of diesel in commercial freight traffic, be it by truck or rail, made it the fastest-growing demand component. In China, the government mandate requiring all trucks to be fuelled by diesel by 2010

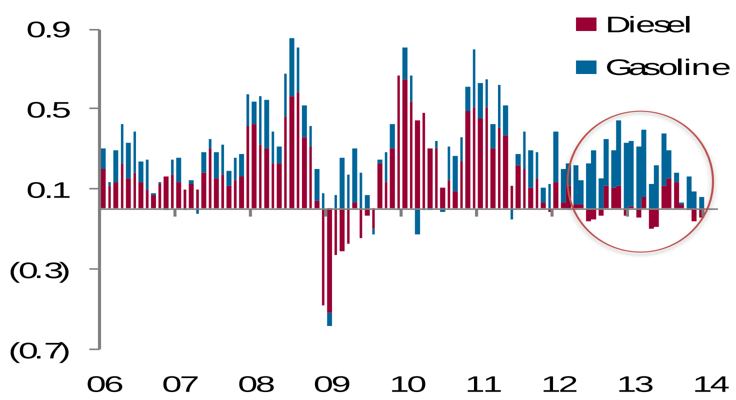
[1] This section is based on Fattouh, B. and A. Sen (2014), 'China's Rebalancing and Oil Consumption Patterns', Oxford Energy Forum, February, Issue 95.

simply accelerated the already rising momentum of diesel demand growth. Further, diesel demand received an extra boost from power problems that led to greater use of diesel as a back-up fuel. Whether in 2004, 2008, or 2010, both power shortages during the winter months and periods of government power rationing to achieve environmental targets contributed to a buoyant diesel demand. Heavy industries and mining such as coal, ship-building, steel, and cement that rely heavily on diesel boomed throughout the 2000s. It is thus hardly a surprise that diesel was the backbone of Chinese oil demand growth, to the extent that Chinese oil demand growth was synonymous with diesel demand growth. However, the objective of Chinese rebalancing is ultimately to transfer more power to consumers, which does not necessarily imply lower commodity demand across the board. In fact, any sector that is more geared towards consumer demand rather than investment will benefit, and this is already evident in China's changing oil consumption patterns. Gasoline and jet fuel, petroleum products more geared towards consumers, have been performing robustly, compared to diesel and petrochemical feedstock, which are more leveraged to investment demand.

Indeed, in a notable reversal of trends, diesel demand growth in China has slowed to 3.5% so far this decade, after having averaged 8.7% in the last decade. The downswing from the peak rates is even greater, with double-digit growth seen in 2004 (0.4 million b/d or 23.4%), 2008 (0.3 million b/d or 12%), and 2010 (0.36 million b/d or 13.2%). This tapered off to flat-to-negative demand growth in 2012 (40 thousand b/d or 1.2%). In comparison, gasoline demand growth has increased steadily over the past few years, picking up pace in recent months. Last decade, Chinese gasoline demand increased on average by 7.4% per year. The momentum has continued into this decade, averaging 10.6% so far. In 2013, gasoline demand was up by nearly 10%, while diesel demand has been lacklustre, up by a mere 0.6% year on year. Gasoline used to be half the size of the diesel market in China and has now become two- thirds its size, with the gap between gasoline and diesel demand rapidly narrowing.

Although diesel demand growth is unlikely to turn negative in the coming years, a longer-term rebalancing away from investment-oriented growth implies far lower growth rates in mining and heavy industries. Such a rebalancing and tighter credit conditions are likely to taper the rates of growth in overall diesel demand. Gasoline demand, on the other hand, has been supported primarily by consumers, with the transportation sector accounting for nearly 50% of total gasoline consumption by 2010. The increasing ownership of private cars and buses is the primary reason for the rising gasoline consumption in the transport sector. While rapid economic development and urbanization over the last three decades have resulted in an average GDP growth rate of 8–10%, the number of passenger cars in China has risen by an average of 25% since 2003, with over one million cars sold each month from early 2009 through 2010. Total numbers of passenger vehicles grew from 12.19 million cars in 1997 to over 100 million cars in 2012, an average annual growth rate of over 15%.

Figure 6: Chinese Demand Growth, Year on Year Change mb/d



Source: IEA, Energy Aspects

Non-OPEC Supply

While demand expectations continued to be revised downwards, supply expectations have been much more stable despite the unevenness in performance within non-OPEC. Outside of the North America region, the supply side looked increasingly challenged in the last few years. Many of the potential centers regarded as key sources for supply growth continued to disappoint. For instance, Brazilian prospects proved to be gloomier than the market expected. Not only do Petrobras and its partners have to drill to record depths to reach oil – a costly procedure in itself- but there are also serious challenges within the country which are having ramifications on the oil sector. The lack of adequate pricing policies has been affecting the company's share value and preventing the inflow of financial resources needed to fund the significant investments involved in developing sub-salt reserves. According to new legislation, Petrobras will stand as the key operator in sub-salt domains and in areas considered to be strategic. However, this focus on pre-salt is coming at the expense of arresting declines at the Campos basin, which is impeding Brazil's ability to grow production. In the FSU, the Kashagan project in Kazakhstan has not reached its potential. BP also announced that output at Azerbaijan's biggest oilfield, the ACG, would fall this year owing to heavy planned maintenance.

Figure 7: Brazilian Oil Output mb/d

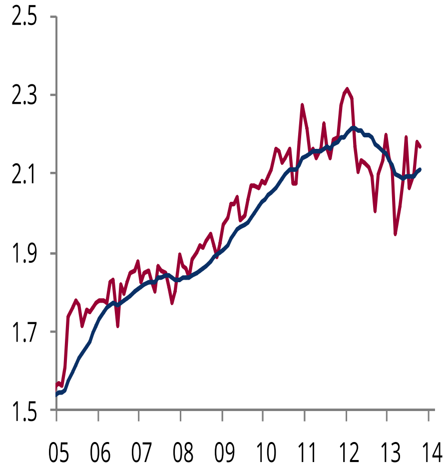
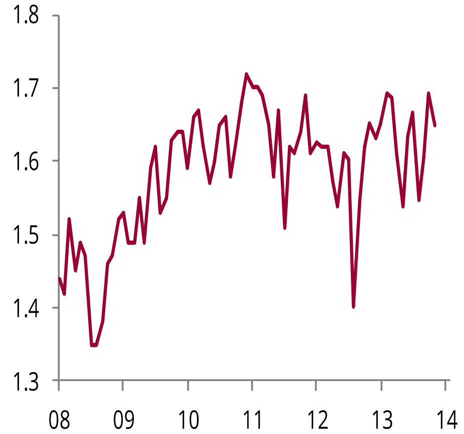


Figure 8. Khazakstan Oil Output mb/d

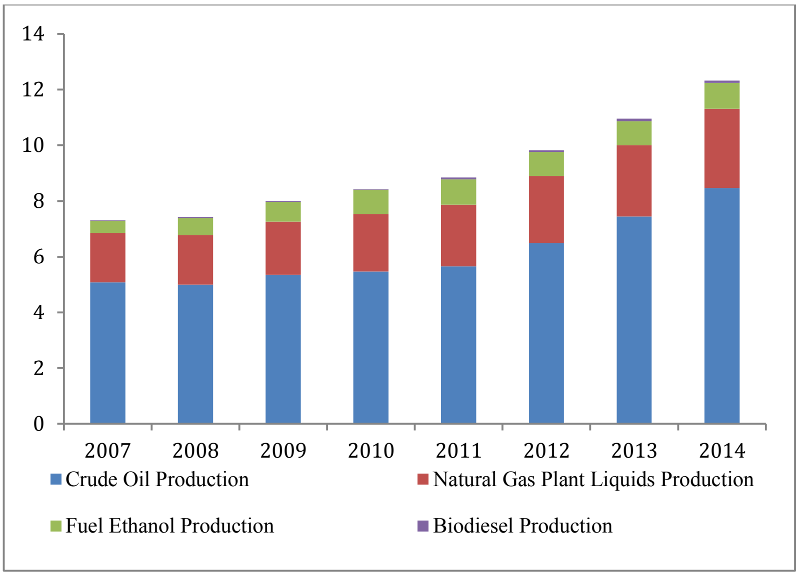


Source: EIA, Energy Aspects

While many supply centres within non-OPEC continued to disappoint, the non-OPEC poor supply performance was counteracted by the sharp increase in US output driven by high oil prices and technological innovation (hydraulic fracturing) which allowed the exploitation of shale oil and gas reserves on a large scale. The received wisdom, only a decade ago, painted the picture of a US economy becoming increasingly reliant on oil imports, especially from the Middle East. Quite the opposite has happened: Overall US oil imports have been declining and now Canada, not the Middle East, is by far the most important foreign supplier of oil to the USA.

The size of the US oil supply shock has been nothing short of phenomenal. From a position of negative growth in 2008, US crude oil production growth turned positive in 2009 and amounted to 840,000 b/d in 2012 and 950,000 b/d in 2013, with growth expected to exceed the 1 mb/d (million barrel per day) mark in 2014. An important feature of the shale revolution is the rapid growth in NGLs, driven by increased drilling activity in liquid-rich basins. Over the period 2008 to 2013, the USA added around 800,000 b/d of NGLs, with production of NGLs exceeding 2.5 mb/d in 2013. This impressive performance has been driven in large part by the development of shale resources. From less than 1 mb/d in 2010, tight oil production increased to more than 3.5 mb/d in the second half of 2014. In its *AEO2014* Reference case, the EIA estimates tight oil production will reach 4.8 mb/d in 2021, comprising more than 50 per cent of total US production compared to 35 per cent in 2012. US production of ethanol increased from around 220,000 b/d in 2004 to close to 900,000 b/d in 2013, though in recent years its growth has slowed due to a variety of factors including saturation in the gasoline market and vehicle and infrastructure issues.

Figure 9: US crude oil and liquid fuel production (mb/d)



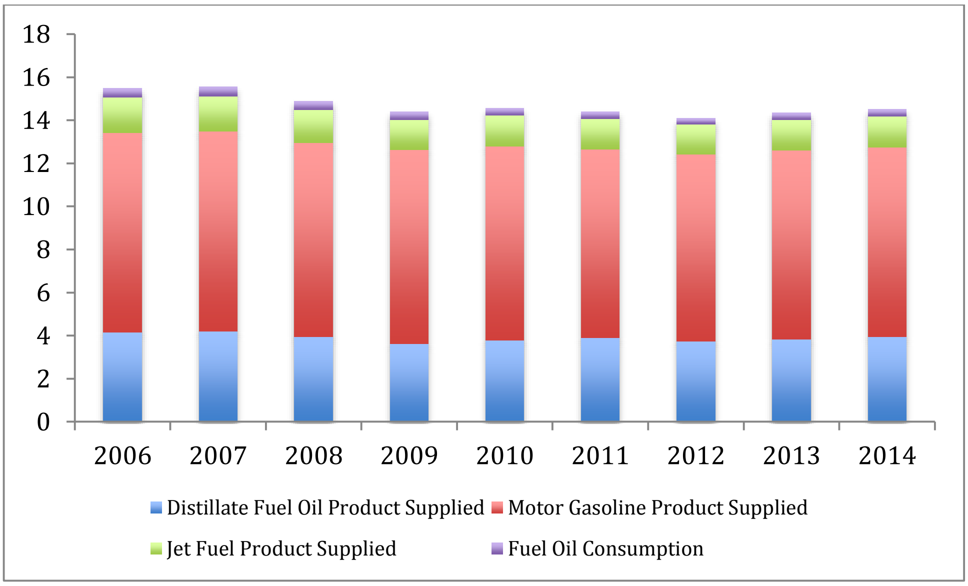
Source: EIA; Estimate for 2014.

These developments on the supply side have reversed two decades of secular decline in US liquid production. US crude oil and liquid fuel production increased from around 7.3 mb/d in 2007 to above 11 mb/d in 2013 and 12.6 mb/d in 2014 (June 2014), constituting one of the key areas of liquid-supply growth in the world. In 2012 and 2013, the USA added 980,000 b/d and more than 1 mb/d of liquid production respectively. This achievement is remarkable. As the 2014 BP Statistical Review of World Energy notes,

> ... only Saudi Arabia has ever had a bigger increase than the US in 2013 [and historically out of nine times in which production rose by more than 1 million b/d] six of those nine times the increment resulted from the ability to tap spare production capacity. In terms of 'organic growth', based on capacity expansion, last year's increase (2013) therefore was the fourth biggest in history.

There have also been some important changes on the demand side. US gasoline consumption has declined from its 2007 peak of around 9.3 mb/d to 8.7 mb/d in 2013. While US gasoline demand is responsive to changes in household income and gasoline prices and consequently part of this decline is reversible, another part of the decline is permanent, induced by structural transformations such as changes in drivers' behaviour, the switch to more efficient vehicles, and more assertive government policies in areas of vehicle efficiency and/or increasing the penetration of hybrid and electric cars. US consumption of distillate fuel oil has also declined from its peak in 2007 of around 4.2 mb/d to 3.84 mb/d in 2013. Unlike gasoline, distillate demand is more responsive to changes in economic activity, either measured by GDP or by industrial production. As the economic recovery in the USA consolidates, consumption of distillates could increase, but it may take some time before it surpasses its 2007 levels.

Figure 10: US oil consumption by product (mb/d)

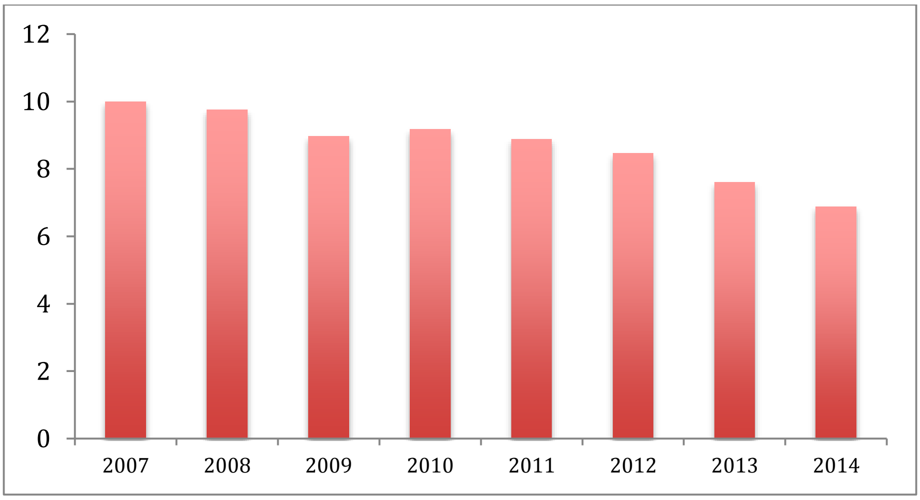


Source: EIA.

These emerging trends on the supply and demand side have had major implications on the domestic and the international oil scene. US dependence on imported oil has declined drastically over the past few years: from 10 mb/d in 2007, net imports have fallen to 7.6 mb/d in 2013, and are expected to fall below the 7 mb/d mark in 2014. The origin of imported crude oil has also changed. In 1990, the Middle East Gulf supplied almost 30 per cent of US crude oil imports. In 2013, this share declined to 25 per cent. Exports from producers in West Africa and North Africa to the

USA have been reduced to a trickle as the increase in US production has backed out imports of light crude oil. In contrast, the share of imports from Canada has increased from around 10 per cent in 1990 to more than 33 per cent in 2013, a trend which is likely to consolidate as Canada continues to enhance its production capacity, and as new infrastructure is put in place.

Figure 11: US net crude oil imports, mb/d

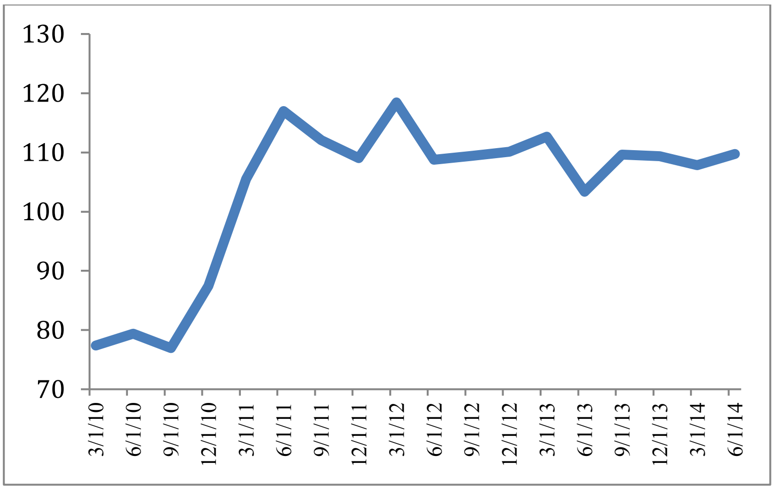


Source: EIA.

The Supply Counter-shocks

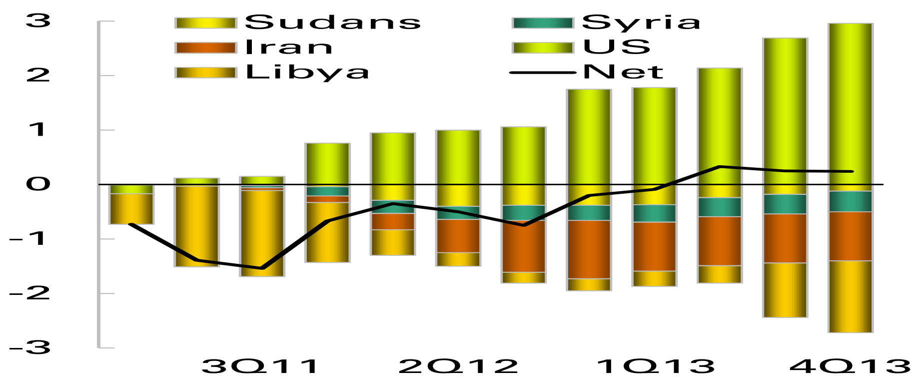
Between 2011 and 2013, US oil supply growth was almost completely offset by supply losses in other parts of the world and as a result, there has been no drastic shift in the global supply curve. The US shock and the 'counter shock' go a long way in explaining why oil prices continued to oscillate within a relatively narrow range for a prolonged period, despite wide macroeconomic uncertainty and a rapidly deteriorating geopolitical situation in many parts of the world. While the sharp increase in tight oil production has had a localized impact on US crude benchmarks over the last three years – as seen in the temporary dislocation of WTI and the large discounts of regional grades such as Bakken, the quarterly average Brent price has been above the $100 per barrel mark for the last 14 successive quarters.

Figure 12: Quarterly Brent prices ($/B)



The Middle East and North Africa (MENA) has been central to this outcome in two very different respects. First, the region has been the main source of the counter supply shock. Geopolitical outages in MENA – particularly from Iran, Libya, Iraq, Syria, and Yemen – have resulted in large losses from the market for a prolonged period of time. Between 2011 and 2013, it is estimated that more than 1,600 million barrels of oil were lost due to outages arising from countries affected by the Arab Spring and due sanctions linked to Iran's nuclear programme. These supply losses matched the supply gains from the USA.

Figure 13: Disruptions offset US supply gains (mb/d)



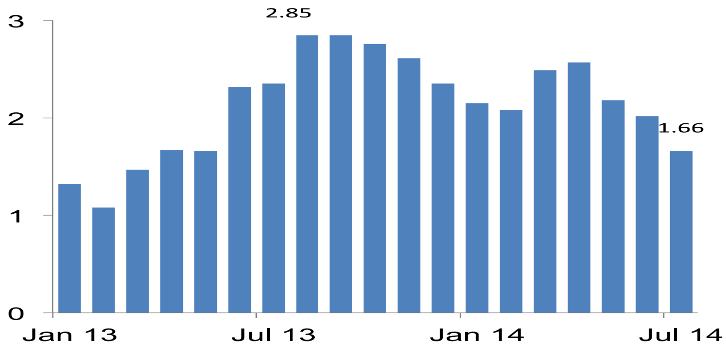
Source: BP.

Second, the extent of these losses has meant that the growth in US tight oil production has not itself been sufficient to balance the market; GCC producers have therefore had to ramp up production to fill the gap. The combined output of Saudi Arabia, Kuwait, Qatar, and the UAE has risen from around 14 mb/d prior at the start of the Arab Spring to above 16 mb/d for much of the last three years. This has not just been an increase in absolute terms. Problems affecting other OPEC members have led to the Gulf States' share of total OPEC production rising above 50 per cent since the beginning of the uprisings resulting from the Arab Spring – exceeding 55 per cent in September 2013. This highlights a dimension that is central to the analysis of oil markets: the world's spare oil production capacity is still concentrated in the GCC, mainly in the hands of Saudi Arabia and, to a lesser extent, in Kuwait and the UAE. If there are disruptions, spare capacity can be used to fill the supply gap, helping to stabilize oil prices and maintain global stocks at a healthy level.

Supply Disruptions Ease

While output disruption played a key role in balancing the market in the last few years, some of the supply disruptions started to ease. Despite the deterioration of the political situation in Libya, output in the country has increased recently although it is still well below its pre-disruption level of 1.6 million b/d. Similarly in Iraq, production from the south of the country has not been affected by the current infighting in the north. In fact, from a high level of disruption of over 2.85 million b/d in September 2013, the level of disruptions in OPEC almost declined to 1.66 million b/d in the second half of 2014.

Figure 14. OPEC Supply Disruptions, mb/d



The Key Uncertainties in the Short Term

The combination of a slower oil demand growth, the robust performance of US shale, and the easing of disruptions, all contributed to the recent sharp fall in the oil price. The final major negative factor has been investor sentiment, which has deteriorated sharply in the past few months. The bearish sentiment is predicated on the fear of a supply glut as a result of rapid growth in US oil output and the return of production from a plethora of supply outages. Indeed, we have entered 2014 with some big 'what ifs' which still have not gone away: What if Libyan barrels return to the market?; what if Iran secures a deal with the US allowing it to boost its exports?; what if Iraq ramps up its production?; and what if OPEC doesn't want or can't hold the line? Some market analysts are getting prepared for a perfect storm of sustained weak oil demand growth due to a fragile macroeconomic backdrop in emerging economies, a sustained increase in US production growth, a sharp improvement in non-OPEC supplies outside the US, a sharp increase in Iraqi production, the return of Iranian barrels and Iraqi barrels, and a breakdown in OPEC cohesion. In such a perfect storm scenario prices could fall to very low levels, with some analysts warning that 'the world might be drifting into an oil price shock', describing the current situation as 'very reminiscent of the period 1981–86 which culminated in the dramatic 1986 oil price collapse'.

Looking ahead for the next year, the following key fundamental factors will play an important role in influencing the oil price:

- The health of global economy and its impact on oil demand growth;
- The growth in US oil output;
- The return of Libyan barrels;
- The return of Iranian barrels;
- Oil output growth from Iraq;
- How fast would supply respond to a lower price environment?
- Will OPEC respond by cutting output, which remains the fastest way to balance the market?

It is important to note that each of these factors is associated with a wide range of uncertainty. For instance, it is very difficult to pin down exactly when Libyan production will come under renewed pressure from increasing levels of domestic violence and protests. While it is fair to say that the maximum output Libya is likely to be able to achieve is around 0.9 mb/d, given the loss of capacity due to natural declines and lack of investment and maintenance, the worst possible outcome entails just offshore fields operating for a period, i.e. production of just under 0.1 mb/d. This constitutes a wide range of uncertainty when estimating supply-demand balances.

Similarly, there is also wide uncertainty when it comes to measuring the potential impact of a low oil price environment on supply. Deepwater, ultra-deepwater and Canadian oil sands are the obvious costly supply areas that will see project approvals slow down. But this will not show up in the balances for a while. Rather, it will shrink the upcoming project pipeline for 2016 and 2017 start-ups, tightening up balances significantly. Tight oil, however, is far more responsive to both higher and lower oil prices. For instance, while US crude output growth has been a steady 1 mb/d for most of 2013 and 2014, there has been a step change since May, with output growth averaging close to 1.2 mb/d. While productivity gains have played their part, $100 WTI has been an equally important factor. With the investment already in the ground and producers well over 70% hedged for 2014, the current drop in prices will not dent 2014 growth profiles as such.

But it would be naïve to assume production will continue to grow at the current pace, whatever the price may be. Indeed, many observers draw parallels with the US natural gas market when production kept increasing even as Henry Hub prices fell below $2 per mmbtu. But with US independents' moving swiftly away to liquid-rich acreage, the impact of falling gas prices was masked somewhat. Moreover, associated gas added significant volumes to overall gas production, which cannot be replicated for oil. The consensus for US production growth next year is another 1 mb/d of production growth but the question about the downside risks to production surely need to be asked. What would happen if prices were to remain around current levels of $75 per barrel for a sustained period (more than six months) of time? It could be too early and difficult to pin-point the extent of the impact of an extended period of lower oil prices on tight oil production growth—though we see little impact in the near term. This is because there is a time lag between Capex cuts and a slowdown in activity. Hedging also plays a role here as the money for H1 15 work has already been lined up for the most part.

Also international companies have been facing some challenges even in a $100 plus environment. As oil prices decline and costs continue to rise, it will be difficult for the industry to sustain current level of capex and growth. A recent report analyses data from the 50 largest companies in non-OPEC and finds that revenue per barrel has only marginally risen while the unit cost of production has increased at a much faster rate. A Goldman Sachs report points to the fact that global oil & gas incumbents are seeing a dramatic deterioration of their asset base, leading to 50-year low returns and a required Brent oil price of US$120 per barrel to be free cash flow neutral after capex/dividends. The key drivers for this deterioration are higher decline rates, rising maintenance capex, increasing replacement costs, and poor exploration success.

In the last few years, Saudi Arabia has acted as a quantity adjuster, allowing its output to fluctuate widely, which helped stabilize the oil price. However, in recent months, there have been many indications that the Kingdom may not be willing to play this role unilaterally in a falling market. Given the importance of Saudi Arabia within OPEC, this has created a key uncertainty in the market: In the case of an oversupply, will OPEC be willing or able to cut production? OPEC's behavior will be a key driver of the oil price in the next couple of years.

II. Beyond the US Oil Supply Shock

From the perspective of Arab producers, the growth in US tight oil should not just be considered as a supply shock. The impact of the shale revolution goes beyond the direct effect of shifting the global supply curve; it has resulted in a shift in perception from a position of oil scarcity to one of oil abundance, affecting long-term prices and the shape of the forward curve. The shale revolution has also changed the dynamics of crude oil and petroleum product trade flows with implications on prices, differentials, marketing, and pricing strategies. It has also changed the perception of the geopolitical importance of the Middle East in the global energy system within some US policy circles; this has potential implications for US foreign policy and on the future relationship of the USA with key Middle East producers.

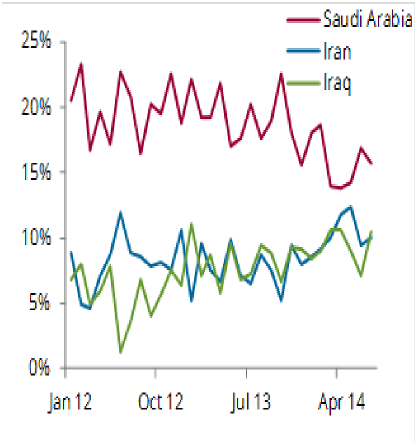
Changes in crude oil trade flows

The US tight oil revolution has resulted in a drastic shift of crude oil trade flows. Growing US domestic production has meant that refineries in the USA have made changes in order to accommodate the increase and this, together with a drop in domestic demand, has resulted in the pullback in US crude imports. Given that roughly 96 per cent of the 1.8 mb/d growth in production from 2011 to 2013 consisted of light sweet grades with API gravity of 40 or above and sulphur content of 0.3 per cent or less, light crudes have borne the brunt of that adjustment, with producers of light crude oil (such as Nigeria, Angola, and Algeria) being the worst affected. However, other GCC exporters such as Saudi Arabia have also been reducing their exports to the USA, especially at times when benchmark prices in the USA weaken. The inability of traditional suppliers to market their crude in the USA has forced them to look for alternative markets. For instance, West African barrels, helped by low freight rates, are proving to be attractive in Asia at a time when other crude exporters – such as Russia, Mexico, and Venezuela – are also trying to move away from Western markets and capture higher share in the main growth market of Asia. Once the Panama Canal is widened, the shift towards Asian markets will only intensify.

The diversion in trade flows is already having important implications for Middle Eastern producers, which have not yet been fully appreciated. The growing economies of Asia have been heavily reliant on Middle Eastern suppliers, particularly from the Gulf, through most of the last decade. This is now starting to change and Middle Eastern exporters face much tougher competition in a key market. In order to maintain their market share in the fastest-growing region, GCC countries will have to compete more aggressively in Asia. This will not be driven only by competition from outside the region, but also from within. The effects are already visible: Iraq has been offering competitive official selling prices (OSPs) for its main export in an attempt to capture market share. Iran has used its own vessels to sell crude on a delivered basis, offering discounted freight rates. The impact has been an erosion in Saudi Arabia's share in some key Asian markets. For instance, average import levels by non-OECD Asian economies have increased by over 1 mb/d (~10 per cent) between 2012 and mid-2014, of which Chinese imports have risen by 0.7 mb/d (~13 per cent) and Indian by 0.33 mb/d (9 per cent). In China, of that 0.7 mb/d increase, Iraq has seen its exports rise by 0.25 mb/d and Iran by 0.18 mb/d, while Saudi Arabia has seen its exports fall by 0.11 mb/d.

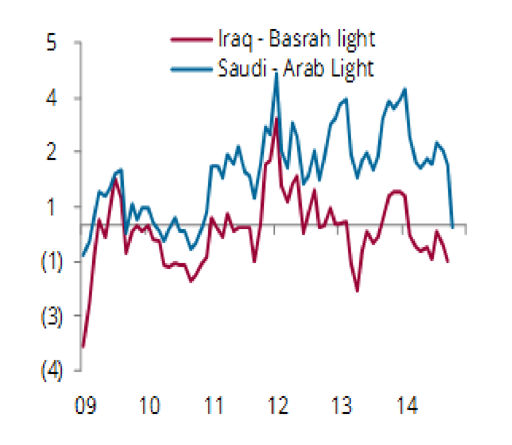
In response to this intensified competition, GCC exporters have been stepping up their efforts to maintain their share in Asia. Kuwait has started to offer its crude on a c.i.f basis, assuming the responsibility for the cost of the goods in transit, providing minimum insurance, and paying freight charges to move the goods to a destination chosen by the buyer. These services amount to an inherent discount embedded in the contracts. Kuwait Petroleum Corporation (KPC) has also been aiming to buy stakes in Asian refineries to secure a market for its supplies. The Indian government has been in talks with ADNOC and KPC to lease some of the space in their newly built Strategic Petroleum Reserves (SPR) caverns in order to reduce the cost burden of holding strategic stocks. Thus, the shift in trade flows is putting pressure on Middle East producers to revisit their crude oil marketing and pricing strategies and to offer Asian buyers more attractive terms. In weak market conditions, the impact is most likely to be felt in the adjustment of crude oil discounts, as has been seen in recent months. Saudi Arabia has had to cut its OSPs to Asia sharply, to compete with other suppliers. Competition through adjusting discounts may feed into benchmark prices, though the relationship between differentials and price levels is not straightforward. In the medium to the long term, the shift in trade flows could also affect the price formation process itself, with the possible emergence of new benchmarks and a greater role for Asian players in the price formation process.

Figure 15: China, imports by selected countries (%)



Source: Energy Aspects.

Figure 16: Saudi and Iraq OSP to Asia ($/barrel)

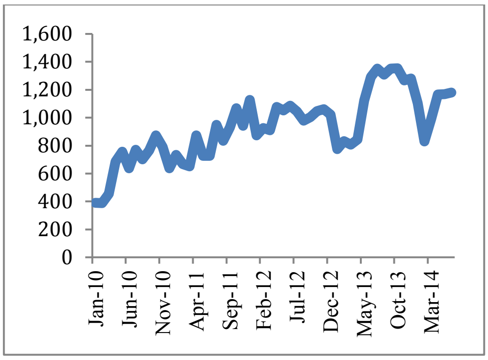


Source: Energy Aspects

Changes in petroleum products flows

In addition to changes in crude oil trade flows, the petroleum products markets (particularly gasoline and diesel) have also witnessed some major transformations. The growth in the export capacity of the US refining industry, fuelled by cheap domestic feedstock and access to discounted crudes, has seen net imports of gasoline fall to historically low levels while US diesel exports have surged to over 1.2 mb/d. The Asian refinery landscape is also undergoing some major transformations. Asian refining capacity has risen sharply in recent years and is mainly biased towards hydrocracking. This is most evident in China, where a massive increase in refining capacity has helped boost product exports – including diesel. Furthermore, as China rebalances its economy towards domestic consumption away from energy-intensive exports, domestic diesel demand growth has started to slow down; combining this with its rise in refining capacity, China became a net exporter of diesel in 2013. The net surplus of diesel in China is likely to continue to rise in the coming two to three years as the rebalancing continues, given that it takes a long time to build new refineries, or to change the configuration of existing ones. Meanwhile, the Russian government's firmly stated commitment to the regeneration of its refining industry indicates that Russian fuel oil output will decline, while that of diesel will increase, during this decade. Although the exact timing of the reduction in fuel oil production remains unclear, as it will depend on when Russian refinery projects are completed, Russia is firmly committed to raising diesel exports to Europe in the coming years.

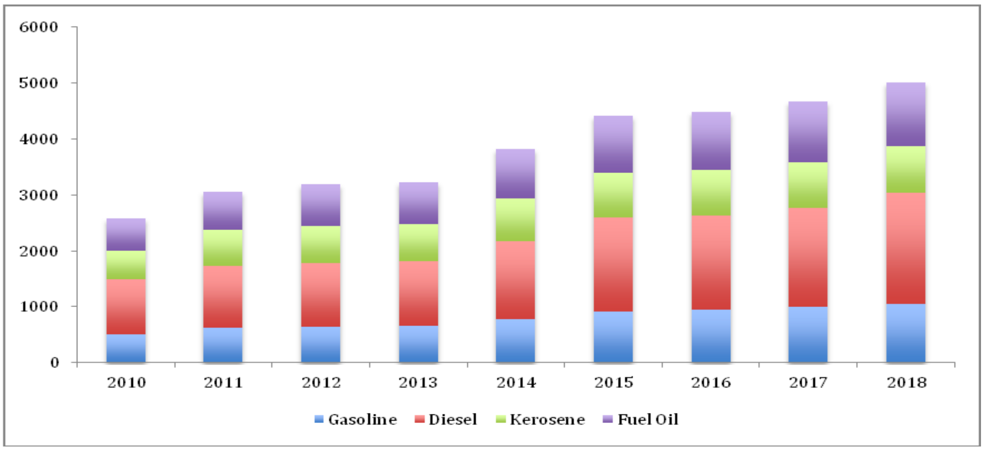
Figure 17: US exports of diesel (thousand b/d)



Source: EIA.

These changes in the global refining scene are happening at a time when refining capacity in the GCC, mainly in Saudi Arabia, has been expanding fast and is likely to expand further as soon as other GCC countries implement their investment plans. Many factors can account for this new drive towards the expansion of refining capacity; the most important motivation is that some of the largest GCC oil producers have been forced to import expensive petroleum products, as domestic demand has outstripped refining capacity for certain petroleum products such as gasoline and diesel. Another factor relates to the shift in strategy towards integrating refineries with petrochemical plants. Some of the other drivers are purely technical, being related to factors such as maximizing the yield of high-value products, producing cleaner fuels, meeting more stringent environmental regulations, and reconfiguring refineries to changing patterns in petroleum product demand. A further consideration is the limited availability of gas for use in the power sector, and in some cases the lack of gas infrastructure, meaning that some GCC countries (Saudi Arabia and Kuwait) have no choice but to continue to rely on liquid fuels for power generation, further increasing domestic demand for liquid products.

Figure 18: Evolution of GCC Refining Capacity by Product (2010–18), thousand b/d



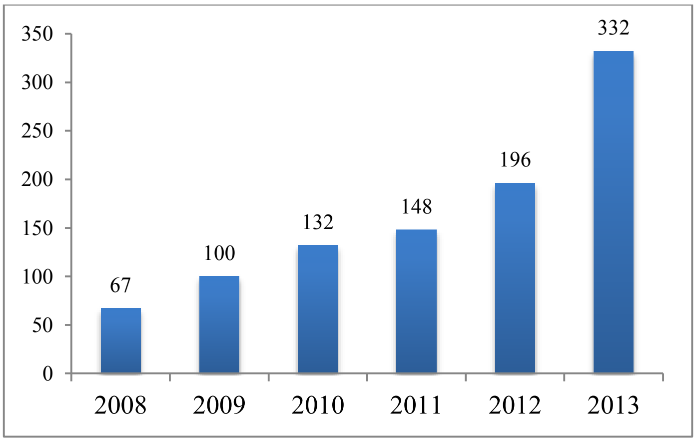
Source: Fattouh and Mallinson (2013).

While the region is expected to continue to be a net importer of gasoline well into the end of this decade, GCC exports of diesel could increase almost four fold. As demand growth for diesel falls and net exports from Asia increase, a significant portion of GCC diesel exports will have to head to Europe, a region where the deficit is still rising despite stagnant to falling demand, as refineries in Europe remain largely gasoline- and naphtha-biased. But all major export refining hubs with a diesel bias are earmarking Europe as their top destination, along with Latin America; parts of Africa are the only regions in the world that will be left with a growing appetite for diesel imports. Thus GCC refineries will face stiffer competition in marketing their diesel, putting pressure on global refining margins. While this represents a challenge, it is also an opportunity for GCC producers to establish and develop their trading arms and to play a bigger role in the global petroleum products markets by opening new markets, enhancing their expertise and skills in the trading of petroleum products, and creating trading hubs.

Changes in LPG trade flows

One of the major developments associated with the US shale revolution, and one that has attracted little attention from market analysts, is the sharp expansion in US liquefied petroleum gas (LPG) exports. The substantial increase in domestic supply has not only meant that US imports of LPG (which mainly come from Canada) have dwindled, but that the USA has now become one of the world's biggest exporters of LPG. From 67,000 b/d or 2.1 million tonnes per annum (mtpa) in 2008, LPG exports increased to more than 0.33 mb/d (10.4 mtpa) in 2013 and in the space of just one year alone, between 2012 and 2013, LPG exports actually rose by more than two thirds (from 0.20 to 0.33 mb/d, see Figure 16). According to the EIA, US LPG exports are expected to persist well into the next decade as NGL output in the USA continues on its upward trend.

Figure 19: US exports of LPG, thousand b/d



Source: EIA.

The sharp rise in US LPG exports is already having wide repercussions on global LPG market dynamics and trade flows. While the bulk of US exports are currently destined for Latin America, it is widely believed that the impact of higher US LPG exports will undermine the position of traditional exporters, mainly those in the GCC. First, as Asian consumers increase their purchase of US LPG in an attempt to diversify their sources of supply and gain access to cheaper LPG, the GCC's share of LPG exports to Asia is expected to fall. For a long time, Asia's petrochemicals market had little choice but to rely heavily on imports from the Middle East, but this is already changing. Many Asian players have already signed export agreements with US propane producers to secure long-term supplies. This trend will continue to accelerate, driven in large part by a desire to diversify sources of supply away from the Middle East, and also by a wish to take advantage of low-cost US propane and butane. Consequently, GCC producers will face more competition in a key market, reducing their share of LPG trade in Asia. Second, LPG prices, together with the existing pricing mechanism, may come under pressure as a result of intense competition from US supplies.

However, it is important to note that the overall impact on prices will depend in large part on the internal dynamics within key Middle East producers – particularly the rapid growth in domestic demand for LPG which is driven by the petrochemical sector – and the impact this may have on their LPG export volumes. While LPG output from the GCC is expected to rise in the next few years, there is large uncertainty regarding the volume available for exports. Internal demand dynamics, the scarcity of ethane in some countries such as Saudi Arabia, and the drive towards diversification imply that a large percentage of the increment in production from the GCC will be used domestically, and hence the potential global impact of increased US supplies on LPG prices will not be severe as some are predicting. Liquid cracking could also offer opportunities for GCC producers to capture a larger share of the higher-value petrochemical specialty products; this would fit within the priorities of GCC governments. Rather than competing for LPG exports, GCC producers may end up relying more on propylene exports. Shipping costs will also provide some support for LPG prices. Shipping and terminal costs alone would be in the range of $200 per tonne, which suggests that the spread between propane CFR Tokyo and spot US Gulf Coast (USGC) prices will have to remain wide in order for the arbitrage to work. The completion of the Panama Canal widening will reduce shipping costs substantially, but the effect of US LPG on prices will only be felt substantially after that.

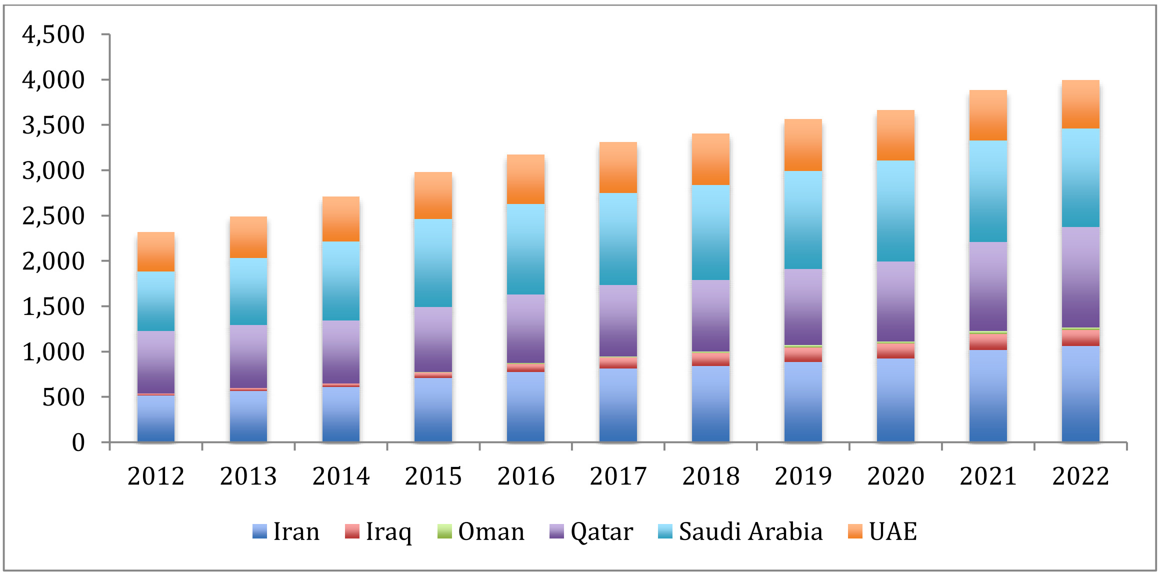
The biggest uncertainty, however, remains as to whether access to cheaper US LPG will induce Asian petrochemicals companies to start seeking alternatives to Middle East naphtha as feedstock; this would have a dramatic effect on LPG and naphtha markets, and consequently on petrochemicals trade. In other words, US LPG exports to Asia could prove to be not only a positive supply shock, but also a shock to the structure of the petrochemical industry and petrochemical trade flows.

Changes in condensate trade flows

An important aspect of the US shale revolution relates to the large increase in condensate output. US condensates from domestic production have traditionally been sold to and processed by refineries, where the naphtha- and gasoline-range compounds are subsequently split from the condensate stream and blended into gasoline pools as reformate to boost refinery gasoline octane levels. However, because US shale production has produced a growing surplus of tight crude oils that naturally contain a high proportion of condensates, and domestic gasoline demand is dwindling, domestic refiners are requiring substantially less plant condensate to meet gasoline-blending needs. As a result, refinery demand for condensates in the US is in long-term structural decline, and is unlikely to prove a ready home for incremental US condensate production in the years to come. In addition, under the existing legislation relating to crude export (put into effect following the oil embargo of 1973) unprocessed condensate streams are classified as a domestic crude oil and are therefore banned from export. In order to capitalize on condensates streams, a number of midstream operators have thus opted to ‘split’ condensate streams into processed oil products in order to circumvent the crude export ban. When ‘split’ into its commodity cuts via refining or processing, condensates will yield roughly 60 to 70 per cent naphtha-range materials, followed by LPGs. All of these are permissible for export as refined oil products. In total, some 0.37 mb/d of condensate splitting capacity in the USGC has been announced recently, by a number of US midstream players. Assuming that these USGC facilities will be primarily export-oriented, then these developments suggest that US naphtha exports are poised to expand rapidly from the figure of 63,000 b/d seen in 2013 – which itself was a 29 per cent year-on-year increase from 2012 naphtha export volumes.

US condensate/naphtha exports will be competing with the Middle East Gulf, which will continue to represent the primary source of incremental growth in condensates production globally for the foreseeable future. By some estimates, production of condensates from the Middle East Gulf will increase from some 2.3 mb/d in 2012 to close to 3 mb/d in 2015 and could surpass 4 mb/d by 2022. Although part of this increase in production will be absorbed domestically, condensates exports from the region to Asia are nevertheless expected to increase sharply, thus impacting global petrochemical feedstock markets.

Figure 20: Mid-East Gulf Segregated Condensate Supply Outlook-Base Case (thousand b/d)



Source: Al Troner (2013).

Some Asian (and European) petrochemicals producers will be keen to access discounted US condensate/naphtha as this can afford them the optionality to split cheap naphtha and, to a lesser extent, LPG for feedstock use. For Asian operators in particular, access to US condensates will also allow them to diversify their sources of supply. But with shipping costs from the Middle East to Asia being substantially lower, US suppliers will face tough competition. For instance, China has already locked in annual contracts with Iran and is not expected to take any US condensates in the short term. In contrast, Japan and South Korea have shown interest in receiving US condensates, but recent quality concerns over variations in condensate composition and a high level of impurities could pose a non-trivial threat to future cargo deliveries and even undermine long-term contracts. At any rate, Asian interest in new splitter projects has picked up in recent years, on the back of growing petrochemicals demand in the region. The prospect of weaker condensates prices from the USA and Middle East is also providing further incentive for new condensate splitters in the region. While a portion of the naphtha-range material is certain to be blended into gasoline (especially in the Middle East Gulf where demand for gasoline is still rising), more volumes of naphtha will inevitably become available as petrochemicals feedstock across the region.

In short, while the Middle East Gulf will remain the source of condensates and naphtha exports to Asia, the USA's entry (as well as that of other players such as Russia, Australia, and West Africa) into the Asian market and the proliferation of new grades of condensates and naphtha will become key factors affecting prices to the East of Suez; this could result in a highly competitive market. As this supply pressure mounts, substitution away from naphtha towards ethane in the USA and the increasing use of LPG by Asian and European crackers imply a more subdued global naphtha demand growth. These trends are poised to put downward pressure and keep a lid on global naphtha and condensates prices.

Shift in trade flows at times of vertical integration

The growth in US tight oil output has resulted in significant shifts in the trade flows of crude oil, petroleum products, LPG, and condensates. These shifts are resulting in greater competition, which would only intensify as US net imports continue to fall. While Middle East producers have to compete more aggressively to maintain market share in key markets such as Asia, this may not necessarily translate into a sharp fall in benchmark prices. In crude oil markets, the competition will be reflected mostly in more competitive discounts, while in LPG, naphtha, and condensates markets, shipping costs and rising domestic demand (which would limit export availability) can continue to provide support for prices of these products. It is important to stress that these more competitive pressures are taking place at a time when the GCC countries are continuing their efforts to capture more value added through vertical integration into refining and petrochemicals. Petroleum products and specialty product markets are intrinsically more competitive than crude oil markets; GCC producers going down the vertical integration path have yet to come to terms with the necessity of developing new marketing tactics and pricing strategies in this rapidly changing environment.

II. The Long Term Drivers of Oil Market Dynamics and the Outlook to 2035

The Demand Side

Global oil demand dynamics are influenced by a wide range of factors such as world economic activity and the structure and distribution of that activity, global demographical factors, demand-side technology, oil prices, the relative price of competing energies and taxation policies. Despite this wide range of factors, the literature has persistently found that one of the main determinants of oil demand is economic activity either measured in terms of GDP in macro studies or household income in household surveys. However, this relationship is not linear and differs considerably across countries depending on their level of economic development, degree of urbanisation and industrial structure.

Regarding the price determinants, there is more than one concept of price to consider. These include the price level; the relative price in the energy mix; price volatility; and price swings. These price determinants affect demand either directly through the usual price elasticity channel; through changing the importance of oil in the energy mix; and/or through their impact on economic growth and consumer behaviour. As in the case of income, the relationship between oil demand and prices is not linear and may be subject to threshold effects.

In addition, there are non-price determinants that could have a lasting impact on oil demand. These include policy measures driven by energy security and climate change concerns; and technological developments, especially in the transport sector. In recent years, there has been convergence between the energy security and the climate change agendas in most consuming countries, though in some instances the two objectives can diverge.

Income and Oil Demand

The relationship between oil demand and economic activity is usually examined within the context of the income elasticity of demand, which measures the relationship between the change in quantity of oil demanded and the change in income. The estimates vary widely according to the method used and the period under study. Despite the widely varying estimates, it is possible to draw the following general conclusions:

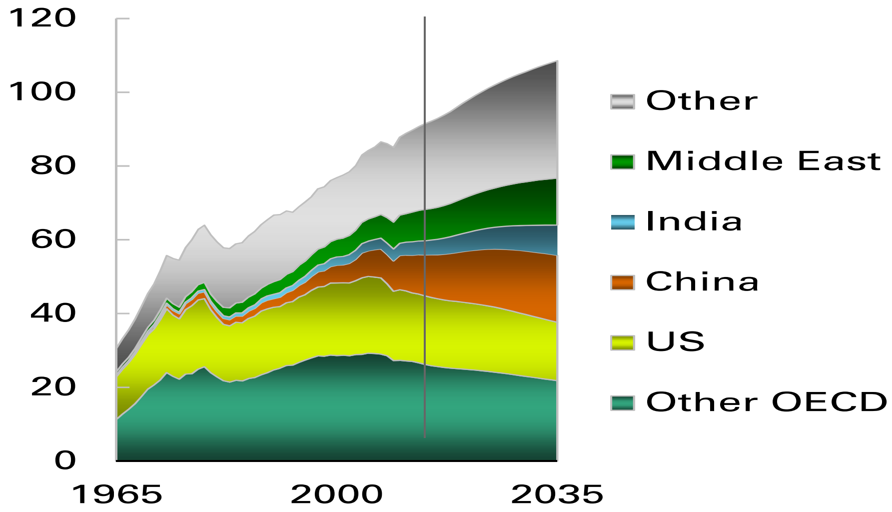
- Oil demand is more responsive to income growth than changes in oil prices;
- Income elasticity is not constant across countries and over time and tends to vary with the level of economic development or income;
- There is a large heterogeneity in estimated income elasticity across countries and/or regions with developing and emerging economies exhibiting higher income elasticity than OECD;
- Oil demand increases faster than GDP below some income threshold but slows down beyond this threshold.

Oil income elasticity in non-OECD is found to be higher than that in OECD. Based on the experience of developed economies, the income elasticity is bound to rise at early stages of development before it falls at high levels of income. This is due to variety of factors. One explanation focuses on the changing nature of economic structure along the process of economic development. As the economy develops, the share of manufacturing relative to non-manufacturing in GDP tends to rise. Given that the energy intensity of production of manufactured goods is higher than non-manufactured goods, the changing composition of GDP can change the overall elasticity of oil demand.

Various theoretical and empirical studies have also suggested the existence of a fuel continuum that varies with the level of income or economic development. As incomes rise, households tend not only to consume more of the same fuel but also move up the energy ladder towards higher quality fuels. For instance, some analysts suggest the existence of an energy ladder in cooking and lighting, which are the dominant energy-using activities for households in developing economies. The energy ladder ranges from traditional biomass or solid fuels (dung cake, crop waste, charcoal, coal) to liquid fuels (kerosene) to gaseous fuels (LPG, gas) to electricity. As we move up the energy ladder, the source of energy becomes more efficient, cleaner and more convenient – but it also becomes more costly. The determinants of switching from traditional fuels to modern fuels have been widely analysed in the literature. Existing studies suggest that fuel choices depend on a complex set of factors, such as the level of income, fuel availability, capital costs, fuel prices, household size, gender roles, wage rates and cultural preferences. There is some evidence that a similar ladder exists for the choice of mode of transport. The ladder ranges from walking to bicycles to public transport to small and then to large vehicles. One of the key factors determining the transition is the level of income per capita though the relationship is not linear.

Due to these effects, demand growth is expected to come exclusively from rapidly growing non-OECD economies. According to the BP Energy Outlook, China, India and the Middle East account for nearly all of the net global increase in oil demand, while OECD demand has peaked, and consumption is expected to decline by 8 million b/d over the period 2012-2035. While China provides the largest increment to liquids demand over the outlook period, in line with the above analysis, its growth volumes are expected to slow relative to those observed over the last 10 years. During 2030-35 Chinese demand rises by only 900,000 b/d (versus 2.3 million b/d for 2005-10). During this period, India will be the largest contributor to oil demand growth.

Figure 21: Oil Demand Outlook to 2035

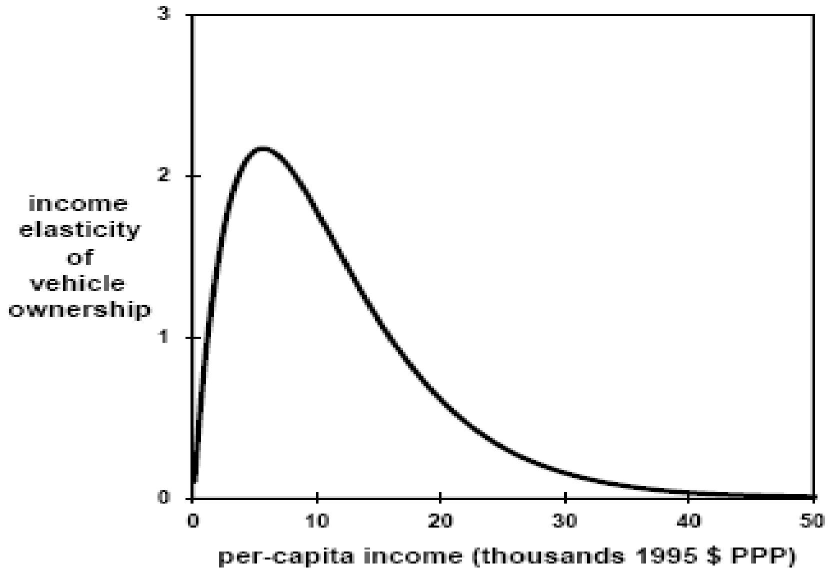


Source: BP Energy Outlook 2035

Oil Demand and the Transport Sector

Oil demand is strongly interlinked with the growth in the transport sector. Evidence from countries with long time-series data such as the US, Japan and European countries shows a slow growth of car ownership at early stages of economic development. As income per capita reaches a certain threshold ownership rates increase very rapidly. This threshold effect is expected given that owning a car is costly and constitutes a lumpy investment which households can only afford after their income has reached a certain threshold. As income per capita crosses that threshold, the growth in car ownership is twice as much as the growth in income. At high income levels, growth in car ownership tends to slow down but will continue to grow as fast as income. The relationship between income per capita and the income elasticity of vehicle ownership is depicted in the figure below. This stylised fact also applies across countries. Countries with relatively lower income per capita tend have lower car ownership rates. However, once countries have crossed a certain income threshold, ownership rates tend to increase faster than income.

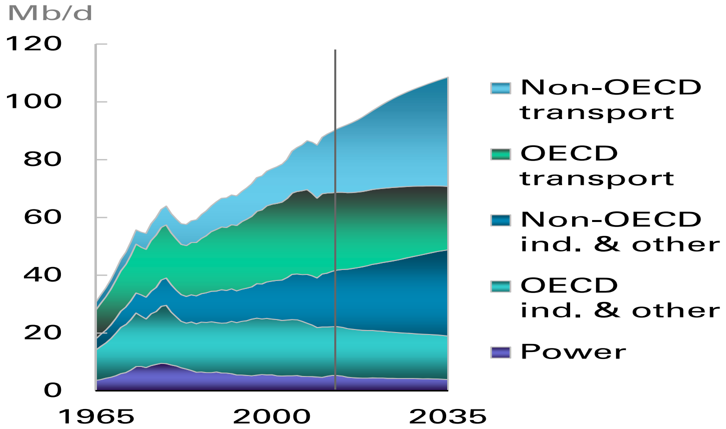
Figure 22: Income Elasticity of Vehicle Ownership and Per Capita Income



Source: Dargay, Gately and Sommer (2007)

In fact, in its projection, BP predicts liquids demand growth to 2035 to come primarily from non- OECD transport (16.6 million b/d) – due to a rapid increase in vehicle ownership – and from non-OECD industry (8.7 million b/d, largely for petrochemicals). In OECD, demand declines across all sectors. Outside of transport there are two main drivers: the continued displacement of oil by cheaper alternative fuels, and the closure of uneconomic industrial plants (in refining and petrochemicals) in favour of newer plants in the non-OECD. In transport, declines are first driven by vehicle efficiency improvements (despite slow growth in the OECD vehicle fleet) and then by increasing penetration of non-liquid alternative fuels, such as natural gas.

Figure 23: Source of Oil Demand Growth to 2035



Source: BP Energy Outlook 2035

Impact of Technology and Efficiency Measures

Therefore, key for assessing the prospects for long-term demand is technology in the transport sector. Assessing the impact of technological advances and policies on oil demand is not straightforward. The rate at which technological innovations occurs is affected by a wide range of factors including developments in the oil market and government policy. Furthermore, the effect of technological innovations on oil demand is difficult to measure and/or predict. For the foreseeable future, however, it is almost certain that the internal combustion engine will remain the dominant technology in the transport sector. Thus, rather than thinking of a disruptive technology that would transform the transport sector and cause a sudden change or collapse in oil demand over a short period of time, one should think of a series of small innovations originating from variety of sources. The impacts of technological innovations and government policies are likely to be manifested in a number of ways, the most important of which are:

- Encouraging technology advances in the transport sector through research subsidies and other unilateral or multilateral initiatives aimed to promote the efficiency of the transport sector.

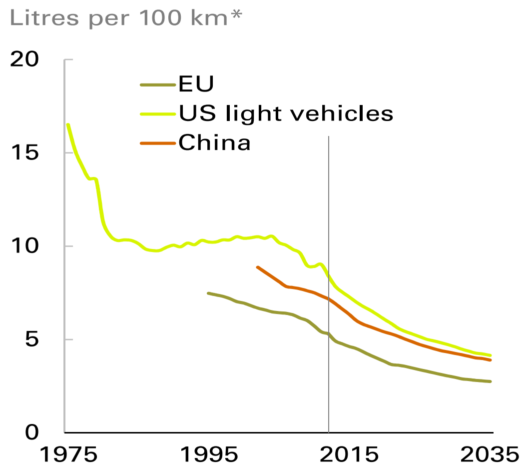
- The increasing penetration of hybrids, flex-fuels, plug-in-hybrids, electric vehicles, and CNG cars into the transport sector. Most of these types of vehicles are currently relatively uncompetitive without financial support, but technological advances, economies of scale, government support, and relatively high oil prices have the potential to change the picture in the long run.
- Technological advances will not originate in the developed world alone. While China has fallen behind in combustion engine technology, it is determined to become a leader in electric vehicle technology, with the objective of creating a world-leading industry. China is pursuing a set of policies to promote the electric vehicle through introducing plans to grant consumers tax credits on their purchase of electric vehicles, offering subsidies to taxi fleets, and encouraging cities to set up electric car charging stations. The Chinese government has also dispersed research subsidies for electric car designs.

Many observers strongly believe that hybrid cars and electric cars are destined to play a key role in the future. Deutsche Bank for instance predicts that in the US, hybrid and electric cars will account for around 25% of new vehicles by 2020 and 8-9% of the vehicles on the road. For China, it predicts that about two thirds of new light vehicle sales will be highly efficient and half of all light vehicles will be electric or hybrid by 2030. Such predictions are subject to wide degree of uncertainty as many variables determine the composition of the vehicle fleet. Government policies and technology are only part of a wider set of factors that determine the decision to purchase a certain type of vehicle. Hence, the penetration of these types of vehicles into the transport sector at a large scale is not a foregone conclusion. That being said, it is important to make the following observations:

- The drive for improved fuel efficiency is already set in motion and is likely to continue unabated driven by technological innovations which would improve the vehicle characteristics and by government policy which favour more efficient and smaller cars;

- The trend for improved efficiency is unlikely to be reversed by oil price declines. On the other hand, an increase in oil price or its volatility and concerns about the future availability of oil supplies can accelerate the growth in efficiency. In other words, the pace in efficiency growth is asymmetric to price changes;
- The pursuit for improved efficiency will occur both in developed and developing economies perhaps with greater vigour in the latter and potential cooperation at the international level on key areas such as advancement of electric car technology will consolidate over time;
- Since most of these electric vehicles will be powered by coal-fired power plants, the entry of electric vehicles at a large scale means an indirect penetration of coal into the transport sector. Similarly, the wide adoption of CNG cars also means an indirect penetration of natural gas into the transport sector. Currently, electric vehicles and CNG vehicles constitute a small share of the electric vehicle fleet. But these are growing very fast encouraged by government policy and an increase in the relative price of oil in the energy mix;
- Despite the fact that these technological innovations will only impact oil demand at the margin, these effects are both cumulative and irreversible and hence cannot be ignored in the long term.

Figure 24: Fuel Economy of New Cars



Source: BP Energy Outlook 2035

Natural Gas and the Transport Sector

The shale gas revolution has offered real opportunities for substitution of gas in the transport sector. However, up until now, and despite nearly five years of very low US natural gas prices, there have been very few signs of widespread substitution from oil to natural gas in the transportation sector. No doubt companies are spending billions in R&D in attempts take advantage of the wide price differential between the two fuels and some companies have been switching to natural gas-fired trucks. But numbers remain extremely small. Equally, it is worth noting that in non-OECD countries like India and China, natural gas prices remain oil-linked and thus offer little price advantage. For these countries, environmental reasons have been an important driver for the switch into gas-fired vehicles, but despite significant volumes of public transport switching to CNG, there has been little dent in oil demand growth. In other words, large-scale substitution to gas remains unlikely till 2020.

A recent report[2] on the prospects of natural gas use in the transport

[2] This section is based on Le Fevre, C.N (2014), 'The Prospects for Natural Gas as a Transportation Fuel in Europe' NG 84, Oxford: OIES.

sector in Europe identifies four key first order factors. The **financial case** primarily hinges on the extent to which the price discount of natural gas to gasoil or diesel outweighs the costs of a natural gas-powered vehicle or vessel. For marine applications this is a simple matter of commodity prices and the present relativities suggest a positive case for natural gas. However, for road transport the differential taxation levels (which typically account for two thirds of the difference) play a crucial role. Whilst the payback time on NGV investments is in general such that for most truck applications there is a positive incentive to switch, the reliance on fiscal terms to make the business case is a real concern amongst operators. The main worry is that given the importance that fuel taxes play in raising revenue it is unrealistic to expect the present favourable discount to be maintained if there is large scale switching. This is clearly less of an issue in marine as fuel prices are generally not subject to tax.

There are clear **environmental benefits** from adopting natural gas in terms of reduced GHGs and zero particulate emissions – this latter point is particularly important in urban areas for large trucks and buses. The lack of sulphur emissions is an additional strong benefit in the marine and IWT sector. The benefits in the car sector are less marked in part due to the rapidly improving performance of conventional and hybrid vehicles and the commitment of some governments to electric cars - which are seen as ultimately providing a route for decarbonising this sector of transportation. Overall the environmental dilemma facing natural gas in the transport sector is not dissimilar to the one it faces in power generation. It is a lower carbon alternative to other fossil fuels but not completely carbon free – this means policy makers seem unwilling to commit to a natural gas route in the expectation (hope?) that zero carbon renewables will eventually become economic. However this creates an inertia that results in options such as coal-fired generation remaining in play and so emissions are higher than they could otherwise be.

In terms of **practicality** the key issue is one often referred to as the chicken and egg problem. Insufficient refuelling infrastructure inhibits growth in new vehicle purchase, which in turn inhibits investment in infrastructure. This circularity applies equally to new vehicles, with manufacturers showing reluctance to develop a comprehensive range of offerings in the absence of clear interest from the market. A combination of economic, reputational and regulatory signals is pushing natural gas (and LNG in particular) as a promising option for larger trucks and marine vessels and this is stimulating some risk based investment in infrastructure and greater interest from manufacturers. This impetus is less obvious in the car sector – particularly in those countries such as the UK that have expressed a preference for electric vehicles as a way of "greening" personal transport – though as we have seen this objective may take many years to achieve. The inherent flexibility of the existing fuel supply and vehicle network can act as a strong disincentive to switch to new, largely untried, alternatives

The final first order issue is the question of how natural gas stands vis a vis **the status quo and other alternatives**. The status quo liquid fuels deliver a high energy content in a small volume. They are also easy to store and to handle, global standards and regulations are well developed, the cost of existing fuelling infrastructure is fully amortised and the vehicle production supply chain is optimised. Furthermore conventional fuel efficiency continues to improve. The IEA estimates that globally fuel consumption for heavy (>16 tonnes) trucks will move from 35 litres/100 km in 2011 to 28 litres/100 km by 2035. Comparable numbers for Europe are 31 litres/100 km and 26 litres/100 km. Furthermore relatively minor investments in vehicle efficiency can generate significant benefits. For example a study by Ricardo-AEA (2012) suggests that improving aerodynamic efficiency and reducing rolling resistance in HDVs can generate up to 10% WTW savings in emissions – this is clearly less than the 65% (biomethane) or 16% (methane) WTW savings from switching to gas but arguably quicker and less risky to achieve.

Natural gas has to demonstrate it can match all of these attributes and deliver significant benefits. Even if a move away from the status quo fuels is seen as desirable is natural gas the best option? Again the picture is mixed across the sectors, with the heavy truck and marine modes presenting the best opportunity at present. In passenger cars and (to a lesser extent) buses, electricity, or even hydrogen, are also being promoted as the best option though the evidence on WTW emissions suggests that at present electricity is only marginally preferable – particularly when compared to a biomethane/natural gas mix. In these sectors NGVs may be **an** answer but not necessarily **the** answer.

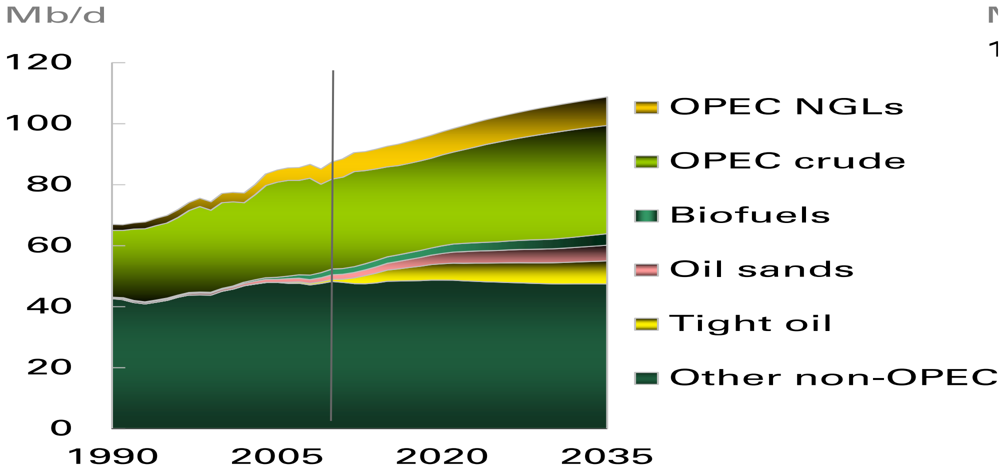
The Long Term Drivers of Oil Supply

Modelling long-term oil supply is complex and projections depend on large number of assumptions such as the level of reserves, technology innovation, prices, and the behaviour of various oil suppliers. Regarding the latter, it is useful to distinguish between OPEC and non-OPEC suppliers. While it is usually assumed that non-OPEC suppliers behave competitively, OPEC behaviour is much more multifaceted, and there are diverse and competing theories describing its behaviour. Although non-OPEC suppliers are fairly diverse – comprising national oil companies, large international oil companies, and smaller, independent firms – empirical studies typically do not distinguish between them, but normally aggregate oil production outside OPEC.

Non-OPEC Supply

BP projects liquids supply to expand by over 18 million b/d between 2012 and 2035 with non-OPEC production contributing nearly 11 million b/d of growth and OPEC crude and NGLs accounting for the rest. The strong growth in non-OPEC supply is attributable to unconventional oil. By 2035, BP projects that the growth of tight oil (5.7 million b/d), biofuels (1.9 million b/d), and oil sands (3.3 million b/d) alone will have accounted for 60% of global growth and all of the net increase in non-OPEC production. Tight oil will account for 7% of global supplies in 2035 while biofuels and oil sands obtain market shares of 3% and 5%, respectively. It is important to note that North America will dominate the expansion in unconventionals with 65% of global tight oil and with Canada responsible for all the world's oil sands production.

Figure 25: Liquids Supply by Type



Source: BP Energy Outlook 2035

The US tight oil revolution

There are wide uncertainties relating to the full potential of US tight oil growth. In its 2014 Annual Energy Outlook, the EIA emphasizes that the:

> ... growth potential and sustainability of domestic crude oil production hinge around uncertainties in key assumptions, such as well production decline, lifespan, drainage areas, geologic extent, and technological improvement – both in areas currently being drilled and in those yet to be drilled.

Therefore, it should come as no surprise that projections of future tight oil supply growth differ widely, according to the underlying assumptions. For instance, in the High Oil and Gas Resource case, the EIA projects that domestic crude oil production will increase to nearly 13 mb/d before 2035, whereas in the Low Oil and Gas Resource case, US oil production is expected to reach 9.1 mb/d in 2017 before falling to 6.6 mb/d in 2040. The large difference in these two scenarios reflects uncertainty about the potential of tight oil production. In the High Oil and Gas Resource case, tight oil production would peak at 8.5 mb/d in 2035 – in comparison with the Reference case peak production rate of 4.8 mb/d in 2021. In contrast, in the Low Oil and Gas Resource case, tight oil production peaks at 4.3 mb/d in 2016 and then declines through 2040.

Given the wide spread of these projections, it is only possible to make some general observations regarding the potential of US tight oil growth. First, some analysts have been sceptical about the ‘financial’ sustainability of shale producers in the USA. For instance, some compare the investment in shale plays to a ‘Ponzi’ scheme, warning that the bubble would collapse when companies ran out of financing to drill more wells. These analysts point out that companies operating in shale plays have not yet succeeded in achieving a positive cash flow and they have thus had to accumulate large amounts of debt to finance drilling new wells. However, while it is true that operating cash flows have fallen short of capital spending in the first years of shale development, this factor will not determine the future sustainability of US tight oil production. The EIA, in its Annual Energy Outlook (2014), argues that future production will depend ultimately on ‘the resource base and the rate of technology advances that lower drilling cost or raise its productivity’. In any case, the finances of shale companies have continued to improve, as they have accelerated the shift away from natural gas towards oil production. Analysts’ consensus forecasts indicate that the operating cash flows of leading shale companies will show an excess of about $2.4 bn over their capital spending in 2015.

Second, most evidence indicates that companies operating in shale plays continue to improve their productivity and recovery rates, although there remains a huge variability across and within shale plays. Such productivity improvements are reflected in a number of areas. Recent evidence shows that in five of the six US shale plays, there have been increases in oil and natural gas production per rig over the past few years, with the Eagle Ford Shale leading the increased production of oil per rig, while the Marcellus Shale has led the increased production of natural gas per rig. Shale producers are drilling and fracking longer laterals, while their ability to target the highest-yielding parts of shale plays is also increasing. Technological innovations are likely to consolidate and enhance these productivity gains (examples include: drilling in multiple oil and gas bearing formations and improvements in well spacing).

Therefore, from the perspective of a GCC producer, it is important for policy makers not to bet on the bust of the shale boom anytime soon. In the current environment of relatively high oil prices, tight oil production will continue to grow. There is, however, wide uncertainty on the growth potential of US tight oil and on how long before the growth in output starts tapering off.

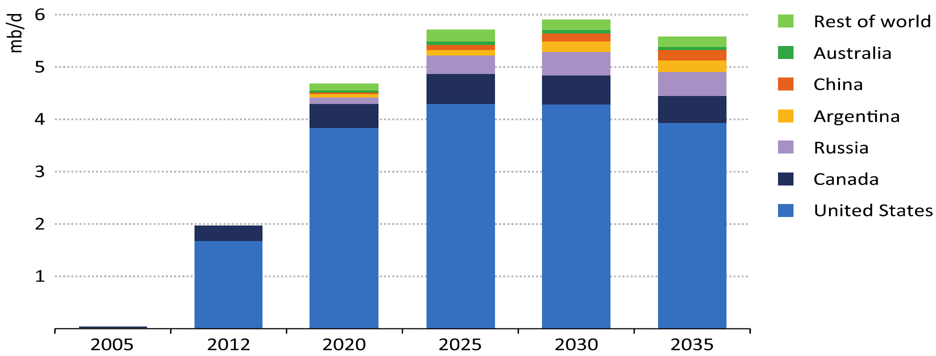
The global diffusion of Shale Technology

A key uncertainty regarding non-OPEC supply is the potential diffusion of shale technology outside the US. The IHS identifies 23 play areas that can be considered as high-ranking and to be of similar quality compared to North America. One of these shale plays is in Russia. A number of recent estimates suggest that the resource base to be exploited across Russia is enormous, although uncertain. The level of this uncertainty is captured in the wide spread of high and low estimates: total tight oil reserves in Russia have been put in the range of 15 billion to 1.05 trillion barrels. Even individual companies have very broad assessments of their own resources, with Rosneft quoting numbers in the range 6–18 billion barrels and TNK-BP offering forecasts of between 4 and 19 billion barrels. Given that Russia's total proved reserves are estimated at 87 billion barrels it is clear that even numbers at the lower end of the range would be significant additions to the country's oil reserve base. This potential was further confirmed by a recent assessment of global shale resources by the US Energy Information Administration, which calculated that Russia has the world's largest shale oil resources with a total of 75 billion technically recoverable barrels.

Despite these massive reserves, there is a big question mark on whether the US tight oil revolution could be replicated in other parts of the world. Shale Development strategies in the US have come at a great cost by drilling hundreds of expensive experimental wells and accumulating large amounts of debt. The existing US 'expensive' model can't be simply replicated in other parts of the world.

There are also doubts on whether the conditions present in the US are present somewhere else. Of course, there would not have been a shale revolution without high oil price and without innovation in Hydraulic fracturing, which was a key enabling technology. But other US specific factors were also important. These include: Favorable mineral rights with landownership; dynamic exploration and production industry (85+ independents); strong logistics and service providers; huge rig availability; deep financial markets and cheap credit; and liquid futures markets allowing producers to hedge production forward and extensive network of pipelines. Compare for instance with Russia where government owns underground reserves; corporate landscape is different and dominated by large vertically integrated companies; the service sector weak; low availability of rigs; the tax system in need of reform; and capital markets are thin. That's why for the next few years, the tight oil revolution is likely to remain mainly a US phenomenon. Elsewhere, most countries will struggle to replicate the North American experience at scale. According to IEA, Light Tight Oil (LTO) production in 2035 reaches 450,000 b/d in Russia, 220,000 b/d in Argentina and 210,000 b/d in China, but elsewhere stays in the tens of thousands of barrels per day.

Figure 26: LTO Production in Selected Countries in New Policies Scenario



Source: IEA

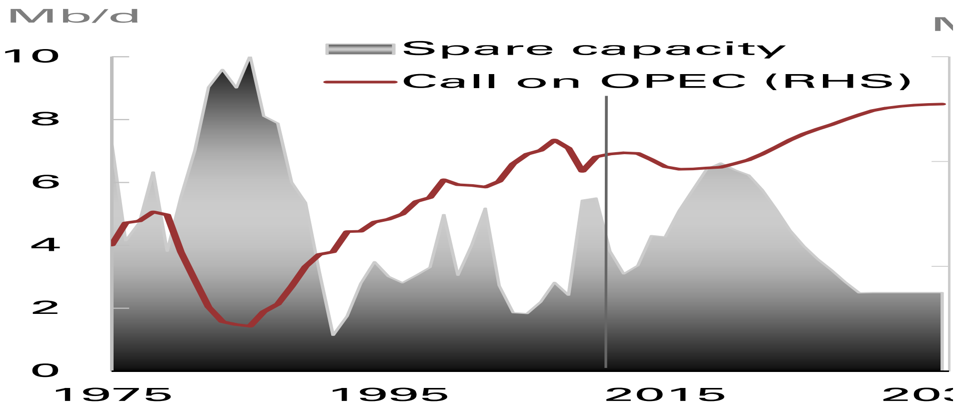
Iraq: The Elephant in the Room

A key factor in the oil market that underpins bearish sentiment is the potential for Iraq to deliver large increase in output. The Iraqi government has plans to keep adding 500,000 b/d each year over the coming years. However, these plans remain constrained by infrastructure limitations in the south. In the longer term, some key projects such as the Common Sea Water Project to produce 10.5 million b/d of water to serve the five major producing fields in the south is more than one year behind an already revised schedule. Even within government circles, the optimism of Iraq reaching its original target has faded. The oil ministry had originally targeted an increase in capacity from fields awarded to foreign oil consortia to 12 million b/d, excluding fields operated solely by the state-owned South Oil Company. It has since revised down its target and Iraq has now settled on a target of 9 million b/d of production capacity by 2020 to be maintained for 20 years.

The Squeeze on OPEC and the Bearish Scenario

According to most projections, the slowdown in demand growth and the expected increase in non-OPEC supplies imply that OPEC members cut production over the current decade to balance the market. According to BP Annual Energy Outlook, spare capacity will exceed 6 million b/d by 2018, the highest since the late 1980s. The market requirement for OPEC crude is not expected to reach today’s levels for another decade before rebounding. Thus the ability of OPEC members to maintain discipline despite high levels of spare capacity is key to oil price outcomes.

Figure 27: OPEC Spare Capacity in Bearish Scenario, mb/d



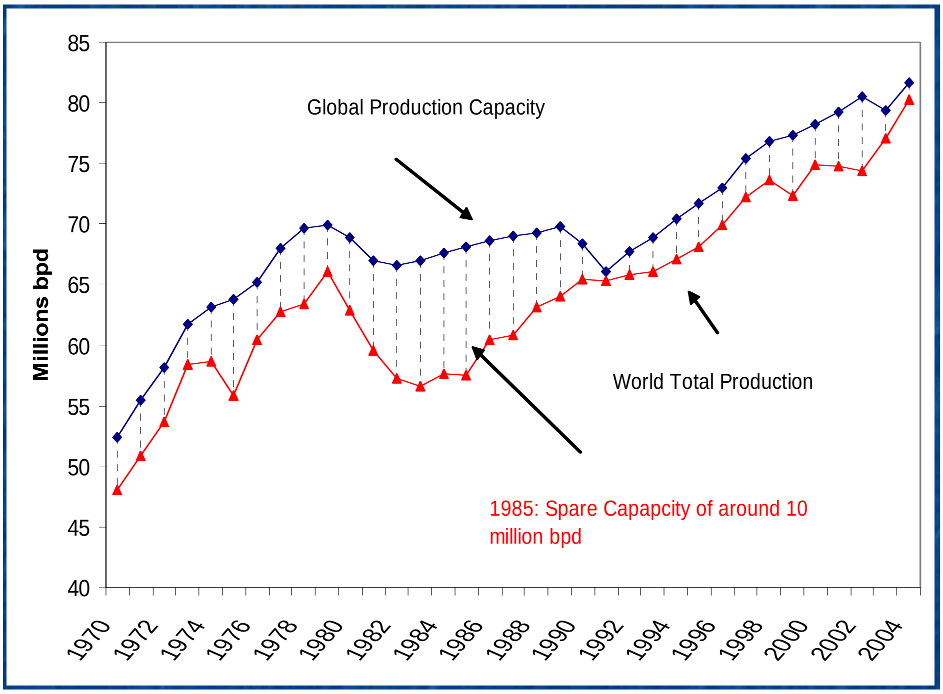
Source: BP Energy Outlook 2035

This is why Iraq is key to any future price scenario, not only because the expected rapid increase in production from Iraq, but also because Iraq is a low-cost producer with massive underground reserves, which could therefore affect cohesion within OPEC. The squeeze from a low-cost producer should be treated differently from a high-cost one, as the production of a low-cost producer is likely to be less responsive to price movements and could generate huge rents even in a relatively low-price environment. This is in contrast to a high-cost producer such as the USA, which has a highly elastic supply curve with supply being more responsive both to upward or downward price movements. One of the key features of the 1986 oil price crisis, which contributed to the collapse of the oil price as well as the OPEC administered pricing system, was the sharp increase in non-OPEC supply from multiple sources such as the FSU, Mexico, and the North Sea, together with the break-up of OPEC cohesion. It is in this context that Iraq is important. Currently, there is a widespread belief that a large-scale entry by Iraq would affect cohesion within OPEC, undermining the ability of the organization to defend prices when market fundamentals are weak.

It is important to stress that the challenge for OPEC is unlikely to be a repeat of the 1980s. In 1980s, spare capacity peaked at over

10 million b/d and group's share of global supply dropped well below 30%. The oil system is much bigger now: Spare capacity as a share of crude production, even in the most bearish scenario will peak at 7% compared to 17% in 1985. Another key difference is that oil demand collapsed after price shock of the 1970s. In the current context, global oil demand is still rising with expectations that demand will continue to grow up to 2035.

Figure 28: Evolution of Spare Capacity in 1980s



Source: Authors' estimation.

While many projections have converged to the view that spare capacity within OPEC will rise within the next decade, which will be bearish for prices, there are many uncertainties surrounding this scenario. These uncertainties can be grouped into four factors:

- The wide uncertainty in the range of tight oil forecasts both in the US and the rest of the world and the extent of diffusion of hydraulic fracturing globally;
- The extent of the increase in production capacity in key OPEC members amidst expectations of a fall on demand for their crude;

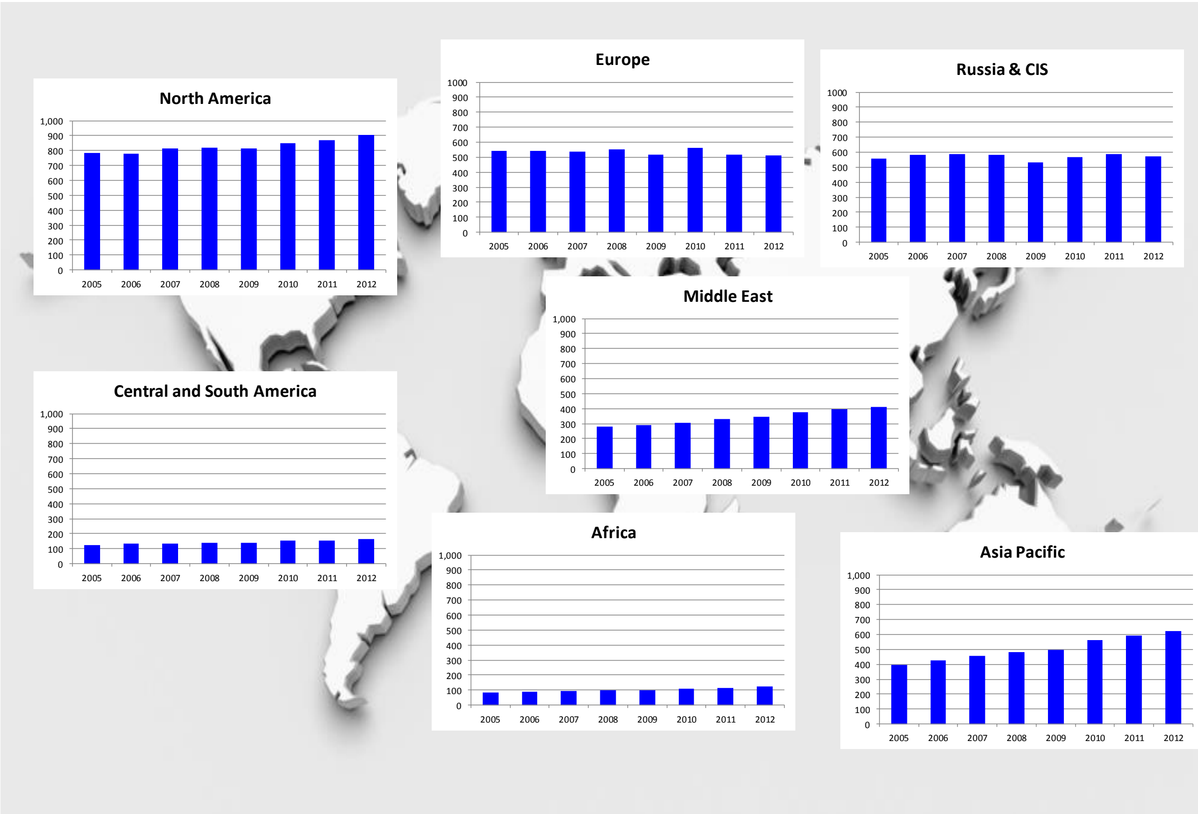
- Geopolitical issues that could constrain investment and the potential to increase future supply in some countries (discussed in details in another part V of the report);
- The decline rates and their evolution over time especially in some of the mature oilfields.

III. Recent Developments in the Natural Gas Market

Regional Demand 2005 – 2012

In the period 2005 to 2012 world gas consumption rose from 2,769 to 3,315 bcma; an annual average growth rate of 2.6%. In the immediate aftermath of the financial crisis, 2009 saw a drop in world gas consumption of 2.2% compared with 2008. This, as well as trend growth rates for the period, varied significantly by region. Figure 30 compares annual gas consumption for the 7 geographically regional gas markets.

Figure 29: Regional Natural Gas Demand 2005 – 2012, bcma

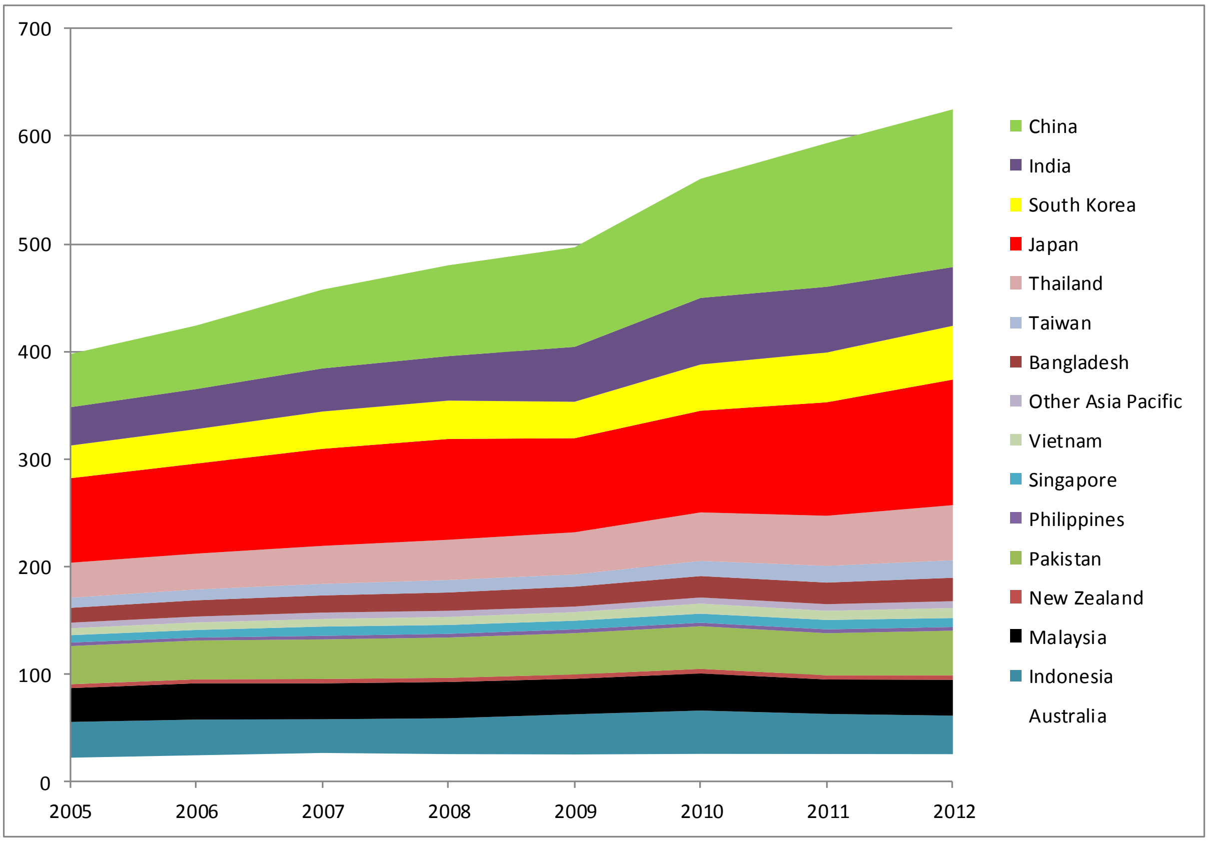


Source: BP Statistical Review of World Energy

In North America (US, Canada and Mexico), the financial crisis had a minimal impact of demand trends as a reduction in industrial sector demand was offset by gains in power generation. Low US gas prices, a consequence of surging shale gas production outstripping demand, resulted in gas displacing coal in the power sector. For the 2005 – 2012 period annual average demand growth in North America was 2.1%. In the same period Europe's gas demand stagnated – falling at an annual average rate of 0.9%, with a drop of 6.7% between 2008 and 2009. The combined effects of market maturity, relatively high gas prices, the growth of renewables and the displacement of gas by cheaper coal in the power sector (with the European Emissions Trading System for CO2 failing lamentably) explains this trend. Over the same period Russia & the CIS saw only a 0.4% annual average demand growth rate. Industrial demand was hit by a combination of recession and higher prices – in the Russian domestic market (due to an increase in the regulated price) and significantly in Ukraine. The Middle East region is discussed elsewhere in this paper, but the bottom line is a 5.7% annual average consumption growth – outstripping domestic supply developments at generally low prevailing domestic prices and requiring supplementary imports of LNG at near oil-parity prices.

Africa and South & Central America have annual average demand growth rates of 5.3% and 4.2% respectively, though these are still small regional markets in absolute terms. South America, although likely self-sufficient as a region seems unable to establish internal gas trade-flows to this effect and instead Brazil, Argentina and Chile import spot LNG cargoes at prices close to oil price parity. Asia Pacific was the fastest growing market over this period with an annual average demand growth of 6.7%.

Figure 30: Asia Pacific Gas Demand 2005 – 2012, bcma



Source: BP Statistical Review of World Energy

Figure 31 shows the significant range in market sizes in this region. The largest markets are China, Japan, India, South Korea, Thailand and Pakistan. In terms of absolute volume growth since 2005, China accounts for 97 bcma with a 16.8% annual average growth rate. Japan's gas demand increased in 2012 as a consequence of the Fukushima disaster in March 2011, increasing the import requirements for LNG.

Supply-Side Developments 2005 - 2012

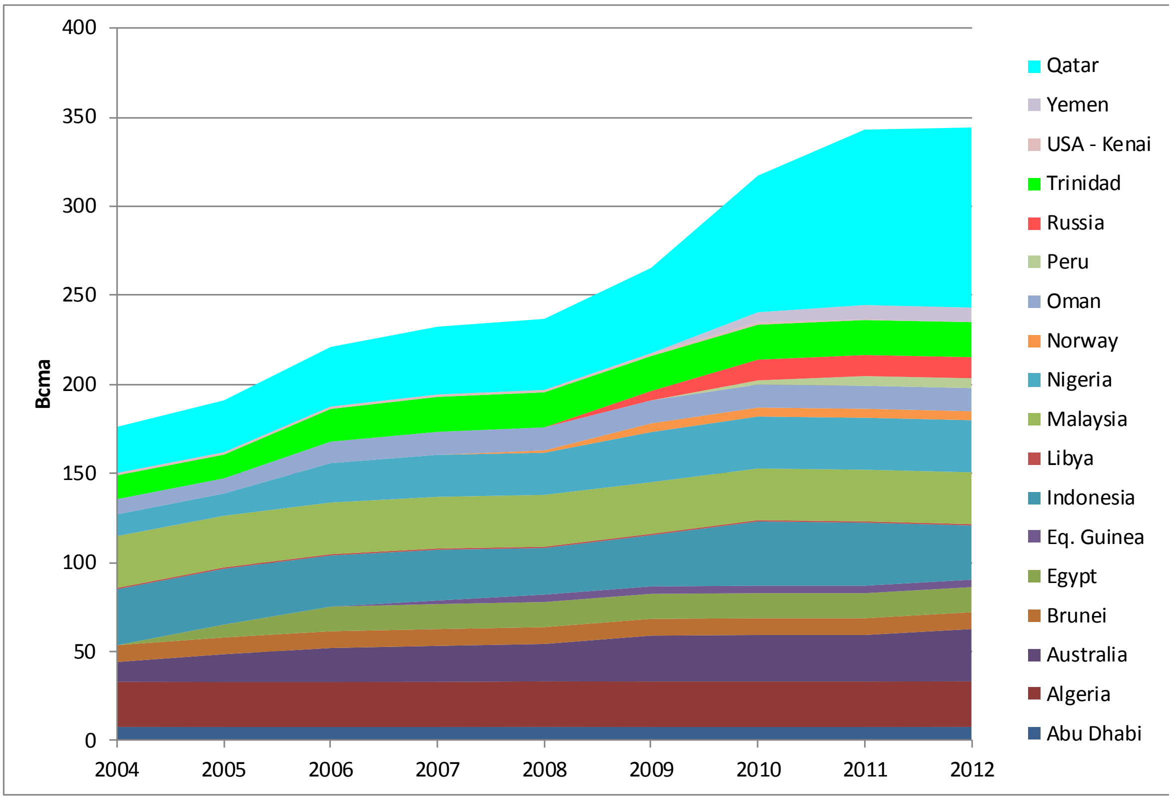
Apart from the apparent difficulty in MENA countries in terms of the failure to bring onstream upstream gas resources in line with burgeoning low-price-driven demand, the two dramatic supply side developments in the 2005 – 2012 era have been:

- The ramp-up in global LNG supply from 2008 after a period of hiatus; and,

- The unforeseen explosion in US shale gas production from 2006 onward.

Figure 32 shows global LNG supply from 2004 to 2012. The growth of some 108 bcma of new LNG supply in the 2008 to 2011 period represented a 45% increase after a 2 year hiatus in LNG supply. Qatar's expansion accounted for 61% of this increase, the remainder being from new projects in Indonesia, Peru, Russia and Yemen. It was no coincidence that these projects were developed in parallel. The signals in the early 2000s which triggered the FID's on these projects were a combination of falling unit LNG liquefaction capital costs and an upward trend in gas market prices – in Europe and Asian LNG as a consequence of oil indexed contracts, and in North America the seemingly inexorable decline in US domestic gas production and rising Henry Hub prices as a consequence.

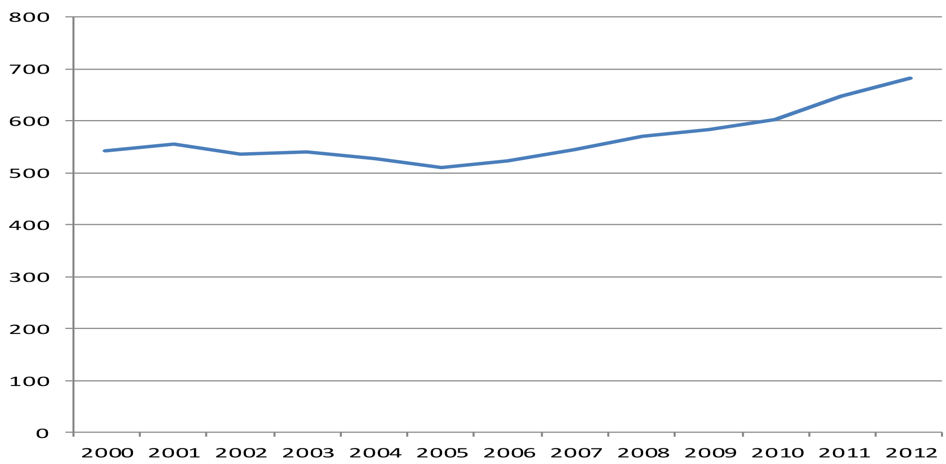
Figure 31: Global LNG Supply 2004 – 2012, bcma



Source: Waterborne LNG

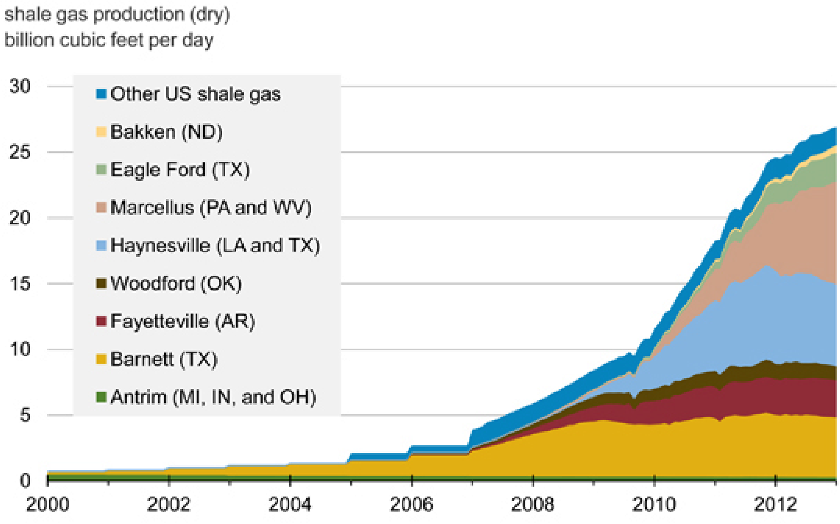
The most significant development was of course the 'Black Swan' of US shale gas production growth. Figure 33 shows US domestic gas production for the 2000 – 2012 period, with the decline of 2000 – 2005 reversed dramatically in the second half of the 2000s. The growth in US shale gas production, by play is shown in Figure 34. Shale Gas is a 'drilling intensive' activity. Well flow-rates are typically lower than those in conventional 'non-tight' reservoirs. Shale gas well decline rates, while serving to 'bring forward' revenues into the early years of production, also mean that wells must be drilled on a continuous basis to maintain production levels. In 2012 the US' shale gas production level of some 250 bcma was supported by the drilling in that year of some 7,500 shale gas wells.

Figure 32: US Domestic Gas Production 2000 – 2012, bcma



Source: BP Statistical Review of World Energy

Figure 33: US Shale Gas Production by Play



Sources: LCI Energy Insight gross withdrawal estimates as of January 2013 and converted to dry production estimates with EIA-calculated average gross-to-dry shrinkage factors by state and/or shale play.

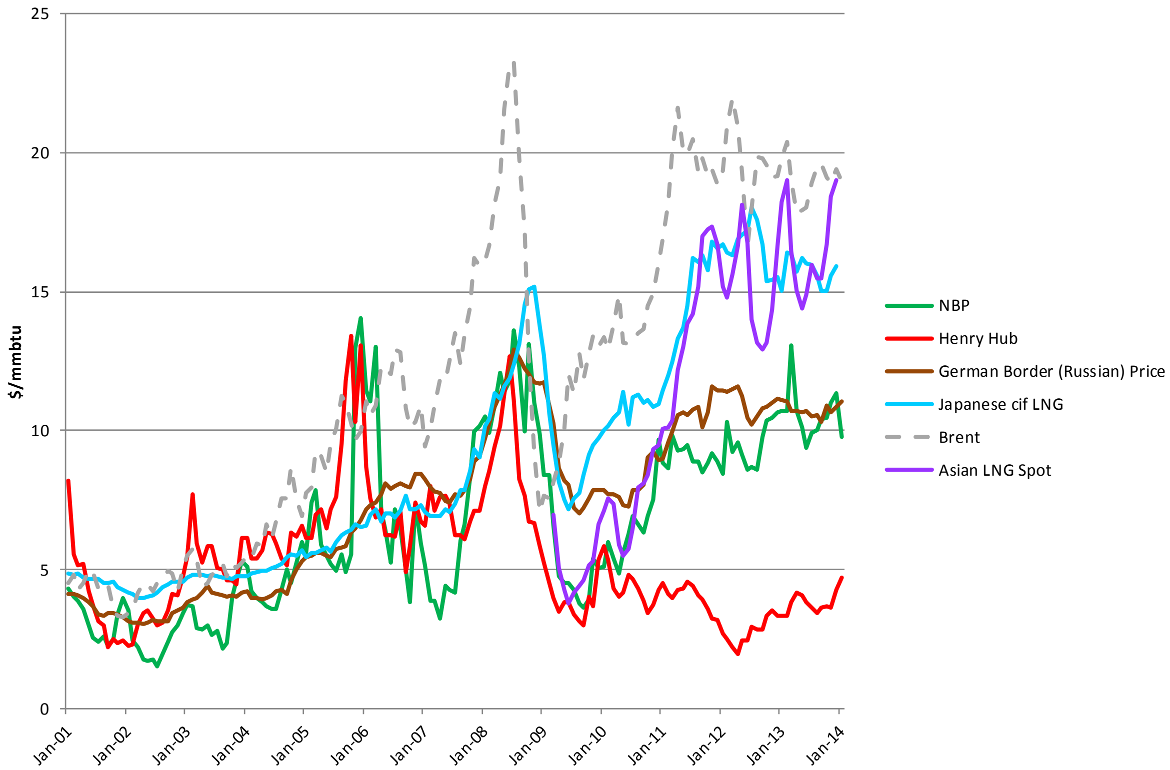
Market Dynamics and Prices

The US shale gas revolution has had impacts which were not just confined to North America. In the early 2000s, in anticipation of a need for LNG imports, the US built some 190 bcma of LNG import capacity. As the strength of shale gas production became apparent many of these import facilities became ‘stranded assets’. With the anticipated growth of new LNG supply, the drastic reduction in European natural gas demand (as a consequence of the financial crisis and economic recession) and the now minimal requirement for US LNG imports, in late 2009 there was a strong expectation that the new LNG ‘surge’ would overwhelm the Asian and European gas markets and result in a ‘dumping’ of LNG into North America. In the event this was avoided by an unexpectedly strong rebound in Asian LNG demand in 2010 (some 18 per cent up on 2009) and abnormally high gas demand in Europe in 2010 due to cold winter weather.

Since 2010 LNG demand growth in Asia (exacerbated by the Japanese Fukushima disaster) has pulled LNG supplies away from Europe. In the light of a plateau in global LNG supplies since

2011 this has caused some nervousness in the European gas market. Clearly there has been ample 'spare' gas supply in Russia – but initially only at a price in excess of European traded hub prices. However, Russia's oil-product indexation contract prices have come under significant pressure as mid-stream utilities, in the position of being committed to buying gas at oil-indexed prices and increasingly required to sell to customers at 'hub-based' prices, were exposed to unsustainable financial losses. This was a consequence of European Union (EU) liberalization policy but also the increased liquidity of gas trading hubs, bolstered by higher LNG imports. Russia, partly as a consequence of arbitration proceedings, made negotiated concessions to contract pricing formulae and instituted a system of ad-hoc rebates. Such concessions have, since 2012, increasingly brought Russian contract prices closer to traded hub price levels.

Figure 34: Regional Gas Prices 2001 – January 2014



Sources: Platts, EIA, BAFA, Argus

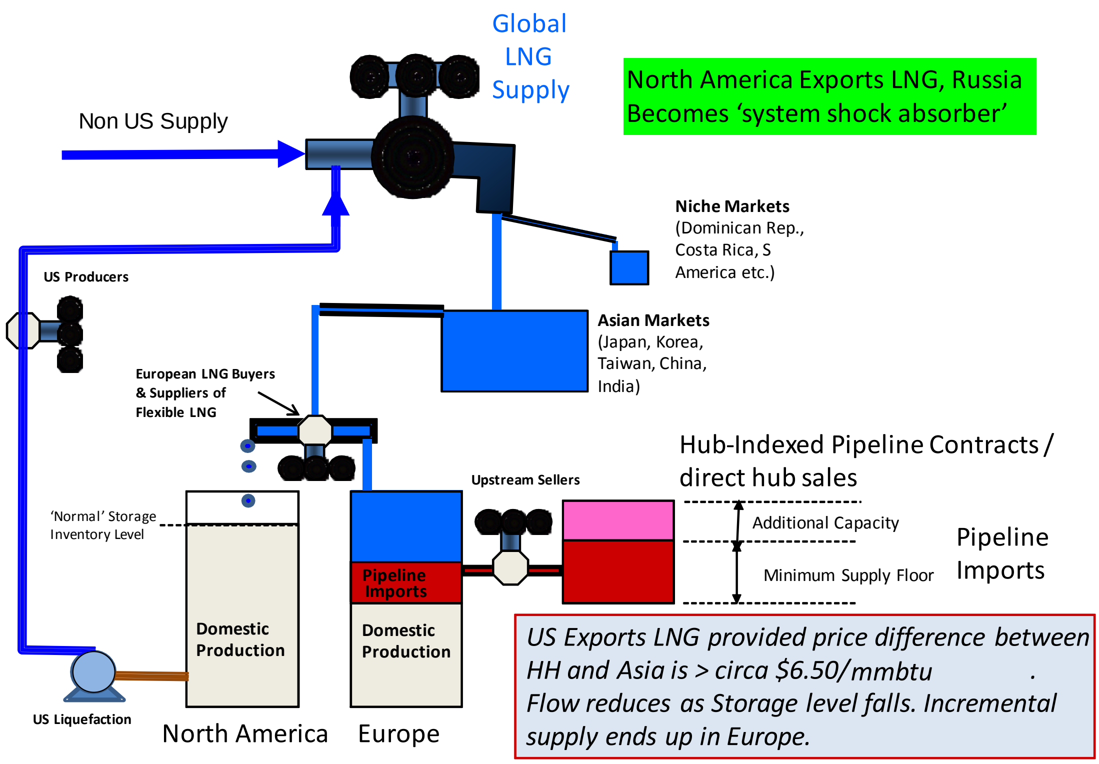
Figure 35 shows regional gas prices. For reference Brent is shown (in $/mmbtu) as the dashed grey line. The trends of Henry Hub (red), European hub prices (represented by the UK's NBP in green) and the Russian oil-indexed gas price (with concessions and rebates post 2012) – in brown, have been described above. In Asia the blue line represents the average monthly Japanese LNG import price (comprising gas sold under some 60 long term oil-indexed contracts plus spot purchases), which clearly follows Brent pricing with a lag. The purple line is the Asian LNG spot price (Platts Japan Korea Marker – (JKM)). In 2009 and 2010 JKM appeared to follow NBP reasonably closely, but following the Fukushima accident and the consequent tightening of the LNG market it has traded at a substantial premium to NBP and appears to oscillate around average Japan LNG import price, albeit with significant volatility.

What is very apparent from Figure 35 is the wide disparity of regional prices since 2011. This disparity, and particularly the high prices paid for LNG in Asia, has spurred investment plans for new LNG supplies from Australia, East Africa, Russia, Canada and, very significantly – the US, where it is proposed to convert many under-utilised regas import terminals to liquefaction and LNG export facilities.

Natural Gas Market Outlook to 2035

The increasing interconnection between regional gas markets created by greater volumes of 'flexible' LNG tradeflows means that any examination of future gas fundamentals needs to focus on the global, rather than the regional picture. An appropriate model for this consideration is shown in Figure 36.

Figure 35: Global System Connected by Flexible LNG



Source: Howard Rogers, OIES

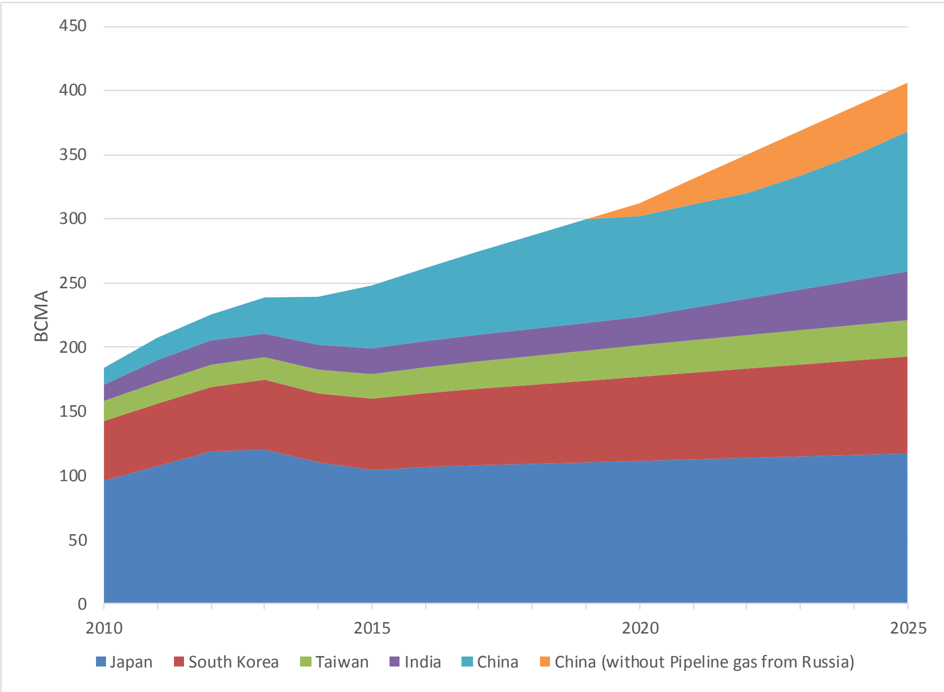
Post 2015, global LNG supply (including that from North America) will flow first to the Asian importing markets (of which Japan, South Korea and Taiwan have no other gas supply). What remains in excess of Asian requirements flows to Europe (apart from small quantities to Mexico and parts of the US East Coast not served by pipeline supply). Europe has its own (declining) domestic supplies and pipeline supplies from North Africa, Iran, Azerbaijan and Russia (of which Russia is by far the most significant supplier). Russia has been following a strategy of maintaining European gas prices by restricting physical flow (either by contract volumes or physical flows to trading hubs) at the expense of volumes. At present Russia is estimated to have a 'production surplus' of 100 bcma which it could flow to Europe and a 'breakeven price' (including export tax) of $7.50/mmbtu at the European border. Clearly pursuing this 'price targeting' strategy, in the context of the system depicted in Figure 36 puts Russia in the role of 'shock absorber' or 'swing producer'.

The 'Big Six' post 2015 Uncertainties

The post-2015 gas system faces six significant uncertainties:

- **Asian Natural Gas and LNG demand**. Figures 30 and 31 demonstrate the recent demand growth rate of Asia Pacific gas consumption. In terms of LNG demand Figure 37 is an illustrative projection based on IEA and other public domain underlying assumptions.

Figure 36: Asian LNG Demand 2010 – 2025 (Japan, Korea, Taiwan, India China)

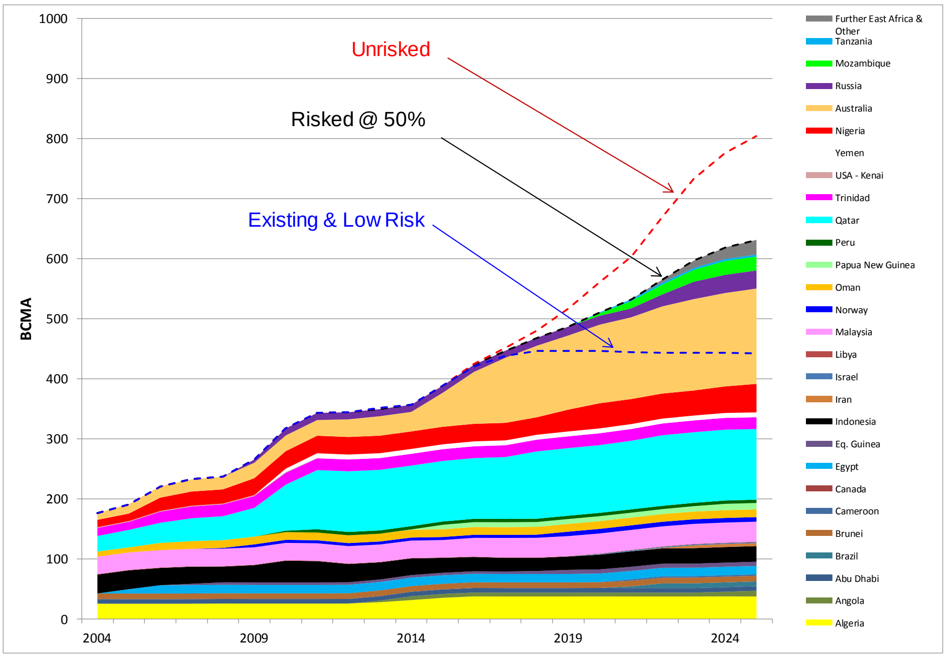


Source: Waterborne LNG, IEA, Howard Roger's Analysis

The medium term uncertainty is the speed at which Japan re-starts its nuclear power plants and this may well be slower than shown in Figure 37. Longer term it is the potential scale of Chinese LNG imports which will come to dominate Asian LNG demand and influence world gas dynamics. The orange tranche in Figure 37 represents the additional LNG China would need if its much heralded (but to date always postponed) agreement with Russia for 38 bcma of East Siberian pipeline gas does not happen. Devising a trustworthy estimate of future Chinese LNG requirements is further complicated by: a) Chinese gas demand generally – in a country with currently fast but in the future uncertain GDP growth but where gas is still only some 5% of primary energy consumption; b) uncertainty over the future level of Chinese domestic gas production, especially shale gas and coal bed methane; c) the future level of pipeline imports from Turkmenistan and Central Asia.

- **US Future Domestic Production Levels and the Scale of LNG Exports**. The US Henry Hub price probably needs to rise to a level between $5 and $7/mmbtu for dry shale gas plays to become economic on a full cycle basis. This is the price range required for US production to meet both domestic demand and also to provide the feed-gas for LNG exports. Of the six export schemes which currently have offtake agreements (or Heads of Agreement) totaling 110 bcma, US Department of Energy Non-Free Trade Agreement approval has so far been granted for some 85 bcma. Only one project in 1Q 2014 is under construction (Sabine Pass) with the others awaiting FERC approval to construct. In a ‘base scenario’ we could expect around 110 bcma of US LNG exports by 2025. Sabine Pass should be onstream by end 2015 but major export volumes will build from 2018. If the performance of the US shale gas industry disappoints however, exports will be constrained as the price spread between Henry Hub and destination markets is squeezed. At $6/mmbtu Henry Hub, US LNG exports can remunerate incremental investment at European hub prices of $10.50/mmbtu and Asian LNG spot prices of $12/mmbtu.
- **New LNG Supply from non-US sources.** With the commissioning of new large Australian projects from 2015 onwards, the world is about to embark on the next ‘ramp up’ in LNG supply. Beyond 2018 however there is uncertainty as to how many projects will achieve FID. This is shown by the uncertainty bar in Figure 38.

Figure 37: LNG Supply (Non-US) 2004 - 2025

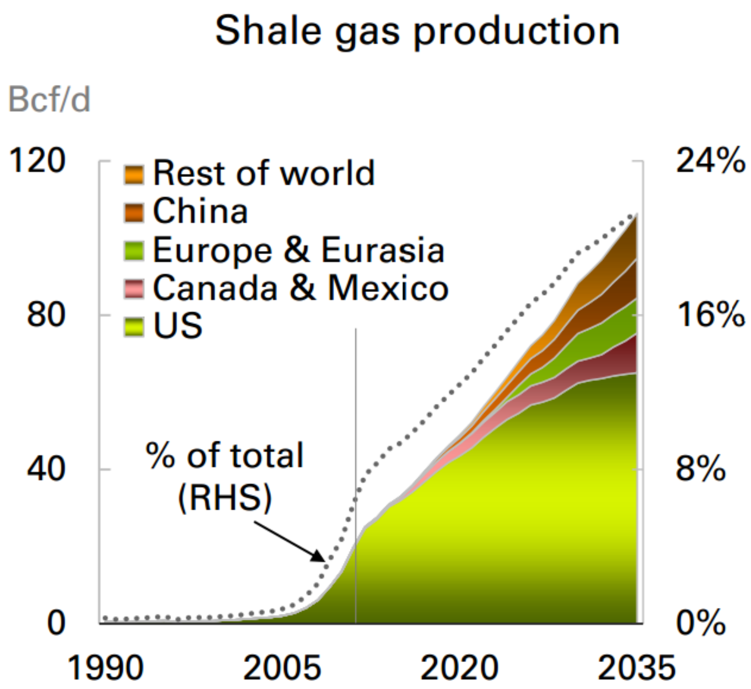


Sources: Waterborne LNG, D. Ledesma, Howard Roger's Analysis

Key suppliers wishing to bring on new projects in the period are Australia, East Africa, Russia and Canada as well as the US projects mentioned earlier. However the period 2018 to 2023 could be one of oversupply and some of these projects may be deferred prior to reaching FID.

- **Shale Gas outside North America**. Results of shale gas exploration and development activities outside of the US have not been hugely encouraging to date. Europe is either indifferent or is actively banning fracking. In Poland only 40 to 50 wells have been drilled since 2010 due to bureaucracy, adverse fiscal terms and perhaps geology. In the UK exploration drilling is just beginning but even with exploration success it remains to be seen whether public opinion would permit the level of drilling required for meaningful production levels to be achieved. Elsewhere in areas such as North Africa, Mexico and India the challenges relate to low domestic prices, upstream policy frameworks and perhaps water availability. Argentina is potentially interesting if liquids are co-produced although the sanctity of foreign investment frameworks and domestic pricing is an issue. In Australia shale gas would have to take its place in the queue with conventional gas and coal bed methane for LNG export markets in what is now viewed as a high cost base country. China appears to have made positive progress although the economic cost effectiveness of is unknown and it is still unlikely to produce significant shale gas volumes this side of 2020. The outlook is well summarised in Figure 39 from BP's World Energy Outlook.

Figure 38: Shale Gas Production to 2035



Source: BP Energy Outlook 2014

- **JCC versus Hub Based Pricing for Asian LNG**. Although Asian long-term LNG contracts have used a price formula linked to crude oil since the 1970s, this is now challenged by Asian buyers. Clearly at crude prices above $100/bbl this has given rise to LNG contract prices which are extremely high by historic standards (see Figure 35). As a consequence mid-stream utility buyers are under severe financial strain. With oil products and gas competing less and less in many Asian countries, the logic of oil indexation is also questionable. In Europe the transition to hub-based pricing was made possible by the following factors:

- Pro-competition laws and regulations by national and European level policy makers which undermined the market power of incumbent 'national champions' and encouraged the formation of nascent gas trading hubs.
- A surge of un-contracted supply from 2009 which created liquidity at trading hubs and a clear transparent (and lower) price reference compared to long-term oil indexed contract prices – causing a loss of customer base (and failure to meet take or pay) on the part of the midstream contract buyers.
- Renegotiation of oil indexed contracts (including arbitration) resulting in price terms incorporating hub price and/or a series of rebates, such that contract prices converged on hub prices (see Figure 35).

For the Asian LNG market in the 2018 to 2023 period, the second and third of these effects might be present, but there seems little willingness or resolve on the part of national governments to enforce the first. Establishing liquid hubs for LNG trading in Asia will be a challenge. Singapore is a first step, but more liquid hubs could be established in Tokyo or Shanghai. The creation of a hub price reference through spot trading, for use in long term contracts would create more active arbitrage between North America, Europe and Asia for LNG trade flows and a more rational market. This is unlikely to be a rapid transition and will not be without financial pain and difficulty for the participants.

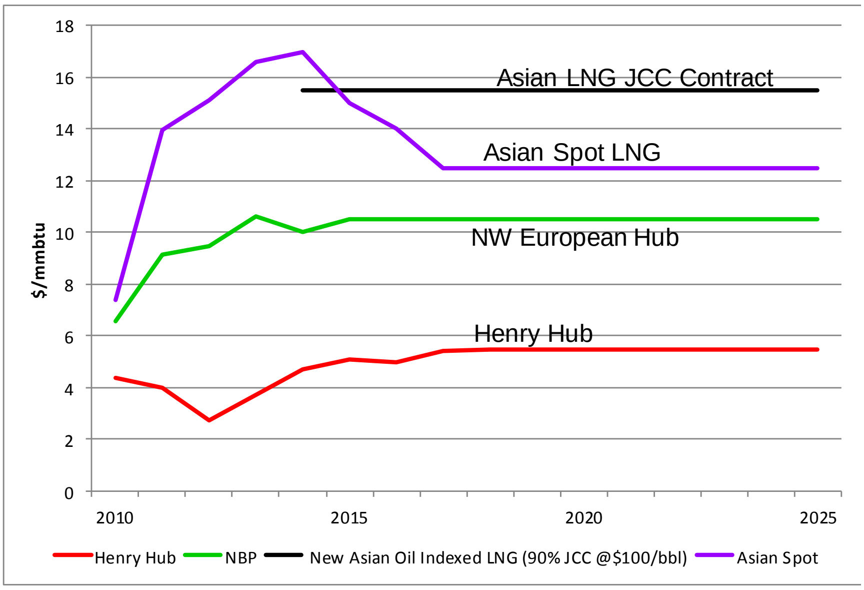
- **Russia's Role as the System Shock Absorber**. In addition to a continued focus on its European export market (and the ongoing negotiations with the Chinese on which much of Gazprom's Asian strategy hangs), Russia will need to take note of the developing and very uncertain global balance for LNG. If a soft market develops towards the end of this decade and results in 'excess' LNG over-spilling into

Europe (as it did in 2010 and 2011) Russia will need to decide whether it intends to continue a ‘maintain price at the expense of volume’ strategy, and risk losing significant market share; or, engage in a price war – in order to discourage US shale gas drilling and other competing supply projects.

Indicative Regional Price Paths

The dynamic system and the main uncertainties for the period 2015 to 2025 described above could result in the following illustrative price paths for the three regions of North America, Europe and Asia (LNG). Figure 40 shows a ‘base case’ view where US exports of LNG create, through arbitrage, a world where a) Henry Hub is high enough to sustain domestic production sufficient to meet US demand requirements and LNG export volumes; b) Russia maintains European price levels no higher than the floor formed by US LNG project economics; c) Asian spot prices reflect an arbitrage with European hub price given the additional US LNG shipping cost; and d) Asian LNG JCC - linked contract prices (at $100/bbl) are ‘out of the money’ from the view point of Asian buyers and hence their long term future questionable.

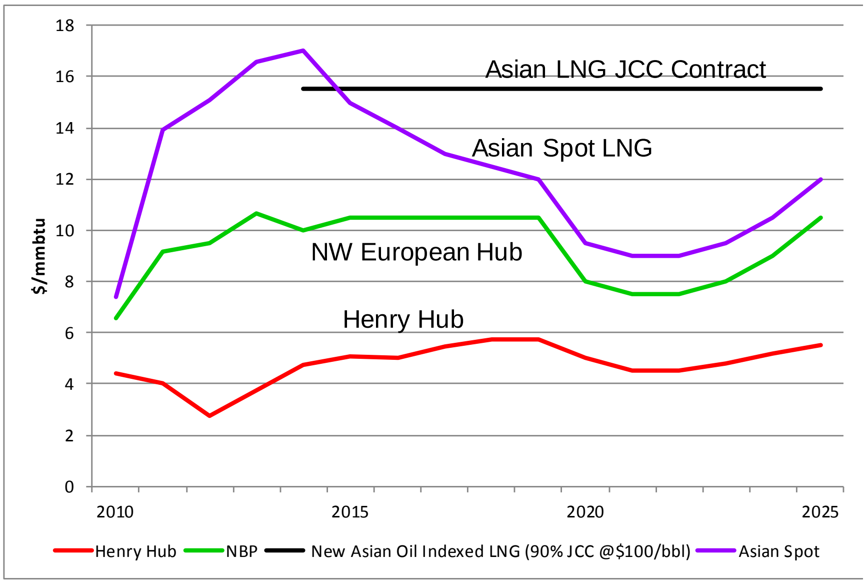
Figure 39: Regional Price Paths (Base Case)



Source: Howard Roger's Assumptions

Figure 41 shows the illustrative impact of a price war initiated by Russia. In the Base Case it might be that in maintaining European hub prices at a level which has encouraged high volumes of US LNG exports, Russia has lost market share in Europe to what it considers to be an 'unacceptable' degree. One recourse is to increase physical flows to Europe (out of the 100 bcma of 'spare' production capacity it currently has and is expected to have to 2020 at least). This would reduce European hub prices (shown in Figure 41 going down to the estimated $7.50/mmbtu 'break-even' price of Bovayenko – sourced pipeline gas), and also (by arbitrage) reduce Asian LNG spot (hub) prices and Henry Hub. This would curtail drilling activity in the more expensive US shale gas plays and also deter other competing pipeline and LNG supply projects. After a period of two years or so, Russia could reduce supply and raise European prices back to a 'target level' but at a higher market share for Russian gas – at least until US drilling levels recovered. Such a scenario would increase the pressure to move to hub pricing for LNG in Asia.

Figure 40: Regional Price Paths (Base Case) with Price War



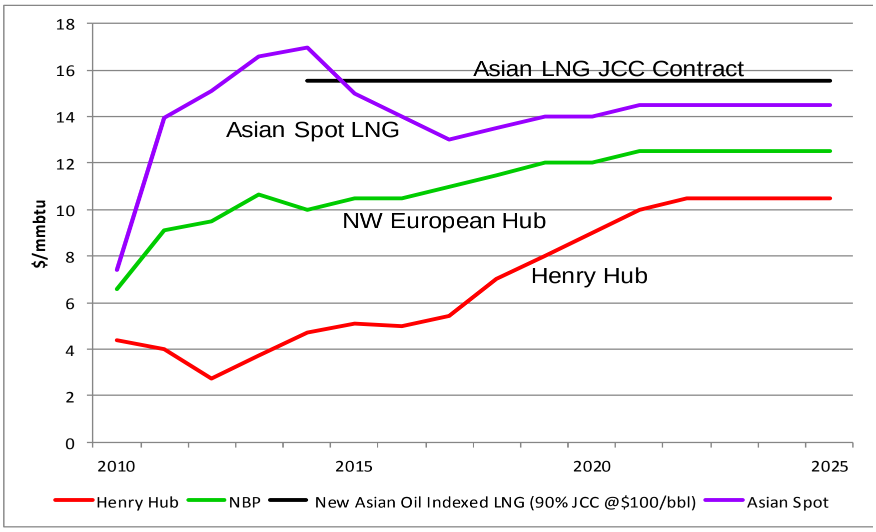
Source: Howard Roger's Assumptions

However, again it should be stressed that the Base Case, and the price war variant, is only valid for assumptions of a robust US shale gas production-price relationship and a view of Chinese LNG demand broadly as shown in Figure 37. Given the inherent uncertainties in these core assumptions, it is also worth considering a 'Tighter Market Case' where one or more of the following pertains:

- US shale gas production is not as robust as generally assumed, even at higher Henry Hub prices,
- Asian LNG demand (and particularly China's) is higher that shown previously,
- In anticipation of high volumes of US LNG exports, many other LNG supplier countries defer FID on new projects by several years.

The illustrative price trends for such a scenario are shown in Figure 42.

Figure 41: Regional Price Paths (Tighter Market Case)



Source: Howard Roger's Assumptions

In this 'Tighter Market Case' it becomes apparent that once US LNG exports commence, US production response is muted as Henry Hub prices rise. Russia, with the threat of this competing supply source diminished, reduces physical flows to Europe to lift hub prices to a higher 'target level' of $12.50/mmbtu. The US continues to export LNG to Asian spot markets and Europe (by arbitrage) even though the price spread between Henry Hub and these destination markets is insufficient to recover liquefaction tolling fees (a fixed cost) but does cover shipping and (for Europe) re-gas costs. This Tighter Market Case however, could be undermined post 2025 by the development of deferred LNG projects.

Future Demand Dynamics and Supply beyond 2025

Given the uncertainties as described in detail above for the 2015 to 2025 period, it is difficult to be specific in terms of quantitative projections to 2035. Several observations are pertinent however.

Demand

In **North America** there is a reasonable case to expect a continuation of steady, moderate demand growth for gas provided that shale gas production does not 'disappoint'. Sustained Henry Hub prices of around $6/mmbtu would ensure gas' future in the residential & commercial and industrial sectors. Also at \$6/mmbtu, although more costly than coal in generation (at present this means an equivalent competitive coal parity price of \$4/mmbtu for gas) the gap is 'bridgeable' from a policy viewpoint given coal's ongoing slow demise due to particulate and other emissions and CO_2. The largest threat to gas in the US would be the emergence of a renewable (or low carbon) energy source without the intermittency problems of wind and solar. Alternatively a cost-effective means of storing power generated from wind or solar could also threaten gas, albeit it is likely that gas would have a significant cost advantage other than in a world of high carbon pricing. Much has been made of gas as a transport fuel and that is certainly a possibility for trucking applications in the US, but probably not to any great extent in automobiles.

In **Europe** gas demand may grow slightly in the 2020s as coal fired plant which have not fitted SO_x and NO_x removal equipment are retired and a net reduction in nuclear generation through retirals and phase-out occurs. As the threat from coal slowly dissipates towards the end of the 2010s the remaining issue for gas in the power generation sector will be the future build-rate of wind and solar renewables. There is a strong possibility that onshore wind build may stall due to public opposition and offshore wind will be limited due to cost levels which will increasingly be reflected in consumer bills. In the residential & commercial sector increasing insulation and efficiency measures (and possibly heat pumps) will likely result in a slow decline in gas consumption. In the industrial sector the ongoing demise of energy intensive industries in Europe will likely reduce gas demand but could be offset to a degree at a regional level if Turkey continues its current growth trend. A generally flat aggregate trend from these demand sectors could be changed to one of slight growth by the addition of a modest gas in transport sector, albeit mainly in trucking and shipping (LNG fuelled).

In Asia Pacific the current growth trends will likely continue albeit difficult to predict into the far future. In general simplistic terms, replacing coal fired generation by gas is desirable (and in parts of China urgently required) from the point of view of air quality, public health and reducing acid rain impact on food crops – but is expensive given the price disparity between gas and coal. Residential & Commercial and Industrial demand is likely to continue with strong growth. Hopefully by the end of the 2010's there will be a more transparent data set from key Asian countries to help improve projections of future gas demand.

Again it is worth stressing that gas, as a power sector fuel, will for some while continue to be 'squeezed' by coal and renewables to varying degrees in different regions. Clearly the higher the regional price of gas – the more intense the squeeze, making coal more desirable on purely cost grounds and renewables in simplistic terms, more affordable by comparison. While Chinese manufacture of solar PV has led to a significant reduction in unit costs, it is unclear whether such might be the case for offshore wind, given the additional installation costs. In favourable climatic locations solar PV may achieve 'price parity' with European retail power prices (as distinct from wholesale) – but this ignores the issue of the flexible 'back-up' required by either hydro or flexible fossil fuel generation. A more rational (and cost-optimal) approach to decarbonisation would include a) the medium term displacement of coal fired generation by gas, b) the application of gas with CCS in parallel with nuclear, solar and onshore wind and c) research into the longer term possibility of cost-effective power storage. However in Europe in particular, energy policy continues to be driven by an unwholesome blend of a) denial at the policy level of the scale of financial support required for, in particular, offshore wind, and an unwillingness to provide overt financial support for other low carbon alternatives, b) an obsession favouring 'local' energy solutions (possibly born of distrust of large energy companies and 'anti-capitalist' sentiment) – though ignoring the need to centrally balance the power system, and c) a reluctance to confront the inevitable reliance of Europe on gas imports for much of its requirements, despite a track record of global trade in other commodities. This to a degree continues to be catalysed by the continual Russia-Ukraine gas transit problems, despite Russia's otherwise strong record of reliability as a gas supplier to Europe.

Supply

In fundamental terms, beyond 2025 the key issues in terms of global gas supply sufficiency can be viewed through the following perspective:

- We may assume that North America remains self-sufficient and could continue to be a net gas exporter in the form of LNG.
- South America could stabilise its import requirements a) by better co-operation between neighbours with differing gas resources relative to demand and b) through the stabilisation of the Venezuelan and Argentinian hydrocarbon sector and possibly through more gas-prone discoveries offshore Brazil.
- Africa, through the development of the Mozambique and Tanzanian discoveries could assist in East and Southern African self-sufficiency.
- Europe and Russia-CIS as a whole could retain self-sufficiency; such is the scale of the remaining resource in West Siberia. This despite the continued decline in European domestic production.
- The remaining parts of the 'puzzle' relate to MENA and Asia Pacific.

It seems clear that certain key Asian countries (China, India, South Korea, possibly Thailand) are likely to continue to grow as economies and also as significant gas importers. It is also plausible that the current 'Great LNG Race' between Australia, East Africa, Russia, Canada and the US for the Asian market 'window' of 2018 to 2023 may result in a classic commodity cycle oversupply, with a consequent period of supply 'famine' in the second half of the 2020s while investors recover their confidence. It is also, at this distance, unclear whether this group of LNG suppliers will have the supply growth potential to deal with the 'next demand wave' in Asia or indeed whether we may see another new gas supply province (such as East Africa) appear un-heralded.

This perhaps is where the 'supply spotlight' comes back to MENA, in two senses:

- Supply from Qatar, above the levels of the North Field moratorium, would no doubt retain its present comparative advantage as a relatively low cost LNG supply source (benign offshore and onshore project locations, stable investment framework, liquids co-production). Iran, by the mid to late 2020s, in a post-sanctions world might also wish to develop commercial and diplomatic linkage through major LNG trade flows, from further development of the South Pars field.
- Elsewhere in MENA the adoption of, at least, a cost-reflective domestic pricing policy for natural gas would a) encourage the development of domestic gas resource, b) reduce inefficient consumption in the domestic gas and power sectors and c) reduce and perhaps even eliminate high cost LNG imports, currently competing on price with Asian buyers.

Of these two points, the first, by the end of the 2020s may be essential, the second, on a number of levels, at the least desirable.

IV. Natural Gas in the MENA Region[3]

The Arab world's resource potential for natural gas is by all means vast, both in absolute terms and in relation to the number of years for which production can be maintained at current levels (Table 1). Reserves are particularly concentrated in the Gulf States, and within North Africa, Algeria and Libya. Qatar continues to hold the Arab world's largest gas reserves as well as, on global level, the world's third largest natural gas reserves after Russia and Iran. Only Lebanon, Morocco and the Palestinian Territories hold no proven natural gas reserves, although these have intensified exploration efforts and are expected to add at least modest hydrocarbon discoveries over the coming years.

The region's overall gas reserves picture – Arab countries hold over a third of total global gas reserves – usually leads to conclusions about the very substantial increase in production and exports that can be expected from the region. However, in the 2000s, a new phenomenon began to appear in Arab countries: shortages of gas leading to curtailment of exports and (in some countries) a need for imports. Kuwait and Dubai began to import LNG in the late 2000s, while Abu Dhabi and Oman continued to export LNG while starting to import significant quantities of gas from Qatar via the Dolphin pipeline. By the late 2000s, a majority of countries in the region appeared to be experiencing domestic 'gas shortages'; some observers claim that the region faces a 'gas crisis'.

[3] This section is based on Fattouh, B. and Stern, J. (2011) *Natural Gas Markets in the Middle East and North Africa*. Oxford: Oxford University Press.

Table 1: Natural Gas Reserves, Production and R/P Ratios in Arab Countries in 2011

		Reserves	Production*	R/P Ratio
		Bcm	*Bcm*	*Years*
Gulf				
Bahrain		92	15	6
Iraq		3,158	19	169
Kuwait		1,784	14	130
Oman		950	33	29
Qatar		25,110	160	157
Saudi Arabia		8,151	102	80
UAE		6,090	82	74
of which				
Abu Dhabi		5,715	69	83
Dubai		100	5	20
Ras-Al-Khaimah		30	1	43
Sharjah		245	8	30
Yemen		479	31	16
Levant				
Jordan		6	0	26
Syria		285	11	26
North Africa				
Algeria		4,504	190	24
Egypt		2,190	67	33
Libya		1,547	10	157
Tunisia		65	3	21
Total Arab World		**54,411**	**738**	**74**

Notes: * Gross natural gas production
Source: Cedigaz

So, how can one begin to explain the MENA gas puzzle? An important dimension of the puzzle concerns the rapid domestic demand growth in the last three decades.

The Gas Demand Challenge

Between 1985 and 2013, the average annual growth of domestic natural gas consumption in the GCC has been buoyant ranging from as high as 10% in the UAE to 4.9% in Saudi Arabia. Similarly, in North Africa, domestic gas consumption grew at a fast rate, especially in Egypt, Libya and Tunisia. In the Levant region, natural gas has made serious inroads during the period 1985-2009 where countries such as Syria and Jordan have witnessed spectacular growth rates, though starting from a very low base. This rapid growth in gas consumption has resulted in the rising importance of natural gas in the total domestic energy mix. Natural gas is the dominant source of energy in Bahrain (91.2%), UAE (81.1%), Qatar (79.5%), Oman (61.1%) and Algeria (56.6%). Gas-producing countries such as UAE, Egypt, Syria, Jordan, Bahrain and Kuwait have witnessed rapid rise in the share of natural gas in the energy mix in recent years. By contrast, in Yemen, Morocco, Lebanon and Iraq, natural gas still plays no or very limited role in meeting domestic energy requirements – owing very much to these countries limited own gas production, limited propensity to import, and, in the case of Yemen, continued focus on gas production almost exclusively for export.

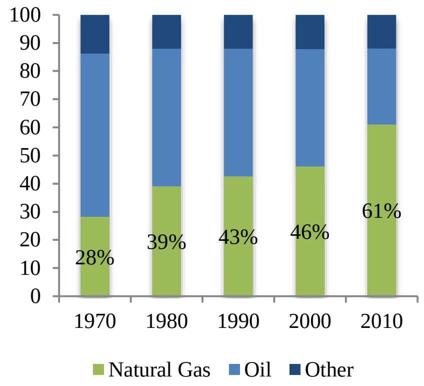
The factors that have contributed to the very rapid growth in gas demand vary considerably across the region depending on a country's individual features such as the structure of its economic activity and industry, its resource endowments, and the degree of flexibility of economic and energy policy. However, despite the diversity of experiences, it is possible to identify some common causes for the rapid growth in gas demand: a rapid economic expansion; an expanding population whose growth rate exceeded the world average; a concerted policy of increasing the role of gas in power generation and water desalination; an economic strategy which aims at diversification into energy-intensive industries; an energy policy that aims to increase the productivity of the oil sector through gas injection into oil reservoirs to enhance oil recovery; gas pricing policy which encourages wasteful consumption; and lack of effective demand management policies. Relatively high oil prices throughout the 2000s and continuingly the 2010s have furthermore raised the value of oil and oil products as export commodities for the region's oil producers, increasing the value of using natural gas domestically as an ever more valuable substitute for oil. The Arab world's continuingly low exposure to energy alternatives such as renewable and nuclear energy will is likely to continue to drive demand for natural gas as a cheaper and cleaner alternative to oil.

Natural Gas and Power Generation

Demand for natural gas in the region has been strongly interlinked with that of electricity demand. In the early stages of MENA gas markets development, the industrial and residential sectors were the main drivers of gas demand growth. More recently, gas consumption in the region has been largely driven by the power generation and the water desalination sector. While the share of oil in electricity production shrank from 72% in 1971 to 36% in 2006, the share of gas increased from 15% to over 56% over the same period. As a result, today, some 61% of the MENA region's power requirements are gas-fired and the sector is set to retain the largest share of gas consumption in the medium-to-long term (Figures 43 and 44).

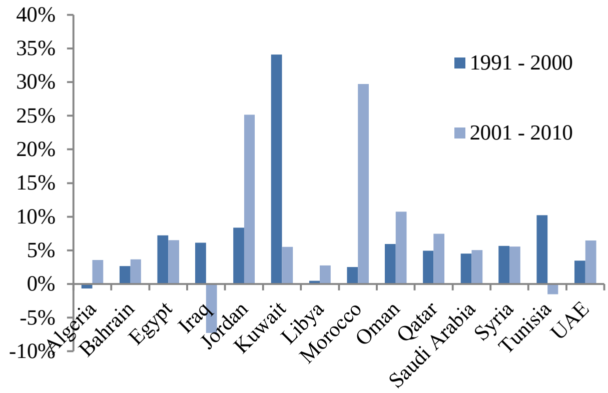
Growth in electricity demand throughout the 2000s has been phenomenal with the average annual increase in electricity demand exceeding 10% in countries such as UAE, Qatar, Libya, and Yemen. This high growth can be attributed to a large number of factors such as rapid population growth, high urbanisation rate, a relatively strong economic performance, and above all low electricity prices which distort the incentive for efficient and rational use of electricity. Electricity prices in most Arab countries are set at very low levels, often not covering the cost of production imposing a serious fiscal cost. The difficulties of the power generation sector to keep pace with demographic pressures and the mounting cost of electricity subsidies which prevented investments in the power generation sector in some countries have resulted in recurring power shortages in a number of countries such as Egypt, Iraq, Yemen, Kuwait, Syria, and Lebanon causing demonstrations and stirring wide public unrest.

Figure 42: Share of Oil and Natural Gas in Electricity Production in the Arab World, 1970 – 2010, in percentage



Source: Oxford Institute for Energy Studies based on World Bank data

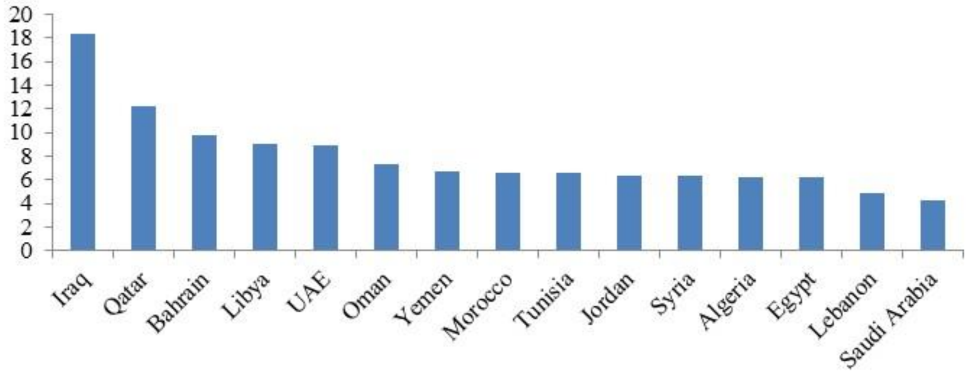
Figure 43: Growth in natural gas consumption by country, compound annual growth rate 1990 – 2010, in percentage



Source: Oxford Institute for Energy Studies based on EIA data

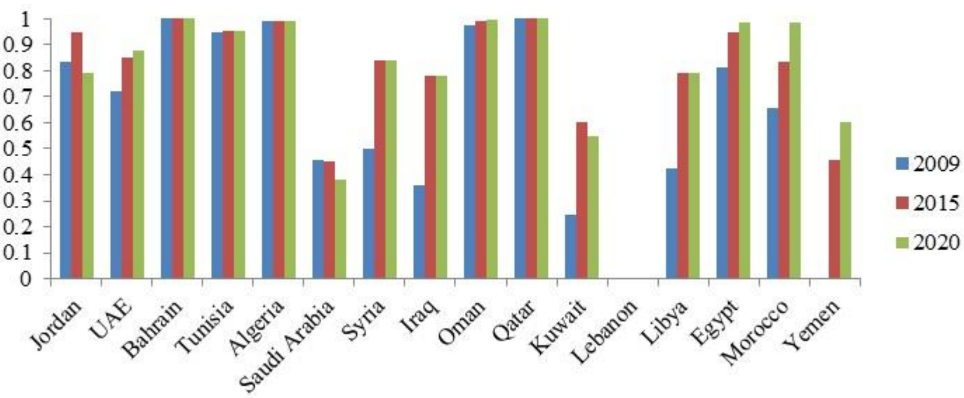
Looking ahead, the rising gas demand pressures from power generation are likely to accelerate as electricity demand is expected to grow at fast rates with average annual rates between 4.2% (Saudi Arabia) and 18% (Iraq) (see Figure 45) during the period 2009-2020 compared to a world average of 2.4%. Furthermore, the share of natural gas in the fuel mix for power generation is expected to increase in most Arab countries as the switch from oil to gas for power generation continues in the region. Figure 46 below shows that between 2009, 2015 and 2020, the share of natural gas in power generation will increase in most Arab countries with some exceptions. In Saudi Arabia, gas will maintain its share until 2015 but will decline by 2020 as it increases its reliance on liquid fuels. In Kuwait, the share of natural gas in power generation will increase by 2015 but then will decline, reflecting a judgment that in the context of limited gas availability, more liquids will be diverted to power generation. In the Mashreq countries, the reduction of liquids in power generation will be dependent on availability of imported gas.

Figure 44: Projected Average Annual Growth Rate of Electricity Consumption in Selected MENA Countries between 2009 and 2020, in GWh



Source: Kharbat (2010), Appendix A.

Figure 45: The Evolution of the Share of Natural Gas in Power Generation (2009, 2015, 2020), in %



Source: Kharbat (2010), Appendix G.

Natural Gas and Economic Diversification

In addition to power generation, the natural gas sector lies at the heart of diversification efforts in many energy-resource rich economies, where natural gas has become the fuel of choice for industrialization through the development of energy intensive industries such as petrochemicals, cement and aluminium. On the one hand, this diversification strategy has achieved some success. During the last decade or so, the petrochemical industry in the

Arab world has witnessed rapid expansion transforming the region into an important global player. In the GCC countries such as Kuwait, Saudi Arabia, Qatar, and UAE, the petrochemical industry is mainly ethane based derived from associated and non-associated natural gas. In these countries, the low cost of ethane constitutes the main source of comparative advantage and is the main factor behind the rapid growth in the region's petrochemical industry.

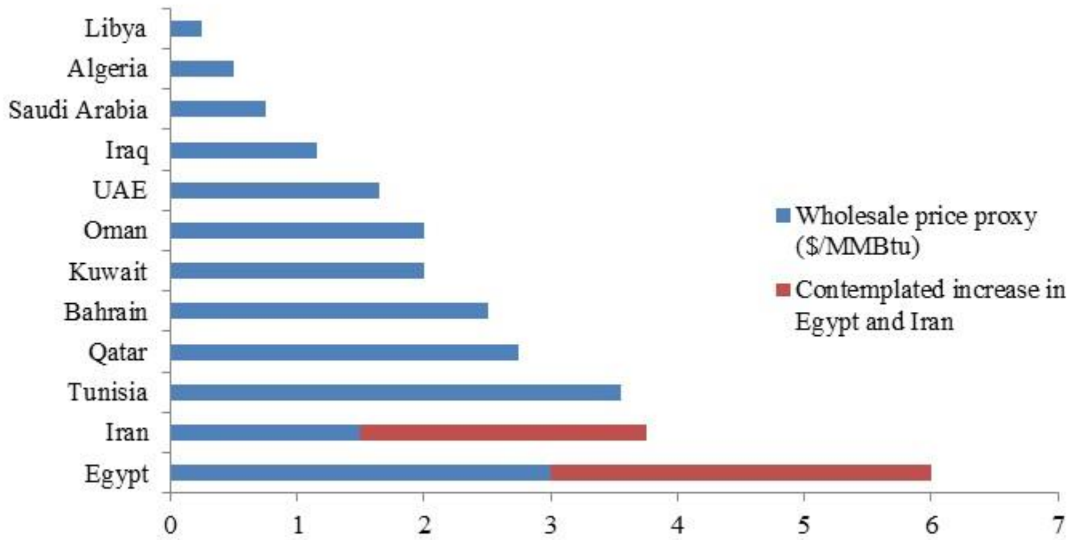
On the other hand, the drive towards diversification through developing petrochemicals and other energy intensive industries' raises a series of challenges in many countries. Given the increasing scarcity of natural gas and in the absence of clear price signals due to artificially low prices, the issue is whether the existing allocation of this scarce resource among the various sectors such as petrochemicals versus power generation or exports versus domestic use is efficient and maximises the value of the utilised resource. From a broader perspective, it raises the issue as to whether industrialisation through energy intensive industries has been successful in achieving certain goals such as diversification and employment creation. Increasing scarcity of natural gas and more costly gas supplies also raise the issue of whether current policies and/or plans of promoting energy intensive industries are sustainable in the long term. Unfortunately, due to data limitations, the chapters in this volume do not provide adequate answers to such questions and these issues are still open for further research.

Gas Pricing Policy

Over the past 30 years in which Middle East and North African production has achieved such substantial levels another extremely unwelcome trend has become evident: the era of low cost gas production – specifically gas associated with oil production and easily accessible non-associated gas which could either be considered "free" or available at less than \$1/MMBtu – has ended; for the majority of countries it probably finished at least a decade ago. The cost of new gas production can be estimated in the range of \$3.50-6.00/MMBtu due to greater depth of resource discoveries, complexity of reservoirs ("tight gas") and the presence of impurities ("sour gas").

Despite the fact that the era low cost gas finished some time ago, the vast majority of countries in the remain in an era of *low price gas* in terms of what they charge industry, power generators, commercial and residential customers in their countries. While it is an open question whether the prices in Figure 47 should be considered "subsidies" in countries with no export infrastructure, these prices are a fraction of the cost of new supplies – domestic or imported – that all countries will need to develop to meet their future domestic requirements.

Figure 46: Maximum Wholesale Gas Prices in the MENA, in $/MMBtu



Source: Ali Aissaoui, APICORP Research, September 2013

The current pricing policy has many adverse allocation and distributional consequences. It encourages domestic gas demand above the levels warranted by their true opportunity costs. Furthermore, the optimisation of resource allocation becomes infeasible under subsidised prices. Subsidised prices often result in the misallocation of investments towards energy intensive industries that would otherwise have not been profitable. For gas exporters, subsidies can give rise to a bias in favour of investments in export infrastructure as producers have no incentive to sell their gas on the domestic market when they can secure much higher prices from export markets. Subsidies are also regressive in nature as the bulk of the benefits accrue to households in high income groups who consume more gas and are better connected to the natural gas network than household in low income groups.

How sustainable therefore are the subsidies which governments are paying to support gas supplies in their countries and for how long will they be able to continue this policy? Here it is important to take a wider view of a group of countries with young and rapidly growing populations. In resource-rich countries, low energy prices can be seen as one of the various methods for distributing rents to the local population. Furthermore, in the majority of OAPEC countries, low gas prices are part of a larger picture of low power prices and low charges for water use. Low price gas allows petrochemicals to be produced at low cost and therefore compete in world markets. It also allows the generation of low price power which allows low cost production of aluminium and water desalination. In turn this allows water to be provided at very low cost. Substantial increases in gas prices – our calculations above suggest the need for a six to twelve-fold increase in the majority of countries – would massively impact those sections of the population on low incomes and hence is socially and politically undesirable. Thus, abolishing subsidies must be accompanied by measures to protect poor households from any decline in real income. Furthermore, high gas prices would impact the industrialisation and diversification strategy in many countries as it reduces the competitiveness of its energy intensive sector.

Some countries have the financial capacity to continue with their current pricing policy – whether or not this would be the most efficient strategy for maximising the utilisation of their gas reserves. Qatar's abundant low cost domestic gas means that a domestic price of around $2.75/MMBtu, while it certainly does not maximise value, probably covers costs. Saudi Arabia's crude oil endowment allows it to utilise greater quantities of fuel oil for power generation while prioritising gas use for the petrochemical industry. However, low domestic gas prices particularly in countries producing primarily (or in the case of Saudi Arabia exclusively) for the domestic market hold indirect costs, including substantial disincentives for the development of new gas reserves. In Saudi Arabia, where the cost of developing sour and shale gas is not expected to be below $6/MMBtu, developers will require substantial additional fiscal incentives other than the current domestic sales price of around $0.75/MMBtu in order to invest in new production capacity.

In other countries, the current policy of subsidising gas prices is already now highly unsustainable. Egypt currently faces an escalating energy subsidy burden of an estimated E£120bn (US$17.4bn) in 2012/2013, around 20% of total government spending and more than four times the value of the IMF aid package Egypt negotiated over at the end of 2013. Egyptian expenditure on subsidies regularly exceeds spending on pro-poor sectors such as health and education, as well as Egypt's otherwise single largest budget item, defence.

Thus, for the majority of MENA countries, the answer to the question of how to reform prices, given their political and economic circumstances of many of these countries, raises crucial questions of macroeconomic management and political legitimacy of governments, and ultimately how some of these countries need to develop towards a "post-Hydrocarbon era". The pace of reform is likely to be uneven across the region. In some countries, the government's ability to manage domestic opposition and social unrest will be the main driver of reform. In other countries a more relevant factor would be the potential impact of higher gas prices on the international competitiveness of their energy intensive industries and the overall impact on the country's development strategy.

Common Problem and Varied Responses

Rising gas demand has caused serious concerns in many countries over the security of gas supplies. Despite its dominant position in reserves, the region is no longer immune to gas security concerns. Issues such as securing long term gas supplies at an 'acceptable' price, diversification of gas supplies to reduce dependency on a dominant exporter, and problems of trans-border pipelines have now become central to the energy policy agenda. In many countries, it is no longer accurate to distinguish between an 'oil policy' and a 'gas policy' and instead the two policies – combined with their contribution to the power sector - should be analysed within an all-encompassing 'energy policy'. Furthermore, developments in the gas sector have become closely interlinked with economic policy given that the gas sector is at the heart of many countries' diversification efforts.

Table 2 below shows net-balances for marketable gas in selected Arab gas producers. As exporters Abu Dhabi, Oman, Qatar, Algeria Egypt and Libya are further bound to long-term gas export contracts, which further diminish the availability of gas to their domestic markets. The responses to potential gas shortages have not been uniform across the Arab world. In resource rich countries such as Saudi Arabia, the strategy has been to increase domestic gas production through an intensive exploration and development program (including for higher-cost sour and shale gas) and by diverting natural gas to the petrochemical sector while burning liquid fuels in power generation at high opportunity cost. The current policy of no export/no import remains the dominant strategy in the Kingdom. As in the case of Saudi Arabia, Kuwait and UAE also burn liquid fuels in power generation, but the rise in demand has forced these GCC countries to secure natural gas supplies through imports, while intensifying efforts to secure more domestic gas supplies through intensive exploration and development programmes. In the UAE, long term solutions beyond natural gas such as investing in nuclear and renewable energy technology are currently being implemented, but these will play a limited role in alleviating the gas shortage over the next decade.

Table 2: Production-Consumption Balances in Selected Arab Producers, 2011

	Marketed production	Consumption	Annual growth in consumption, 2010-2011	Net balance
	Bcm	*Bcm*	*% change*	*Bcm*
Gulf states				
Abu Dhabi	43.0	39.7	4.2%	3.3
Bahrain	12.6	12.6	-1.2%	0.0
Dubai	1.8	17.4	7.9%	-15.6
Kuwait	13.5	17.0	17.1%	-3.5
Oman	26.5	17.5	-0.2%	9.0
Qatar	145.5	25.5	19.7%	120.0
Saudi Arabia	92.3	92.3	5.2%	0.0
North Africa				
Algeria	82.8	32.1	10.5%	50.7
Egypt	61.3	50.7	9.9%	10.6
Libya	7.9	5.4	-22.9%	2.5
Tunisia	1.9	3.7	13.1%	-1.8

Source: Cedigaz

In countries such as Oman, Algeria, Libya and Egypt, the rise in domestic demand is already presenting these countries with hard choices regarding the allocation of natural gas between domestic uses and exports. Egypt's highly volatile political climate since the overthrow of the Mubarak regime in early 2011 has meant the country has only been able to fulfill its export contracts through the help of Qatar and the UAE who have provided in-kind help via LNG cargo swaps with Egypt's contract partners. Even in Qatar, there is reprioritisation of its natural gas monetization strategy towards meeting domestic needs and diversifying its economy through the development of energy intensive industries. In Yemen, on the other hand, while the analysis suggests that diverting gas for domestic use in power generation may yield a higher value for the use of natural resource, the government has adopted the export option to secure additional revenues.

While strategies to meet the rising demand challenge vary considerably across countries, a regional default model seems to be emerging based on increasing natural gas supplies through exploration and development of associated and non-associated gas reserves. This even applies to countries with limited gas reserves such as Tunisia. Oil-rich countries can afford to leverage on their massive oil reserves against the failure of this strategy though at a high opportunity cost. Gas exporters, such as Egypt and Oman, can switch their gas exports to domestic consumption but must face the prospects of revenue losses. On the other hand, resource-poor countries such as Bahrain have little room to manoeuvre and must invest in infrastructure such as pipelines and LNG to enable them to import their needs otherwise they will face a gas deficit in the near future.

The default model of increasing domestic gas supplies is premised on heavily investing in the gas sector. Historically, in most Arab countries, the development of the gas sector has lagged behind the oil sector. In fact, for countries whose gas reserves are mostly in associated form, gas production was simply a by-product of crude oil production. However, with the rapidly expanding demand, fears of gas shortage and substitution between oil and gas in sectors such as power generation, water desalination and the petrochemical sector, the issue of gas is currently receiving much more weight in the formulation of long term energy policy. Recently, there has been a change in strategy and investment flows into the gas sector have increased both in non-associated gas fields and gas gathering infrastructure.

Foreign investment is playing an important role in this new drive. For example, Saudi Arabia which has traditionally precluded foreign investment in its exploration activities has allowed foreign companies to explore for non-associated gas in the Empty Quarter though with limited success so far. In gas exporting countries such as Qatar, Yemen, Oman and Egypt, foreign companies constitute the backbone of the gas industry and have been responsible for developing these countries' export capability. On the other hand, political complications have hindered some potentially important gas developments in the wider Arab region. Syria has since the beginning of political protests in early 2011, the Syrian 'Arab Spring' fallen into growing domestic civil infighting, preventing any new developments and exploration in the country's offshore territories. Neighbouring Lebanon has seen several years of delays in its own domestic gas exploration efforts owing to domestic political stalemate. In Iraq, the obstacles facing a successful gas development are paramount including the lack of a clear legal framework, security issues, and a fragile political system.

A common feature in most countries is that little progress has been made on the issue of adjusting gas prices to reflect opportunity cost or the long term marginal cost of gas production. The policy of low gas prices has intensified the gas supply challenge by providing little incentive for domestic and foreign companies to invest in exploration and production of gas. Low gas pricing policy has also affected the incentive to invest in local gas infrastructure in some countries. For instance, by incurring large losses by selling gas and LPG to the domestic market at below cost prices, the Egyptian state gas company (EGAS) has been unable to meet the financing requirements of connecting the residential sector to natural gas.

Until the late 2000s, very few governments have been willing to raise domestic prices for natural gas. Recognising the grave challenges ahead, there has been a slight change in attitude which seemed to occur towards the end of the decade. The since late 2010 raging Arab Spring that has impacted many North African and Levantine countries, however, has arguably contributed unhelpfully to the pursuit of previously aimed for domestic pricing reforms, including in the relatively unaffected Gulf states. For instance, a 2008 announcement by the Mubarak government of Egypt to remove subsidies on gas and electricity provided to energy intensive industries over a three-year period was subsequently halted by the overthrow of the government and its successor governments. While energy subsidies have begun to move back into the public attention, their structural reform across the region seems unlikely to be anywhere close, given that many governments, especially in countries with large populations on low incomes, fear the political consequences of rapid and radical gas price increases.

Inter-Arab Gas Trade

While the region is well endowed with gas reserves, the distribution of these reserves is highly uneven with some countries facing potential deficits while others have turned to gas exports to secure a major source of revenue. Such imbalances should in principle give rise to active inter-regional gas pipeline development and provide a regional solution to the gas challenge. Despite its high potential, inter-regional gas trade is still very limited with very few regional gas pipelines being built so far. The most well-known is the Dolphin Project linking Qatar, UAE and Oman. There is also the Arab Gas Pipeline from Egypt to Jordan, Syria, and Lebanon, although its future seems uncertain as Egypt experiences further domestic gas shortages itself and contracted deliveries to Jordan have been erratic for three years. An existing Egypt-Israel pipeline is no longer in use since Egypt cancelled its supply contract to Israel in April 2012. While many other projects have been discussed (such as to build pipelines from Qatar to Bahrain, from Iran to UAE, Oman and Syria), and in some cases agreements were signed, all of these and other regional projects face political and commercial obstacles and are unlikely to be realized anytime soon.

There are many obstacles that prevent the further expansion of regional pipelines. The region is entrenched in longstanding political problems and border disputes which have affected the development of the gas sector and the dynamics of gas trade. For instance, sanctions and/or threats of sanction have constrained the growth of the gas sector in Libya and Iraq. International and regional geo-politics and border disputes played an important role in delaying and limiting the geographical reach of the Dolphin pipeline during the late 2000s. Despite the rapprochement between Saudi Arabia and Qatar, Saudi Arabia is unlikely to rely on imported Qatari gas as this would raise serious concerns about regional influence and energy security for the Kingdom. In North Africa, regional rivalry between Morocco and Algeria militated against the development of pipeline export infrastructure to Spain until the late 1980s and early 1990s. Besides gas trade, regional disputes in the Maghreb have defined the trajectory of gas market development in countries like Morocco, whose continued aversion to contracted gas imports from Algeria remains the main stumbling block to a more meaningful penetration of natural gas in its energy mix.

Apart from political factors, expectations of cheap gas prices have been a key limiting factor in the implementation of regional agreements. Regional LNG exporters have direct experience of the price which they receive from international markets, including Asian premium markets whose price levels alongside high oil prices have spiralled up to $18/MMBtu, and somewhat lower ranges of around $10/MMBtu in the Atlantic basin since 2010. Since the development of its gas industry, Qatar has given priority to supplying high paying customers in Europe, the United States and Asia, rather than its neighbouring countries. Qatar has made it abundantly clear that there will be no additional exports to the region priced at $1.50/MMBtu, which is what UAE pays for Dolphin Phase 1 gas. Algeria, too, while it has held an interest in supplying neighbouring countries at a discounted rate, see with its increasing move towards higher-cost gas developments commercial incentives moving towards more LNG, rather than more regional pipeline gas. Thus, it is becoming clearer to all players that securing regional gas supplies at cheap prices is no longer a viable option and that gas prices must eventually increase towards global levels for any chance for regional gas trade to take off on a large scale.

Marketed gas production and end user consumption

We expect Arab gas demand to continue to grow strongly in almost every country in the region throughout the 2010s, contingent on available gas supplies. A remaining challenge in some OAPEC producers is the optimized use of natural gas between reinjection and end-user markets, further reducing unnecessary losses through flaring and shrinkage. Flaring of gas has been vastly reduced across Arab producers since the 1970s and 1980s, when the majority of associated gas was not used productively. By the 2010s, flaring and venting continued to fall, particularly in Algeria and Libya, while flaring is negligible in GCC producers Kuwait, Qatar and Saudi Arabia. Iraq continues to form an important exception and continues to flare more than half of its gross production, in addition to further losses thereby significantly curtailing the amount of gas available to its domestic economy (see Table 3 and Figure 48 below). With plans to curtail flaring and to produce an increasing share to market, Iraq's flaring rates should significantly fall over the coming years as more projects to capture associated gas come online.

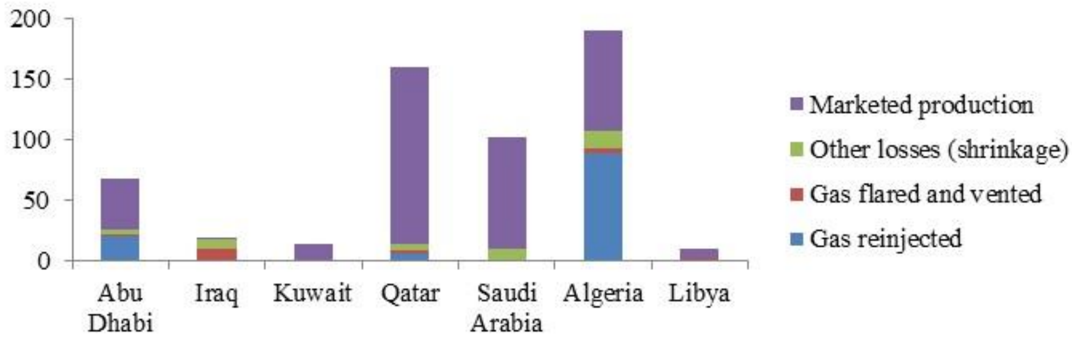
Table 3: Evolution of Flaring in OPEC Countries in 2011

	Bcm		**% Share**		**Growth**
	2010	*2011*	*2010*	*2011*	
OAPEC					
Algeria	5.0	3.6	4.0%	2.8%	-28.0%
Iraq	7.6	9.6	6.0%	7.6%	26.9%
Kuwait	0.2	0.2	0.2%	0.2%	0.0%
Libya	3.5	1.3	2.8%	1.0%	-62.6%
Qatar	2.8	2.7	2.2%	2.1%	-3.6%
UAE	1.0	1.0	0.8%	0.8%	1.0%
Other OPEC					
Angola	7.0	7.2	5.6%	5.7%	2.0%
Ecuador	0.5	0.5	0.4%	0.4%	10.2%
Iran	16.6	16.7	13.2%	13.2%	0.4%
Nigera	16.5	17.5	13.1%	13.8%	6.4%
Venezuela	6.7	8.4	5.3%	6.6%	25.0%
Total OPEC	**67.3**	**68.7**	**53.5%**	**54.3%**	**2.0%**
Non-OPEC	**58.6**	**57.9**	**46.5%**	**45.7%**	**-1.2%**

Source: Cedigaz

Aside from flaring, reinjection of natural gas production remains a major constraint on domestic market supply in OAPEC producers UAE and Algeria (see Figure 48 below); and outside OPEC, for Arab producer Yemen, which continues to reinject around two thirds of its gas production into oil and gas fields.

Figure 47: From gross to marketed production 2011, in Bcm



Source: Cedigaz

Looking ahead: Gas exports and imports

Tables 4 shows imports and exports of gas for 2011-2012 divided into pipeline gas and LNG. With only limited intra-regional trade, an increasing number of Arab countries have started to import LNG, including OAPEC members Kuwait, Oman, and the UAE (Dubai, in the future also Abu Dhabi). Although volumes remain comparatively small, we believe that a regional trend will move towards a further increase in net-imports and a gradual reduction in net exports by most current producers, with the notable exception of Qatar and possibly Algeria and Libya.

Key OAPEC countries which could increase gas exports post-2015 are Qatar, and Iraq. The Qatari case is in many ways the most straightforward: the moratorium or “gas pause” is not due to be lifted until 2015, and may indeed be extended indefinitely, after which an increase could be achieved by debottlenecking the existing trains which would provide nearly 19 Bcm/year of additional exports. Assuming a decision to increase production further in 2015, any new project would require a minimum 4-5 year lead time to develop which would mean very little chance of additional exports prior to 2020. Additional production could as easily be channelled towards domestic industrial development or regional gas exports (assuming a willingness to pay international prices) as to additional LNG exports. Existing LNG trains plus debottlenecking would bring capacity close to 140 Bcm and it seems unlikely that a nation with a population of around 250,000 will want to increase its exports substantially beyond that level.

In 2010, there was considerable optimism from international companies that Iraq could become a major exporter of gas prior to 2015, with volumes up to 15 Bcm available for the Nabucco pipeline to Europe via Turkey. Developments in subsequent years, however, provided no foundation for a belief in a near-term turn-around of Iraq's current gas supply picture, which remains subject to considerable uncertainty. The resolution of the institutional problems between Baghdad and the regions – in particular the administration in Kurdistan – combined with the need to devote substantial volumes of gas to domestic reconstruction and reindustrialisation, in our view will take several more years. We would be surprised if export volumes in the range of 10-15 Bcm/year could be arranged prior to 2020 and should they were, confidence in the security of these supplies would require a dramatic and lasting improvement in the security situation in the country. Assuming that an exportable surplus of gas was to become available in the north of the country, we think it as likely that this gas could be directed towards the Mashreq, given that it is unlikely that Egypt will be able to satisfy the needs of those countries, and may even be seeking to retain gas for domestic consumption rather than maintain current levels of exports.

Outside Arab countries but with regional relevance, Israel has in recent years emerged as a potential future regional gas player with both pipeline and LNG export potential. After new gas trade agreements concluded with the Palestinian Authority and Jordan in January and February 2014, the materialization of Israeli exports into the wider region may only be months away. However, Israel's gas trade situation will be complex both commercially and politically. In the future, arrangements could be made to use existing pipeline infrastructure to export Israeli gas into Egypt (depending on Egypt's future domestic gas developments) and/or to export Israeli gas via Egypt's (currently underutilised) LNG facilities; or alternatively through the Arab Gas Pipeline to Mashreq countries and as LNG from Jordan.

With continued buoyant domestic gas demand throughout the region, most remaining exporters, including the UAE, Oman, Egypt, Syria and Yemen are by contrast expected to divert future production rises increasingly into their domestic markets. Regionally, Lebanon and Morocco are currently exploring for offshore hydrocarbon resources and may yet turn the picture in their favour, although expected volumes are likely to be on more modest levels, and the pace of development inside their markets is likely to render any such prospects more close to the 2020s.

Table 4: Middle East and North Africa Gas Imports and Exports 2011-2012, in Bcm

	Imports				**Exports**			
	Pipeline		*LNG*		*Pipeline*		*LNG*	
	2011	2012	2011	2012	2011	2012	2011	2012
Gulf								
Kuwait*	-	-	3.2	2.56	-	-	-	-
Oman	2.0	2	-	-	-	-	10.9	11.2
Qatar	-	-	-	-	19.2	19.2	102.6	105.4
UAE*	17.3	17.3	1.4	2.05	-	-	8.0	7.6
Yemen	-	-	-	-	-	-	8.9	7.1
North Africa & the Levant								
Algeria	-	-	-	-	34.4	34.8	17.1	15.3
Egypt	-	-	-	-	1,8	n/a	8.6	6.7
Jordan	0.8	-	-	-	-	-	-	-
Libya	-	-	-	-	2.3	6.5	0.1	n/a
Syria	0.3	-	-	-	-	-	-	-

Notes: *LNG import volumes for 2012 are Oxford Institute for Energy Studies estimates
Source: BP, Oxford Institute for Energy Studies

LNG imports are expected to account for the vast majority of new gas imports in the later 2010s and early 2020s, owing primarily to missing gas resources available for export within the region and with Qatar being expected to continue to focus on its LNG export business in the Atlantic Basin and Asia Pacific. The UAE and Kuwait are expected to account for most incremental LNG demand on the Arabian Peninsula, whilst Jordan and possibly Lebanon offer new LNG markets in the Levant. In North Africa, Morocco may yet turn towards LNG, albeit current exploration and some scope for more pipeline imports from Algeria leave North Africa as perhaps the only spot in the region with potential for more pipeline trade, albeit small in volume.

V. Geopolitical Developments in the Arab World and Their Implications on the Oil and Gas Sector[4]

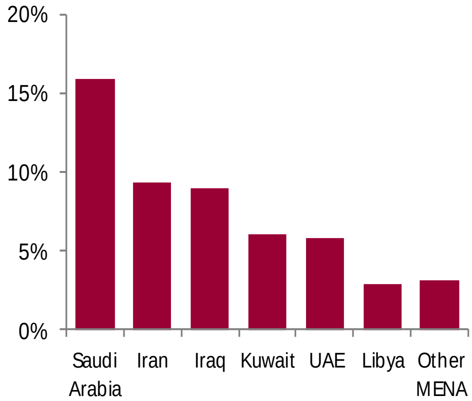
More than three years have passed since the Arab Spring began in Tunisia. Several long-serving leaders have left office and ruling elites across the Arab world have been shaken to the core. In countries like Libya, Egypt, and Yemen, transitional governments are still grappling with political, social, and economic problems, while the Gulf States have increased social spending as they attempt to temper public discontent. At the extremes, civil war rages on in Syria, with a heightened risk that the crisis could spill over to its neighbours, upsetting a precarious balance in these countries. In many ways the outcome of the Arab Spring is still in flux three years on. It will be some time before the dust settles and the new political shape of the region is known. In parallel to the Arab Spring, the international controversy surrounding Iran's nuclear programme has worsened since early 2010, leading to the most comprehensive international sanctions programme yet seen against one of the Middle East's most important oil and gas producers. In addition Iraq still looms in the background, continuing to suffer from volatility in both its political environment and security situation.

The spreading instability across MENA has raised widespread concerns about oil supply disruptions and reignited the ever-recurring debate about energy security. In particular, the region's reliability as an energy supplier, and the efficacy of market mechanisms in coping with supply disruptions, have re-emerged as key topics for policymakers. This should come as no surprise. After all, MENA accounts for 52 per cent of global proved oil reserves and almost a third of global oil production, while holding 47 per cent of the world's proved gas reserves (see Figures 49 and 50). While concerns about energy security are not new, the context of the debate has fundamentally changed. The global

[4] This section is based on El-Katiri, L., B. Fattouh and Richard Mallinson (2011), 'The Arab Uprisings and MENA Political Instability: Implications for Oil & Gas Markets', MEP 8, Oxford: Oxford Institute for Energy Studies.

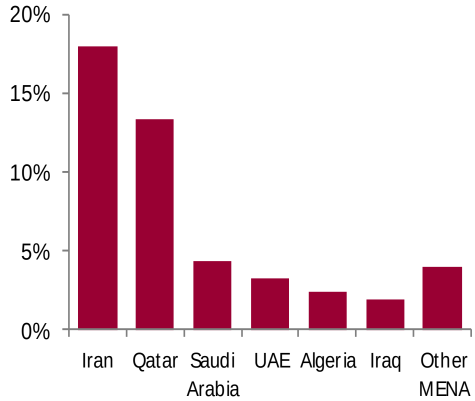
economy is still recovering from the deepest financial crisis since the Second World War; global energy demand dynamics and trade flows continue to shift towards non-OECD countries, mainly to Asia; and the shale gas and tight oil revolution has renewed US aspirations of energy independence or, at least, of a steep reduction in its dependency on imported oil.

Figure 48: Proved oil reserves, % of global total



Source: BP (2013)

Figure 49: Proved gas reserves, % of global total



Source: BP (2013)

The many historical precedents of oil disruptions from the region do not help allay energy security concerns. With international oil prices beginning to rise from 2010, there were serious fears among market and political actors that any further increase in prices would put at risk the fragile recovery of the global economy. These concerns proved justified – in the sense that many disruptions did eventually occur and oil prices did rise, especially following the Libyan revolution in 2011, and in early 2012 when fears of a potential military confrontation between Iran and the USA intensified. However, the short-term effects on oil and gas markets of the recent events in the region have been less dramatic than originally feared. The Arab Spring did not spread to the large Gulf oil producers; the rise in oil price induced by political and geopolitical factors proved to be transient; and oil and gas markets have shown relative resilience in filling the supply gap and in redirecting oil and gas trade flows.

Beyond the immediate impact of the past three years of political turmoil in the MENA, however, we argue that it is the more subtle, long-term effects of regional political instability and international sanctions that are likely to make the most lasting mark on regional oil and gas markets. Potential repercussions are likely to be felt through a long-term effect on production capacity expansion across many MENA energy producers (including oil and gas producers in the MENA formally unaffected by the Arab Spring and political sanctions) which has resulted from several years of an unstable regulatory and investment environment, deteriorating security, and a lack of energy pricing reform.

Short-term effects of political turmoil on MENA oil and gas supply

While the final outcome of the Arab uprisings is as yet unknown, one certainty is that the Arab Spring has already earned its place in history as creating one of the oil market's largest disruptions in oil supplies. More than 1,600 million barrels of oil production disruption has been caused over the last three years by outages arising from the Arab Spring and sanctions linked to Iran's nuclear programme. Supply disruptions from the MENA region since December 2010 come second only to oil market losses incurred as a result of the Iraqi invasion of Kuwait in 1990 (see Table 5 below). And unlike previous cases of conflict affecting the MENA region's oil supply – such as the 1950s Suez War, the 1960s Six-Day War, and the 1970s Arab-Israeli War – the Arab Spring has, for the first time, also affected gas markets, albeit to a far lesser degree than oil. Below, we assess the short-term effects of the Arab Spring and Iranian sanctions on oil supply from the MENA region and on oil prices, and then its impact on regional gas markets.

Physical oil supply disruptions

A striking feature of the Arab Spring has been that its actual impact on oil and gas production has varied widely between affected countries. While significant volumes of production were lost in some MENA oil and gas producers, others have seen their energy sectors less directly impacted by popular protest. The most significant short-term impact of the Arab Spring on oil production has undoubtedly been in Libya. This North African OPEC member can produce over 1.5 million b/d and plays an important export role in global oil markets. Libya's output virtually halted in the summer of 2011 as civil war raged across the country, but it returned more quickly than many in the market had anticipated, reaching 1.4 million b/d in early 2012. Rising security concerns and political instability disrupted Libyan production significantly again in 2013, as strikes and protests at fields and export terminals took an increasing toll on the oil sector (see Figure 51). Militia groups formed during the revolution have been central to the more recent problems, as weak central government security forces have been unable to exert control. The extent of the disruption is enormous. In 2011, 411 million barrels of Libyan output were lost due to the revolution. The total annual disruption fell to under 75 million barrels in 2012 as oil fields were rapidly restarted after the revolution, but in 2013 an estimated 249 million barrels were disrupted as a result of the various protests that increased in significance as the year went on.

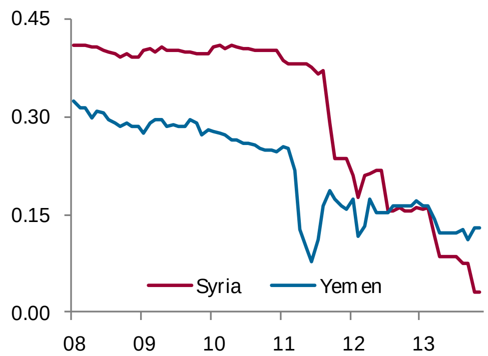
Violence linked to uprisings has also impacted production elsewhere in the region. Syria has been on an inexorable descent into civil war and bloodshed, as the Assad regime has proved unwilling to release its grip on power. Syria is a relatively minor oil producer, averaging 0.4 million b/d in 2010, but this figure has reportedly fallen below 20 thousand b/d as fighting and international sanctions disrupted the entire oil sector. As of January 2014, the Syrian government reported total economic losses, as a result of the domestic crisis, of over $20bn, largely due to losses incurred by the country's hydrocarbon sector – both through direct (damage to infrastructure, spillage, and theft) and indirect (ceased oil exports) losses. Yemen, at around 0.3 million b/d prior to the Arab Spring, is another relatively minor producer. Even before 2011, Yemen was a fragile state, but it has been further destabilized and now sees frequent militant attacks disrupting oil production, particularly due to bombings of the 0.2 million b/d Marib pipeline. Between early 2011 and the end of

2013, 215 million barrels of Syrian and 108 million barrels of Yemeni oil production have been lost (see Figure 52).

Figure 50: Libyan oil production, million b/d

Source: OPEC, *MEES*

Figure 51: Syria and Yemen oil output, million b/d



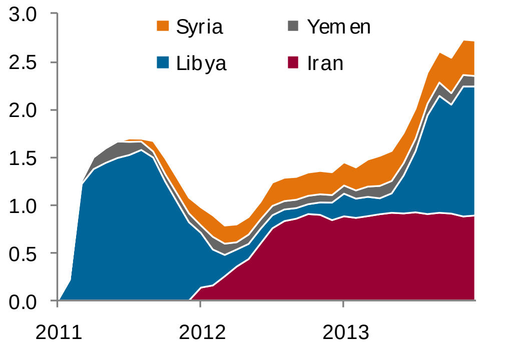
Source: EIA

Egypt has seen the impact of the Arab Spring on its energy sector play out in a fundamentally different way. Despite fraught politics, the episodes of serious violence before and after the overthrow of President Hosni Mubarak have not had a direct effect on Egyptian oil and gas output – given that the initial concentration of political protest through youth protest movements occurred in Cairo, while the Egyptian oil and gas fields, which are mainly in the Western Desert and offshore, are relatively isolated. Oil production has held remarkably steady around the 0.72 million b/d level. Egypt's energy sector has primarily been affected through the lack of badly needed investment in the maintenance and expansion of the country's oil and gas production capacity, with natural gas fields and refineries being particularly affected. The lack of investment into new production capacity that dates back to the mid-2000s, but which has been further delayed by near-political paralysis since early 2011, is likely to fuel Egypt's rapidly growing gap between domestic production and consumption of crude oil and oil products. This gap has curtailed the country's ability to generate much-needed export revenues to fund the process of rebuilding Egypt's post-revolutionary economy and, alongside the loss of tourist revenue and of foreign investment, has left Egypt reliant on the Gulf Cooperation Council countries to supply Egypt's growing domestic energy gap.

Short-term supply disruptions due to the Arab Spring have happened in parallel with supply disruptions in other parts of the MENA region. Despite the absence of a secular youth-led Arab Spring uprising in its own right, Iraq has also been affected by the spill-over from events in other countries during the Arab Spring, particularly by the increasingly sectarian conflict in Syria. Rising sectarian tensions have led to an upsurge in violence in Iraq including bombings of the Kirkuk–Ceyhan export pipeline and attacks on other oil infrastructure in northern Iraq. Beyond the well-publicized maintenance work at the southern Basra terminal – which began in September 2013 and will continue into spring 2014 – that has slowed the growth of Iraqi oil exports, the ongoing dispute between Baghdad and the Kurdistan Regional Government over exports from Iraqi Kurdistan has limited Iraq's potential in the oil market. Iran has seen the most dramatic losses, as a result of US sanctions on Iranian crude exports linked to the Iranian nuclear crisis. Since mid-2012, Iranian oil production has dropped by around one million b/d to around 2.7 million b/d and is likely to remain near this level unless a comprehensive deal can be reached between Iran and the P5+1 world powers.

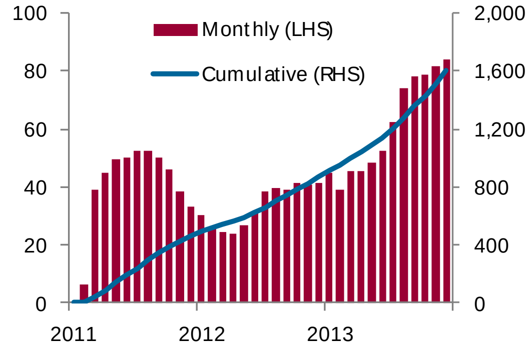
The combined production oil losses from the Arab Spring disruptions (Libya, Syria, and Yemen) and the Iranian sanctions have averaged 1.5 million b/d since the start of 2011. The highest level of disruption to date occurred in September 2013 when, on average, over 2.7 million b/d of production was offline from these four countries. At the end of 2013, the accumulated lost MENA crude production (including Iran) over the previous three years exceeded 1,600 million barrels. The amount of oil production lost in recent years is significant even when compared with some other major oil market disruptions (see Figures 53 and 54 and Table 5).

Figure 52: MENA supply disruptions, million b/d



Source: Authors' calculations based on OPEC supply estimates and EIA International Energy Statistics

Figure 53: Lost MENA oil output, million barrels



Source: Authors' calculations based on OPEC supply estimates and EIA International Energy Statistics

Table 5: Historic disruptions to oil production, million barrels

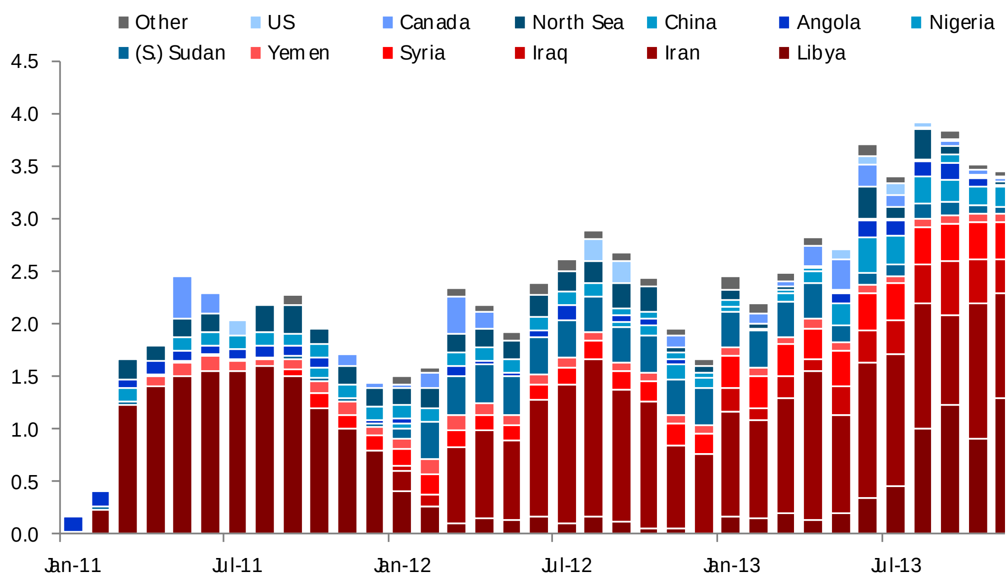
Event	Dates	Total loss (mb)	Peak supply loss (mb/d)
Historic			
Iranian revolution	Nov 1978 - Apr 1979	678	5.3
Iraq Invasion of Kuwait	Aug 1990 - Dec 1991	2,488	5.35
US Invasion of Iraq	Mar 2003 - Dec 2011	1,417	2.4
Current			
Arab Spring (Libya, Yemen & Syria) - continuing	Jan 2011 - Dec 2013	1,058	1.85
Iranian sanctions - continuing	Jul 2012 - Dec 2013	543	0.92
Arab Spring and Iranian Sanctions		**1,601**	**2.73**

Source: Authors' calculations based on data from *MEES* and EIA International Energy Statistics. The loss is estimated as the difference between the maximum level of oil production in the six-month period prior to the disruption and the actual supply during

Impact on oil prices

The disruptions in the region have naturally raised significant anxieties in the oil market, and at times have contributed to a rise in the oil price. Parallel production shutdowns outside MENA producers, including significant losses in Nigerian output and shutdowns in South Sudan's (albeit comparably small) oil production, exacerbated market anxieties. Globally, supply disruptions rose rapidly in early 2011 and exceeded 1.5 million b/d for most of the year, largely due to the revolution in Libya (see Figure 55). In this context, the prospect of a new sanctions round targeting Iranian oil in July 2012, together with Iranian threats of closing the Strait of Hormuz, prompted a round of concerns in late 2011 that oil prices could be driven to extremely high levels.

Figure 54: Global supply disruptions by country, million b/d



Source: Authors' calculations based on OPEC supply estimates, EIA Petroleum Supply Monthly, EIA International Energy Statistics and various national government statistics

Despite these big supply losses, the actual effect of the Arab Spring and Iranian sanctions on oil prices has fallen far short of alarmist projections. This is in part because the Syrian crisis did not spill over to and further destabilize Iraq to an extent that reduced its oil production significantly; Iran did not make any move to close the Strait of Hormuz; and oil markets have shown remarkable resilience in dealing with those supply disruptions that did materialize, through adjustments in price levels but, more importantly, through adjustments in price differentials that helped oil markets redirect oil flows and encouraged inventories to be drawn down. The Gulf Cooperation Council (GCC) states have, with the partial exception of Bahrain, remained largely unaffected by the Arab Spring, leaving those key producers with spare capacity – primarily Saudi Arabia and to a lesser extent Kuwait and the UAE – as stable and reliable suppliers.

The events of the Arab Spring in early 2011 were indeed the catalyst for prices moving back above $100 per barrel from February 2011 onwards, and only once in the last three years has the monthly average price fallen below that level. Yet, geopolitical events have not offered sustained support for oil prices. Events have triggered brief price increases, especially in early 2011 following the start of the Libyan uprising; in early 2012 on fears of a military confrontation between Iran and the USA and anticipation of Iranian oil sanctions; and again in early 2013 over a number of security concerns in North Africa ranging from oil disruptions in Libya (paralleled by French intervention in southern neighbour Mali), to protests in Egypt, and growing concern about security in the aftermath of Algeria's In Amenas attacks. A feared spike in prices to new record highs, however, has not materialized. Instead, the oil price has generally been stuck in a $100–110 per barrel range.

There are several factors that explain why prices have not risen further despite the significant disruptions to supply experienced over the last three years:

(i) *Spare capacity inside OPEC.* The availability of sufficient spare oil production capacity, mainly held by Saudi Arabia and to a lesser extent by other Gulf States, is one of the most likely reasons for oil prices remaining within a narrow band. These countries have proactively used their spare capacity to fill the gaps left by Arab Spring disruptions and Iranian sanctions. The combined output of Saudi Arabia, Kuwait, Qatar, and the UAE has risen from around 14 million b/d prior to the start of the Arab Spring to above 16 million b/d for much of the last three years. This has not just been an increase in absolute terms. Problems affecting other OPEC

members have led to the Gulf States' share of total OPEC production rising above 50 per cent since the beginning of the Arab Spring – touching 55 per cent in September 2013.

Figure 55: Saudi Arabia oil output, million b/d

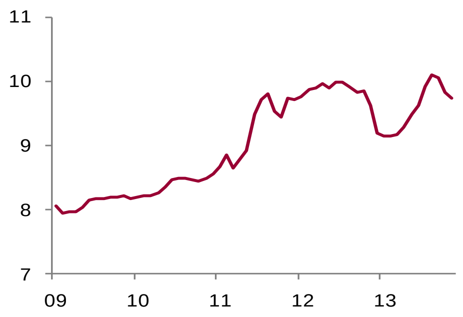
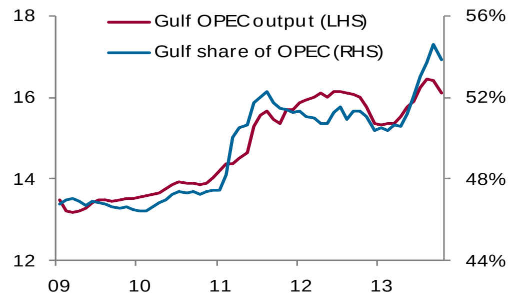


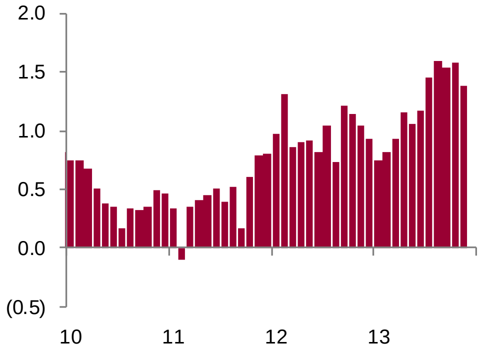
Figure 56: Gulf OPEC states output, million b/d



Source: OPEC

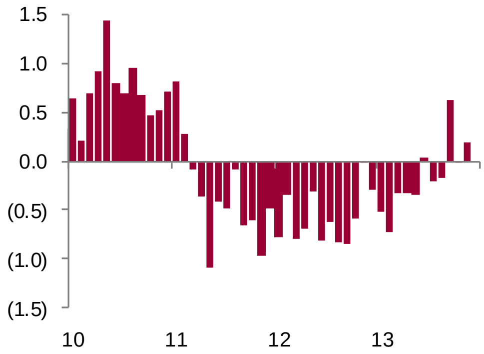
(ii) *North American unconventional oil production growth.* The last three years have also seen the rapid growth of US tight oil production and this has helped to keep the market well supplied. In contrast, non-OPEC supplies outside the USA have generally disappointed. Mature basins such as the North Sea and in Mexico are declining, and potential sources of supply growth such as Brazil and Kazakhstan have been beset by delays and disappointment (see Figures 58 and 59). Nevertheless, US output growth has prompted excessive optimism about the long-term supply outlook and the need for oil supplies from the Middle East. The recent shift in the oil market's fundamental narrative from one of oil scarcity, to one where oil is abundant and it is expected that spare capacity will rise in the coming years, seems to have also mitigated fears over the potential impacts of disruptions.

Figure 57: US output growth, y/y, million b/d



Source: EIA

Figure 58: Rest of non-OPEC, y/y, million b/d



Source: EIA

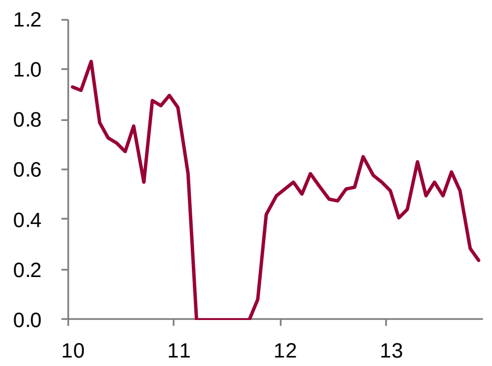
(iii) Limited demand growth. Subdued global oil demand growth has also helped to mitigate the impact of MENA region supply losses. Global oil demand increased by 0.5 million b/d in 2011, then by 0.9 million b/d in 2012, and rose to 1.2 million b/d in 2013. This growth has prevented the market from becoming oversupplied but has also not led balances to tighten to the extent that oil prices would be forced to find a higher price range.

It is therefore the combination of strong US tight oil growth, limited demand growth, and increased output from the Gulf States that has helped the oil market weather the supply outages caused by the Arab Spring and Iranian sanctions. However, by the same token, it is these very supply outages, together with the risk premium associated with potential further outages, which have contributed to keeping oil prices elevated above the $100/barrel mark in recent years.

The Arab Spring and regional gas markets

Recent events have also had an impact on gas production across MENA, although the region's overall limited role as a global gas supplier, and Qatar's stability during the Arab Spring, has meant that the effect has been far lesser on gas than on oil markets. Qatar is the largest LNG exporter in the world and has been insulated from disruptions throughout the Arab Spring. Other producers have experienced a range of direct and indirect effects. Libya, Egypt, Yemen, and Algeria have each seen periods of disruption to their gas exports. Libyan pipeline exports to Italy were offline during the civil war in 2011 – with Greenstream pipeline's closure to Italy in 2011 being the longest disruption to regional trade in pipeline gas so far – and have been disrupted by protests in late 2013. However, the impact of the loss of Libyan gas on the Italian and European markets has been minimal and ENI has been able to meet its customers' demand for gas without much difficulty given subdued gas demand and comfortable storage levels. Yemen's gas pipeline to the Bahlaf terminal has been bombed multiple times by insurgents, with the most significant disruption occurring in spring 2012, before the planned maintenance of the export terminal.

Figure 59: Libyan gas exports, bcm per month



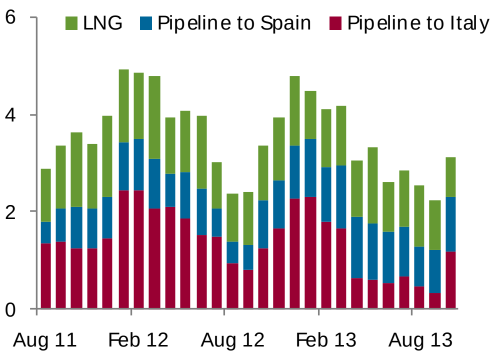
Source: SNAM and Bloomberg data

Figure 60: Yemeni gas exports, bcm per month

Source: Bloomberg data

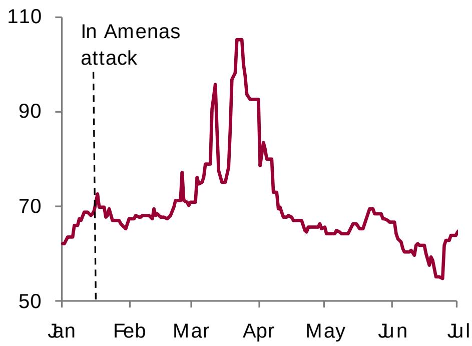
Algeria, the MENA region's second largest gas exporter, has, for most of the duration of the Arab Spring, maintained relative stability, despite recurring protests in the capital Algiers. The Algerian government's appearance of having full control over insurgent groups nevertheless came to a sudden halt in January 2013 with a devastating terrorist attack on the country's gas processing facilities in In Amenas. The reduction in gas output from In Amenas (which accounts for around 10 per cent of Algerian gas production) following the attacks has contributed to declines primarily in Algerian pipeline exports in 2013, although weak demand in the key markets of Spain and Italy (down by 8 per cent and 6 per cent from their 2012 levels respectively) and the renegotiations of take-or-pay gas contract provisions between the Algerian government and ENI, have also played their part. The impact of the In Amenas crisis on European gas prices was short-lived and negligible overall; UK NBP prices, as an indicator of European prices, rose around 4.4 per cent after the initial attack, but dropped back shortly after (see Figures 62 and 63).

Figure 61: Algerian gas exports, bcm/month



Source: Enagas, SNAM, and Bloomberg data

Figure 62: NBP prices in 2013 pence/therm



Source: Bloomberg data

In general, disruptions to North African gas production have had limited impact on global, particularly European, gas markets due to a variety of factors. Inside Europe, which is one of the main markets for North African gas, low post-recession gas demand, together with ample pipeline gas and global LNG supplies, has prevented Libyan and Algerian supply disruptions from causing widespread market concern. Indeed, some have argued that the short-term disruption came at a commercially favourable point in time for ENI, which was struggling to fulfil its take-or-pay commitments for Russian gas in any case. More generally, outside Qatar and its dominance in the LNG market, MENA gas does not have the same significance as MENA oil. Despite the region's large natural gas reserves, its share in global production remains quite small and most of the gas produced is used in domestic markets. Furthermore, with MENA gas consumption growing rapidly over the last 10–15 years, driven largely by demand for electricity, energy-intensive industries, and by artificially low prices, the region (outside Qatar) will continue to play a relatively modest role in international gas exports. Indeed, many countries in the region have already turned into net gas importers, and the contribution of some of the region's traditional LNG exporters, such as Oman, Egypt, and Algeria, to global LNG trade is expected to decline in the next decade, as domestic demand continues to grow faster than domestic supply and as new global players such as Australia, East Africa, and the USA turn into LNG exporters.

The Arab Spring's long-term effects on the MENA's energy sectors

Notwithstanding the fact that oil and gas markets have shown resilience in dealing with the recent acute disruptions originating from MENA, the Arab Spring's more indirect effects, whose full repercussions are expected to be felt over the long term, are likely to make the most lasting mark on oil and gas markets. Most importantly, political turmoil and fear of regional spill-over will alter many regional oil and gas producers' priorities in social spending; this will affect sectoral policies such as the ability of governments to implement large energy infrastructure projects and to adjust their fiscal terms to attract foreign investment, in view of the fact that many MENA oil and gas producers have changed their priorities relating to the maximization of oil and gas resource rents. It will also reinforce pre-existing difficulties in reforming the region's domestic energy markets, most importantly energy prices, with likely consequences for medium- and long-term domestic energy demand growth, which will affect some of the MENA oil and gas producers' export capacity. The Arab Spring is also likely to affect foreign companies' investment decisions into the wider region as political instability, the threat of spill-over, and the deteriorating security thereof increase country-based and regional risk ratings and hence the cost and the uncertainty of investing in the region's energy sector.

Increase in social spending

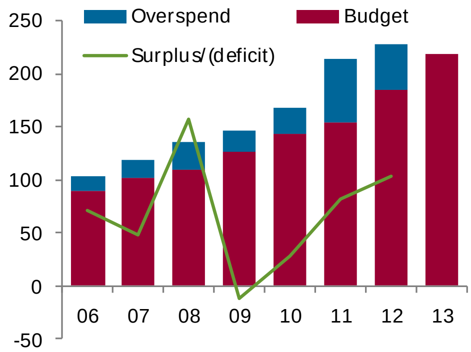
Many of the MENA region's larger oil and gas producers – principally the Gulf monarchies and, to a lesser extent, North Africa's hydrocarbon producers – have historically overseen large welfare states that have channelled oil and gas revenues into social security, health, education, and the provision of employment as part of these countries' implicit social contracts. Many of these countries, including those unaffected by the immediate repercussions of the Arab Spring, have responded to the upsurge in political turmoil across the region by further increasing their social spending. Across the region, spending is being directed towards areas such as housing, employment creation, unemployment benefits, subsidies, higher wages for government workers, and compensation for rising living expenses. For instance, Saudi Arabia's budget rose from $127 billion in 2009 to $219 billion in 2013, largely because of big increases in social spending and infrastructure projects (see Figure 64 below). In 2014, the government set its budget spending at a record $228 billion. In Kuwait, government spending jumped by 14 per cent for the fiscal year 2012/13, and again by over 50 per cent for the first half of the fiscal year 2013/2014, much higher than originally expected. The increase in government spending was driven almost entirely by current rather than capital expenditure; that is benefits, subsidies, and government salaries together with public sector 'job creation'.

In addition to increased spending on their local economies, the oil-rich Gulf States have increased their financial support for some of their ailing strategic partners in the region. For instance, following the protests in Bahrain and Oman, the Gulf Arab foreign ministers pledged $20 billion in financial aid over 10 years to the two neighbouring Gulf countries. The national armies of Saudi Arabia and the UAE were dispatched, and no financial efforts were spared, to assist the Bahraini government in restoring order following its own political protests that escalated into violence in spring 2011. Gulf support has also been instrumental in keeping Egypt's severely restrained domestic energy sector from collapsing under several years of neglect and lack of investment. While Egypt's production level for oil has remained mostly stable throughout the Arab Spring, the country's surging domestic demand and large pre-existing export commitments for Egyptian natural gas have meant that the country's energy sector would have been at the point of virtual collapse by 2013, were it not for a series of Gulf aid packages. Kuwait, Saudi Arabia, and UAE pledged a $12 billion aid package to Egypt following President Morsi's overthrow by the military, in addition to in-kind aid and loans in the form of Qatari and Emirati LNG swaps and fuel supplies from the UAE, Kuwait, and Saudi Arabia.

To fund their increasing expenditure outlays, oil exporters have become even more dependent on high oil revenues, forcing them to assume higher oil prices in order to balance their budgets. Indeed, the oil price assumed by MENA oil exporters in their official budgets has risen sharply in recent years, from a reported range of $40–55 per barrel in 2008 to above $70 per barrel in 2014 for Kuwait, and $100 per barrel for Iran (see Figure 65). Research by APICORP suggests that effective break-even prices, which factor in the cost of production on a full life-cycle basis, are significantly higher, with estimates of the OPEC output-weighted average having risen to $105 per barrel in 2013. Many analysts, therefore, expect oil producers to be more assertive in their output policies, to defend prices should oil prices fall to levels deemed unacceptable. However, it could be overly simplistic to treat a calculated break-even price as indicative of the new price floor for the world's major producers. Key Gulf oil producers such as Saudi Arabia, Kuwait, and the UAE have low foreign and domestic debt, as well as large reserves of foreign currency, which provides a large fiscal buffer – meaning that they are in a better position to deal with lower oil revenues for a short period. Also, producers do not have to balance their budget on an annual basis. However, the increase in social spending puts pressure on governments to maximize the rent captured from oil exports by supporting prices.

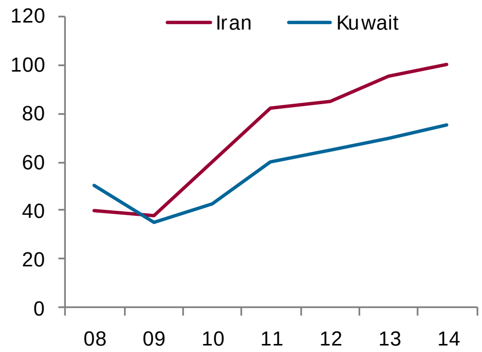
While the increased break-even price implies greater dependency on high oil prices, a potential fall in the oil price could induce some of the producers to increase output to compensate for lower revenues. Under certain conditions, this could be self-defeating if the overall increase in supply leads to a sharp fall in oil prices and a decline in oil revenues. Nevertheless, the pressure to increase social spending can induce some producers to release more oil to the market rather than to restrict output – depending on market conditions, the strategic responses by key producers, and the degree of cohesion within OPEC.

Figure 63: Saudi Arabia public expend., $ billion



Source: Kingdom of Saudi Arabia Ministry of Finance

Figure 64: Oil price in budgets, $ per barrel



Source: Media reports of Iran and Kuwaiti government budgets

Delay of energy pricing reform

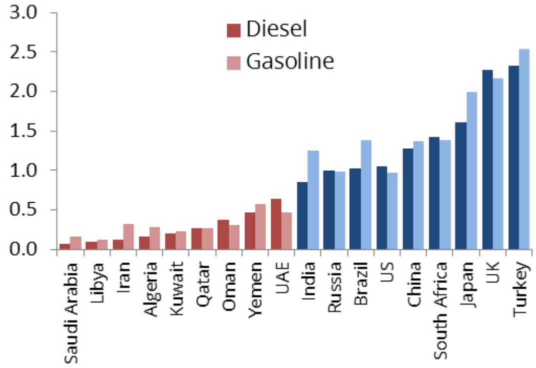
Energy subsidies are one of the most contentious forms of government spending, not only in the Middle East but across many oil and gas producers and emerging economies. In most MENA economies, liquid fuel and natural gas are sold on domestic markets at prices significantly below their international market value (implicit government transfers, or subsidies), or below the cost of import in the case of energy imports (via explicit subsidies), with the result that regional energy prices have, for many decades, been among the lowest in the world (see Figure

66). Subsidies are an indirect form of social spending and, in the case of explicit subsidies, have made a major contribution to the rapid rise in government expenditure witnessed in many countries across the region. For example, fuel subsidies are budgeted by the Egyptian government at around $14.3 billion for the fiscal year of 2013/2014, about a sixth of total governmental expenditure and more than the equivalent of total Gulf aid pledged to Egypt for the running fiscal year.

Because subsidies continue to be a popular form of government spending, the Arab Spring is likely to reinforce governments' reluctance across the MENA to reform domestic energy prices in the immediate future. Past cases of delayed reform as a direct result of the Arab Spring are those of Egypt, which had government plans to reform energy subsidies prior to the ousting of the Mubarak-led government in 2011, and Bahrain, whose domestic fuel price reform plans were quickly dropped from the government's agenda following the outbreak of popular unrest in February 2011.

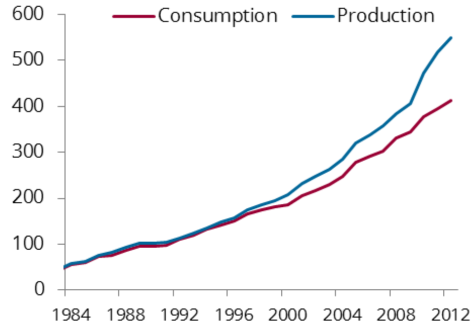
Social pressure is likely to continue to at least delay such reforms, in order to fend off further unrest. All else being equal, this is likely to result in continued solid growth of energy consumption in these countries. For instance, in Egypt, political turbulence has stalled the reform of energy subsidies and exacerbated delayed payments to foreign gas companies. This has resulted in rapidly rising demand and delays to new supply projects, forcing the government to divert gas intended for export clients to meet domestic demand. In the summer of 2013 Egypt relied on help from Qatar, which donated five LNG cargoes that were used to meet Egypt's contractual supply commitments, to maintain this unsustainable balancing act. Egypt is only a particularly acute case of a wider regional problem. Despite the region's massive reserves, rapidly rising demand for natural gas is absorbing almost all of the increases in production over the last ten years.

Figure 65: 2012 Retail prices in selected MENA and non-MENA countries, US$ per litre



Source: World Bank (2013)

Figure 66: ME gas supply and demand, bcm/year



Source: BP (2013)

Furthermore, many MENA governments will anxiously focus on creating jobs for young people, in the hope of allaying their socio-economic grievances. In gas-rich countries, these efforts will take the form of investment in energy-intensive industries using gas as feedstock. Policymakers in the region have invariably considered the availability of relatively cheap gas feedstock as a source of competitive advantage for their economies, allowing them to attract foreign investment, add value to their resources, and create job opportunities for unemployed young people. Although many experts are sceptical about the viability of this strategy, the recent uprisings will only reinforce this approach. As a result, instead of pushing for export polices, some MENA governments will increasingly want to use gas domestically to create jobs and improve living conditions. This could lead to smaller volumes of gas being available for export than would otherwise have been the case, and may further reinforce the importance of contractual terms, such as those for local content, within their domestic oil and gas industries.

Upstream investment and long-term productive capacity

The Arab Spring uprisings will also have direct implications on the region's investment environment, on the participation of foreign players in the energy sector, and hence on the long-term productive and export capacity of the region. Although many MENA countries have large resource endowments, transforming these endowments into revenue requires high levels of investment and long-term strategic planning, including the attraction of foreign investment and technology into the sector. While MENA countries have grappled with a variety of investment barriers for years, the Arab Spring has clearly reinforced some of the barriers which hold the potential to further affect spending and investment priorities across different MENA oil and gas producers; this includes those MENA producers that have remained unaffected by direct political protest. Most of these priorities are likely to influence decisions as to whether existing petroleum laws and fiscal regimes provide the necessary incentive for foreign investment into the upstream sector.

Security

Violence and security problems have affected oil and gas production in a number of MENA countries. The risk that poor security undermines long-term investment rates in new upstream capacity is not so much because oil and gas companies are unwilling or unable to operate in dangerous environments, as operations in countries such as Iraq and Nigeria show. However, security concerns introduce additional costs and risks that reduce the attractiveness of investment opportunities, particularly where existing fiscal terms offered to investors are already poor. Security risks across North Africa have fundamentally increased over the last three years. The highest profile incident was the January 2013 attack on Algeria’s In Amenas gas plant, which threw the country’s reputation for secure oil and gas operations into question. Perhaps Libya faces the most serious situation, as the government is unable to maintain security at oil and gas facilities; this has led to many international companies suspending plans to resume exploration, or even considering abandoning operations in Libya.

In Iraq, more than ten years after the removal of the Saddam regime by US forces, a persistently difficult security environment necessitates costly security arrangements. As a consequence of the intense violence of the decade since the 2003 US invasion, Iraq's energy sector has developed a high level of security, particularly in the protection of foreign workers. However, recent pipeline bombings and the killing of foreign contractors in mid-December 2013 show the sector is not entirely immune to the rising tide of violence. Security challenges are most serious for projects in the centre and north of Iraq. The Angolan firm Sonangol has decided to exit Iraq after several attacks on its fields in the northern Nineveh province. In Yemen, too, militant activity remains a major problem, one that moved back into public view at the height of the Arab Spring and the resignation of Ali Abdallah Saleh's forty-year regime. Al-Qaeda splinter groups are believed to have sought refuge in both Yemen and Saharan Africa, adding international terrorism to the list of possible threats to emanate from the region.

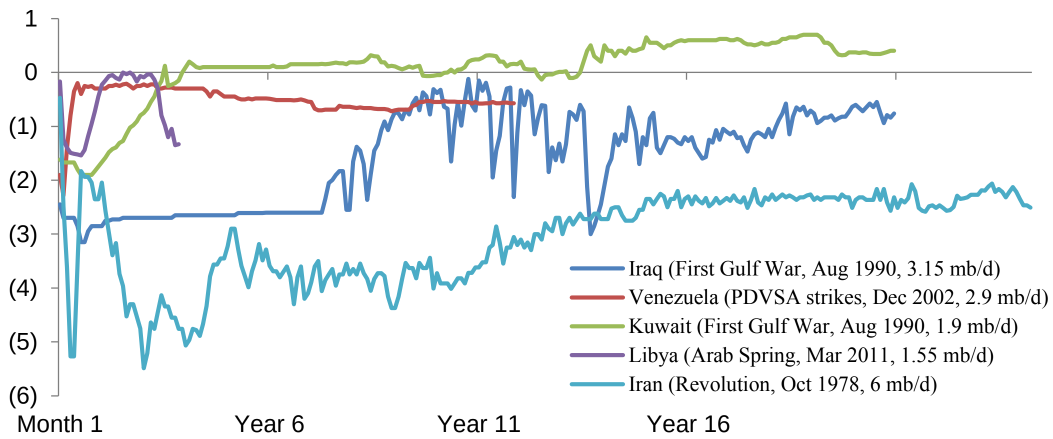
If levels of violence and political instability in the Middle East and North Africa remain high and the disruptions to regional oil and gas production continue, this will also increasingly colour how companies perceive both individual countries, and the region as a whole. Far from improving in the wake of the Arab Spring uprisings, security appears to be worsening in many countries across the MENA. The overthrow of long-serving regimes has resulted in power struggles that in many cases are violent in nature. Militant Islamist groups have also become more active across the region because many of the state security institutions that had previously sought to suppress them have been swept aside. It can often be a slow process to establish new military and police forces to counter these numerous security challenges, as we are seeing in Libya, Yemen, and elsewhere in the region. Foreign companies rely on state forces for the security of oil and gas facilities, in addition to their own security arrangements. When government forces are not up to the task, the consequences can be tragic. For these reasons the current lack of security has become a major impediment to upstream investment.

Political instability and policy uncertainty

Political uncertainty weighs on investment decisions, with repercussions for a country's oil and gas production lasting far beyond the actual time period of political turmoil. Given the large financial commitments and long timelines for upstream projects, political stability is important to companies that want to secure benefits from their investments. At one level, political transitions make bureaucratic delays almost inevitable, especially in a region where stable governments seldom move quickly. A more serious issue is whether political upheavals jeopardize entire projects. This sort of environment tends to reinforce companies' desire for shorter-term projects with faster payback times that are often in conflict with resource holders' visions for their own development. Political instability in several countries in a region can also impact perceptions about the level of political risk, and overall investment attractiveness, of the wider region itself, as recent APICORP research has shown in relation to the Arab Spring. Hence, even where physical security is less of a concern, the political turbulence caused by the Arab Spring has directly impacted the MENA investment outlook.

Historical experience shows that political instability following major political transitions can affect the long-term productive capacity of a country, reducing its future supply potential. The Iranian and Libyan revolution and the Venezuelan unrest, and the lack of security that followed each episode prevented these countries from undertaking the necessary investment in their oil sectors for many years (see Figure 68). Indeed, in contrast to physical damage to infrastructure, which can be repaired, political instability (due mainly to a lack of political consensus and weak institutional framework) reduces the effectiveness of government in a number of areas: implementing its policies; making changes to the regulatory framework, which affects the organization of the oil sector and government's relations with foreign companies; and in transforming attitudes relating to foreign involvement in the oil sector. Several years of political turmoil, transitional governance, severe disruptions to physical investment, and the revision of investment terms will undoubtedly affect MENA producers over the longer term, even as stability may eventually be restored. North Africa, which alongside Syria has been hit hardest, and most directly by the Arab Spring's sweeping political change, is at the forefront of the current concerns. While Libya was able to return to close to its pre-disruption levels of output of 1.6 million b/d fairly quickly, to the surprise of most market analysts, the fragile political context and lack of credible institutions have prevented the country from maintaining or exceeding these levels (see Figure 68).

Figure 67: Pace of production recovery after major disruption, million b/d



Source: Author's analysis based on OPEC supply estimates

The succession of unstable governments in Egypt since 2011 have caused similar headaches for international companies operating in Egypt's oil and gas sector, in terms of both whether the payment terms of existing concessions are honoured, and in the award of new concessions – some licences were indicatively awarded in 2009 and 2010 but were held up until 2013 because no parliament had been able to approve them. Payment delays, uncertainty over fiscal terms, and delays in consultation processes have already led to the deterioration of Egypt's domestic energy supply situation. There are signs that the current military-backed Egyptian government is trying to address these delays and tackle the issues of overdue payments to foreign companies. However, the elections promised for later this year are likely to again be contentious and so the political outlook for Egypt remains uncertain. Relatedly, the sweeping political success of Islamist political parties in countries such as Egypt and Tunisia, and of clearly religiously positioned government figures inside Libya’s new government, holds additional reason for uncertainty; for it is not yet clear what policy orientation these entirely new political streams will hold vis-à-vis investment codes and foreign company participation in their national energy sectors over the coming years. Syria’s hydrocarbon sector, too, is likely to remain affected by the current political crisis for the foreseeable future, as a result of international sanctions, the virtual shut-down in domestic oil production, and the exit of foreign oil and gas companies from the country.

Paralleling the Arab Spring-induced political uncertainties, two other large MENA oil (and in the Iranian case, gas) producers have suffered from political and investment uncertainty, Iran and Iraq. The Iraqi case has shown that even after stabilizing the security situation to some extent from 2008 to this year, factors such as bureaucratic hurdles, lack of government cohesion, and weak government capacity have all made it difficult to implement the infrastructure projects needed to expand oil productive capacity at a rapid pace, and actual production has consistently lagged projections. Western sanctions against Iran, Libya, Iraq, and Sudan also limited the access these countries had to technology and foreign capital, hindering their plans for capacity expansion. This remains the situation in Iran, where the role of western companies in upstream projects has been restricted for several decades and almost non-existent in recent years. Sanctions have two effects on oil supplies. First, they usually result in supply losses because they impact the ability of the embargoed country to produce and export oil. Second, they affect the long-term productive capacity by hindering foreign investment and technology transfer, slowing efforts to restore production capacity to pre-disruption levels.

Issues of revenue distribution

It would be difficult enough if MENA governments only needed to develop upstream investment strategies, but this must find its place among a wide range of tasks – particularly challenging in the wake of the events of recent years. A particularly contentious issue in many countries has been the allocation and distribution of oil and gas revenues. In Iraq, disputes between the central government and the Kurdistan Regional Government (KRG) over the distribution of oil revenues, and over which authority has the ultimate power to sign oil contracts with foreign energy firms, have had a profound impact on investment, the nature of the players involved in the various parts of the country, and potential export routes. In Libya, demands relating to the distribution of oil revenues are central to the current disruptions, particularly in the east of the country. The protestors controlling the major ports in the east justify their claims by highlighting the fact that two-thirds of oil reserves and production are in the eastern region and thus revenue sharing along with a more regional political settlement should be written into the new Libyan constitution.

Social spending and fiscal terms

With governments across the region expanding their medium- to long-term public expenditure through increased public sector wages and social transfers, in the hope that this will quell popular agitation, it is likely that they will seek greater revenues from the oil and gas sector in order to meet these commitments. It is worth briefly recalling the driving forces behind the Arab Spring. Although each country had its own dynamics, the uprisings were generally youth-led and mostly secular. Many of the triggers were economic, from high levels of youth unemployment and rising living costs to perceived economic mismanagement, including widespread corruption among the ruling elite. Some argue that in Yemen, capital-intensive investments in the oil and gas sector that yielded few local jobs and mainly seemed to benefit a small elite, were key contributors to the crisis of political legitimacy that led to the 2011 popular uprising. A similar pattern can be seen in many other oil- and gas-rich MENA countries.

One theme already manifesting itself is a questioning of the fiscal terms that should be offered in oil and gas licensing rounds. International companies are lobbying for more competitive terms, arguing that the costs of exploration and production have risen, particularly given the additional security costs. There is also more caution among the new political elites that are now well aware of the power of the public. The spectre of resource nationalism, as it has been known in the region during the 1960s and 1970s, will of course take a decisively different character today. Rather than leading to calls for the nationalization of their domestic oil and gas industries (much of which has been achieved in previous decades) this drive to maximize the rent in order to increase its distribution, together with closer public scrutiny of signed deals, could reduce the ability of governments to offer more fiscal incentives for foreign investors, thus potentially limiting their involvement in upstream development.

The overall business environment

In addition to access to the upstream resources, production capacity depends on whether countries offer an attractive business environment, particularly in relation to the fiscal terms for production contracts. One of the direct impacts of the Arab Spring has been a deterioration of the general business environment in many of the countries involved. The ousted authoritarian regimes were widely seen as presiding over corruption and excessive state bureaucracies, but what was less well-recognized was the extent of the institutional weakness beneath the security apparatus. Thus, any hopes that the Arab Spring uprisings would quickly yield economic liberalization and an improved business environment, have so far proven false. A 2013/14 APICORP Delphi survey assesses the extent of an ‘enabling environment for business’ as underpinned by oil, gas, and energy policies and the domestic financial environment. The survey concludes that energy-relevant business factors were widely perceived to have worsened significantly over the past year in Syria, Sudan, Libya, and Yemen; whereas greatly enhanced business frameworks were found in the UAE, Saudi Arabia, and Qatar, with generally more positive results for the GCC countries than anywhere else in the region (Table 6).

Table 6: APICORP's Enabling Environment Delphi Survey Results

	UAE	Saudi Arabia	Qatar	Oman	Kuwait	Bahrain	Tunisia	Iran	Algeria	Egypt	Morocco	Jordan	Lebanon	Iraq	Yemen	Mauritania	Libya	Sudan (N&S)	Syria
	10.0	9.8	9.2	9.0	8.7	8.5	7.0	6.2	6.2	6.2	6.2	6.1	5.9	5.1	4.3	4.1	3.5	3.5	3.2
Hydrocarbon and Energy policies	7.7	7.3	6.8	7.0	5.9	6.1	5.7	5.4	5.3	5.2	5.1	5.0	3.1	4.5	4.0	3.2	3.1	3.0	2.5
Institutional, legal and fiscal framework	7.4	6.9	6.7	6.6	6.5	6.2	5.4	5.2	4.6	4.6	4.2	4.1	4.2	3.9	3.4	3.5	2.8	2.6	2.6
Financial structure and environment	7.8	8.2	7.6	6.9	7.4	7.0	4.8	3.6	4.3	4.3	4.9	4.8	6.2	3.2	2.3	2.7	2.2	2.3	2.1

Source: APICORP Research, assessed through a Delphi survey in December 2013.

VI. Energy Challenges Facing the Arab World[5]

There are wide uncertainties surrounding the oil and gas market in the next two decades. Given the heavy dependency of the Arab world on oil and gas revenues, either directly or indirectly, implies that these uncertainties will have direct impact on political, economic and social developments in the region. The challenges facing the Arab world are various. In what follows, we focus on few of the challenges related to the energy sector.

Investment in Arab World

Oil and gas revenues will continue to play an important role in shaping the development path of Arab economies, at least into the foreseeable future. Thus, maintaining a well-functioning oil and gas sector and expanding oil and gas output capacity is of key importance to the region's economic, social, and political stability. At first sight, fiscal linkages may appear as a one-way flow of revenues from the oil sector to the state. But the ability of the petroleum sector to generate revenues needed by the government also depends on the ownership structure, the incentives faced by the energy sector, pricing issues, and most importantly the mechanisms available to channel part of the revenues back to the energy sector.

Until the early 2000s, investment in the energy sector of the Arab world was stagnant (with some notable exceptions such as Qatar which embarked on a massive investment programme to develop its gas reserves, and Algeria which revised its legal framework and fiscal terms to attract foreign investment). The large spare capacity and the oil price decline in the 1980s and most of the 1990s threw the energy industry into deep recession, reduced the attractiveness of existing investment plans, and adversely affected the incentive to invest. This was accompanied by widespread oil demand pessimism and exaggerated expectations of non-OPEC supply, reducing the incentive for Arab producers to invest in their

[5] This section is based on Fattouh, B. and L. El-Katiri (2012), 'Energy and Arab Economic Development'. United Nations Development Programme; and Fattouh, B. and L. El-Katiri (2011), 'Energy Subsidies in the Arab World', United Nations Development Programme.

energy sectors.

Geopolitics has also prevented capacity expansion in many Arab countries. For example, the Iran–Iraq war, the Iraqi invasion of Kuwait, the US invasion of Iraq and the lack of security and instability that followed has prevented these countries from undertaking the necessary investment in their oil sectors. Sanctions against Libya, Iraq, and Sudan limited the access to technology and foreign capital, and hindered capacity expansion.

In countries such as Kuwait and small producers such as Yemen and Syria, the relationship between the owner of the natural resource (the government) and the national oil company that extracts the resource is highly inefficient, yielding low rates of investment. In many countries in the region, the national oil company does not determine its capital budget, and the decision on how much funding to divert into the oil sector is usually determined subject to general government budgetary requirements. As a result, the capital budget for national oil companies is often quite tight, preventing them from either undertaking new projects or upgrading human capital and technological capabilities. Consequently, NOCs in the Arab world are not of uniform quality, and while some are relatively well managed and score highly on commercial performance, human resources, and technology, others perform very poorly and have to rely heavily on foreign companies for exploration and development of oil and gas reserves.

Since many countries will have to rely on foreign oil companies if they are to expand capacity, the relationship between governments and/or national oil companies and international oil companies becomes a key determinant of investment. Many consider that restricting access to reserves is an important barrier to investment in the region. However, access is effectively restricted only in Saudi Arabia and Kuwait, and then only in the upstream sector. All other Arab countries allow some form of foreign involvement in the upstream sector. What is more important than access is the nature of the relationship between the parties and the attractiveness of the business environment and the fiscal terms.

There is also wide uncertainty facing Arab producers regarding the long-term demand on their oil. As suggested in the literature regarding irreversible investment under uncertainty, the large investment outlays in oil projects and the irreversible nature of these investments have the effect of increasing the value of the option to wait. There is thus a case for delaying the investment until new information emerges about market conditions, especially information about expected global demand and oil supplies from other countries. One key area of uncertainty is the impact on long-term demand of oil substitution polices in consuming countries driven by energy security and climate change concerns. While the impact of such policies is small in the short-term, the effects on long-term oil demand are cumulative and irreversible, and hence can be large. Another key uncertainty is the potential of tight oil growth and the diffusion of technology to the rest of the world.

The above discussion suggests that the determinants of investment in the energy sector are various and interrelated: some are driven by local factors and others by international market dynamics. Consequently, the flow of investment in the energy sector is expected to vary considerably across the region, with some countries failing to modernize their oil and gas sectors. As to the international dimension, while in recent years some Arab countries have managed to invest heavily in their energy sector and expand output capacity (most notably Saudi Arabia, which increased its oil capacity to 12.5 million b/d in 2009), whether the region will meet most of the surge in expected growth in global demand should not be taken for granted. First, there is the issue of willingness: Are key Arab producers willing to increase capacity in the current environment of high uncertainty? Second, there is the issue of capability: Can Arab producers increase their capacity in the current political and economic context? In this respect, countries with more competent NOCs, a stable legal framework, attractive fiscal terms, and a clear and effective fiscal system which allows revenues to be channelled back into the sector, are better equipped to undertake the necessary expansion.

The Diversification Challenge

Levels of economic diversification differ significantly across the Arab world. The region’s most diverse economies – Morocco, Tunisia, Lebanon, and Jordan – are all net importers of oil and natural gas. In the absence of dominant hydrocarbon industries and a revenue base established on extractive industries, these economies have had to develop a range of long-term productive industries to sustain their development process. In contrast, the economies of many Arab oil and gas producers are still considerably less diversified, with a higher rate of economic reliance on the oil and gas sector as the single most important productive factor in the economy. The six GCC economies, together with Libya and Iraq, generally remain some of the Arab world’s least diversified economies, with the highest degree of economic dependence on the hydrocarbon sector for the generation of economic output, export, and government revenues.

A number of different explanations exist for the dominance of the oil and gas industry in many Arab oil and gas producers’ economies. Some have argued that the main reason for lack of diversification is the emergence of vertically integrated state-owned companies promoted by state sector-specific policies and the persistence of old-style industrial policies. Despite serious strains on the economic development model in many Arab resource-rich economies, the flow of oil revenues often reduces the pressure for change. The core of the argument is contained in the debate surrounding many regional oil and gas producers’ strategies of diversification into energy-intensive industries such as refining and petrochemicals production. While seen by producers as a strategy of raising the value-added of their exports, and of diversifying away from crude exports, many critics of this policy suggest such forward linkages reinforce rather than mitigate energy producers’ dependence on energy. Furthermore, several of the smaller Gulf oil producers have begun industrialization at a much later stage than many of their neighbouring countries, typically following costly state-coordinated industrialization strategies, a position which, in the eyes of many development economists, renders these countries less likely to change their industrial strategies once they are in place, even if the economic outcome is below the optimum level. Finally, varying levels of resource endowments beyond oil and natural gas – including the size of the economy, the availability of a skilled workforce, a history of established local manufacturing sectors, or the availability of arable land – have been put forward as factors putting a strain on economic diversification in some Arab hydrocarbon producers.

Significant variations exist between individual Arab oil and gas producers. Among the GCC states, Bahrain and the UAE have diversified their economies to a larger extent than have their more oil-rich neighbours Kuwait and Saudi Arabia, due primarily to the need for Bahrain and UAE to build up alternative industries in view of a decreasing resource base in Bahrain and lack of oil and gas resources in the UAE emirates other than Abu Dhabi. Smaller oil and gas producers, especially Egypt and Syria, have maintained a far smaller role for their hydrocarbon industries in terms of their contribution to both export revenues and gross economic output, with other strong and long-established key sectors. Conversely, years of international economic sanctions, as applied to Iraq and Libya, have left their mark on these economies' levels of industrial diversification, leaving both states more dependent on oil and natural gas exports than any of their Arab Gulf neighbours.

Low levels of economic diversification amongst the Arab world's oil and gas producers raise a number of different long-term policy challenges. A high rate of dependence on oil and gas revenues reinforces patterns of volatile government revenues, whose level and stability remains outside producing countries' control. High levels of economic dependence on the oil and gas sector also reinforce established patterns of long-term dependence on export revenues. Furthermore, over the past decade rising levels of government expenditure in a number of Arab oil and gas producers have raised the fiscal break-even price for crude oil which is needed to sustain balanced budgets. There is thus the threat of long-term budget deficits as a consequence of lower-than-needed hydrocarbon export receipts resulting from falling oil prices.

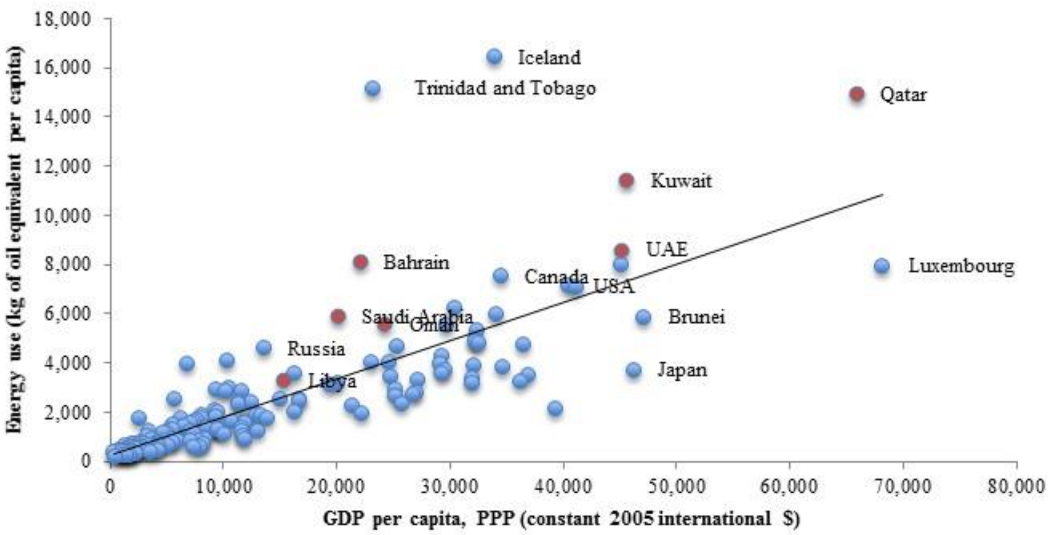
Moreover, high levels of oil and gas sector dependence in Arab producing economies do little to help the region deal with its looming unemployment challenge, the gravity of which has been felt across the entire Arab region – not least since the beginning of the Arab uprisings since late 2010. In the GCC, the oil and gas sector contributes nearly half of GDP, but employs less than 5 per cent of the workforce. A large part of the remaining workforce in many Arab oil and gas producing countries is employed by the public sector – known in many cases to be overstaffed, and hence losing out on factor productivity.

Other economies with a high inflow of natural resource rents, such as Canada and Norway, have begun to invest in pensions and sovereign wealth funds earlier in their histories, which has helped to manage governmental revenue fluctuations and to secure resource export revenues for future generations. Several Arab oil and gas exporters have similarly embarked on the creation of national investment funds which save current oil and gas receipts or invest them in productive assets in other parts of the world: Kuwait, Abu Dhabi, and Qatar being some of the most prominent examples. The share allocated to many of these funds remains small in comparison to the sums these economies allocate to general government expenditure on an annual basis; and despite their importance for the region's future economic macro-management, sovereign wealth funds do not generate employment opportunities within their investing countries. In-country economic diversification will hence remain an important long-term challenge in several Arab oil and gas exporters.

Energy Sustainability

The Arab world's rapidly rising energy consumption raises the question of how sustainable their energy consumption patterns are. This issue not only highlights the region's past demand growth history, but also its development into a major growth market for energy in the coming decades, if demand continues to grow at the past decade's pace. Continuing population growth and rising living standards in many Arab economies are likely to set a trend of rising per capita energy consumption, as has been experienced in many parts of the developing world. This situation has already become particularly urgent in the Arab Gulf economies – the GCC states and, to a lesser extent up to now, conflict-torn Iraq. The GCC members' stellar economic growth and a dedicated focus on energy-intensive industrialization, coupled with low domestic energy prices, imply that the GCC states are among the most energy-intensive economies in the world. Per capita primary energy consumption in the GCC states today is among the highest in the world (plotted against per capita GDP levels in Figure 70), well above the average for the OECD and other industrialized economies. This development stands in marked contrast to a mere forty years ago, when Middle East per capita consumption was less than half that of OECD countries.

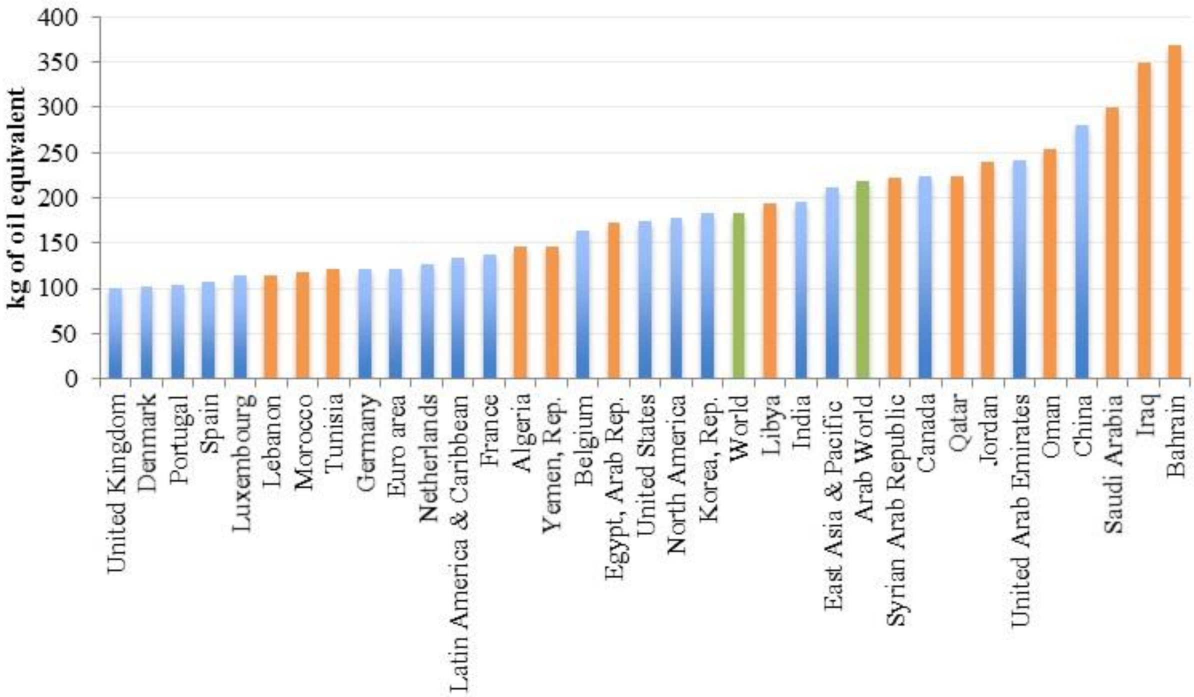
Figure 68: Energy Intensity in the World, 2009



Source: World Bank

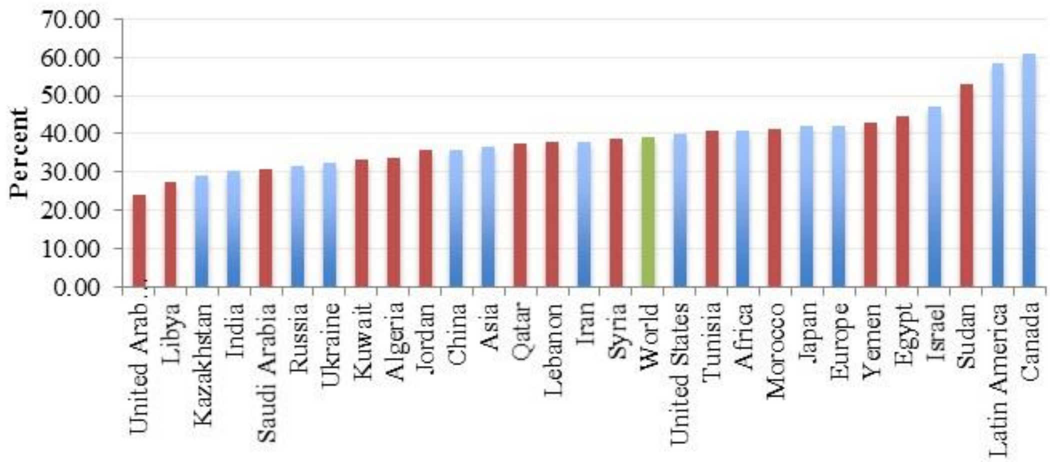
Low-cost energy has particularly reinforced a region-wide reliance on energy as an integral part of GDP. In contrast with most other parts of the world, the energy intensity of many Arab economies has been rising consistently over past decades and stands now, like per capita energy consumption, at levels which are among the highest in the world. The GCC economies, together with the more diversified economies such as Jordan and Syria, require more than twice as much energy per unit of GDP output than the more energy-efficient economies of central Europe. They are also more energy intensive than other Arab economies such as Lebanon, Morocco, and Tunisia (see Figure 71). Diversification strategies into energy-intensive industries such as steel, aluminium, and petrochemicals production have reinforced these patterns. At the same time, energy efficiency levels are low, particularly in those economies most reliant on energy as an industrial input, primarily because of the decades-long perception of energy as a low-cost input factor (compare with Figure 72).

Figure 69: Energy Use (kg of oil equivalent) per $1,000 GDP (constant 2005 PPP) in selected economies, 2008



Source: World Bank

Figure 70: Energy Efficiency in Power Generation in Selected Economies (%), 2009



Source: ABB

For many Arab net energy importers (or small net exporters such as Egypt, Syria, and Jordan) a chief question in the future will be whether or not they can afford to continue to waste increasingly scarce, and increasingly precious, energy resources. Over the past ten years, import options for both oil and natural gas have become more expensive. In several smaller Arab economies, the cost of current levels of energy consumption, often at highly subsidized prices, has become an insurmountable fiscal burden, with the result that some have attempted careful reform of their domestic regulatory and pricing framework.

For the large Arab oil and gas producers, the most immediate question is not one of immediate lack of energy reserves, for many of the region's crude oil producers continue to leverage on their production to compensate for shortfalls in natural gas. Burning crude oil in summer to overcome shortages in domestic supplies of natural gas in some Gulf countries has become the norm. This generates vast losses in foregone export revenues, in contrast with the comparably benign cost option of importing natural gas. The question is rather whether or not many of these producers can, and want to, continue consuming rising shares of their own depletable energy resources at the cost of exports – and hence export revenues. From a fiscal point of view, what is at stake for large oil and gas exporters is their ability to collect export revenues, which have kept and will continue to keep these economies running for as long as few alternative industries have been developed.

As yet unachieved remains both the diversification of the Arab world's energy base – an objective which is important for security reasons as much as for economic reasons – and the oft-quoted desire for access to technology. The majority of Arab primary energy demand up to now has been met by the region's two chief energy resources, crude oil and petroleum products on the one hand, and natural gas on the other. Combined, these resources account for over 98 per cent of regional energy consumption. Tentative moves towards including renewable energy on Arab governments' agendas have been pushed forward by only a few Arab countries, namely Morocco, Algeria, and Tunisia under the European-led Desertec initiative, and in more limited form by some of the Gulf States, which have pledged and begun tentative renewables initiatives themselves. Nuclear power is also likely to form a part of the region's energy base within the next ten years, although only marginally, with UAE having the most advanced nuclear plans at present; but along with this technology come a number of unanswered questions and caveats which are likely to plague the region for years to come, including the unclear financial cost and likely repercussions for national security.

Domestic Energy Pricing Reform

Domestic energy prices remain a vexed question in many parts of the Arab world. Energy prices throughout the region – including those for oil and oil products, natural gas, and electricity – have for many decades been among the lowest in the world. Energy subsidies are in many cases policies that follow very legitimate government objectives; in many developing countries, subsidies reduce the cost of essential forms of energy to ensure universal access to energy. Particularly in large countries with poor populations and little state capacity to administer and direct a targeted social protection system, broadly targeted energy subsidies may indeed prove a practical step to alleviate poverty and protect poor households' income. Fixed government-administered prices for some fuels and electricity also protect households against large energy price – and hence disposable income – fluctuations.

Furthermore, in many large hydrocarbon-producing economies, low energy prices are often not conceived of as being part of a subsidy; the marked reference price for domestic pricing here is often the marginal cost of production – for instance of crude oil – rather than the achievable export price for the barrel of crude on international markets. The resulting opportunity cost is often not seen as a direct form of subsidy, while the state incurs a quasi-fiscal loss, which remains invisible in fiscal terms. Low energy prices in these countries are frequently also regarded as a birth right by citizens who have been used to static prices, often for more than a generation.

The various, unintended, consequences of energy subsidies and low energy pricing are visible throughout the Arab world, both in energy producing and importing economies. Energy subsidies distort market signals and lead to an inefficient allocation of depletable resources. They encourage waste and an overconsumption of energy, and disincentivize investment in energy-saving technology and behaviour, as well as in alternative energies such as renewables which are unable to compete with highly subsidized fossil fuels. Energy subsidies are key contributing factors to many of the region’s consumption patterns observed above, including fast growth in consumption of various fuels and electricity, high energy intensity and the reliance on energy-intensive industries rather than alternative industries, and low levels of efficiency in the use of electricity.

Where energy subsidies are poorly implemented and do not allow energy producers to recover the full cost of production, they may also defer necessary investment in the energy sector, and hence exacerbate existing or expected capacity shortcomings. The Arab world’s electricity sector is an important case in point. In many cases, decades of subsidized electricity have left their mark on public utility companies’ access to capital for investment in new capacity and infrastructure. This has resulted in poor service and frequent service disruptions, due to both insufficient generation capacity and aging infrastructure. Lebanon, Iraq and many of the GCC countries experience regular power shortages during peak hours in summer, with devastating consequences for businesses and industry. Yemen's electricity situation is possibly the most precarious one in the entire Arab world; the country allocated more than a third of its budget on fuel subsidies, but a mere half of the population has access to some form of electricity, and two thirds of the country are not connected to national or local electricity grids. Subsidy policies which do not adequately compensate producers may also lead to recurring fuel shortages, as was most recently (in 2011) observed in the UAE – paradoxically so since the country is one of the world's most important crude oil producers. Additionally, many of these losses are further exacerbated by region-wide, and highly damaging, cross-border fuel smuggling, which is incentivized by price differences between neighbouring countries.

Furthermore, contrary to their original objective, energy subsidies tend to be socially regressive, that is they benefit primarily high-income groups. This effect has been shown by various research studies, suggesting that energy subsidies are at best an inefficient way to alleviate poverty, and are at worst counterproductive, for they consume government funds which would otherwise be available for targeted social benefit schemes. Moreover, the Arab world's largest subsidizers are economies with some of the highest per capita incomes in the world, suggesting that the bulk of the region's energy subsidies benefits populations in comparatively wealthy economies, rather than countries which have significant proportions of poor people.

Perhaps the most acutely visible consequence of energy subsidies in the Arab world is the budgetary burden they cause in some of the region's energy importing countries. Egypt's official energy subsidy bill rose from E£40 billion (US$7.2 billion) in 2005/6 to E£68 billion (US$11.9 billion) in 2009/10, some 21 per cent of the country's budget and equalling Egypt's expected budget deficit for the fiscal year. A recent calculation by the African Development Bank suggests that Egypt's actual costs incurred by direct and indirect energy subsidies are substantially higher, with a total estimate of E£140 billion ($23 billion) – equivalent to 11.9 per cent of GDP. Yemen's budgeted expenditure on fuel subsidies (excluding electricity subsidies, which are budgeted separately) in 2008, the last year with data available, amounted to more than 34 per cent of total government expenditure – more than one and a half times its expenditure on education and health combined.

In many Arab energy importing countries the fiscal burden of energy subsidies has, over the past years, become increasingly unsustainable, rendering reform a necessity rather than a choice. International experience illustrates a potential scheme whereby the reform of domestic energy prices can be made politically more acceptable – by coupling price rises to a parallel compensatory cash scheme which hands out fiscal savings to households instead of energy subsidies. Similar schemes, which may include an element of coupled social security system reform (as in Jordan) and more gradual price rising schemes, may also allow governments in energy importing countries to reform their energy prices in a socially acceptable way.

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